IIASA COLLABORATIVE PROCEEDINGS SERIES

CP-83-S4

CONVENTIONAL AND UNCONVENTIONAL WORLD NATURAL GAS RESOURCES

IIASA COLLABORATIVE PROCEEDINGS SERIES

CP–81–S1	LARGE-SCALE LINEAR PROGRAMMING Proceedings of an IIASA Workshop G.B. Dantzig, M.A.H. Dempster, and M.J. Kallio, *Editors*
CP–81–S2	THE SHINKANSEN PROGRAM: TRANSPORTATION, RAILWAY, ENVIRONMENTAL, REGIONAL, AND NATIONAL DEVELOPMENT ISSUES A. Straszak, *Editor*
CP–82–S1	HUMAN SETTLEMENT SYSTEMS: SPATIAL PATTERNS AND TRENDS Selected Papers from an IIASA Conference T. Kawashima and P. Korcelli, *Editors*
CP–82–S2	RISK: A SEMINAR SERIES H. Kunreuther, *Editor*
CP–82–S3	THE OPERATION OF MULTIPLE RESERVOIR SYSTEMS Proceedings of an International Workshop, Jodłowy Dwor, Poland Z. Kaczmarek and J. Kindler, *Editors*
CP–82–S4	NONPOINT NITRATE POLLUTION OF MUNICIPAL WATER SUPPLY SOURCES: ISSUES OF ANALYSIS AND CONTROL Proceedings of an IIASA Task Force Meeting K.-H. Zwirnmann, *Editor*
CP–82–S5	MODELING AGRICULTURAL–ENVIRONMENTAL PROCESSES IN CROP PRODUCTION Proceedings of an IIASA Task Force Meeting G. Golubev and I. Shvytov, *Editors*
CP–82–S6	LIQUEFIED ENERGY GASES FACILITY SITING: INTERNATIONAL COMPARISONS H. Kunreuther, J. Linnerooth, and R. Starnes, *Editors*
CP–82–S7	ENVIRONMENTAL ASPECTS IN GLOBAL MODELING Proceedings of the 7th IIASA Symposium on Global Modeling G. Bruckmann, *Editor*
CP–82–S8	PROGRESS IN NONDIFFERENTIABLE OPTIMIZATION E.A. Nurminski, *Editor*
CP–82–S9	INNOVATION POLICY AND COMPANY STRATEGY H. Meier and J. Robinson, *Editors*
CP–82–S10	THE KINKI INTEGRATED REGIONAL DEVELOPMENT PROGRAM Y. Sawaragi and A. Straszak, *Editors*
CP–82–S11	EUROPEAN AND UNITED STATES CASE STUDIES IN APPLICATION OF THE CREAMS MODEL V. Svetlosanov and W.G. Knisel, *Editors*
CP–82–S12	MULTIOBJECTIVE AND STOCHASTIC OPTIMIZATION Proceedings of an IIASA Task Force Meeting M. Grauer, A. Lewandowski, and A.P. Wierzbicki, *Editors*
CP–83–S1	ENVIRONMENTAL MANAGEMENT OF AGRICULTURAL WATERSHEDS A Selection of Papers Presented at a Conference held in Smolenice, CSSR G. Golubev, *Editor*
CP–83–S2	INPUT–OUTPUT MODELING Proceedings of the Third IIASA Task Force Meeting M. Grassini and A. Smyshlyaev, *Editors*
CP–83–S3	EUTROPHICATION OF SHALLOW LAKES: MODELING AND MANAGEMENT. THE LAKE BALATON CASE STUDY Proceedings of an International Workshop L. Somlyódy, S. Herodek, and J. Fischer, *Editors*
CP–83–S4	CONVENTIONAL AND UNCONVENTIONAL WORLD NATURAL GAS RESOURCES Proceedings of the Fifth IIASA Conference on Energy Resources C. Delahaye and M. Grenon, *Editors*

CONVENTIONAL AND UNCONVENTIONAL WORLD NATURAL GAS RESOURCES

PROCEEDINGS OF THE FIFTH IIASA CONFERENCE
ON ENERGY RESOURCES
June 1980

Christian Delahaye and Michel Grenon, Editors

INTERNATIONAL INSTITUTE FOR APPLIED SYSTEMS ANALYSIS
Laxenburg, Austria
1983

International Standard Book Number 3-7045-0070-4

Volumes in the *IIASA Collaborative Proceedings Series* contain papers offered at IIASA professional meetings, and are produced with a minimum of editing and review.

The views or opinions expressed in this volume do not necessarily represent those of the Institute or the National Member Organizations that support it.

PREFACE

The problem of energy supply is one of the most serious facing mankind today. The demand for energy continues to increase against a background of rapidly diminishing fossil fuel reserves. It is clear not only that the search for conventional fuels should be intensified, but also that new sources of energy should be identified and exploited, and that new technologies should be developed and implemented. Any future policy on energy supply should contain elements of both the conventional and the unconventional; it should be based on estimates of the relative availability and abundance of the various sources of energy, and on consideration of the political, economic, and environmental implications of different energy strategies.

The International Institute for Applied Systems Analysis (IIASA) has been deeply involved in the study of energy systems over the past decade. The Energy Systems Program, led by Professor Wolf Häfele, was established to analyze the global aspects of the energy supply problem*, and, in collaboration with another group led by Professor Michel Grenon, was responsible for organizing annual conferences on world energy resources**.

The conferences were initially introduced to provide researchers working at IIASA and elsewhere with a more complete picture of the level and distribution of energy resources throughout the world. Work at IIASA has shown that information on petroleum reserves (oil and gas) is particularly difficult to obtain; this constitutes a major deficiency in the data base because of the great and continuing importance of these fuels in models of future energy supply. The few figures given in the scientific literature are not generally supported by details of the assumptions made and methods used in obtaining them--it is impossible to compare or check data provided in this form. Moreover, most of the estimates are given only at the global or continental level, and this aggregated data is very difficult to incorporate in some of the models developed at IIASA.

The series of annual IIASA conferences brought together scientists from East and West to discuss mutual problems arising from the estimation and exploitation of energy resources. The work presented at the conferences has gone some way toward filling in the blanks in the current state of knowledge about world energy supplies. Previous conferences dealt with topics such as methods and models for assessing energy resources, analyses of the supply of petroleum and coal, and a study of gas in geopressure zones. This book

---

*The work of the Energy Systems Program is summarized in the book *Energy in a Finite World*, by Wolf Häfele, published by Ballinger in 1981.

**Reserves are defined as those deposits that are known to exist and that can be recovered economically; resources include deposits that have not yet been discovered or that are not currently economically viable.

contains the proceedings of the fifth IIASA conference on energy resources, which was concerned with conventional and unconventional sources of natural gas.

Gas is becoming increasingly important in the world energy picture. The main aims of the conference were to consolidate existing knowledge about the geological formations associated with this resource, to compare and discuss the various estimates of the amount of natural gas remaining to be found, and to evaluate the prospects for its continued use as an economic energy source. The relationship between conventional and unconventional sources of natural gas, and the economic, political, and technological constraints facing development of this resource provoked much discussion. Although syngas lay outside the main scope of this conference, two papers on this subject were accepted and presented to illustrate the relationship between syngas (derived from biomass and coal) and conventional and unconventional sources of natural gas.

It was originally intended to include here edited transcripts of the discussion sessions, but constraints on the size and cost of the volume unfortunately made this impossible. However, single copies of the transcripts may be obtained on microfiche from the IIASA Publications Department, A-2361 Laxenburg, Austria on request.

The fifth IIASA conference on energy resources was jointly sponsored by IIASA and the Colorado School of Mines; Dr. Harry Kent of the Colorado School of Mines deserves our particular thanks for his interest and support. It is hoped that collaboration between IIASA and other scientific organizations will continue to flourish and that future cooperative ventures will be as successful and as useful to the scientific community as was this conference on world natural gas resources.

Christian Delahaye
Michel Grenon

CONTENTS

Preface v

THE IMPORTANCE OF NATURAL GAS IN WORLD ENERGY SUPPLIES

The Importance of Natural Gas in the World Energy Picture 1
H.R. Linden

The Economic Potential of World Natural Gas Resources 31
A.K. Arsky and T.Ya. Bukhtoyarova

The Role for Natural Gas in the International Energy Agency 39
F.W. Gorbet and A. Hansen

Gas: Its Price and Future Role in the Energy Scene 69
O. Al-Rawi

THE ORIGIN OF NATURAL GAS, AND METHODS AND MODELS FOR ASSESSING GAS RESOURCES

The Deep Earth Gas Hypothesis 75
T. Gold and S. Soter

Methods for Assessing Gas Resources 111
R.L. Whiting

The Geologic Setting of Giant Gas Fields 133
H.D. Klemme

Data Sources Used in the Estimation of World Natural Gas Resources 161
J.D. Parent

A Discovery Model for Petroleum Exploration 171
P.J. Lee

REVIEW OF MAJOR WORLD GAS RESOURCE ESTIMATES

Past World Gas Resource Estimates 179
R.L. Whiting

Assessments of World Natural Gas Resources 201
R.B. Kalisch

World Resources of Conventional Gas 213
M.S. Modelevsky

NATIONAL AND REGIONAL STUDIES OF MAJOR GAS PRODUCERS: HISTORY AND PERSPECTIVES ON NATURAL GAS DEVELOPMENT

Natural Gas Resource Potential of the United States 221
H.C. Kent

Methodology of the US Geological Survey Resource Appraisal Group for Gas Resource Estimates in the United States 237
B.M. Miller

The Development of Models to Study the Natural Gas Deposits of Northwestern Siberia 267
G.N. Kuznetsov, M.V. Sidorenko, and I.N. Zimin

TECHNOLOGICAL AND ECONOMIC ASPECTS OF GAS EXPLORATION, PRODUCTION, TRANSPORTATION, AND CONSUMPTION

The Importance of Deep Drilling to the Natural Gas Supply of Austria 279
A. Kaufmann and A. Kröll

Gas Production from Very Deep Reservoirs 283
M. Lorbach and W. Mohr

The Structure of Natural Gas Supply and Possible Consumption Management 293
R.Th. Kastner

The Impact of Government Policy on Natural Gas Resource Development 299
R.B. Kalisch

Institutional and Economic Constraints on the Utilization of Natural Gas Resources, With Special Reference to Western Europe and Latin America 313
P.R. Odell

GAS IN GEOPRESSURE ZONES: CURRENT STATUS AND FUTURE PROSPECTS

Geopressured Formation Parameters of the Armstrong and Corpus-Christi Fairways, Frio Formation (Oligocene), Central and South Texas 339
M.H. Dorfman

Underground Disposal of Water Produced from Geopressured Zones 353
B.H. Caudle

Reservoir Mechanics of Geopressured-Geothermal Aquifers: Pleasant Bayou Well 361
H. Ohkuma, K. Sepehrnoori, J.T. Lewis, R.M. Knapp, and R.C. MacDonald

The US Department of Energy Program in Geopressured Resources 379
K. Westhusing

Methane Entrained in Geopressured Aquifers, Texas Gulf Coast 391
R.A. Morton

UNCONVENTIONAL GAS

Review of World Resources of Unconventional Gas 409
V.A. Kuuskraa and R.F. Meyers

Possible Gas Reserves in Continental and Marine Deposits, and Prospecting and Development Methods 459
A.A. Trofimuk, N.V. Tchersky, U.F. Makogon, and V.P. Tsariov

Methane in Coal Basins of the USSR 469
M.V. Tolkachev and B.M. Zimakov

Biomass and Biogas--Present and Possible Future 481
D.O. Hall

Development of a Synthetic Gas From Coal Industry in the United States 513
W.T. McCormick, Jr. and P.C. Iribe

Natural Gas Resources in Coal Deposits 535
A.I. Gritsenko, Y.I. Yermakov, and I.P. Zhabrev

THE IMPORTANCE OF NATURAL GAS IN THE WORLD ENERGY PICTURE

Henry R. Linden
Gas Research Institute, Chicago, Illinois, USA

INTRODUCTION

Successful management of the transition from the abundant and underpriced supplies of oil and natural gas which sustained and subsidized the tremendous world economic expansion after World War II, to coal and other less desirable fossil fuels and then to renewable and inexhaustible energy forms based on solar and nuclear energy, is of utmost importance to the survival and eventual strengthening of the existing world order. In this enterprise, too narrow a focus on the technical, environmental, resource and economic issues is likely to lead to growing difficulties. Without due attention to broader humanistic values on regional, national and international scales, management of the transition may fail because the ability of societies to accept radical technology and infrastructure changes is limited.

The severity of the problem caused by the most desirable energy forms becoming increasingly scarce and costly is related to the pivotal position which energy occupies in all matters concerning social and economic progress and mobility and, therefore, social and political stability. In fact, it has been the substitution of inanimate energy forms and associated technologies for human and animal labor beginning with the industrial revolution that has been responsible for the development of a world society increasingly free of slavery, serfdom, child labor and subjugation of women and minorities. Clearly, any regression in the substitution of energy and capital for human labor because of the unavailability or excessive economic or environmental costs of energy could only lead to growing world instability and recurrence of the resource wars so typical of human history.

If we assume that the world's remaining fossil fuel resources -- crude oil, natural gas, coal, and oil shale and other bitumens -- are mutually substitutable by virtue of available synthetic fuel and clean combustion technologies and will be produced and traded freely on equitable terms, we do have substantial lead time before having to make a commitment to either a solar or a nuclear future, or some combination of the two. As will be shown later, the proved reserves of these fossil fuels, plus what is generally believed to be ultimately economically recoverable represent about a 100-year supply of the world's total primary energy needs if demand growth can be kept within reasonable boundaries. This ought to be enough time to put in place energy supply and utilization systems which are no longer dependent on the storehouse of fossil fuels which nature provided over tens and hundreds of millions of years.

While energy has been at the leading edge, it is important to note that a revolutionary change is also underway in the pricing and production policies for all of the world's exhaustible essential resources. This is due to the growing awareness of producers that the fully internalized costs of replacement or substitution of these resources will be much higher than previously assumed on the basis of traditional economic considerations. Thus, we are in a period of price increases far outstripping the general rate of inflation and of widespread measures to manage production rates so as to maximize the economic return of depleting resources to the producers. The best example is, of course, crude oil. Even today it sells at world prices substantially below the replacement cost with synthetic fuels of equivalent form value. Unfortunately, we may be only at the beginning of this radical change in pricing and production policies for depleting resources with little theory and historical precedent to guide us in assessing what the future may hold.

THE PLIGHT OF THE LESS DEVELOPED COUNTRIES

World industrialization, as measured by the usual economic indices that distinguish between the haves and have-nots, is at most only one-third complete. It is this latter problem that adds much to the urgency of the proper management of the energy transition because the less developed countries (LDCs) have also counted on abundant and cheap supplies of hydrocarbon fuels to support their industrialization. Clearly, their hopes have now been dashed, and the political and social reaction to what must be increasingly unfulfilled expectations poses a potentially serious immediate threat to world stability.

Therefore, it is in the interest of the industrialized countries to assist the LDCs in creating energy supply and utilization systems which bypass the problems caused by over-dependence of the existing infrastructure on rapidly depleting, insecure and increasingly costly resources. Rather than follow the model of the industrialized world at a time when it may no longer be valid, it seems more appropriate for LDCs to rely on technologies capable of using local resources to provide essential energy services. What may appear to be uneconomic in highly industrialized areas because of the subsidies imbedded in the existing infrastructure may be highly economical in India, China, Africa and South America.

In contemplating how to feed, clothe and house a world population unlikely to stabilize at a level of much below 10 billion (1 U.S. billion = 1×10^9), it is of great urgency to establish the fundamental feasibility and then the relative merits of the various long-term energy options. We know what the low-technology solar economy was like in the millennia prior to the industrial revolution -- it never provided for even one-tenth as many people, and that in a most inadequate and inequitable manner. I believe we are now in a position to at least theoretically specify the outlines of a high-technology solar economy, one nominally capable of providing the foodstuffs, the fiber, the primary metals and other construction materials, the transport fuels and all the other basic needs of a modern world society of 10 billion or more. The question is this: In a steady-state situation, that is one without subsidies from still under-priced exhaustible resources, does such an economy have a greater value of output of goods and services than the value of the necessary inputs of capital, labor and energy? Clearly, if we discover any fundamental flaws in the high-technology solar option, we would have to look with much greater care at the nuclear fission and fusion options, some of which may suffer from similar net value-added deficiencies. The implications of the possible outcomes of such inquiries are enormous in terms of the future of mankind.

THE ROLE OF NATURAL GAS IN MANAGING THE ENERGY TRANSITION

One critical aspect of managing the transition to inexhaustible or renewable energy resources is how we use our remaining precious hydrocarbon fuel resources. In this regard, the role of natural gas as a transition fuel becomes particularly important because of the substitutability of natural gas for oil in nearly all stationary heat applications. Estimates of the ultimately economically recoverable resources of conventional natural gas and of crude oil are roughly equivalent on a gross heating value basis. However, even though natural gas consumption is now approaching 20 percent of world primary energy consumption, the rate of depletion of the crude oil resources is still roughly two times greater. Thus, increased relative use of gas is clearly a promising option for easing the transition. However, this oversimplifies the relative prospects for oil and gas. As the economic value of hydrocarbon fuels increases in comparison to other goods and services with progressively more realistic assessments of their true replacement cost, the impact of differing supply elasticities and form values may alter the relative roles of these two currently dominant energy sources.

It would seem logical that liquid hydrocarbons will be increasingly preserved for transport fuel uses where their replacement with synthetics derived from coal, oil shale and other bitumens, and biomass materials is relatively more costly than the displacement of fuel oil in stationary applications. More radical changes in the transportation infrastructure, such as electrification of surface transport or use of liquid hydrogen or other high-energy content chemical fuels for air transport, would be even more costly and hampered by capital availability and institutional barriers. Thus, the role of the relatively abundant gaseous fuels during the transition from exhaustible to inexhaustible or renewable energy sources should be increasingly one of substitution for stationary uses of liquid fuels where direct combustion of coal or the use of coal- or nuclear-based electricity is not practical for technical, environmental or economic reasons. However, this reassessment of the relative form values of liquid and gaseous hydrocarbons also means that the current trend of pricing oil and natural gas identically on a heating value basis at the wellhead or the point of export or import must cease and be readjusted appropriately. Not only do liquids that can serve as, or can be converted to transport fuels with existing refinery technology have higher form value than gas, they are also much cheaper to transport and store.

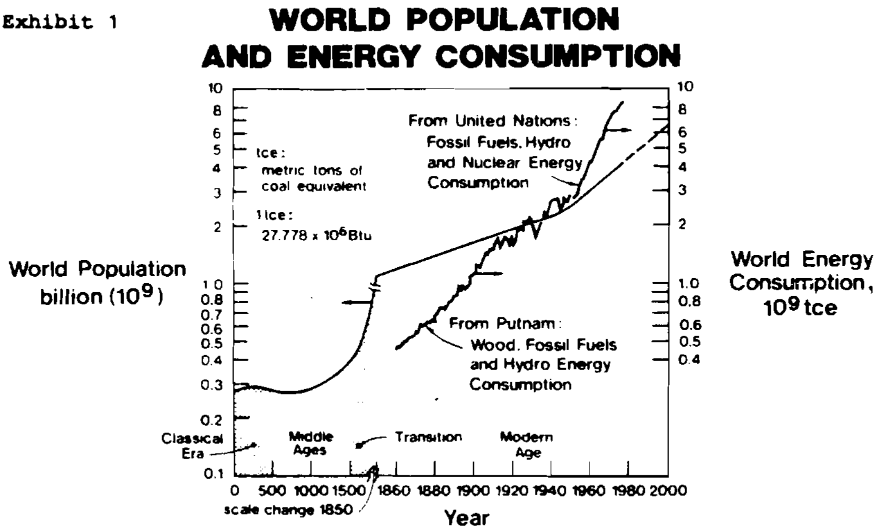
In regard to supply elasticity, it is hard to predict in the face of the pricing uncertainty noted above, how much the conventional crude oil and natural gas resource base can be expanded with marginal hydrocarbon resources. Clearly, the occurrence of methane in the earth's crust, below the oceans in the form of solid hydrates, and perhaps in the interior of the earth in the form of abiogenic methane is staggering. In North America alone, the additional quantities of methane that could be recovered from tight geologic formations, from geopressured brines and from coal seams could easily double the resource base at prices below those of prevailing world oil prices. However, the supply elasticity of liquids at prevailing and prospective world energy prices may also be huge. The true potential of the world's oil and tar sands, black and heavy oil, other bitumens, and tertiary recovery resources has not been assessed in light of the new pricing structure. Thus, while the relative futures of gaseous and liquid fuels may be somewhat clouded, we know that they must reflect resource base, form value and economic and technical realities which we are only now beginning to understand.

VARIATIONS IN ENERGY USE IN INDUSTRIALIZED COUNTRIES

Until the scientific and industrial revolution, world population grew at no more than 0.1 percent per year. The availability of abundant inanimate energy sources and the development of technology to employ them then made it possible for population growth to increase to 2 percent per year. This high rate will of necessity be transitory. In the developed countries, the rate has already dropped to 0.8 percent per year. But the population of the underdeveloped countries is still growing at 2.5 percent per year, and this may increase somewhat, because mortality is still declining. Therefore, even if reproduction rates in all countries could be brought down to replacement levels by the year 2000, the world's population would grow to more than 8 billion in the first quarter of the 21st century.

The close linkage between population growth and energy consumption is beyond question (Exhibit 1). Thus, vast quantities of energy will be required to support this steady-state world population level of at least 8 billion, and conceivably nearer 10 to 15 billion, at a standard of living conducive to social and political stability. Even with a minimal consumption level of 3 metric tons of coal equivalent (tce) per capita

Exhibit 1



(1 tce = 27,778 x 10^3 Btu or 7 x 10^9 calories), this would lead to world energy consumption levels 3 to 5 times current levels.

In the last century, the increase in world energy supply was largely provided by coal, whereas in this century it has been provided increasingly by oil and natural gas (Exhibit 2). Unless this rapidly accelerating dependence on the relatively less abundant conventional hydrocarbon fuels that began after World War II (Exhibit 3) can be stemmed, it will be impossible for policymakers to manage effectively the transition to renewable or inexhaustible energy sources and to avoid major social, economic and geopolitical upheavals.

The economic and social implications of adequate energy supply are clear. The best available measure of economic well-being, the gross domestic or gross national product (GDP or GNP) per capita, has shown a striking correlation with per capita energy consumption (Exhibit 4). The per capita gross world product index used in Exhibit 4 is an average for all countries at 1963 prices. This type of correlation has been found to apply to a number of individual countries also.

While average world energy consumption has increased steadily to the present level of 2 tce per capita, the spread between the haves and have-nots continues to grow. The highly industrialized nations at the top of the economic scale have per capita energy consumptions which range typically from 4 to 12 tce, compared to less than 1 tce for most of the third world.

Of course, many less developed countries use non-commercial energy, especially wood and agricultural waste material, in relatively large

Exhibit 2

ANNUAL WORLD ENERGY PRODUCTION OF INDIVIDUAL ENERGY SOURCES

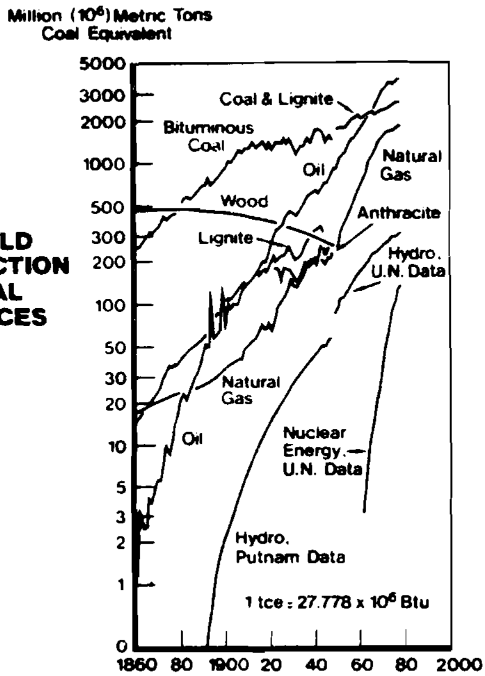


Exhibit 3

SHARE OF FOSSIL FUELS IN WORLD PRIMARY ENERGY PRODUCTION, %

Source: U.N. Data

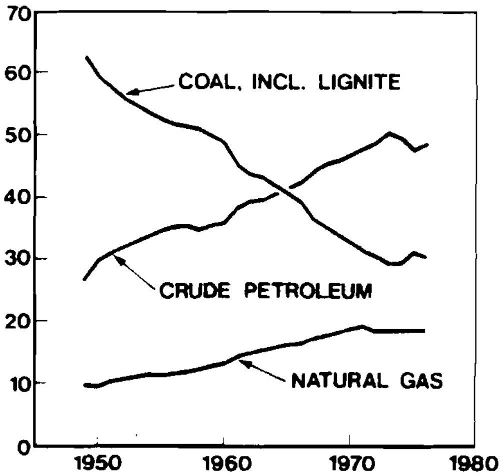
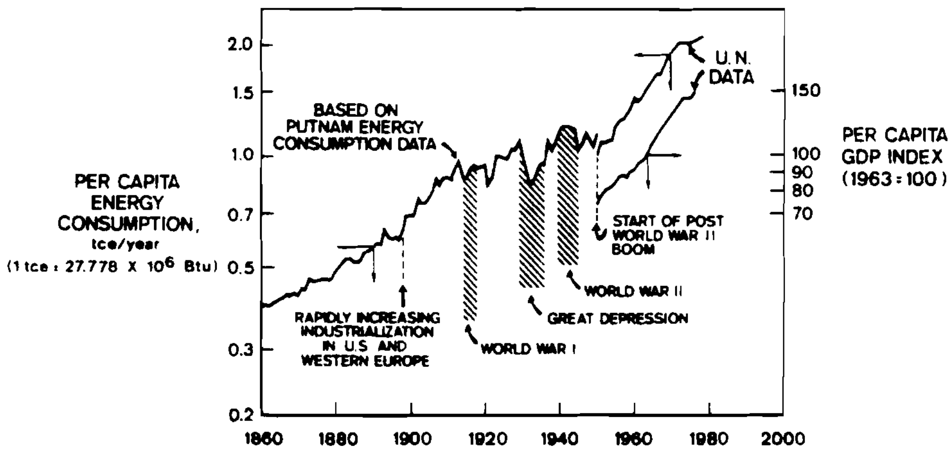


Exhibit 4 **ANNUAL ENERGY CONSUMPTION AND GROSS WORLD PRODUCT PER CAPITA**



quantities. Manufacturing wastes are also used, notably in Sweden where by-products of paper-making are widely employed. It has been estimated that about a billion cubic meters of fuel wood were used annually in the 1970s, mostly by developing countries. Wood alone is said to provide more than 90 percent of the fuel demand in some African countries, and nearly 60 percent in Brazil. Some countries also use large quantities of agricultural wastes such as dung. In India, wood and dung provide over half of the fuel supply. Accordingly, the total energy consumption of some of the less developed countries can greatly exceed the commercial energy reported by official statistics. A recent Chase Manhattan Bank study has evaluated the annual growth of the world's forests as equivalent to 633 million barrels per day of oil. Recovery of even a small fraction of this for efficient fuel use could be quite helpful.

Per capita energy consumption has been increasing at an appreciable rate in most industrialized countries for some time, and few countries have made marked progress in conservation until very recently (Exhibit 5). Some countries heavily dependent on foreign oil made efforts to hold the line on energy consumption as early as 1970. The recent slow-down, however, was largely due to the recession of 1974 and 1975. And the continued slowdown since then is largely due to the sluggish recovery and the recurring threat of recession. The fast growth of per capita energy consumption in the United Arab Emirates as the energy-intensive petroleum industry developed deserves special note as a recent example of the impact of industrialization and rapidly increasing affluence.

Among the large industrial nations, the United States and Canada show the highest per capita energy consumption, although generating an apparent per capita national product little or no greater than some other countries. Hence, the United States and Canada are often indicted as wasters of energy. However, even after correcting for the well-known differences in purchasing power of a nominally equivalent unit of GNP or GDP per capita, intercountry comparisons of energy consumption must also allow for such variable factors as the degree of industrialization; the energy-intensiveness of the major industries of the country; energy prices; vintage of capital equipment; climate; population density; availability of raw materials, including indigenous energy sources; and national energy policies. These factors are, in part, reflected in the sharp differences in the sectoral uses of energy among the industrialized nations, a situation which should have a major impact on per capita energy consumption (Exhibit 6). In fact, in studies of energy consumption in individual U.S. states or regions, patterns very similar to those encountered in Western European countries and in Japan were identified in highly industrialized and high population density states or regions whose economies and energy and raw material sources are also similar.

In spite of these considerations, it is common practice to single out the ratio of energy consumption to GDP or GNP (E/G) for international

Exhibit 5

PER CAPITA ENERGY CONSUMPTION OF SELECTED COUNTRIES
(U.N. Data)

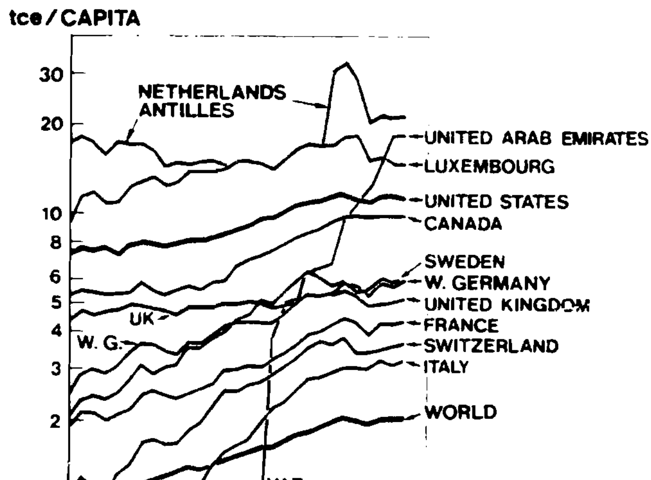


Exhibit 6

SOME OECD DATA RELATED TO ENERGY CONSUMPTION

COUNTRY	SECTORAL ENERGY CONSUMPTION, 1978 INDUSTRY	RESIDENTIAL / COMMERCIAL*	TRANSPORT	NON-ENERGY
	GROSS CONSUMPTION, %			
SWITZERLAND	29	50	19	2
UNITED STATES	38	34	25	3
CANADA	41	36	19	4
UNITED KINGDOM	46	37	16	2
W. GERMANY	46	37	14	3
SWEDEN	47	39	13	1
NORWAY	53	30	14	3
ITALY	53	29	16	1
JAPAN	59	24	14	3
LUXEMBOURG	71	16	11	1

*Includes Agricultural Uses
Data Source: IEA/OECD

comparisons of energy use in the economy. Obviously, such a procedure provides a limited view at best because of the exclusion of the many other relevant factors, some of which have been noted here. Moreover, values of E/G reported in the literature for various countries involve considerable statistical uncertainties. This is so because expressing energy consumption in a common unit such as Btu or tons of oil or coal equivalent, and GDP in another common unit, normally U.S. dollars of a given year, can be effected only with imprecise and arbitrary procedures. In the case of energy consumption evaluations, there is the choice of net rather than gross heating values; the decision to include or exclude nonenergy uses; variations in heating values of fuels from time to time and place to place; and the manner of accounting for electricity consumption -- i.e., the simple thermal equivalent, or the equivalent energy input to conventional thermal power plants, even for electricity produced from hydropower and nuclear energy. The United Nations, the Statistical Office of the European Communities, and the Organization for Economic Cooperation and Development show different values for energy consumption of different countries due to such differences in energy-accounting procedures (Exhibit 7).

Even more importantly, conversion of national currencies to U.S. dollars is based on exchange rates which involve political, monetary and other considerations and often distorts the true relative purchasing power within the countries being compared. Moreover, such rates refer primarily to items in international trade, not to the whole economy. Nor can conversion procedures properly allow for differences in national inflation rates and discontinuities caused by revaluations of currencies. Efforts to develop meaningful purchasing power parities for application to specific intercountry comparisons of economic and social well-being are underway, but have not matured to the point where quantitative corrections of nominal E/G ratios can be made.

Within these constraints on valid comparisons, Switzerland, France, Sweden and West Germany appear to have much lower E/G ratios than the United States, the United Kingdom and Canada (Exhibit 7). Sweden is said to achieve this in several ways, such as more modern manufacturing facilities based on expensive energy, stricter building codes to minimize heat loss, some cogeneration of electricity, greater use of waste materials for fuel, more recycling of used products, greater use of small autos and public transportation, and stricter governmental fuel-conservation policies. Much the same has been written about West Germany. However, in both of these countries and others in Europe, and in Japan, the apparent energy frugality may be primarily due to the historic high cost of energy. Switzerland's exceptionally favorable ratio is believed to be the result of greater concentration on light industries and very high net value-added goods and services.

Several countries show a higher ratio of energy consumption to GDP than even the United States (Exhibit 8). These generally are countries with large components of energy-intensive industries, such as mining, iron and steel manufacturing, and petroleum production and refining. Examples are Luxembourg, Trinidad, Guyana, and South Africa, although such selective and qualitative comparisons suffer from the same uncertainties as those which beset the comparisons and countries with lower E/G ratios.

Probably the most reliable measure of comparative economic and social well-being is the number of working hours required to purchase a selected market basket of essential goods and services in various locations throughout the world. This eliminates the problem of establishing the true purchasing power of the respective currencies. The Union Bank of Switzerland has published a series of such studies for the major cities of the world, and the latest of these is summarized in Exhibit 9. The market basket is a selection of items such as food, clothing, rent, appliances, transportation and services obtainable in each city, with some allowance

Exhibit 7

SELECTED GROUP OF COUNTRIES USING LESS ENERGY PER UNIT OF GDP THAN THE UNITED STATES In Current Dollars

	ENERGY/GDP, tce/$1000 GDP			
	1976		1977	1978
COUNTRY	U.N. DATA	OECD DATA	U.N. DATA	U.N. DATA
UNITED STATES	1.65	1.46	1.33	1.19
UNITED KINGDOM	1.49	1.34	1.16	0.95
CANADA	1.36	1.44	1.16	1.13
ITALY	1.08	1.14	0.90	0.70
W. GERMANY	0.92	0.83	0.69	0.58
JAPAN	0.82	0.90	0.62	0.45
NORWAY	0.81	0.95	0.62	0.57
SWEDEN	0.75	0.97	0.63	0.56
FRANCE	0.75	0.73	0.61	0.49
SWITZERLAND	0.41	0.56	0.38	0.28

made for the differences in consumers' buying habits. In spite of the obvious shortcomings of using such a limited sample of the various economics, the comparisons are instructive in that they certainly fail to contradict the broad beneficial impact of high per capita energy consumption with the notable exception of Switzerland. Moreover, the data of Exhibit 9, while correcting the misconception of relatively low living standards at high energy consumption in North America, are not very helpful in explaining the apparently erratic variations in energy consumption relative to GNP or GDP and population size in the leading industrialized countries.

Exhibit 8 **SELECTED GROUP OF COUNTRIES USING MORE ENERGY PER UNIT OF GDP THAN THE UNITED STATES**

Source U.N. Data.
In Current Dollars

COUNTRY	ENERGY/GDP, tce/$1000 1976	1977	1978
UNITED STATES	1.65	1.33	1.19
GUYANA	1.88	1.95	—
TRINIDAD	1.66	1.27	1.43
SOUTH AFRICA	2.31	2.20	2.55
LUXEMBOURG	2.26	1.92	1.58

Another important consideration in comparing national E/G ratios is their trend with time (Exhibit 10). During the postwar period, and until the rapid oil price increases in the fall of 1973, Sweden and Switzerland showed substantial increases. Only the United Kingdom and West Germany among the OECD countries showed substantial continuous declines in their E/G ratios, indicating increasing effectiveness of energy use. During this period the percentage of energy supplied by oil and natural gas in all of the major industrial countries increased relative to coal consumption (Exhibit 11). This fact may have been responsible to some degree for the improvements in the effectiveness of energy use but fails to explain the contrary trend in Sweden and Switzerland. Some of the improvement in the E/G ratio prior to the 1973-1974 oil embargo and subsequent rapid energy cost escalations was undoubtedly due to the long-term

Exhibit 9

WORKING HOURS REQUIRED TO PURCHASE A SELECTED BASKET OF GOODS & SERVICES, AS OF JUNE, 1979

Data Source: Union Bank of Switzerland; Study Dated Dec. 1979

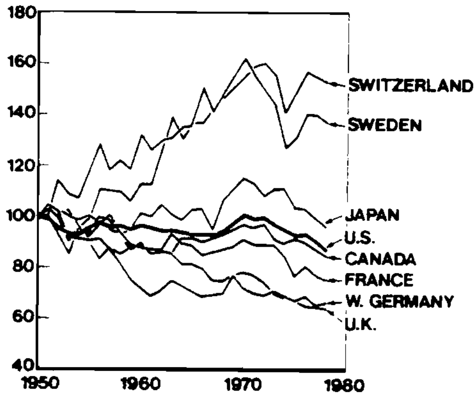
CITY	HOURS NEEDED
*FOUR U.S.A. CITIES	75.3-85.5
MONTREAL, TORONTO	86, 87.8
ZURICH, GENEVA	84.3, 92.3
DUSSELDORF	98.3
STOCKHOLM, OSLO	97.3, 116.5
TOKYO	136.5
PARIS	138.8
MILAN	139.5
LONDON	150.3
MADRID	155.8
MEXICO CITY	189.3
SÃO PAULO, RIO DE JAN.	194.3, 224.8
TEHERAN	204.3
BUENOS AIRES	283.3

*Chicago, San Francisco, Los Angeles, New York.
Based on Exchange Rates of June 1979.

Exhibit 10

TRENDS OF THE E/G INDEX FOR SELECTED COUNTRIES

ENERGY CONSUMPTION ÷ GDP; 1950 = 100



Source: OECD Data

Exhibit 11 **CHANGE IN MIX OF COMMERCIAL FUEL USED BY SELECTED COUNTRIES**

Source: U.N. Data; Remainder is hydro and nuclear.

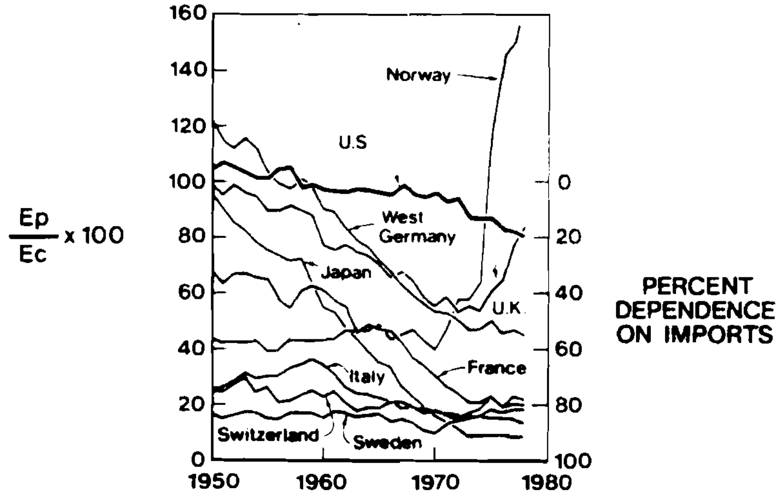
	OIL, %			GAS, %			COAL, %		
	1950	1965	1978	1950	1965	1978	1950	1965	1978
FRANCE	17.2	46.3	62.8	0.3	4.4	12.0	79.9	45.3	19.8
W. GERMANY	3.1	39.6	49.2	0.0	1.8	17.1	95.9	57.7	31.7
JAPAN	4.3	56.6	74.3	0.2	1.5	5.2	85.3	37.0	17.4
SWEDEN	35.9	75.2	78.0	0.0	0.0	0.0	49.5	8.9	4.4
SWITZERLAND	27.6	72.0	76.0	0.0	0.0	4.4	49.4	10.6	1.3
U.K.	9.1	31.5	40.3	0.0	0.4	20.7	90.8	67.2	37.2
U.S.	38.9	41.7	47.1	19.9	33.0	29.8	40.1	23.9	20.8

trend of substitution of capital investment and improved technology for energy use. Most industrialized countries have experienced an accelerated decline in the E/G ratio since 1973-1974 because of price-induced conservation and concern for stability of supply. The United States has been making unexpectedly rapid progress in lowering its E/G ratio since 1970 and this is expected to continue.

There is also the question of the impact of exports and imports on E/G ratios. It would seem that countries importing large quantities of energy-intensive basic commodities such as steel, aluminum, and food grains should gain in terms of apparent economic effectiveness of energy use, whereas countries which export such commodities should lose. This should apply to an even greater extent to imports and exports of fuels and electricity which are highly energy-intensive commodities in their own right. However, the relative contributions of energy-intensive goods to the GDP's and energy uses of the trading partners, obviously vary widely. Moreover, there have been tremendous gyrations in energy import dependence of industrialized countries since World War II (Exhibit 12). For example, Japan, nearly self-sufficient in 1950, is currently more than 90 percent dependent on imports, while Norway and the U.K. have benefited greatly by the discovery and production of oil and natural gas in the North Sea to the point that Norway is now a net exporter of energy. This, combined with the radical changes in fuel mix, sectoral energy use, currency

Exhibit 12

TRENDS OF THE RATIO OF ENERGY PRODUCED (Ep) TO ENERGY CONSUMED (Ec) FOR SELECTED INDUSTRIALIZED COUNTRIES Source: U.N. Data



revaluation and purchasing power makes intercountry comparisons of economic effectiveness of energy use extremely difficult.

In terms of impact on energy consumption trends and economic efficiency of energy use, natural gas has had no readily identifiable effect that can be distinguished from the impact of the overall displacement of coal as a primary energy source in the industrialized world following World War II. However, in the following sections, the special role of natural gas as a transition fuel in an era of tightening and increasingly costly oil supplies will become more apparent.

WORLD ENERGY RESOURCES, PRODUCTION AND DEMAND

For assessment of the world's energy future, we have at our disposal reasonably good estimates of proved and currently economically recoverable fossil fuel and uranium resources (normally identified as proved reserves) and sometimes highly speculative estimates of total remaining recoverable resources, assuming continuation of current economic and technological trends (Exhibit 13). Unfortunately, uranium reserves and resources exclude the U.S.S.R. and the Peoples Republic of China. They are expressed in terms of the oxide (U_3O_8): one short ton of U_3O_8 is assumed to produce 400×10^9 Btu (14.4×10^3 tce) in burner reactors and 30×10^{12} Btu (1.08×10^6 tce) in breeder reactors, a ratio of 1:75.

The preponderance of the world's fossil fuel resources is in the form of coal, and the ratio of the total remaining recoverable resource base to proved reserves is roughly 7:1 (Exhibit 14). Next to coal, the largest

Exhibit 13

TOTAL NONRENEWABLE WORLD ENERGY RESOURCES - 12/31/78

Conventional U.S. Units

	Proved & Currently Recoverable	Estim. Total Remaining Recoverable
Natural Gas, 10^{12} cu ft	2329-2549	7900-9200
Natural Gas Liquids, 10^9 bbl	66-73	223-259
Crude Oil, 10^9 bbl	563-614	1653-2047
Syncrude, 10^9 bbl	265	2320
Coal, 10^9 short ton	819-876	6380-7135
Uranium Oxide		
1000 short ton < \$30/lb	2410	4334 (5309*)

*Includes U.S. possible and speculative.

fossil resource is in the "syncrude" category, comprising oil recoverable from oil shale, tar sands and other bitumens. It would be seven-fold larger if highly speculative estimates of total oil shale resources in the 25 to 100 gallons per ton range were included. The remaining recoverable conventional oil and natural gas resources are roughly equivalent and, if fully exploited, should be sufficient to meet demand for hydrocarbon fuels beyond 2000. In view of the large resources of unconventional hydrocarbons, a good portion of which are not included in Exhibits 13 and 14, and the convertibility of coal to liquid and gaseous fuels, the crisis atmosphere in regard to energy supply does not seem justified except insofar as escalating costs are concerned. The 6×10^{12} tce of fossil fuel resources compare to current world consumption of 9×10^9 tce annually, a ratio of nearly 700:1.

Reasonably priced uranium, say, up to \$30 per pound, would make only a minor impact on world energy resources, if it is limited to use in light-water and other burner reactors. Only if the uranium resources were used in breeder reactors would they markedly extend the world's fossil fuel resources (Exhibit 14). This would hold, even if uranium oxide costing up to \$100 per pound were used. These nominal uranium costs are the so-called "forward costs," which currently are roughly one-fourth to one-third of actual costs.

A critical problem in managing the transition from fossil fuels to inexhaustible or renewable energy sources is the uneven distribution of fossil fuel resources throughout the world (Exhibit 15). Europe, excluding the U.S.S.R., is in particularly poor circumstances in regard to its endowment in fossil fuel resources in relation to its population. Moreover, the climate of Europe makes it unlikely that it will be able to derive a major share of its energy needs from the various direct and indirect forms of solar energy. The Western Hemisphere is reasonably well off in most respects on the assumption that free trade in energy materials and technology can be maintained at least on this regional basis, and seems to be especially well endowed in marginal hydrocarbon resources such

Exhibit 14 **TOTAL NONRENEWABLE WORLD ENERGY RESOURCES - 12/31/78**

	Proved & Currently Recoverable, 10^9 tce	Estim. Total Remaining Recoverable, 10^9 tce
Natural Gas	86-95	293-341
Natural Gas Liquids	9.5-10.5	32-37
Crude Oil	118-128	345-427
Syncrude	55	484
Coal	622-667	4650-5190
Uranium Oxide @ <$30/lb		
In Burners	34.7	76*
In Breeders	2600	5730*

One Metric Ton of Coal Equivalent (tce) = 27.778 X 10^6 Btu = 7 X 10^6 kcal

*Includes U.S. possible and speculative

as tar sands and oil shale. The huge unconventional natural gas resources in North America are not included in any of the statistical compilations or analyses, although they are increasingly competitive with alternative energy sources. Obviously, the resource data for Asia and Africa are in question because exploration has barely begun. It seems likely that huge new fossil fuel resources, including oil and gas, will be discovered in many of the geologically promising areas.

Using the existing limited data base, the important role of coal as a large contributor to total energy supply over a wide range of possible scenarios for uranium fuel utilization is made apparent in Exhibit 16. Together, these sources form by far the major part of both the currently recoverable and total remaining recoverable nonrenewable world energy

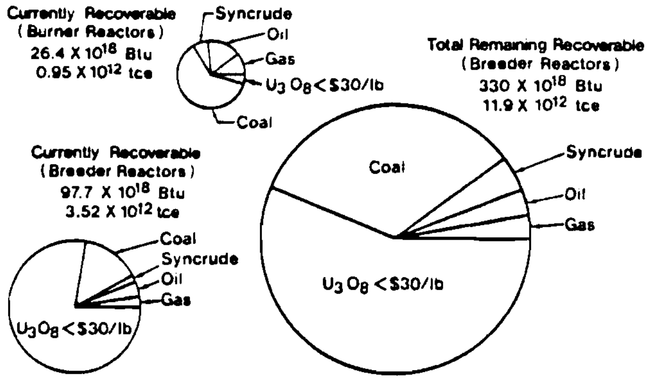
Exhibit 15 **REGIONAL DISTRIBUTION OF ESTIMATED REMAINING RECOVERABLE WORLD FOSSIL FUEL RESOURCES, %**

AS OF DECEMBER 31, 1978

	NATURAL GAS	NATURAL GAS LIQUIDS	CRUDE OIL	SYNCRUDE	COAL
AFRICA	5.2	5.2	6.7	4.3	0.9
WESTERN HEMISPHERE (Incl. U.S.A.)	22.0	22.0	18.2	84.5	24.7
EUROPE (Excl. U.S.S.R.)	5.0	5.0	5.5	7.3	5.4
ASIA (Incl. European U.S.S.R. and Middle East)	62.0	62.0	69.2	3.9	66.0
AUSTRALIA, NEW ZEALAND	5.8	5.8	0.4	-	3.0
TOTAL	100	100	100	100	100
MIDDLE EAST ONLY	26.3	-	43.2	-	-

Exhibit 16 **NONRENEWABLE WORLD ENERGY RESOURCES**

As of Dec. 31, 1978



Note : Oil includes natural gas liquids. Syncrude from oil shale and bitumens.
tce : metric ton of coal equivalent : 27.778 X 10^6 Btu

resources. In view of the uncertainties overhanging nuclear and renewable energy development, it is reassuring that the life of world coal and other fossil fuel resources at reasonable demand growth rates would be on the order of 100 years even if there were little reliance on non-fossil energy forms (Exhibit 17). However, the containment of energy demand growth to no more than 3 percent annually without serious economic, social, and political consequences will depend importantly on containment of population growth and improved efficiency of energy use. In addition, there is the growing concern over carbon dioxide buildup in the atmosphere associated with continuing and increasing fossil fuel use. Moreover, current trends in the expansion of world energy supply do not bode well for the capacity of likely energy infrastructures in being by 2000 to provide the equivalent of 3 tce per capita for 6 billion people. This would be roughly equivalent to a world consumption level of 12 to 13 x 10^9 tons of oil equivalent (toe), approximately midway between the high and low growth cases shown in Exhibit 18.

The data of Exhibit 18 were reported in the OECD Observer of September 1979 and are based on a 3-year study of "the future development of advanced industrial societies in harmony with that of the developing

Exhibit 17 **LIFE OF WORLD FOSSIL FUEL RESOURCES AT VARIOUS DEMAND GROWTH RATES**

(Based on 1978 Year-End Estimates)

Annual Growth Rate, %	Date When Remaining Reserve/Production Ratio Drops to 10 Years		
	A	B	C
4	2010	2054	2071
3	2016	2072	2095
2	2024	2103	2137

A: Proved Reserves (0.884 to 0.948 trillion tce)
B: Total remaining recoverable resources (5.8 to 6.5 trillion tce)
C: Effective doubling of B resources by use of non-fossil sources

tce : Metric Tons of Coal Equivalent

Exhibit 18 **WORLD* ENERGY SUPPLY IN THE YEAR 2000 AS ESTIMATED BY INTERFUTURES AND IIASA, 10^6toe**

	COAL	OIL	NAT. GAS	NUCLEAR	HYDRO & OTHER	TOTAL**
INTERFUTURES, HIGH GROWTH RATE	3290	5960	2305	1855	1190	14,600
IIASA, HIGH GROWTH	3610	5230	2150	2640	770	14,400
IIASA, LOW GROWTH	2915	4025	1610	2100	700	11,350

* INCLUDES CENTRALLY PLANNED ECONOMIES.

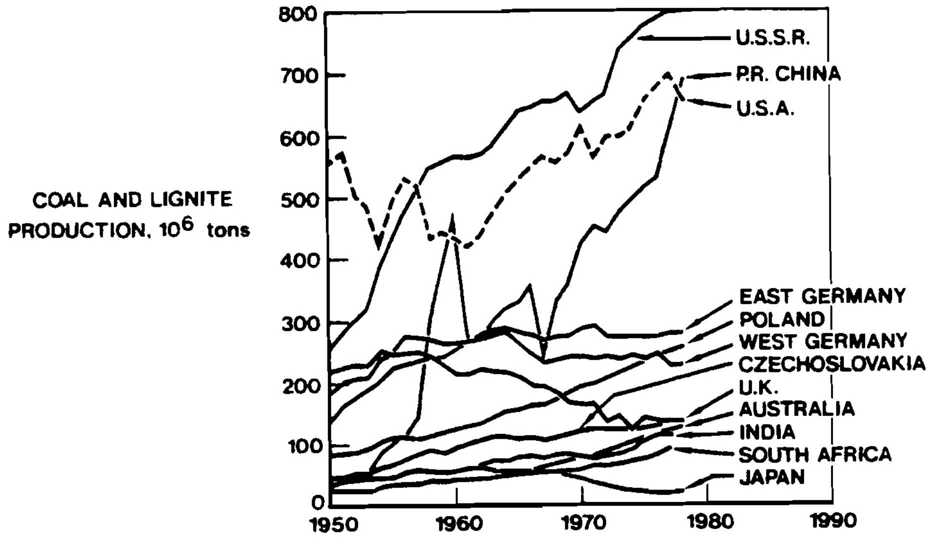
** THE TOTAL FOR INTERFUTURES ESTIMATE FOR MODERATE GROWTH WAS 13,000 × 10^6 toe, OR ABOUT 260 MILLION bbl OF CRUDE OIL EQUIVALENT PER DAY.

countries" known as Interfutures, whose projections are compared with those of the International Institute for Applied Systems Analysis (IIASA). Metric tons of oil equivalent are based on a heating value of 10,000 cal/gram so that 1 toe = 1.43 tce = 39.68 million Btu. It is interesting to note the large projected reliance on oil and the relatively limited reliance on natural gas in 2000. This seems to reflect undue pessimism on expansion of world gas trade and corresponding optimism on the continued expansion of world oil supplies.

World coal and lignite production reached about 2800 million tce (metric tons of coal equivalent) in 1978, according to preliminary U.N. data. In actual tonnage this was 3508 million tonnes (metric tons or 3867 short tons) including 1069 million short tons of lignite and brown coal. Production is expected to reach about 4000 million short tons in 1980. The U.S.S.R., the United States, and the Peoples Republic of China are the major producers (Exhibit 19). China's production has been rising rapidly as it moves to modernize its industries. However, coal substitution for oil in stationary heat energy applications is progressing at much too slow a pace in light of the limited prospects for further expansion of world crude oil production.

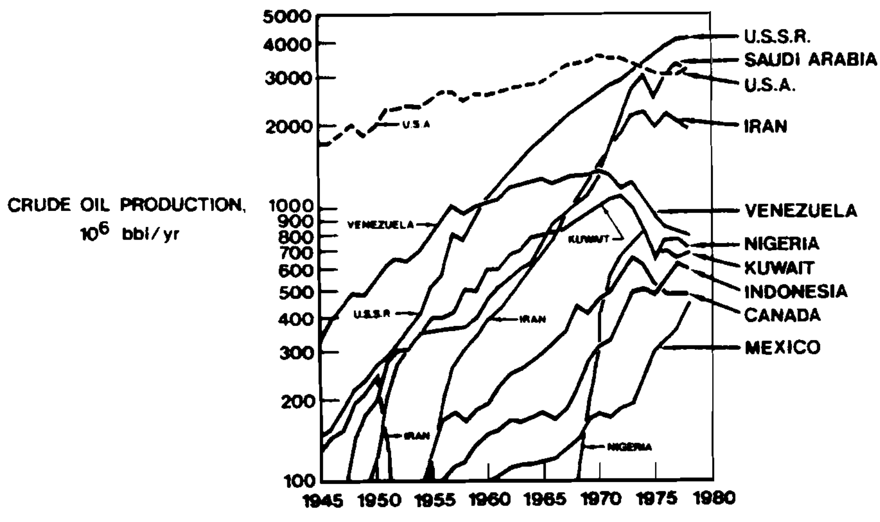
The United States was for many years the principal producer of petroleum, producing as much as two-thirds of the world's supply, even as late as the 1920s. The U.S.S.R. is now the No. 1 crude oil producer, and Saudi Arabia has also surpassed the United States (Exhibit 20). World annual production grew at about 7.5 percent per year in the period 1942-73. The subsequent production curtailments and price rises have reduced this rate. In the near term, the growth rate will depend largely upon OPEC pricing and political considerations and the success of non-OPEC producers in increasing their share of world production. As the turn of the century is approached, resource limitations will have increasing impact. Mexico, once a principal producer, is increasing its production rate rapidly and is expected to again become a very important producer, due to the recent discoveries of substantial quantities of oil. However, it seems unlikely that projected world demand in the 75 to more than 100 million barrel-per-day range in 2000 (compared to 62 million now) will be satisfied.

Exhibit 19 **ANNUAL COAL AND LIGNITE PRODUCTION BY SELECTED COUNTRIES**



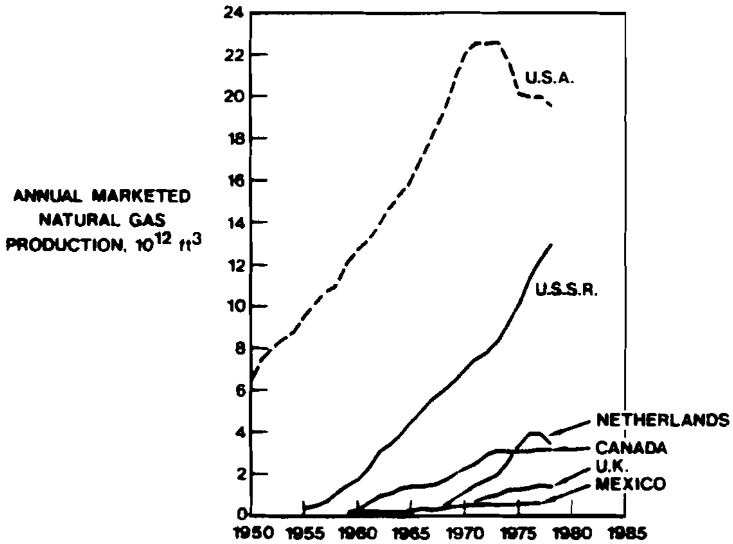
U.N. data indicate that about 20 percent of the world's commercial energy production is accounted for by natural gas. There is a great deal of waste of natural gas associated with crude oil due to the lack of pipelines to transport it to market and lack of industrialization of many oil-producing countries. Total world gas production is in excess of 60 trillion cubic feet (10^{12} cubic feet or Tcf) annually, whereas marketed production is nearer 50 Tcf per year. Successful efforts to build facilities for liquefying the unused gas and exporting it to oil-importing

Exhibit 20 **ANNUAL CRUDE OIL PRODUCTION BY SELECTED COUNTRIES**



countries have opened new markets for this resource. The United States and the U.S.S.R. are by far the leading producers of natural gas (Exhibit 21). Conventional U.S. production is expected to continue to decline slowly, but total world production should continue to increase substantially until the turn of the century and, perhaps, some time beyond, as a result of the favorable world resource picture.

Exhibit 21 **ANNUAL MARKETED NATURAL GAS PRODUCTION BY SELECTED COUNTRIES**



Based on the estimates of remaining recoverable world resources on a heating value basis (1 quad = 10^{15} Btu = 1.055×10^{18} joules), the depletion rate of conventional natural gas is about half that of crude oil (Exhibit 22). This allows the possibility of substantial substitution of gas for oil in stationary heat applications during the energy transition. However, this will depend importantly on growing world gas trade, both in form of liquefied natural gas and through international pipelines. This, in turn, will depend not only on greater stability in export prices but also on general acceptance of a price differential between natural gas and oil that recognizes the much higher transmission and storage costs of gas and its lower form value in comparison with hydrocarbon fuels suitable for transportation uses.

THE FUTURE ROLE OF NATURAL GAS IN THE UNITED STATES

As in much of the rest of the world, the growth in U.S. energy demand since the early 1900s has been satisfied primarily by increased consumption of petroleum liquids and natural gas, while the contribution of coal has remained at about the same average level since the turn of the century (Exhibit 23). However, in the early 1970s the use of natural gas peaked because of domestic supply limitations and is now on a plateau corresponding to about 25 percent of primary energy demand.

Exhibit 22

WORLD CONVENTIONAL NATURAL GAS AND CRUDE OIL RESOURCES AND RATES OF CONSUMPTION

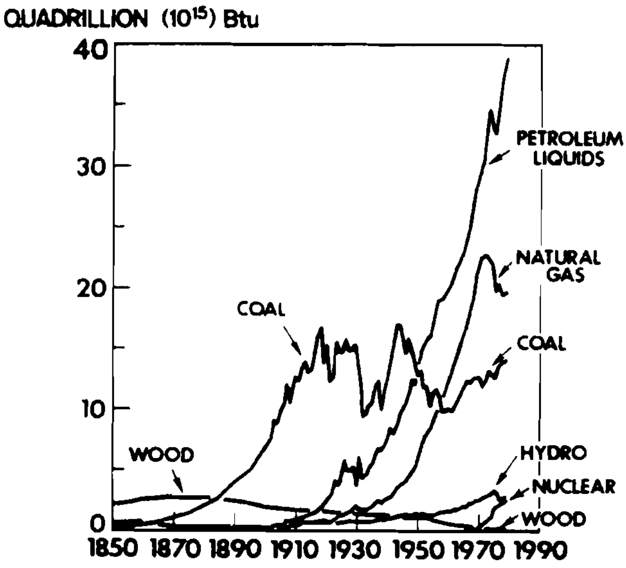
	GAS	OIL
AMOUNT OF RESOURCE, quads	8,100—9,500	9,600—11,900
1978 ANNUAL DEPLETION RATE, %	0.61	1.20

Estimates of the remaining economically recoverable supplies of conventional natural gas and petroleum liquids in the United States vary substantially, in part because of the differences in future wellhead price expectations and the technological and economic uncertainties in the potential of enhanced oil recovery. There is also growing optimism about so-called "unconventional" resources of natural gas and other natural sources of methane not now in use in regard to quantities expected to become recoverable at a cost competitive with other premium forms of

Exhibit 23

CONTRIBUTION OF VARIOUS SOURCES TO U.S. PRIMARY ENERGY CONSUMPTION, 1850 - 1978

[DATA IN 5-YEAR INTERVALS: 1850—1900]



energy. The current best estimate of the U.S. fossil fuel resource base excluding unconventional natural gas is 28,000 to 45,000 quads (Exhibit 24), or roughly 500 times the current rate of annual consumption. As in the case of world fossil fuel resources, coal resources represent 80 percent of the U.S. total. Consideration of the quantities and nature of these U.S. fossil fuel resources leads to the same conclusion as for the world as a whole: there is no shortage of fossil fuel resources, only a regional scarcity of proved reserves of the most desirable forms of these fuels.

Exhibit 24

U.S. FOSSIL FUEL RESOURCES 12/31/79

	Proved & Currently Recoverable, 10^{18} Btu	Estim. Total Remaining Recoverable, 10^{18} Btu
Dry Natural Gas	0.20	0.71-1.22
Natural Gas Liquids	0.02	0.08-0.13
Crude Oil	0.16	0.77-2.12
Coal	4.76	20.69-35.72
Shale Oil & Bitumens	0.44	6.04
Total	5.58	28.28-45.24

Estimates of the U.S. resource base of unconventional forms of natural gas (Eastern shales, Western tight sands, coal seams, and geopressured aquifers) are very sensitive to assumptions of production technology improvements and cost competitiveness with energy sources of equivalent form value (Exhibits 25 and 26). It appears that the relatively near-term sources (Western tight sands and Devonian shales) would double proved reserves and that the ultimate potential is much greater. A major technical research, development and demonstration effort is underway in the United States in conjunction with a greatly accelerated exploration effort, to fully develop the potential of all the various forms of unconventional natural gas. The Gas Research Institute (GRI) has become increasingly active in this area.

Thanks to the improved outlook for U.S. natural gas supply, there is a growing concern for the size of future gas markets. In fact, at this time, gas use in the United States is demand limited. In the residential and commercial markets, electricity is the major competitor. In the industrial and power plant markets, it is coal and, at present, low-priced residual fuel oil which has also been in oversupply.

A widely accepted premise has been that electricity is the preferred source of energy needs in the future because it can be derived with existing technologies from abundant domestic energy sources -- coal and nuclear fission. It is, of course, in the consumer interest to use electricity where it can provide superior service, and these uses are expected to provide continuing demand growth, perhaps higher than that of other energy forms. However, it is illogical to use electricity where other energy forms can do the job as well at lower cost and with less impact on the environment. For example, while the relative merits of coal-by-wire versus coal-by-pipeline are still being vigorously debated, a

Exhibit 25 **UNCONVENTIONAL SOURCES OF NATURAL GAS**

SOURCE	ESTIMATED RESOURCE BASE, TCF	ESTIMATED RECOVERABLE AT MARGINAL COST UP TO $4/1000 CF, TCF
EASTERN SHALES	600	30
WESTERN TIGHT SANDS	600	170
COAL SEAMS	2500	350
GEOPRESSURE AQUIFERS	3,000–100,000	160

SOURCE: ERDA MARKET ORIENTED PROGRAM PLANNING STUDY, JUNE, 1977.

Exhibit 26 **1980 GRI ESTIMATE OF UNCONVENTIONAL SOURCES OF NATURAL GAS, TCF**

SOURCE	ESTIMATED RESOURCE BASE	ESTIMATED RECOVERABLE AT MARKET PRICE OF $6/1000 CF ($ 1979)	
		EXISTING TECHNOLOGY	ADVANCED TECHNOLOGY
TIGHT FORMATIONS:			
WESTERN TIGHT SANDS	800	60	150
DEVONIAN SHALE	600	25	45
COAL SEAMS	500	30	60

number of studies have shown that gas-from-coal would result in lower marginal consumer costs and less environmental impact. A typical current government view of increases in electrical energy use at the expense of increased penetration by gaseous fuels is represented by National Energy Plan II (Exhibit 27). However, GRI believes that gas energy end-use in 2000 could be as high as 33 x 10^{15} Btu (quads) based on cost-competitive economic demand (Exhibit 28).

The amounts of energy used and the degree of substitution of one source for another are price-dependent in the long run, other things being equal. Although the apparent cost of residential energy has been rising appreciably, in terms of constant dollars the increase has been relatively modest so far (Exhibit 29). The relationships between the average cost of fuel to U.S. residential customers shown in Exhibit 29 are expected to hold in the future with the possible exception of a temporary acceleration of gas cost increases compared to electricity cost increases. The same applies to fuel prices for the industrial sector. Thus, on an equal heating value

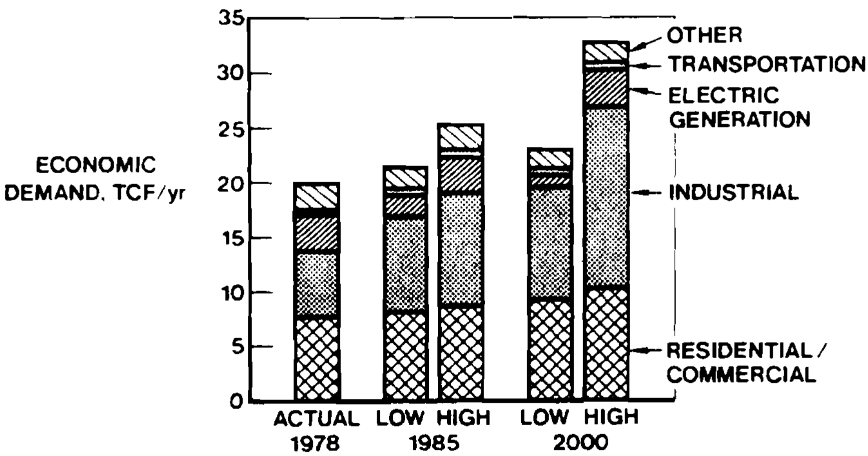
Exhibit 27

END-USE ENERGY CONSUMPTION IN THE YEAR 2000 PROJECTED BY NEP-II

(Source: DOE)

		WORLD OIL PRICE, $(1979)/bbl		
	1977	$21	$32	$38
	quads/yr			
END-USE CONSUMPTION				
LIQUIDS	33	42	35	29
GASES	17	21	22	22
DIRECT COAL	4	9	9	9
ELECTRICITY	7	13	14	15
RENEWABLES	2	4	5	5
SUBTOTAL	62	90	85	80
CONVERSION LOSSES	16	33	35	37
TOTAL CONSUMPTION	78	123	119	117

Exhibit 28 **GRI ECONOMIC GAS DEMAND SCENARIOS**



basis, natural gas should remain considerably less expensive than heating oil, and both considerably cheaper than electricity.

In comparisons of energy costs, allowance must, of course, be made for differences in seasonal utilization efficiency, say 100 percent for the heating efficiency of electricity in resistance heaters, and 50-60 percent for gas and oil in domestic boilers and furnaces. This still leaves a big margin in favor of gas, especially since new boilers and furnaces have seasonal efficiencies much greater than the average of the existing stock. However, GRI's modeling work indicates that, in the future, advanced high

Exhibit 29 NATIONAL AVERAGE COST OF FUEL TO RESIDENTIAL CUSTOMERS, 1972 $/10^6 Btu

DATA SOURCE: DOE

	1973	1975	1977	1978	1979
HEATING OIL	—	2.11	2.25	2.29	2.94
NATURAL GAS	1.19	1.30	1.59	1.62	1.88
ELECTRICITY	7.00	8.00	8.20	8.10	7.79

NOTE: TO CONVERT TO 1979 DOLLARS MULTIPLY BY 1.52.

efficiency gas space heating technology, such as pulse combustion furnaces and gas heat pumps, will be required to compete with electric heat pumps on a marginal space heating service cost basis (Exhibit 30). The "price of service" in Exhibit 30 considers the marginal cost of the delivered energy, energy conversion efficiency, and equipment capital costs.

The U.S. Department of Energy (DOE) view as expressed in National Energy Plan II of the prospects for gas supply and demand to the year 2000 indicates stabilization at or somewhat above the current level of 19 to 20 trillion cubic feet per year, thanks to the increased availability of supplemental sources to compensate for the decline in conventional Lower 48 natural gas supply (Exhibit 31). It is the view of GRI that the true economic demand for gas in 2000 can be satisfied with larger quantities of supplementals at competitive costs than projected by DOE (Figure 32). Unconventional natural gas is expected to play an especially important role in this projected departure from recent trends.

Exhibit 30 COMPARISON OF MARGINAL COSTS FOR RESIDENTIAL/COMMERCIAL SPACE HEATING TECHNOLOGIES

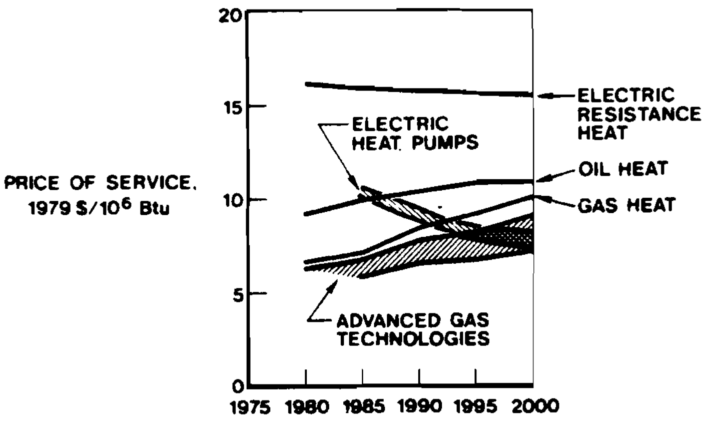


Exhibit 31

GAS SUPPLY PROJECTION BY NEP-II

(Source: DOE)

	1977	1985	2000
	quads/year		
NATURAL GAS			
CONVENTIONAL LOWER 48	19.5	16—18	12—14
ALASKA	0.1	0.8—1.0	1—2
UNCONVENTIONAL	--	0.3—0.8	1—5
SYNTHETICS			
FROM COAL	--	0—0.1	1—2
FROM PETROLEUM	0.3	0.2—0.5	0.2—0.5
TOTAL DOMESTIC	19.8	18—20	16—22
IMPORTS	1.0	1.8—2.2	1.5—2.0
NET WITHDRAWALS FROM STORAGE	−0.6	--	--
TOTAL SUPPLY	20.3	20—22	18—24

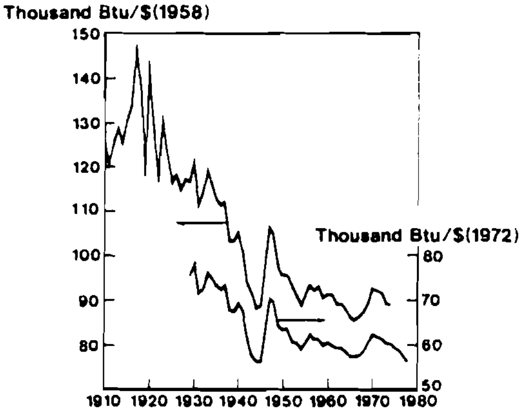
An erroneous picture exists in regard to energy conservation in the United States: namely, the concern for energy conservation began only after the 1973-1974 oil embargo. In fact, the energy consumption-to-GNP ratio (E/G) on the basis of constant 1958 dollars declined from about 140,000 Btu per dollar of GNP post-World War I to an average of about 90,000 Btu per dollar of GNP in the 1960s. Currently, the ratio is again declining quite rapidly and reached a modern low of 54,900 Btu per 1972 dollar of GNP in 1979 (Exhibit 33).

Exhibit 32

GRI RANGES OF POTENTIAL GAS SUPPLIES, TCF

	1985	2000
NATURAL GAS		
CONVENTIONAL	16-18	12-14
ALASKAN	0.7-0.9	1.5-2.0
UNCONVENTIONAL	0.2-0.4	2.0-10.5
SYNTHETIC NATURAL GAS		
FROM PETROLEUM	0.5-1.0	0.2-0.5
FROM FOSSIL FUELS (Coal, Peat, Oil Shale)	0-0.1	1.4-4.5
FROM BIOMASS AND WASTES	—	0.1-1.0
PIPELINE IMPORTS		
CANADIAN	1.0-1.4	1.0-1.5
MEXICAN	0.3-0.7	
LNG IMPORTS	0.8-1.0	1.0-1.5
TOTAL	19.5-23.5	19.2-35.5
PROBABLE RANGE	19.5-23.5	24.7-30.1

Exhibit 33 **TREND OF ENERGY CONSUMPTION PER UNIT OF GNP IN THE U.S.**



In view of the uncertainty of the conservation potential, it is difficult to forecast future energy consumption, even at an assumed growth rate for the gross national product. One need only consider the events following the 1973-1974 OPEC oil pricing action to realize this. Optimistic projections of the rate of growth of the GNP and domestic fossil fuel and nuclear energy production have been continuously downgraded. The current thinking is that the GNP will grow at about 3 percent per year over the long term. Since the energy-GNP coefficient has averaged 0.6 percent growth in (primary) energy consumption per 1 percent growth in GNP in the interval 1970-1978, the long-term growth in energy consumption is now being assessed at 1.8 percent per year. This leads to an energy use of 114 quads (10^{15} Btu) in 2000 -- a figure much lower than previously forecast, and one which is certain to require conservation and improved efficiency in all sectors of the economy (Exhibit 34). However, with an expected population of 250 to 280 million, this would still allow a modest growth in per capita energy use.

On the basis of a year 2000 total U.S. energy demand in the 100 to 120 quad range, and likely total gas supplies in the 25 to 30 trillion cubic foot range (1 trillion cubic foot of gas per year = 1 quad = 0.5 million barrels per day of oil equivalent), gaseous fuels are expected to hold their present market share of 25 percent. The reason is that in the

Exhibit 34 **POSSIBLE LEVEL OF ENERGY USE IN 2000**

$$\frac{\Delta E}{E} \Big/ \frac{\Delta G}{G} = 0.60;\ 1970\text{-}78$$

1979 PRELIMINARY VALUE OF E = 78.2 QUADS

$$78.2\,(1.018)^{21} = 114 \text{ QUADS IN 2000}$$

$$\text{ENERGY USE/CAPITA} = 114 \times 10^{15} \text{ Btu}/265 \times 10^{6}$$

$$= 430 \times 10^{6} \text{ Btu}$$

Exhibit 35 HIERARCHY OF SUPPLEMENTAL ENERGY SOURCES BY COST

SUPPLEMENTAL SOURCE	ESTIMATED PRICE AT POINT OF PRODUCTION * $(1979)/10^6 Btu
DEEP CONVENTIONAL NATURAL GAS	3.00 – 4.00
LIQUEFIED NATURAL GAS (New Projects)	3.50 – 4.50
UNCONVENTIONAL NATURAL GAS (Excluding Geopressured Zone and Coal Seam Gas)	3.50 – 5.00
HIGH-Btu GAS FROM COAL (2nd Generation)	4.00 – 5.50
MEDIUM-Btu GAS FROM COAL (1st Generation)	4.00 – 5.50
SOLVENT REFINED COAL (Solid)	4.00 – 5.50
ENHANCED OIL RECOVERY	4.00 – 6.00
CRUDE SHALE OIL (All Processes)	4.00 – 6.00
NATURAL GAS FROM ALASKA (At the Border)	5.00 – 6.00
HIGH-Btu GAS FROM COAL (1st Generation)	5.00 – 6.00
LOW-SULFUR HEAVY FUEL OIL FROM COAL	5.00 – 6.50
DISTILLATE FUEL OIL FROM COAL	6.00 – 7.00
METHANOL FROM COAL	6.00 – 9.00
GASOLINE FROM COAL	8.00 – 11.00
BUS-BAR ELECTRICITY FROM COAL (With Scrubbers)	12.00 – 14.00
ETHYL ALCOHOL FROM BIOMASS	13.00 – 18.00

* Or point of import

hierarchy of supplemental sources of energy ranging from deep and unconventional natural gas to synthetic fuels, Alaskan gas and coal-fired electricity, and finally to alcohol from biomass, all the various sources of gas appear to be competitive with alternative clean energy sources in stationary heat energy applications (Exhibit 35). There have been some shifts in the relative prices since 1979. Imported liquefied natural gas and to a lesser extent deep conventional natural gas have lost a portion of their price advantage.

Comparative energy costs such as those shown in Exhibit 35 do not reflect the true value of the various energy forms in performing energy services. Premium liquid fuels, which are cheap to store and deliver and which can be used to fuel automotive or air transport, have the highest form value of any chemical fuel and are also the most costly to replace from non-petroleum sources. Electricity, which can be converted directly to shaft horsepower as well as to heat at very high efficiencies obviously has the highest form value of any energy source on a delivered heat equivalent basis. But electricity suffers in terms of its economic competitiveness in many applications because its delivered cost reflects the relatively low efficiency and great capital intensiveness of generating it, the high cost of transmitting and distributing it, and the extremely high cost of storing it.

Gaseous fuels, and particularly high methane-content fuels, because of their clean-burning characteristics, environmental compatibility, and ease of combustion control, compete with electricity as a utility service, across-the-board with all grades of fuel oil in the smallest to the largest stationary heat energy markets, and even with coal. They also compete with the appropriate liquid feedstocks as a source of petrochemicals. This broad spectrum of markets, and the fact that gaseous fuels ranging from low heating value industrial fuels to methane can be derived

Exhibit 36 **RELATIVE VALUES OF SUPPLEMENTAL ENERGY SOURCES**

ELECTRIC POWER	**2.0**
TRANSPORT FUELS	**1.5**
GASOLINE, ETHYL ALCOHOL, JET FUEL, DIESEL FUEL	
PREMIUM FUELS	**1.25**
NATURAL GAS, SYNTHETIC PIPELINE GAS, NO. 2 FUEL OIL AND SYNTHETIC EQUIVALENTS, METHYL ALCOHOL	
HIGH-GRADE INDUSTRIAL FUELS	**1.0**
MEDIUM-Btu GAS, LOW-SULFUR NO. 6 FUEL OIL AND SYNTHETIC EQUIVALENTS	
BOILER FUELS	**0.75**
SOLID SOLVENT REFINED COAL, LOW-Btu GAS	

from probably the widest variety of natural and synthetic sources of any energy form, complicates the assessment of relative form value. Obviously, if a reliable answer is sought, the only basis for comparison is the actual cost of the energy service provided, i.e., the cost of space heating, heat delivered at a given temperature in an industrial process, or transportation provided at a given comfort level. Weighting factors of the magnitude suggested in Exhibit 36 can be employed to account very roughly in an aggregated fashion for differences in form values arising from differences in transportation and storage costs, efficiency and convenience of use, environmental impact, and mutual substitutability.

It seems a truism that a sound energy policy should lead to the use of each energy source at its highest form value since this should result in providing the various energy services at the lowest, fully internalized cost to the consumer. Consistent with this concept is the displacement of liquid fuels from inferior stationary heat energy applications to transport fuel uses. The cheapest, most readily available source of more transport fuel is not synthesis from coal or oil shale, or fermentation of biomass, but replacement of distillate fuel oil used in stationary applications with gas -- natural or synthetic, conventional or unconventional. This would reduce the diversion of refinery streams used in the production of gasoline, jet fuel and diesel fuel to production of fuel oil (Exhibit 37). It is also cheaper and technologically less complex to convert most residual fuels to transport fuels than to synthesize them. In fact, it seems possible that by reserving liquids for U.S. transport fuel needs, projected to remain at no more than 10 million barrels per day through 2000, these needs can be satisfied from domestic petroleum production (Exhibit 38) plus managable quantities of synthetics produced from oil shale and coal. Obviously, because of its abundant supply and relatively low commodity cost, coal should be substituted in every stationary heat energy use where it can compete after making full allowance for the higher investment and operating costs associated with coal combustion.

Exhibit 37 **FUEL SWITCHING TO INCREASE TRANSPORT FUELS**

	REFINED PETROLEUM PRODUCT DEMAND (1979), 10^6 bbl/day
GASOLINE	7.0
JET FUEL	1.1
OTHER TRANSPORT FUEL USES	1.6
STATIONARY FUEL USES	
DISTILLATE	2.1
RESIDUAL	2.4
OTHER USES OF REFINED PETROLEUM PRODUCTS	4.2
TOTAL	18.4

DISPLACE WITH GAS TO MAKE MORE GASOLINE, DIESEL FUEL, AND JET FUEL, AND REDUCE OIL IMPORTS

DISPLACE WITH GAS TO REDUCE OIL IMPORTS

Exhibit 38 **ESTIMATED TREND OF U.S. PETROLEUM PRODUCTION BY SOURCES**

	ACTUAL 1978	1980	1985	1990	1995	2000
	10^6 bbl/day					
CRUDE OIL						
LOWER 48 ONSHORE CONVENTIONAL	6.3	6.0	5.0	4.2	3.9	3.7
LOWER 48 ONSHORE EOR	--	--	--	0.2	0.5	1.0
ALASKA EXISTING	1.2	1.5	1.5	0.9	0.4	0.2
ALASKA FRONTIER	--	--	0.1	0.5	0.9	1.3
LOWER 48 OFFSHORE	0.7	0.6	0.5	0.4	0.3	0.2
FRONTIER OFFSHORE	--	--	0.1	0.2	0.3	0.4
SUBTOTAL	8.2	8.1	7.2	6.4	6.3	6.8
NATURAL GAS LIQUIDS	1.9	1.8	1.6	1.7	1.7	1.7
TOTAL	10.1	9.9	8.8	8.1	8.0	8.5

SOURCE: U.S. GENERAL ACCOUNTING OFFICE

CONCLUSION

The overall conclusion from this assessment of the prospects of natural gas is that gas should continue to be a growth industry in much of the world on the basis of all reasonable resource, cost, technology, environment, total energy demand, and consumer benefit considerations. In the United States, the leading producer and consumer of natural gas, the future looks bright as well, because of the plethora of economically competitive supplemental sources of gas. Moreover, substitution of natural and synthetic gases for stationary uses of liquid fuels frequently offers a least-cost strategy for maximizing the availability of transport fuels, the major use for which liquids have superior form value.

ACKNOWLEDGEMENT

Sections of this paper were taken from "Perspectives on U.S. and World Energy Problems," April 1980 Edition and subsequent updates of the data contained therein, which are largely the work of Joseph D. Parent. His contributions are hereby gratefully acknowledged. Also acknowledged with thanks is the assistance of George K. Oates in the preparation of the manuscript and exhibits.

THE ECONOMIC POTENTIAL OF WORLD NATURAL GAS RESOURCES

A.K. Arsky and T. Ya. Bukhtoyarova
Working Consultative Group for the President of the USSR Academy of Sciences on Long-Term Energy Forecasting, Moscow, USSR

The estimation of the economic potential of gas resources is one of the most complex and difficult of all resource estimates.

The method of estimation used should be chosen bearing in mind the precise object of the study. For example, when optimizing the energy economy with a model which considers fuel transportation costs and consumer effects separately, an estimation of specific exploration and production costs, as was done by Stanford Research Institute (1977), Arsky (1979), and Astakhov (1979), is required. When it is necessary to assess the economic effect of consuming a certain resource in a particular region, total development (exploration, production and transportation) costs should be estimated and, where appropriate, refining costs.

There is also the problem of determining a resource value (benefit) or the economic potential of resources, in a particular geographical area.

The economic potential (value) of the resource can be estimated as the difference between the sale price of the product and its total production and distribution costs (Gofman, 1977). The problem is how to estimate the resource value and its development costs.

The discounting of future costs and benefits is widely used, but this represents an attempt to evaluate the present resource value. This approach is justified, and on the whole reasonable, only from today's point of view and only for the solution of current problems of resource development. It may be suitable for such important tasks as: (a) the optimization of the depletion time for a particular field (or resources in a particular region) or (b) an economic comparison of the cycling process used in the development of a gas-condensate field with forced production of gas entailing considerable losses of gas liquids.

However, in research on long-term forecasting (like the IIASA Energy Program) another approach should be applied, because long-term discounting (up to 50 years in the IIASA Energy Program, and more than 100 years in work done by the authors' research group) leads to meaningless results: according to such estimates the resource value approaches zero. This result probably reflects the current view on resource development economics, but from the point of view of the distant future, the energy pattern of which we are trying to determine, this approach is obviously not suitable. Economic potential estimated for long-term prospects should be evaluated without discounting future costs and benefits.

It is very important to decide how to determine a product's value at the point of use. Only a few years ago it was determined by some authors (Makarov, 1977) on the basis of "shadow price" (marginal costs of coal taking into account the advantages of gas fuel consumption and the difference in transportation costs). In the past this approach was reasonable since in the 1960s prices of natural gas delivered to electricity plants in many countries, including Western Europe and the USA, were determined largely by the price of steam coal. With changes in the energy situation it became clear that natural gas (as well as crude oil) and coal are not economically interchangeable. This is due to the global scarcity of gas, its high consumer qualities and environmental advantages. Now natural gas (as well as crude oil) and coal are interchangeable only through coal-based synfuel production; only syngas from coal may substitute for natural gas.

The present value of natural gas for countries participating, or intending to participate, in world gas trade is determined by the level of new contract prices for gas supplies. (Due to very large investments in international gas supply projects, contracts on these supplies are signed for long periods--usually 15-20 years. This fact explains why old contract prices are considerably lower than new ones and are not typical despite price escalation clauses and price corrections.) Accordingly, the resource value of natural gas determined for the future should be evaluated as the difference between the future world price of natural gas and future costs of resource development and distribution.

Due to its high consumer qualities, including minimum environmental pollution, and because of its scarcity (in the USA a certain amount of gas is produced from naphtha), natural gas prices at the point of consumption should not be lower than world crude oil prices. In actual practice, in most international contracts signed recently, gas prices were lower than world oil prices. However, the gap between c.i.f. prices of natural gas and world oil prices is closing. For instance, under the terms of the recently approved PacIndonesia deal, LNG from Indonesia would realize a price of \$5.11/Mcf or \$180/1000 m^3 if shipped to California today (Segal, 1979).

For evaluating the gas-resource value in the distant future, it is important to estimate at least approximately a possible future gas price. This will mainly be determined, in our opinion, by the costs of coal-based syncrude and syngas, which will meet the demand for natural hydrocarbon fuels in the twenty-first century, and to some extent by the end of this century.

Synfuel costs are very sensitive to the price of feed coal. The cost of syncrude or syngas of high calorific value produced from relatively expensive coal (calculating per 1 t or 1000 m^3

respectively) will differ from the cost of synfuel from lower-priced coal by about twice the difference in coal price per ton of coal equivalent. Hence it is clear that large-scale syncrude production for exports has good prospects in countries rich in cheap coal.

As was shown by Astakhov (1979), very large resources of cheap coal are concentrated in a few countries, mainly in the USSR, China and the USA, and, to a smaller extent in Australia. Taking into account this concentration and the extensive environmental pollution at the site of production, it seems doubtful that there will be large-scale export of coal-based syncrude without differential costs.

At the initial stage of industrial development, world oil prices will ensure profitability of synfuel production only from cheap coal and there will be no differential costs. At this stage, extensive foreign trade in synfuel from coal is clearly improbable.

However, world oil prices are certain to increase, partly because only a comparatively small part of total unconventional petroleum resources may be developed at relatively low costs (i.e., at or slightly below coal-based syncrude costs), and these comparatively cheap resources are located in a few countries (Arsky, 1979).

World oil prices may be expected to stabilize in the distant future only at costs relative to syncrude from coal, which are marginal in terms of the world energy economy. At the beginning of the twenty-first century these marginal coal costs (taking into account future transportation costs for imported coal) in Western Europe and Japan are likely to be at least $50/t of coal equivalent in 1979 dollars. Currently coal prices in Western Europe and Japan are considerably higher, though relatively cheap coal resources are still available in the United Kingdom and Western Germany (Astakhov, 1979). Coal prices are high because world production has not yet responded to the rapid rise in world oil and other energy resource prices in 1973-74 and again in 1979. In the future a certain decline of world coal prices (in constant dollars) can be anticipated.

In the remote future the world coal-based syncrude price--taking into account world marginal coal costs and the increase of environmental and water-supply costs--will not be lower than $280-330/t or $40-45/bbl (in 1979 dollars).

The analysis of data given in a previous paper (Arsky, 1979), shows that the cost pattern of conventional gas resources is much better than that of oil resources, particularly when the latter include resources technically recoverable in the distant future by EOR methods. Comparatively cheap gas resources, with exploration and production costs at $90/t of oil equivalent and lower (in 1976 dollars; including a 15% rate of return, but without taxes, royalty or any other kinds of costs), make up 70-80% of total known and undiscovered gas resources of the main producing regions, even if the cheap resources in developing countries are not taken into account. In the case of crude oil, such relatively cheap resources account for substantially less than one half of total technically-recoverable resources.

Thus in frontier areas, a substantial part of oil resources technically recoverable by new EOR methods may appear economically unattractive even at a price of \$280/t in 1979 dollars, though transportation costs are of little importance to the consumer when crude oil prices are so high.

Transportation costs are of great importance for the economics of gas resource development, especially for the development of the remote Arctic resources and for resources which are shipped over long distances. For example, LNG delivery costs (including liquefaction costs) from the Persian Gulf to the US Atlantic seaboard via the Suez Canal, amount to as much as \$90/1000 m^3 in 1976 dollars (Mossadeghi, 1977) or approximately \$140-150/1000 m^3 in 1979 dollars. Due to high transportation costs f.o.b. prices are unsatisfactorily low from the producing countries' point of view. Under present economic conditions, the economic potential of the Persian Gulf gas resources is many times lower than that of the oil resources.

In the long term, the growth of natural gas c.i.f. price and the decrease of LNG delivery costs due to technical advances (transportation of LNG in a 300000 m^3 vessel will be around 30-40% cheaper than in a 125000 m^3 vessel (Anon, 1979a)) will raise the economic potential of the Persian Gulf gas resources and promote their development.

The cost of gas delivered by long-distance pipelines from the Arctic is of the same order as the cost of LNG shipped over large distances. Total investments in the Alaska Highway Gas Line with a capacity of 34 billion m^3/year amounts to \$10 billion in 1975 dollars (Anon, 1978a) and investments per 1000 m^3/year are about \$300. The costs (taking 25% of specific investments; a rate of return of 15%, depreciation at 4%, and fuel costs, wages, and other operating costs at 6%) are about \$70/1000 m^3 in 1975 dollars, or about \$120/1000 m^3 in 1979 dollars.

One of the key factors determining the gas resource value of the northern areas of Western Siberia is the economic viability of gas exports to Western Europe, but this is difficult to assess.

In this case the resource value should not be estimated as a differential between export prices and total costs, determined on the basis of typical data published in the USSR then converted into foreign currencies according to the official rate of exchange. The published cost data reflect a specific pricing policy within the country and the fact that domestic wholesale prices of pipes, compressors and other equipment in the USSR are several times lower than their world prices. It should also be kept in mind that pipes and equipment are usually imported for the construction of export-oriented capacity, since domestic pipes and equipment are needed for new units to meet domestic gas demand. Since imported pipes and equipment are obtained at world prices and represent over half the total investment, the cost of gas transportation from northern parts of Western Siberia to the countries of Western Europe is close to that of gas piped from Northern Alaska to the 48 lower States of the USA, taking into account the difference between the total lengths of both pipelines and of those parts which cross permafrost terrain. Determined in this way, specific costs of gas piped from the northern parts of Western Siberia to Western Europe exceed \$90/1000 m^3.

Gas transportation from the Canadian arctic archipelago will be much more expensive than transportation from Northern Alaska. When exploration and production costs, which are also higher in the Canadian arctic shelf, are added, total costs for the less favorable part of the reserves (i.e., for relatively small fields) may be even higher than the future world gas price (\$250-280/1000 m^3 in 1979 dollars or more). Hence, these resources will be of no economic value even in the remote future, but their contribution to global gas resources is comparatively small.

Thus at prices which we consider the most probable in the distant future (\$250-280/1000 m^3 in 1979 dollars or higher), almost all conventional gas resources may be profitably developed.

In assessing the gas industry's resource base, the uncertainty of economic estimates of unconventional gas resources (coal seams, Devonian shale, tight formations, geopressured methane, gas hydrate) is extremely high; much higher than for unconventional crude oil resources.

The first assessment of development costs of unconventional gas resources has been published recently by the American Gas Research Institute (GRI) and is based on data provided by the US Department of Energy. The estimate seems attractive as it comprises all the main unconventional gas resources, except for gas hydrate, in the USA differentiated according to production costs.

Unfortunately, we have been unable to determine from published articles (Anon, 1978b,1979b) what dollars were used in making the estimates. If late 1970s dollars are used, which is most likely, the estimates seem to be too optimistic. Data casting doubt on the GRI estimates have been published, especially concerning geopressured gas resources. According to GRI, 4 trillion m^3 may be extracted at costs up to \$140/1000 m^3 or \$4/Mcf and practically all economically recoverable resources (11 trillion m^3) at costs up to \$210/1000 m^3 or \$6/Mcf.

However, available information does not confirm GRI's estimates and gives ground for criticism. Doscher, *et al.* (1979) have shown that even with favorable assumptions about the size of geopressured gas reservoir, porosity, gas/water ratio, production rates and stability, the selling costs of methane recoverable from geopressured brines, before federal income taxes and with a 15% rate of return, would range from \$140 to \$525/1000 m^3 (\$4-15/Mcf). They concluded that considerable quantities of geopressured gas will not be available in the USA at less than \$350/1000 m^3 (\$10/Mcf). Recently, Zinn (1979) reported his results showing that Doscher's assessments were not overestimated. According to Doscher, at a brine production rate of 4000 m^3/day the selling price of geopressured gas will be around \$140/1000 m^3 (\$4/Mcf).

Zinn (1979) reported that the cost (with a 15% rate of return, 48% federal tax and 12.5% royalty) of gas resource development and utilization of hot brine heat in the most likely fairway of the Frio formation (the Brazoria fairway) would exceed \$140-175/1000 m^3 (\$4-5/Mcf). However, he assumes a production rate not of 4000 m^3/day, as Doscher assumed, but of 6400 m^3/day. The brine production rates of other fairways in the most explored Frio formation (Texas) are expected to be much lower.

Thus, the development of only a small part of the technically-recoverable geopressured gas resources will be economically justified even at higher world oil and gas prices. The economically-recoverable part of other unconventional gas resources (coal seams, Devonian shale and tight formations) will probably be much larger than that of geopressured resources. The development of the gas hydrate resources of the ocean floor is most problematic, as not only the data concerning the economics of production, but also clear ideas about the technology of their development are unavailable. The economic potential of unconventional gas resources is comparatively small on the whole.

Unlike unconventional crude oil resources (heavy oil, bituminous sands and shale oil), unconventional gas resources will not play an important role in world energy supply even in the distant future, although they may be significant for local gas supplies.

CONCLUSIONS

Only a few years ago the economic value of natural gas was determined by some authors on the basis of marginal coal costs. With the changes in the energy situation it became clear that this was unacceptable since the particular qualities of natural gas can be matched only by coal-based syngas. The value of gas resources should be assessed as the difference between total costs and world gas prices. In the long run both world prices and the economic potential will be determined by costs of syngas production. Preliminary estimates show that in the foreseeable future, development of almost all of the technically-recoverable conventional gas resources is economically justified, unlike conventional oil resources, a considerable part of which will not be economically recoverable. However, for unconventional oil and gas resources, the situation is reversed.

REFERENCES

Anon. (1978a). Alaskan Highway Gas Project. Pipeline and Gas J., 4:25.

Anon. (1978b). Digging deeper eases threat of gas shortages. Chemical Week, Nov. 29:11-12.

Anon. (1979a). LNG transport saving with new gas carrier design. Int. Petroleum Times, Feb. 15:26.

Anon. (1979b). Next decade will see birth of US synfuel industry. Oil and Gas J., 46:189-200.

Arsky, A.K. (1979). Economic Estimates of the Natural Hydrocarbon Resources in Capitalist and Developing Countries and the Possible Prospects of their Development.

Astakhov, A.S. (1979). Some Estimates of Global Effective Coal.

Research Report, International Institute for Applied Systems Analysis, Laxenburg, Austria.

Doscher, T.M., Osborne, R.H., Wilson, T., Rhee, S., Cox, D., and Kuuskraa, V. (1979). The technology and economics of methane production from geopressured aquifers. J. Petroleum Technol., 12:1502-1515.

Gofman, K.G. (1977). Economic Estimation of Natural Resources in the Socialist Economy. Nauka, Moscow.

Makarov, A.A. (1977). Problems and methods for the long-term forecasting of the USSR national fuel-energy complex structure. In Y. Kononov (Editor), Methods of Systems Analysis for Long-Term Energy Development, CP-77-2. International Institute for Applied Systems Analysis, Laxenburg, Austria.

Mossadeghi, T. (1977). The prospects of LNG export and its limitations. Arab Oil and Gas, 144:23-29.

Segal, J. (1979). Future clouded by uncertainty. Petroleum Economist, 12:515-520.

Stanford Research Institute (1977). Stanford National Energy Model, Final Report, Vol. 2, Stanford Research Institute.

Zinn, S.D. (1979). Seminar on Geopressured Gas Resources. International Institute for Applied Systems Analysis, Laxenburg, Austria.

THE ROLE FOR NATURAL GAS IN THE INTERNATIONAL ENERGY AGENCY

Frederick W. Gorbet and Asger Hansen
International Energy Agency, Paris, France

I. INTRODUCTION

Natural gas can play a critically important role in the energy systems of IEA countries over the next two decades, as a relatively easily accessible and clean burning fuel that can substitute for limited supplies of oil in many uses. We are currently preparing an IEA study on Natural Gas Prospects to 2000 -- which will be published in early 1981, and this presentation reports some of our preliminary findings and indicates some of the issues that we think will become increasingly important. Many of the specifics will be covered by others in the course of this Conference, and in some detail, so these remarks will be rather general and try to give you a sense of the overall framework that we see emerging. To summarise our conclusions in one sentence: we feel that natural gas prospects are very encouraging, but that a number of very difficult issues are going to have to be addressed squarely and resolved, if the potential of natural gas is to be achieved.

The potential role of natural gas must be considered in the context of the overall energy situation and general economic conditions. We would therefore like to review briefly how we see current energy prospects before looking more specifically at the natural gas situation.

The world energy situation has changed dramatically over the last eighteen months.

The oil market tightened sharply in early 1979, due to the temporary cessation of Iranian production. But the considerable political uncertainty resulting from the Iranian revolution, coupled with heavy stockbuilding in the second half, maintained pressure on price throughout the year, even in the face of record levels of OPEC oil production. Prices more than doubled in the course of 1979. Price pressures have continued through the first half of 1980 as well, despite falling oil demand, and as of July 1 prices are scheduled to increase again. This will take them to a level about 150% higher than they were eighteen months ago.

The economic implications of these price increases for the industrialised countries and for the world will be serious. Inflationary pressures are increasing; and growth will continue to slow. The direct and indirect effects of the price increases will be to reduce GNP in the OECD region by more than $400 billion (or 5%) in 1980. The direct transfer from OECD countries to oil producing countries will be over $150 billion. Estimates of the OPEC surplus for 1980 are in the range of $115-120 billion, with almost two-thirds of this reflected in deficits of the oil-importing developing countries. These countries will face a massive financing challenge that has the potential, if not addressed cooperatively and constructively, to result in immense human tragedy.

The energy implications of what has recently happened are also serious. Both the higher levels of oil prices and the political events of the past year have had a significant impact on the attitudes of oil producing countries about desirable levels of oil production. It is becoming increasingly clear that production will be managed much more conservatively. The world oil market, for the foreseeable future, will continue to be relatively tight and will be characterised by heightened political uncertainty.

It is against this general background that we wish to deal first with the overall energy outlook; second with an analysis of the role of natural gas by IEA-region and the import opportunities; and finally with some general issues in the natural gas picture that require further consideration.

II. IEA ENERGY OUTLOOK

The Secretariat is now working on OECD's World Energy Outlook-II which will update the World Energy Outlook published in 1977. This report, which will be published towards year-end, will include projections of world energy supply and demand to the year 2000.

At the moment, however, our most recent outlook is based upon the energy forecasts of Member countries, adjusted by the Secretariat to take into account reduced energy demand due to higher oil prices and expectations of lower economic growth. Assuming an economic growth rate on the order of 3% to 3.5% over the 1980s, and taking into account the price increases since end-1978, we arrive at an energy requirement in 1990 which is 25% higher than that of 1978 (Figure 1). This represents an average energy demand growth of 2% per annum. The detailed assumptions underlying these projections are recorded in the Review of IEA Countries' Energy Policies and Programmes* and will not be repeated here. The estimated 1990 IEA energy requirement of 4535 Mtoe is about 20 per cent lower than the IEA's own forecast of two or three years ago and reflects projected economic and energy growth very much lower than historical trend levels. Indeed, the implied TPE/GDP elasticity in this scenario is 0.6 over the 1980-90 decade.

There are two relevant questions related to this scenario. First, can the energy demand growth projected be met without increasing oil imports, as Figure 1 suggests? Second, even if it can, is this likely to be good enough given the increasingly tightening oil situation we foresee through the 1980s?

---

* See Energy Policies and Programmes of IEA Countries, 1979 Review. OECD, May 1980.

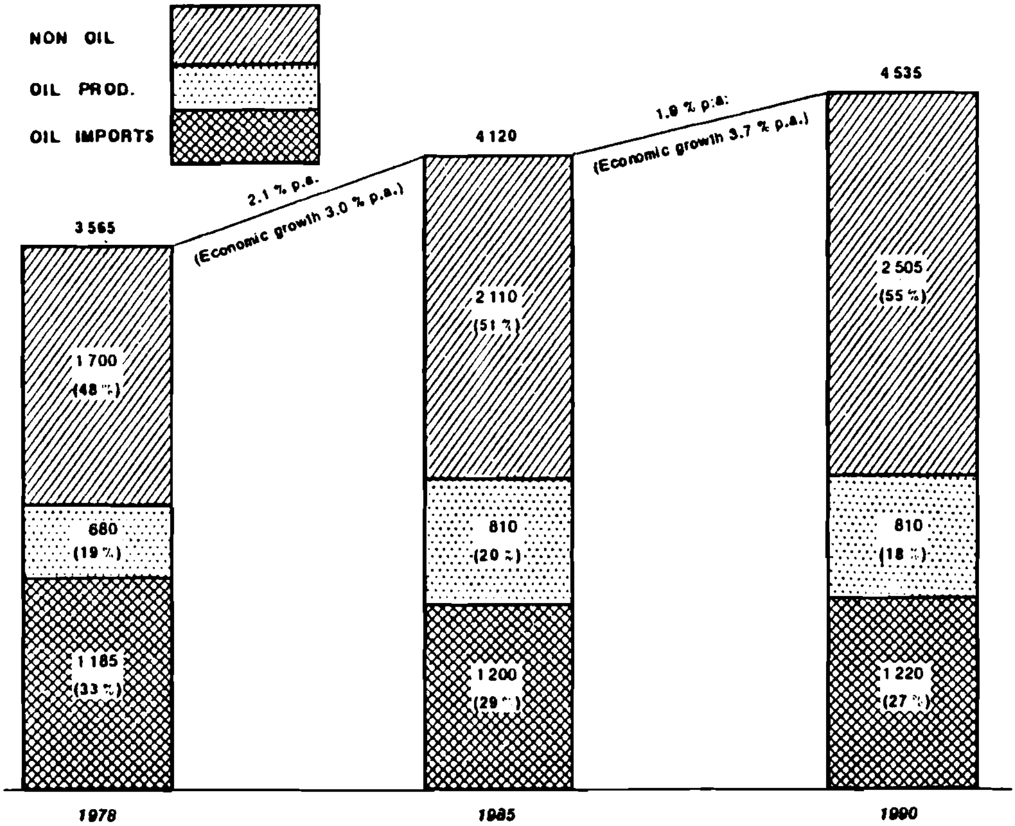
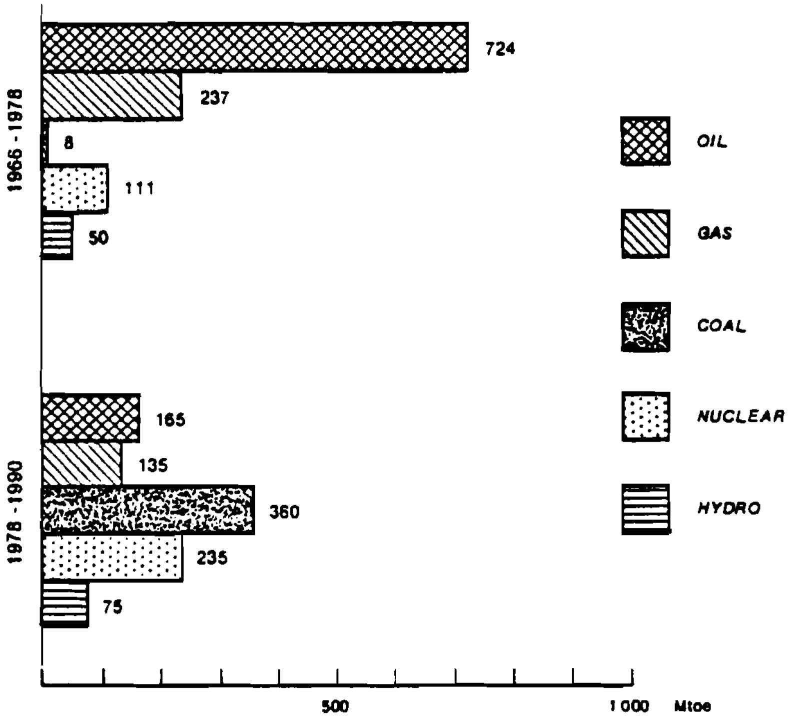


Figure 1 IEA ENERGY REQUIREMENTS Million tons oil equivalent

Figure 2, which shows how the IEA Secretariat expects incremental demand to be satisfied in the 1978-90 period compared with the previous 12 year period, gives a partial answer to the first question. Between 1966 and 1978, energy demand increased by 1130 Mtoe; 45 per cent came from IEA production and 55 per cent from energy imports, nearly all of which was oil. From 1978-85, it is expected that indigenous production will account for 80% of incremental energy required, and of the 20% imported most will be natural gas and coal.

Coal's increasing role is conspicuous. Every year since 1977, Member countries have increased their projections for 1990 coal production and use. In May 1979 IEA Ministers adopted a set of Principles for IEA action on coal to help promote substantial expansion of coal use, production and trade, and it



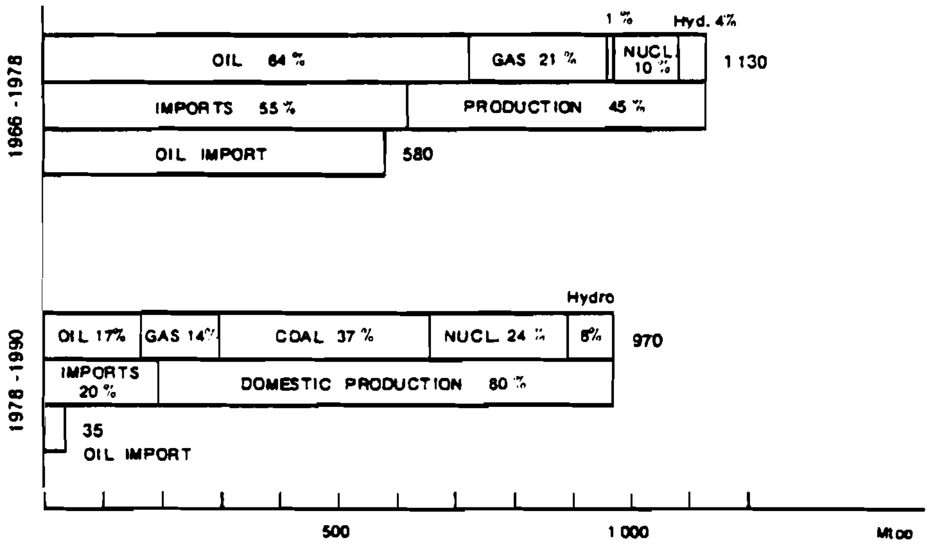


Figure 2

CONTRIBUTIONS TO INCREASED IEA ENERGY DEMAND is now widely accepted that coal will be used more extensively in the future. The attractiveness of increased reliance on coal has been enhanced by market developments and increased concern about the availability of oil and nuclear power. Countries' projections for 1990 were more than 100 Mtoe above the shown increase. We have adjusted it downward, not because the potential isn't there -- in fact we believe it could be even greater -- but because we do not yet see the policies clearly in place that will allow that potential to be achieved. Additional action is required to:

- ensure that government policies and administrative measures strongly support the shift to coal in electricity generation and industry;

- remove bottlenecks in national and international coal transport systems; and

- shorten lead times in getting projects approved, financed and constructed.

The Agency set up a Coal Industry Advisory Board early this year to draw up a blueprint for actions necessary to achieve a doubling of coal production and use by 1990. The Board will report to governments before the end of the year.

Contrary to coal, projections for nuclear power availability have been steadily lowered. Countries' most recent projections for nuclear electricity production by 1990 were only 75% of those made two years earlier. Lead times have continued to increase and a considerable portion of the current 1990 projection must be regarded as being at risk in that year simply because construction is not yet under way or sites have yet to be selected. Consequently, in our present balance the Secretariat has also reduced the contribution from nuclear power by 100 Mtoe. The main cause of the present nuclear situation is due to public concern about the nuclear fuel cycle and related issues of safety and nuclear proliferation. But there are some encouraging indications that nuclear may have been through its worst period with respect to public objection. The Swedes, in their March referendum, expressed support for the nuclear option. The French have reaffirmed their intentions to rapidly expand their programme and are pressing ahead with both the fast breeder and reprocessing. The German Chancellor has recently voiced his strong support for nuclear power. These examples suggest that the majority of the public may be recognising that losing the nuclear option would have unacceptable consequences.

IEA production of oil from 1978-90 is projected to increase by almost as much as it did in the previous 12 year period. There is also some further potential for increased domestic oil production if prospective acreage is made available for exploration in the near future. Marginal field development and enhanced recovery processes might add to production as well, but part of the forecast production in Figure 2 is from yet to be discovered reserves or from sources requiring new technology. We feel that there could be as much as 1.5 Mbd downside risk on the United States 1990 oil production figure, but this might be offset by production from the Canadian Arctic and offshore, from the North Sea and from some synthetic production in the United States.

As to gas, the scenario in Figure 2 shows a considerable increase in imports into the IEA, but hardly any production increase. The gas situation is discussed in more detail below, but in general we feel there is considerably more potential to expand natural gas use by 1990.

On balance, therefore, the answer to the first question -- can IEA energy requirements be met with no increase in imported oil -- is a cautious "yes". The resources are there; the technology is there; the economics are favourable and, indeed, even more than we are forecasting could be achieved. But the question mark is whether the policy initiatives required will be forthcoming.

What about the second question? Even if we manage to develop alternatives on the scale shown in Figure 2, is that good enough? Figure 3 shows a projected global oil balance, based on this scenario and a number of other assumptions about the rest of the world (shown in more detail in Table 1), the answer is clearly "no".

Briefly, the scenario in Figure 3 suggests that:

* IEA countries' oil consumption is expected to increase only slightly from now to 1985 and hardly at all from 1985-90. Net oil imports by IEA countries are expected to show no significant increase right through the decade.

* Even in this situation, however, it is expected that potential world oil demand will exceed available supplies by over 2 Mbd in 1985 and that this notional gap will grow to almost 6 Mbd by 1990. This results from continuing demand growth in the rest of the world and virtually no increase in OPEC production.

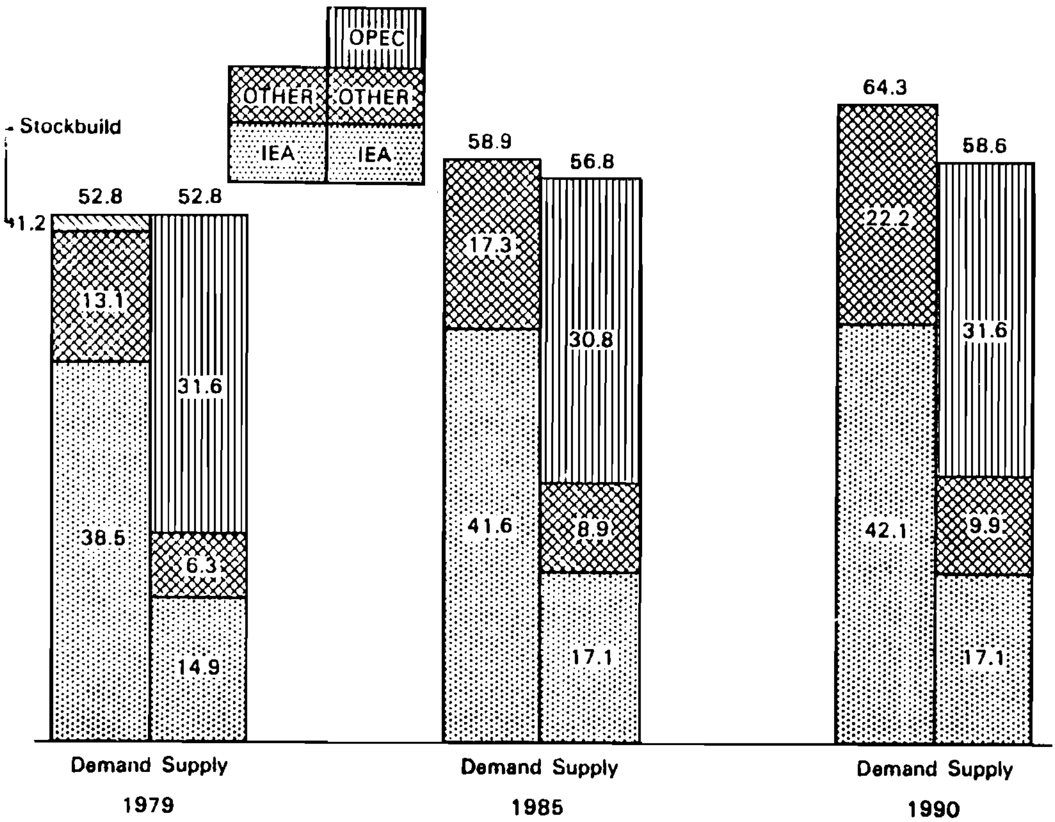


Figure 3 **GLOBAL OIL DEMAND AND SUPPLY** Million barrels per day

* There are a number of uncertainties associated with these projections. Demand may well be lower because of the recent price increases and reduced economic growth. At the same time, there is undoubtedly scope for more vigorous oil conservation and substitution, with supporting government policies. But uncertainties are equally real on the other side of the balance. Given the North American oil production outlook, IEA countries will have to run very hard to maintain oil production through the 1980s at the levels shown. And the production assumptions we have made for OPEC may well turn out to be high.

This picture of emerging global oil market imbalance, together with the experience of the last eighteen months, indicate both the seriousness and nature of the energy challenge we will face through the 1980s. Stronger and more determined policy measures are required to reorient our energy systems away from oil and, in particular, away from potentially insecure sources of supply. But this process will take time and while it is going on it will be essential to devote increasing efforts to ensuring relative stability in the international oil market.

How well we deal with these two dimensions of the energy challenge will have a profound and lasting impact on how our economies and societies develop through the eighties. There is a real risk that higher oil prices and economic recession may lead us into a "low-growth trap" where pressures for protectionism increase, the will to look beyond short-term national self-interest weakens, and confidence in future prospects erodes. If this were to happen, it would increase the difficulty of making the required structural changes in our energy systems - changes that are necessary to ease the constraint that limited oil production will otherwise put on economic growth. Alternatives would not be developed rapidly enough and when economic growth picks up we could face another oil price explosion that would cause the cycle to repeat itself yet again. In such a scenario, expectations would be frustrated and tensions would increase both within and among nations. It is difficult even to speculate about the ultimate economic, political and strategic consequences of such developments. But it is clear that no country would be unaffected.

It is in this context -- of managing the energy challenge in an interdependent world -- that the role of natural gas needs to be addressed.

III. THE ROLE OF NATURAL GAS

As a source of energy supply, natural gas has many advantages. It does not suffer from the psychological difficulties that coal has to overcome: it is clearly recognised as a fuel of the future. The technology is understood and proved and in both North America and Europe, substantial infrastructure is already in place. Finally, natural gas is less clouded by environmental and safety concerns than either coal or nuclear; indeed it is recognised as a premium fuel. The critical issues are quite simply availability and cost. But the IEA does have extensive resource potential and very large reserves in non-IEA countries are within economic reach.

Notwithstanding these opportunities, the facts are that over the 1973-1978 period very little oil was displaced by gas for the IEA as a whole. Gas use did not increase over the period, but this masked very divergent trends in the different IEA regions. In the United States, declining production (the equivalent of 1.4 Mbd) led to decreased consumption and some substitution of oil for natural gas, particularly in the industrial sector. In Europe, gas use increased by 50% over this period (the equivalent of 1 Mbd) and almost all of this reflected Dutch, Norwegian and United Kingdom production. Gas use tripled in Japan, all of the increase coming from imports. (See Table 2)

Although further production potential exists within the IEA, particularly in Canada, Australia and the North Sea, all IEA regions will increasingly have to rely on imports to satisfy demand. This will require careful negotiation to ensure secure

Table 1 Global Oil Balance*

	1978 Actual	1985	1990
IEA (Mtoe)			
Total Primary Energy	3516	4040	4450
Non-Oil Energy Consumption	1705	2110	2510
Oil Consumption	1811	1930	1940
(Net Oil Imports)**	(1185)	(1210)	(1220)
World Oil Consumption (Mbd)			
IEA Countries	38.8	41.6	42.1
Others (incl. OPEC)	12.6	17.3	22.2
World (excl. CPE)	51.4	58.9	64.3
Non-OPEC Oil Production (Mbd)			
IEA Countries	14.2	17.1	17.1
Developing Countries	4.6	8.5	11.0
Net Imports from CPE	1.3	0.4	-1.1
TOTAL	20.1	26.0	27.0
OPEC Production (Mdb)	30.5	30.8	31.6
Additional Production or Savings Required (Mbd)	-	2.1	5.7

* Conversion factor: 1 Mbd = 48.3 Mtoe/year.
** Includes marine bunkers: 62 Mtoe in 1978, 80 Mtoe in 1985 and 84 Mtoe in 1990.

supplies at competitive prices. The supply position of Western Europe in particular might well be difficult, since the intention of the Netherlands not to renew existing export contracts could leave a large gap in European supplies in the early 1990s. The gas development policy of Norway will be very important in this context in light of the uncertainties as to future Algerian and USSR imports. Before discussing the opportunities for gas imports from areas outside IEA, the situation within each of the IEA regions is briefly described below.

Table 2

NATURAL GAS PRODUCTION, CONSUMPTION AND TRADE (MTOE)

	1973			1978			1985			1990		
	Prod.	Cons.	Net Exports	Prod.	Cons.	Net Exports	Prod.	Cons.	Net Exports	Prod.	Cons.	Net Exports
Canada	63.3	38.7	23.4	64.3	43.5	20.4	69.9	49.4	20.5	57.9	52.8	5.1
USA	514.5	526.7	-22.7	445.4	464.7	-21.0	420.3	452.7	-32.4	402.1	437.2	-35.1
IEA North America	577.8	565.4	0.7	509.7	508.2	-0.6	490.2	502.1	-11.9	460.0	490.0	-30.0
Australia	3.4	3.4	-	6.2	6.2	-	23.0	14.8	8.2	23.0	16.2	6.8
New Zealand	0.3	0.3	-	1.3	1.3	-	1.7	1.7	-	3.4	3.4	-
Japan	2.6	5.4	-2.8	2.4	16.1	-13.6	5.4	40.6	-35.2	6.4	60.3	-53.9
IEA Pacific	6.3	9.1	-2.8	9.9	23.6	-13.6	30.1	57.1	-27.0	32.8	79.9	-47.1
Austria	2.0	3.4	-1.4	2.1	4.1	-2.4	1.0	6.4	-5.4	0.9	7.0	-6.1
Belgium	0	7.3	-7.3	0	8.7	-8.7	0	12.0	-12.0	0	13.0	-13.0
Denmark	-	-	-	-	-	-	2.0	2.0	-	3.0	3.0	-
Germany	15.4	27.6	-12.3	15.8	41.2	-26.6	14.4	61.5	-47.1	12.5	62.7	-50.2
Greece	-	-	-	-	-	-	0.4	0.4	-	0.2	0.2	-
Iceland	-	-	-	-	-	-	1.1	1.1	-	1.1	1.1	-
Italy	12.9	14.5	-1.7	11.5	22.8	-11.8	10.0	32.2	-22.2	10.0	38.8	-28.8
Luxembourg	-	0.2	-0.2	-	0.5	-0.5	-	0.6	-0.6	-	0.8	-0.8
Netherlands	54.8	29.0	25.7	68.4	33.2	35.1	62.6	33.6	29.0	52.7	33.8	18.9
Norway	-	-	-	12.0	0.6	11.4	23.0	-	23.0	18.0	-	18.0
Spain	-	1.0	-1.0	-	1.4	-1.5	1.7	6.6	-4.9	1.8	7.7	-5.9
Sweden	-	-	-	-	-	-	-	-	-	-	-	-
Switzerland	-	0.2	-0.2	-	0.7	-0.7	-	1.7	-1.7	-	1.9	-1.9
Turkey	-	-	-	-	-	-	-	-	-	-	-	-
UK	25.0	25.6	-0.7	33.2	37.6	-4.4	37.5	47.5	-10.0	40.0	50.0	-10.0
IEA Europe	110.0	108.0	1.1	143.0	150.8	-10.1	153.7	205.6	-51.9	140.2	220.0	-79.8
IEA TOTAL	694.1	683.2	-1.0	662.6	682.6	-24.3	674.0	764.8	-90.8	632.0	789.7	-156.9

Source: 1973 and 1973 figures from 1980 OECD Energy balances
1985 and 1990 figures from 1979 Submissions to SLT

A. European Prospects

During the period of rapid growth following World War II, Western Europe increased its reliance on oil dramatically. European oil consumption quadrupled from 1960 to 1973. Its share in total energy consumption doubled, from 30% to almost 60%.

Since 1973, there has been virtually no increase in European energy demand and oil consumption has fallen slightly, despite the fact that Europe's Gross Domestic Product grew at 2% per annum. This represents a significant move towards conservation in response to higher prices and one that we hope will be maintained and intensified.

Figure 4 shows the European IEA Member countries' projections of their energy, oil and gas situations through the eighties.* These projections are about one year old and they will undoubtedly be modified substantially in the light of recent oil price increases. But what we want to focus on is not the precision of the numbers, but the relative developments of gas in energy balances.

During the 1960s and the 1970s several European countries established sizeable markets for natural gas based on onshore gas fields, including the giant Groningen field in the Netherlands. There is now an integrated European grid and the United Kingdom also has a nationally integrated transmission system with supplies from its own fields in the North Sea and some imports from Norway. Today, total gas consumption in IEA-Europe is about 150 Mtoe (6 Tcf), covering 15% of total primary energy consumption. The largest share is in the Netherlands with 50%, followed by the United Kingdom, Germany and Italy with about 15-20% each.

---

* Table 2 shows gas production, consumption and trade by country. Table 3 shows the share of natural gas in alternative uses.

Figure 4

IEA - EUROPE

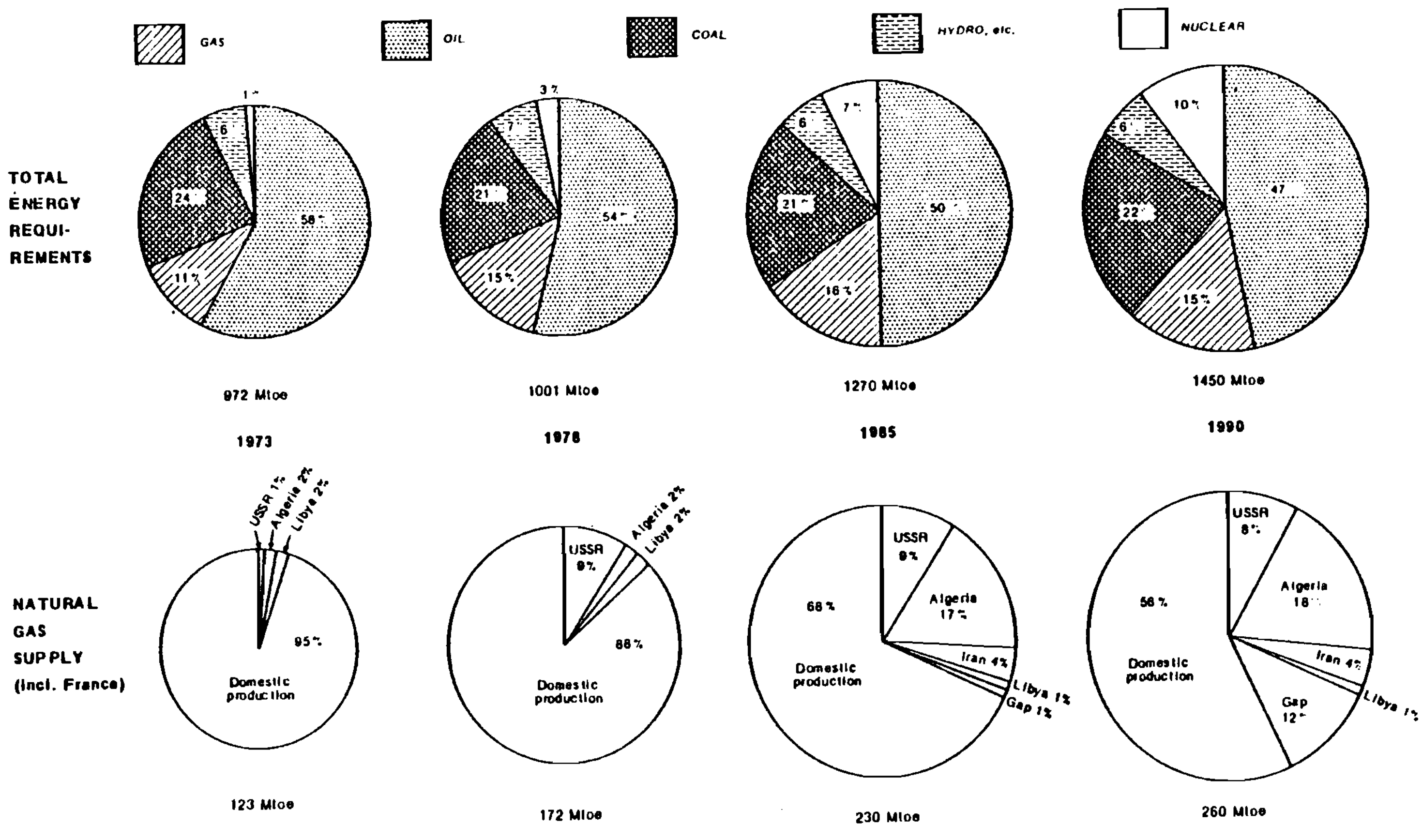


Table 3

SHARE OF NATURAL GAS IN ALTERNATIVE USES (%)

	1973			1978			1985			1990		
	Res/Comm	Ind	Elec	Res/Comm	Ind	Elec	Res/Comm	Ind	Elec	Res/Comm	Ind	Elec
Canada	33.3	33.3	11.9	41.0	40.2	6.8	43.5	33.6	6.7	41.1	35.6	6.3
USA	33.1	35.9	16.6	39.8	28.9	16.4	38.1	38.7	10.5	41.6	39.5	2.6
IEA North America	33.1	35.7	16.3	39.8	30.1	15.6	38.2	38.2	10.1	41.5	39.1	3.0
Australia	25.7	42.8	22.8	19.4	54.8	17.7	15.5	43.2	22.3	15.4	43.2	22.2
New Zealand	33.3	-	33.3	7.1	14.3	71.4	5.9	35.0	29.4	2.9	20.6	4.8
Japan	83.6	38.2	34.5	40.0	10.9	67.3	26.4	9.6	67.0	22.2	10.9	68.2
IEA Pacific	60.2	38.7	30.0	32.8	22.4	54.6	23.1	17.6	56.0	20.3	17.3	57.3
Austria	17.6	52.9	23.5	18.6	46.5	30.2	25.4	30.2	31.7	31.4	30	25.7
Belgium	20.5	50.7	26.0	33.7	43.2	23.2	41.7	52.5	18.3	37.7	54.6	17.7
Denmark	100	-	-	100	-	-	80.0	20.0	-	73.3	26.7	-
Germany	28.3	54.3	23.6	30.7	36.9	35.9	48.8	24.4	28.0	52.2	17.3	23.6
Greece	-	-	-	-	-	-	25.0	-	-	50.0	-	-
Iceland	100	-	-	100	-	-	9.1	9.1	54.5	9.1	9.1	54.5
Italy	28.3	62.8	6.9	36.9	41.3	10.2	35.4	44.7	7.8	36.6	46.9	5.2
Luxembourg	50.0	50.0	-	20	40	40	33.3	50.0	16.7	37.5	50	12.5
Netherlands	39.3	28.6	33.1	46.6	29.3	24.2	56.0	26.5	17.6	56.2	29.6	14.2
Norway	-	-	-	-	-	-	-	-	-	-	-	-
Spain	30.0	40.0	10.0	26.7	53.3	13.3	10.6	66.7	3.0	11.7	63.6	3.9
Sweden	-	100	-	100	-	-	-	-	-	-	-	-
Switzerland	100	-	-	42.9	42.9	4.2	47.1	41.2	5.9	52.6	36.8	5.3
Turkey	-	-	-	-	-	-	-	-	-	-	-	-
UK	53.1	40.6	3.9	55.3	37.0	2.1	58.9	32.6	0	63.0	29.0	0
IEA Europe	36.4	35.7	19.2				48.0	33.1	15.0	58.8	35.9	14.5
IEA TOTAL	34.0	35.8	16.9	39.8	31.8	18.1	39.8	35.3	14.8	43.6	36.0	11.4

Source: 1973 and 1978 figures from 1980 OECD Energy Balances
1985 and 1990 figures from 1979 Submissions to SLT

The major European producer today is the Netherlands, based on the large reserves in the Groningen field. The North Sea is also a major supply source, with considerable potential. Total European gas production is still slightly higher than oil production but, contrary to oil, domestic production accounts for almost 90% of total gas use.

Through the 1960s, natural gas substituted primarily for coal, but since 1973 there has been increasing substitution of gas for oil. There is considerable room for further substitution if supplies can be made available and our work suggests that the present share of natural gas could increase from 15% of TPE today to perhaps 25-30% by 1990.

Whether this kind of penetration takes place will depend upon gas availability and gas prices. If additional gas supplies can be made available at competitive prices, European gas use could increase faster, taking pressure off oil demand and consequently prolonging the availability of world oil supplies.

As the lower panel of Figure 4 shows, however, a more active posture by gas importers is required even to secure supplies now projected, let alone increase them substantially by 1990. A small gap, representing projected supplies not now covered by contract, exists in 1985 and a much larger gap (31 Mtoe) exists in 1990, even assuming substantial imports from Algeria, the USSR and Iran.

Within the IEA, the North Sea, and particularly Norwegian exports, can play a critical role here. North Sea gas production is now about 55 Mtoe, accounting for 37% of European supplies. Official forecasts see an increase to 60 Mtoe in 1985, but no further increase to 1990. We feel that these projections understate potential considerably, particularly for the post-1985 period. For example, present discoveries in the North Sea (south of 62 degrees) are roughly 2 to 3 times the level of reserves now authorised for development.

Norwegian gas exports have grown from 14 Mtoe in 1978 to about 22 Mtoe (1 Tcf) today. There is considerable interest in Continental Europe and the United Kingdom in expanding North Sea imports even further - which is an increasingly sensible policy in the light of recent oil price increases, the attitude of some OPEC countries toward gas exports, and the planned termination of Dutch exports.

It now appears, with recent finds in the Norwegian sector and the re-evaluation of a United Kingdom gas-gathering system, that there is enough gas for two new transportation systems: one for the United Kingdom with a capacity of 10-15 Mtoe per year (possibly including some Norwegian gas), and a second Norwegian gathering system with 20-25 Mtoe annual capacity. The United Kingdom system has now been announced and should be operational by 1985. In Norway, the recent oil price increases have led to some reconsideration of whether the gas should best be piped to Europe or delivered to Norway for export as LNG. A government proposal is now expected in the Spring of 1981 and Parliament will hopefully take a decision shortly thereafter, making a delivery system possible towards the end of the 1980s. Completion of the Norwegian system would fill the gap shown for 1990 and might as well allow additional gas penetration in European markets, thus helping to ease an increasingly difficult oil situation.

B. The Situation in North America

The increase in energy requirements from 1973 to 1978 (4%) was slightly higher than in Europe. In the United States, shown in Figure 5, natural gas use declined substantially and oil grew both absolutely (about 2 Mbd) and relative to total energy use. Indigenous oil production declined throughout the period and the result in 1978 was a dependence on oil imports for almost 21% of total energy consumption, compared with 15% in 1973.

The share of natural gas in total energy consumption had reached 14% by the late 1940s and it increased to 30% in 1960.

This share of a constantly growing energy economy held until the mid 1970s when shrinking domestic supplies supported by imports from Canada were no longer able to maintain market share.

Since 1966, annual production of natural gas from the lower 48 states has been greater than new additions to reserves, resulting in a decline in the Reserve/Production ratio from about 17 to 1 in 1966 to less than 10 to 1 today. Even if the large discoveries in Alaska are added, consumption for more than a decade has been increasing more quickly than additions to reserves.

In Canada, the turning point for the natural gas industry was the discovery in 1947 of a series of major fields in Western Canada which led to a rapid expansion of domestic gas use as well as exports. As early as 1960, some 20% of total gas production was exported to the United States, with close to half the natural gas production being exported in 1973.

Even more so than in Europe, the demand for natural gas is not a limiting factor on market growth. Canada has now decided to extend its pipeline infrastructure into eastern Canada and expanded natural gas demand will displace some oil imports over the 1980s. The situation in the United States is more problematical, but there are some indications that higher netbacks could lead to substantially greater production, even from the lower 48 states, as has been the case in Canada since 1973. If the United States' consumption in 1990 could be raised again to its 1973 level -- through domestic production and imports -- the increment would amount to over 2 Mbd of oil equivalent.

Exploration activity is at very high levels in North America. In the United States, however, drilling has been concentrated on the more modest prospects in the lower 48 States and not on the high potential offshore basins and in Alaska. This reflects government leasing policies and gas price regulations but there are now indications of changes. Offshore drilling in 1979 surpassed previous levels and 1980 activity is foreseen to be even higher.

Present government projections foresee a continued slight decline in production to less than 20 Tcf in 1990. We believe, however, that the potential exists to increase production above current forecasts in the United States, mainly from Alaskan gas fields and the Continental Shelf. Canadian forecasts do not include gas supplies from the frontier basins. There are presently over 15 Tcf of proved reserves in the high Arctic and plans are nearing completion to deliver at least some of these reserves as LNG. Company forecasts for 1990 range from 0.5 to 1.5 Tcf annually from the Mackenzie Delta/Beaufort Sea and from the Arctic Islands, and there may also be some production from Nova Scotia on stream by 1985, given a promising 1979 discovery.

On the other hand, the problems which we see today regarding the Alaskan gas pipeline project do not increase confidence about the timing of gas deliveries from frontier areas. In Figure 5, a 5% contribution from Alaska is shown for 1985, but it is no longer likely that the pipeline will be operational in this time frame.

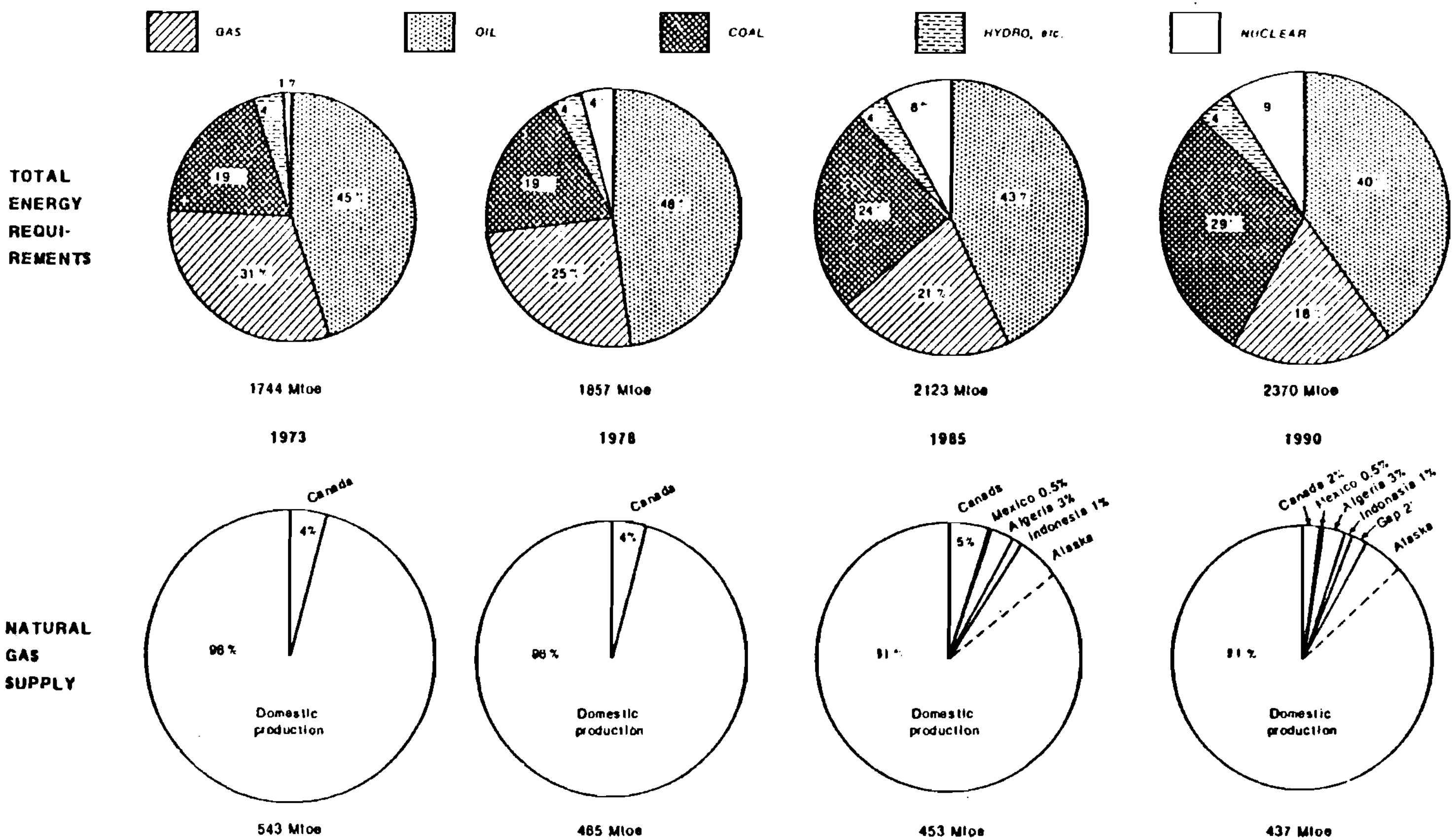
C. The Pacific Region

The gas era is much newer in the Pacific. In 1960, only Japan had a tiny production of natural gas. However, one of the Japanese policy thrusts in reducing oil dependency is to encourage gas use, and an increase by a factor of 12 is foreseen from 1973 to 1990. Almost all of this is to be imported and, as shown in Figure 6, over 40% of the expected imports in 1990 are as yet not covered by contracts.

Part of this gas could be supplied from Australia where the present gas production of 6.5 Mtoe is foreseen to increase to 23 Mtoe in 1985, with an exportable surplus on the order of 7 Mtoe. The recent surge in proved reserves on the Australian Outer Continental Shelf indicates potential for significant new discoveries, and announced development plans indicate rapid production growth potential, particularly after 1985.

Figure 5

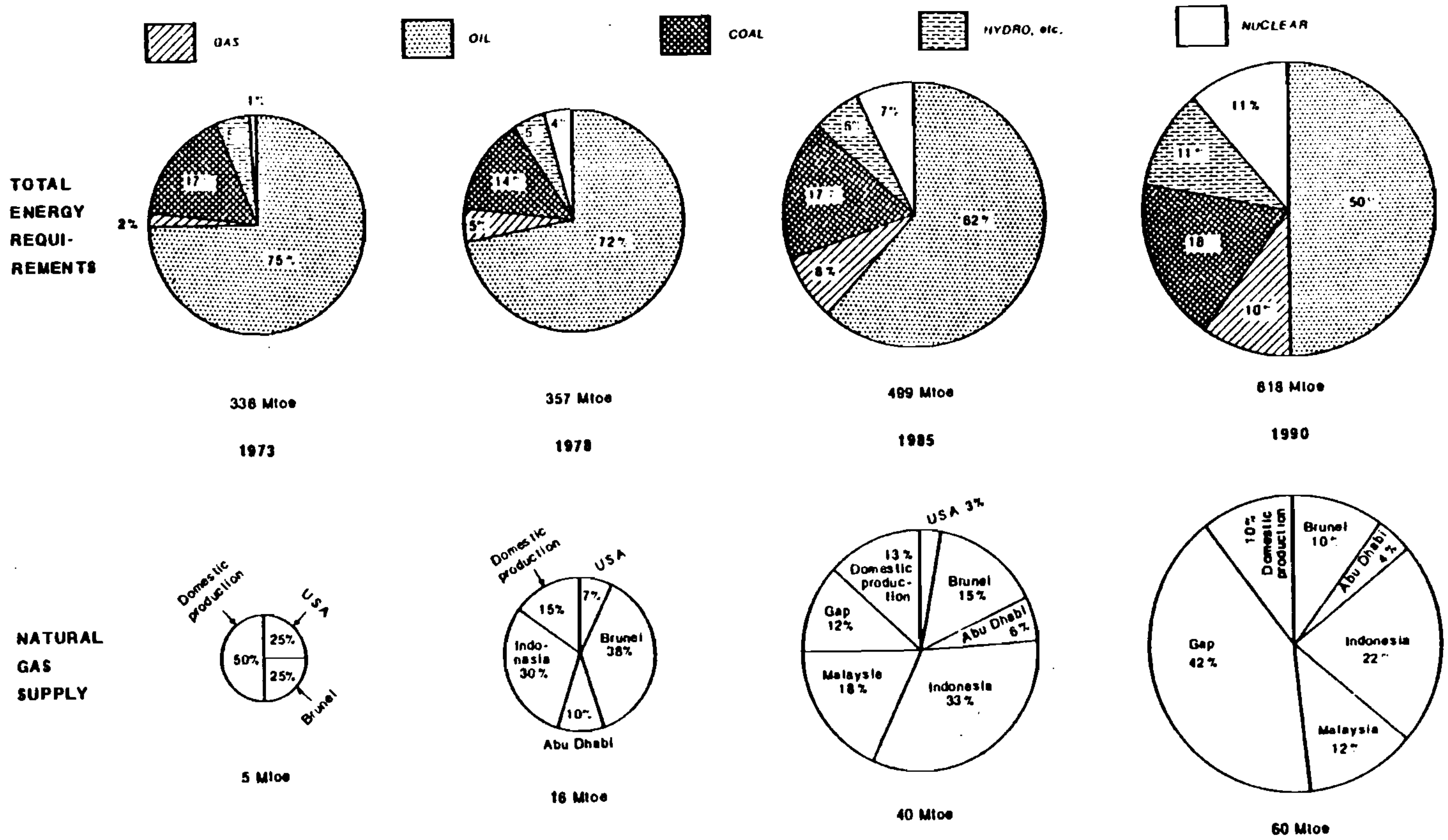
USA



GAS
OIL
COAL
HYDRO, etc.
NUCLEAR
TOTAL ENERGY REQUIREMENTS
NATURAL GAS SUPPLY
1744 Mtoe
1857 Mtoe
2123 Mtoe
2370 Mtoe
1973
1978
1985
1990
Canada
4%
96 %
Domestic production
543 Mtoe
485 Mtoe
453 Mtoe
437 Mtoe
5%
Mexico 0.5%
Algeria 3%
Indonesia 1%
Alaska
Canada 2%
Mexico 0.5%
Algeria 3%
Indonesia 1%
Gap 2
91 %

Figure 6

JAPAN



D. Non-Conventional and Synthetic Developments

The projections shown in the previous figures do not include production of non-conventional and synthetic gas. Except for some substantial exploration plays in Canada, which appear to be quite promising, non-conventional gas has attracted relatively little attention. Similarly, not much was done on synthetic developments until last year, when major initiatives were introduced by the United States and Germany, although the United Kingdom and Japan have modest programmes to support synthetic demonstration projects. This subject will be addressed specifically during this conference and we will not pursue it here, except to note in passing that the recent increases in oil prices have enhanced the commercial viability of such projects and this, together with increased concern as to security of energy supplies, should lead to higher priority for such new sources.

E. Potential For IEA Gas Imports

Let us now turn to gas trade and particularly the opportunities for increased imports into the IEA. Gas imports by IEA countries in 1978 were approximately 4 Tcf, three-quarters of which was supplied by Canada, the Netherlands and Norway. They are projected to more than double by 1990 to almost 9 Tcf, but only about 25% to 30% will be supplied by IEA exporting countries. Canada and Mexico will remain most important in the North American context, but OPEC and USSR exports will grow rapidly and might begin to dominate the international gas trade by the late 1980s. For example, gross imports into IEA Europe are expected to more than double between 1978 and 1990, from about 2.4 to 5.0 Tcf. But imports from outside the IEA will increase from 17% of total imports in 1978 to 64% in 1990. And of the imports for 1990 now contracted, Algeria and the USSR are projected to supply about 55% (about 2 Tcf).

The world gas resource base could easily support a several fold expansion of projected 1990 IEA trade levels. Jensen

Associates have done some useful work in this area.* The approach was to survey proved gas reserves and assign them by the following categories:

- inaccessible or flared
- deferred reserves (in gas caps or being reinjected)
- committed to domestic markets
- remote from existing markets
- already committed to export markets, and finally
- exportable surplus.

Their conclusion is that over 800 Tcf out of total proved reserves of 2500 Tcf appear favourably situated for additional international trade. Of this additional 800 Tcf, 600 Tcf is located in the USSR and Iran. However, as there has only been a limited amount of exploration to date in prospective gas-bearing sedimentary basins outside of North America and Europe we could also expect large reserves additions in the future if conditions favourable for exploration exist. Estimates of future discoveries range from 2500 to 8500 Tcf, much of which should be considered as exportable surplus. Moreover, with the recent oil price increases development of gas reserves in the High Arctic and northern North Sea, which are presently excluded from the exportable surplus category, now appear to be economically viable.

The major question is, of course, whether the economic and political climate in producing and importing countries will be conducive to the development of these reserves for export. The relatively high costs of gathering and transporting gas will continue to dominate remote gas project economics. But higher oil prices are rapidly changing the overall economics. Our analysis of the economics of moving previously marginal high cost gas from major gas reserve countries to different IEA markets suggests, for example, that delivering Arctic Island

---

* Jensen Associates, Inc. "Imported Liquified Natural Gas" - A Report to the Congress of the United States, Office of Technology Assessment. September 1979.

pipeline gas to southern markets is commercially viable at current Canadian and Mexican gas export price levels of $4.47/million BTU at the US border. Similarly, it is profitable to move North African LNG to both Europe and the United States at these prices, and the possible netback on LNG shipments from the Middle East has now become positive.

It must be understood, however, that the existence of the reserves and the ability to exploit them commercially is not necessarily sufficient to ensure that trade will take place. There are additional factors that require consideration from the perspective of both producing and importing countries.

For potential gas exporters, a critical factor is the value to place on reserves in the ground. This will depend on current and prospective marketing arrangements for gas, expectations about the price of oil, and the overall resource position, financial requirements, and aspirations of the country concerned. The results of this calculus can vary considerably between OPEC producers with large excess oil revenues and social/economic adjustment problems and developing countries in need of foreign exchange sources and keen on infrastructure and industrial offshore benefits associated with large gas export projects.

It is unlikely that there will be sufficient incentive to justify a major expansion of Gulf exports before the 1990s as there is no economic need for the area's major oil producers. Iran had developed previously ambitious gas development programmes but given the present uncertainties, it is unlikely that an IGAT-II type of project will come on stream before 1990.

The situation in Algeria is also highly uncertain at the moment. The Trans-Med Pipeline is almost complete and will be delivering about 11 Mtoe to Italy before 1985. But Algeria appears to be reconsidering the relative profitability of LNG deliveries versus direct pipeline sales and there are indications of an emerging preference to shift away from LNG. The degree to which this is entangled with the current negotiating position of Algeria vis-a-vis El Paso and Gaz de France is difficult to sort out.

Finally, with regard to the USSR, there are again some current uncertainties, although there would appear to be good prospects for a new large project on stream for the second half of the 1980s.

Opportunities for new LNG projects in the 1980s are to be found in the present OPEC LNG producing countries, Nigeria, Malaysia, Trinidad, Colombia, Chile, Australia, perhaps New Zealand and, as noted above, possibly Norway. In the North American context there are also good prospects for increased Canadian and Mexican natural gas exports.

From the perspective of potential importers, there are two prime considerations: price and security of supply.

Pricing Considerations

The price of imported gas delivered at the border has to fall within two limits: the cost of supply and market value less the cost of service.

Obviously no export project will be undertaken unless the producer can expect a reasonable rate of return on his investment and a netback price that reflects the inherent value of the resource.

Price escalation clauses are important in this respect because, given the large sunk capital costs in gas export projects subsequent increases in market price can generate very attractive rents. A critical issue in consumer/producer discussions is naturally the allocation of such rents. Under the present LNG contracts, both parties benefit in that the price escalation has tended to be related to prices fob the liquefaction plant. The final consumer also benefits as there are normally lags in the adjustment of gas prices to increases in the price of competing oil products.

The recent initiatives by gas exporting countries to price gas on a BTU-equivalent basis with crude oil is critical when discussing additional gas supplies. At the beginning of the year, Algeria raised the asking price to the crude oil equivalent price, a little more than $6 per million BTU ($36/bbl) fob. The principle that gas and crude oil must have the same price per unit calorific content represents a very important political point for gas producers and was, in a general sense, endorsed by OPEC Ministers at their recent meeting in Algiers. What it will mean in practical terms, however, and how it will work out in the process of price negotiations are matters that are not very clear at present.

Our analysis of central European markets suggests that, based on the current market distribution of gas, the weighted average cost of competing oil products -- to the consumer -- is about $6.60 per million BTU. The Algerian position would, after allowing for shipping, regasification and distribution charges, result in an average price for gas in these markets of about $10.00 per million BTU, 50% higher than the competing fuels. At a minimum, this kind of pricing structure would restrict natural gas use to the high end of the market, where volumes necessary to achieve the required economies of scale in transportation could be developed, if at all, only over rather long time periods.

How the current negotiations are resolved, therefore, will have quite a dramatic impact on the future market penetration of natural gas and natural gas trade.

Security of Supply

With regard to the security of future gas supplies, several of the largest actual or potential exporters of natural gas are OPEC members -- notably Algeria, Iran, Indonesia and Nigeria. As noted, OPEC and the USSR will tend to dominate international gas trade in the 1990s. OPEC members have in the past imposed oil price increases at short notice and often retroactively. Some have embargoed crude exports for political reasons. The interruption of Algerian supplies, in the course of price renegotiations, has naturally heightened concerns about security of supply.

Are LNG import projects any more secure than oil import arrangements? We would give a qualified yes to that question, but some reconsideration of financing arrangements for delivery infrastructure may be warranted. LNG projects are technically and financially integrated, highly capital intensive and tied to specific project circumstances. It is highly unlikely, for example, that a spot market for LNG will develop. Consequently, there are strong incentives for producers to supply on an uninterrupted basis. The consequences of supply interruption for the producer will increase with the degree of financial exposure in the project. The trend to date, however, has been to decrease the financial exposure of the producer through various financial assistance arrangements, often through an export-import facility of the consuming country, and it may make sense to reconsider these arrangements.

How important security of supply considerations are to a country are of course dependent on a country's particular vulnerability. The United States has a large domestic production base and an extensive and integrated pipeline system with considerable storage capacity. It is therefore considerably less vulnerable to supply interruption than Western Europe where there is not much system flexibility, rather limited integration of national grids and where reliance on non-IEA imports will increase from 12% of total gas use in 1978 to 45% by 1990 and possibly reach 60% by 2000. It may appear somewhat ironic, but the fact remains that the larger the domestic production base the more confident a country should be in increasing gas imports to displace oil.

IV. CONCLUSION

As noted above, the IEA Secretariat is developing a natural gas study, which should be available at the beginning of

1981. The objective of this study will be to outline expected trends in OECD gas production and trade to the year 2000, indicate areas where potential exists and identify the policy responses necessary to achieve that potential.

In conclusion, we would like to indicate a few areas where stronger policy action seems necessary to promote natural gas production, use and trade.

Our analysis suggests that more importance needs to be given to the timely and aggressive exploration and development of the large remaining conventional gas resource base of the IEA: in the North Sea, Alaska, the Arctic, offshore North America and the North West Shelf of Australia. With aggressive exploitation of the hydrocarbon prospects in these areas, it should be possible at least to offset declines in production from established producing regions in the IEA. This in turn will enhance IEA capability to increase non-IEA imports.

The situation in Europe deserves special comment because of Europe's much greater degree of energy vulnerability. The cautious attitude that characterises resource depletion policies, particularly in the United Kingdom, Norway and the Netherlands, has tended to restrict the pace of exploration and therefore delay the accumulation of information about the true potential of the resource base.

The period to the end of this century will be one of significant change in European energy systems. Countries are now facing alternative options (coal, nuclear, imported natural gas and synthetic fuels) that are expensive, irreversible once committed, and risky to various degrees. There is a pressing need for more information about oil and gas potential. A critical issue here is to consider whether the link can be broken between exploration activity and subsequent decisions about the pace of exploitation of proved reserves.

This would require more aggressive leasing policies and strengthening the work requirements of licensees in some areas.

It might also require changes in fiscal arrangements and the role of state companies in order to compensate for possibly longer delays between the proving up of reserves and their commercial exploitation. But if it can be done, and exploration activity increased significantly, then producing countries would have a better information base on which to develop long-term resource depletion policies and prospective importers would have a more complete picture of the range of energy supply options open to them.

With regard to current production, although most governments have the power to reduce or defer production, only the Netherlands intends to go this route in order to preserve the Groningen gas reserves. This policy will result in the Netherlands having the fastest rate of growth in oil imports of any IEA country over the next 5 years; and it could cause problems for other European countries in the early 1990s when Dutch export contracts are scheduled to end.

The major reason for country's decision to reduce current oil or gas production is often its concern to have adequate post-1990 hydrocarbon production available. Such a decision today is, nevertheless, based on incomplete information. In the present situation, with general continued pressure on the oil market and the particular dependence on oil imports, decisions to reduce current production without knowing the true potential seem difficult to defend against the background of the world energy outlook described above.

Finally, we would note briefly that accelerated development of non-conventional and synthetic gas sources is becoming increasingly important, particularly if major gas-using IEA countries are to manage with confidence a shift to SNG at the end of the century. This is especially so for the United States, faced with a trend decline in production from the "lower 48" States. And there will as well have to be increased emphasis on gas utilization strategies, transportation and distribution system flexibility, and emergency reserve systems. In the near term, it is particularly important for the IEA countries that the Alaska Gas Pipeline and the Norwegian gathering system move forward quickly.

In summary, we would re-emphasize the following points:

* The world energy situation will be increasingly difficult through the 1980s. How well it is managed will have a profound influence on economic growth, social stability and relations among nations. The key challenge will be for countries to work cooperatively to improve the total situation on which they all depend, rather than competing more and more sharply with one another for increasingly scarce oil supplies.

* Natural gas could make a significantly larger contribution to IEA energy balances than now anticipated. There are substantial opportunities to increase gas availability which are not being pursued aggressively enough. These include:

  - high cost but high potential frontier regions of the IEA;
  - non-conventional and synthetic sources;
  - imports from non-IEA reserves within economic reach.

* And particularly with regard to imports, it should be stressed again that the resource availability is a necessary but not sufficient condition for gas trade to increase. It is also necessary that additional gas be made available at competitive prices and that the supply arrangements can be regarded as secure. On balance, the development of natural gas imports should be pursued with strong determination, but also with some caution.

GAS: ITS PRICE AND FUTURE ROLE IN THE ENERGY SCENE

Othman Al-Rawi
Organization of Petroleum Exporting Countries (OPEC), Vienna, Austria

I am particularly pleased to have been invited to discuss the development of gas prices. The reason for my pleasure is that I believe the question of energy pricing to be the most important issue facing the world today and its importance will increase further in the future. I should make clear at the outset that, although I represent the OPEC Secretariat, I am expressing here only my own personal views on one of the most important problems facing the energy industry--the establishment of a gas-pricing mechanism.

The energy crisis today has occurred not merely because of a lack of adequate resources but also because of the absence of a coherent pricing policy. Such a policy would stimulate the supply of conventional fuels and encourage the development of unconventional fuels, in addition to making the consumer more energy-conscious and reducing wastage of hydrocarbon fuel resources.

Crude oil, in the past, has dominated the world energy market in terms of supply and price, and it will continue to do so until the turn of the century. This is so because it is the optimal form of energy--it is a concentrated fuel, it can be easily pumped, stored, and transported (whether by pipeline or otherwise), and it can be produced and used with minimum disruption to the environment. Coal, in contrast to oil, is difficult and costly to transport and has an adverse influence on the environment both when it is being produced and used.

Natural gas not only satisfies the requirement for a plentiful, transportable, and convertible energy source, but is also a ready-to-use petrochemical feedstock and an energy form which is acceptable to environmentalists. It is interesting to note that whilst natural gas reserves are equal to oil reserves (on a Btu basis), its share in the total energy balance is expected to be only 18% in 1980 as compared with 54% for oil.

Whilst OPEC member countries possess some 38% of the total world gas reserves of 2573 Tcf, their marketed production is a mere 6% which, with the production of crude oil, would not satisfy world demand. With the limited capacity for expansion of coal production, as well as the long lead time required for development of other sources of energy, the only possible way to satisfy the energy market is to increase the production of gas and move it to the consuming areas. The latter task is no longer insurmountable as modern technology has overcome the difficulties associated with transporting gas, and technology is available to transform it to more readily transportable forms.

Table 1 shows actual and projected values of the world liquefied natural gas and natural gas demand for the period 1970-1990. It is clear from this table that a great potential exists for development of international trade in natural gas (pipeline or liquefied natural gas). It is anticipated that the international trade in liquefied natural gas will increase by more than 300% in the next 10 years, whilst pipeline gas demand will increase by more than 200% during the same period. However, it should be noted that the potential supply is located in regions far from the consuming areas, a situation which will place a great responsibility, even a moral one, on the industrialized countries, which are the holders of the required technology and capital and which have the potential market to help create the right environment (economically or otherwise) for the producers to realize such supply. I feel that without this development of potential supplies of natural gas, it will be difficult for the world to cross the transition period from an economy based on depletable natural resources to one based on renewable energy resources.

The right environment in which to develop natural gas is one which is economically attractive for the producer in realistic commercial terms and stimulates both the producer and the consumer, via a coherent pricing mechanism, to ensure maximum recovery and optimal utilization of the product.

In the past the price of hydrocarbons was determined by the consuming countries and was kept artifically low in order to speed up the growth of their economies, at the expense of the producing countries. This low pricing of hydrocarbons not only discouraged development of alternative sources of energy but also encouraged the wasteful use of these depletable resources.

TABLE 1 Actual or projected figures for the world natural gas and liquefied natural gas demand for the period 1970–1990.[a]

	1970		1975		1980		1985		1990	
	TCF	%	TCF	%	TCF	%	TCF	%	TCF	%
Liquefied Natural Gas	0.1	6	0.25	6	1.6	24	3.5	30	5.0	31
Pipeline	1.6	94	4.0	94	5.2	76	6.2	70	11.0	69
Total	1.7	100	4.25	100	6.8	100	11.7	100	16.0	100

[a]Figure from: International transport of gas--a progress report. J.W. Kerr The World Gas Option--A Symposium, March 27, 1980.

PRICES OF LIQUEFIED NATURAL GAS AND NATURAL GAS

Table 2 shows the evolution of liquefied natural gas prices on a cif basis during the period 1972-1980, compared with average crude oil prices and the prices of some refined products. As can be seen from the table, a comparison of liquefied natural gas with other products which are used as fuel, and with crude oil, shows that the price of liquefied natural gas has decreased, not even maintaining its 1972 value. Compared with even high sulfur fuel oil, although liquefied natural gas was 71% more expensive in 1972, this differential decreased to 10% by the first quarter of 1980. Based on the prices of petroleum products in the first quarter of 1980 and taking the relative value between liquefied natural gas and petroleum products which existed in 1972, the price of liquefied natural gas should be US$6.21-6.91/ MMBtu.

Considering the cost of regasification and transportation from North Africa and the Gulf to North Europe to be US$1.00 and US$1.70/MMBtu respectively, the fob price of liquefied natural gas could be US$5.21/MMBtu in North Africa and US$4.51/ MMBtu in the Gulf, which is higher than the existing sales prices of some member countries.

In my opinion the price of natural gas should be related to the cost of synthetic gas from coal gasification, since it is really a manufactured commodity. This is the long-term strategy that should be adopted by gas producers. In the short term, however, the price of liquefied natural gas should be equal to the price of fuel oil at the producers' ports, which it could replace, with a premium for quality. This premium should be increased to bring the price in line with the prices of alternative sources of energy over a period of 20 years.

TABLE 2 Evolution of gas prices in comparison with crude oil and refined products in Europe (US$/MMBtu).

	1972	1975	1978	1st Qtr. 1980[a]
Average OPEC crude oil prices	0.54	2.01	2.46	5.54
LNG/crude oil	1.11	0.85	0.85	0.71
LNG/fuel oil no. 2	0.95	0.73	0.70	0.55
LNG/L.S.F.O. (1%)	1.43	0.99	0.97	0.86
LNG/H.S.F.O. (3-3.5%)	1.71	1.11	1.08	1.10

[a]Figures from: M. Ait-Laoussine, Towards a new order in gas pricing, LPG Seminar 1980, St. Paul-de-Vence, Nice, April 16-18, 1980.

LIQUEFIED PETROLEUM GAS

Traditionally, the main users of liquefied petroleum gas have been the residential/commercial, industrial, and agricultural sectors of the Western countries. It is used for heating, burning in boilers for electricity generation, and in other industries; also for heating and drying crops in agriculture.

The major potential market for liquefied petroleum gas is the petrochemical industry, although the development of this market depends more on the security of supply of liquefied petroleum gas than its price, since the latter can compete with other feedstocks. Other potential markets, in addition to the traditional one of petrochemical feedstock substitution, are internal combustion, direct injection, etc.

The high demand for liquefied petroleum gas which occurred in 1979 is a clear indication that a high market potential for this product exists. Again, it has to be said that it is the responsibility of the consumers to make liquefied petroleum gas economically attractive for the producers, who could then satisfy the potential demand and produce the maximum quantity of product, thus helping the world to cross smoothly the energy transition period and lengthen the lifespan of hydrocarbons.

LIQUEFIED PETROLEUM GAS PRICING

Table 3 shows the price of liquefied petroleum gas in Btu's for the period 1974-1980. It is clear that up until the second half of 1979, the price of liquefied petroleum gas did not keep pace with that of the Marker Crude (Arabian Light). By the second half of 1979, however, the price of liquefied petroleum gas exceeded the price of the Marker Crude by 56%. This increase is a good indication of the fact that liquefied petroleum gas was underpriced and that the market could absorb higher prices.

The use of liquefied petroleum gas should be limited to transportation and the petrochemical sectors, and its uses as a boiler fuel should be phased out. Alternatives such as coal can be used for the latter purpose. Some advantages exist, however, in using liquefied petroleum gas in the transportation and petrochemical sectors.

TABLE 3 Evolution of liquefied petroleum gas prices in relation to the marker crude (US$/MMBtu).

					1979, quarter			
	1974	1975	1976	1977	1st	2nd	3rd	4th
Arabian Light	1.093	2.09	2.19	2.32	2.44	2.66	3.35	3.35
LPG[a]	2.44	2.45	2.44	2.42	2.59	2.59	4.14	5.21
LPG/Arab. Light	1.28	1.17	1.11	1.04	1.06	0.97	1.24	1.56

[a]LPG: 50% propane, 50% butane.

Linking the price of liquefied petroleum gas to its end-use

Table 4 shows the possible end-uses for liquefied petroleum gas and the share of each of these end-uses in the three major consuming markets, namely the United States, Japan, and Europe. From the data given in this table and the average prices of substitutes during the 1st quarter of 1980, the price of liquefied petroleum gas should be US$282.90 per ton or US$5.85 per MMBtu, and US$254.28 per ton or US$5.26 per MMBtu in the United States and Japan, respectively. These prices correspond to netback prices of US$217.90 per ton and US$202.08 per ton fob Gulf.

Price of liquefied petroleum gas for use as a petrochemical feedstock to compete with naphtha and gas oil (50/50)

If the use of liquefied petroleum gas is limited to that of a petrochemical feedstock, then its price should be determined relative to naphtha and gas oil only. The average price of naphtha and gas oil in the Gulf during the first quarter of 1980 was US$7.58 and US$8.56/MMBtu, respectively. In this way, the price of liquefied petroleum gas is calculated to be US$8.07/MMBtu and US$390.23/ton.

The purpose of this exercise is not to suggest a pricing formula for liquefied petroleum gas but rather to indicate that the use of liquefied petroleum gas in the transportation and petrochemical industries gives a higher price for the product than does its use in other markets.

TABLE 4 Share of liquefied petroleum gas in the major markets in 1980 (%)[a].

End-uses	USA	Japan	Europe	Substitutes	C-Factor
Domestic/commercial	32.27	42	49	N. Gas or LNG	0.92
Automobile manufacture	5.58	2.0	--	N. Gas or LNG	0.92
Industry	5.98	29.0	27	(F.O.+ N. Gas)	0.70-0.92
Gasoline production	19.31	9.0	9	Gasoline	1.12
Petrochemicals	27.28	11.5	12	Naphtha	1.16
Utility and miscellaneous	9.58	6.5	3	N. Gas or LNG	0.92

[a]The price of LPG = share of the substitute × price of substitute (US$/tonnes) × C-factor. The C-factor is the ratio of Btu's per ton of LPG over Btu's per ton of the substitute and, in the case of gasoline, the ratio of barrels per ton of LPG over barrels per ton of gasoline. It is assumed that in industry LPG will substitute 70% of the fuel oil used by heavy industry and 30% of the clean fuel, LNG, used by light industry (food, glass, etc.). The break-even cost of using naphtha feedstocks vis-a-vis LPG was assumed to be 1.12 based on a medium-sized plant. For the price of LNG on the east coast of the USA, the cost of Canadian pipeline gas was used (US$4.47/MMBtu); in the Gulf area, the cost of Mexican pipeline gas was used (US$4.712/MMBtu). Product prices are average spot prices for 1979 in the respective markets.

Summary

The price of liquefied petroleum gas should be equal to the prices of substitutes. However, unnecessary use of liquefied petroleum gas, such as boiler fuel, should be phased out and its use should be limited to the transportation and petrochemical sectors. The price should be adjusted to be equal to the prices of its competitors in these two sectors only.

If this could be agreed upon between producers and consumers, major investment by producers in the development of the liquefied petroleum gas industry would take place. This incremental supply would, in turn, help the energy balance.

I have tried to outline here the potential growth that could take place if an economic incentive were given to producers to develop the gas industry, through the development of a pricing mechanism for liquefied petroleum gas that would be fair and equitable to both the producers and the consumers.

THE DEEP EARTH GAS HYPOTHESIS

Thomas Gold and Steven Soter
Center for Radiophysics and Space Research, Cornell University, Ithaca, New York, USA

Abiogenic gases, including methane, emerging from deep within the Earth appear to influence the earthquake process. A better understanding of the mechanism and pathways of the degassing process may lead to improved earthquake predictions and to the discovery of major natural gas reserves.

Volcanic eruptions are known to supply carbon dioxide, water vapor, and lesser amounts of other gases to the Earth's atmosphere. Over geological time this has undoubtedly been an important means of degassing the interior of the Earth to supply the volatiles that constitute the atmosphere and oceans as well as the carbon in the biosphere and sediments. But there is now evidence that such degassing also occurs in non-volcanic regions, where deep crustal faults can provide a pathway to the surface. In such regions, the interior gases can migrate upward at a modest rate, punctuated occasionally by larger outbursts during major earthquakes. We believe that the movement of such gases is the primary phenomenon underlying a wide range of known earthquake precursory effects and that it plays a significant role in the actual triggering of earthquakes. Furthermore, there is reason to believe that a significant fraction of the gas emerging from the Earth's interior is abiogenic methane.

The composition of the emerging deep Earth gas is a difficult question, as the observational evidence is scanty and not easily interpreted. The gases observed in volcanic emissions are dominated by H_2O and CO_2, but CO, CH_4, NH_3,

H_2, H_2S and others are frequently detected. However, it is not possible to deduce directly from such observations the initial gas composision at depth, because (1) an unknown proportion of the volcanic gas may consist of volatiles recycled from crustal sediments rather than juvenile gas arriving for the first time from the mantle; (2) hydrogen-rich (reduced) gases will have been mostly oxidized in the liquid magma on the way to the surface; and (3) most of the gas samples have been acquired during the more quiescent (and safer!) phases of activity, but these may be chemically unrepresentative of the greater volumes emitted in explosive eruptions.

Gases released during earthquakes are probably more accurate samples of those present in the deep crust and upper mantle. The sampling of such gases is only just beginning, particularly in the Soviet Union, and it is too early to draw confident conclusions from the data. Undoubtedly, the composition of the deep Earth gases varies with geographical location, since the disposition of mineral deposits in the crust suggests substantial heterogeniety in the underlying mantle. Methane (CH_4) may be more important in this respect than previously realized. Because it is also the principal constituent of natural gas and, indeed, because there is the possibility that abiogenic methane may play an important role in the growth and maintainance of petroleum deposits, we will concentrate our attention on it here. But this is not to minimize the possible importance of the other deep Earth gases in the earthquake-related phenomena to be discussed later.

The notion of abiogenic methane runs counter to the prevailing view in petroleum geology that virtually all the oil and natural gas in the Earth is of biological origin. In that view, the carbon in the hydrocarbon fuels was all originally derived from atmospheric CO_2 and the energy to dissociate the CO_2 came from sunlight, in the process of photosynthesis by green plants. The burial of some of these organic compounds before they could become oxidized would then have provided the source materials for oil and gas. There is little doubt that this process contributed to the genesis of much of the petroleum that has been recovered, but there may be more to the story.

The modern abiogenic theory of petroleum begins with the observation that hydrocarbons, rather than being exclusively biogenic, are the dominant carbon containing molecules in the solar system. The universe is made mostly of hydrogen, and the evidence of cosmochemistry suggests that the Earth originally condensed out of a hydrogen-saturated solar nebula. Most meteoritic carbon is in the form of complex hydrocarbons having some chemical similarities to oil tars. The Earth may well have acquired most of its carbon in the form of such hydrocarbons. The primitive atmosphere was a reducing one and probably contained most of its carbon in the form of methane. The early stages of life on Earth are thought to have required such an atmosphere. With the subsequent production of oxygen by photosynthesis, the terrestrial atmosphere gradually attained its present oxygen-rich composition, and it is that fact which today makes hydrocarbons such a useful source of chemical energy, i.e., a combustible fuel.

What is the fate of the Earth's primordial supply of hydrocarbons? We can suggest the following hypothesis. Buried under conditions of elevated pressures and temperatures, these hydrocarbons liberate methane and this gas, often together with others, tends to migrate upward toward the surface, preferentially along zones of weakness in the crust, leaving the bulk of the heavy hydrocarbons behind. Where the pathway leads through hot volcanic lava, the CH_4 will be oxidized to CO_2 just before entering the atmosphere. Where the pathway allows a pressure reduction in a cooler non-molten region (as along a cold fault), the gas can reach the surface in its original reduced state (although it will not survive as such for more than a few years in the oxygen-rich atmosphere). Other pathways will cause some of the methane to be trapped temporarily beneath relatively impermeable strata, where it can contribute to the known deposits of natural gas. And, finally, some methane, on pathways diffusing it through hydrocarbon deposits (including biogenic oils) may be trapped by a chemical augmentation (polymerization) to those hydrocarbons.

Most of the carbon in the upward migrating methane will eventually enter the atmosphere, either directly as methane or oxidized as CO_2. From the atmosphere, the CO_2 will be dissolved and precipated through the oceans. The Earth's crustal rocks contain an enormous quantity of carbon, mostly in the form of sedimentary limestone. Carbon is much more concentrated in the sediments than in the igneous rocks from which the sediments derived; this "excess" carbon must have been brought to the surface in the form of CO_2 and CH_4 degassed from the interior, although in what proportion between these two gases we cannot say.* We think that at least some of it originally came up as methane, and continues to do so. There is no compelling reason to believe that the Earth is today completely degassed of its primary volatiles. If the amounts remaining below are comparable with those that have come up, there is the possibility of an enormous quantity of deep methane being present. The prime reservoirs would no doubt be too deep to drill, but one may be able to identify the formations that have guided some of this gas to more accessible levels where it can be reached.

An objection sometimes raised against the viewpoint that inorganic hydrocarbons exist deep in the Earth is that such materials would readily be oxidized into CO_2 at the elevated temperatures found at great depths. But this argument neglects two important considerations. Firstly, the enormous confining pressures present even at modest depths favor the stability of methane and other hydrocarbons over CO_2 because they take up less volume in the chemical equilibrium. Secondly, even if the rocks contain oxygen in a form that could oxidize methane, it is only in liquid rock that this oxygen would be available in significant quantity. If the pathways of the gases are confined to fissures through solid rocks, the accessible surfaces can yield only small amounts of oxygen, and for a large supply of methane there would be little loss to oxidation. Thus, the observation that most carbon in volcanic gases is in the form of CO_2 and not CH_4 does not tell us anything about how it originated, because methane bubbling

*cf. Table I and Figure 1.

TABLE I: CARBON AND REDUCED CARBON IN THE EARTH'S CRUST*

[in kilograms per square centimeter vertical column; to convert to global totals, multiply by Earth's surface area, 5×10^{18} cm^2]

CRUST OF THE EARTH			
Total mass	5600	kg/cm^2	
Carbon content	17.5		(0.3% of crust)
Reduced carbon	3.7		(22% of the carbon)
IGNEOUS AND METAMORPHIC ROCKS			
Total mass	5100	kg/cm^2	(92% of crust)
Carbon content	2.6		(0.05% of these rocks)
Reduced carbon**	1.4		(54% of this carbon)
SEDIMENTARY ROCKS			
Total mass	470	kg/cm^2	(8% of crust)
Carbon content	15		(3% of these rocks)
Reduced carbon	2.3		(16% of this carbon)

* Data principally derived from J. M. Hunt (1972). Distribution of carbon in crust of Earth. Bull. Amer. Assoc. Petrol. Geol. 56, 2273-2277.

**includes elemental carbon

through lava at low pressures and high temperatures would readily be oxidized into CO_2 in any case.

Another objection often raised against abiogenic hydrocarbons is based on the ratio of the stable carbon isotopes. Of the two, ^{12}C predominates, but a small admixture (about 1%) of the heavier isotope ^{13}C is always present in terrestrial carbon sources. (The much rarer heavy isotope ^{14}C is unstable and will be discussed later.) The precise ratio in the abundance of ^{13}C and ^{12}C varies somewhat among different kinds of carbon deposits, and this is often

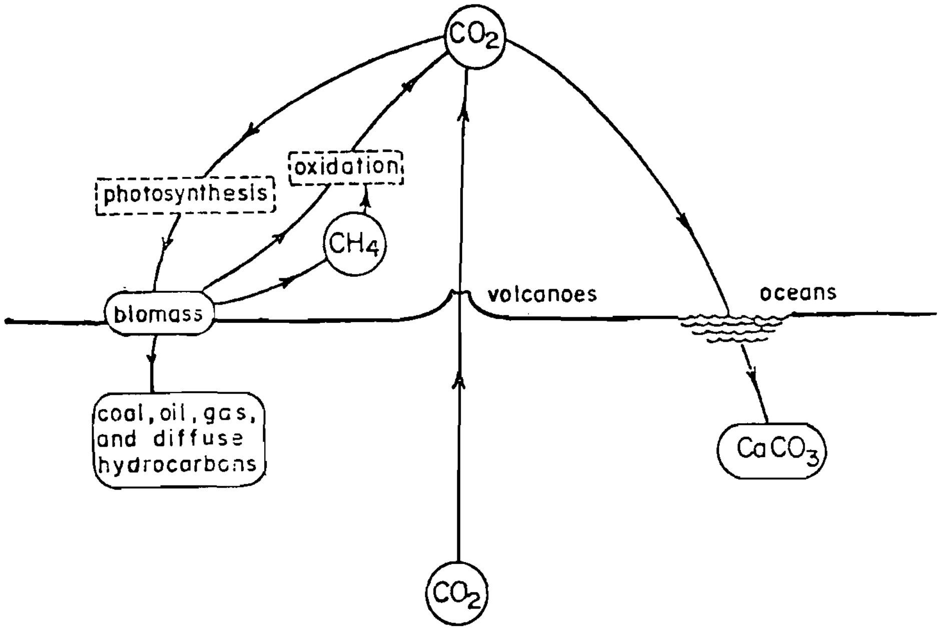


Figure 1(a). Terrestrial carbon budget. The conventional view that all coal, oil, and gas is of biological origin, the product of photosynthetic reduction of atmospheric CO_2 into hydrocarbons which were buried before they could be fully oxidized. The initial source of the carbon is assumed to be deep-seated CO_2 that enters the atmosphere via volcanic emissions. The principal sink in the carbon cycle is precipitation through sea water into sedimentary carbonates, mainly limestone ($CaCO_3$). Almost all the atmospheric CH_4 is here assumed to be biogenic.

used in attempts to identify the sources. The carbon in the biomass is isotopically "light" compared to that in atmospheric CO_2, because photosynthesis selects against the heavier isotope when plants take up CO_2. The fact that carbon in petroleum is also depleted in ^{13}C relative to carbon in atmospheric CO_2 is often cited as evidence for the exclusively biological origin of oil and gas.

But this argument is not secure, because there are also several non-biological processes that can sort carbon isotopes. For example, depletion of a stream of methane by oxidation enriches the light isotope; diffusion through water enriches the heavy one. Complex hydrocarbons that chemically resemble those in oil tar and in carbonaceous meteorites are readily made, abiogenically, by a mineral-catalyzed reaction between carbon monoxide and molecular hydrogen. Significantly, the carbon in the resulting hydrocarbons is isotopically much

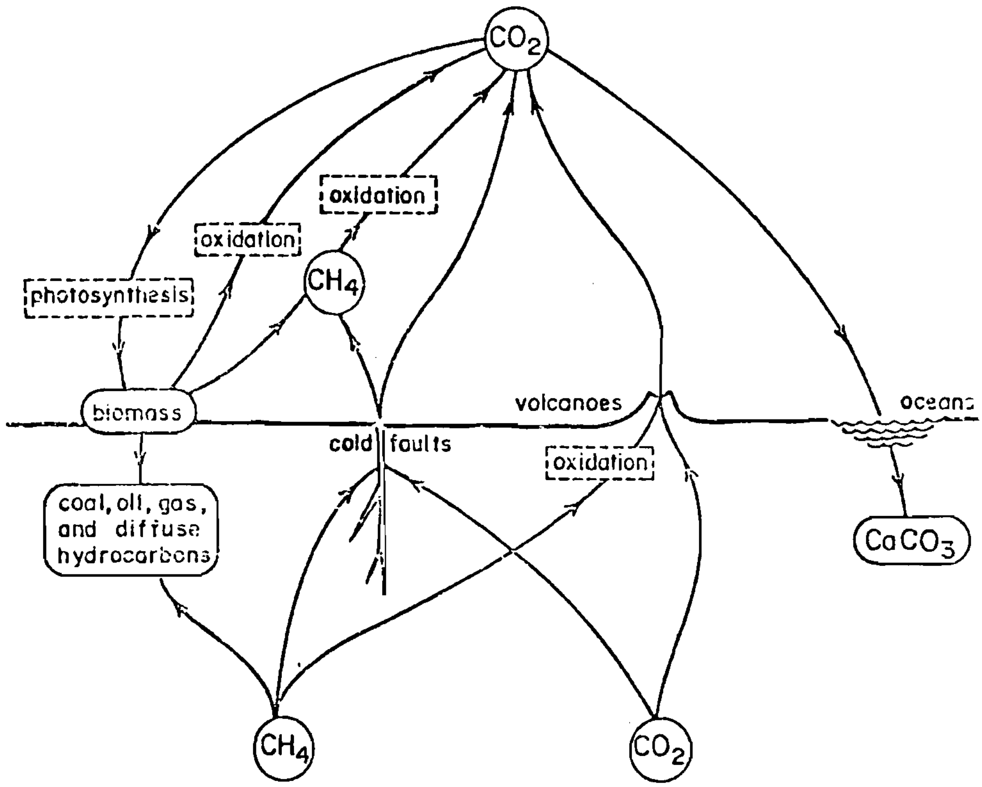


Figure 1(b). The duplex origin theory assumes, in addition to the photosynthetic reduction of CO_2, that there is a deep source of abiogenic methane contributing directly to the growth and maintenance of coal, oil, and natural gas deposits. Some abiogenic methaneis oxidized to CO_2 as it reaches the surface through hot volcanic lava at low pressure. But CH_4 can also enter directly into the atmosphere through cold faults, perhaps mainly during earthquakes, providing an abiogenic contribution to the atmospheric methane. Faults also provide a means for the seismic degassing of deep-seated CO_2 and other gases.

lighter than that in the CO_2 produced in the same reaction. This process, known as the Fischer-Tropsch synthesis, very likely occurs under natural conditions deep in the Earth and may well contribute to some hydrocarbon deposits.

The relative abundance of ^{13}C in natural gas deposits shows a general increase the deeper the present depth of burial, regardless of the composition, age, or past depth of burial of the confining rock. This is true whether the gas is "free" or associated with petroleum. In the latter case, the isotopic weight of the methane bears no relation to that of the oil. These facts strongly suggest, as also noted by the Soviet geochemist E. M. Galimov, that all crustal gas deposits were emplaced only recently, that they are young relative to the age of the confining rock or the time for that rock to change its depth, and that the gas, even where it is found with oil, does not have a common origin with it. Galimov has suggested that methane deposits derive from dispersed sedimentary hydrocarbons and that temperature-dependent isotopic fractionation and continuous loss of methane would then lead to the observed ^{13}C depth dependence. But, in our view, a gas deposit could just as well be emplaced by an upward migrating stream of abiogenic methane which, with proper catalysts, would gradually be depleted of its ^{13}C by odixation and isotope exchange on its way up. Unfortunately, not enough is yet known about the relevant processes; the complicated carbon isotope story can be interpreted in too many ways to decide whether or not some methane in natural gas deposits is abiogenic. But in any case, the depth dependence shows that the gas has only a short residence time in the crustal rocks, and that a much larger rate of outflow has to be supposed than was considered previously.

Finally, it is often said that the presence of porphyrins and other molecular residues of living organisms in many oil formations is proof that all the oil was derived from the decay of organic sediments. But many sedimentary rocks (in the porosity of which oil is most commonly found) are rich in biological residues. If such rock is invaded from below by abiogenic oil and is left to soak for a few million years at elevated temperatures and pressures, it would be difficult to prevent the contamination of that oil by biological substances derived from the sediments.

The chemist Sir Robert Robinson has written that "it cannot be too strongly emphacized that petroleum does not present the composition picture expected of modified biogenic products, and all the arguments from the constituents of ancient oils fit equally well, or better, with the conception of a primordial hydrocarbon mixture to which bio-products have been added." Indeed, we do not believe that any of the evidence usually invoked in favor of an <u>exclusively</u> biological origin for petroleum is compelling. The picture that we favor is one of a duplex origin, with some petroleum made directly from buried organic sediments and a (probably larger) portion derived abiogenically.

The latter process may involve the chemical augmentation of existing hydrocarbon deposits from a stream of abiogenic methane. This is still hypothetical, but methane, usually assumed to be chemically inert, may well be able to polymerize into crude oil under suitable conditions of temperature, pressure, and catalytic action (including perhaps microbiology). If this indeed occurs, then an ascending stream of methane in a given geographical region could slowly augment existing hydrocarbon deposits (of oil and perhaps even coal) at different levels in that same region. The process need not be very efficient; even if most of the gas is not captured but goes on up to escape at the surface, still a modest flux persisting over geological periods of time could deposit an enormous mass of hydrocarbons. The process would resemble mineralization, in which high grade ore is precipitated out a long-lived stream of hydrothermal fluids.

The chemical augmentation of hydrocarbon deposits would have a positive feedback, because the larger the accumulation the more probable the capture of a rising methane molecule. This might help explain why the few largest petroleum fields are so enormous compared to all the rest. Of the many thousands of commercial oil fields, a mere 33 fields (25 of them in a single region—the Middle East) contain about half of the world's known recoverable crude oil.

This process would further account for the presence of biogenic molecules in most crude oils. The primer deposits that commence the process are likely to be biogenic oily substances such as often occur in many sedimentary layers. Even a slight concentration of such hydrocarbons would favor the growth of a given layer over those adjacent to it, due to the positive feedback mechanism. Without the methane augmentation process, many such biogenic deposits would remain insignificant, but in areas where methane is flowing from deep sources they can grow into large oil fields.

The upward streaming methane that is neither oxidized in volcanic regions nor entrapped in petroliferous deposits will enter the atmosphere, where it ought to be detectable. It will not contain any of the heavy carbon isotope ^{14}C, a fact that can help in distinguishing it from methane of recent biological origin. Atmospheric CO_2 contains some ^{14}C, which is produced when cosmic rays collide with atmospheric nitrogen. Through photosynthesis, ^{14}C gets incorporated into the biomass. It is absent from oil and gas since it decays with a half-life on only 5800 years. Most of the atmospheric CH_4 is produced by known biological sources (microbial fermentaion in paddy fields, swamps, and ruminants, with a turnover time not exceeding a few years); the known non-biological sources (mainly from industrial pollution) contribute much less. Thus, atmospheric methane ought to have nearly the same ^{14}C concentration as the biomass from which most of it thought to be derived. Instead, there is some indication that it may be deficient by as much as 20%. If real, this depletion may be explained by the natural emission of deep methane both by gradual seepage and seismic eruptions. Atmospheric methane is present at about 1.5 parts per million and it is thought to have a lifetime, prior to oxidation, of about five to seven years. Careful monitoring of the global atmospheric methane concentration as well as of any changes in its isotopic abundances (for both ^{13}C and ^{14}C) would be most useful.

Let us now examine some of the more local evidence for the escape of such methane from the interior of the Earth. An important place to look is along the crustal faults and fissures of the tectonic plate boundaries; these ought to provide the best access to the deep interior. And indeed, hydrocarbons appear to be clearly associated with such places. For example, large concentrations of dissolved methane have been measured in waters overlying plate boundaries and rift zones. The deep brines of the Red Sea contain about 1000 times as much methane as normal sea water. Hydrothermal plumes found issuing from seafloor vents on the East Pacific Rise contain high concentrations of methane together with hydrogen and ^{3}He, indicating a deep abiogenic source for the gases. Lake Kivu, which occupies part of the East African Rift Valley, contains some 50 million tons of dissolved methane, for which there is no adequate microbial source. We suspect that these waters are all supplied by abiogenic methane seeping up through deep crustal fissures.

Another line of evidence connecting abiogenic hydrocarbons with such features is the striking correlation between major oil and gas producing regions and the principal zones of past and present seismic activity. Even on the local scale, oil fields often lie along active, or over ancient, fault lines. Most of the known natural seeps of oil and gas are found in seismically active regions. The most spectacular gas seeps are the so-called "mud volcanoes", which are hills or sometimes substantial mountains of mud built up by the intermittant and sometimes violent eruptions of natural gas, often almost pure methane. There are scores of mud volcanoes known and almost all occur on or near plate boundaries, in places such as Trinidad, New Zealand, Indonesia, Burma, Pakistan, Iran, and Italy. In any one region, groups of them tend to lie along local fault lines. The world's largest active mud volcanoes are near Baku in Soviet Azerbaijan. One recent eruption there produced a flame that initially shot up to a height of several kilometers and burned some 200,000 tons of methane. Major eruptions of mud volcanoes frequently coincide with earthquakes.

In seismically active regions, many thousands of violent earthquakes are likely to occur in the course of a few million years. One might at first expect that the repeated fracturing of the rocks in such places would have released or strongly depleted any nearby accumulations of oil and gas in times short compared to the age of the confining strata. The fact that oil and gas fields show, on the contrary, a preferential association with such earthquake-prone regions suggests to us that the deep faults may provide a conduit for the continuous input of abiogenic methane streaming up from below. Furthermore, the upward migration of methane and other gases in fault zones may play an important role in the actual triggering of earthquakes.

An earthquake is due to the release of stress in the subsurface rock by a sudden brittle fracture, involving the rapid propagation of a crack, and the elastic rebound or slippage between the two sides. (The stress may accumulate due to slow viscous motions in the mantle, which are thought to generate all the phenomena of plate tectonics, including earthquakes.) Seismologists have long recognized a difficulty in accounting for deep earthquakes. At a depth of more than about five kilometers, the pressure due to the overburden of rock is so great that a crack cannot open up by itself. Instead of breaking suddenly by brittle fracture, rock at these pressures simply deforms when excessive shear is applied. At even greater depths, the increase in temperature further reduces the shear strength of rock. Continuous plastic flow would relieve the stress long before any fracture could ever occur. And yet, earthquakes are known to occur at depths as great as 700 km, and their seismographic "signatures" show that, like shallow earthquakes, they involve a sudden discontinuous fracture.

The presence of deep earth gas could resolve this contradiction. If the deep rocks in a region contain pores held open by gas at the ambient pressure, then the interconnection of these pores can lead to the formation of a crack that remains open. The gas effectively unburdens the rock along a nearly frictionless layer. Discontinuous slippage can then occur (as would be the case under low confining pressure), and the crack will propagate, releasing the strain energy and causing an earthquake.

If the shocks so created are strong enough to fracture the ground up to the surface, this same gas will find a rapid escape route, and will produce what we interpret as the gas eruption effects that are reported in many major earthquakes. These effects include: flames seen shooting from the ground; "earthquake lights"; fierce bubbling in bodies of water; stifling or sulfurous air; loud explosive and hissing noises; and "visible waves" seen slowly rolling along alluvial ground. We have collected hundreds of independent reports of such phenomena, spanning many centuries, and from all parts of the world, and these show a remarkable consistency. Only a small sampling can be given here.

The flaming phenomenon indicates that some of the gas erupting during earthquakes is combustible, most likely methane or hydrogen. One of the more violent earthquakes ever recorded in North America occurred on February 5, 1663, along the St. Lawrence River in Quebec. French Jesuit missionaries reported that during the shocks, there emanated from the ground "fiery torches and globes of flame—now relapsing into the earth, now vanishing into the very air like bubbles." Lest this be regarded as fantasy or exaggeration, there exist scores of similar descriptions from other earthquakes. Thus, according to contemporary newspaper accounts of the Owens Valley earthquake of March 26, 1872 (the most violent earthquake ever recorded in California), "Immediately following the great shock, men, whose judgment and veracity is beyond question, while sitting on the ground near the Eclipse mine, saw sheets of flame on the rocky sides of the Inyo mountains but a half mile distant. These flames, observed in several places, waved to and fro apparently clear of the ground, like vast torches; they continued for only a few minutes."

Such accounts can readily be explained if these earthquakes liberated large quantities of combustible gas, under high pressure, through fissures in the ground. The gas will be self-igniting from sparks generated by the electrostatic charging of dust grains carried along in the flow. This is the same mechanism that causes eruptions of mud volcanoes to burst spontaneously into flame. The reality of the flames in such earthquake reports is verified by the physical evidence sometimes left behind. For example, during the Sonora (Mexico) earthquake of May 3, 1887, there were many reports of flames, and afterwards burnt branches were discovered overhanging fissures in the ground.

The flaming phenomenon, when seen at a distance of a few kilometers, may also be responsible for some of the "earthquake lights" which are frequently reported during seismic shocks occurring at night. These are usually described as hemispherical glows on the horizon; some of these have been photographed. Other kinds of earthquake lights, including sharp flashes, "fireballs", and diffuse luminosity in the sky, may be due to electrostatic effects from the sudden emission of gas into the atmosphere.

There are a great many accounts of the vigorous bubbling of the sea or other bodies of water during major earthquakes. For example, during the great

Chilean earthquake of May 22, 1960, observers on the shore over a range of 450 km reported that the sea appeared to be "boiling". This is precisely what one would expect if large quantities of gas were liberated during the earthquake.

Frequently, a sulfurous odor is reported to linger in the air after a great earthquake. Methane itself is odorless, but hydrogen sulfide is a common constituent of natural gas. Since H_2S is soluble in water and highly toxic to fish, the eruption of natural gas containing it may account for some of the many reports of dead fish found floating on the water after major earthquakes at sea. For example, Capt. Fitz-Roy of the H.M.S. Beagle (of Charles Darwin fame), at Valdivia during the great earthquake of Feb. 20, 1835, reported that "the water in the bay appeared to be every where boiling; bubbles of air, or gas, were rapidly escaping. The water also became black, and exhaled a most disagreeable sulphureous smell. Dead fish were also thrown ashore in quantities; they seemed to have been poisoned, or suffocated."

There are also many reports of earthquakes accompanied by hissing and booming noises, of the sort that might be expected to accompany the eruption and/or explosion of confined gas. The explosions may in some cases be due to the physical impact of gases at high pressure with the air, as occurs with explosive sounds during conventional volcanic eruptions. During the New Madrid earthquakes of 1811-1812 (the most violent ever recorded in North America), loud roaring and hissing noises "like the escape of steam from a boiler" were heard, together with multiple explosions. Fires were reported in the sky and the smell of sulfur filled the air. The Mississippe River boiled up in huge swells and confined gas was seen to burst from its surface.

The phenomenon of "visible waves" is observed in many, perhaps most, major earthquakes that occur in alluvial ground. The solid surface of the earth is usually described as rolling in waves resembling those at sea. A quite typical description of the phenomenon was given by a mining engineer who witnessed the Sonora earthquake of 1887: "These waves seemed to be two feet high, about twenty feet apart, and moved as rapidly as the incoming waves along the seashore."

A police sergeant who saw the San Francisco earthquake of 1906 said: "The whole street was undulating. It was as if the waves of the ocean were coming towards me, billowing as they came." Waves of such small wavelength and especially with such low propagation velocities as to be clearly visible are not at all explained by conventional seismology. They are much too slow to be elastic waves due to the shock itself. But there is no doubt whatever as to their physical reality.

Perhaps the phenomenon is a kind of gravity wave, like waves at sea, but with the relevant fluid being compressed gas. As a result of a major fissure in the underlying rock during an earthquake, a large amount of gas shoots up with pressures that may be of the order of hundreds or thousands of atmospheres. The alluvial layers covering the fractured bedrock are less brittle and will not so readily open to large fissures. They act as an extra impediment to the outflowing gases, whose pressure is easily sufficient to lift them entirely by inflating the porosity. When so lifted from the bedrock, the material has a low rigidity and is quite unstable; it can then propagate gravity waves. (We find that a quite similar explanation for the phenomenon was given in 1760 by the English astronomer John Michell, who, incidentally, was also the first person to postulate the existence of black holes.)

If visible waves are produced by seismic gas eruptions on land, perhaps tsunamis are an analogous phenomenon at sea. It is usually assumed that the energy in such seismic sea waves is transferred by a sudden displacement of the seafloor over a vertical distance comparable to the observed height of the wave. However, this mechanism would require that a slab of rock extending from the seafloor down to the hypocenter of the earthquake (say 10 km) must all be raised through the height of the sea wave (say 1 m), which would in turn require many thousands of times as much energy as the potential energy in the sea wave itself. And yet, the total energy liberated in a tsunami earthquake (as calculated from its observed seismic magnitude) is usually found to be only an order of magnitude greater than the measured energy in the sea wave. A more efficient energy transfer mechanism seems to be required. A gas eruption would produce the required volumetric displacement of the water with much less energy. The sea wave volume will roughly equal the gas volume when the latter has expanded almost to atmospheric pressure. An earthquake energy only some ten times larger than the tsunami energy then appears to be a possibility.

There is as yet no proof that any of the above effects are due to gas eruptions during earthquakes, but at least for the flaming and bubbling phenomena it is difficult to imagine a likely alternative. Even in the conventional view, however, it might be argued that gas eruptions are occasionally to be expected during major earthquakes because the shattering of the bedrock ought to liberate any local pockets of confined gas derived from the adjacent strata. But there is evidence that the gas plays more than a passive role in the earthquake. We believe that most of the well-known earthquake precursory phenomena can best be explained in terms of an increase in deep gas pressure occurring well before an earthquake actually shatters the bedrock.

Many of the precursory phenomena have been detected by instruments. These include: changes in the velocities of seismic waves through the ground; in the flow of ground water; in the electrical conductivity of the ground; in the tilt and precise elevation of the surface; in the chemical composition of gases in the soil and ground water; and in the emanation of radon gas. The time interval between the onset of a precursor and an earthquake ranges from minutes to as long as years, depending on the phenomenon and the earthquake magnitude.

These precursors are usually discussed in terms of rock "dilatancy", that is, the opening of microcracks in the rock as the shear stress approaches the critical value for fracture, as observed in laboratory experiments. We agree that an increased porosity and concomitant volumetric expansion of the rock would indeed contribute to most of the above precursory phenomena. But what has generally been neglected in these discussions is that at depths of tens of kilometers (where most earthquakes originate), the rock by itself would not have the strength to hold open such cracks against the enormous overburden pressure. Dilatancy could not even begin unless there were present a high pressure fluid to hold open the cracks.

We suggest that the deep earth gas does just that. In our model for brittle fracture at high ambient pressures, described above, there are two prerequisites for the occurrence of a deep earthquake: there must be a shear stress that would be sufficient to cause brittle fracture were the same rocks at a shallow depth, and there must be a high pressure gas to hold open incipient cracks and thereby mitigate the enormous friction due to the lithostatic overburden. It is the invasion of the rock by such a gas from below that changes it from a ductile to a brittle material, simultaneously causing its volumetric expansion and the associated dilatancy phenomena.

As the deep earth gas increases the porosity prior to triggering an earthquake, some of it may begin to find its way to the surface, disturbing the ground water, altering the electrical conductivity of the ground and the composition of the soil gases. The radon precursor effect seems, in particular, to require the presence of a carrier gas streaming through the ground. Radon is a minor trace gas produced chiefly by uranium ores at considerable depth. Since its half-life is only 3.8 days, it could not by itself diffuse more that a few meters through the soil porosity before decaying. And yet, substantial increases in the surface emanation of radon have been detected prior to some earthquakes, and at distances as great as 100 km from the epicenter. The simplest explanation is that the radon is merely a convenient tracer for a much more abundant gas that sweeps it along, an otherwise undetected gas with a sufficient flux to travel past the depths of the radon sources to the surface in only a few days.

Not all earthquake precursors require instruments for their detection. Some are so obvious to the senses that they have been recognized since ancient times. We believe that these effects are also due to an increased gas flux through the ground. Among these "macroscopic" precursors are: dull explosive noises of unknown origin; the bizarre behavior of wild and domestic animals; anomalous increases in local temperature; sulfurous fumes, sometimes accompanied by a peculiar fog; bubbling and other disturbances of well water; and flames from the ground.

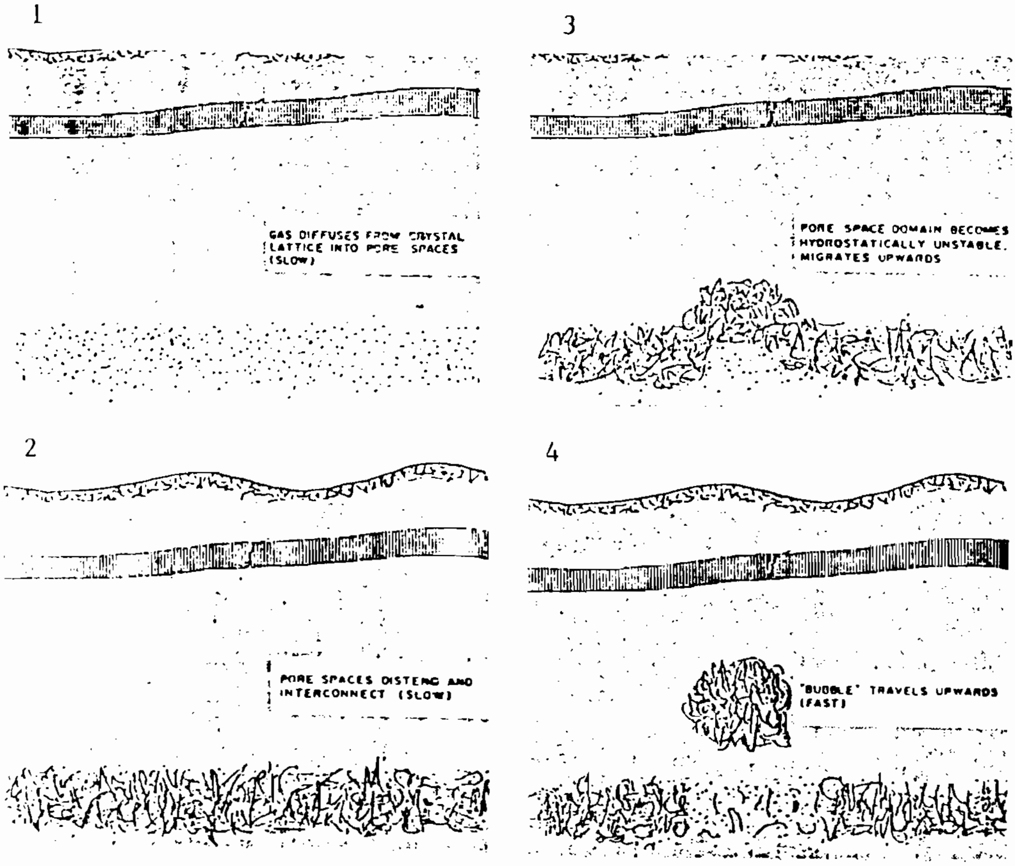
Episodes of mysterious booming noises, resembling distant artillery over several days or months, were reported as preceding the great earthquakes in Charleston (1886), Assam (1897), San Francisco (1906), and East Anatolia (1976). Some of these noises, called "brontides" in the earlier earthquake literature, may have been due to the sudden release of high pressure gas into the air.

The most widely reported precursor is the anomalous behavior of animals. Farm animals often rush about in confusion and try to break out of confinement, dogs howl incessantly, burrowing animals are seen to leave their holes, and fish to come up to the surface, usually beginning some minutes or even hours before a major earthquake. Again, the reports are so widespread and consistent that there can be little doubt as to the reality of the phenomena. If the deep earth gas begins to force its way up into the soil prior to some earthquakes, it will tend to push out ahead of it the ambient soil-entrapped gases. The carbon dioxide normally present in the soil porosity will begin to invade the homes of burrowing animals, who will be driven to the surface to avoid asphyxiation. If the deep earth gas contains even small amounts of hydrogen sulfide, it will be dissolved upon entering the bottoms of lakes and other bodies of water, driving the fish toward the surface. Many mammals have an enormous superiority over humans in the detection thresholds of their olfactory organs, and for this reason the sense of smell appears to be the most likely explanation for their strange behavior prior to earthquakes. Although methane and carbon dioxide are odorless to humans, some of the soil gases are not. These, on entering the atmosphere, might well constitute an "olfactory cacaphony" with no discernable source—producing the kind of animal panic so often reported. In a few cases, the odors emanating from the ground prior to an earthquake are even strong enough to affect people, so it seems reasonable that in a great many cases only animals will notice them.

Such gas emission may also cause other peculiar effects in the atmosphere. For example, analysis of meteorological records has revealed that for several weeks before the earthquake of February 4, 1975 in Haicheng, China, communities along the entire length of the fault zone had recorded air temperatures systematically higher (by as much as 4 to 6°C) than in the surrounding region. A sulfurous odor was also intermittantly but strongly in evidence, occasionally driving people indoors. Bubbling was observed in ditch water. During this same period there were frequent reports of anomalous animal behavior: snakes were found frozen on the roads and rats acted as though dazed; farm animals showed clear signs of restlessness and alarm, which was a minor but contributing factor in the successful prediction of that earthquake.

One or two hours before the Haicheng earthquake, there appeared in the same region what people described as a low-lying "earth gas fog" with a peculiar smell. This phenomenon may have a simple explanation. During winter, the air temperatures are lower than the seasonal average found in the soil gases at depths of only a few feet. The soil gas can thus hold more water vapor than the air above. If suddenly expelled from the ground by the invasion of deeper gas from below, this CO_2-rich air will remain near the ground despite its higher temperature and as it cools its water vapor will condense into a low-lying fog.

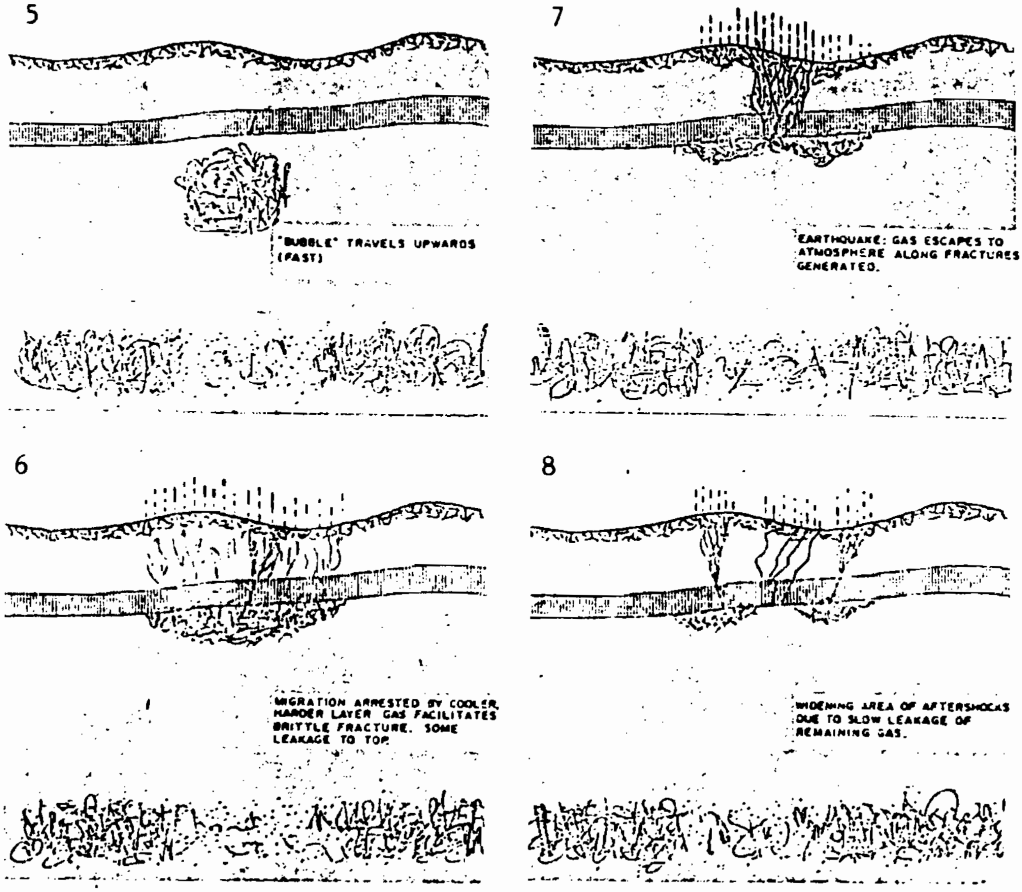
The connection between various gas-related precursory phenomena has been noted for centuries. We have, for example, the following account from the great Calabrian earthquake of 1783: "At the time of the earthquake, during the night, flames were seen to issue from the ground...exactly from the place where some days before an extraordinary heat had been perceived." Another account of the same earthquake reports: "The waters of the wells, of the sea, and also of the fishponds, a few hours before the earthquake of 5 February struck in Cosenza and neighboring villages, was seen to raise its level, all foaming as though boiling, without being observed to have a greater heat than normal." According to Alexander von Humboldt, half an hour before the earthquake at Cumana (Venezuela) on December 4, 1797, a strong smell of sulfur was perceived, and at the same time flames appeared on the banks of the Manzanares River.



The movement of a high-pressure gas towards the surface.

Gas liberated by diffusion into pore-spaces will commence an upward movement when a sufficiently great pressure imbalance has been created to overcome the strength of the rock. The supply of such gas in pore-spaces may allow sudden fracture of rocks to occur, and leakage towards the surface may be responsible for precursor and earthquake-related phenomena.

If the gases expelled from the ground as precursors to an earthquake make a combustible mixture in air, they can self-ignite electrostatically and give rise to the flaming phenomenon. An extraordinary account which we believe to be of this kind was recently reported from China by Lucile Jones of the Massachusetts Institute of Technology. Almost one month prior to the Songpan-Pingwu earthquakes of August 16, 21, and 23, 1976, Chinese seismologists observed fireballs rising from the fault zone some 150 to 200 km form the epicenters-to-be. The fireballs were about a foot or more in diameter, tapering toward the top, with the color of a "newly lit match"; they rose 10 meters above the ground,



lasting only a few seconds; over 100 were seen in one night; they caused vines on the ground to be burned.

It might of course be argued that the occurrence of such gas-related precursory phenomena is simply due to the disengagement of gas from the expanding porosity of shallow rocks undergoing increasing strain prior to an earthquake. Some gas generation due to such dilatancy no doubt occurs but it seems unlikely to account for the fact that the characteristic precursory behavior is abrupt and irregular, at times while the measured strain is either steady or only gradually increasing and still far from critical. Furthermore the precursors are often prominent at great distances from the epicentral region where the strain ought to be highest.

The source of the gas responsible for the observed precursors is therefore more likely to be found at depths corresponding to the focus of the subsequent earthquake, where the strain is greatest. If we require a deep-seated gas both for the dilatation and for the subsequent triggering of an earthquake, it may well be that same gas which is detected in the macroscopic precursors. The flaming phenomenon then suggests that a combustible gas is being released, and deep-seated (abiogenic) methane is the most likely candidate.

It is often assumed that porosity cannot exist at great depths because it would be crushed out and the fluids expelled upward by the excessive lithostatic pressure. But this is not always the case. The porosity of the lithosphere falls into two quite different regimes. As one drills down from the surface one generally encounters pore spaces in the rocks, usually interconnecting and filled with water. The pressure in them is that appropriate to the overburden of water, approximately three times less than the pressure within the adjacent rock. As one goes deeper the porosity slowly diminishes and eventually a level must be reached where the rock is no longer strong enough to support this differential pressure. Interconnected pore spaces there will indeed collapse, and whatever liquid or gas is in them will be expelled upwards. As one approaches this <u>critical level</u>, the porosity rapidly diminishes, but the pressure will still in general be given by the water overburden. However, beneath this level there can be another domain in which pockets of gas can again exist, but with the pore fluids now at the higher pressure approximating that in the rock. Of course if any connection ever establishes itself through the critical level, gas would rapidly escape and the connection would be crushed shut. The depth of this layer is dependent on the strength of the rock, but is usually between four and six kilometers.

We can assume that at great depths below the critical level, gas is generated at a rather steady rate, either by chemical reactions or by diffusion out of the solid. It begins to open pores. When a "pore space domain" becomes interconnected over a sufficient interval of height (probably several kilometers), it becomes hydrostatically unstable and will begin to ascend. This is because the strength of the rock is no longer sufficient to support the difference between the pressure gradients in the gas and in the denser rock. At this stage, the pores at the bottom will collapse and pores at the top will be opened up; the pore space domain as a whole will slowly migrate upwards. It probably requires some years to work its way from a depth of a few hundred kilometers to the surface. Since the average pressure in the gas decreases during the ascent, the volume of the pore space domain must increase. It is to this that we might attribute the gradual rising of the surface (of order 10 cm) that has sometimes been detected over a period of years preceding an earthquake. When the pore space domain penetrates the critical layer and enters the hydrostatic regime, rapid venting may lead to macroscopic precursors and shallow earthquakes.

Gases evolving from deep below will therefore exist in pockets left over in each case from the last venting episode, and such pockets must then be just a little smaller in vertical extent than the size that would drive upward migration and venting. But the amount of gas in such a region (with a vertical dimension of several kilometers) is probably much larger than that in most of the pockets trapped beneath impermeable layers in the upper hydrostatic domain, the conventional natural gas deposits.

If both the macroscopic precursors and those involving dilatancy are in fact merely secondary symptoms of a principal underlying cause—namely, the increasing gas pressure and porosity at depth--then it might be possible to monitor the primary phenomenon itself and thereby obtain a more secure basis for earthquake prediction. Perhaps it will be possible, by repeating seismic refraction profiles at the same location at intervals of a few months, to detect small changes in the seismic velocities due to changing porosity; we might then actually observe the ascent of a pore space domain. Efforts to monitor directly the subsurface gas composition and pressure in fault zones would be most useful. Several research groups in the Soviet Union are already engaged in substantial programs to observe changes in the chemistry and isotope ratios of ground gases, changes that are now known to occur prior to earthquakes. Much of this work is being done by that substantial minority of chemical geologists in the Soviet Union who have also taken an interest in abiogenic petroleum.

We believe that in addition to suggesting new approaches to earthquake prediction, the deep Earth gas hypothesis also suggests the possibility that truly large amounts of methane from internal sources have accumulated in regions where, on the basis of the conventional biogenic theory, they would never have been suspected. The upper domain in which gas is at the hydrostatic pressure has been extensively surveyed, but perhaps even that not well enough. The lower domain, however, where gas can exist only at lithostatic pressures, has as yet received little serious consideration. In a few places, deep "geo-pressured" gas has been tapped, but in each case has been thought to be present only as a result of an unusual geological configuration. If it turns out, however, that this is a widespread phenomenon and that below the critical level of zero porosity there generally exists another regime of large porosity due to high pressure gas, then the whole outlook regarding the world's fuel supplies might have to be re-evaluated. The quantities of gas that have been associated with carbon degassing of the Earth as a whole have of course been enormous, and if methane has been a significant contributor, then even the fraction "temporarily" caught in the high pressure domain on the way up may still be very large compared with all other known fuel reserves.

It is clear that we understand very little as yet of the degassing processes of the Earth. No one really has any secure evidence regarding the gas regime more than a few kilometers below the surface. Undoubtedly our model will turn out to be oversimplified and in places overstated. In this many-sided discussion, ranging from cosmochemistry to seismology, we have made a first attempt to formulate a relatively simple hypothesis to account for a large number of previously unrelated and sometimes anomalous facts. Further research leading eventually to the refinement or even the rejection of these ideas will, in either case we hope, help to enlarge our understanding of the Earth.

The authors of this article gratefully acknowledge support by the Gas Institute Research Grant # 5014-363-0205.

APPENDIX I:

ANNOTATED BIBLIOGRAPHY

(by subject in order of presentation in text)

GENERAL SURVEY OF THE PROBLEM

Thomas Gold (1979). Terrestrial sources of carbon and earthquake outgassing. J. Petrol. Geol. 1 (3), 3-19. — Provides an overview of the deep Earth gas hypothesis, and includes many references not listed in this annotated bibliography.

ABIOGENIC PETROLEUM

W. Sokoloff (1889). Kosmischer Ursprung der Bitumina. Bull. Soc. Imperial. Naturalistes de Moscou. Nouv. sèr. Tome III. — The earliest statement of the hypothesis that petroleum is representative of the hydrocarbon chemistry of extraterrestrial materials.

P. C. Sylvester-Bradley and R. J. King (1963). Evidence for abiogenic hydrocarbons. Nature 198, 728-731. — Examines primarily the geological evidence.

R. Robinson (1963). Duplex origin of petroleum. Nature 199, 113-114.
R. Robinson (1966). The origins of petroleum. Nature 212, 1291-1295. — In these two papers, a Nobel Prize winning biochemist presents the chemical evidence for an abiogenic component in petroleum.

P. N. Kropotkin (1965). Abyssal non-biogenic origin of oil and gas and the problem of the origin of life on the Earth. J. Geol. Soc. India (Bangalore) 6, 130-142.

G. Rudakov (1967). Recent developments in the theory of the non-biogenic origin of petroleum. *Chem. Geol.* **2**, 179-185.

V. B. Porfir'ev (1974). Inorganic origin of petroleum. *Bull. Amer. Assoc. Petrol. Geol.* **58**, 3-33.

EARTH'S PRIMITIVE ATMOSPHERE

A. C. Lasaga, H. D. Holland, and M. J. Dwyer (1971). Primordial oil slick. *Science* **174**, 53-55. — Calculates that an early methane-rich atmosphere would have been polymerized by solar uv radiation to produce a general oil slick of possible importance in the development of life.

M. H. Hart (1979). Was the pre-biotic atmosphere of the Earth heavily reducing? *Origins of Life* **9**, 261-266. — Argues that not all of the reduced carbon in the sediments originally degassed from the interior as CO_2 because there is not an equivalent amount of oxygen present in the sêdiments.

DEEP EARTH GAS COMPOSITION

B. G. Lutts, I. A. Petersil'ye, and V. K. Karzhavin (1976). Composition of gases in rocks of the upper mantle. *Doklady Akad. Nauk SSSR* **226**, 440-443 (English transl. in *Doklady Earth Sciences Section* **226**, 197-200). -- Hydrogen and methane-rich gas inclusions are found in kimberlite pipes formed in the upper mantle.

K. Bailey (1979). Volcanic activity: the continual degassing of the Earth. *New Scientist*, 1 February 1979, 313-315.

A. P. Vinogradov (1967). Gas regime of the Earth. In *Chemistry of the Earth's Crust*, Vol. II, pp. 1-19. Israel Prog. Sci. Transl. -- Estimates that the Earth is only 10% degassed of its primary volatiles and proposes that the degassing process has irregular variations.

I. N. Yanitskiy, V. M. Korobeynik, and T. V. Sozinova (1976). Expression of crustal faults in helium field. *Geotectonics* **9**, 378-384.

METHANE STABILITY AT HIGH PRESSURE

B. M. French (1966). Some geological implications of equilibrium between graphite and a C-H-O gas at high temperatures and pressures. *Rev. Geophys.* **4**, 223-253.

V. K. Karzhavin and V. P. Vendillo (1970). Thermodynamic equilibrium and conditions for existence of hydrocarbon gases in a magmatic process. *Geochem. International* **7**, 7970803.

STABLE CARBON ISOTOPES

A. N. Fuex (1977). The use of stable carbon isotopes in hydorcarbon exploration. *J. Geochem. Explor.* **7**, 155-188. -- Survey according to the conventional outlook.

J. Hoefs (1972). Is biogenic carbon always isotopically "light", is isotopically "light" carbon always of biogenic origin? Adv. Org. Geochem. 1971, pp. 657-663. — Argues that reduced carbon with nearly constant isotopic composition, in all igneous rock types at a concentration of about 200 ppm, can be understood as abiogenic in nature.

E. M. Galimov (1969). Isotopic composition of carbon in gases of the crust. Internat. Geology Rev. 11, 1092-1104. — Finds that the carbon isotopic variation of natural gas with depth is evidence of an upward migration.

METEORITIC HYDROCARBONS AND FISCHER-TROPSCH SYNTHESIS

E. Anders, R. Hayatsu, and M. H. Studier (1973). Organic compounds in meteorites. Science 182, 781-790. -- Demonstrates the impressive chemical similarities between hydrocarbons of meteorites, terrestrial shale oil, and products of laboratory Fischer-Tropsch type syntheses.

M. S. Lancet and E. Anders (1970). Carbon isotope fractionation in the Fischer-Tropsch synthesis and in meteorites. Science 170, 980-982. -- The Fischer-Tropsch reaction between CO and H_2 gives the same type of carbon isotope fractionation as found in meteoritic and terrestrial hydrocarbons and carbonates.

R. A. Friedel and A. G. Sharkey, Jr. (1963). Alkanes in natural and synthetic petroleums: comparison of calculated and actual composition. Science 139, 1203-1205. Demonstrates a chemical similarity between the alkane isomers in crude oil and in abiogenic Fischer-Tropsch products.

CHEMICAL AUGMENTATION OF HYDROCARBONS

W. E. Pratt (1934). Hydrogenation and the origin of oil. In Problems of Petroleum Geology (W. E. Wrather and F. H. Lahee, Editors), pp. 235-245. Amer. Assoc. Petrol. Geol., Tulsa.

H. E. Hawkes (1972). Free hydrogen in genesis of petroleum. Bull. Amer. Assoc. Petrol. Geol. 56, 2268-2277. -- This paper and the preceding one argue that the chemical incorporation of deep-seated hydrogen by petroleum deposits must occur.

E. M. Galimov (1973). Carbon Isotopes in Oil-Gas Geology. NASA TT F-682. — Mentions, on page 318, that "the chemical 'growth' of coal from methane carbon is entirely possible."

A. A. Meyerhoff (1976). Economic impact and geopolitical implications of giant petroleum fields. Amer. Scientist 64, 536-541.

D. H. Root and L. J. Drew (1979). The pattern of petroleum discovery rates. Amer. Scientist 67, 648-652. -- This paper and the preceding one give the statistics showing that most of the world's known petroleum is concentrated in a very small number of giant fields (which we interpret as evidence for a positive feedback mechanism in the accumulation process).

ATMOSPHERIC METHANE

D. H. Ehhalt (1974). The atmospheric cycle of methane. Tellus 26, 58-70. -- General survey, including evidence for 20% depletion of atmospheric ^{14}C relative to biogenic methane.

R. A. Rasmussen and E. Robinson (1977). Atmospheric hydrocarbon concentrations in global background air samples. NTIS PB-275759. -- Detection of atmospheric methane in lower stratosphere at 1.40 ppm from Oct. 26 to Nov. 18, 1976.

W. Seiler, F. Müller, and H. Oeser (1978). Vertical distribution of chloroflouromethanes in the upper troposphere and lower stratosphere. Pure & Appl. Geophys. 116, 554-566. -- Detection of atmospheric methane in lower stratosphere at 1.7 ppm from Nov. 24, 1976 and again in 1977, suggesting possible large recent input of atmospheric methane.

DISSOLVED METHANE

J. W. Swinnerton and V. J. Linnenbom (1969). Low molecular weight hydrocarbon analysis of Atlantis II waters. In Hot Brines and Recent Heavy Metal Deposits in the Red Sea (E. T. Degens and D. A. Ross, Editors), pp. 251-253. Springer, New York. -- Detection of high methane concentration in Red Sea.

J. A. Welhan and H. Craig (1979). Methane and hydrogen in East Pacific Rise hydrothermal fluids. Geophys. Res. Lett., in press.

W. G. Deuser, E. T. Degens, G. R. Harvey, and M. Rubin (1973). Methane in Lake Kivu: new data bearing on its origin. Science 181, 51-54.

PETROLEUM-SEISMICITY CORRELATION

E. Fossa-Mancini (1939). Terremotos y yacimientos de petroleo. Bol. Inform. Petrol., Buenos Aires, añ. 16, no. 176, pp. 23-50. -- Perhaps the earliest demonstration of the correlation globally.

H. D. Klemme (1975). Geothermal gradients, heat flow and hydrocarbon recovery. In Petroleum and Global Tectonics (A. G. Fischer and S. Judson, Editors), p. 266. Princeton Univ. Press. -- His Figure 6.3 demonstrates the correlation between global tectonic fold belts and the major petroleum fields of the world.

R. D. Wilson, P. H. Monaghan, A. Osanik, L. C. Price, and M. A. Rogers (1974). Natural marine oil seeps. Science 184, 857-865. -- Their Figures 1 and 2 demonstrate the impressive global correlation between major oil seeps and earthquake zones.

MUD VOLCANOES

G. E. Higgins and J. B. Saunders (1974). Mud volcanoes--their nature and origin. Verhandl. Naturf. Gesellsch. Basel 84, 101-152. -- General survey and geographical distribution.

V. A. Sokolov, Z. A. Buniat-Zade, A. A. Goedekian, and F. G. Dadashev (1969). The origin of gases of mud volcanoes and the regularities of their powerful eruptions. Adv. Organic Geochem. 1968, pp. 473-485. -- Data on the volume and frequency of mud volcano eruptions in the South Caspian basin.

A. A. Jakubov et al. (1971). Mud Volcanoes of the Azerbaijan SSR. Atlas. Publishing House of the Academy of Sciences of the Azerbaijan SSR, Baku. -- A large book containing many spectacular color photographs of the worlds most impressive mud volcanoes.

DEEP FOCUS EARTHQUAKES - PARADOX

E. Orowan (1960). Mechanism of seismic faulting. In Rock Deformation (D. Griggs and J. Handin, Editors), pp. 324-345. Geol. Soc. Amer. Mem. 79.

D. Griggs and J. Handin (1960). Observations on fracture and a hypothesis of earthquakes. ibid., pp. 347-364. — This paper and the preceding one discuss the problem of seismic fracture at the enormous pressures of deep earthquakes.

EARTHQUAKE GAS ERUPTION PHENOMENA

Robert Mallet (1852, 1853, 1854). Third report on the facts of earthquake phenomena. Report of the British Association for the Advancement of Science 22, 1-176; 23, 117-212; 24, 1-326. -- This 600-page catalogue lists descriptive phenomena of some 5000 earthquakes between 1606 B.C. and 1842 A.D., including accounts of earthquake lights, explosions, peculiar atmospheric conditions, etc.; a valuable mine of archival information.

Ignazio Galli (1911). Raccolta e classificazione de fenomeni lumenosi osservati nei terremoti. Bollettino della Societa Sismologica Italiana 14, 221-447. — This 226-page paper describes 148 earthquakes which were accompanied by earthquake lights, including many cases of flames from the ground; some of these are cited in the following appendix.

J. S. Derr (1973). Earthquake lights: a review of observations and present theories. Bull. Seismol. Soc. Amer. 63, 2177-2187. -- Contains color photographs of earthquake lights from Japan.

John Michell (1760). Conjectures concerning the Cause, and Observations upon the Phaenomena, of Earthquakes...Phil. Trans. Roy. Soc. 51, 600. — Explanation of visible waves in terms of earthquake gas.

EARTHQUAKE PRECURSORS

T. Rikitake (1976). Earthquake Prediction. Elsevier Scientific Publ., Amsterdam. -- Useful survey of the precursory phenomena and discussion of dilatancy hypothesis.

C. H. Scholz, L. R. Sykes, and Y. P. Aggarwal (1973). Earthquake prediction: a physical basis. Science 181, 803-810. -- Good discussion of dilatancy.

C.-Y. King (1978). Radon emanation on San Andreas Fault. Nature 271, 516-519. — Precursory radon emanation shows spatially coherent large variations.

T. Gold and S. Soter (1979). Brontides: natural explosive noises. Science 204, 371-375. A review with many references.

EARTHQUAKE GAS COMPOSITION

G. I. Voytov, G. D. Osika, T. G. Grechukhina, and I. A. Plotnikov (1972). Some geologic and geochemical consequences of the Dagestan earthquake of May 14, 1970. Doklady Earth Sciences Section 202, 6-9.

N. I. Khitarov, G. I. Voytov, S. A. Kasparov, T. A. Krylova, and V. S. Lebedev (1972). Earthquake-induced changes in isotopic composition of carbon dioxide and hydrocarbons in natural gas. Doklady Earth Sciences Section 204, 10-12.

B. A. Mamyrin, I. N. Tolstikhin, and L. V. Khabarin (1979). Possible use of the helium-3/helium-4 ratio in predicting earthquakes. Geokhimiya 1979 (3), 384-386 (in Russian).

A. I. Kravtsov, M. I. Kucher, and A. I. Fridman (1979). Changes of the isotopic composition of carbon in natural gases in relation to seismic activity. Geokhimiya 1979 (3), 387-390 (in Russian).

R. Sugisaki (1978). Changing He/Ar and N_2/Ar ratios of fault air may be earthquake precursors. Nature 275, 209-211.

W. Ernst (1969). Erdbeben-Vorhersage aufgrund von Bodengas-Messungen. Naturwiss. 56, 280. Some measurements of methane increases in ground gas prior to earthquakes in Germany.

APPENDIX II:

SELECTED EARTHQUAKES SHOWING GAS ERUPTION PHENOMENA

QUEBEC Feb. 5, 1663

Sounds: "a rumbling like thunder..amid a noise that made people think there was a fire crackling in their garrets"

Flames: "pikes and lances of fire were seen, waving in the air, and burning brands darting down on our houses—without, however, doing...injury"; "...from the earth...emanated fiery torches and globes of flame—now relapsing into the earth, now vanishing in the very air, like bubbles"; "a great section of the earth [was] borne upward and carried into the river; and, at the place whence it was separated by the yawning open of the earth, there burst forth globes of smoke and flame"

Sulfur and gas: "the river changed its color...for eight entire days, [it] put on a sulphurous one"; "during the whole night, sweltering heat puffs exhaled from the soil"

Principal source: The Jesuit Relations and Allied Documents, Vol. 48.

VOSGES (France) May 13, 1682

"Flames were also seen coming from the earth, without there appearing any opening, nor any other outlet, except in a single spot, where there opened a cleft, the depth of which could not be measured...The flames which issued from the earth, and which occurred most frequently in places that had been planted, such as woods, in no way burnt the objects they encountered; they gave off an extremely disagreeable odor, but one that had nothing sulphurous about it..."

Claude Perrault, quoted in Galli's catalog, #27, p. 266.

LISBON Nov. 1, 1755

"The 1st of November, the day broke with a serene sky...but about nine o'clock the sun began to grow dim, and about half an hour after we began to hear a rumbling noise, like that of carriages, which increased to such a degree as to equal the noise of the loudest cannon; and immediately we felt the first shock, which was succeeded by a second and a third; on which, as on the fourth, I saw several light flames of fire issuing from the sides of the mountains, resembling that which may be observed on the kindling of coal...I observed from one of the hills called the Fojo, near the beach of Adraga [near Colares], that there issued a great quantity of smoke, very thick, but not very black; which still increased with the fourth shock, and after continued to issue in a greater or less degree. Just as we heard the subterraneous rumblings, we observed it would burst forth at the Fojo; for the quantity of smoke was always proportional to the subterraneous noise..."

Mr. Stoqueler, Phil. Trans. Roy. Soc. **49**, 413-418 (1756).

CALABRIA Feb. 5, 1783

"At the time of the earthquake, during the night, flames were seen to issue from the ground in the neighborhood of the city towards the sea, where the explosion extended, so that many countrymen ran away for fear; these flames issued exactly from the place where some days before an extraordinary heat had been perceived. (emphasis added)

Francesco Ippolito, Phil. Trans. Roy. Soc. **73**, Appendix i-vii (1783).

"The water of the wells, of the sea, and also of the fishponds, a few hours before the earthquake of 5 February struck in Cosenza and neighboring villages, was seen to raise its level, all foaming as though boiling, without being observed to have a greater heat than normal." (emphasis added)

Nicolo Zupo, Riflessioni su le cagioni fisiche dei Tremuoti accaduti nelle Calabrie nell' anno 1783 (Naples, 1784), quoted in Galli's catalog, #57, p. 303.

CUMANA (Venezuela) Dec. 14, 1797

An hour before the shock, a strong smell of sulfur was perceived, and before the earthquake flames appeared on the banks of the Manzanares.

Alexander von Humboldt, Personal Narrative of Travels to the Equinoctial Regions of America during the years 1799-1804, Vol. I, p. 163 (1889).

NEW MADRID (Mississippi Valley) Dec. 16, 1811 through Feb. 7, 1812

Sounds: "distant rumbling sounds, succeeded by discharges, as if a thousand pieces of artillery were suddenly exploded"; "a loud roaring and hissing... like the escape of steam from a boiler, accompanied by...tremendous boiling up of the waters of the Mississippi in huge swells"; "explosions"

Lights: "many sparks of fire emitted from the earth"; "flashes such as would result from an explosion of gas"

Sulfur: "complete saturation of the atmosphere with sulphurous vapor"

Visible waves: "the earth was observed to roll in waves a few feet high with visible depressions between...these swells burst, throwing up large volumes of water, sand, and coal"

M. L. Fuller, USGS Bull. 494 (1912)

CALLAO (Peru) March 20, 1828

Water in the bay "hissed as if hot iron was immersed in it", bubbles and dead fish rose to the surface, and the anchor chain of H.M.S. Volage was partially fused while lying in the mud on the bottom.

Quart. J. Sci. Lit. & Arts, Jan.-June 1829

LIMA (Peru) March 1, 1865

The surface of the bay was agitated with jets of water 12 to 15 inches high, there was a strong odor of hydrogen sulfide, and the white paint on the U.S. Ship Lancastre was turned black.

Amer. J. Sci., 2nd Ser. **40**, 365 (1865).

ARICA (Chile) Aug. 13, 1868

"From every fissure there belched forth dry earth like dust, which was followed by a stifling gas...which severely oppressed every living creature, and would have suffocated all these if it had lingered longer stationary than it did, which was only about 90 seconds."

New York Tribune, Sept. 14, 1868.

OWENS VALLEY (Calif.) March 26, 1872

Sounds: "Several [shocks] were distinctly preceded by a dull, explosive sound, like the noise of the firing of a piece of heavy artillery at a great distance, or the letting off of a heavy blast...in several cases the explosive sounds were heard by our party when no subsequent vibration was perceived."

J. D. Whitney, Overland Monthly **9**, 130-140, 266-278 (1872).

Flames:

"People living near Independence...said [that] at every succeeding shock they could plainly see in a hundred places at once, bursting forth from the rifted rocks great sheets of flames apparently thirty or forty feet in length, and which would coil and lap about a moment and then disappear."

San Francisco Chronicle, April 2, 1872.

"Immediately following the great shock, men, whose judgment and veracity is beyond question, while sitting on the ground near the Eclipse mine, saw sheets of flame on the rocky sides of the Inyo mountains but a half a mile distant. These flames, observed in several places, waved to and fro apparently clear of the ground, like vast torches; they continued for only a few minutes."

Inyo Independent, April 20, 1872.

CHARLESTON (S.C.) Aug. 31, 1886

Sounds:

Heavy explosions were heard in Summerville (near the epicenter) on Aug. 27 and 28.

C. E. Dutton, Ninth Ann. Rept. USGS, pp. 270-272 (1889)

After the earthquake, in Summerville, "All during the day there was a constant series of detonations...from all possible directions. It resembled the discharge of heavy guns at intervals of about ten minutes, and was like the sounds of a bombardment at a great distance...it was only occasionally that the earth would quake from the subterranean discharges... Nearly all the wells had been at low water. There was a sudden rise in these wells...Just before any of the land detonations, [one could] see the water rise up the walls of the well and after the shock again subside."

Charleston News and Courier, Sept. 1, 1886

Atmospheric effects:

"Immediately after the great shock...a strong odor, remarkable for the presence of sulfur gases, permeated the atmosphere, and was perceptible throughout the night."

Dutton, op. cit.

A witness in Charleston reported that "It was terribly hot about 20 minutes before the shock. It was a peculiar scorching heat that I never felt before. I saw people on the streets taking off their coats and vests as they walked along. Then there was a rumbling noise." [note: the earthquake occurred at 9:51 p.m.]

New York Times, Sept. 4, 1886

Visible waves: "The ground began to undulate like a sea...I could see perfectly and could make careful observations, and I estimate that the waves were at least two feet in height."

eyewitness quoted by Dutton, op. cit. [Many similar accounts of visible waves were published by Dutton.]

SONORA May 3, 1887

Lights: Flames issued from fissures, in some cases scorching overhanging branches.

G. E. Goodfellow, Science 11, 162 (1888).

Visible waves "seemed to be two feet high, about twenty feet apart, and moved as rapidly as the incoming waves along the seashore."

B. MacDonald, Bull. Seismol. Soc. Amer. 8, 74 (1918).

SAN FRANCISCO April 18, 1906 [5:13 a.m.]

Lights: In San Jose, according to engineer J. E. Houser, "the whole street [was] ablaze with fire, it being a beautiful rainbow color but faint." Reports of blue flames also from Petaluma Creek and "hovering over the bases of foot-hills in western San Francisco."

E. L. Larkin, Open Court 20, 393 (1906).

Sounds: Healdsburg mining engineer George Madeira reported "Heavy detonations and rumblings were heard near the base of Mt. Tamalpais, Marin County, during the winter months and previous to the great earthquake which destroyed San Francisco...and have been heard up to this writing [May 5, 1908]."

T. Alippi, Boll. Soc. Sismol. Italiana 15, 65 (1911).

Visible waves: San Francisco police sergeant Jesse Cook said "...I could see it actually coming up Washington Street. The whole street was undulating. It was as if the waves of the ocean were coming towards me, billowing as they came."

G. Thomas and M. M. Witts, The San Francisco Earthquake, p. 69.

Twenty-two similar accounts of visible waves, distributed over a 600-km span, were reported by the State Earthquake Investigation Commission in The California Earthquake of April 18, 1906, Vol. 1, Pt. 2, pp. 380-381 (1908). The amplitude most often reported was about a foot.

SWABIA (South Germany) Nov. 16, 1911.

Lights: "We saw a sea of flames, gas-like and not electrical in nature, shoot up out of the paved market street. The height of the flames I can estimate at 8 to 12 cm; it was like when you pour petroleum on the ground and light it."

"I observed very precisely how a bright fire, which had a bluish color, came up out of the ground in the meadow. The height of the fire might have been about 80 cm."

eyewitness accounts, among many others, from A. Schmidt and K. Mack, Württ. Jahrbücher f. Statist. u. Landeskde., Jahrg. 1912, Heft I, p. 96 et seq. (1913).

Gas: There are several accounts of people feeling giddy just prior to the earthquake, or noticing stifling air. After the earthquake, Lake Constanz appeared to "boil". The smell of sulfur was prominent in the air.

G. Rüetschi, Jahresberichte und Mitteilungen des Oberrheinischen geologischen Vereins Karlsruhe N.F. 3, 113 (1912).

RUMANIA Nov. 10, 1940

Flames: "flames in rhythm with the movements of the soil"; "flames issuing from rocks, which crumbled, with flashes also issuing from non-wooded mountainsides"; "irregular gas fires"

Gas: "a thick layer like a translucid gas" above the surface of the soil.

G. Demetrescu and G. Petrescu, Acad. Roumaine, Bull. Sci. 23, 292-296 (1941).

CHILE May 22, 1960

Observations of the sea having the appearance of "boiling" were reported over a range of nearly 450 km.

H. A. Sievers, Bull. Seismol. Soc. Amer. 53, 1125 (1963);
W. M. Adams, Earthquakes (1964).

HAICHENG Feb. 4, 1975

Earthquake lights were seen immediately before the shock.

C. Barry Rayleigh, personal communication, Dec. 1977

Gas: The emission of "earth gas" and hot air preceded the earthquake. "Many areas were covered with a peculiar fog...just prior to the quake. The height of the fog was only 2 to 3 meters. It was very dense, of white and black color, non-uniform, stratified and also had a peculiar smell. It started to appear 1 to 2 hours before the quake and it was so dense that the stars were obscured by it. It dissipated rapidly away after the quake. The area where this 'earth gas fog' appeared was related to the fault area responsible for the earthquake...People in the quake area remarked that the air temperature was higher than usual during the days before the quake. Just before the earthquake many were not feeling well because of the warm weather...People...smelled this gas in an area measuring 15 x 5 km; one person fainted because of this. A certain commune member in Fung-hsing-hsein in fact saw gas bubbling out of a ditch. According to an incomplete survey, this 'earth gas' appeared quite a few times: it was noticed on Dec. 24, 1974, Jan. 14, 15, 22, 27, 30, Feb. 3, 1975, in many areas."

Acta Geophysica Sinica 20, 270 (1977).

EAST ANATOLIA Nov. 24, 1976

Booming sounds were heard several times in the two weeks prior to the quake; oil seepages were also noticed as a precursor. "Töksoz also interviewed villagers after a 6.7 magnitude quake in another part of eastern Turkey on Sept. 5, 1975. He says that survivors of this quake reported...a brightening of the sky the night before the event. Some geologists 250 km away also noticed the brightening in the direction of the earthquake epicenter."

Science News 112, 408 (1977).

METHODS FOR ASSESSING GAS RESOURCES

Robert L. Whiting
Texas A&M University, College Station, Texas, USA

INTRODUCTION

This paper is directed to the methods for assessing gas resources. It is first necessary to classify petroleum reservoirs and to identify the mode of occurrence of the gas resource, then the initial volume of the gas resource in place is estimated using various techniques. Thereafter, the reservoir drive mechanism is determined, thereby defining the hydrocarbon recovery efficiency, and the gas reserves estimated by different methods.

CLASSIFICATION OF PETROLEUM RESERVOIRS

Petroleum reservoirs have been typed and characterized in many different ways. The most common and still the most popular method of classifying such reservoirs is on the basis of the producing surface gas-oil ratio. Using this method, any well (or field) which produces at a gas-oil ratio in excess of 100,000 cubic feet per barrel is considered as a gas well; one producing with a gas-oil ratio of zero to several thousand, an oil well; and one producing at a gas-oil ratio of 5000 to 100,000, a gas condensate well. In practice, similar surface gas-oil ratios have been obtained for reservoirs containing a variety of hyrocarbon fluid compositions, existing over a wide range of reservoir pressures and temperatures and producing with natural or artificial mechanisms. This has resulted in both technical and legal misunderstanding of the nature of petroleum reservoirs. The aforementioned simplified classification is considered inadequate since the surface gas-oil ratio is the result of the composition of the reservoir fluid, the reservoir pressure and temperature, the reservoir mechanism and the producing operations and techniques.

Hence, technically it is thought that petroleum reservoirs should be defined upon the basis of the location of their initial reservoir pressure and temperature on the usual pressure-temperature (P-T) diagram. For a particular reservoir fluid composition, a P-T diagram is shown in Figure 1. The phase envelope is bounded by the dew point and bubble point lines converging at the critical point. At all P-T conditions enclosed within these boundaries, two phases, vapor and liquid, coexist. Utilizing the P-T diagram, petroleum reservoirs may be instantly characterized as gas, gas-condensate or oil. Considering an initial reservoir condition at A, the pressure history of such a reservoir by normal depletion would be along the path A-A. A single phase reservoir fluid (gas) would exist throughout the history of production. Also the composition of the fluid produced will remain constant. These conditions will persist for gas reservoirs having initial temperatures exceeding the cricondentherm. It is evident that the fluid produced at surface conditions may be single phase or two phase (shown by path A-A_2) depending upon the surface P-T conditions.

Consider next a reservoir fluid existing initially at P-T condition B. The fluid is single phase and is usually called gas since it exists at a temperature exceeding the critical point. Upon pressure reduction in the reservoir, along path B-B_1-B_2-B_3, the reservoir phase conditions would be successively single phase, two phase (vapor and liquid) and single phase (vapor). For such conditions to prevail, B must be located between the critical point and the cricondentherm. Within the two

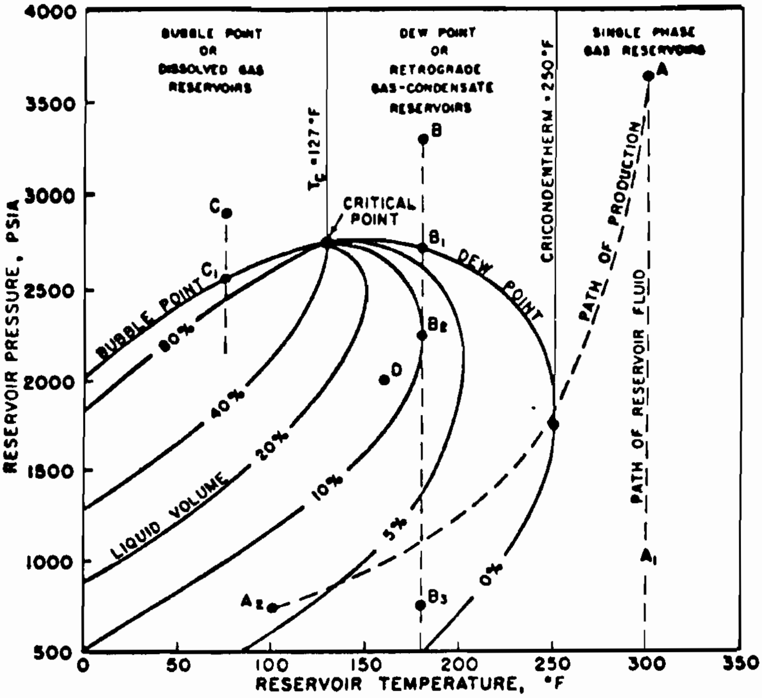


Fig. 1 Pressure-temperature phase diagram of a reservoir fluid.

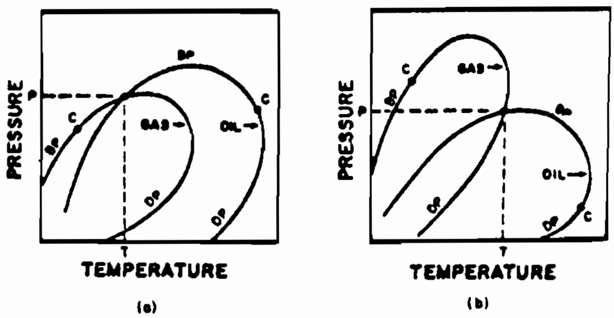


Fig. 2 Phase diagrams of a cap gas and oil zone fluid showing (a) retrograde cap gas, and (b) non-retrograde cap gas.

Permission: Craft and Hawkins, Prentice-Hall Inc.
Englewood Cliffs, N.J. U.S.A.

phase region the maximum volume of liquid that will be condensed in the reservoir is dependent upon the initial reservoir fluid composition and the reservoir temperature. Along the path B-B_1 the composition of the produced fluid remains constant. However, as the reservoir pressure decreases due to fluid withdrawal, retrograde condensation occurs and liquid is condensed from the gas and accumulates in the reservoir. As a consequence, the composition of the produced fluid changes and is characterized by lower liquid content (higher gas-oil ratio). This retrograde condensation continues until a maximum volume of liquid is condensed. In some cases, a sufficient volume of liquid will be condensed in the reservoir to provide mobility of the liquid phase. In such cases the surface fluid composition is dependent upon the relative mobilities of the vapor and liquid in the reservoir. Unfortunately, as retrograde condensation occurs, the reservoir fluid composition changes, and the P-T envelope is shifted such that retrograde liquid condensation increases.

As reservoir pressure is reduced further along path B_2-B_3, revaporization of the retrograde liquid occurs and decreasing surface gas-oil ratios are observed. Generally for a particular initial hydrocarbon fluid, retrograde loss increases at lower reservoir temperature, higher abandonment pressure and for greater shifting of the phase envelope to the right.

Hence, it is seen that conventional gas reservoirs exist initially in a single-state phase, ordinarily considered as gas. As fluid is produced from a reservoir, having an initial temperature above the cricondentherm, and reservoir pressure decreases, the reservoir fluid remains single phase gas and the composition of the produced fluid remains constant. In a reservoir in which the initial reservoir temperature lies between the critical temperature and the cricondentherm the reservoir fluid conditions will be successively single phase gas, two phase gas-liquid and single phase gas upon adequate pressure reducation. The composition of the produced fluid will be dependent upon the relative mobilities of the gas and liquid in the reservoir.

Other possible reservoir fluid conditions are represented by initial conditions C and D, a single phase liquid (oil) reservoir and a two phase vapor-liquid (oil zone overlain by a gas cap) reservoir, respectively. The reservoir performance characteristics of these two type (associated gas) reservoirs is discussed later in this paper. However, attention is directed to the fact that in the gas cap type reservoir the gas cap may be either of the retrograde or nonretrograde type as illustrated in Figure 2.

ESTIMATION OF INITIAL HYDROCARBONS IN RESERVOIR

Volumetric Method

Once a petroleum prospect has been drilled, the discovery well completed and drilling of other wells commenced, it is standard practice to estimate the hydrocarbons in place, the expected hdyrocarbon productivity and the hydrocarbon recovery. Increasing emphasis is being placed upon early estimates due to the increased costs experienced in deeper drilling and in the more hostile environments, particularly offshore; the low discovery success ratio offshore and the limited areal (volume) extent; and multiple reservoir complexity of the majority of offshore discoveries to date.

First, the hydrocarbons in place are estimated by the volumetric method. This method necessitates use of surface and subsurface data to construct cross sections and structure and isopachous maps. These cross sections and maps are prepared using data from cores, downhole logs and drill-stem and production tests. A subsurface contour map depicts the geologic structure by lines connecting points of equal elevation on the top of the marker bed. Multiple cross sections through various wells define the boundary of the structure and reservoir.

The boundary of a reservoir may be determined by development drilling which establishes permeability barriers, fluid contacts and faults. However, it is preferable in the early life of a field to conduct constant-rate production tests or build up tests to detect the reservoir limits. Further, pulse testing should be utilized as a means of evaluating reservoir heterogeneity. During the past twenty years a new technology in formation evaluation using well testing has evolved. New techniques continue to be developed permitting exploitation of the reservoir with fewer wells and at a lower cost. Net isopachous maps show lines connecting points of equal net formation thickness (oil or gas). The structure and thickness maps are used to determine the bulk volume of the oil and/or gas reservoir. The accuracy of this estimate is primarily dependent upon the interpretation of net sand thickness and the identification of the reservoir boundary.

For each well, little difficulty is experienced in estimating the gross formation thickness of intergranular rocks from available data. However, such estimates for carbonate rocks, particularly those which are fractured and fissured, are extremely difficult. Assuming that the estimate of gross thickness is possible, the estimates of net (oil or gas) formation thickness frequently vary over a wide range. This occurs because, in the writers opinion, fewer core analyses, drill-stem and production test data are being obtained today than in the past. Increasing reliance for fluid saturation estimates (oil, gas and water) is being placed on downhole log interpretation. Often there are insufficient core analysis data to permit calibration and/or correlation with downhole log determined results.

A high degree of sophistication in downhole log interpretation through the use of fundamental rock and fluid property data utilizing high speed computers has been developed. Techniques permit estimates of the gross formation thickness utilizing porosity, shale content and/or permeability as descriminators. Density and neutron logs are often used to determine shale content.

Since the density and neutron logs respond differently to shale content, their response equations can be simultaneously solved to accurately determine shale fraction. The response equations and the simultaneous solution are:

Density Curve: $\emptyset = \emptyset_D - (\emptyset_{Dsh} V_{sh})$

Neutron Curve: $\emptyset = \emptyset_N - (\emptyset_{Nsh} V_{sh})$

Simultaneous Solution: $V_{sh} = \dfrac{\emptyset_N - \emptyset_D}{\emptyset_{Nsh} - \emptyset_{Dsh}}$

Where: $\emptyset$ = Porosity

$\emptyset_D$ = Density porosity

$\emptyset_N$ = Neutron porosity

$\emptyset_{Dsh}$ = $\emptyset_D$ at shale reference point

$\emptyset_{Nsh}$ = $\emptyset_N$ at shale reference point

V_{sh} = shale-fraction

Typical cross plots for a shaly sand and a shaly limestone are shown in Figures 3 and 4, respectively. When such data are substantiated by core analysis data, that is, the logs are calibrated using the core analyses, one has a high degree of confidence in the results obtained for the gross formation thickness.

In the absence of well log information, core analysis data for porosity and/or permeability are used as the descriminators to obtain the gross formation thickness. Permeability transforms may be developed utilizing a computer analysis cross plot of core analysis porosity versus core analysis permeability. Hence, core analyses and well log data may be related.

The results of such calculations can be represented graphically in the strip log form utilizing computer data plotters and printing acces-

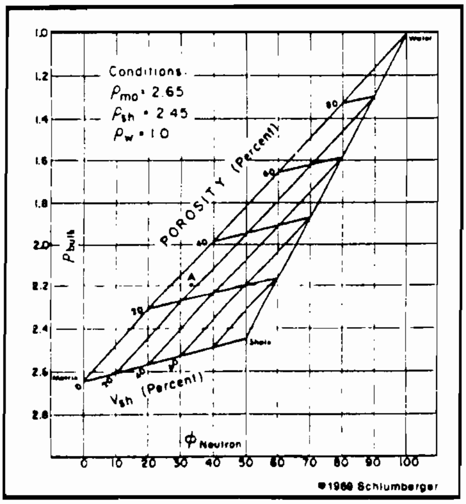


Fig. 3 — *Neutron-Density crossplot showing matrix, water, and shale points, scaled for determination of V_{sh} and porosity.*

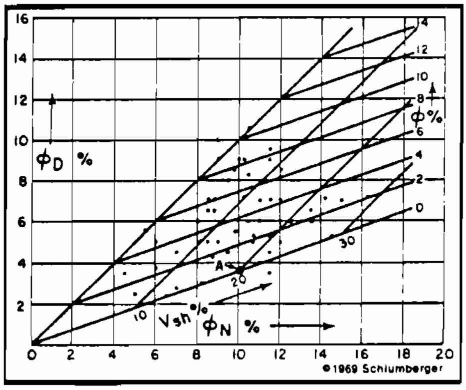


Fig. 4 — *ϕ_D vs ϕ_N crossplot over a section of shaly limestone.*

Permission:

Schlumberger, Houston, TX, U.S.A.

sories. However, the usual practice is to prepare net (oil or gas) formation thickness (h) maps. The bulk volume of the reservoir may be estimated from this map by planimetering.

Once the net (oil or gas) formation thickness map has been prepared, a porosity (Ø) map is prepared from core analysis, well log and computer calculated data. The porosity (Ø) map is superposed on the net (oil or gas) formation thickness map and an (hØ) map drawn. The pore volume of the reservoir may be estimated by planimetering this (hØ) map.

It is then necessary to determine the oil saturation (S_o) in the formation. This variable may only be determined directly by retorting of cores and the interpretation of the results is difficult and often subject to question. Hence, oil saturations are ordinarily determined indirectly from core analysis and well logs from water saturation (S_w) measurements and calculations.

Water saturation estimation from cores obtained using water base drilling fluids is difficult. Ordinarily, only water saturations of cores which are obtained using oil base drilling fluids are considered reliable.

Water saturations may be obtained from capillary pressure data using the $J(S_w)$ function. Cation Exchange Capacity (CEC) may also be used to estimate water saturation. However, such estimates in shaly sands are often questioned because of the difficulty in distinguishing between laminated and dispersed shale. A total shale relationship, developed through both laboratory investigation and field experience with many shaly formations, may be used. This relationship is independent of the distribution of the shale and has been found to be applicable over the range of water saturation values encountered in practice.

$$\frac{1}{R_t} = \frac{\emptyset^2 S_w{}^2}{aR_w(1-V_{sh})} + \frac{V_{sh}S_w}{R_{sh}}$$

Where:

R_t = Resistivity of fluid saturated formation, ohms

a = Constant in Archie Equation

R_w = Formation water resistivity, ohms

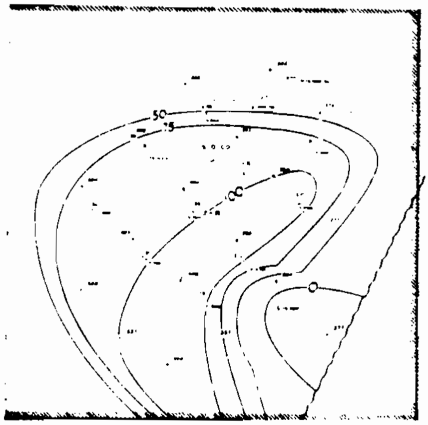
S_w = Water saturation in formation, fraction

R_{sh} = Resistivity of shale beds, ohms

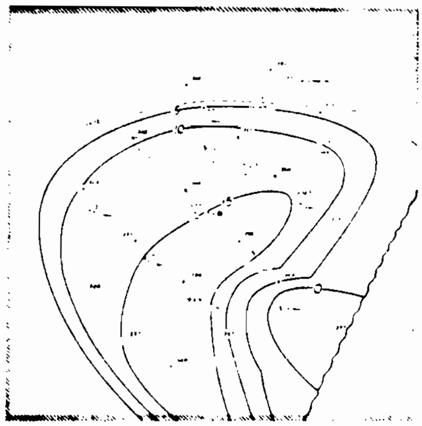
These methods of estimation of water saturation (S_w) may be compared with production results obtained in drill stem tests on the wells. Reconciliation of the data and results should yield appropriate values of water saturation (S_w) from which oil and/or gas saturation may be calculated.

Oil and/or gas (S_o, S_g) saturation maps are then prepared. These maps are then superposed and the $h\emptyset S_o$ and $h\emptyset S_g$ maps are drawn. The oil and free gas, associated or non associated, in place in the reservoir may be estimated by planimetering the $h\emptyset S_o$ and $h\emptyset S_g$ maps, respectively, Figure 5.

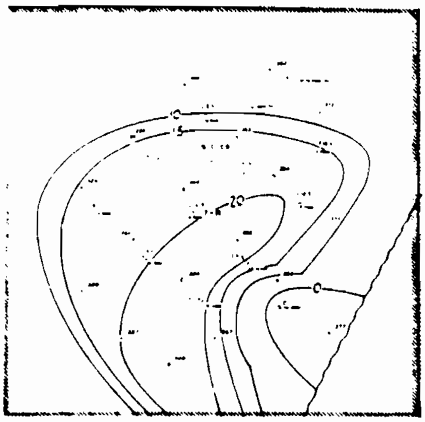
Knowing the oil or gas formation volume factor (B_o, B_g) at the initial reservoir pressure and temperature, the initial volume, at standard (surface) conditions, of oil in the reservoir or gas in the reservoir, associated or non associated, may be calculated. The average net (oil,



Net Formation Thickness (h) Map



Net Formation Thickness-Porosity-Gas Saturation ($h\emptyset S_g$) Map



Net Formation Thickness-Porosity ($h\emptyset$) Map

Fig. 5 Maps Used in Volumetric Estimate of Initial Gas in Place

gas) formation thickness ($\overline{h}$), average porosity ($\overline{\emptyset}$), average oil saturation ($\overline{S}_o$) and also the areal extent (A) may be obtained from the respective maps. Hence, the oil initially in the reservoir and the free gas may be calculated from

$$N = \frac{7758\ A\ \overline{h}\ \overline{\emptyset}\ \overline{S}_o}{\overline{B}_o} \qquad G = \frac{43{,}522\ A\ \overline{h}\ \overline{\emptyset}\ \overline{S}_g}{\overline{B}_g}$$

Materials Balance Method

Materials balances may be used to estimate the initial volumes of hydrocarbons in place in a reservoir, identify the type of reservoir drive mechanism and predict the future performance of the reservoir and the ultimate hydrocarbon recoveries. The type of material balance used in such estimates is similar to that used in many other fields of engineering for quantity and quality estimate and control. However, custom has established that the material balance be written on a volumetric basis, although this is not necessary. In the simplest form, the materials balance equation can be written as initial volume = volume remaining + volume removed.

Since oil, gas, and water are present in petroleum reservoirs, the material balance can be written for the total fluids or for any one of the fluids present. Furthermore, there are numerous ways of expressing the physical properties of the fluids present and the relationship among these properties. The petroleum literature contains numerous material balances which may appear to be different but upon critical examination will be found to be identical.

The following materials balance equation is one of the most general that my be written to estimate the initial oil in place, N. Nomenclature may be found at the end of this paper.

$$N = \frac{N_p[B_o + (R_c - R_s)\frac{B_g}{5.61}] - W_eB_w + W_pB_w - W_iB'_w - \frac{G_iB'_g}{5.61}}{B_t - B_{ti} + mB_{ti}(\frac{B_g - B_{gi}}{B_{gi}}) + B_{oi}\bar{c}_{f+w}(P_i - P)}$$

From this equation the following equations may be written for specific reservoir drive mechanisms. For an undersaturated reservoir

$$N = \frac{(N-N_p)B_o}{B_o-B_{oi}} = \frac{(N-N_p)B_o}{B_t-B_{ti}} = \frac{(N-N_p)B_t}{B_t-B_{ti}}$$

For a solution gas (depletion drive) reservoir

$$N = \frac{N_p[B_o + (R_c - R_s)\frac{B_g}{5.61}]}{B_t - B_{ti}} = \frac{N_p[B_t + (R_c - R_{si})\frac{B_g}{5.61}]}{B_t - B_{ti}}$$

For a solution gas - gas-cap drive reservoir

$$N = \frac{N_p[B_o + (R_c-R_s)\frac{B_g}{5.61}]}{B_t-B_{ti}+mB_{ti}(\frac{B_g-B_{gi}}{B_{gi}})} = \frac{N_p[B_t + (R_c-R_{si})\frac{B_g}{5.61}]}{B_t-B_{ti}+mB_{ti}(\frac{B_g-B_{gi}}{B_{gi}})}$$

In the event that there are fluid productions and injections into the reservoir other than those indicated in the specific reservoir drive equations, the equations may be modified in accordance with the generalized materials balance equation.

It can be seen from these equations that both field and laboratory data are desired to obtain an estimate of the initial oil in place in the reservoir. Modern reservoir engineering practices are such that these data are available. However, such is not the case for older fields and hence one must often depend upon empirical data and/or data from fields producing from the same formation.

It should be noted that in some of the equations that both the initial oil in place, N, and the initial gas in place, expressed by m, are unknown. Estimation of N may be made by using the volumetric estimate for G. Also various values for m may be assumed and the value of m established by some optimization tool such as deviation from the mean.

Also it is seen that the cumulative water influx, W_e, must be estimated. This variable may be expressed generally as follows:

$$W_e = C\left\{f(p,t)\right\}$$

The function $\left\{f(p,t)\right\}$ may be determined from past performance data, pressure and time, or may be matched to past performance by assuming steady state, successive steady state or unsteady state production conditions.

Once the value of N is estimated, the volume of gas dissolved in the oil initially may be calculated from NR_{si}. The total volume of gas in the associated gas reservoir is obtained by summing the dissolved gas and the free gas in the gas cap.

Materials balances may be used to estimate the initial gas in place, G, in non associated gas reservoirs and also the ultimate recovery or gas reserves, G_p. The following is the most generalized equation that may be written for estimation of initial gas in place, G, in the reservoir.

$$G = \frac{G_{pw}B_g + 5.61(W_p - W_e)B_w}{B_g - B_{gi}}$$

In practice G may be calculated for each pressure survey made in the field and the best value estimated from this series of calculations. Here again the value of cumulative water influx, W_e, must be estimated and this is done as discussed previously. Also, it is necessary to ascertain the source of the cumulative water production. This water may have been derived from connate water in the reservoir or from the reservoir gas. Further, condensate (distillate) is often extracted from the produced fluid at the surface. Hence, the reservoir source of this condensate must be determined. Such determinations for the water and condensate will dictate whether these surface productions are to be restored to reservoir vapor or liquid. Hence, the cumulative gas production, G_{pw}, is considered to have been derived from reservoir wet gas (hydrocarbons and water vapor) and the cumulative water production, W_p, is considered to have been derived from reservoir liquid.

GAS RECOVERY FACTORS FOR ASSOCIATED AND NON ASSOCIATED GAS RESERVOIRS

As mentioned previously, in conventional oil fields (associated gas reservoirs), the natural gas of interest is that dissolved in the oil in the oil zone and free gas in the gas cap. In practice, the recovery of gas and its rate of recovery is dependent upon the characteristics of the oil (gas solubility and shrinkage), the reservoir rock properties (homogeneity, vertical and horizontal permeabilities, fluid saturations, relative permeabilities), well spacing, relative prices of oil and gas, and the reservoir mechanism. During the past thirty years increasing attention has been directed to laboratory and field research which would result in most efficient utilization of the reservoir mechanism to maximize petroleum recovery and productivity.

Results to date identify various types of reservoir mechanisms and document experience as follows: In an oil reservoir with no free gas cap, two initial reservoir conditions may be visualized, namely, a saturated reservoir and an undersaturated reservoir. In the latter, all gas is dissolved in the oil. Gas solubility in oil ranges from zero (a dead oil) to several thousand cubic feet per barrel.

Considering that the oil zone is initially filled with gas saturated oil and connate water, upon fluid withdrawal from the reservoir, the reservoir mechanism may be one or a combination of different types. The most common mechanism in such a reservoir is a solution-gas drive. This type drive is characterized by a short period of high oil production rate at the initial solution gas ratio followed by rapidly declining oil production rate and rapidly increasing gas-oil ratio. Oil recovery by this mechanism is relatively low (20-40% of that originally present). Solution gas production is rapid and gas recovery is relatively low (30-70%). Free gas remaining in the oil zone and solution gas remaining in the residual oil is lost for all practical purposes. The magnitude of the loss is dependent primarily upon the oil recovery, since free gas must occupy the reservoir volume previously occupied by the produced oil, at the reservoir abandonment pressure. A potential source of additional gas reserves is from low pressure crude oil and natural gas reservoirs. Research is needed to develop technology by which this resource may be recovered economically.

Another possible reservoir mechanism may develop when fluid withdrawal rates and reservoir rock and fluid properties are such as to permit segregation of the gas to form a secondary gas cap. Development of a secondary gas cap is accelerated by a high ratio of vertical to horizontal permeability and low fluid withdrawal rates. A secondary gas cap can also be developed artificially by injecting gas on the crest of the structure. The gas cap formed helps to maintain the reservoir pressure and prevents liberation of the dissolved gas from the oil. As a consequence, higher oil recovery (30-60% of oil originally present) and oil production rates are obtained than by solution gas drive. Although the gas recovery may be the same or greater than that obtained by solution gas drive, gas production rates are lower and gas production is delayed due to the accumulation of the segregated gas in the gas cap and the gas invaded oil zone.

As mentioned earlier, oil zones filled with gas saturated oil and connate water often have associated aquifers. Fluid withdrawal from the oil zone may induce water encroachment. The fluid withdrawal rates may be such that the rate of water encroachment may maintain the reservoir pressure. In such a case, high oil recovery (40-80% of oil originally present) is obtained at virtually a constant gas-oil ratio corresponding to the initial solution gas-oil ratio. The gas recovery and gas production rate is probably higher for this type of reservoir mechanism and gas recoveries range from 40-80% of the gas initially in solution in the oil originally present.

However, in some water drive reservoirs, fluid withdrawal rates, reservoir rock and fluid properties and aquifer properties may be such that only a partial water drive develops and the reservoir pressure declines as fluids are withdrawn. Partial water drive reservoirs yield oil and gas recoveries and productivities intermediate between solution-gas drive and water drive dependent upon the predominant mechanism. Obviously, a secondary gas cap could develop naturally in a partial water drive reservoir and the recoveries and productivities would change accordingly.

Frequently a petroleum reservoir containing gas saturated oil in the oil zone has an associated free gas cap initially. In such a reservoir, fluids are withdrawn from the lower structural portion with a gas cap drive mechanism prevailing. The gas cap helps to maintain the reservoir pressure, the larger the size of the gas cap relative to the oil zone, the greater the degree of pressure maintenance. The oil recovery and production rates and gas recovery and production rates correspond to those obtained in reservoirs which develop secondary gas caps.

Some petroleum reservoirs consist of a gas saturated oil zone with an initially associated gas cap and an aquifer. It is obvious that such a reservoir could be produced by a number of different reservoir mechanisms or a combination of mechanisms. In such a reservoir, production is generally regarded to be the result of a combination drive mechanism. However, it will be recalled that oil and gas recoveries and productivities by water drive are ordinarily the highest. Hence, efforts are made to control fluid withdrawals from the oil zone in such a manner that the water encroachment maintains a constant reservoir pressure and that the gas oil contact remains at the same subsea depth. This is exceedingly difficult to achieve in practice. In an active water drive reservoir with an associated gas cap, the principal concern is to prevent displacing the oil from the oil zone into the gas cap. Withdrawal of gas from the gas cap would certainly encourage such migration. In the event that oil is displaced into the gas cap, the great majority of such oil is considered unrecoverable.

Undersaturated oil reservoirs with very active water drives (constant reservoir pressure) yield gas recoveries approaching that of the initial solution gas. Hence, gas recovery is directly related to the residual oil saturation remaining after water encroachment. Laboratory research indicates that for any particular reservoir rock and fluid system there is an optimum reservoir pressure (and hence oil and gas saturation) at which oil and gas recovery is maximized. This implies that reservoir fluid withdrawals should be matched with fluid encroachment to achieve the desired pressure drawdown. In practice, this has been difficult to achieve due first to reservoir rock and fluid property data and secondly to field operational problems.

From the foregoing, it is evident that a petroleum reservoir is a complex rock and fluid system in which natural and artificial energies must be controlled in order to achieve maximum economic hydrocarbon recovery and productivity.

Gas recovery in non associated gas reservoirs is predicted most expediously by converting the gas in place materials balance into the following form utilizing P-V-T relationships and assuming volumetric control:

$$\frac{P_i V_i}{T_i Z_i} = \frac{PV}{TZ} = \frac{P_a V_a}{T_a Z_a} \quad \text{and} \quad B_g = \frac{V}{V_a} = \frac{P_a}{T_a} \frac{T}{P} \frac{Z}{Z_a}$$

$$\text{hence } \frac{B_g}{B_{gi}} = \frac{P_i}{P} \frac{Z}{Z_i} \quad \text{and} \quad T = \text{constant}$$

$$\text{then } \frac{P}{Z} = \frac{P_i}{Z_i} - \frac{(P_i/Z_i)G_p}{G}$$

which yields a straight line when P/Z is plotted versus G_p as shown in Figure 6. The initial gas in place is the value of G_p when P/Z = 0. The ultimate gas recovery may be obtained by establishing the P/Z at abandonment and reading the value of G_p. The gas recovery factor is G_p/G. For volumetric non-associated gas reservoirs the range of gas recoveries is 75-92%. The gas recovery factor is dependent upon the well spacing, well locations structurally, heterogeneity of the reservoir and the abandonment pressure.

Gas recovery factors for retrograde condensate non-associated gas reservoirs are dependent upon the same variables. The range of gas recoveries is approximately the same but the recovery factor range for the retrograde liquid is 40-60%. The recovery factor obtained is highly dependent upon maintenance of reservoir pressure in order to prevent retrograde condensation.

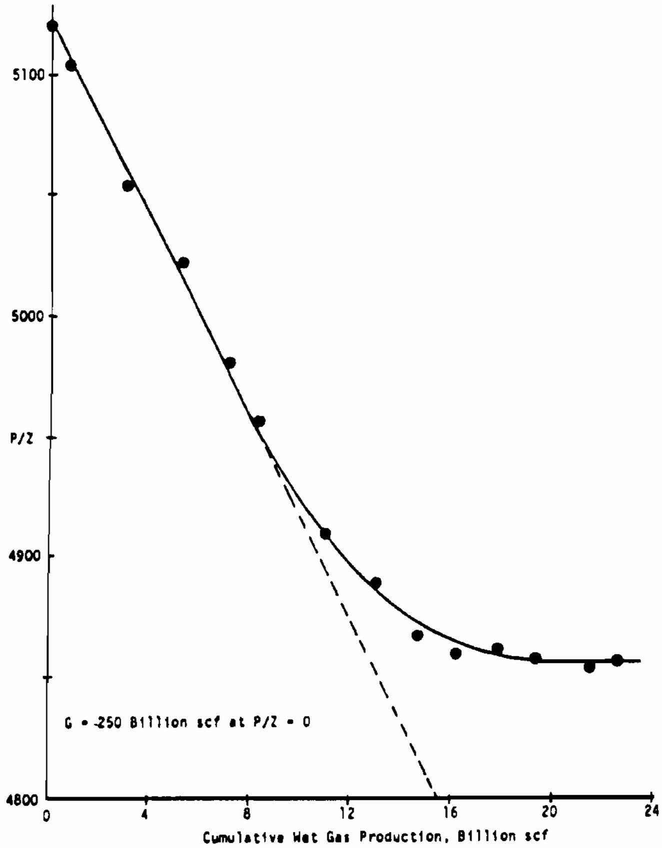


Fig. 6 Estimation of Initial Gas in Place for a Non-Associated Gas Reservoir

Gas recovery factors for water drive non-associated gas and gas condensate reservoir are dependent on the aforementioned parameters also. However, the rate of gas production is generally the most critical variable in defining gas recovery. Water coning is highly dependent upon gas production rate and excessive rates will result in "watering out" of wells. However, high gas porduction rates are desireable since less high pressure gas will be trapped by the invading water, thereby increasing ultimate gas recovery. In some reservoirs, excessive gas production rates will result in lower ultimate gas recovery because of pore size distribution of the reservoir rock and/or heterogeneity. Present practice is to locate producing wells high structurally, thereby minimizing coning, and attempt to produce at gas production rates that will "outrun" the invading water.

Obviously this cannot be done if the reservoir hydrocarbon is a retrograde condensate. Even under favorable circumstances the range of gas recovery factors in water drive non associated gas reservoirs is 50-80%.

SUMMARY AND CONCLUSIONS

The principal methods for assessing hydrocarbon resources in associated and non associated gas reservoirs are the volumetric method and the materials balance method. The estimate of initial hydrocarbons in place by the volumetric method is largely dependent upon the number, spacing and location of wells, well production tests, well logs and core analysis. Hence, the accuracy of early estimates is largely dependent upon the rate of development of the field and the financial resources invested in obtaining the desired field data.

The estimate of initial hydrocarbons in place in associated and non associated gas reservoirs by the materials balance method may be made with limited field production data but requires laboratory PVT data for the reservoir fluids. Unquestionably, earlier estimates may be made by this method than by the volumetric method, but experience has shown that the accuracy of estimates, just as in the case of volumetric estimates, improves as more data are available.

Best present practice would appear to be to secure the necessary fluid production and laboratory PVT data as early as possible to permit estimates of initial hydrocarbons in place by the materials balance method. Such estimates should assist in planning the most appropriate field development program, particularly when complemented and supplemented with volumetric estimates.

Volumetric and materials balance estimates for initial hydrocarbons in place ordinarily are found to yield similar results when appropriate data are available.

It is not possible to estimate the ultimate recovery of hydrocarbons by the volumetric method. However, if one chooses he can utilize empirical and/or past experience data in similar reservoirs to estimate the hydrocarbon recovery factors. In the author's opinion, this is not ordinarily acceptable.

During the past two decades a high degree of sophistication in reservoir operations has been achieved. Mathematical models utilizing materials balance have been developed for reservoirs which permit, when appropriate laboratory and field data are available, the identification of the natural reservoir mechanism, the estimation of the initial hydrocarbons in place, the prediction of the future performance of the reservoir utilizing the natural and/or artificial reservoir mechanism and the ultimate hydrocarbon recoveries. Early in the life of a reservoir, in the absence of sufficient data, assumed rock and fluid properties, reservoir mechanism, etc. can be used in the simulation and the hydrocarbon recovery, rate of recovery, etc. predicted. These predictions can be compared with those obtained from the field with time and the simulator modified in accordance to match actual reservoir performance. Results obtained from this work may be used to plan the orderly development of a reservoir to achieve maximum hydrocarbon recovery and the greatest economic return on investment.

Reservoir simulation research is presently directed toward reducing simulation costs particularly for heterogeneous (vertical and lateral) combination drive reservoirs. However, there is still a great need for additional, simpler, less expensive simulators for the more conventional type reservoir drive mechanisms. Practical utilization of the results from reservoir simulations is limited by the quantity and quality of the rock and fluid property and field data available. Due to the high costs of core and fluid analysis and downhole logging, increasing dependence is being placed upon the evaluation of such properties from production, build up or pulse tests.

NOMENCLATURE

Petroleum engineering nomenclature has been standardized as indicated below. Except as indicated, the subscript "i" refers to initial reservoir conditions and all other subscripts refer to reservoir conditions thereafter. A bar over any symbol, such as $\bar{h}$, indicates variable is specified at average reservoir conditions.

A = area, acres

B_o = oil formation volume factor = volume at reservoir conditions per volume at stock-tank conditions

B_g = gas formation volume factor = volume at reservoir conditions per volume at standard conditions (used to denote solution-gas volume when more than one type of gas is present)

B_w = water formation volume factor = volume at reservoir conditions per volume at standard conditions

B_{gc} = gas-cap gas formation volume factor = volume at reservoir conditions per volume at standard conditions

B'_g = injected gas formation volume factor = volume at reservoir conditions per volume at standard conditions

B_t = $B_o + (R_{si} - R_s)(B_g/5.61)$ = composite oil or total oil formation volume factor = volume at reservoir conditions per volume at standard conditions

$\bar{c}_{f+w}$ = formation (rock) c_f and water c_w compressibility = pore volume per pore volume per psi = $c_f/(1-S_w) + c_w S_{wi}/(1-S_{wi})$

G = initial gas-cap gas volume, scf

G_i = cumulative gas injected, scf

G_p = $G_{ps} + G_{pc}$ = cumulative gas produced, scf

G_{ps} = cumulative solution gas produced, scf

G_{pc} = cumulative gas-cap gas produced, scf

h = net (oil or gas) formation thickness, feet

m = $GB_{gi}/5.61NB_{oi}$ = ratio of initial gas cap gas reservoir volume to initial reservoir oil volume

N = initial oil in place, stock-tank bbl

N_p = cumulative oil produced, stock-tank bbl

P = reservoir pressure, psia

P_i = initial reservoir pressure, psia

R_s = solution-gas-oil ratio, scf/stock-tank bbl

R_{si} = initial solution-gas-oil ratio, scf/stock-tank bbl

R_p = producing gas-oil ratio, scf/stock-tank bbl

R_c = G_p/N_p, scf stock-tank bbl

S_o = oil saturation, fraction of pore space

S_g = gas saturation, fraction of pore space

S_w = water saturation, fraction of pore space

W = initial water in place, reservoir bbl

W_e = cumulative water influx, bbl at standard conditions

W_p = cumulative water produced, bbl at standard conditions

W_i = cumulative water injected, bbl at standard conditions

THE GEOLOGIC SETTING OF GIANT GAS FIELDS

H.D. Klemme
Weeks Petroleum Ltd, Westport, Connecticut, USA

Abstract

Free gas in giant gas fields (over 3.5 TCF) and associated, dissolved gas (over 3.5 TCF) in some of the larger giant oil fields represent over 80% of the worlds proven and produced natural gas reserves. The present worlds proven and produced gas reserves represent about one-third of the conventionally recoverable reserves of proven and produced gaseous and liquid hydrocarbons, on a BTU (BOE) basis. A recent surge (1965 to present) in discovery of giant gas reserves has accompanied a decline, over a similar period, in the discovery of giant oil reserves. Analysis of giant gas fields and their comparison to giant oil fields on the basis of basinal setting and geologic characteristics suggests the worlds ultimate resources of conventionally recoverable gas will approach those of oil.

Traps, reservoirs and cap rocks of giant gas fields are generally similar to those of giant oil fields, however, age and depth distribution of giant gas reservoirs and the character of giant gas source rocks are often at variance with those of giant oil fields. More Paleozoic reservoired gas than oil indicate a generally older set of reservoirs in giant gas fields. The Cretaceous and Permian are the principle reservoir ages. Source rocks for gas giants appear to be older than oil giants with Middle Cretaceous, Upper Jurassic, Carboniferous and Lower Paleozoic the principle source rock ages. Lower Paleozoic, Jurassic and Cretaceous source rocks appear to be related to either marine "anoxic events" or their

landward "humic" counterparts, while the Carboniferous is related to worldwide coal occurrence. These fundamental differences in petroleum accumulation may be related to various basin types (which may be classified on the basis of architectural and evolutionary tectonic characteristics). The prime areas of giant gas reserves appear to be large basins with high sediment volume to area ratio, with large traps, containing mixed carbonate and clastic lithology, with either high amounts of humic source material and/or extensive evaporitic seal over deep oil prone source material and moderate to high geothermal regime. Upper Tertiary to recent deltas occupying regional depocenters also appear gas prone.

Although similar traps hold less gas than oil on a BTU basis, the prospect for gas involves a more extensive vertical portion of the sedimentary fill of any given basin. Because of the more extensive vertical environment of gas, the past premium placed on oil production - often resulting in "bypassed" gas, the continued discovery of gas resources in new developing frontier basins and the prospect for more gas in mature development basins; estimates of "in place" future gas resources have a greater chance of upward adjustment than oil.

The world's ratio of conventionally recoverable, proven and produced gas to oil reserves is 1 to 2, respectively. Until 1965, gas represented about 10%(1 to10) of the reserves of all giant fields. The increase in the percentage of worlds reserves of gas to oil has occurred in the last fifteen years, (Fig. 1A). Significant reserves from giant gas fields have occurred in two of the worlds super basins (West Siberia and the Middle East Arabian-Iranian) and in the North Central Europe basins of Netherlands and the North Sea, and the Sredne-Caspean Basin (Zhabrev 1975) of southcentral U.S.S.R. During the same period, additions of reserves from discovery of giant oil fields have declined (Fig. 1B). The addition of these new gas reserves (in large basins with prospects for additional discoveries), the potential for gas below the hydrates of the arctic permofrost, the development of "by passed" gas discoveries (as in the

Middle East), and deeper drilling below the "oil window" (where down-dip source and reservoir rocks are present in producing basins); suggest that the world ultimate resources of conventionally recoverable gas will approach those of oil.

Over 80% of the worlds proven and produced gas reserves are found in giant fields (3.5 TCF - 0.1 TCM); either as, 1) 68% "free gas" giant gas fields in association or non-association with oil, or 2) 13% as giant size reserves of gas, associated as "dissolved" gas in giant oil fields (Halbouty 1970, Int. Pet. Ency. 1977, Tiratsoo 1979). In addition, it is estimated that "liquified gas" represents about 12% of the ultimate petroleum yield from present proven and produced gas reserves (Meyerhoff 1979). Most discussions of giant gas fields have been limited to the "free gas" fields, however for this discussion both 1) "free gas" giants and 2) giant oil fields with giant reserves of "dissolved," associated gas are considered. Giant oil fields (Nehring 1978) represent about 3/4 of the present proven and produced reserves of oil.

Any trap can contain considerably more oil "in-place" than gas - on a BTU basis. The field size characteristics of supergiant oil (5×10^9 bbls) and gas (30 TCF) fields generally confirms this (Fig. 2). Even though conventional recovery from a gas field is 70% to 80% of the gas "in-place" as opposed to 20% to 35% conventional recovery from oil accumulations - giant oil field traps contain more conventionally recoverable reserves (BOE based upon BTU value) than giant gas fields. This is due to the differences in physical properties of gas and oil, which will not allow as much gas to accumulate in any given reservoir-trap as opposed to oil.

Analysis of the fundamental petroleum characteristics of the worlds giant gas fields indicates both similarities and differences from the giant oil fields. Trap types are generally similar to those of giant oil fields and appear to be related to the tectonic setting and genesis of the basin in which they occur. The lithologic types of the reservoir rocks of giant gas fields have the same ratio (about two fifths carbonate,

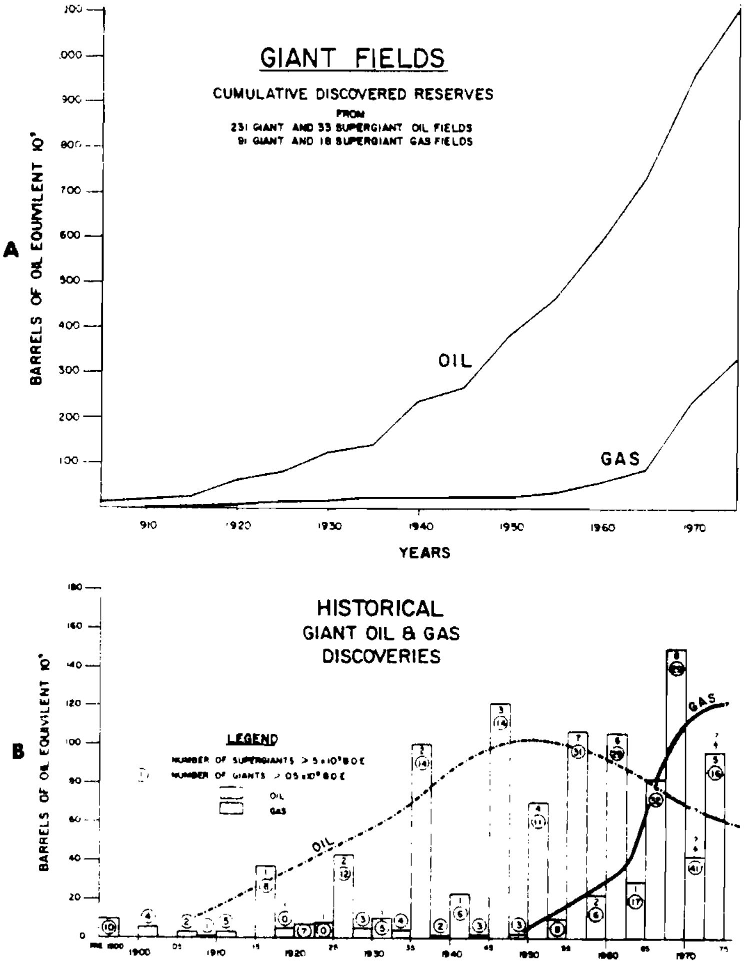


Figure 1 Giant Fields (visual curve in B)

and three fifths sandstones) as giant oil fields, however differences are noted in the age and depth distribution of giant gas reservoirs (Fig. 3). The depth (Fig. 3C) of giant gas accumulations includes more intermediate (6000' to 9000') and deep (over 9000') reservoirs than those of giant oil fields, thus supporting the temperature and maturation zonation (Hunt 1979) of "oil and gas windows". Along with deeper accumulations, older (Fig. 3A) reservoir rocks are found in giant gas fields than those of giant oil fields. The predominance of carbonate reservoirs (Fig. 3C)

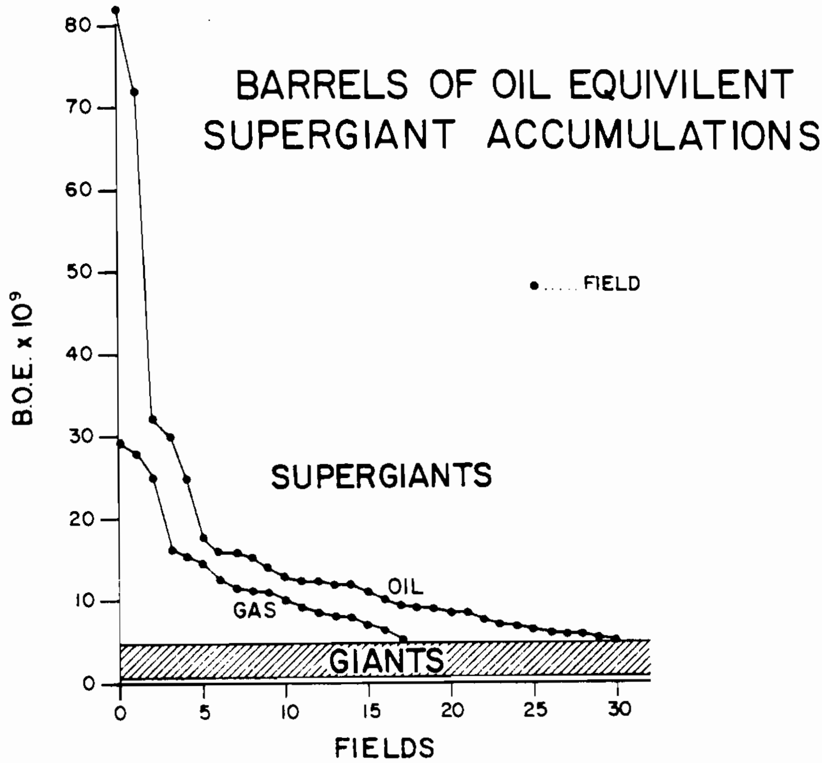


Fig. 2

in the deeper giant gas accumulations may support the general premise of the deterioration of clastic reservoirs with depth (Klemme 1975A) and suggests that carbonates together with specially preserved porosity in clastics are targets for deeper drilling. Shallower (0 to 6000') sandstone reservoirs (Fig. 3C) contain a large portion of biogenic gas, notably in West Siberia (Rice and Claypool - in press). To date, less than 2% of the "free gas" giant fields have reservoirs below 12,000'.

Reservoir rocks are predominantly of Mesozoic and Paleozoic age. Over 90% of the Paleozoic reservoirs are Permo-Carboniferous. The Cretaceous contains over 50% of the Mesozoic reservoirs, while the Jurassic reservoirs contain much less gas than oil.

Cap rocks for giant gas fields like giant oil fields are provided by shales and evaporites, plus hydrates. Regional evaporitic seals appear to be equally important for either giant gas or oil accumulations. The most

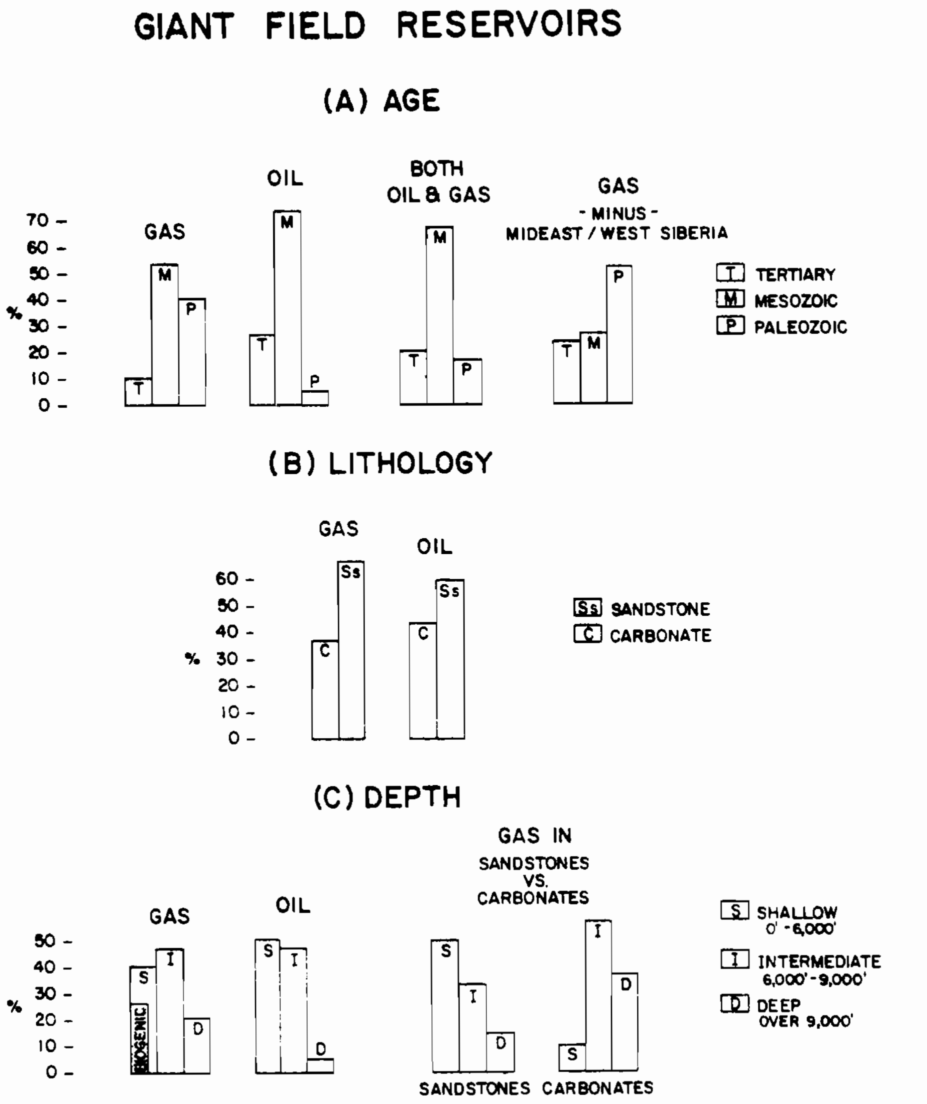


Fig. 3

effective cap rocks sequences for large gas accumulations appear to be the regional seal provided by extensive evaporite deposits often interbedded with carbonates, and regional permafrost with attendant hydrates. All of the supergiant gas fields are over-lain either by direct cap or at some distance above the reservoir by permafrost or regional evaporite beds.

Little geochemical correlation of source and reservoir gas has been undertaken and therefore the origin and source of giant gas accumulations remains highly speculative. It appears that the gross age distribution of source sediments for giant gas fields is about the same as that of giant oil field reservoirs (Fig. 4A). With present information, it is speculated that about three fifths of the giant free gas accumulations are related to "coaly" or humic source sediments, while the remaining two fifths of the giant free gas fields appear to be related to thermal alteration of oil or oil prone source rocks as they have passed into the "gas window". In this tabulation, a sequence of source material was labeled "humic" when any amount of "humic" material or coals were described as being present, even though variable amounts of marine sediments may have interfingered. Oil prone source rocks were labeled on the basis of the presence of a predominantly marine, saprcpelic sequence.

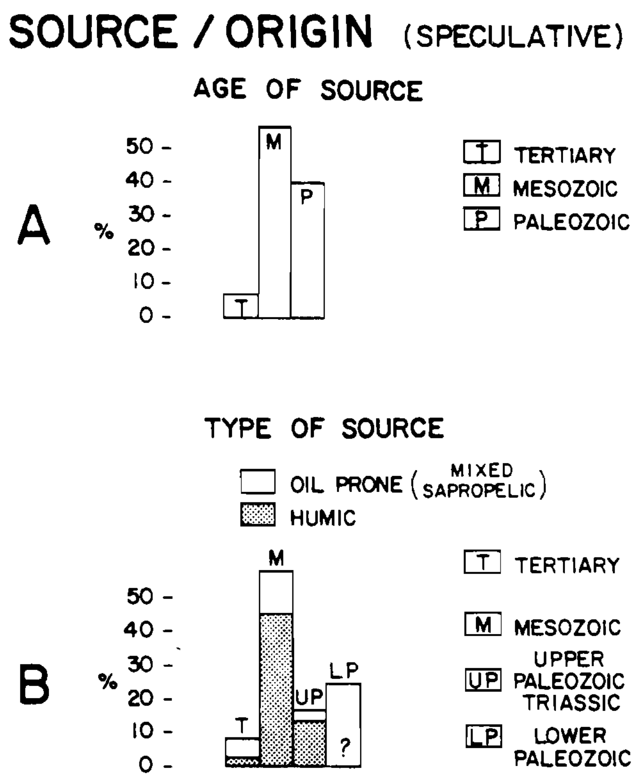


Fig. 4

In gross, the age of gas source rocks (Fig. 4A) are essentially the same as gas reservoir rock ages, however the Lower Paleozoic appears to have a much higher amount of source material, much of which has migrated to and is reservoired in Upper Paleozoic. Particular ages of source rocks are primarily; 1) the Aptian, Albian and Cenomanian, including the tremendous area of humic and "coaly" source rock of West Siberia and areas of thermal alteration of sapropelic or mixed-paralic oil prone sources in the Middle East and Sredne-Caspean basins, 2) the Oxfordian/Kimmeridgian to Aptian thermal alteration of sapropelic sources in the North Sea graben areas, the North Slope of Alaska and the Northwest Shelf of Australia, 3) the Upper Paleozoic (Carboniferous and Permian) also display a high amount of humic gas in basins of the craton, some directly related to Carboniferous coal sequences such as the southern North Sea, while 4) the Lower Paleozoic source rocks (primarily Ordovician-Silurian black shales) involve most often, thermal alteration of sapropelic material with limited migration to Cambro-Ordovician and considerable migration to Permian carbonate reservoir rocks. With little direct evidence, it is speculated that the large Mideast Permian "Khuff" gas reserves are derived - like gas in Algeria - from unconformably underlying Ordovician and Silurian black shales: see (Szabo and Kheradpir - 1978) for stratigraphic relations of Permian reservoirs in the Central Persian Gulf and Iran. The unequal distribution of major source rock sequences (North 1977, 1979, Hallam 1980) and their relation to worldwide "anoxic events" or "coal-ages" has recently received considerable attention. This speculative analysis of giant gas field source rock supports recent linkage of anoxic, black shale events with extensive to worldwide deposits of high rank source material. In the case of the Middle Cretaceous, it is noted that these marine anoxic events not only develop in an oceanic environment but the same age units develop a continental equivalent with rich terrestial (humic) source elements.

It appears that temperature, depth and rate of basin subsidence generally control the timing of gas generation and migration. It is estimated that over 90% of the giant gas fields began generation, migration and accumulation in the relatively late Phanerozoic - ie Cretaceous and Tertiary (Tissot et al 1980). It has been suggested that considerable gas accumulation may have occurred during the Pleistocene to recent glacial epoch with inter-glacial concentration of biogenic gas in "free gas" fields by repeated hydrate formation and decomposition as the permafrost zone expands and contracts (Trofimuk 1977).

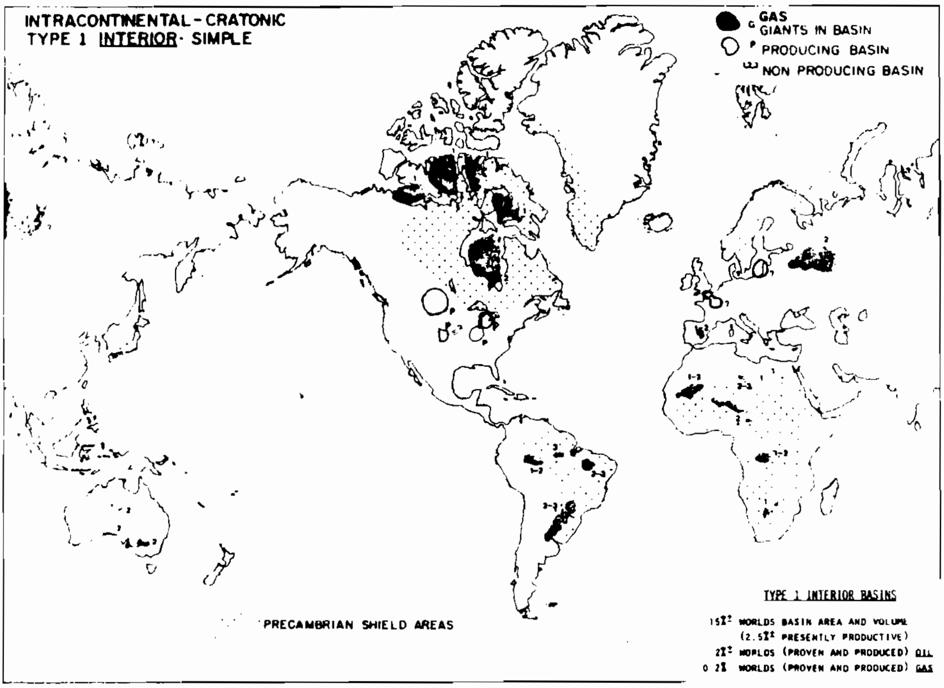
Trap types, the age and character of reservoir rocks, heat flow, maturation, and secondary migration of gas in giant fields may be related to the various basins in which they are located. A basin classification when linked to the variability of petroleum characteristics may provide a worthwhile exercise in appraising the petroleum potential of new "frontier" basins or developing further production in newly developing basins. The relative usefulness of applying a "look-alike" or analog derived from basin classifications in appraisal or estimation of ultimate resources in untested basins, new "frontier" basins or mature producing basins has been rejected by about as many specialists in petroleum geology as those that consider it useful.

PETROLEUM BASINS

The dimensions and shape of basins may be divided into both 1) large and small sizes, and 2) linear and circular shaped basins. Further differences are noted in the effective basement profile or cross section of basins and the ratio of a basin's surface area to the volume of sediments contained therein. These architectural characteristics when related to the earth's crust, tectonic setting, and basin evolution (primarily in the framework of plate tectonics) result in eight types of basins with notable sub-types (Klemme, in Press).

TYPE 1 INTERIOR BASINS (Fig. 5)

Type 1 Interior basins are simple, large, circular basins with a symmetrical profile. They are generally areas of Paleozoic platform deposition and the ratio of the volume of sediments in the basin to the

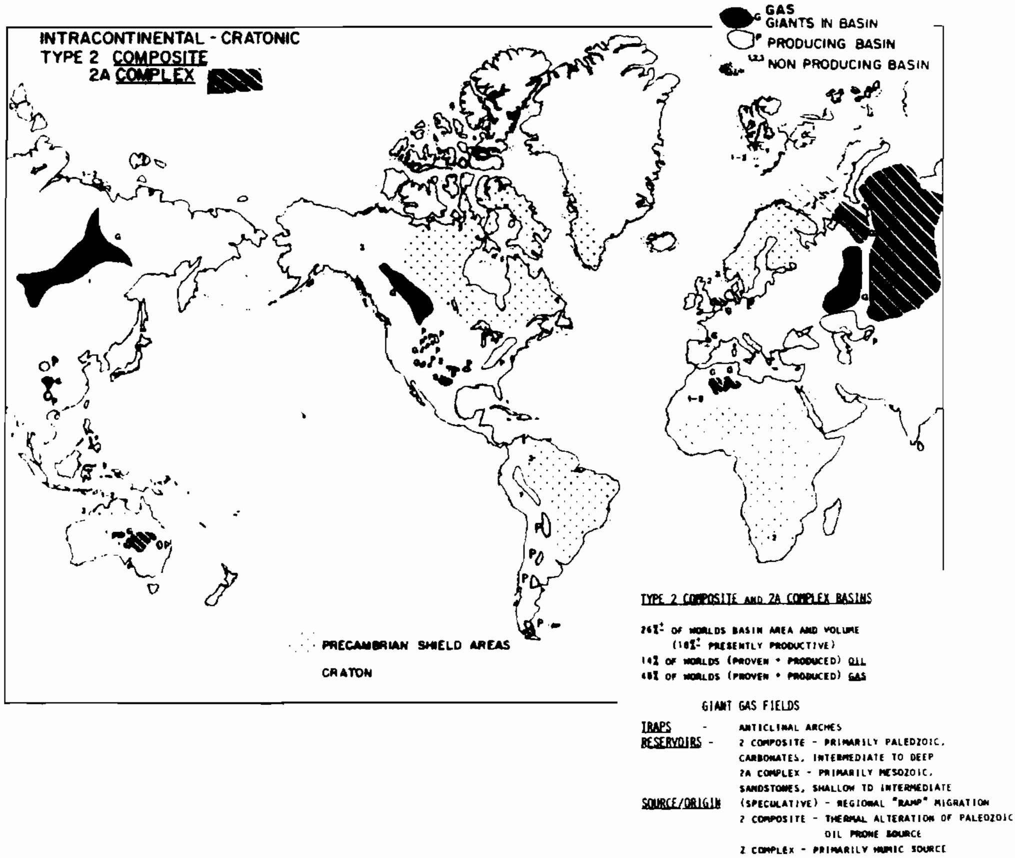


NO GIANT GAS FIELDS

surface area of the basin is low. They are located in the central portion of cratons near or upon Precambrian shield areas. They generally consist of a mixture of clastic and carbonate sediments. They generally display low hydrocarbon recovery with no giant gas fields. The relatively shallow basement in many of these basins probably accounts for their low thermal gas recovery. Their traps are predominantly associated with central arches or stratigraphic traps around the basin margin.

TYPE 2 COMPOSITE AND 2A COMPLEX BASINS (Fig. 6)

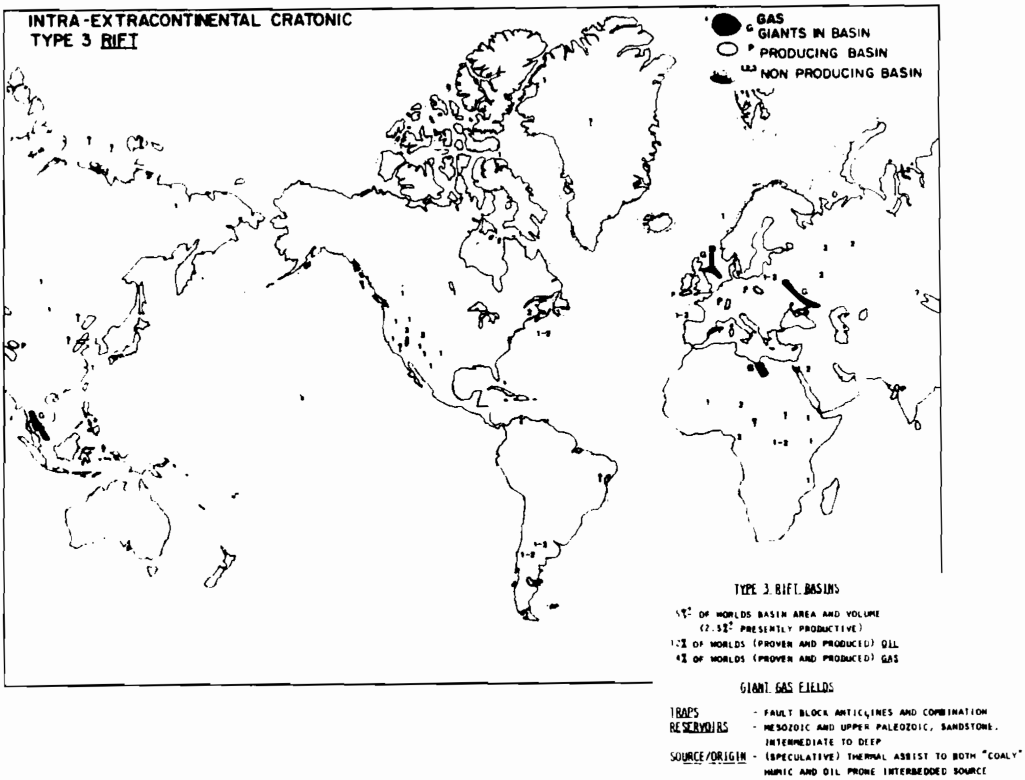
Type 2 Composite basins are large, linear to elliptical intracontinental, cratonic basins with an asymmetric profile. They are generally areas which, initially, were sites of shield derived Paleozoic platform deposits displaying characteristics similar to Type 1 basins. They became multicycle or composite in upper Paleozoic or Mesozoic time when a second cycle of sediments derived from an organic uplift on the exterior margin of the craton providing sediments from an opposite source area (2 sided source)



thus creating the asymmetry to the basin profile. The ratio of the volume of sediments to surface area is high, particularly on the asymmetric side, thereby providing sufficient burial of sediments for maturation of hydrocarbons and their thermal alteration to gas.

Type 2A complex basins are also multicycle basins located in exterior portions of cratons. They are large, more often elliptical basins with an irregular to asymmetrical profile. Their genesis appears to have been more complex, with multiple rifting followed by a more or less symmetrical sag resembling a Type 1 basin. Giant gas fields occur in both the rifted grabens and the overlying sag which blankets the grabens.

Type 2 basins generally consist of a mixture of carbonate and clastic sediments, however, some are dominately clastic. Their traps are primarily large arches or block uplifts. Compression folds and stratigraphic accumulations



also act as traps in most Type 2 Composite basins. Type 2 Composite basins generally display normal geothermal gradients and intermediate to deep gas production from carbonate reservoirs. Type 2A Complex display higher geothermal gradients and produce from sandstones at shallow to intermediate depths. Average to high gas recovery occurs in Type 2A complex basins where more humic source and often higher geothermal gradients are present. Evaporites develop in both types of basin and often form an effective regional seal. Both Type 2 basins represent about one quarter of the worlds basin area yet they contain nearly half of the worlds gas. About three quarters of the basins are productive.

TYPE 3 RIFT BASINS

(Fig. 7)

Type 3 Rifts are small, linear basins with an irregular profile displaying a high sediment volume to surface ratio. They appear to be a very fundamental earth structure as they are formed at various stages during the development of almost all other types of basins. They are primarily Upper Paleozoic, Mesozoic and Tertiary in age and are located on or near cratonic areas. Their sedimentary fill is most often clastic, however where the rift opened to a warm climate sea, carbonates are often present.

Because their genesis provides extension features, they form an irregular basement profile with considerable fault block movement. As a result, they display more than normal combination structural-stratigraphic traps where depositional variations and unconformities are developed over differentially subsiding blocks. Geothermal gradients are normal to high.

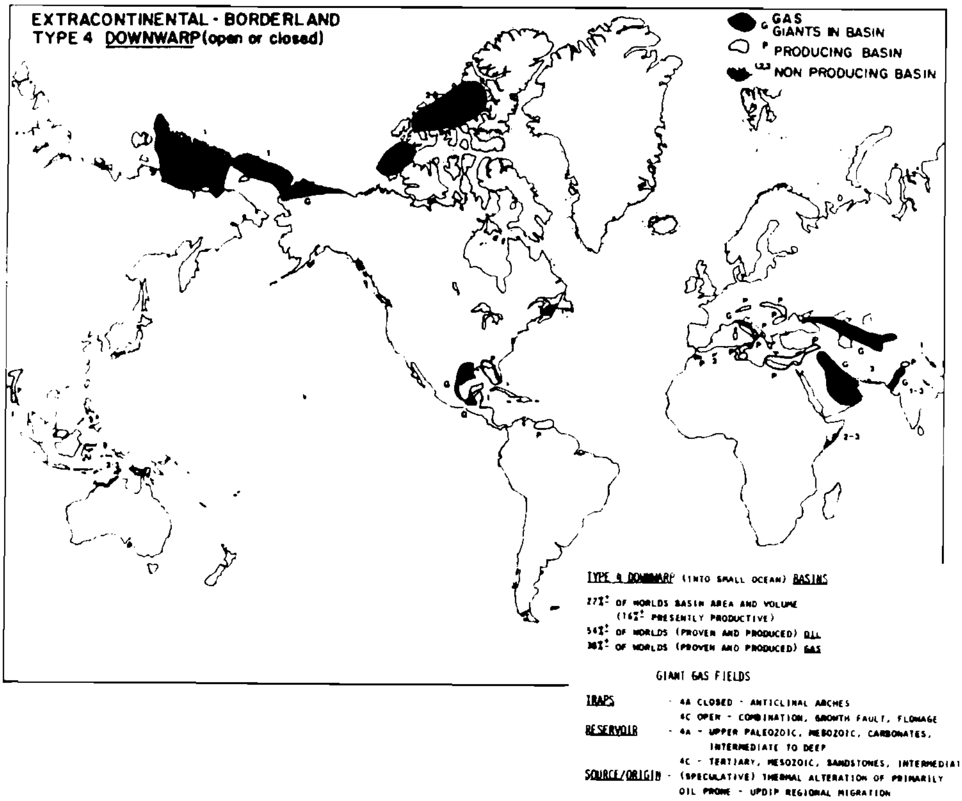
Rift basins have a low gas to oil ratio in total, despite higher geothermal gradients and the presence of considerable humic sediments. Some basins are predominantly gas such as the Gulf of Thailand and portions of the Dnieper Donetz basin. The richest rift basins, however, are predominantly areas of giant oil fields.

TYPE 4 DOWNWARPS (INTO SMALL OCEAN BASINS) A CLOSED, B TROUGH, C OPEN

(Fig. 8)

Type 4 Downwarp (A closed and B trough) basins resemble Type 2 Composite basins in size, profile and sediment volume to area ratios. Type 4 Downwarp (C open) basins, architecturally, resemble Type 5 Pull-apart basins. However, because of their unique genesis, a different temperature regime, and often a different sedimentary environment from that of Type 2 Composite basins, they warrant a seperate category.

Type 4C, open Downwarps, are seperated from the main trends of major ocean basin spreading zones and are located along portions of the South China Sea, East and Northeast Africa and the American segment of the Tethyan trend between Gondwana and Laurasia and in the Arctic. They often overlie older deformed orthogeosynclinal zones (miogeosyncline/eugeosyncline sequence) and have been labeled as "successor basins." They are large, linear basins



with a one sided source and seaward asymmetry. Their genesis is related to the evolution of the small ocean basin that they open into. Considerable, speculative mechanisms have been proposed for the highly complex genesis of the Arctic Ocean, Gulf of Mexico, Caribbean, Eastern Mediterranean and South China Sea where 4C basins are present.

Type 4C open basins may become Type 4A closed basins as the result of collision of continental plates. The Middle East and South Asia Tethyan basins result from collision of the African and Indian plates with the Eurasian plate. Upon closing a large, linear, asymmetric basin with a two sided source (similar to Type 2 Composite basins) is formed. Further plate movement appears to destroy a considerable portion of the Type 4A closed basin leaving only a Type 4B trough such as the narrow, sinuous basins south of the Himalayas on the India plate and the narrow Alpine and North African troughs.

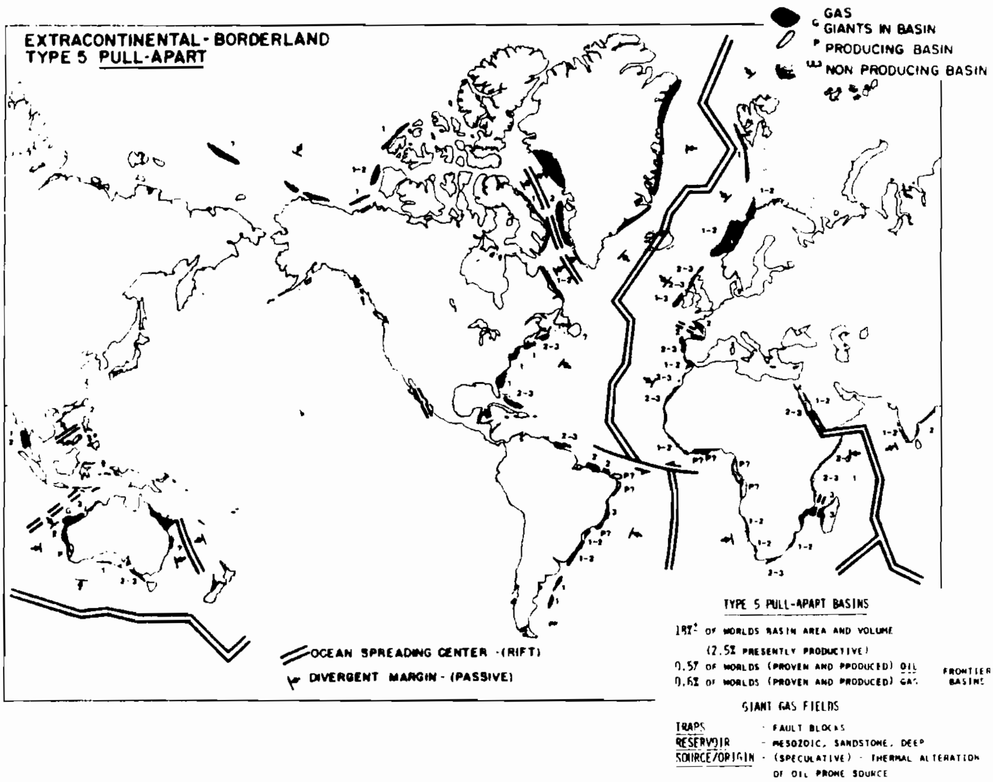
Type 4 Downwarp basins represent 19% of the worlds basin area, however, they contain 48% of the worlds oil and gas reserves. Relatively high recovery rates in Type 4A and C may be related to the above normal to often high geothermal gradients which may provide more efficient maturation and primary and secondary migration of hydrocarbons. Often, differing from their cratonic counterparts, the sedimentary facies associated with a small, restricted ocean basin appears to provide rich source shales and considerable evaporites. In addition, along Tethys and its extension between the American continents, considerable porous carbonates were developed which provide extensive reservoir rocks. Trap types are dominantly anticlinal (either drape over large arches or compressional folds) in Types 4A and 4B, while more than normal structural-stratigraphic traps are present in 4C open basins. The presence of considerable evaporite deposits in many Type 4 basins result, in many instances, in highly effective cap rocks and large flowage features.

Most of the giant gas fields in Type 4 basins appear to be sourced by either Tertiary (Type 4C) or Mesozoic (Type 4A) paralic, or Lower Paleozoic (Type 4A) oil prone source rocks, thermally altered to gas. Evaporites, regionally, overly and effectively seal many of the carbonate reservoirs.

TYPE 5 PULL-APART (Fig. 9)

Type 5 Pull-apart basins are large, linear basins displaying a relatively high volume of sediment to surface ratio, and a one sided source asymmetry, that occupy the intermediate crustal zone (between thick continental crust and thin oceanic crust). They are located along the divergent margins of spreading plates.

Due to an extensional genesis, most traps are tensional growth (rollover) anticlines, or flowage type. Generally normal to low geothermal gradients and deeper than normal production are present where oceanic distances of spreading have occurred. The initial rifts may have had a higher heat input. Sediments are dominantly clastic, although the post-rift series may form as a carbonate bank as well as a clastic fan. The basins

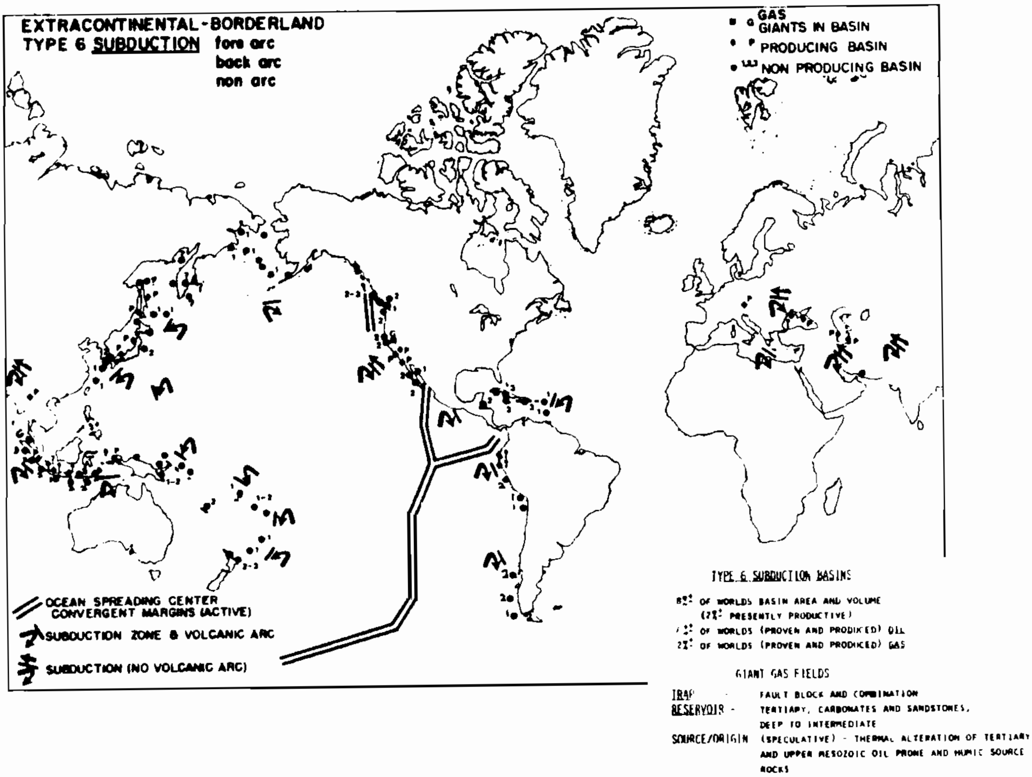


are primarily of Mesozoic and Tertiary age. They represent 18% of the worlds surface basin area, however due to their predominant offshore location and accessibility to the petroleum industry technology (90% offshore and 55% in deep water), only 10% of these basins are productive. To date, these basins have displayed low productivity, however many appear to be gas prone, particularly where humic source rocks predominate. The eventual contribution of these recently explored basins will greatly effect the magnitude of the worlds ultimate petroleum resources.

TYPE 6 SUBDUCTION BASINS

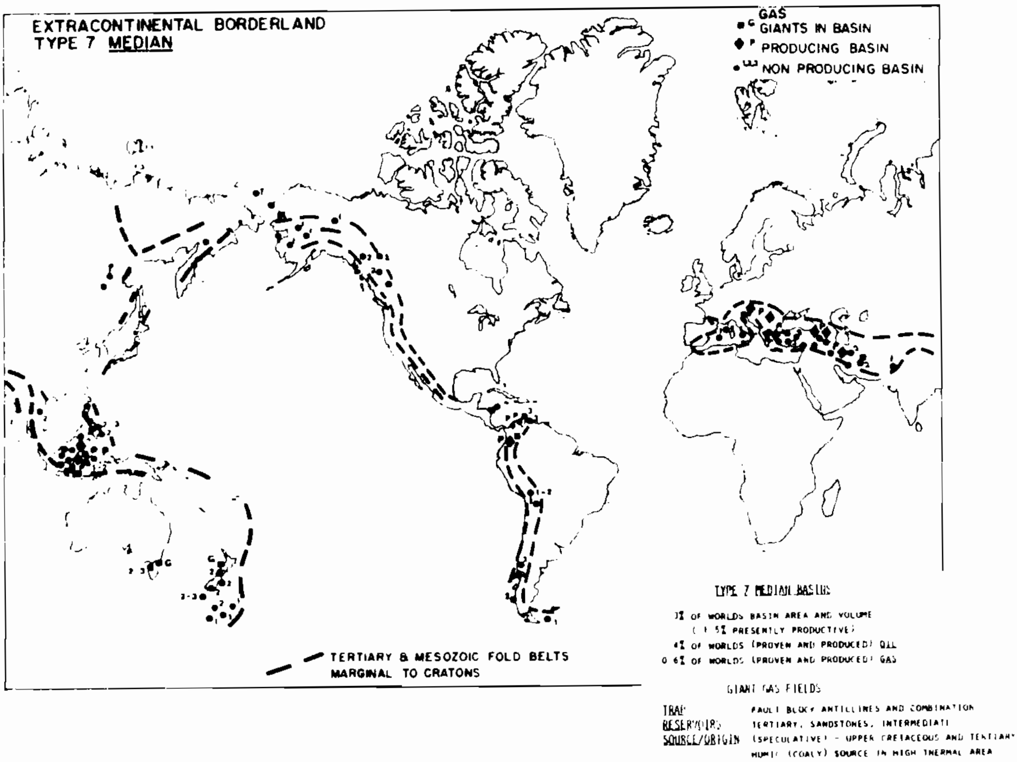
(Fig. 10)

Type 6 Subduction basins are small, linear basins with an irregular profile. They may be subdivided on the basis of their relation to the volcanic island arc which is often present on the back side of a subduction zone: -- 6A Fore-arc basins, are located on the oceanward side of the



volcanic arc; 6B Back-arc basins are located on the back side or cratonic side of the volcanic arc; and 6C Non-arc basins are located where subduction and wrench faulting have destroyed the island arc. Their genesis is related to regional compression along subducing or convergent margins. They are most often Tertiary in age and most often filled with clastic sediments. Although regional compression is present in the areas where these basins develop considerable wrench movement takes place creating tensional block movement over which sediments are draped. Drape over fault blocks provide the main traps while compressional anticlines, wrench anticlines and flowage features provide the traps in some basins.

Type 6B and 6C basins, because of the high heat flow in back of or on the craton side of subduction zones display high geothermal gradients often providing for a highly efficient maturation and migration of petroleum, however to date this has been typified by a very low gas to oil ratio. Reservoirs are

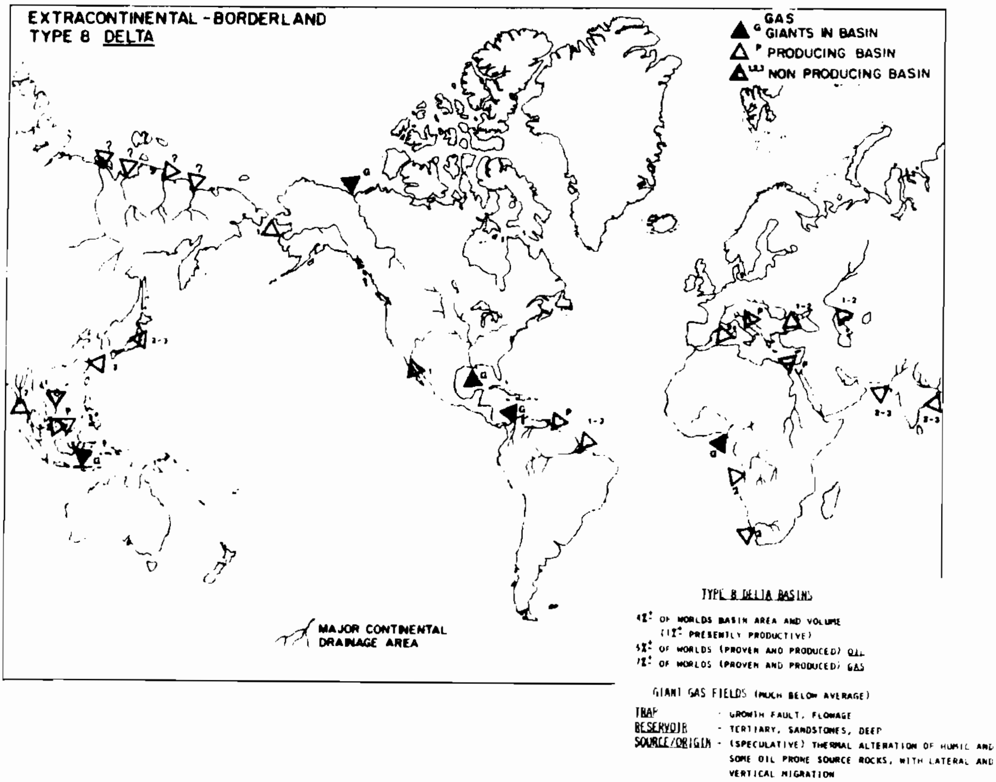


predominantly sandstones, ranging from shallow marine deposits to turbidites, often in the form of multiple pay zones. These basins represent 7% of the worlds basin area. Some of these basins (6C and 6B) have the highest oil recovery per volume of sediments of all basin types.

The gas to oil ratio in these basins appears to be low representing only a small percentage of world gas reserves.

TYPE 7 MEDIAN BASINS (Fig. 11)

Type 7 Median basins are small, linear basins with an irregular profile. They occupy the mountainous, folded, "median" zone (or interior portions of Cenozoic/Mesozoic megasutures) which has been developed either between an oceanic subduction zone and the basins of the craton or the collision zone between two cratonic plates. They are essentially the "rifts" of the median zone formed by wrench movements and foundering creating local tension within the compressed and uplifted mountain belts surrounding the convergent margins



of some continents.

Geothermal gradients appear to be normal to high, sediments are dominantly clastic and trap types are block uplifts over which structural-stratigraphic accumulations occur -- characteristics similar to Type 3 Cratonic Rifts.

TYPE 8 DELTAS (Fig. 12)

Type 8 Deltas are generally small, circular shaped depocenters with an extremely high ratio of sedimentary volume to their surface area. They are most often the site of present day "bird foot" deltas which are prograding seaward. Their sedimentary fill is derived from major continental drainage areas. They appear to develop in any tectonic setting; with more than one third developed over Type 4 Downwarp basins, 17% along Type 5 Pull-apart basins, 16% are over Type 6 Subduction basins, 12% in Type 3 Rift basins, 12% in Type 7 Median basins, and 7% over the submerged portions of Type 2 Composite basins. Their location is about equally divided between divergent and convergent margins either along open or confined coastal areas.

They are predominantly Upper Tertiary in age with an entirely clastic fill. The tensional regime results in "non-basement" or sedimentary/structural development of traps primarily by tensional, growth (roll-over) anticlines and flowage. Low geothermal gradients, down to a commonly present overpressured zone, are perhaps due to the dampening effect of rapid deposition, resulting in below average depths of most accumulations. A unique field size distribution (in those deltas which have production to date) involves few giant fields even though the producing basins are quite rich in hydrocarbons (Klemme 1975B). A predominance of land derived terrestrial (humic) organic matter and extensive overpressured zones leads to a high gas to oil ratio.

COMPARISON OF PETROLEUM CHARACTERISTICS BY BASIN TYPE

The world's heat flow and resulting temperature regime in any given basin influence the depth at which oil and much gas begins primary migration and the depth that oil alters thermally to gas. Temperature, depth, and the timing of initial hydrocarbon accumulation in reservoir rocks also effects the secondary changes in reservoir rock petrography. The geothermal regime for the various basin types appears to be related to tectonic location and basin evolution (Klemme 1975A). More heat input occurs on the backside of subduction zones (Type 6B and C), along convergent margins, within many Type 3 cratonic rifts and during the initial rifting of divergent margins. More than normal heat input seems to be present in portions of Type 4 Downwarps into small ocean basins. Higher geothermal gradients are often present in Type 2A basins whose evolution includes initial rifting. Type 1 Interior and Type 2 Composite basins generally have a low heat flow. Lower gradients are present in Type 8 Deltas and Type 5 Pull-Apart basins where rapidly deposited, thick fans of sediments are present.

The small basins with high geothermal gradients (3, 6, and 7), surprisingly, have low gas to oil recovery ratios. Many of these oil rich basins may have gas at depths which has not been prospected, due to the premium placed upon oil production. Some may have "dogleg" geothermal gradients (Hunt 1979) which considerably reduce the interval of the "gas window" - thus limiting the sedimentary volume of the basins prospective gas zone by a more shallow hydrocarbon destruction zone. High geothermal gradients will reduce the actual thickness of the gas generation zone, thereby limiting the volume of gas prone sediments in many small, hot basins. In general, it appears that (Fig. 13) relatively more gas, per unit volume of sediments, occurs in the larger basin types (2, 2A, 4A, 4C, and possibly 5) and the high volume to area depocenters of Type 8 deltas. It is speculated that the more extensive "drainage" areas between the larger than normal trap areas, the source (extensive humic or "coaly" deposits), the presence of effective regional seal or caprocks and reservoir quality (extensive evaporite and carbonate sequences) often typical of the sedimentary fill in these basins, may result in more efficient migration and entrapment of greater volumes of gas than in the small basins. In part, the efficiency of larger basins for accumulating large gas reserves may be related to the difference of the physical properties of gas and oil which was previously discussed in considering the differences in BTU magnitude of giant oil vs. gas fields (ie. with more space available, in large

BASIN TYPE	PRESENCE OF GAS GIANTS*	RELATIVE GAS RICHNESS**	% OF WORLDS GAS***
TYPE 1	NONE	LOW	0.2%
TYPE 2	BELOW AVERAGE	AVERAGE	16%
TYPE 2A	ABOVE AVERAGE	HIGH	32%
TYPE 3	ABOVE AVERAGE	LOW TO AVERAGE	4%
TYPE 4A	ABOVE AVERAGE	HIGH	31%
4B	ABOVE AVERAGE	LOW	0.9%
4C	BELOW AVERAGE	AVERAGE	6%
TYPE 5	AVERAGE?	LOW?	0.6%?
TYPE 6	BELOW AVERAGE	LOW	1.6%
TYPE 7	ABOVE AVERAGE	LOW	0.6%
TYPE 8	VERY FEW	VERY HIGH	2%

* 66% GIANTS (AVERAGE)
** PER UNIT AREA OR VOLUME
*** (PROVEN AND PRODUCED)

Fig. 13

basins, for more gas dispersal to large trap areas - and possibly more leakage of gas from poorly sealed small basins).

At present, the least measurable or distinguishable phase of the petroleum cycle of generation, migration and acculation appears to be migration. Movement of hydocarbons from source rocks to traps involves both 1) primary migration, which involves the release and expulsion of petroleum from source rocks, and to a considerable extent, is dependent upon temperature and depth, and 2) secondary migration which involves the movement of petroleum to traps, principally by buoyancy, where the tectonic and hydrodynamic character (Coustau 1975) of the basin become equally important. Type 1, 2, 4A, and 4B basins are more consolidated and compressed (mature) on both an evolutionary basis and as a hydrodynamic setting, with considerable invasion of meteoric waters where centripital movement along extensive structural-stratigraphic "ramps" and a tilted potentiometric surface provide the framework for long distance secondary migration of gas from an extensive area of source material. Type 4C, 5, 8, and some Type 3 basins are younger, tensional, less consolidated, less mature basins and involve more vertical fractures (often underlain by geopressured zones). A large portion of these basin sediments are still compacting and secondary migration may be influenced

BASIN TYPE	% WORLDS PROVEN AND PRODUCED RESERVES	% WORLDS BASIN AREA	% (OVER 4,500' - 18,000') WORLDS VOLUME	% OFFSHORE AREA	% DEEPWATER AREA	% PRODUCTIVE AREA	VOLUME	% NON-PRODUCTIVE AREA	VOLUME
Type 1	1.5	18.2	6.2	9	1	3.5	1.2	14.5	5
Type 2	25	27.3	25.4	14	5	19.6	17.7	7.4	7.7
Type 3	10	5.4	5.5	27	14	2.5	2.8	3.0	2.7
Type 4	47	17.5	26.3	38	17	12.2	19.5	5.3	6.5
Type 5	0.5	18.2	19.3	90	55	2.2	2.7	15.8	16.6
Type 6	7.5	7.1	8.8	93	50	1.8	2.3	5.2	6.5
Type 7	2.5	3.7	3.7	44	20	1.1	1.1	2.6	2.6
Type 8	6	2.6	4.8	85	50	0.6	1.1	2.0	3.7
TOTALS	100%	100%	100%	35+	25+	44	49	55.6	51

TOTALS
Area
30,000,000 m^2 (77,000,000 km^2)
Volume
40,000,000 m^3 (165,000,000 km^3)

Fig. 14

by both centrifugal and more than normal vertical water and gas movement. A basin's evolution through time often includes different tectonic environments with different hydrodynamic regime. Variation in premeability of both the basin fill and the vertical fracturing or faults within the fill may change as a basin evolves. Initial tension basins with vertical fracturing and vertical migration may mature to consolidated basins with extensive "ramp" migration, which when further compressed may again fracture vertically allowing late phase vertical migration - as in the Iranian Fold Belt of the Arabian/Iranian basin (Dunnington 1958, Young 1977).

The various basin types have a general commonality on the basis of dimensional and tectonic configuration. When the sedimentary fill of the eight basin types is considered, there is greater variation. Basin fill source material and primary reservoir quality is a critical modifier of the hydrocarbon potential. Variations in basin lithology may be linked to basin size, the time they take to be filled, and their age and tectonic setting. Geologically older, larger, long lived basin Types 1, 2, and 4 generally are mixed clastics and carbonates, while smaller basin Types 6, 7, and 8 with shorter fill time contain more clastics. Younger basins frequently display rapid lateral facies changes. Types of crude oil and gas to oil ratios appear to be initially related to lithologic types, more specifically to the influx of humic (terrestrial) or sapropelic (marine, lacustrian) organic matter (Hunt 1979). The large type 2 basins with mixed clastics and carbonates display sources of both humic and sapropelic material. Primarily thermal alteration of sapropelic source shales provide the giant gas fields in type 2 Composite basins, while the giants in type 2A Complex basins are dominated by the biogenic, humic gas of the West Siberia giants and the thermal alteration of both humic and sapropelic source material in the 2A basins of Central Austrialia and North Africa. Large Type 4 Downwarp basins are predominated by thermal alteration of oil prone sapropelic or mixed paralic source shales. Smaller, predominantly clastic basins (Type 3, 6, and 7) have about an equal amount of giant gas reserves derived from both humic and oil prone source rocks, most often paralic. Type 8 Deltas are generally a mixture of interfingering sapropelic and humic source rocks.

Giant gas fields (over 3.5 TCF) represent less than 1% of the worlds gas fields, yet they make up two thirds of all gas found to date. The 1) ratio of giant to non-giant gas fields, the 2) relative recovery of gas per unit of area or volume and 3) world gas reserves are shown by basin type in Figure 13. Type 2 Composite, 2A Complex, Type 4B Downwarp trough and Type 8 Deltas appear to be gas prone. To date, Type 1 and, with exceptions, Type 3, 6, and 7 basins are oil prone. Type 8 Deltas, Type 2A

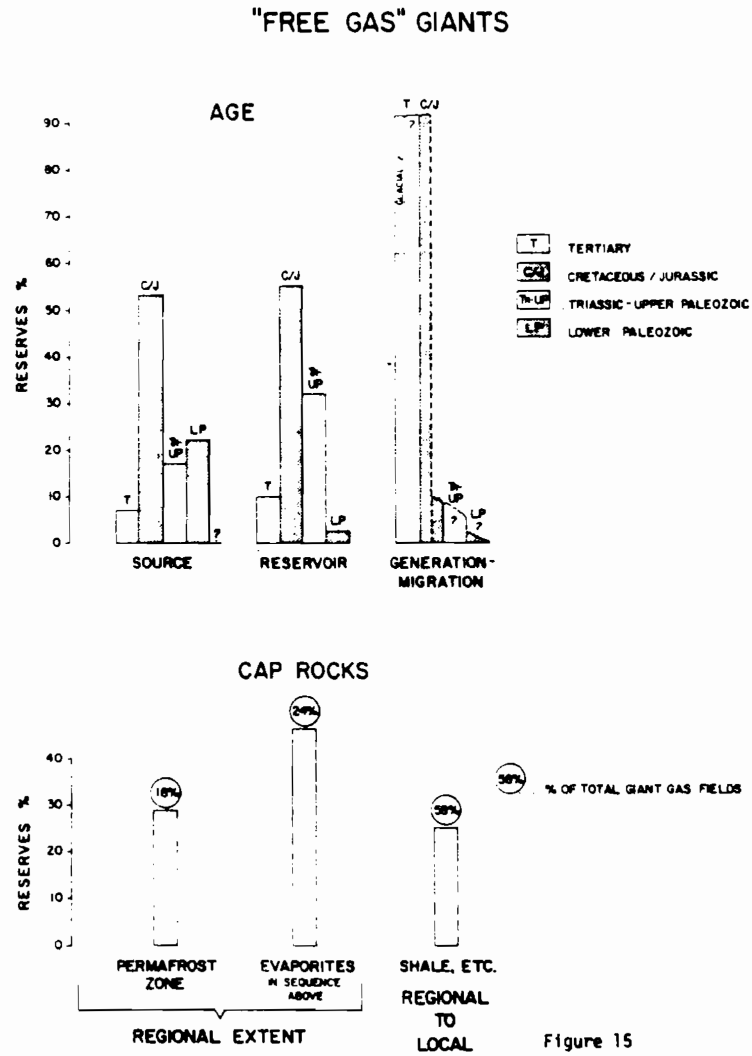


Figure 15

Complex and Type 4A Downwarp closed basins display a high degree of gas recovery per unit (volume or area) of sedimentary fill; the latter two basin types have above average giant gas accumulations while Deltas have few giants. The relationships in Figure 13 appear to have the same general magnitude when the "super basins" (Arabian/Iranian and West Siberia) are removed from the tabulation.

Although more oil than gas (on a BTU basis) can accumulate in any given trap, gas occurs over a wider depth range than oil in any given basin. Considerable giant gas reserves are found above the oil and gas condensate "window" as the result of either a biogenic origin or in the marginally mature zone of source rock maturation. Below the "oil window" gas becomes the main product of deep drilling (15,000 ft.). Therefore, in most basins the vertical potential, and the extent of basin volume available for gas formation and accumulation exceeds that of oil. Most of the giant gas fields are located in the intermediate to deeper zones where higher temperatures prevail and older reservoirs (often carbonates) are present, while about a quarter of the giant reserves are related to a shallow biogenic origin.

In addition to the fundemental parameters of petroleum accumulation, the following factors appear critical for gas giants; 1) basin size, 2) trap size, 3) effective seal or regional cap rocks, and 4) humic source beds or deep oil prone source material. Basin types as classified herein determine or influence, 1) basin size, 2) trap type and size, 3) reservoir lithology and character, 4) prevelance of regional evaporitic seal, 5) temperature (geothermal gradients), 6) depth and rate of basin subsidence -- however, they appear to have little influence on the amounts or ratio of humic to sapropel material.

The characteristics of gas accumulations and the history of the petroleum search suggest that the ultimate reserves of "in place" conventionally recoverable gas will approach that of oil.

BIBLIOGRAPHY

Adams, T. D. and M. A. Kirkby, 1975 Estimates of World Gas Reserves, Vol. 3, 9th World Petroleum Cong. Tokyo, P.3.

Coustau, H. et al 1975, Classification Hydrodynamique des Bassins Sedimentaires Utilisation Combinee avec d' Autres Methodes pour Rationaliser l' Exploration dans des Bassins Non-productifs, Vol. 2, Proc. 9th World Petroleum Cong. Tokyo.

Dunnington, H.W., 1958 - Generation, Migration, Accumulation and Dissipation of Oil in Northern Iran, in L.G. Weeks, ed., Habitat of Oil, AAPG, P. 1194.

Grunau, H. R. and U. Gruner, 1978 - Source Rocks and the Origin of Natural Gas in the Far East, Vol. 1, No. 2 Journal Petroleum Geology, P. 3.

Halbouty, M. T. et al 1970, - Worlds Giant Oil and Gas Fields, Geologic Factors Affecting Their Formation, and Basin Classification, M. T. Halbouty ed., Memoir 14, AAPG, P. 502.

Hallam, A. 1980, - Black Shales - "thematic set of papers on BLACK SHALES, " Vol. 137, Pt. 2, P. 1.

Hunt, J. M., 1979 Petroleum Geochemistry and Geology, W.H. Freeman and Co., San Francisco.

Hunt J. M., 1980 - The Future of Deep Conventional Gas, UNITAR Conference, November 1979, Montreal (in press).

International Petroleum Encyclopedia - 1977, The Petroleum Publishing Co., Tulsa, OK, P. 239.

Klemme, H. D., 1975A - Geothermal Gradients, Heat Flow and Hydorcarbon Recovery, ed. A. G. Fischer and S. Judson, Petroleum and Global Tectonics, Princeton University Press, Princeton, N.J.

Klemme, H. D., 1975B - Giant Fields Related to their Geologic Setting - a Possible Guide to Exploration, Vol. 23, No. 1, Bull. Can. Petrol. Geology.

Klemme, H. D., 1977 - Worlds Oil and Gas Reserves from an Analysis of Giant Fields and Basins (Provinces), ed. R. F. Meyer and M. Grenon, Future Supply of Nature - Made Petroleum and Gas, Pergamon Press.

Klemme, H. D., in press, - The Geology of Future Petroleum Resources, 26th Int. Geol. Congress, Paris, France.

Meyerhoff, A. A., 1979 - Proved and Ultimate Reserves of Natural Gas and Natural Gas Liquids in the World, 10th World Petroleum Cong., Bucharest (preprint).

Nehring, R., 1978 - Giant Oil Fields and World Oil Resources, Rand Corp. Rpt., R-2284-CIA.

North, F. K., 1977 - Age Incidence of Natural Gas, Vol. 28, No. 3, Bull. Can. Petrol. Geology, P. 704.

North, F. K., 1979 - Episodes of Source-Sediment Deposition, Vol. 2, No. 2, Journal Petroleum Geology, P. 199.

Rice, D. D. and G. E. Claypool in press - Generation, Accumulation, and Resource Potential of Biogenic Gas.

Szabo, F. and A. Kheradpir 1978 - Permian and Triassic Stratigraphy, Zagros Basin, South-West Iran, Vol. 1, No. 2, Jour. of Petroleum Geology, P. 57.

Tiratsoo, E. N., 1979 - Natural Gas, Third Edition, Scientific Press, Beaconsfield, England.

Tissot, B. P. et al 1980, Principle Factors Controlling The Timing of Petroleum Generation, Mem. 6, Facts and Principles of World Petroleum Occurence, Canadian Society of Petroleum Geologists, A. D. Maill Ed., P. 143.

Trofimuk, A. A. et al 1977, The Role of Continental Glaciation and Hydrate Formation on Petroleum Occurrence, Future Supply of Nature-Made Petroleum and Gas; R. F. Meyer, Ed. - Pergamon Press, P. 919.

Young, A. et al 1977, - Calculation of Ages of Hydocarbon in Oils - Physical Chemistry Applied to Petroleum Geochemistry, Vol. 61, No. 4, P. 573, P. 30.

Zhabrev, I. P. et al 1975, - Comparative Evaluation of Oil and Gas Potential of the Epi Paleozoic Basins of the U.S.S.R. Vol. 2, Proc. 9th World Petroleum Cong. Tokyo.

DATA SOURCES USED IN THE ESTIMATION OF WORLD NATURAL GAS RESOURCES

Joseph D. Parent
Institute of Gas Technology, Chicago, Illinois, USA

Summary. The Institute of Gas Technology has been issuing a resource report annually which includes estimates of the proved and remaining recoverable natural gas resources of the United States and of the world.[1] The U.S. proved reserves data used are those of the American Gas Association, and the estimated range of U.S. additional remaining natural gas is based on values published by major oil and gas producing companies, the United States Geological Survey, and the Potential Gas Agency.

Estimates of world proved reserves are based primarily but not exclusively on the annual publications of World Oil, Oil and Gas Journal, and of the individual country oil, gas and energy ministries. World total ultimately recoverable natural gas has generally been given by broad regions rather than by countries, but in any case, estimates are few in number and quite variable.

These data do not always agree well, so an effort must be made to pick the most suitable values. In general, it is impossible to pick a single value for any particular case except in a very few instances where a consensus might be reached. Even then, it really should be accompanied by a statement of the uncertainty. It is virtually always better to use a range, preferably one based on probability levels of, say, 10% and 90%.

Proved Reserves Data Sources

Country	Source
USA	American Gas Association[2]
Canada	Canadian Petroleum Association[2]
Mexico	Various spokesmen for PEMEX
U.K.	U.K. Dept. of Energy
W. European countries	Eurostat (Statistical Office of the European Communities)[3]

World Oil and Oil and Gas Journal publish data annually for all of the gas and oil producing countries. Other journals such as the Petroleum Economist publish single country data from time to time.

Proved Reserves of Natural Gas by Country: Procedure & Problems

For many years, the principal detailed sources of worldwide oil and gas reserves data by country and region have been the Oil & Gas Journal and World Oil.

The former has been publishing such data annually in late December as of the current year-end (or January 1 of the next year), while the latter has been publishing comparable data each August 15 as of the end of the previous year. World Oil also publishes revised data for the prior year. Agreement has generally been reasonably good in the past, but in the last several years, World Oil has been considerably more conservative than Oil & Gas Journal. Oil & Gas Journal has not been giving data for individual communist countries other than China and the U.S.S.R.

These journals try to obtain proved reserves data for each producing country, and their data are labeled as proved. However, comparison with some Western European data published by Eurostat and the U.K. Dept. of Energy[4] indicate that in some cases the published estimates included some reserves which might be more properly classed as "probable." Of course, there is a problem with rapidly developing areas, such as the North Sea, where evaluation of new discoveries is difficult due to insufficient data - a situation which improves as more wells are drilled and operating experience gained. It is expected that reserves for developing areas will increase for some time until the production rate catches up with the rate of addition to reserves.

To arrive at figures for proved reserves for the IGT report, annual reserves data of the two journals for 1971-1978 were tabulated along with data from other sources, such as the U.S. Geological Survey's compilation as of year-end 1971 in Prof. Paper No. 817[5], various W.E.C. surveys[6,7,8], the annual surveys of the British Petroleum Co, ANEP (Annuaire de L'Europe Petroliere), and of the U.K. Dept. of Energy. Where data were available directly through national agencies, these were taken into consideration also. Then, the data were examined for consistency and reasonableness of trends. In some cases, there have been large changes upward or downward in successive annual estimates, indicating great difficulty in obtaining reliable data. In such cases, an effort was made to select the most appropriate current values. The accompanying table (1) shows the IGT estimates for year-end 1978 determined in this way. U.S. and Canada data are those of the American Gas Association, American Petroleum Institute, and Canadian Petroleum Association.[2]

U.S. Undiscovered Gas

A number of estimates have appeared in recent years of the amount of natural gas which exists in the United States over and above proved reserves (Fig. 1). This

ESTIMATES OF REMAINING RECOVERABLE U.S. CONVENTIONAL NATURAL GAS RESOURCES AT YEAR-END. TCF

YEAR END	SOURCE	POTENTIAL SUPPLY OLD FIELDS	POTENTIAL SUPPLY NEW FIELDS	PROVED RESERVES*	TOTAL
1977	SHELL	—	315 (190-300)	209	—
1976	POTENTIAL GAS COMMITTEE	215	733 (700-750)	216	1164
1974	EXXON	[illegible]	287 (127-657)	237.1	835 (420-1275)
1974	U.S. GEOL. SURVEY (Theobald et al)	202	322-655	237.1	761-1094
1974	NATIONAL ACADEMY OF SCIENCES	118.6 (Curry)	530	237.1	886
1974	MOODY	63	405	237.1	707
1974	AVERAGE SOME MAJOR OIL COS (Garrett)	100	500	237.1	837
1973	MOBIL OIL (Moody & Geiger)	86	443	250.0	780

* American Gas Association

Figure 1

Table 1.

IGT Estimate of
Worldwide Proved Natural Gas Reserves
as of 12-31-78, TCF

Algeria	105-122
Angola	1.2-1.7
Cameroon	--
Congo	1.0-2.3
Dahomey	--
Egypt	2.2-3.0
Gabon	0.04-2.4
Ghana	--
Libya	24.2-28.5
Morocco	0.01-0.03
Mozambique	0.2-2.6
Nigeria	42-51.6
Rep. S. Africa	0.4
Sudan	0.1
Tanzania	0.05
Tunisia	6.0
Zaire	0.06
Total, Africa	182.5-220.7
Canada	59.5
U.S.A.	208.9
Total, N. America	268.4
Mexico	35
Barbados	0.03-0.3
Trinidad	7.5
Cuba	--
Guatemala	--
Honduras	--
Total, C. America	42.5-45.8
Argentina	8.5-12.0
Bolivia	6.3
Brazil	1.4
Chile	3.0
Colombia	4.8
Ecuador	0.3-4.0
Peru	1.2
Venezuela	41.5
Total S. America	62.0-74.2
Austria	0.45
Denmark	2.5
France	2.9-6.5
W. Germany	6.4-7.8
Ireland	1.0
Italy	6.7-8.0
Netherlands	60-62
Norway	23.5
Spain	0.3
United Kingdom	26.4
Total, W. Europe	130.2-138.5

Albania	0.45
Bulgaria	0.47
Czechoslovakia	0.47
E. Germany	3.19
Greece	0.05-4.0
Hungary	4.2
Poland	4.7
Roumania	4.36
Yugoslavia	1.4
Total, E. Europe excl. U.S.S.R.	19.3-23.2
Bahrain	7.0-9.3
Iran	400-500
Iraq	27.6
Israel	0.01-0.06
Kuwait	31.7-37.3
N. Zone	5.0-19
Oman	2.0-2.5
Qatar	40-58
Saudi Arabia	66-90
Syria	1.5-2.6
Turkey	0.03-0.50
U. Arab Emirates	20.2-21.5
Total, Middle East	601.0-768.4
Afghanistan	2.6
Bangladesh	8.0
Brunei/Malaysia	25-30
Burma	0.17
China/Taiwan	0.8
India	3.45
Indonesia	24
Japan	0.5-0.8
Pakistan	14.7-16.0
Phillipines	0.2
Thailand	4.8
Total, Far East excl. Communist	84.2-99.8
China, Mainland	21-25
U.S.S.R.	775-900
Total, Communist Asia	796-925
Australia	28.5-31.0
N. Zealand	6.0
New Guinea	0.2
Total, Oceania	34.7-37.2

	Regional Totals	
	Crude Oil, 10^6 bbl	Natural Gas, TCF
Africa	53,152-59,602	208.8-228.7
N. America	34,660	282.3
C. America	29,578	66.4-66.7
S. America	24,605-25,323	73.4-79.3
W. Europe	15,518-17,973	116.2-136.4
E. Europe, excl. U.S.S.R.	1,906-2,456	19.0-30.9
U.S.S.R.	58,000-67,000	810-900
Middle East	311,426-337,756	600.5-645.1
Far East, incl, China, P.R.	32,169-36,574	118.2-142.2
Oceania	2,410-2,925	34.2-37.2
World Total	563,424-613,847	2329.0-2548.8
World Midrange	588,636	2,439

additional gas may be found in the future in both new and known fields. Future reserve additions in known fields include gas to be found as extensions and revisions to known amounts and in separate reservoirs close to, as well as in, strata above and below known pools.

The Potential Gas Committee (PGC) has periodically assessed the U.S. potential gas supply (exclusive of proved reserves). The last evaluation was as of December 31, 1978.[9]

As used by PGC, probable potential resource includes gas from known accumulations by extensions and revisions and by discoveries above and below and near existing reservoirs. Possible potential resource includes gas which may exist in new fields in formations previously found productive, but separated distinctly from existing fields. Speculative potential resource refers to gas which may exist in formations or provinces not previously productive; PGC appears to be more generous than some other agencies in this category. The problem here is the high degree of uncertainty.

PGC estimates are not based on a specific wellhead price, but adequate incentives for developing the gas, and steady development of technology are assumed. The latest study was limited to a depth of 30,000 feet and a water depth of 1000 m. The well depth and water depth figures may differ from those used by other agencies. And no agency has used price directly as a factor in its estimates of undiscovered gas.

The U.S. Geological Survey has also preiodically assessed the U.S. natural gas potential supply. Its most recent publication was in 1975.[10] Instead of reporting a consensus value, as in the PGC report, USGS used a range corresponding to 5% and 95% probabilities. Where a single value was given, it was the "statistical mean," defined as the average of high, low and modal values.

Figure 2 shows the USGS estimates of potential oil and gas resources with the aid of the McKelvey diagram. Measured reserves are the proved reserves as reported by A.G.A., which currently is the only agency regularly providing such data. USGS figures for economic identified-inferred oil and gas represent hydrocarbon quantities expected to be recoverable from known fields over and above what has been proved. As such, these quantities are essentially similar to the PGC probable potential resource. The USGS quantities were calculated by means of Hubbert's α factor, which is one of several methods which have been proposed for expected growth over time (and field development) of new discoveries data. One may question why several other techniques were not used to provide other estimates for know field growth.

Quantities in the identified-subeconomic class represent those which might

NATURAL GAS RESOURCES OF THE UNITED STATES
(TRILLION CUBIC FEET)

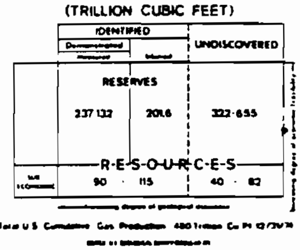


Figure 2

become economically recoverable from known fields in the future solely because of improved recovery technology. They are based on a gas recoverability increase from the assumed 80% to 90%.

It is not known how the USGS figures for undiscovered recoverable resources were obtained, so it is difficult to compare data in this class to the PGC possible and speculative quantities. PGC does offer a brief discussion of their estimation techniques for all potential gas supply. For example, the basic procedure is to compare factors that control known occurrences with factors present in prospective areas. Presumably, USGS uses this method also.

Checks on U.S. Proved Reserves Estimates

The U.S Federal Power Commission reported an independent assessment of U.S. proved gas reserves in 1973.[10] They accounted for 261.6 TCF as of year-end 1970; this compared to the A.G.A. figure of 286.7 TCF for that time. Seay[11] made an analysis of the two sets of data and concluded that the problem was inadequate sampling and uncertainty in the average reserves attributed to the various reservoir size classes.

Subsequent to the FPC study, the Federal Energy Administration (FEA) also made a check on U.S. proved reserves[12]. FEA reported U.S. proved reserves of 237 TCF of natural gas as of December 31, 1974; this compared to the A.G.A. figure for the same date of 237.1 TCF, or 233.2 TCF when put on the same basis as FEA (excluding 3.9 TCF produced and in underground storage). FEA said that, "these estimates seem to differ no more than might be expected of estimates from different sources." FEA's final report[13] showed nearly the same numbers: 240.2 TCF of natural gas.

FEA indicated that it would have liked to classify reserves according to price, but could not obtain the necessary data.* This is still a desirable objective. Indeed, the recent allowance of higher gas prices by the Natural Gas Policy Act of 1978 was intended not only to encourage the search for new gas but to move some known gas resources from marginal status to economically recoverable.

In still another reliability check, the National Research Council (NRC) engaged in a study of the potential for increasing natural gas production from six fields in the Gulf of Mexico in the near term.[14] Because the results of the study were somewhat unexpected, an effort was made to reevaluate the reserves of the fields which were examined. The consulting firm which did the work found values very much less for most of the fields than had been quoted by USGS (largely on the basis of operators' data). The consulting firm used standard procedures, and the general nature and calibre of their work was approved by an independent consultant. It was concluded that the data originally supplied by USGS were probably based on initial estimates and adjusted for cumulative production, and that the original estimates were probably very imprecise. NRC in its report not only suggested periodic re-appraisals (which presumably is done by most responsible operators), but went so far as to say that if the overestimation they found is representative of other fields, the total proved gas reserves of the country may be significantly lower than previously

*This may be very difficult to realize since estimates are not tightly related to wellhead prices or to producers' costs.

estimated. This suggestion seems out of order in view of the studies conducted previously by FEA and FPC. However, it is clear that individual values can be quite uncertain and even somewhat erroneous. Also, errors are expected in both plus and minus directions, with a tendency to counterbalance in the aggregate; they are not expected to be biased heavily in one direction.

Some Checks on the U.S. Potential Gas Resource

Because of the lack of agreement among the various estimates of undiscovered gas, the National Academy of Sciences (NAS) made a study of its own.[15] The end result was much like the oil company estimates. The probable increment to proved reserves in known fields was taken as 50% of the proved reserves. The amounts expected in new fields appear to be a consensus of the experts who served on the NAS committee. A useful result of the study was to bring earlier USGS estimates to more probable values in terms of economically recoverable quantities rather than the much higher total potential resources which seem to have characterized earlier USGS estimates.

A partial check was also made by the American Association of Petroleum Geologists with a study of several regions on the Rocky Mountain province.[16] It was concluded that recoverable natural gas in the Wind River basin was some six times that estimated by USGS, and that in the Green River basin, recoverable natural gas was twice that estimated by USGS.

Judging by this and other studies already mentioned, there is considerable latitude in estimates of undiscovered reserves.

As promised in its 1975 report, USGS has been working on a revision of their estimates. A new report may be forthcoming this year. Preliminary news releases indicate considerable differences in some regions and some tightening of ranges.

Remaining Recoverable Natural Gas

More than a dozen rough estimates of world ultimately recoverable natural gas were published in the interval 1967-79. The average value was 9,000 to 10,000 TCF. The variation was great, from 6,000 to 16,000 TCF, with a standard deviation of 3,000 TCF. It is difficult to say which data are too high or too low. In this connection, Odell[17] has reported a disagreement on world gas reserves at a 1975 International Institute for Applied Systems Analysis workshop in which a producing industry representative estimated world natural gas resources at 5,000 TCF, while Grossling of the USGS felt it should or could be six times higher. According to Odell, the industry representative "agreed that his figures (2 T bbl of oil and 5,000 TCF of gas) are not really ultimately recoverable reserves of oil and gas, but his company's expectations as to how the situation could develop up to the year 2000 under certain assumed economic, political and technical conditions."

The methodology used in making estimates of remaining recoverable gas or of ultimately recoverable gas (remaining recoverable plus cumulative production) is by its nature very imprecise. For example, Hubbert[18] in his 1974 testimony to the U.S. Senate said, "About the best that can be done at present is to assume that the ratios of natural gas and of natural gas liquids to crude oil will be about the same for the world as it is for the United States." Using ratios of 6,400 cu ft of natural gas per barrel of crude oil and 0.2 barrel of natural gas liquids per barrel of crude oil along with a resource base of 2,000 x 10^9 bbl of crude oil, he calculated 12,800 TCF of natural gas and 400 x 10^9 bbl of natural gas liquids.

Although recent estimates of ultimate recovery of natural gas have tended to be on the order of 9,000 to 10,000 TCF, Adams and Kirby of British Petroleum Co. suggested 6,000 TCF as a more reasonable ultimate recovery of natural gas[19]; the National Academy of Sciences gave 7,000 TCF for proved plus undiscovered, and 7,740 TCF for the ultimate recovery.[15] The latest estimate is that of Meyerhoff presented at the 1979 World Petroleum Congress.[20] He indicated the current remaining recoverable nonassociated gas resources to be 6,950 TCF, of which 2,473 TCF are in the proved reserves class. Meyerhoff gave no indication of associated gas resources. One could, of course, assume a ratio of associated gas to crude oil and estimate this quantity. A rough estimate by the author indicated that the ultimately recoverable natural gas including associated-dissolved gas would be about 9,100 to 9,900 TCF based on Meyerhoff's estimate, plus cummulative production of 1,027 TCF through 1978 and nonassociated gas being 70 to 80% of the potential gas resource.

Regional Distribution of Remaining Recoverable Gas Resources

Several estimates of remaining or ultimately recoverable resources have been published on a regional basis. For example, in 1965 Hendricks published a list of estimated quantities of petroleum, natural gas and natural gas liquids in various regions throughout the world.[21] Rough estimates were presented for quantities originally in place and for possible ultimate discoveries. His gas estimates can be harmonized with those of more recent data by taking about 50% of his natural gas in-place estimates as recoverable. 70% to 80% seems more reasonable for conventional natural gas, but lower figures are in order for accumulations in tight rock and certain other situations.

Mobil and the National Academy of Sciences also published regional data,[15] and A.G.A. also presented estimates at the 1977 World Energy Conference.[22] Meyerhoff presented regional estimates of remaining recoverable nonassociated gas. The various regional data are in poor agreement, making a good consensus estimate all but impossible. Using these data and adjusted Meyerhoff data, regional estimates were made of the ultimately recoverable gas. Then the remaining recoverable gas was obtained by subtracting the cumulative production. (Table 2).

Table 2. Estimated Remaining Recoverable Natural Gas As of Year-End 1978

Region	Remaining Recoverable
U.S.	715-1215
Canada	400
Latin America	500
Africa	350-550
Europe	350-500
Middle East	2000-2450
U.S.S.R. / Other Asia	3000
Oceania	500
Antarctic	85
	7900-9200

LITERATURE REFERENCES

1. See, for example, Parent, Joseph D., "A Survey of United States and Total World Production, Proved Reserves, and Remaining Recoverable Resources of Fossil Fuels and Uranium as of December 31, 1977." Chicago, Illinois: Institute of Gas Technology, March, 1979.

2. Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1978, Vol. 33. Published jointly by American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, June, 1979.

3. See annual issues of Basic Statistics of the Community, published by the Statistical Office of the European Communities.

4. "Development of the Oil and Gas Resources of the United Kingdom 1978," and annual issues of Digest of United Kingdom Energy Statistics, U.K. Dept. of Energy, H. M. Stationary Office, London.

5. Albers, J. et al., "Summary Petroleum and Selected Mineral Statistics for 120 Countries, Including Offshore Areas," U.S. Geological Survey Professional Paper 817. Washington, D.C., U.S. Govt. Print. Office, 1973.

6. Survey of Energy Resources, 1974. New York: The United States National Committee of the World Energy Conference, 1974.

7. Survey of Energy Resources, 1976. London: World Energy Conference, 1977

8. World Energy Resources 1985-2020, IPC Science and Technology Press, 1978

9. "Potential Supply of Natural Gas in the United States (as of December 31, 1978)", Potential Gas Comm. Evaluated and published by Potential Gas Agency, Colorado School of Mines, Golden, Colorado, 1979.

10. Miller, B. et al, "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States", U.S. Geol. Survey Circ. 725, U.S. Dept. Interior, Washington, D.C., 1975.

11. Federal Power Comm., "National Gas Reserves Study, A Staff Report" Washington, D.C., May, 1973.

12. Seay, J. C., "The FPC National Gas Reserves Study" in Gas Supply Review, American Gas Association, June 15, 1973. Published by Institute of Gas Technology, Chicago, Illinois.

13. FEA, "Initial Report on Oil and Gas Resources, Reserves, and Productive Capacities". Washington, D.C., June, 1975.

14. "FEA Cites Higher Reserves Estimates" Oil and Gas Journal, 73 p. 150 Nov., 10, 1975.

15. "The Potential for Increasing Production of Natural Gas from Existing Fields in the Near Term", National Research Council, National Academy of Sciences, Washington, D.C., 1978.

16. "Mineral Resources and the Environment", National Academy of Sciences, Washington, D.C., 1975.

17. McCaslin, J.C., "AAPG Report of Undiscovered Reserves Released", Oil and Gas Journal, 76, p. 125, Oct. 30, 1978.

18. Odell, P., "Energy Resources and Energy Demand", Energy Policy, p. 250, Sept., 1975.

19. Hubbert, M. K., "U.S. Energy Resources, A Review as of 1972, pt. 1," in A National Fuels and Energy Policy Study: U.S. 93rd Cong., 2nd Sess., Senate Comm. Interior and Insular Affairs, Comm. Print., Serial No. 93-40.

20. "Greatest Gas Potential is in Middle East and Russia" (Anon), Oil and Gas J. 73, 57, May 26, 1975.

21. See, for example, Rahmer, B., "New Assessment of Resources", Petroleum Economist, 46, P. 501, Dec. 1979.

22. Hendricks, T.A., "Resources of Oil, Gas and Natural-Gas Liquids in the United States and the World," U.S. Geol. Survey Circ. 522, Washington D.C., 1965.

22. Kalisch, R., "The Future of World Natural Gas Supply", A.G.A. Monthly, p. 15, Oct., 1977.

A DISCOVERY MODEL FOR PETROLEUM EXPLORATION

P.J. Lee
Institute of Sedimentary and Petroleum Geology, Geological Survey of Canada, Calgary, Alberta, Canada

ABSTRACT

A model for simulating petroleum exploration history is formalized, displaying one possible outcome of future exploration of an area. The model consists of two components: the Markov chain and the mechanism of sampling without replacement. The simulated exploration history can provide significant information for energy policy formulation and cost analysis. Data from the Labrador Shelf of Canada is used to demonstrate the applications of the model.

INTRODUCTION

The procedure of estimating oil and gas potential developed by the Geological Survey of Canada (Roy, 1975; Energy, Mines & Resources, Canada, 1977) presents the oil or gas potential in a probability curve. Based on the potential at a given probability level, e.g. P_{10} (potential at probability 10%), the procedure can also generate a set of hypothetical pools distributed in accordance with a conditional pool size distribution. The sum of all pools is approximately equal to the estimate, P_{10}. The pools generated also take account of all the input data including appropriate reservoir characteristics such as pool area, net pay, depth, productivity, etc. Such hypothetical pools can be used for economic and cost analysis.

One question that arises is whether or not a discovery rate may be projected to determine how much exploration activity is required in order to achieve a desirable value of reserve. This paper explains how to establish and apply such a discovery model for simulating petroleum exploration.

THE DISCOVERY MODEL

The discovery model for petroleum exploration consists of two components. The first is a Markov chain, the second is the mechanism of sampling without replacement.

The Markov Chain Component

The realization, D-G-G-D-D-G-D-D-D-D-G-G-D, represents the exploration history of the Labrador Shelf of Canada in chronological sequence. The symbol D represents a dry hole state, while the symbol G represents a gas discovery state. The realization indicates not only the number of discoveries but also the frequencies from one state to another state. The exploration history data can be tallied as:

	Dry Hole State	Gas Discovery State
Dry Hole State	4	3
Gas Discovery State	3	2

The above array indicates that the exploration history has passed four times from dry hole to dry hole; two times from gas discovery to gas discovery, and three times from gas discovery to dry hole and vice versa. From this information the estimated transition probabilities are:

$$P = \begin{bmatrix} 0.571 & 0.429 \\ 0.600 & 0.400 \end{bmatrix} \qquad (1)$$

The transition probabilities specify that the probability of a dry hole following a dry hole is 0.571; the probability of a gas discovery following a gas discovery is 0.400, the probability of a gas discovery following a dry hole is 0.600 and so on. Thus the probability for a following dry hole is dependent on the previous state. This is a two-state Markov chain (Cox and Miller, 1965, p. 76-145).

Given the matrix of transition probabilities P, one can find the state probabilities at any time n using matrix multiplication of P. Thus, for example, given that the first well is a dry hole, the probability that the third well is a dry hole or a gas discovery is expressed by the following matrix:

$$P^2 = \begin{bmatrix} 0.584 & 0.417 \\ 0.583 & 0.416 \end{bmatrix} \quad (2)$$

In time the exploration history settles down to a condition of statistical equilibrium in which the state probabilities are independent of the initial conditons as:

$$P^5 = \begin{bmatrix} 0.583 & 0.417 \\ 0.583 & 0.417 \end{bmatrix} \quad (3)$$

Thus, the mean recurrence time of gas discovery is equal to 1/0.417 = 2 dry holes. In words, on the average for every three holes there would be a gas discovery.

The matrix P and its multiplication are used to simulate an exploration history. This mechanism will generate a series of D's and G's displaying one of the possible exploration outcomes. The next question concerns the pool size for each discovery. This is considered in the following section.

The Mechanism of Sampling Without Replacement

Factors controlling the discovery probability of a hypothetical pool, or 'pool' are pool size, X_i, play risk P_r for the 'pool' and exploration activity E_i.

The pool size can be expressed in terms of volume or area. The play risk is a marginal probability that the 'pool' bears hydrocarbons. The exploration activity can be quantified by footage drilled or any arbitrary number.

The probability for the i-th 'pool' to be discovered is:

$$P_i = X_i \cdot P_r \cdot E_i / \sum_j^N X_j \cdot P_r \cdot E_j \quad (4)$$

where X_i = pool size, P_r = play risk for the 'pool', E_i = exploration activity, N = total number of 'pools' in the population.

Table 1 illustrates how these factors can influence the discovery probability. Suppose that for an area containing only two 'pools', these 'pools' have the pool volumes 8.0 and 2.0 billion cubic meters of gas, respectively. Then their discovery probabilities would be 0.8 and 0.2, respectively. The play risk is assumed to be 0.1 for 'pool' 1 and 0.30 for 'pool' 2, thus, the discovery probabilities become 0.57 and 0.43, respectively. Finally, if the factor of exploration activity is considered (Table 1), then their final discovery

TABLE 1 - FACTORS CONTROLLING THE DISCOVERY PROBABILITY OF A HYPOTHETICAL POOL

Hypothetical Pool	1	2
Pool Volume	$8.0 \times 10^9 m^3$	$2.0 \times 10^9 m^3$
Probability	0.80	0.20
Play Risk	0.10	0.30
Probability	0.57	0.43
Exploration Activity	0.40	0.60
Probability	0.50	0.50

probabilities are equal.

The mechanism of sampling without replacement is adopted in the model. When a 'pool' is discovered, it will be removed from the population. Discovery probabilities for the remaining yet-to-be discovered 'pools' are then rescaled.

The discovery model executes the Markov chain and sampling without replacement components until all 'pools' are discovered.

SIMULATED EXPLORATION HISTORY

A total of 56 hypothetical pools were created from a recent Labrador Shelf assessment. They are from seven plays with play risks ranging from 0.08 to 0.33. The exploration activity was not considered in this case. For purposes of illustration one possible value of potential for a given probability level has been selected. Figure 1 shows the past exploration history and a simulated future exploration discovery. It indicates that about 172 exploratory wells would have to be drilled in the Labrador Shelf in order to discover all 'pools'. The figure also suggests that larger 'pools' with relatively low play risks would be found at the early stage of exploration. Figure 2 shows the cumulative reserve found at different exploration stages and characterizes the behavior of the future discovery rate in the Labrador Shelf.

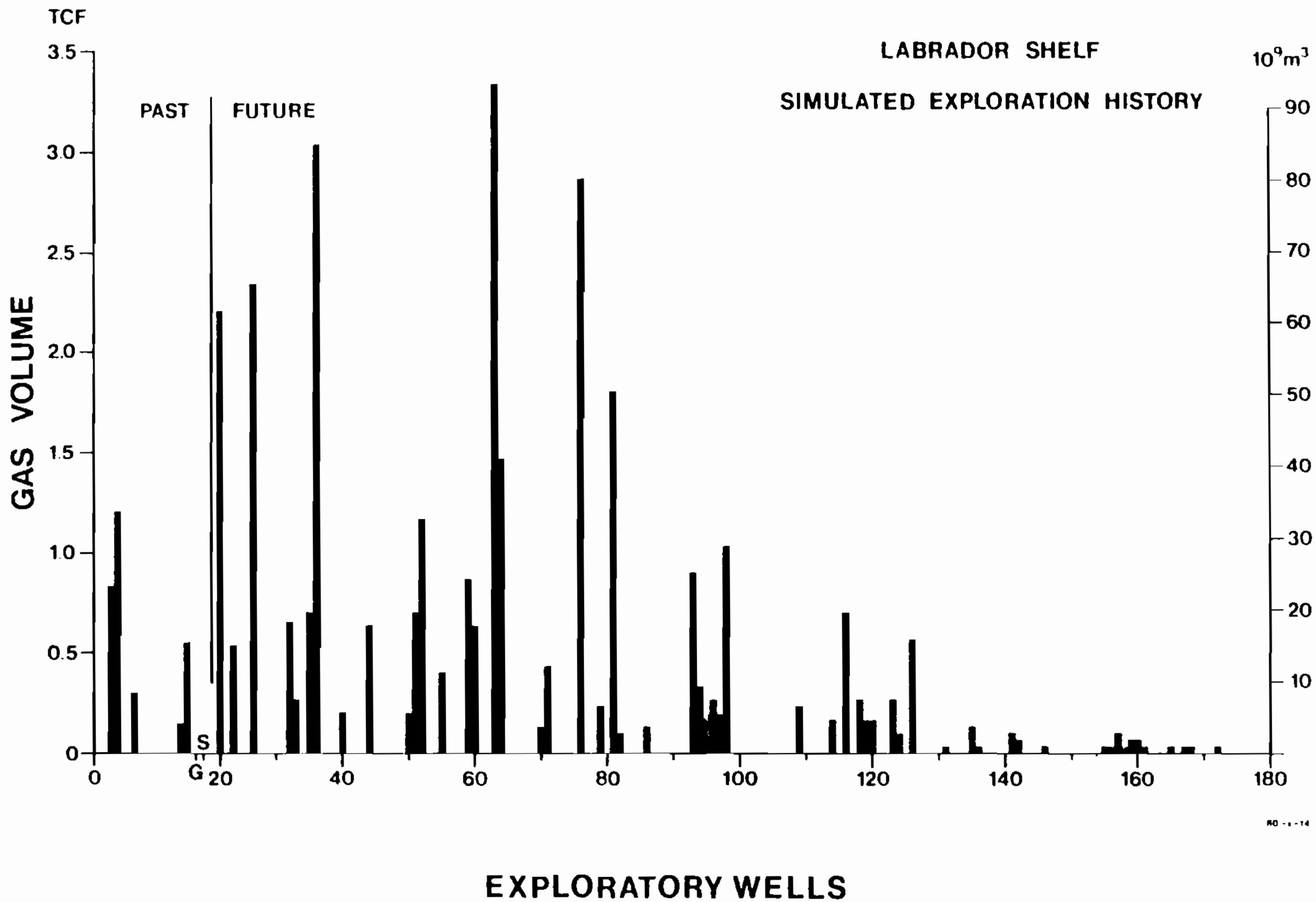


FIGURE 1. Simulated Exploration History for the Labrador Shelf

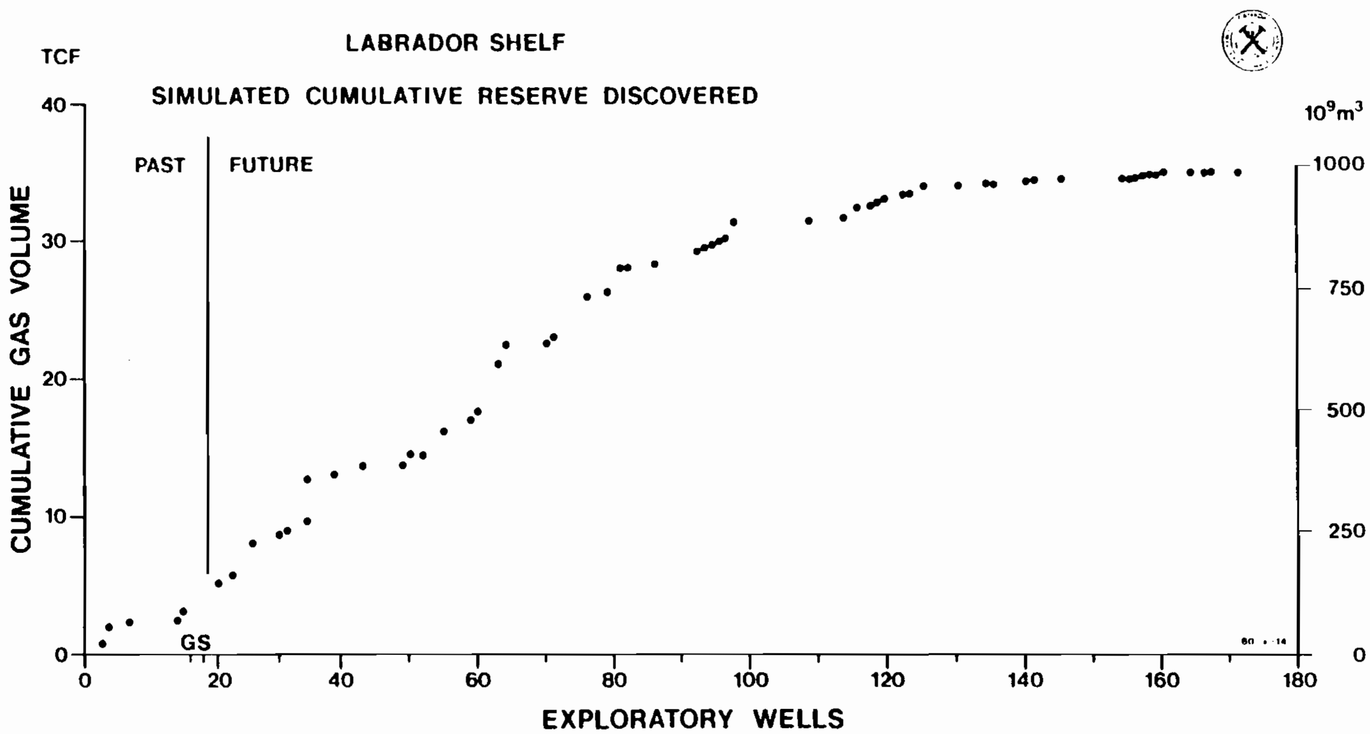


FIGURE 2. Simulated Cumulative Reserve Yet-to-be Discovered for the Labrador Shelf

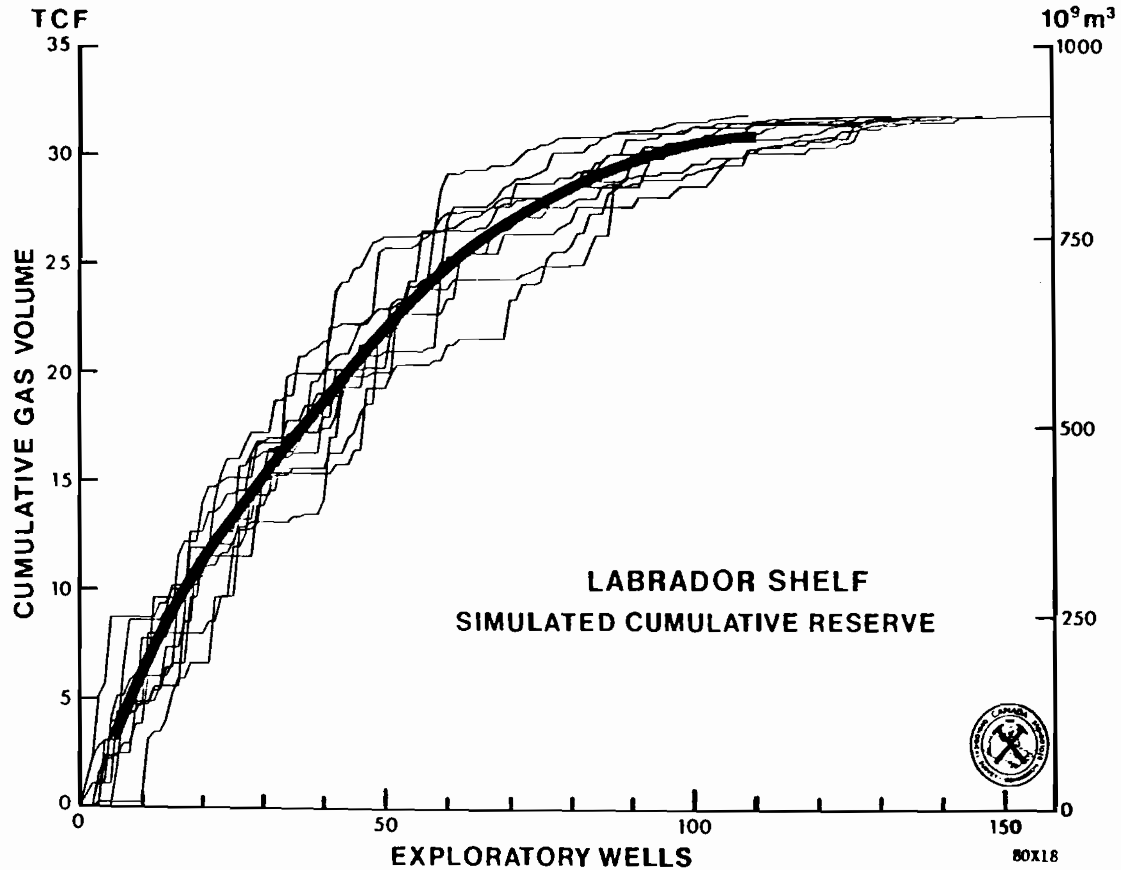


FIGURE 3. Average (heavy line) Cumulative Reserve Yet-to-be Discovered of the Ten Simulation Runs for the Labrador Shelf

The result of simulation is also controlled by the initial random number used to start the simulation process. Different initial random numbers might yield slightly different results. The heavy line of Figure 3 shows the average of the ten simulation runs. Figures 1 and 3 would provide significant information for energy policy formulation and development cost analysis.

CONCLUSIONS

The discovery model simulates a future petroleum exploration history. It displays one of many possible outcomes. However, the characteristics of the simulated exploration history will provide valuable information for energy policy and cost analysis.

The model is applicable to the situation that all exploration wells drilled utilize previous well information. In Canada, this model has greatest application in frontier and offshore regions where relatively sparse drilling has occurred.

ACKNOWLEDGMENT

The author is grateful to Dr. R.M. Procter for his critical reading of this manuscript and suggestions.

REFERENCES

COX, D.R. and H.D. MILLER (1965) The theory of Stochastic Processes. Methuen & Co. Ltd., London

Energy, Mines and Resources, Canada (1977) Oil and Natural Gas Resources of Canada, 1976. Minister of Supply and Services Canada

ROY, K.J. (1975) Hydrocarbon Assessment using Subjective Probability and Monte Carlo Methods. Pages 279-390, First IIASA Conference on Energy Resources, May 20-21, 1975, edited by Michel Grenon. Oxford: Pergamon Press

PAST WORLD GAS RESOURCE ESTIMATES

Robert L. Whiting
Texas A&M University, College Station, Texas, USA

INTRODUCTION

The purpose of this paper is to present and analyze past world gas resource estimates. Present and past investigators have based their predictions of the ultimate recoverable resource of gas upon either the estimated volume of conventional gas which has been discovered to the date of the prediction or upon the estimated conventional gas reserves at the time of prediction. Most investigators have chosen the latter option since such estimates are the most readily available.

Since conventional gas reserves are derived from both associated and non associated gas reservoirs, estimates of crude oil reserves must be known. Hence, both oil and gas reserve estimates are presented and related to the time at which the estimates were made. The influence of field and laboratory data, the natural reservoir drive energy, production practices, economics, etc. on the accuracy of such estimates is discussed.

It is concluded that the estimate of ultimate recoverable gas resource should be based upon the estimate of initial gas in place and the appropriate reservoir drive energy and production practices. Examples of such estimates for associated and non associated gas reservoirs are presented and discussed.

Using these observations and conclusions, past world gas resource estimates are reviewed and analyzed.

INITIAL GAS IN PLACE AND GAS RESERVE ESTIMATES

Procedure

In order to make an accurate estimate of the initial gas in place and/or the gas reserves, much field and laboratory data are needed and detailed geological and engineering analysis are required.

The methods used in assessing gas resources have been presented in a companion paper at this conference and hence will not be repeated here. However, the generalized procedure may be summarized as follows. Since the conventional initial gas in place and gas reserves may be derived either from free gas and/or gas in solution in reservoir oil, it is first necessary to ascertain the type of gas accumulation, that is, associated or non associated. The reservoir pressure, temperature, fluid compositions and fluid properties must also be determined initially and at subsequent times as fluids are produced from the reservoir. The volume of the hydrocarbons in the reservoir is estimated by the volumetric and/or materials balance method. Simultaneously, the natural reservoir energy drive must be determined. Under ideal conditions, with this information the initial gas in place may be estimated. Then the gas reserves may be estimated assuming the reservoir drive energy is applicable throughout the production history of the reservoir to the date of the estimate. However, rarely in practice does the reservoir drive energy and/or production practices remain constant for an appreciable period of time - and certainly not throughout the entire life of the reservoir - due to physical and economic restraints.

Effect of Field and Laboratory Data

In most cases, initial estimates of oil and gas in place and oil and gas reserves are based upon very limited field and laboratory data. As a consequence, errors in these estimates may occur and are magnified by reservoir heterogeneity coupled with indecision as to the type of reservoir energy drive. As additional data are obtained, these estimates may be made with greater precision.

Such estimates have been characterized[2] into three periods in the life of a reservoir as shown in Figure 1. During the first period - before any wells are drilled on the structure or in the sedimentary basin - estimates are generally made upon the basis of the areal extent established by geophysics, surface and/or subsurface geological reconnaissance studies and analogy to similar reservoirs in the same or similar petroleum provinces. These estimates, expressed in barrels per acre, range from pessimistic (non-productive) to very optimistic.

Assuming the first (wildcat) well proves the structure to contain hydrocarbons, the gross formation thickness is obtained from drilling and/or drilling fluid logs. Hence, the bulk volume of the hydrocarbon reservoir may be estimated. With the additional information provided by down-hole logging, core analysis and reservoir fluid analysis, an esti-

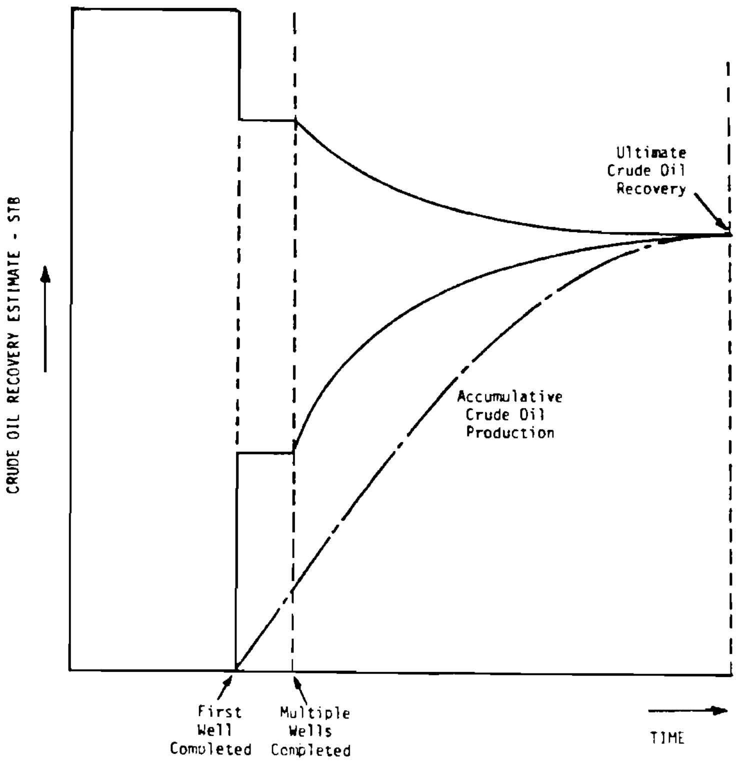


Figure 1 - Crude Oil Recovery Estimates During the Life of a Field

mate of the hydrocarbon content of the reservoir may be made and the result may be expressed in barrels of hydrocarbon per acre foot. Early pressure history may provide a basis for a qualitative determination of the natural reservoir drive energy. Estimates may then be made with better accuracy and the range of estimates, shown in Figure 1, is smaller than that made initially.

As additional wells are drilled and more reservoir rock and fluid data are accumulated, subsurface maps of all types are prepared permitting more accurate volumetric estimates of the hydrocarbons in place.

After the discovery well is drilled, hydrocarbons are produced from the reservoir. Simultaneously with the hydrocarbon volumetric estimates, production decline curve and/or materials balance calculations are made to estimate the initial hydrocarbons in place, the type of natural reservoir energy drive and the hydrocarbon reserves. With increased hydrocarbon production and continued estimation by various methods, the range of optimistic and pessimistic estimates decreases and, as shown in Figure 1, they become identical on the date of ultimate hydrocarbon recovery.

From the foregoing, it is evident that the estimate of initial hydrocarbons in place and the hydrocarbon reserves is highly dependent upon the field and laboratory data available on the date of estimation. Hence, such estimates are constantly being reviewed, updated and changed.

Effect of Type of Natural Reservoir Energy Drive

A further complication in estimates is that it is often very difficult to identify, quantitatively, the type of natural reservoir energy drive early in the life of the reservoir. Further, failure to recognize the presence of a more efficient type of natural reservoir energy drive than that assumed may result in greatly overestimating the initial hydrocarbons in place. Also the origin, occurrence, migration and accumulation of petroleum is such that the type of natural reservoir energy drive may change as fluids are produced from the reservoir. Although in most cases this does not change the estimate of hydrocarbons initially in place in the reservoir, the ultimate recovery of hydrocarbons may be greatly affected.

The simplest illustration of this is found in many non associated gas reservoirs throughout the world. Development drilling may establish a large occurrence of gas and a sufficient number of wells are drilled to provide the desired gas production rate. However, drilling may be inadequate to delineate the extent of the gas accumulation. Since it is a large gas accumulation and the gas withdrawals are small in comparison, field pressure and production data may indicate that the natural reservoir energy drive is volumetric. Estimates of initial gas in place and gas reserves are made on this basis. With continued production it may be observed that some of the wells located structurally low decrease in production and in some cases completely "water out". It is evident then that at least a portion of the natural reservoir energy drive is provided by water encroachment. Under these circumstances, all wells should have been located structurally high in the reservoir to minimize damage by encroaching water. Further, if the water encroachment is exceedingly strong the wells should have been produced at exceedingly high rates in order to minimize the pressure and hence volume of the gas trapped behind the invading water.

In such a gas reservoir, the overall effect of a change of the type of natural reservoir energy drive from volumetric to water drive may be a reduction of gas recovery from 80-90% to 35-65% depending upon reservoir rock and fluid properties and the activity of the water drive. This will greatly reduce the ultimate recovery of gas from the reservoir. Hence, the initial estimates of gas reserves will need to be reduced accordingly.

Similarly, oil reservoirs with and without associated gas may exhibit changes in the type of natural reservoir energy drive during the producing life of the reservoir. Such reservoirs may have associated aquifers which remain dormant during much of the early life of the reservoir and later become the dominant natural reservoir energy drive. Also reservoir rock and fluid conditions may be such that as the reservoir pressure declines and gas is released from solution in the oil, the gas will migrate upward forming a secondary gas cap. Such developments may cause considerable changes in the ultimate recovery of oil and gas from the reservoir and hence the gas reserves.

Effect of Economics

Society unknowingly restrains the development of gas resources - and hence gas reserves - because of economics. Unquestionably, gas producers - be they countries, corporations or entrepenuers - are in the business to make a profit. In fact, if geologists and engineers are to best serve gas producers - and yes, even society - they should use their expertise to maximize the profit from each investment in gas resources. Hence, there is an optimum well spacing for oil and/or gas wells in any particular reservoir for a given price of oil and/or gas. If the price of oil and/or gas is increased, more wells may be drilled in the same reservoir thereby increasing the estimate of initial gas in place in the reservoir and/or the ultimate gas recovery from the reservoir. The recent explosive infield drilling in West Texas has clearly demonstrated the influence of economics on gas resources, reserves and productivity.

The case cited for the non associated gas reservoir which developed an active water drive later in the life of the reservoir motivates the gas producer to higher gas production rates in order to improve economic return on investment, while at the same time improving ultimate gas recovery. Hence, ultimate gas recovery may be related to gas production rates.

Effect of Production Practices

The ultimate recovery of gas from a reservoir is not only affected by the natural reservoir energy drive but also by supplemental reservoir energies which man selects to apply to the reservoir. These supplemental energies are ordinarily characterized as secondary or tertiary processes. and involve the injection of water, gas or chemicals into the reservoir. Ordinarily, although such processes do not change the estimate of the initial hydrocarbons in the reservoir, the ultimate recoveries of the hydrocarbons may be increased appreciably. Here again it is demonstrated that production practices may increase ultimate hydrocarbon recovery.

In associated gas reservoirs, with or without water drives, production practices can decrease the ultimate hydrocarbon recovery. As gas prices become more favorable relative to oil prices, the incentive will be to produce the associated gas, thereby decreasing the ultimate oil recovery and some of the gas associated with the oil as solution gas. Improper production practices in combination solution gas-gas cap-water drive reservoirs can also reduce the ultimate hydrocarbon recovery from such reservoirs.

Effect of Technology Improvement

It was mentioned in the previous section that application of secondary and tertiary processes to associated gas reservoirs could increase crude oil and natural gas recovery. Although these processes are well developed at this time, there exists the opportunity for their improvement. Also, economics and the methods for characterizing reservoirs with respect to heterogeneity are the principal deterrents to greatly expanded application of secondary and tertiary processes.

Improvements in hydraulic fracturing, explosives, acidization and other reservoir stimulation techniques are being made constantly. Such improvements in technology could conceivably double natural gas reserves.

RESERVE ESTIMATES

Crude Oil

Historically, world gas resource estimates have been based most frequently upon conventional gas reserve estimates probably because initial gas in place estimates are not readily available. Hence for this paper, historical estimates of oil and natural gas reserves were assembled from all known sources and coupled with the author's petroleum data base. After analysis of the data and selection of the estimates which were considered to be most representative, the data were recorded in tabular and graphical form. To the extent practical, the data were also organized to indicate geographical distribution of estimates as well as the time at which the estimates were made. The crude oil reserve estimates were organized by country for the period 1932 to 1979. To conserve space, only eight surveys are shown in Table 1. However, all of the total world crude oil reserve estimates are shown in Figure 2. Efforts to complete the author's continuing study of crude oil and natural gas reserves on five year intervals for the period 1900-1950 were unsuccessful. However, this work is continuing and ultimately will be completed on a year to year basis.

The crude oil reserves - time relationship shown in Figure 2 clearly indicates the year to year variation of such estimates for the reasons discussed in the previous section of this report as well as additions of reserves of new fields. The growth of these crude oil reserves during the period 1945-1970 was predicted quite accurately by petroleum geologists and engineers in the mid 1950's. However, most expected the reserves to continue such increase until 2000 A.D. The writer is unable to explain to his satisfaction the anomalous reserve estimates for the past ten years. To the pessimist, this trend is evidence that our world crude oil reserves are peaking. It must be admitted that the shape of the curve is similar to that of Texas, USA and Pennsylvania, USA when their reserves peaked. However,

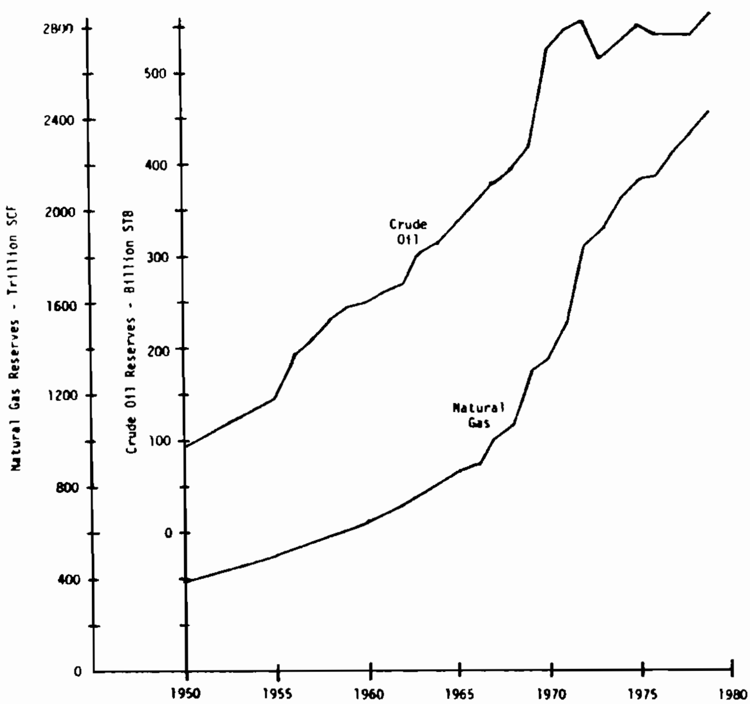


Figure 2 - World Petroleum Reserves

Table 1
ESTIMATED WORLD CRUDE OIL RESERVES
(AS OF JANUARY 1 OF YEAR)
BILLIONS OF STOCK TANK BARRELS

Country	1932	1947	1955	1960	1965	1970	1975	1979
Saudia Arabia		5.0	35.0	48.0	59.2	137.0	103.5	113.3
Kuwait		9.0	28.0	60.0	70.0	71.2	70.9	71.4
USSR	3.0	9.5	10.0	23.0	33.0	58.0	48.6	58.4
Iran	2.2	6.0	13.0	22.0	37.0	55.0	68.0	45.0
Iraq	2.5	6.0	14.0	23.0	26.0	28.5	35.1	34.4
UAE			.1	.1	6.5	16.0	26.4	31.6
Mexico	.3	.9	1.7	2.5	2.6	5.6	3.1	28.4
USA	12.0	21.7	30.3	31.7	31.0	29.6	34.2	27.6
Libya				1.5	9.0	30.0	23.0	27.2
China				.4	0.8	5.7	14.8	20.0
Venezuela	2.0	7.5	10.7	16.9	17.2	16.0	14.6	18.2
Nigeria				.1	1.3	5.0	19.6	12.3
United Kingdom							12.0	10.2
Algeria				3.0	6.0	8.0	9.0	9.6
Indonesia			2.1	8.0	8.5	18.0	12.0	7.8
Neutral Zone			.3	2.6	10.0	13.0	10.1	6.2
Canada		.2	2.4	3.5	6.2	8.6	7.2	5.8
Norway							5.5	4.1
Qatar			1.5	2.0	3.8	3.9	5.4	3.8
Oman						3.0	3.3	3.3
Australia					.2	1.8	2.7	3.1
Brunei-Malaysia	1.0	1.1		.4	.4	.7	4.7	2.4
Argentina	.1	.2	.3	1.4	2.2	1.6	2.5	2.4
Others	1.4	2.4	3.9	5.8	10.9	17.6	20.0	22.1
Total	24.5	69.5	153.3	255.9	341.8	533.8	556.2	568.6

the writer prefers to believe that the shape of the curve is due to overestimation of the crude oil reserves for fields discovered during 1965-70. Recently, such estimates have been corrected - and perhaps even underestimated - and hopefully the crude oil reserves curve will soon resume its upward trend. Also, many of the large oil fields, those containing four billion barrels crude oil reserve, have been reduced in reserves not only by reestimation but by very high withdrawals of crude oil. However, the existing crude oil reserve trend must be viewed with great concern.

Natural Gas

To prepare the summary of the natural gas reserve estimates, the gas reserves of associated gas reservoirs - the gas cap gas and the solution gas - were combined with those of the non associated gas reservoirs. The results are shown in Tables 2, 3 and 4 and in Figure 2. The natural gas reserves are presented for the period 1945-1979 and are organized in the tables to show the trend of reserves by country at five year intervals, except for the classical estimate of Weeks' which was made in 1962. One table presents these data for the five most recent years. Figure 3 clearly shows the historical growth of the natural gas reserves and the phenomenal growth since 1965. From this evidence it appears that this growth is continuing at a constant rate and there is no evidence to indicate that it will

Table 2 ESTIMATED WORLD NATURAL GAS RESERVES
(AS OF JANUARY 1 OF YEAR)
TRILLIONS STANDARD CUBIC FEET

	1945	1950	1955	1960
USSR	4.0	25.0	30.0	66.0
Iran	10.0	6.0	4.0	8.0
USA	144.0	186.0	224.0	264.0
Algeria	36.0	38.0	38.0	51.0
Saudia Arabia	9.0	29.0	37.0	41.0
Netherlands				2.0
Canada	9.0	11.0	27.0	34.0
Mexico	10.0	11.0	13.0	11.0
Qatar	3.0	3.0	3.0	5.0
Nigeria				0.8
Venezuela	9.0	14.0	21.0	30.0
Kuwait	6.0	3.0	37.0	40.0
Brunei-Malaysia	1.0	0.8	0.6	0.4
Australia	4.0	3.0	2.0	1.0
Libya	6.0	4.0	2.0	2.0
United Kingdom				0
Iraq	17.0	21.0	20.0	21.0
Pakistan	5.0	5.0	14.0	14.0
China			1.0	1.0
Indonesia	7.0	5.0	2.0	3.0
Abu Dhabi				2.0
Neutral Zone			3.6	2.0
Argentina	4.0	4.0	4.0	4.0
Norway				0
Rumania			2.0	3.0
Others	21.0	24.0	26.0	35.0
Totals	305.0	392.8	510.2	640.2

not continue at this rate.

Figure 2 clearly shows the year to year variation of natural gas reserve estimates due to the factors mentioned previously, as well as additions of reserves of new fields. During the past ten years, natural gas reserves in many of the largest fields have been reduced. However, these reductions have been offset by new natural gas field discoveries.

Summary

The total world reserves (1/1/79) of natural gas of 2426 trillion cubic feet can be considered to be approximately thirty-five percent (35%) associated gas and sixty-five percent (65%) non associated gas. This is testimony to the fact that the future availability of natural gas from present reserves is dependent to a great extent upon future oil production and practices related to oil production.

Table 3 ESTIMATED WORLD NATURAL GAS RESERVES
(AS OF JANUARY 1 OF YEAR)
TRILLION STANDARD CUBIC FEET

	1962	1965	1970	1975	1979
U.S.S.R.	75.0	98.4	322.0	699.8	813.6
Iran	22.5	80.0	107.0	374.4	372.0
U.S.A.	275.0	281.3	275.1	237.1	200.3
Algeria	50.0	60.0	145.0	100.2	122.0
Saudia Arabia	45.0	52.0	82.0	61.0	68.8
Netherlands	2.6	43.0	85.5	77.0	66.8
Canada	36.0	43.4	52.0	56.7	62.7
Mexico	10.0	11.5	12.0	11.2	58.9
Qatar	7.5	8.0	7.3	7.8	58.5
Nigeria	.3	1.7	5.0	50.2	51.8
Venezuela	33.0	30.7	26.5	42.9	45.0
Kuwait	33.0	35.0	40.0	38.1	37.3
Brunei-Malaysia	.5	.6	4.0	18.2	36.4
Australia	.8	3.1	15.1	32.3	34.5
Libya	3.7	5.0	26.0	28.3	30.6
United Kingdom	.1	.1	35.0	30.0	27.0
Iraq	22.5	21.5	19.5	27.5	26.7
Pakistan	15.0	18.8	18.9	15.5	26.4
China	2.0	3.0	3.6	17.0	26.0
Indonesia	2.0	2.0	2.8	15.0	24.2
Abu Dhabi	3.0	5.0	8.8	24.9	19.2
Neutral Zone	2.0	4.0	5.8	19.8	19.0
Argentina	6.0	6.5	6.4	7.1	15.3
Norway	0	0	0	19.4	14.3
Rumania	4.8	7.8	6.0	6.8	12.3
Others	69.2	45.4	62.3	128.7	156.1
Totals	721.5	867.8	1373.5	2146.9	2425.7

Over the past twenty years supporting data permit the following observations:

1. Sixty-five percent (65%) of the natural gas reserves are located in five (5) countries; seventy-seven percent (77%) are located in ten (10) countries.
2. Fifty-nine percent (59%) of the crude oil reserves are located in five (5) countries; eighty-one percent (81%) in ten (10) countries.
3. Eighty-five percent (85%) of the natural gas and ninety percent (90%) of the crude oil reserves are located in fifteen (15) countries.
4. One hundred-and-thirty (130) natural gas fields, each with a reserve exceeding one trillion cubic feet, contain eighty-four percent (84%) of the natural gas reserves.
5. Seventy-four (74) oil fields, each with reserves exceeding one

Table 4 ESTIMATED WORLD NATURAL GAS RESERVES
(AS OF JANUARY 1 OF YEAR)

TRILLION STANDARD CUBIC FEET

	1975	1976	1977	1978	1979
U.S.S.R.	699.8	710.0	781.0	774.9	813.6
Iran	374.4	374.8	375.0	373.4	372.0
U.S.A.	237.1	228.2	216.0	208.9	200.3
Algeria	100.2	115.5	115.5	122.5	122.0
Saudia Arabia	61.0	63.4	64.9	66.8	68.8
Netherlands	77.0	73.9	70.6	69.0	66.8
Canada	56.7	57.0	58.3	59.5	62.7
Mexico	11.2	11.9	19.4	27.9	58.9
Qatar	7.8	47.8	58.8	58.8	58.5
Nigeria	50.2	52.2	51.4	51.6	51.8
Venezuela	42.9	44.3	44.9	44.8	45.0
Kuwait	38.1	37.8	37.2	37.3	37.3
Brunei-Malaysia	18.2	19.0	17.5	16.9	36.4
Australia	32.3	36.6	34.7	34.5	34.5
Libya	28.3	28.5	28.3	28.5	30.6
United Kingdom	30.0	31.9	31.9	32.0	27.0
Iraq	27.5	27.5	27.3	27.4	26.7
Pakistan	15.5	18.4	19.3	19.1	26.4
China	17.0	19.4	21.0	25.0	26.0
Indonesia	15.0	18.0	22.8	24.6	24.2
Abu Dhabi	24.9	19.5	19.2	18.7	19.2
Neutral Zone	19.8	19.7	19.1	19.0	19.0
Argentina	7.1	7.4	7.1	16.0	15.3
Norway	19.4	24.7	24.0	17.0	14.3
Rumania	6.8	6.7	5.8	12.2	12.3
Others	128.7	131.2	134.9	142.4	156.1
Totals	2146.9	2225.3	2305.9	2328.7	2425.7

billion barrels, contain fifty-four percent (54%) of the crude oil reserves.

6. Twenty-three (23) oil fields, each with reserves exceeding four billion barrels, contain thirty-nine percent (39%) of the crude oil reserves.
7. Seventy percent (70%) of the hydrocarbon reserves are located onshore or on the continental margins.
8. Over eighty-five percent (85%) of the hydrocarbon reserves are found in post-Permian sediments.
9. Of the hydrocarbon reserves, approximately twenty-five percent (25%) are found in sandstones, twenty-five percent (25%) in carbonates and fifty percent (50%) in other types of rocks.

COMBINED CRUDE OIL AND NATURAL GAS RESERVES AND CUMULATIVE PRODUCTIONS

Some investigators base their ultimate gas resource estimates on a crude oil total equivalent of the crude oil and natural gas reserves and productions. Hence, the world reserve estimates discussed earlier were combined with the writer estimates of the historical world cumulative productions of oil and natural gas. The results are shown in Table 5.

The results are as expected by the writer but are somewhat lower than other investigators have reported. Due to the trend in crude oil reserves during the last ten years the total equivalent crude oil and natural gas is increasing less rapidly than in the past. An analysis of these results for the 1955-1975 period on a five year interval, yields percentage increases from 1955 of 47, 36, 52, and 26. The writer's most recent information for 1979-1980 indicates that the increase will be approximately 18% for the 1975-80 period. This result leads one to believe that future predictions by earlier investigators may be optimistic.

PROPOSED METHOD FOR ESTIMATING ULTIMATE NATURAL GAS RESERVES

For many years, on a continuing basis, the writer has actively participated in oil and gas and other energy resource and reserve estimates. His procedure for making such estimates for crude oil reservoirs ordinarily necessitates the estimate of the original oil in place; the cumulative oil production; the oil recovery by the natural reservoir energy, primary recovery; the oil recovery by waterflooding and/or gas injection, secondary recovery; the ultimate oil recovery by combined primary and secondary recovery; the residual oil in place after primary and secondary recovery; the oil recovery by enhanced oil recovery techniques and finally the total oil recovery by all processes. Reservoir rock and fluid criteria together with economic analyses, are used to select the most favorable enhanced oil recovery process for a particular reservoir.

The results of such an evaluation made by the author for the world crude oil reservoirs, and updated to December 31, 1977, are shown in Table 6. In order to quantify and characterize the crude oil resource and reserves, tables similar to this are prepared for crude oil reservoirs having various characteristics including API gravity, viscosity, gas solubility, etc. Also, statistical studies are made of reservoirs to estimate the original oil in place and reserves related to time, cumulative crude oil production, annual crude oil production, etc. All of this information is combined to

Table 5
SUMMARY OF CRUDE OIL AND NATURAL GAS
RESERVE AND PRODUCTION DATA
(AS OF JANUARY 1 OF YEAR)

	Crude Oil - Billion STB			Natural Gas - Trillion SCF			Natural Gas Billion STB Equivalent*	Total Equivalent Billion STB Crude Oil and Natural Gas
	Reserves	Cumulative Production	Total	Reserves	Cumulative Production	Total		
1979	568.6	404.69	973.3	2425.7	973	3399	567	1540
1975	556.2	319:94	876.1	2146.9	696	2843	474	1350
1970	533.8	226.05	759.9	1373.5	473	1847	308	1068
1965	341.8	160.69	502.5	867.8	330	1198	200	703
1960	255.9	116.10	372.0	640.2	226	866	144	516
1955	153.3	84.17	237.5	510.2	165	675	113	351
1950		61.76		392.8	123	516	86	
1947	69.5	51.91	121.4	305.0	98	403	67	188
1945		46.56						
1932	24.5	21.42	45.9					

* 6000 SCF = 1 STB

Table 6 WORLD OIL RESOURCE RECOVERIES BY COUNTRIES

CONVENTIONAL METHODS AND ENHANCED RECOVERY PRESENT TECHNOLOGY AND ECONOMICS
AS OF 12-31-77

(Billions of Stock Tank Barrels)

Country	Original Oil in Place	Cumulative Production	Ultimate[1] Recovery	Reserves	Residual Oil in Place	Enhanced Recovery	Total Recovery
Saudia Arabia	522.4	30.8	194.6	163.8	327.8	40.5(7.75)	235.1
U.S.A.	445.0	113.8	143.3	29.5	301.7	25.8(5.80)	169.1
Kuwait	349.8	18.3	120.7	102.4	229.1	29.7(8.49)	150.4
U.S.S.R.	316.2	53.3	128.4	75.1	187.8	13.9(4.42)	142.3
Iran	270.8	26.4	93.3	66.9	177.5	15.0(5.50)	108.3
Venezuela	238.7	33.6	51.6	18.0	187.1	20.0(8.38)	71.6
Iraq	181.5	12.3	62.6	50.3	118.9	10.0(5.50)	72.6
Abu Dhabi	111.1	4.0	40.1	36.1	71.0	10.0(9.00)	50.1
Libya	104.6	11.2	48.3	37.1	56.3	4.0(3.82)	52.3
China	68.5	3.8	24.7	20.9	43.8	2.7(3.94)	27.4
Nigeria	65.5	6.1	24.8	18.7	40.7	1.4(2.14)	26.2
Indonesia	57.3	7.3	20.9	13.6	36.4	2.0(3.49)	22.9
Algeria	52.3	4.6	17.8	13.2	34.5	3.1(5.92)	20.9
Mexico	46.0	6.2	19.6	13.4	26.4	1.1(2.39)	20.7
Canada	43.3	8.3	14.3	6.0	29.0	3.9(9.01)	18.2
United Kingdom	40.5	0.4	13.9	13.5	26.6	1.1(2.72)	15.0
Neutral zone	38.0	2.8	12.2	9.4	25.8	3.0(7.89)	15.2
Norway	23.7	0.3	6.3	6.0	17.4	2.0(8.43)	8.3
Brunei-Malaysia	12.8	1.7	4.7	3.0	8.1	0.4(3.13)	5.1
West Germany	5.7	1.2	1.6	0.4	4.1	0.4(7.02)	2.0
Netherlands	3.7	0.3	1.1	0.8	2.6	0.2(5.41)	1.3
Pakistan	1.3	0.1	0.4	0.3	0.9	0.1(7.69)	0.5
Total	2,998.7	346.8	1,045.2	698.4	1,953.5	190.3(6.35)	1,235.5
Other	231.1	28.5	69.1	40.6	162.0	11.8(5.11)	80.9
Total World	3,229.8	375.3	1,114.3	739.0	2,115.5	202.1(6.26)	1,316.4
%Original in Place		11.6	34.5	22.9	65.5	6.3	40.8

[1]Sum of Primary and Secondary Recovery Processes

form the data base for predicting the original oil in place and reserves for each individual formation, type of rock (sandstone, limestone), field, county, district, state and for countries. The accuracy of the data base is checked periodically by comparing results for the future obtained through its use with actual performance data. Modification of the data base has been made historically to improve accuracy of predictions.

The results shown in Table 6 are, to the writer's knowledge, the first published summary of world resource data in the detail shown. The writer is convinced that investigators who predict future crude oil and natural gas resources should predicate such estimates on summary tables such as Table 6. Obviously, these summaries are a compilation of individual field studies and evaluations.

There is little opportunity for comparison of Table 6 results with the efforts of other investigators other than in the totals shown for each column. The original oil in place for the world falls within the range of estimates of other investigators. However, this provides little confidence since the range reported has been from 2800-3600 billion stock tank barrels. The cumulative oil production for each country and the total cumulative oil production represent the best data available and are those used by the writer in evaluations.

The reserves shown are for the most part considerably higher than those reported by others. Reserves are considered to be indicative of the crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The author's higher reserve estimates are due to his acceptance of the applicability of secondary and/or enhanced recovery techniques to specific reservoirs prior to completion and/or operation of the method. However, pilot testing has indicated in such reservoirs that the techniques are economic. Similar comments are applicable to the ultimate recovery estimates. The ultimate recovery values shown represent combined primary and secondary recovery processes.

The residual oil in place values indicate the volume of oil remaining in the reservoirs after application of primary and secondary recovery operations. Hence, the residual oil volume is the target for application of enhanced oil recovery techniques.

The enhanced recovery estimates were made after detailed reservoir evaluation considering the rock and fluid properties, reservoir temperature and pressure and economics. As might be expected an extremely wide range of percentage recoveries were obtained due to the diversity of rock and fluid properties applied, the engineering management of the reservoirs and economics. Enhanced oil is considered to be new oil in the U.S. and the estimates for recovery are based upon a world price of $25 per barrel in the future (constant dollars).

It is significant that of the 3,229.8 billion STB of oil in place, only 1,114.3 billion STB of oil is estimated to be recoverable by combined primary and secondary recovery methods. Hence, 2,115.5 billion STB of oil will remain in the reservoir as residual oil. At the date of the report, the combined primary and secondary crude oil production was estimated to yield a 34.5% recovery based upon original oil in place. It is estimated that an additional 202.1 billion STB of oil will be recovered by enhanced recovery methods, which would yield a 40.8% ultimate oil recovery total.

It should be recognized that the application of enhanced recovery techniques to petroleum reservoirs is dependent upon technology, economics, and government policy. Improved economics and government policy stability is essential if the residual oil resource is to be expeditiously exploited through application of enhanced recovery techniques.

It is proposed that summaries such as Table 6 be employed to estimate the natural gas reserves in associated gas reservoirs and serve as the basis for prediction of ultimate gas resources.

Further, it is recommended that similar studies be conducted and the results published for non associated gas reservoirs. Many investigators who are predicting ultimate natural gas resources are utilizing natural gas reserve estimates without a knowledge of the estimate of initial gas in place, the cumulative gas production, the assumed type of reservoir energy drive, etc. More precise estimates are urgently needed in order to formulate plans for alternative energy resources in the future.

At the present time, the writer is conducting a study of the major oil and gas fields in the world and hopes to prepare a table similar to Table 6 for natural gas.

PAST WORLD CRUDE OIL AND NATURAL GAS RESOURCE ESTIMATES

It appears that there was little concern among the petroleum experts in the world as to the longevity of the crude oil and natural gas supply prior to 1955. In the U.S.A., at this time, U.S.A. Congressional action in the Phillips case, upheld by the U.S.A. Supreme Court, fixed the price of natural gas at the wellhead. Immediately thereafter there was much discussion, study, reports and papers concerning the future crude oil and natural gas reserves. However, during the period 1955-65 there was a much greater petroleum producing capacity in the U.S.A. than demand. For example, for an extended period of time in Texas, wells were permitted to produce only four days a month with an allowable of 10 STB/day and gas wells were shut in. There were many warnings by individuals, major petroleum companies, independents and financial institutions of impending petroleum shortages commencing in the 1970's. However, due to curtailed petroleum production, economics were such that petroleum exploration was minimal and crude oil reserves remained constant for 10 years. However, foreign operations increased and potentially large new reserves of crude oil were identified, particularly in the Middle East and North Africa. During this same period of time, the petroleum demand continued to increase. At the time, natural gas was considered to be an undesireable product of crude oil production. However, with its low cost fixed by law, natural gas demand increased rapidly and by 1965 the petroleum industry was actively engaged in natural gas property development. This history indicates how economics may seriously deter the development of resources.

During the period 1955-65, many predictions of the ultimate crude oil and natural gas resources, Table 7, were made and with few exceptions fell within a range of two to three times the reserves estimated at the time. Using the historical estimates presented in this paper, this would be 300 to 1000 billion STB for crude oil and 1000 to 2500 trillion SCF of natural gas. At the present time (1/1/79) crude oil reserves are estimated at approximately 550 billion STB and cumulative crude oil production is approximately 400 billion STB. Hence, it appears that the 1955-65 crude oil ultimate resource estimates have been realized. For natural gas the reserves are estimated at approximately 2400 trillion SCF and the cumulative natural gas production is 970. It appears that these early estimates of ultimate natural gas resources have also been exceeded.

A noteable exception to these predictions was that of Lewis G. Weeks[12] in 1959. He predicted, Table 7, the ultimate crude oil resource by primary processes as 1900 billion STB and by secondary as 1500 billion STB for a total of 3400 billion STB. He also predicted the ultimate natural gas resources from petroleum reservoirs as 6000 trillion SCF. Excluding secondary crude oil recovery, Weeks' estimate for the ultimate crude oil resource is over seven times (1900/250) the estimated crude oil reserve in 1959 and over five times (1900/345) the estimated crude oil reserves plus the accumulative crude oil production. His estimate for ultimate natural gas resources was ten times (6000/620) the estimated natural gas reserves and

Table 7

ULTIMATE RESOURCE ESTIMATES

			Ultimate Resource Estimate			Reserve Estimate	
Reference	Area	Date of Estimate	Crude Oil Billion STB	Natural Gas Trillion SCF	Total Crude Oil Equivalent* Billion STB	Crude Oil Billion STB	Natural Gas Trillion SCF
Weeks (12)	World	1959	1900	6000	2900	250	620
North (9)	World	1974	1000	3000	1500	540	2064
Moody (10)	World	1975	2000	6000	3000	540	2102
Adams (1)	World	1975	2000	6000	3000	556	2102
Klemme (7)	World	1976	2000	6000	3000	545	2164
Various ( )	USA	1955-65	60-100			30	
Hubbert (6)	USA	1969	190			31	
AAPG (4)	USA	1971	256			39	
USGS (11)	USA	1972	568			38	
NPC (5)	USA	1972	228			38	
Whiting (3)	USA	1974	200			35	

* 6000 SCF - 1 STB

over seven times (6000/834) the estimated natural gas reserves plus the cumulative natural gas production.

In the late 1960's it became more evident that the U.S.A. crude reserves and production would peak in the 1970's. Hence, increasing attention was directed to evaluation of the ultimate crude oil resources in the U.S.A., although little interest was shown in natural gas resources. Numerous National studies were made and the results are shown in Table 7. With one exception, the ultimate crude oil resources were approximately six times the crude oil reserves existing at the time of the estimate. Later revisions in the one exception made it agree more closely with the other estimates.

With the Arab Embargo, the world became more conscious of petroleum supply and demand. As a consequence, numerous studies of petroleum reserves, production, recovery, ultimate resources, etc. were initiated. Many of the studies are still underway or their results have not been released. However, the results of world studies, known to the writer and made public, are summarized in Table 7. With one exception, the concensus is that the estimated ultimate crude oil resource is 2000 billion STB, the ultimate natural gas resource is 6000 trillion SCF and the total equivalent crude oil and natural gas is 3000 billion STB. The exception cites these estimates as 1000, 3000 and 1500, respectively. For those in general agreement, the ultimate resource estimates for crude oil and natural gas are approximately three times the estimated reserves of crude oil and natural gas, respectively, at the time of estimation. Combining the results of Table 7 with the crude oil and natural gas production data shown in Table 5 gives an ultimate total equivalent crude oil and natural gas estimate twice the total equivalent crude oil and natural gas reserves plus crude oil and natural gas productions at the time of estimation. This implies that additional crude oil and natural gas equal to that already discovered will be found.

It should be noted, to the writer's knowledge, none of these estimates for crude oil consider secondary or tertiary recovery processes. Table 6 shows the crude oil discovered (1/1/78) as 3229 billion STB. However, the ultimate recovery by combined primary and secondary processes is estimated to be only 1114 billion STB corresponding to a recovery of 34.5% of the original oil in place. Enhanced oil recovery is estimated as only 202 billion STB, or 6.3% of the original oil in place. This latter estimate is limited primarily by economics, and under favorable conditions could be 500 billion STB. However, favorable economics may be deterred because of the price of alternative energy resources. It is interesting to note that Weeks in 1959 predicted that the ultimate crude oil resource by secondary recovery would be 1500 billion STB. Table 6 predicts only 150 billion STB. There are two explanations for this low estimate. One is economics and the other is that in many of the large oil fields of the world, little or no attention has been directed to secondary recovery because the business of crude oil production is preeminent. The fact that the estimate of crude oil reserves of the world have remained approximately constant for the past ten years should be a warning that we may be approaching peak reserves. It is already late to plan pilot projects and/or initiate secondary recovery operations in many of the world's great oil fields. Ultimate crude oil and natural gas recovery has already been reduced by delay in application of these processes. I suspect that North's estimates were influenced by the trend in the crude oil reserve estimates. Hence, the concensus ultimate crude oil resource estimate must be viewed with concern. However, the concensus ultimate natural gas resource estimate appears to be easily realizeable if economics of alternative energy resources permit.

SUMMARY AND CONCLUSIONS

There is evidence that there is sufficient crude oil and natural gas in the Earth's crust, and drilling and production technology is adequate to achieve the ultimate crude oil and natural gas estimates made in the past - particularly those made during the past decade.

Economics of competing alternative energy resources, environment considerations and politics are considered to be the principal deterrents to achieving the estimated ultimate resources.

Reserve estimates are dependent upon field and laboratory data, type of natural reservoir energy drive, production practices, technology, economics and politics. As a consequence, reserve estimations for all types of petroleum reservoirs are periodically revised.

There is evidence that the reserves of recently (1965-75) discovered large crude oil and natural gas fields have been overestimated. Adjustment of these reserves has been occurring and this may account - at least in part - for the constancy of world crude oil reserve estimates during the past ten years.

The future ultimate resources of crude oil and natural gas are largely dependent upon discoveries and development in the unexplored offshore basins, West Siberia and the Mideast. Overestimation of the resources of these regions could seriously impair achievement of the estimated ultimate resources.

The consensus world ultimate crude oil resource estimate is 2000 billion STB, corresponding to approximately four times the present crude oil reserves and twice the present crude oil reserves plus cumulative natural gas production.

The consensus world ultimate natural gas resource estimate is 6000 trillion SCF, corresponding to approximately three times the present natural gas reserves and twice the present natural gas reserves plus cumulative natural gas production.

The consensus world ultimate total equivalent crude oil and natural gas estimate is 3000 billion STB, corresponding to twice the equivalent crude oil and natural gas reserves plus the equivalent cumulative crude oil and natural gas productions. Simply stated, it is predicted that a quantity of crude oil and natural gas equal to that already discovered will be found in the future.

REFERENCES

1. Adams, R. D. and M. A. Kirkby, Estimate of World Gas Reserves, Panel Disc. 6, Paper 1, Preprint of the proceedings of the 9th World Petroleum Congress, Tokyo, Japan, 1975.

2. Arps, J. J. Estimating Oil Reserves, Jour. Pet. Tech., July 1954, pg. 55.

3. Berg, R. R., Calhoun, J. C., Jr., Whiting R. L., Prognosis for Expanded U.S. Production of Crude Oil, Science, V. 184, pg. 331, April 1974.

4. Cram, I. H. Future Petroleum Provinces of the United States, Assn. Petrol. Geol., Mem. 15, V. 1, p. 1, Tulsa, Okla., 1971.

5. Elkins, Lloyd E., U.S. Energy Outlook, Natl. Pet. Council, Washington D.C., Dec. 1972.

6. Hubbert, M. K., Degree of Advancement of Petroleum Exploration in the United States, Am. Assn. Petrol. Geol. Bull. 51, pg 2207, 1967.

7. Klemme, H. D., World Oil and Gas Reserves from Analysis of Giant Fields and Petroleum Basins (Provinces), The Future Supply of Nature-Made Petroleum and Gas, pg. 217, Laxenburg, Austria, 1976.

8. Klemme, H. D., One Fifth of Reserves Lie Offshore, Oil and Gas Jour., V. 75, No. 34, pg 108, 1977.

9. Mackay, I. H. and F. K. North, Undiscovered Oil Reserves, in AAPG Res. Symposium, Aug 21-23, 1974, Dept. of Applied Sciences, Stanford University, Stanford, California, 1974.

10. Moody, J. D., An Estimate of the World's Recoverable Crude Oil Resources, Panel Disc. 6, Paper 2, Preprint of the proceedings of the 9th World Petroleum Congress, Tokyo, Japan, 1975.

11. Theobald, P. K., Schweingurth, S. P. and Duncan, D. C., U.S. Petroleum Potential, U.S. Geol. Sur. Circ. No. 650, July 1972.

12. Weeks, L. W., Where Will Energy Come From in 2059?, Pet. Eng. V. 31, No. 9, pps. A24-31, 1959.

ASSESSMENTS OF WORLD NATURAL GAS RESOURCES

Robert B. Kalisch
American Gas Association, Arlington, Virginia, USA

The remainder of this century could be the beginning of the transition from conventional oil and gas resources to alternate energy sources. Certainly at some future date, the world must depend more on renewable and currently sub-economic oil and gas resources. Throughout the world, long range planners are attempting to estimate how rapidly this transition can occur. The key element of knowledge in trying to make this estimate is an accurate, consistent evaluation of the world's conventional oil and gas resources.

This paper will consider only the problems of estimating world natural gas resources. Further, the perspective is that of the user of such evaluations. The geologic and engineering problems involved in producing useful estimates are so formidable that it may be productive to specify the non-geologic requirements for these estimates. In this way the geologic and engineering questions can be defined with a more precise understanding of need.

Users of world resource estimates often experience the frustration of incompatible definitions. One of the most difficult aspects of the definitional problems is that in the assessment of recoverable volumes of natural gas some essential definitions are frequently omitted.

Economics, Technology and National Policy

Estimates of recoverable volumes of natural gas require some definition of the economic value of natural gas. Recoverability implies a cost restraint - at some price the gas can be recovered, at a lower price it can not be recovered. A resource estimate, however, implies that some of the gas might not be developed for ten, twenty or fifty years. This long period over which the economic restraint must be applied makes the economic resource evaluation particularly difficult. Some quantitative wellhead price data from the U.S. are shown in Figure 1 to illustrate this point. Clearly, a resource evaluation made in the 1960 time period could not reflect the vastly improved wellhead price incentives of the late 1970's.

A separate aspect of the economic problem is the level of technology which is used for determining recoverability.

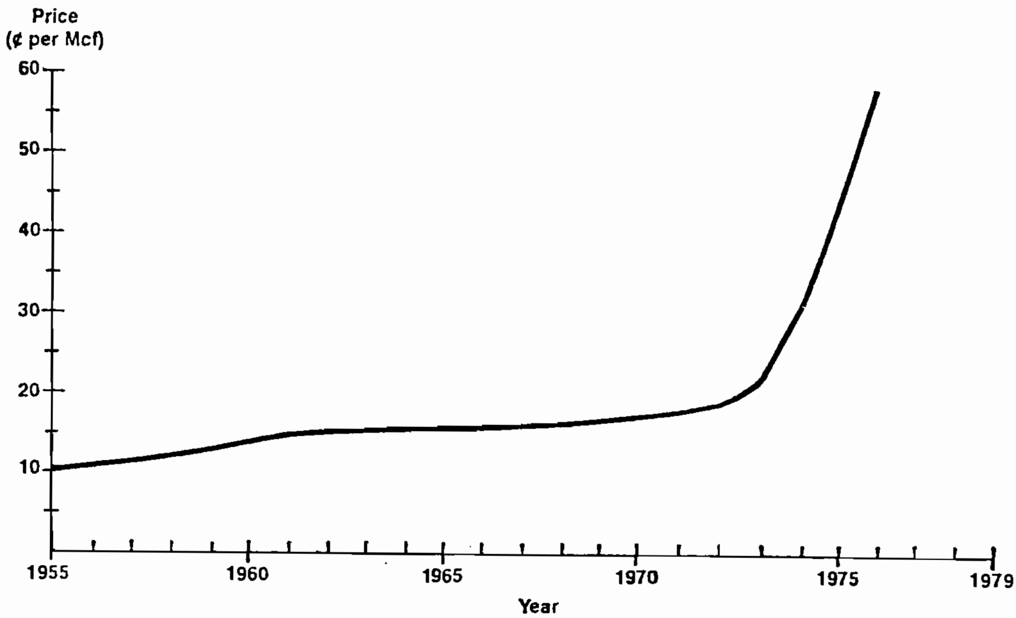


FIGURE 1 Average Wellhead price.

Technology and economics are usually viewed as different issues. However, trade-offs exist between technology and economics. At a high future level of technology the resource may be producible at low cost. At current levels of technology the cost of production may be excessively high. The estimator then faces the problem that he is asked to judge not only difficult economic issues which vary with time but also the interaction of technology and economics while the technology is changing with time.

In nations with centrally planned economies the consideration of the economics of gas recovery is even more difficult. Typically, there is no overt economic judgement on a well by well basis. The economic evaluation of how much drilling should occur and what regions are to be explored are decisions made without regard to the economic viability of individual wells.

Even in a competitive economy national policy considerations can distort the economic considerations. Wellhead pricing, taxation policies, market controls and environmental restrictions are just a few of the areas in which national policy goals can accelerate or inhibit resource development.

Economics, technology and national policies are interacting variables which are themselves constantly changing with time. Collectively, they cause major uncertainties in the assessment of the recoverability of gas in a field. Because of the difficulty in stating the assumptions regarding these variables and projecting these assumptions and their interactions over the time in which the resource will be developed, the resource assessment is usually not definitive in this regard.

Market Conditions

A related, but distinct, part of the resource evaluation is the market conditions which are assumed over the period necessary to develop the resource. In the U.S. the future gas supply and the resource development which can be anticipated are greatly influenced by market conditions. The availability of other fuels, the price competitiveness of alternate energy sources and the willingness of the end users to buy natural gas are factors which guide producers in determining if they should invest capital in natural gas projects. Interestingly, the popular view of the availability of natural gas is itself a major factor in determining how much gas is developed.

Market conditions are affected by national policy also. For example, U.S. legislative and regulatory bodies have been attempting to implement "incremental pricing". The intent of incremental pricing has been to allow residential and commercial gas users to purchase less expensive "old gas" and to force certain industrial customers to pay the additional costs of the "newer" more recently developed gas. This was to be implemented by an extraordinarily complicated set of regulatory rules which would have had a dramatic effect on every interstate pipeline and many distribution companies. As a result of action by the House of Representatives in May, incremental pricing has been restricted to large boiler customers only. Other industrial customers are not subject to federal incremental pricing rules. Nevertheless, if this concept is applied more broadly at some future date, it will serve to destablize the natural gas markets. This in turn will distort the exploration and production activities just as wellhead price regulation did and render a portion of the national resource of natural gas unmarketable.

Geologic Considerations

Just as it is important to define and specify those factors described above which strongly influence the resource assessment, the primary geologic evidence must also be specified to maximize the utility of the estimate. Existing estimates usually describe the broad methodological approach. However, in the past there has not been either a periodic updating of such assessments or, as an alternative, sufficient sensitivity studies so that the assessment can be interpreted in light of subsequent discoveries and experience.

In addition to the ability to adjust estimates to allow for more recent data, there is a need to be able to compare resource evaluations applicable to different parts of the world. For example, to be useful in world resource planning an evaluation of natural gas in China must be comparable to other regional estimates. This is, of course, most difficult in regions where the exploration and drilling have been minimal. Yet, geologic methodology should reflect both the possible size of the resource and the degree of geologic uncertainty. The Potential Gas Committee approaches the task as shown in Figure 2 with four categories of recoverable gas, i.e., proved reserves and probable, possible and speculative potential resources. A quantitative estimate is made for each category. This technique gives the user

ULTIMATELY DISCOVERABLE VOLUME				
DISCOVERED		UNDISCOVERED		
CUMULATIVE PRODUCTION	PROVED RESERVES	POTENTIAL SUPPLY		
		PROBABLE	POSSIBLF	SPECULATIVE

Figure 2—Categories of past, present and future natural gas supplies.

an insight into the nature of the resource as well as its size.

Specification Needs

The foregoing might be interpreted as a desire to cast the geologist making world gas evaluations into the analysis of economic, political, technological and market conditions. Even worse, the geologist might be called upon to project future trends in these various disciplines in such a way as to provide a basis for an estimate of recoverable natural gas. Such ideas are clearly not practical. However, for reasons cited earlier a carefully detailed description of the assumptions made by the estimators would allow different estimates to be compared and to used effectively.

Two examples might clarify this point of view. Many world estimates are based on the analogy of one basin to another. Because of the maturity of U.S. basins the analog basin is often in the U.S. Recoverable gas volumes are related to the recoverable gas estimate for some major U.S. gas field. The analog estimate has quantitative significance only if the assumptions regarding the recoverable gas estimate for the model are known. Estimates of recoverable gas volumes from many U.S. fields have increased significantly with the changing economic and marketing conditions of the past ten years. For example, the Hugoton field of the mid-continent area has been increasing in the estimated ultimately recoverable gas volumes. Prior to 1970 the Hugoton field was assessed to have an ultimate recoverable volume of natural gas of 22.0 trillion cubic feet. By 1979 this volume has increased to 26.5 trillion cubic feet. Although greater understanding of the geology and more production data were important factors in this newer assessment, a major factor was that the economically determined abandonment pressure for the field changed. Similar situations exist in many of the older and larger gas fields in the U.S.

An assessment of the natural gas resources of the USSR is greatly affected by the evaluation of the recoverable gas volumes in the large Arctic fields east of the Ural Mountains. Such estimates are greatly influenced by economic, technological and policy decisions made, not on the basis of competitive commercial economics, but as an element of long range Soviet national planning. The decisions as to when these fields will be developed are but one part in the implementation of their overall national plan of action. As such, these estimates are very different in character from the assessment of natural gas fields in the U.S., Middle East, Africa, or the Far East. Again no detailed analysis is needed to justify the geologists' views. Rather, the assumptions that were made to derive these volumes just need to be stated. The user of the estimate is then in a position to adjust the estimate, as required, to integrate this evaluation with the resource evaluation from other parts of the world.

Current Resource Assessments

Some of the most frequently referenced world natural gas assessments are listed in Table 1. The comparability of these estimates on the basis of the factors cited above is seriously in doubt. In fact because of the time span over which these estimates were made and the probable inconsistencies in assumptions regarding these factors, it is surprising that the estimates are as close as they are numerically.

In the 1977 paper titled "The Future For World Natural Gas Supply"[1] an average of these estimates was made which was weighted in favor of some of the more recent assessments. The resultant estimate of world recoverable natural gas was taken to be 9,650 trillion cubic feet or 10,500 exajoules. Even with the more recent estimates having a greater weight in the averaging, it still appears that the estimates place insufficient emphasis on the rapidly increasing incentives for developing natural gas resources.

Figure 3 illustrates one dimension of the improved incentives for developing gas resources. It is a plot of the ratio of gas to oil prices in the U.S. with both prices expressed in dollars per million Btu. It is evident that there has been a shift favoring gas exploration since the mid-1960's and although the Arab oil embargo reversed the trend briefly the steady trend favoring gas resumed in

---

[1]McCormick, W.T.; Fish, L.W.; Kalisch, R.B.; Wander, T.J.; The Future For World Natural Gas Supply, Arlington, VA; American Gas Association, 1977.

TABLE 1. Remaining recoverable world gas resources.

Source	Year of Estimate	Resources Remaining Year-End 1975 (Exajoules)
Hendricks (U.S.G.S.)[2]	1965	9470
Ryman (ESSO)[3]	1967	12137
Shell[4]	1967	10221
Coppack (Shell)[5]	1973	7249
Hubbert (U.S.G.S.)[6]	1974	13003
Mobil[7,8]	1975	7641-8599
Adams & Kirby[9]	1975	5606
National Academy of Sciences[7]	1975	7511
I.G.T.[10]	1977	9960-10395

[2] Hendricks, T.A. (1965) Resources of Oil, Gas, and Natural Gas Liquids in the United States and the World. Geological Survey Circular 522, (Washington, DC: USGS).

[3] Ryman (ESSO) (1967), cited in Adams and Kirby.

[4] Royal Dutch/Shell Group (1967) Energy Patterns of the Future.

[5] Coppack, C.P. (1974) Natural gas. Phil. Trans. R. Soc. London, pp.463-83.

[6] Hubbert, M.K. (1974) U.S. Energy Resources: A Review as of 1972, Part I, in US Congress Senate Committee on Interior and Insular Affairs, A National Fuels and Energy Policy Study. Committee Print, Serial No. 93-40.

[7] National Research Council (1974) Mineral Resources and the Environment (Washington, DC: National Academy of Sciences).

[8] Moody, J.D. and Geiger, R.E. (1975) Petroleum resources: How much oil and where? Technology Review March/April, pp.39-45.

[9] Adams, T.D. and Kirby, M.A. (1974) Estimate of World Gas Reserves, Proceedings of the 9th World Petroleum Conference, Tokyo, 1974.

[10] Parent, J.D. and Linden, H.R. (1977) A Survey of United States and Total World Production Proved Reserves and Remaining Recoverable Resources of Fossil Fuels and Uranium as of December 21, 1975 (Chicago: Institute of Gas Technology).

1975. Figure 4 also depicts the competition between oil and gas objectives as seen by the driller. More oil wells are completed each year than gas wells although the gas to oil ratio for well completions in approaching unity-equal

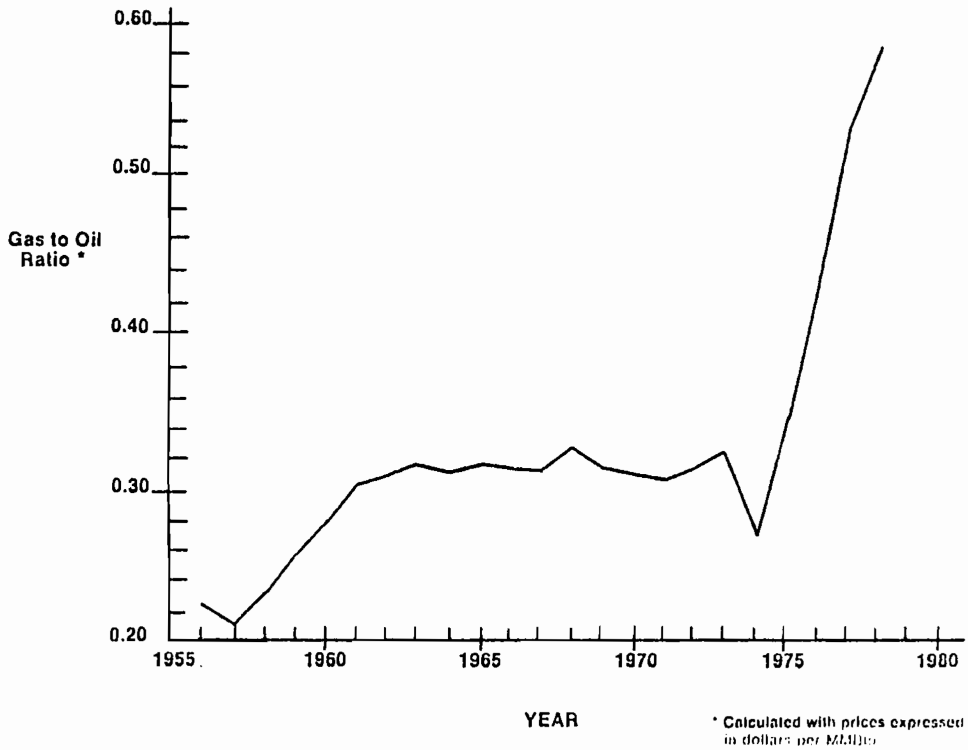


Figure 3. Wellhead prices - Gas to oil ratio, 1956-78.

numbers of oil and gas wells being completed in a given year. In contrast productive wildcats completed have clearly favored gas wells over oil wells.

Conclusion

Current gas resource assessments are needed throughout the world as an aid to energy planning. Increasing demand for oil and gas coupled with rapidly rising prices have created a difficult environment in which such estimates must be made. Variables such as economics, technology, national policy and market conditions can quickly make a valid geological assessment obsolete. More specific descriptions of the assumptions and greater attention to

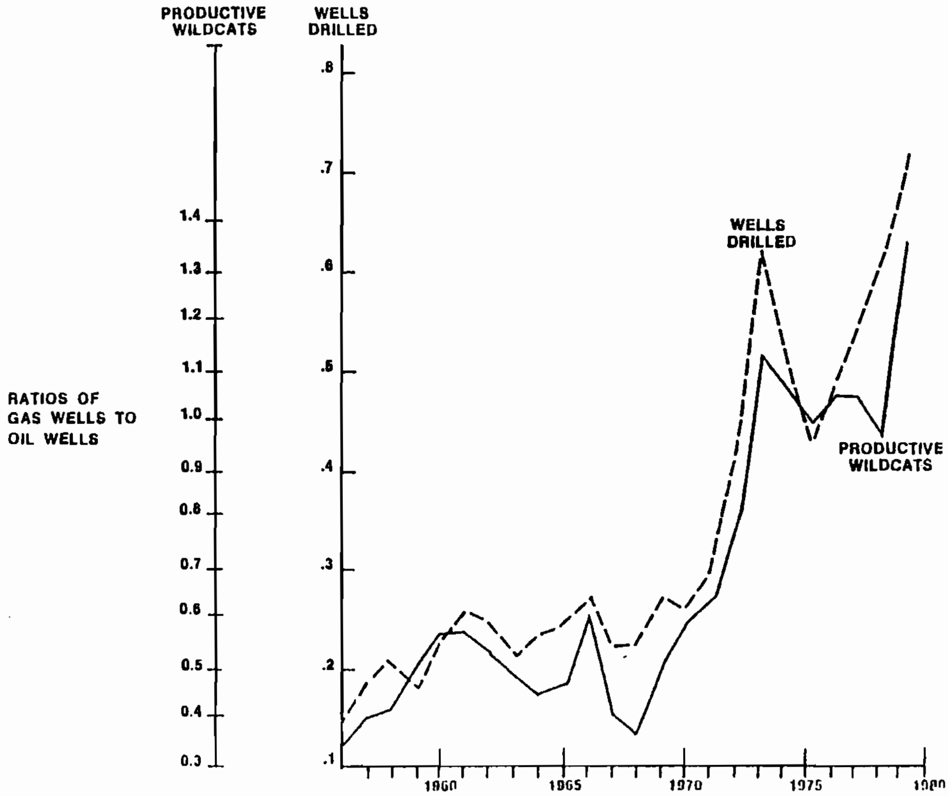


Figure 4. Gas to oil ratios - Wells drilled and productive wildcats.

sensitivity analyses can reduce the impact of changing world conditions. Periodic updating of such assessments made on a comparable basis with a common set of defintions will do much to aid the energy planner.

WORLD RESOURCES OF CONVENTIONAL GAS

M.S. Modelevsky
Academy of Sciences of the USSR, Moscow, USSR

Gas is, at present, one of the main sources of energy. Its share in the world energy balance has doubled during the period 1950-1978 and is now about 20%. Gas demand is steadily growing and there is a need to estimate the extent to which this demand can be met by natural gas resources. These estimates vary from 87 to 580 MB m^3 (Table 1) for the period 1967-1972. So wide a rate of estimates is a proof of the great differences in objectives and methods of estimation. It should be noted that estimates from the major oil companies are, as a rule, lower than those from governmental and scientific sources or from independent specialists.

The energy crisis of 1973-1974 was followed by a sharp decrease in the estimates of world gas resources. It is significant that these decreased estimates were reported by the large oil companies at the 9th World Petroleum Congress in Tokyo and at the 1st IIASA Conference on Energy Resources in 1975. The decrease in gas resource estimates was obviously dictated by prevailing circumstances. A year later, at the 2nd IIASA Conference on Energy Resources, higher estimates of gas resources were given (180 MB m^3 for conventional gas fields only) (Whiting, 1977). At the 10th World Petroleum Congress in Bucharest, Meyerhoff (1977) also gave a significantly higher estimate of these resources. An estimate of the amount and distribution of conventional gas resources on a single and sound methodological basis is necessary to obtain objective information.

In the USSR, a number of methods for estimating gas resources have been developed. The principle of geological analogy is used in most cases. This consists of studying the structure and constants of field distribution, and the concentrations of gas-in-place reserves in well-known (training) areas. The connections between these constants and gas reserves are then deduced and the results so obtained are extended to lesser-known (target) areas which are geologically similar to the training areas. In some cases, when a great volume of geo-chemical information is obtained, it is possible to calculate directly the amount of gaseous hydrocarbons which formed in the source rocks, emigrated from them and accumulated in reservoir rocks (Buyalov et al, 1962; Bakirov and Ovanesov, 1971; Buyalov and Nalivkin, 1979; Modelevsky, 1979). These methods are well known. They were partially reported at the 2nd IIASA Conference on Energy Resources in 1976 (Semenovich et al., 1977).

It is more difficult to estimate resources of those regions and basins which have not been studied enough to enable the principle of comparison of training and target areas to be used successfully. Under these circumstances it is reasonable to make more generalized estimates for the whole sedimentary cover of the basin or of a large part of its area.

Table 1. World gas resource estimates (with the exception of deep-water resources)

Year	Source	Estimate (MB m^3)
1956	US Department of the Interior	140
1958	Weeks (Jersey University, USA)	140–170
1959	Weeks	170
1965	Weeks	200
1965	Hendriks (US Geological Survey)	430
1967	Riman (Esso)	340
1967	Shell	290
1967	Ion (Great Britain)	580
1968	Weeks (Weeks et al.)	200
1969	Hubbert (US Geological Survey)	226–340
1971	Weeks	200
1973	Koppak (Shell)	210
1973	Hubbert	340
1973	Linden (IGT, Chicago)	310
1975	Adams and Kirkby (1975)	170
1975	Sickler (1976)	87[a]
1976	Modelevsky (1976)	280[a]
1977	McCormick et al. (1976)	290
1979	Meyerhoff (1979)	197
1979	Modelevsky (1979)	255[a]

[a]Excluding the socialist countries.

Analysis of 85 well-known petroleum-bearing basins was carried out by the author. A statistical relationship was deduced between the volume of sedimentary cover in the basin and the gas-in-place resources (Figure 1). There are three groups of basin, differing in the rate of gas resource concentration per unit of sedimentary filling volume: those with a high, middle, or low value of this ratio.

The first group includes basins in which the specific values of gas resource concentration are the highest known. These are such predominantly gas-bearing basins as the north-central European, the Dnieper-Donets, the Lena-Viluj, the Gulf of Bengal, the Azov-Kuban, and the Santa Barbara-Ventura. Middle ("normal") gas resource concentration is characteristic of such basins as the Los Angeles, the north Sahara, the west Siberian, the Timan-Pechora, the Persian Gulf, and the Gulf Coast. Low gas resource concentration is characteristic of predominantly oil-bearing basins, for example, the Rhine and the Sumatra basins. It should be stressed that the overwhelming majority of the basins considered (67%) are "normal". About 26% of all basins are

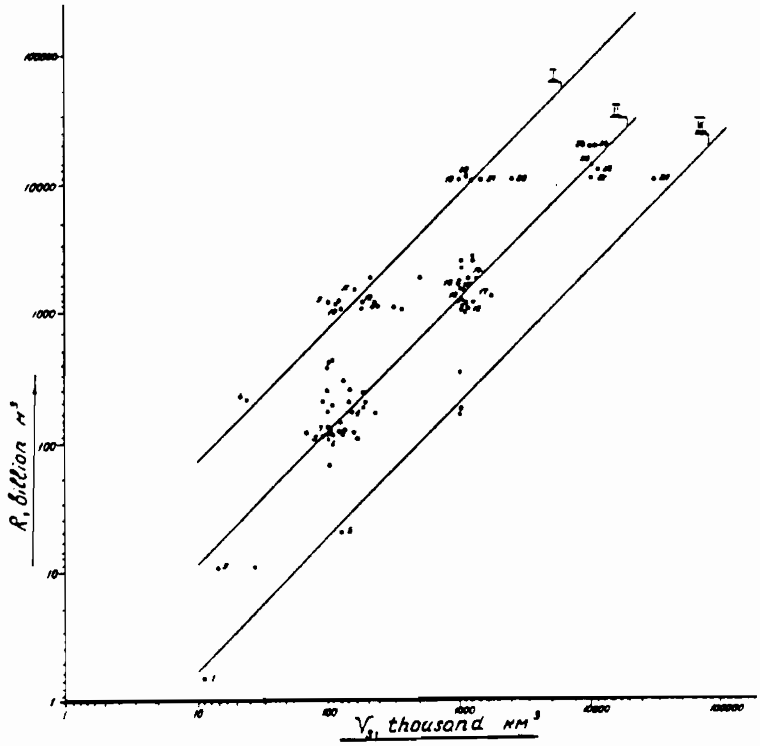


Figure 1. Statistical relationship between the volumes of basin sedimentary filling and gas-in-place ultimate resources. I - Predominantly gas-bearing basins, II - middle ("normal") basins, III - predominantly oil-bearing basins. The individual basins are (1) Rhine, (2) Vienna, (3) South Sumatra, (4) Los Angeles, (5) Fergana, (6) Big Horn, (7) Gulf of Suez, (8) Illinois, (9) Santa Barbara-Ventura, (10) Great Valley, (11) Dnieper-Donets, (12) Azov-Kuban, (13) Adriatic, (14) west Canada, (15) Saravack, (16) Permian (USA), (17) Timan-Pechora, (18) south Caspian, (19) north-central European (20) east-Australian interior, (21) Gulf of Guinea, (22) Lena-Viluj, (23) west Siberian, (24) Persian Gulf, (25) Gulf Coast, (26) Karacum, and (27) north Sahara. The gas resources of the USSR include free and gas-cap gas only.

highly gas-saturated and 7% are gas-saturated to a small extent. The specific gas resource concentration does not depend on the size of a basin. Small basins such as the Fergana, the Vienna, and the Big Horn, and large basins such as the west Siberian and the Persian Gulf are also characterized by middle gas saturation. Low gas saturation is characteristic of the Rhine basin, the volume of sedimentary filling of which only slightly exceeds 10 M km^3, and the Sumatra basin, the volume of whose sedimentary cover is 100 times as great. The minimum volume of a basin must be larger than 10 M km^3 before it is viable commercially. In the overwhelming majority of the basins, as shown in Figure 1, sedimentary cover exceeds 100 M km^3.

These ratios and more detailed estimates about the well-known basins made it possible for the author and his assistants to work out the gas resource estimates of all the sedimentary basins of the world, excluding those of the USSR (Petroleum resources, 1974, 1977; Modelevsky, 1976, 1979). Gas resource estimates of the USSR basins were published later (Vasilyev and Zabrev, 1975). Recoverable gas resources of the other European socialist countries have been estimated as 1.6 MB m^3 (Meyerhoff, 1979).

The total amount of gas, including past production, in all sedimentary basins of the world (with the exception of dissolved gas in the oil fields of the USSR) is estimated as 680 MB m^3. However, only part of this gas can be detected and extracted from the earth by existing techniques. This fraction of the total gas-in-place resources is termed economically recoverable resources (ERR). According to the rate of activity, i.e. ability for development, it is reasonable to divide these resources into three groups: active resources, the development of which is profitable under present technical and economic conditions, form the main basis for forecasting gas production over the next 15-20 years; subactive resources, the development of which is uneconomic under current conditions but could become economic as a result of a price increase to not less than 1.5 times the price level at the date of estimation (in real terms, excluding inflation); passive resources, the rest of the ERR, the development of which would become economic only in the case of a sharp price increase or under uncertain conditions in the distant future.

Passive resources include the gas resources of the polar shelves, the deep waters of oceans, the Antarctic, and at depths below 10 km in onshore areas. Passive resources also include those in underdeveloped areas, where their utilization is noneconomic because of a lack of consumers and the impossibility of long-distance gas transportation. As is well known, construction of large gas pipelines and gas liquefaction and processing plants is very expensive and time-consuming. If such facilities are not at present being built in the regions considered, it is not difficult to predict that these gas resources will have little or no effect on world gas consumption during the next 15-20 years. Therefore, the gas resources of most of the interior basins of continents distant from the industrial centers of the most developed countries are not included in the active resources of ERR because development would require too great a capital investment and technical expertise. However, even in those developing countries where gas is now being produced, a considerable part of the resources cannot be considered because of the absence of sufficient consumers and the difficulty or impossibility of exporting gas in large amounts. In the developing countries, most of the associated gas extracted with oil is flared, and the majority of known gas fields are not being exploited. In the mid-East, for example, 160 B m^3 of associated gas is flared annually and a number of giant gas fields are not yet being developed. Even in such countries as Iran, Iraq, Kuwait and Saudi Arabia, consideration of the gas resources as active is subject to many reservations. Not more than 20-30% of the ERR of gas can be regarded as active in developing countries where marketable production is very small and meets only home requirements. In the USSR, active resources include discovered reserves and undiscovered resources of the D_1 subgroup to a maximum depth of 5 km, which account for 64% of all USSR gas resources (with the exception of dissolved gas).

A summary of the active gas resources of the world and their geographical distribution is given in Table 2. These resources account for 215 MB m^3. Adding subactive resources to this amount, the total value of the economically recoverable resources at present and in the relatively near future accounts for approximately 250 MB m^3. About 185 MB m^3 of total active gas resources are concentrated in onshore areas and only 30 MB m^3 offshore. The gas potential of the onshore areas, subactive resources included, has now increased

Table 2. Active world gas resources in 1979 (Vasilyev and Zabrev, 1975; Meyerhoff, 1979; Modelevsky, 1979) in million billion m^3

Regions and countries	Resources		Cumulative production	Reserves	Estimated undiscovered resources
	Ultimate	Current			
North America	49.2	30.6	18.6	7.4	23.2
USA	42.2	25.0	17.2	5.7	19.3
Latin America	13.0	10.8	2.2	4.0	6.8
Venezuela	2.9	1.8	1.1	1.2	0.6
Mexico	4.3	3.9	0.4	1.7	2.2
Western Europe	13.8	12.1	1.7	3.4	8.7
Gt. Britain	3.4	3.1	0.3	0.7	2.4
Netherlands	4.1	3.4	0.7	1.6	1.8
Norway	1.7	1.7	0.02	0.5	1.2
Africa	13.2	12.5	0.7	5.3	7.2
Algeria	7.5	7.3	0.2	3.0	4.3
Asia	43.9	40.1	3.8	23.2	16.9
Indonesia	1.6	1.5	0.1	0.7	0.8
Iran	19.5	18.9	0.6	14.2	4.7
Saudi Arabia	5.3	4.8	0.5	1.9	2.9
Australia and Oceania	2.6	2.5	0.05	0.6	1.9
USSR[a]	77.4	75.6	1.8	22.6	53.0
Other European socialist countries[b]	2.2	1.6	0.6	0.8	0.8
Total	215.3	185.8	29.5	67.3	118.5

[a]In 1974, without dissolved gas.
[b]In 1978.

to 200 MB m^3 and that offshore to 50 MB m^3. About one-third of all gas resources are in the USSR.

At the beginning of 1979 about 97 MB m^3 of gas had been discovered including 67 MB m^3 of proven reserves and about 30 MB m^3 of past production. Thus, about 45% of the active gas resources of the world have been discovered during the first hundred years of the gas industry. The depletion of these resources accounts for 14%. The resources of the onshore areas of the old gas-producing countries in North America and Western Europe have been extracted to a very high degree (55–65%) but those offshore to a considerably lesser degree (18–20%). The gas resources of the mid-East are well investigated – more than 60% of these resources have been converted to proven reserves. In spite of this, however, the gas resources of this region are developed to a very small degree; there is a great potential for growth. The rates of discovery and depletion are very low in many regions of the world. In the USSR the prospects for increased gas production are very great: only 31% of active gas resources have been discovered and a mere 2% depleted.

World gas production in 1978 reached 1.4 MB m^3, a figure which includes 0.3 MB m^3 of gas losses. If marketable gas production increases to 2-2.5 MB m^3 per year and gas losses decrease by a factor of 2000, 75-85 MB m^3 of gas will be produced during a period of 22 years all over the world, i.e., 2.5-3 times as much as has been produced during the previous history of the gas industry. Even in such a case, only half of all the active gas resources would have been depleted. This means that the growth of world gas production is limited by technical and economic rather than geological factors, mainly by the difficulties of transporting the gas over long distances from the areas of production to the consuming centers. At present the possibilities of overcoming these problems are very limited. Combined efforts between countries and general international cooperation will be necessary before the problems of gas transportation can be resolved.

REFERENCES

Adams, T.D., and M.A. Kirkby (1975). Estimate of world gas reserves. 9th World Petroleum Congress. Proc., Vol. 3, London.

Bakirov, A.A., and G.P. Ovanesov (1971). On scientific principles of estimation of undiscovered oil and gas resources. 8th World Petroleum Congress, Moscow.

Buyalov, N.I. et al. (1962). Methods of Estimating Undiscovered Oil and Gas Reserves. Gostoptechizdat, Moscow.

Buyalov, N.I., and V.D. Nalivkin (Editors) (1979). Methods of Petroleum Potential Estimating. Nedra, Moscow.

McCormick, W.T. et al. (1977). The future for world natural gas supply. Executive summary. 10th World Energy Conference, Istanbul.

Meyerhoff, A. (1979). Proved and ultimate reserves of natural gas and natural gas liquids in the world. 10th World Petroleum Congress, PD 12, Bucharest.

Modelevsky, M.S. (1976). Oil and gas resources of foreign countries. Geologia nefti i gaza, 8.

Modelevsky, M.S. (1979). Oil and Gas Resources and Methods of their Estimation, Vol. 4. VINITI, itogi nauki i techniki, Moscow.

Petroleum resources of capitalist and developing countries: Vol. 1 (1974), Vol. 2 (1977). Nedra, Leningrad.

Semenovich, V.V. et al. (1977). Methods used in the USSR for estimating potential petroleum resources. In: The Future Supply of Nature-made Petroleum and Gas. UNITAR-Pergamon Press, New York.

Sickler, R.A. (1976). World petroleum resources, part 2: a survey of petroleum resources in the world outside centrally planned economies. In: First IIASA Conference on Energy Resources, Laxenburg, Austria.

Vasilyev, V.G., and I.P. Zabrev (Editors) (1975). Gas and Gas-condensate Fields. Nedra, Moscow.

Whiting, R.L. (1977). Gas from conventional gas fields. In: The Future Supply of Nature-made Petroleum and Gas. UNITAR-Pergamon Press, New York.

NATURAL GAS RESOURCE POTENTIAL OF THE UNITED STATES

Harry C. Kent
Potential Gas Agency, Colorado School of Mines, Golden, Colorado, USA

Over the past two decades the question of the quantity of natural gas resources which will be available to meet the future gas-energy needs of the United States has become of great concern. An accurate understanding of the amount and nature of natural gas resources is considered essential for long-range industrial and governmental planning. Prior to the 1960s, estimates of gas resources varied widely and were often made as a percentage of oil resources rather than considering gas as an independent commodity. Since the 1960s, estimates have been made using more rigorous procedures and based on greater knowledge of the resource.

The analysis of U.S. natural gas potential presented in this paper is based largely on the work of the Potential Gas Committee (Potential Gas Committee, 1979). Additionally, some comparisons will be made with the estimates of various companies, the U.S. Geological Survey and individuals.

Currently (1979) the United States is producing and consuming between 19 and 20 trillion cubic feet (Tcf) (between 0.54 and 0.57 trillion m^3) of natural gas per year. About 5 percent of the consumption is supplied by imports. The level of production and consumption has been essentially steady since 1975 but there was a slight rise (to 19.9 Tcf) in 1979. Prior to 1975, production was about 16 Tcf (0.45 trillion m^3) in 1965 and rose to a high of almost 23 Tcf (0.65 trillion m^3) in 1970. Production gradually declined from 1970 to 1975. It must be noted, however, that the production level of the 1970s was maintained at the expense of decreased proved reserves. The reserves-to-production ratio dropped from about 20 in the early 1960s to slightly more than 10 in the mid and late 1970s.

This paper will address the size of the potential U.S. natural gas resource base, the geographic and depth distribution of the resources, and the impact of this resource in meeting future energy needs.

It is first important to establish some basic terminology relating to gas resources. Figure 1 shows the classification of gas resources used by the Potential Gas Committee. The classification is based on the concept of an ultimately recoverable volume of natural gas existing within the crust of the earth and susceptible to exploration and development by conventional means. Further, some of that ultimately recoverable gas can be considered as already discovered while other quantities are, as yet, undiscovered. Discovered gas consists largely of that which has been produced in past years, plus the quantity which has been proved by drilling and engineering tests, and is included in the present proved reserves. The remaining resource consists of the potential which is susceptible to discovery and production through further exploration and development.

ULTIMATELY DISCOVERABLE VOLUME				
DISCOVERED		UNDISCOVERED		
CUMULATIVE PRODUCTION	PROVED RESERVES	POTENTIAL SUPPLY		
		PROBABLE	POSSIBLE	SPECULATIVE

Figure 1. Classification of natural gas resources used by Potential Gas Committee.

To some extent the potential resource bridges the boundary between discovered and undiscovered resources. This is because there are, associated with certain fields already drilled and discovered, quantities of gas, in addition to proved reserves, which will become proved through further development drilling and through deeper and shallower new pool discoveries. This gas is included in the Probable category; there is a rather high degree of geologic and engineering knowledge about its existence, and the estimates of this quantity are fairly well assured. In decreasing order of geologic knowledge, there are Possible and Speculative resources. Possible resources are related to further developments in provinces and formations which are already known to be productive, while Speculative resources include the gas which is believed to exist in frontier provinces in formations or at depths where no production is presently known.

Figure 2 is a comparison of the natural gas resource classification used by the U.S. Geological Survey in Circular 725 (Miller and others, 1975) with the Potential Gas Committee classification. For natural gas, the USGS category Inferred Reserves is essentially equivalent to the PGC Probable resources; the USGS category Undiscovered Recoverable Resources is essentially equivalent to the combined Possible and Speculative resources of the PGC. Other classifications are similar. For instance, Petroconsultants, Ltd., in its reports on natural gas worldwide (Petroconsultants, Ltd., 1979), uses the terms Expanded Reserves to refer to what is essentially the equivalent of the combined Proved Reserves and Probable resources of the PGC, and Resources in Undrilled Traps to refer to essentially the equivalent of the combined Possible and Speculative resources. Thus, although resource terminology varies, it is often possible to compare resource estimates prepared by different workers as will be done later in this paper.

UNITED STATES GEOLOGICAL SURVEY RESOURCE APPRAISAL GROUP CIRCULAR 725	INFERRED RESERVES	UNDISCOVERED RECOVERABLE RESOURCES	
POTENTIAL GAS COMMITTEE	PROBABLE	POSSIBLE	SPECULATIVE

Figure 2. Comparison of natural gas resource classification used by U.S. Geological Survey in Circular 725 with Potential Gas Committee classification.

In almost all resource estimates dealing with natural gas the recoverable resource is estimated. Since it is believed widely that gas recovery is usually a very efficient process, no allowance is made for enhanced recovery. There are, however, economic and technological limits to resource estimates. Most published estimates deal only with gas which may be recovered from conventional underground reservoirs in porous and permeable rocks through drilling and completion of wells. Gas resources which are not recoverable by conventional means are usually referred to as non-conventional (unconventional) resources. The magnitude and recoverability of gas from non-conventional sources is subject to a great deal more speculation than the conventional resource.

To some extent the boundary between conventional and non-conventional resources is not fixed but depends upon economics and technology. For example, certain accumulations of gas in low permeability gas reservoirs ("tight gas sand") in the western U.S. and accumulations in certain brown Devonian shales of the eastern U.S. may be included in conventional resources, recoverable with present prices and technology. To the contrary, some resources in these same general conditions may not be recoverable without a significant increase in price of the product or significant improvement in technology. The Potential Gas Committee includes, as a recoverable resource, all of the gas which may be recovered under conditions of adequate economic incentives in terms of price/cost relationships and current or foreseeable technology. These limits are, of course, subject to interpretation and are modified as changes occur in either price or technology.

The Potential Gas Committee releases only its estimate of the most likely volume of gas which is believed to exist in a given province or area. It is recognized that the actual volume may well be either greater or less than the Committee's estimate, but the estimate presented is a consensus of the working members.

Estimates of potential gas supply made by the Potential Gas Committee are based on comparison of factors that control known occurrences of gas with factors present in prospective areas. From known provinces, for a formation or province, a yield factor is determined which is equivalent to the volume of discovered gas (cumulative production plus proved reserves) divided by the volume of productive rock.

$$\text{Yield factor} = \frac{\text{Volume of Discovered Gas}}{\text{Volume of Productive Rock}}$$

In general, the estimation procedure involves the following steps:

(1) Estimation of the volume of potentially productive rock, especially emphasizing the number and size of potential traps. This estimate is then adjusted for known or postulated variations in the lithologic nature of the potential reservoir rock.

(2) The adjusted volume of potentially productive reservoir rock is then multiplied by a yield factor. The yield factor is determined, as described above, from known similar or identical productive formations within the productive province or by analogy with the most similar

geologic conditions which can be determined. The yield factor from an analogous area is adjusted as necessary for known variations in the productive character of the reservoir rocks in the area under consideration (these variations include nature and extent of source rocks, porosity, permeability, etc.)

(3) The product of the volume of potential reservoir times the yield factor is then discounted both for the probability that the postulated trap actually exists and for the probability that an accumulation exists even if the trap exists.

(4) Variations in the estimates of volume of potential reservoir and yield factor because of the uncertainties of unknown areas and variations in the estimates of the probability of occurrence lead to a range of estimates of the potential resource for any given play or province. The judgment of the estimators must then enter into the overall probability of occurrence of estimated volumes and to determination of the most likely estimate.

The estimation procedure may be diagramed as follows:

Table 1 lists the estimates of each of the components of the resource base in the lower 48 states of the United States through the years from 1963 through 1978, and Table 2 lists the same information for both the lower 48 states and Alaska for the years 1968 through 1978. It can be seen that as cumulative production has risen gradually throughout the years, proved reserves have decreased. If the Potential Gas Committee's estimates of Potential resources are added to Cumulative Production and Proved Reserves, it can be seen further that the estimate of the total

Estimate of volume of potential reservoir ± Adjustment for lithologic variation

X Yield factor ± Adjustment for variations

X Probability that trap exists

X Probability that accumulation exists

= Potential Resource Estimate

- - - - - - - - - - - - - - - - - - -

Potential Resource Estimates X Evaluation of Probability

= Most Likely Resource Estimate

resource base for the lower 48 states rose gradually from the year 1963 to 1968. A good part of this increase resulted from the expansion of offshore area considered feasible for development. The estimate of total recoverable resource has remained fairly uniform since 1968.

Table 3 lists the distribution of cumulative production and the estimates of proved reserves at year-end 1979. The figures are totals for each of 12 resource areas which are used by the Potential Gas Committee for its estimates and comparisons (Fig. 3). Data for production and reserves are taken from the reports of the Committee on Natural Gas Reserves of the American Gas Association (API, AGA, CPA, 1979). In looking at the values

Table 1. Recoverable natural gas resources, lower 48 states, 1963 through 1978

(trillion cubic feet)

Year	Cumulative Production*	Proved Reserves*	Total Potential Resources**	Total Recoverable Resource
1963	265	276	630	1,171
1966	307	286	690	1,283
1968	344	282	800	1,426
1970	387	260	851	1,498
1972	431	235	780	1,446
1976	514	184	748	1,446
1978	552	169	830	1,551

* Based on estimates of Committee on Natural Gas Reserves, American Gas Association.
** Based on estimates of Potential Gas Committee.

Table 2. Recoverable natural gas resources, total United States, 1968 through 1978

(trillion cubic feet)

Year	Cumulative Production*	Proved Reserves*	Total Potential Resources**	Total Recoverable Resource
1968	345	287	1,227	1,859
1970	387	291	1,178	1,856
1972	432	266	1,146	1,844
1976	515	216	973	1,704
1978	553	200	1,019	1,772

* Based on estimates of Committee on Natural Gas Reserves, American Gas Association.
** Based on estimates of Potential Gas Committee.

Table 3. Cumulative production and proved reserves, 1979, by area (trillion cubic feet)

Area	Cumulative Production[1]	Proved Reserves[1]
A - Eastern States-Atlantic Coastal (onshore and offshore)	33	8
B - Southeastern States (onshore and offshore)	6	2
C - North Central States	2	2
D - Arkansas-North Louisiana-East Texas	55	11
E - South Louisiana (onshore and offshore)	129	43
G - South Texas and Texas Gulf Coast (onshore and offshore)	103	27
H - Northern and Central Rocky Mountain States	16	9
I - Southern Rocky Mountains --Arizona and New Mexico	12	10
J_N - Mid-Continent --Oklahoma, Kansas and Texas Panhandle	125	31
J_S - Permian Basin	63	14
L - California, Nevada and Pacific Northwest (onshore and offshore)	28	5
K - Alaska (onshore and offshore)	2	32

[1] Area totals do not add to national totals because of rounding.

for cumulative past production, it can be seen that over 80 percent of the natural gas produced in the United States through the year 1979 came from five geographic areas: (1) South Louisiana, both onshore and offshore; (2) the Mid-Continent region of Oklahoma, Kansas and the Panhandle of Texas; (3) South Texas and the Texas Gulf Coast, onshore and offshore; (4) the Permian basin of southeastern New Mexico and west Texas; and (5) the Ark-La-Tex area of Arkansas, north Louisiana and northeast Texas.

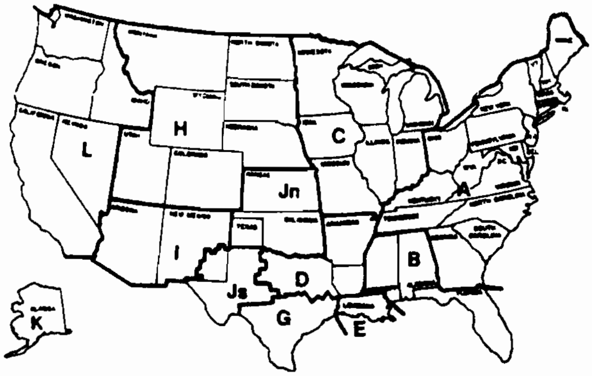


Figure 3. Resource areas used by Potential Gas Committee.

Turning to proved reserves, the geographic distribution of proved reserves is similar to that of past production, although not exactly the same. Alaska is now an important area with its North Slope reserves. Over 80 percent of the present proved reserves lie in six of the 12 geographic areas: (1) South Louisiana, onshore and offshore; (2) Alaska; (3) the Mid-Continent region; (4) South Texas and Texas Gulf Coast, onshore and offshore; (5) the Permian basin; and (6) the Ark-La-Tex area. Other than Alaska, these are the same areas which have had the greatest past production. The total of these proved reserves amounts to approximately 195 Tcf (5.5 trillion m^3) and they theoretically should represent a resource capable of sustaining U.S. production at the rate of 19 to 20 Tcf (0.54 to 0.57 trillion m^3) per year throughout the next ten years.

However, it is not realistic to assume that production can continue at the present rate for these proved reserves. In numerous cases the production life of wells will extend well beyond the next 10 years and, therefore, not all of the proved reserves can be produced within 10 years; furthermore, delays in production caused by such factors as the time lapse before hooking up to a pipeline or the down time spent in workover of completions will undoubtedly prolong the time necessary to produce these reserves. Therefore, in order to maintain a reasonable rate of production, it will be necessary for additional new reserves to be proved and added to the available supply.

This, then, leads to the question of what resources exist beyond proved reserves and how reliable and useful are the estimates of these resources.

For the United States as a whole, including Alaska, at year-end 1978, the Potential Gas Committee estimates that there remain to be found approximately 199 Tcf (5.63 trillion m^3) in the Probable category, approximately 399 Tcf (11.30 trillion m^3) in the Possible category, and 421 Tcf (11.92 trillion m^3) in the Speculative category. This amounts to a total potential of 1,019 Tcf (28.85 trillion m^3), although it must be emphasized that this total represents the summation of three categories which have considerable variation in available data and in range of probability of estimates.

Table 4 lists the estimates of potential resources for each area of the U.S. It can be seen that there are shifts in the geographic areas where the potential resource exists as compared to areas of past production and present proved reserves. Over 80 percent of the Probable potential lies, again, in six areas of the United States: (1) South Louisiana, (2) South Texas and the Texas Gulf Coast, and (3) the Mid-Continent area--the classic areas of production and reserves. Next in importance, however, is (4) the Eastern states and Atlantic coastal area, then (5) the northern and central Rocky Mountain states, and (6) the Permian basin.

Further shifts in the location of potential are seen in the Possible category, where the greatest potential lies in the northern and central Rocky Mountain states, and in the Mid-Continent region. Other significant areas of Possible potential are South Louisiana, South Texas and the Texas Gulf Coast, Alaska, and the Permian basin. Again, these six areas

Table 4. Estimated potential supply of natural gas in United States by geographic areas, 1978

(trillion cubic feet)

Area		Probable	Possible	Speculative
A	Onshore	26	9	33
	Offshore	--*	--	53
B	Onshore	6	7	7
	Offshore	--	--	33
C	Onshore	--	3	1
D	Onshore	8	20	22
E	Onshore	11	15	--
	Offshore	27	45	--
G	Onshore	18	22	4
	Offshore	18	23	--
H	Onshore	23	80	57
I	Onshore	2	3	1
J-North	Onshore	28	70	45
J-South	Onshore	16	36	1
L	Onshore	3	18	19
	Offshore	--	8	9
	48 States Subtotal	186	359	285
K	Alaska -- Onshore	11	19	29
	-- Offshore	2	21	107
	Total United States	199	399	421

* In this table, dashes are used to represent estimated potential of less than 0.5 Tcf.

contain more than 80 percent of the Possible potential. Finally, in the Speculative category, over 80 percent of the potential lies in Alaska; the Eastern states and Atlantic coastal region, onshore and offshore; the northern and central Rocky Mountain states; the Mid-Continent region; and the Southeastern states.

To summarize the distribution of resource potential, almost 20 percent of the resource lies below 15,000 feet in onshore basins, about 34 percent lies in offshore areas, and 19 percent of the potential occurs in Alaska. Considering Alaska, the offshore areas, and deep basins below 15,000 feet as hostile and expensive environments for resource development, almost 60 percent of the resource potential exists in areas and at depths which are expensive and difficult for exploration and production.

The conclusion from the evaluation of resource potential and its distribution is that indeed there is a considerable resource potential remaining yet to be developed in both the lower 48 states and in Alaska but also that considerable shift in geographic area of exploration and development will be necessary if this potential is to be realized.

At this point it is appropriate to compare the results of the estimates of the Potential Gas Committee with those of other companies and agencies which have made similar estimates. Table 5 gives the estimates of natural gas prepared by several different groups in recent years. Comparisons are made, where possible, with similar resource categories, as discussed previously. As you can see, the Potential Gas Committee's estimate is more optimistic than some others, notably those of Hubbert and Shell. The estimate of Hubbert differs from the other estimates in the methodology used—extrapolation of past discovery and production data. Although the Shell estimate is taken from recent published data, it is quite likely that an estimate for the growth of known fields (= Probable) was not included and that the total should be higher. The 1974 USGS estimates, which are also somewhat lower than those of the Potential Gas Committee, were made before the rather dramatic changes in exploration philosophy and price policy of the last few years. Members of the Potential Gas Committee believe that their estimate is realistic, consistent, and, perhaps, even somewhat conservative. Even if the Potential Gas Com-

Table 5. Comparison of estimates of recoverable volumes of natural gas, total U.S.[1]

(trillion cubic feet)

Estimator	Year of Estimate	Cumulative Production	Proved Reserves	Growth of Fields (Probable)	Undiscovered Potential	Total Resources
M. King Hubbert	1971	409	279	135	361	1,184
National Academy of Sciences	1973	454	250	125	530	1,359
Mobil (Moody & Geiger)	1973 (mean estimate)	454	250	52	485	1,241
Institute of Gas Technology	1974 (high)	476	237		1,138	1,851
	(low)	476	237		663	1,376
Exxon	1974 (mean of full inventory estimate)	477	237	111	582	1,407
USGS Circular 725	1974 (mean estimate)	481	237	162	484	1,364
Shell	1977 (mean estimate)	540	220		315	1,075
Potential Gas Committee	1978	553	200	199	820	1,772

1 Source: Potential Gas Committee, 1977.
Kent, 1979.

mittee estimates should be somewhat high, it can be seen that by taking some of the more conservative estimates we should have a considerable resource potential available for future exploration and development.

If natural gas is to be available to meet future energy needs there must be continued incentive for exploration and drilling, and this incentive must be sufficient to encourage drilling in areas where the potential exists, which, in many cases, are areas of expensive and difficult exploration and drilling. Even if there is an increase in drilling and a shift in drilling emphasis, it is doubtful that sufficient wells can be drilled and sufficient gas discovered in the lower 48 states to provide the production rate needed to meet the gas-energy demands of the year 2000 (Haun, 1979). It will be necessary to supplement conventional supplies from the lower 48 states with gas from Alaska, imports, gasification of coal, and recovery from non-conventional sources using new technologies (American Gas Association, 1979). Vigorous exploration can serve to close the gap between supply and demand and lessen reliance on the supplemental sources.

REFERENCES

American Gas Association (1979) The future for gas energy in the United States. Arlington, Virginia: A.G.A. 24 p.

American Petroleum Institute, American Gas Association, Canadian Petroleum Association (1979) Reserves of crude oil, natural gas liquids, and natural gas in the United States and Canada, as of December 31, 1978. Washington, D.C.: API, AGA, CPA. 253 p.

American Petroleum Institute, American Gas Association, Canadian Petroleum Association (1980) Reserves of crude oil, natural gas liquids, and natural gas in the United States and Canada, as of December 31, 1979. Washington, D.C.: API, AGA, CPA.

Haun, J. D. (1979) Future of petroleum exploration in the United States. Unpublished manuscript.

Kent, H. D. (1979) Comparison of estimates of U.S. natural gas resources: Comparison of conventional natural gas supply forecasts. Arlington, Virginia: American Gas Association.

Miller, B. M., Harry L. Thomsen, Gordon L. Dolton, Anny B. Coury, Thomas A. Hendricks, Frances E. Lennartz, Richard B. Powers, Edward G. Sable, and Katharine L. Varnes (1975) Geological estimates of undiscovered recoverable oil and gas resources in the United States: Circ. 725. Reston, Virginia: U.S. Geological Survey. 78 p.

Petroconsultants, Ltd. (1979) Natural gas worldwide, a non-exclusive report. Dublin: Petroconsultants.

Potential Gas Committee (1977) A comparison of estimates of ultimately recoverable quantities of natural gas in the United States. Golden, Colorado: Potential Gas Agency, Colorado School of Mines. 27 p.

Potential Gas Committee (1979) Potential supply of natural gas in the United States (as of December 31, 1978). Golden, Colorado: Potential Gas Agency, Colorado School of Mines. 75 p.

METHODOLOGY OF THE US GEOLOGICAL SURVEY RESOURCE APPRAISAL GROUP FOR GAS RESOURCE ESTIMATES IN THE UNITED STATES

Betty M. Miller
US Geological Survey, Reston, Virginia, USA

INTRODUCTION

The state of the art for appraising petroleum resources has advanced rapidly during the past decade because of the growing awareness of the need for petroleum resource estimates for the formulation of reasonable energy policies and long-range planning.

Events triggered by the Arab-Israeli war of 1973 focused the attention of the world on energy problems and on the inherent uncertainty of the estimates made for petroleum resources. Many nations will need realistic forecasts of future petroleum supplies; these estimates of the distribution and magnitude of oil and gas resources throughout the world must be based upon the most reliable methods and data available. This situation calls for a high level of domestic and international cooperation among appraisers of petroleum resources.

Published appraisals of oil and gas resources in the United States date back at least 70 years (Thomsen, 1979). The first published estimates by the U.S. Geological Survey in 1909, by David T. Day, covered the known producing areas of the conterminous United States which at that time had a reported cumulative production of 2 billion barrels, 4 billion barrels of proved reserves and 4 to 18 billion barrels of potential supply. Since then, many published estimates have been made by the USGS, industry and individual researchers. In the 20-year period after 1955, the amounts reported from these appraisals varied widely, giving rise to great confusion and much controversy. Attempts to compare these estimates revealed that many of them were based upon inadequate data and were poorly documented. Each effort had utilized different assumptions, definitions, appraisal methods, geographic boundaries and data bases and therefore should not be compared. Increased efforts during recent years have been directed toward resolving some of these major problems, and there is evidence that progress is being made. This paper discusses the efforts made by the USGS within the last 6 years to improve upon its methods for petroleum resource appraisal.

METHODS

Many methods exist for estimating petroleum-resource potential with numerous variations in the basic techniques. Each method requires a certain level of knowledge or degree of available information on the area to be assessed. Each method, however, has recognized limitations. Problems arise because of misinterpretation of results and lack of recognition of these limitations on the methods and data used. Emphasize must be made that no single technique has universal application or appeal -- nor is there unanimity on the results. In 1974, the Oil and Gas Resource Appraisal Group was created by the USGS to devise and study resource appraisal methods and to apply these methods in assessing the nation's petroleum resources as a full-time responsibility.

The first nationwide appraisal of the undiscovered oil and gas resources [1] for more than 100 geologic provinces was published by the Resource Appraisal

---

[1] Undiscovered resources are defined by the USGA as follows:
Undiscovered resources: Quantities of a resource estimated to exist outside of known fields on the basis of broad geologic knowledge and theory.
Undiscovered recoverable resources (potential resources): Those economic resources, yet undiscovered, which are estimated to exist in favorable geologic settings.
Original in-place resources: Includes all discovered oil and gas reserves (produced and remaining), and the undiscovered resources believed to exist, both recoverable and nonrecoverable (Miller et al, 1975).

Group in 1975 as USGS Circular 725, "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States" (Miller et al, 1975). In this study, the appraisal methodology was applied on a broad scale and designed for the geologic basin or geologic province. The estimates of the undiscovered resources were made: (1) by reviewing and analyzing all available geological and geophysical information compiled on more than 100 geologic provinces; (2) by applying resource appraisal techniques, which included extrapolations of known producibility into untested sediments of similar geology for well-developed areas, and volumetric techniques using geologic analogs with ranges of yield factors; (3) by using group appraisals (in a modified Delphi procedure) determined by geologic experts applying subjective probability procedures; and (4) by reporting final results as probability ranges rather than as single numbers values.

Since the organization and the first publication of the Resource Appraisal Group's work, the evolution in petroleum resource appraisal procedures has been significant. The methods developed and employed by the Resource Appraisal Group are designed to emphasize the compilation and evaluation of all available geological and geophysical data by geological basins or provinces. Resource estimates can be made on any level of data; however, the amount of data available will determine the method or methods to be used for the appraisal. The method or procedure used can change as the amount and nature of the available data change within a specific basin.

In the frontier stages of exploration when some information exists on the gross interpretation of basin geology, and, when the principles of petroleum occurrence from worldwide experience are applied, subjective judgment may be used with minimum amounts of data as a basis for the assumption of the presence or absence of potential hydrocarbons. As the data base grows, because of increased exploration, and as the results of geophysical surveys, drilling, and geochemical data become available, methods using more objective data should become increasingly dominant. The methods used in making estimates may evolve to the level of assessing exploration plays and may eventually focus on making estimates of undiscovered prospects, if this level of resource assessment is desirable. If abundant and detailed data are available, the choice of the method to be used may become more dependent upon the availability of the estimator's time, the effort involved, and the purpose of the resource estimate. The quality of the estimate is, however, dependent upon the quality of the geologic data and studies upon which the estimate is based (Miller, 1979).

DEVELOPMENTS IN THE USGS SINCE 1975

Since the initial studies and the resource-appraisal methods described in Circular 725, the older methods have been refined, alternate resource appraisal techniques have evolved, and new and more detailed oil and gas data have been compiled, particularly field and pool information, for stratigraphic units within specifically designated pilot areas in the United States. By using the new information increasingly available to the Resource Appraisal Group and the refinement in resource appraisal methodology, resource assessments can now be made for individual stratigraphic units and by depth increments within many basins. Results of the Permian Basin study conducted by the Resource Appraisal Group are reported in this paper to illustrate the use of these methods. Estimates can also be made on the probable size and number of fields in which the remaining undiscovered resources may be found within a semi-mature or maturely explored area and on the probable depth increments within which these fields are likely to occur. The Gulf of Mexico studies, completed by the Resource Appraisal Group are also used to demonstrate these methods. Additional refinements of resource assessment methods have been completed for the application of computerized geologic models using play analysis techniques for the appraisal of conventional petroleum resources in the National Petroleum Reserve of Alaska, and of unconventional natural gas resources in the Devonian black shales of the Appalachian Basin.

CURRENT METHODS USED BY THE USGS

The following discussion reviews the evolution and development of each of the basic resource appraisal methods currently being used by the Survey's Resource Appraisal Group. Specific applications from current studies by the Resource Appraisal Group are reviewed for each method. Although the Group works on both oil and gas resource estimates, and the methods are often similar for both, this paper will be directed primarily to the application of methods and results for natural gas resources.

METHODS USING VOLUMETRIC-YIELD ANALOGS

Volumetric-yield techniques have been used in a wide variety of ways in making petroleum-resource estimates. These techniques range from the use of worldwide average yields expressed in barrels of oil or cubic feet of gas per cubic mile of sedimentary rock, or per square mile of surface area (assuming constant thickness) applied uniformly over a sedimentary basin, to more sophisticated analyses in which the yields from a geologically analogous basin have been used to provide a basis of comparison. The pioneer works by Weeks (1950), Zapp (1962), and Hendricks (1965) are illustrative of early techniques.

In Circular 725, wherever yield factors were used,it was done in the context of a reasonably sound consideration of the geology of the basin or province and the selection of a geologically analogous basin or province. The records of 75 North American basins were compiled, the oil and gas yields being expressed per cubic mile of sediment as determined from well-explored areas within these basins, to establish a scale of hydrocarbon yields for geologically analogous basins. Figure 1 shows a frequency distribution of hydrocarbon yields for these basins. The productivity of a basin may range from less than 1,000 barrels per cubic mile of sediment to more than 3 million barrels per cubic mile of sediment, as in the exceptional case of the Los Angeles basin.

The accuracy of this method depends on the expertise of the geologist

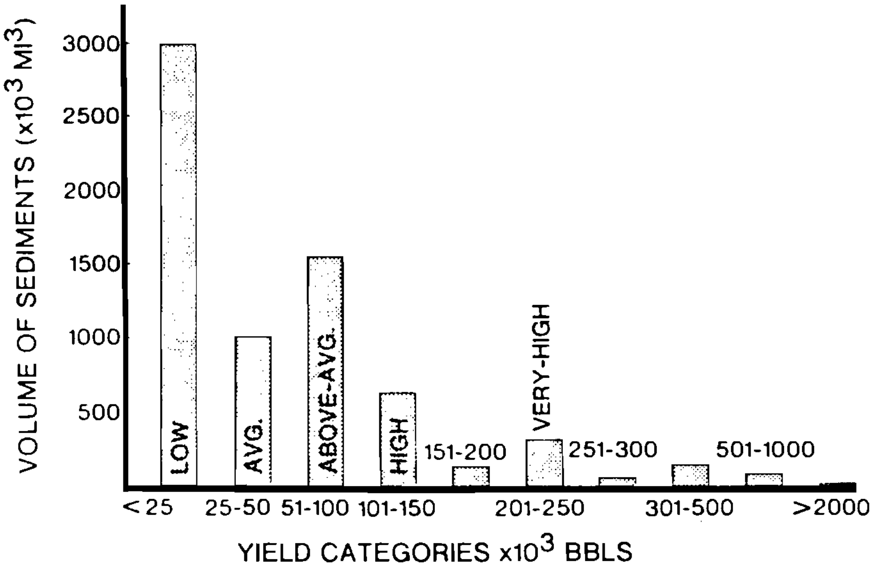


Figure 1. Frequency distribution for total sediment volumes from 75 provinces of North America versus their recoverable hydrocarbon yield.

who compares the similarity of the geology of an unexplored basin with that of a developed basin, prior to the selection of a hydrocarbon yield used to make a forecast for the potential of the unexplored basin or unexplored part of a basin. A highly recommended approach to this method is the selection of a representative range of analogous yields to which probabilities are assigned to determine a minimum and maximum estimate for the potential resource. The results obtained by this method can be useful on a broad regional basis or in a reconnaissance-type estimate of the resource potential, particularly in evaluating frontier or unexplored geologic areas.

Volumetric-yield methods have been refined recently by the Survey to categorize hydrocarbon yields for specific stratigraphic units, which may be characterized by lithology, environment of deposition, geologic age and basin classification, or by relation to geologic structures and basin tectonics. In this way, the potential of individual stratigraphic units in unexplored or partly explored basins may be evaluated by using analogous stratigraphic units from known basins. Hydrocarbon yields expressed as probability distributions are used for each potential stratigraphic unit because subjective judgments must be made on the various combinations of favorable geologic characteristics chosen for the analogs. Estimates of the total potential for the province are the sum of the individual stratigraphic units aggregated by using Monte Carlo simulation. The aggregated results of the resource estimates are reported in the form of a probability distribution.

A recent study by the Resource Appraisal Group that applied various aspects of this methodology has been completed on the Permian Basin of west Texas and southeastern New Mexico (Dolton et al, 1979). In this study, separate analyses were completed for the geologic units in the Permian, the Carboniferous, and the older Paleozoic, with individual appraisals made for each unit. In addition, the province was also evaluated at depth increments of 0-10,000 feet, 10,000-20,000 feet, and deeper than 20,000 feet. Drilling

Permian Basin Assessment Matrix

Estimates of Undiscovered Non-Associated Gas in-place (Trillion Cubic Feet) (95% - 5% Range, and Mean) *

	Geologic Age			
Depth Interval (ft.)	Permian System	Carboniferous Systems	Older Paleozoic Systems	Total Geologic Ages
0 - 10,000	.17 - 1.33 .57	.27 - 3.81 1.40	.42 - 3.00 1.34	1.43 - 5.98 3.31
10,000 - 20,000	.01 - .08 .03	.12 - 1.38 .53	3.30 - 22.09 10.14	3.73 - 21.90 10.70
20,000 - 30,000	Negligible	.01 - .20 .06	.71 - 4.94 2.23	.75 - 4.86 2.29
Total	.19 - 1.31 .60	.64 - 4.34 1.99	6.16 - 25.45 13.71	8.24 - 28.27 16.30

*Values correspond to the 95% and 5% probability that there is at least that amount. (Source, Dolton, et al, 1979)

Figure 2. An assessment matrix of the individual units analyzed for natural gas by geologic age and depth increments. The values represent the 95-5 percent range and the mean for undiscovered gas (in place).

density maps penetrating each of these units as plotted from computerized well-data systems played an important part in these assessments. Figure 2 shows an example of the individual units independently analyzed for resource assessments of natural gas in the Permian Basin. Figure 3 shows examples of resource estimates for natural gas reported in the form of probability distributions for the lower Paleozoic of the Permian Basin.

The volumetric-yield method is a valid procedure for resource appraisal, providing care is taken in the selection of geologic analogs and in documenting and qualifying the results properly. There are more sophisticated resource appraisal methods, which, when closely analyzed, reveal a key volumetric element within their respective systems. This volumetric element usually consists of individual variables for either stratigraphic units, or exploration plays, or reservoirs, which, when mathematically manipulated, provide a volumetric estimate.

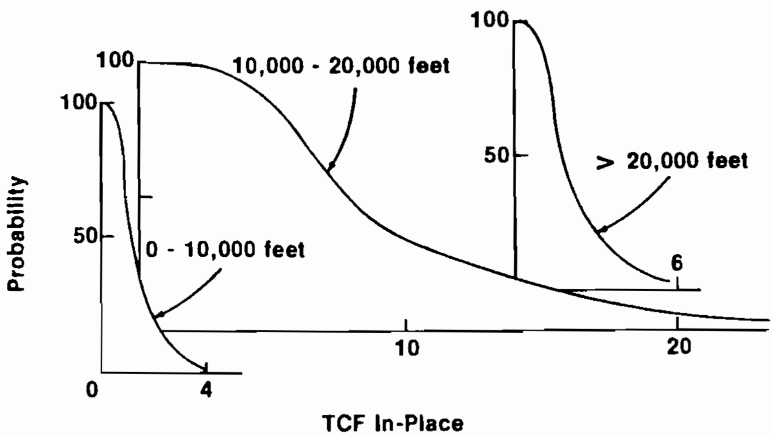


Figure 3. Resource appraisal for undiscovered non-associated gas in-place for the Lower Paleozoic by depth increments. The resource estimates are reported in the form of three probability distributions.

DISCOVERY-RATE OR BEHAVIORISTIC METHODS

Performance or behavioristic methods are based upon the extrapolation of past experiences from historical data such as discovery-rates, drilling rates, and productivity rates, and upon the fitting of past performances into logistic or growth curves by various mathematical derivations that are projected for the future. These techniques are not directly applicable to unexplored or nonproducing areas or to any area that is not a geologic and economic analog of the historical model. Generally speaking, they are most applicable to the later stages of exploration in a maturely explored area. Well-known examples of these models are: Hubbert's growth curve projections (1962, 1974); Arps and Roberts (1958); Zapp (1962); and the National Petroleum Council (1973).

Two aspects of the performance or behavioristic methods have been applied by the Resource Appraisal Group to resource assessment work. They are: 1) discovery-rate or finding-rate techniques projected for undiscovered fields, and 2) probability techniques for predicting the size of fields to be discovered with future exploration. Both techniques are discussed briefly below.

Discovery-Rate or Finding-Rate Methods

Since 1975, the Resource Appraisal Group has undertaken a continuing study of regional oil and gas finding-rate methods for the United States. The concept of finding-rate has been used at one time or another by most researchers in assessing and projecting resource availability. Terms and units of measurement used in defining finding-rate are variable; as a result, general finding-rate definitions have evolved. An understanding of the applications of finding-rate procedures is required before terms can be defined for any particular study. Regardless of the definitions used, the ultimate purpose of determining finding-rate is to permit statistically valid projections of resource availability based upon historical data within a given geologic and economic frame of reference.

As pointed out by Moore (1966), the fundamental concept of continuity of historic patterns and their validity for projecting future patterns must be assumed. Accordingly, most historical studies begin with empirical data and attempt to improve the projection of these data by being as quantitative as the limits of the data permit.

Many factors must be considered when predictions of undiscovered resources are made, but past studies indicate that the two most significant factors are drilling-rate and finding-rate. Drilling-rate is by far the single most important factor and the most easily controlled. Finding-rate, on the other hand, is difficult to control and is largely dependent upon the geologic characteristics of the area, field sizes, drilling-rate, and economic and technological factors.

In an attempt to minimize the effect of economic and political variables on finding-rates, some authors (principally Hubbert, 1974) have expressed finding-rate as a unit of oil or gas discovered per unit footage of exploratory drilling and as a function of cumulative exploratory drilling, determined from historical data.

Most published studies to date have made projections of resources based primarily on statistical studies of historical data and have included very little geological information. This emphasis upon historical drilling data rather than geologic data is due, in part, to the very large sample areas that have generally been evaluated, such as the entire conterminous United States, and the difficulty in assessing and quantifying the many and varied geologic factors that ultimately contribute to the control of resource occurrences over such large areas. The lack of essential data for more detailed finding-rate studies has also been a crucial element.

In order to improve finding-rate methods so that they can be applied to resource assessment work, the following procedures have been developed in the Resource Appraisal Group:

1. Directly relate geologic information to finding-rates, and limit the area of study to a well-defined geologic basin or to a specific stratigraphic unit or geologic section within a basin or province.
2. Separate the oil and gas discoveries by: year of discovery, geologic age of producing horizon and/or reservoir lithologies,

depth increments for producing reservoirs, and field-size categories. If data are available, also identify the type of structural or stratigraphic trap for each field discovered.

3. Analyze the discovery-rate patterns for any of the above categories for which data are available to determine: whether there are any significant trends; whether these trends can be explained by the geologic data; and whether valid projections can be made that would contribute to an understanding of the remaining resource availability within a specified basin or province.

These finding-rate methods not only meet the requirement of being applicable to basins or provinces, they have also attained a refinement that will permit increased accuracy in analog comparisons between mature areas and frontier areas.

A study by the Resource Apraisal Group in which various aspects of the finding-rate methods have been applied has been completed on the offshore Gulf of Mexico (Miller, et al, 1978). In this study, all the oil- and gas-field data were compiled by size of in-place reservoir volumes, year of discovery, age of major producing reservoirs, and depth increments for major accumulations. Figure 4 depicts the historical finding-rate for all natural gas fields in the Gulf of Mexico, from 0 to 200 meters water depth, that are producing from the Miocene, Pliocene, and Pleistocene reservoirs. The discoveries, in trillions of cubic feet, are plotted with respect to the cumulative exploration effort in units of 5 million feet. The obvious decline in finding-rate from 1940, when the first major discovery was recorded, to 1975, ranges from 29 trillion cubic feet per 5 million feet of exploratory drilling to less than 6 trillion cubic feet per 5 million feet. One very useful method of projecting finding-rates consists of separating the known fields into field-size categories and using the historical finding-rates for each category to predict the amount of remaining resources yet to be found in each specific

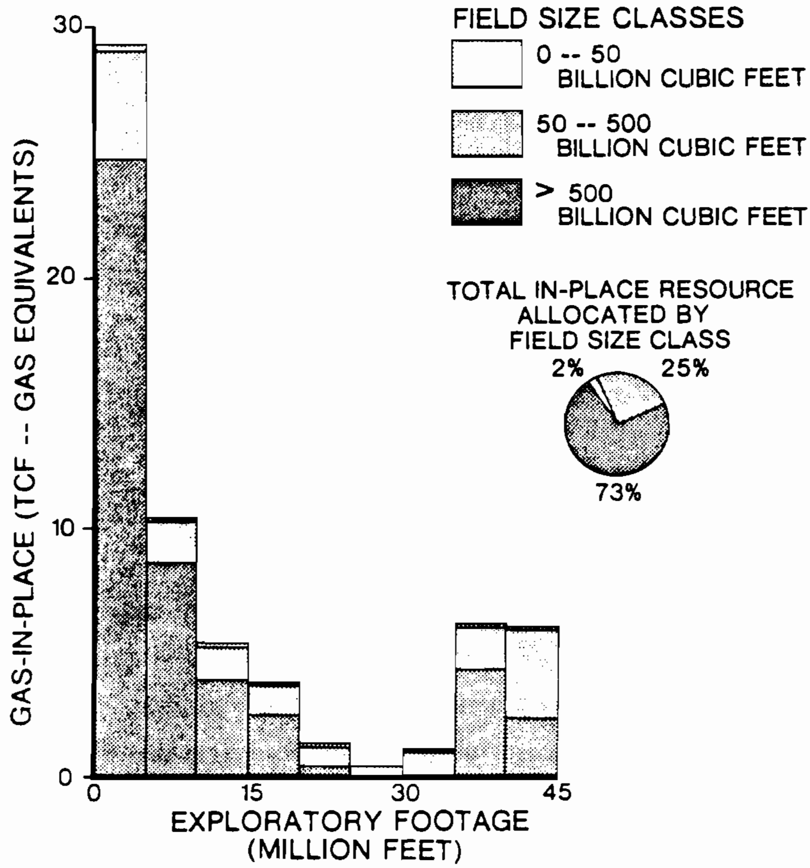


Figure 4. Gulf of Mexico natural gas historic finding rate by field size class (gas equivalents in-place). Data through 1975.

field size class. The finding-rates are consistently different for each field-size category in the Gulf of Mexico and in other areas in which these methods have been applied. The amounts for each class can be summed to obtain the total estimate of resources remaining to be found in the predictable future. Figure 5 depicts an example of the historical finding-rates for only those gas fields in the Gulf of Mexico in the greater-than 0.50 trillion cubic feet in-place field-size class. Hyperbolic and exponential decline curves fit by regression analysis to historical data show the best promise for finding-rate projections for these investigations. The "best fit" was selected by the highest index of determination and the F-statistic. The projected finding-rates

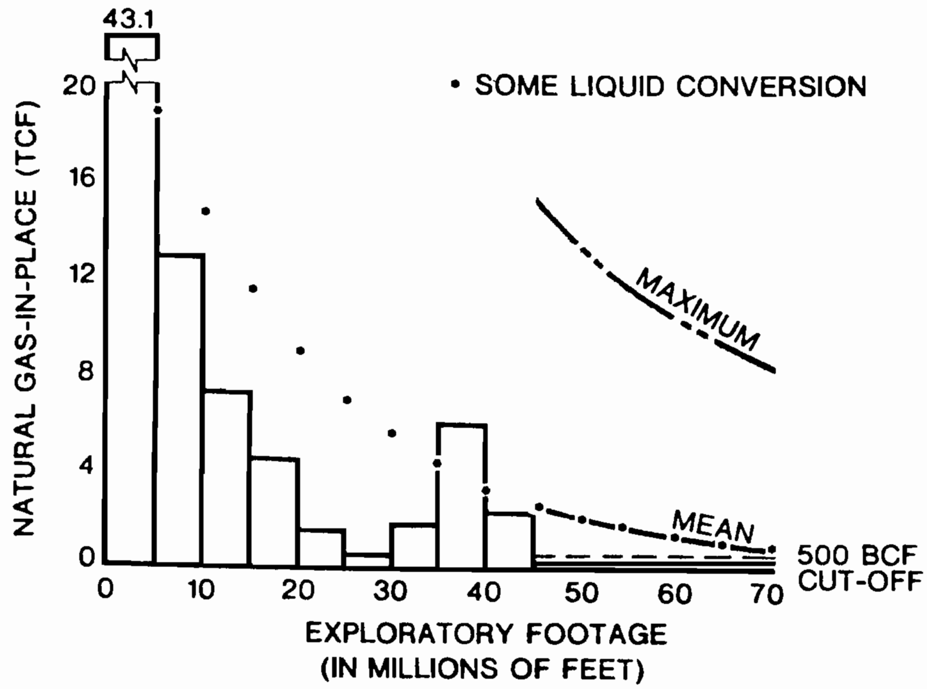


Figure 5. Gulf of Mexico natural gas finding rate, projection class >5000 BCF.

are usually extended another 15 million to 25 million exploratory feet into the future, or approximately 5 to 10 years of additional drilling. All projected finding-rates are terminated if they reach the minimum field-size level set for the respective field-size category.

The major shortcomings of the finding-rate methods for projecting remaining resource estimates are: They can only be applied directly to semi-mature and maturely drilled producing areas, and they are considered a conservative technique for estimating resources, as they do not allow for any radical surprises in petroleum exploration, or significant improvements in exploration technology or economics.

Finding-rate techniques are very useful for providing a means of comparative checking on other resource-appraisal procedures used to analyze the same basin or province. Finding-rate procedures when applied to specific categories of geologic data often reveal some interesting exploration trends within the basins studied. Finally, finding-rate studies for known productive areas may be used with care as in analogs for immaturely explored or frontier areas.

Field-Size Distributions for Estimating Undiscovered Resources

New developments in projecting the estimated field sizes of the remaining undiscovered resources hold great promise as another method of estimating remaining resources. Several techniques have been devised to estimate the field-size distributions for the remaining undiscovered fields in a maturely explored area. These techniques result from detailed studies on finding-rate methods that make use of historical field-size distributions. Seismic data on drilled and undrilled structures in the Gulf of Mexico are used by these methods to determine probable field size as related to the historical field-size distributions within the same or adjacent areas. (See Table 1.) Field-size distributions can be estimated by subjective probability procedures. The probable number of remaining undiscovered fields may be estimated in a similar manner. The total resource potential is determined, using an aggregation of the probable field sizes and probable numbers of fields, by means of Monte Carlo simulation techniques. A separate procedure is used whereby the resource assessment by some other method and the probable field-size distribution

Table 1. Gulf of Mexico, Texas, and Louisiana: Summary table of structure count and status for total shelf, 0-200 meters water depth.

Type	NUMBER OF STRUCTURES Total	Untested	Tested	Productive	Discovery Ratio (percent)	Percent Structures Productive
Fault	197	112	85	52	61	26
Piercement	158	51	107	61	57	39
Domal	225	78	147	96	65	43
No Seismic Control	6	1	5	4	80	66
Total	586	242	344	213 1/	61	36

1/ There are 59 total additional fields not identified on seismic structure count (Source: Miller et al 1978).

are used as input to a Monte Carlo simulation to determine the probable number of remaining undiscovered fields in a specific area. These techniques are still considered experimental and should be used with caution.

EXPLORATION PLAY-ANALYSIS METHODS

Conventional Petroleum Resources

Exploration play-analysis methods have been designed for identified or conceptual exploration plays within a basin or province for conventional petroleum resources. The basic definition of an exploration play is: a practical, meaningful planning unit around which an integrated exploration program can be developed. A play has geographic and stratigraphic limits and is confined to a formation or a group of closely related formations on the basis of lithology, depositional environment, or structural history.

There are, however, many variations to this definition and to play concepts that have been applied by various resource estimators using play-analysis techniques; these variations usually make the results noncomparable for any specific area.

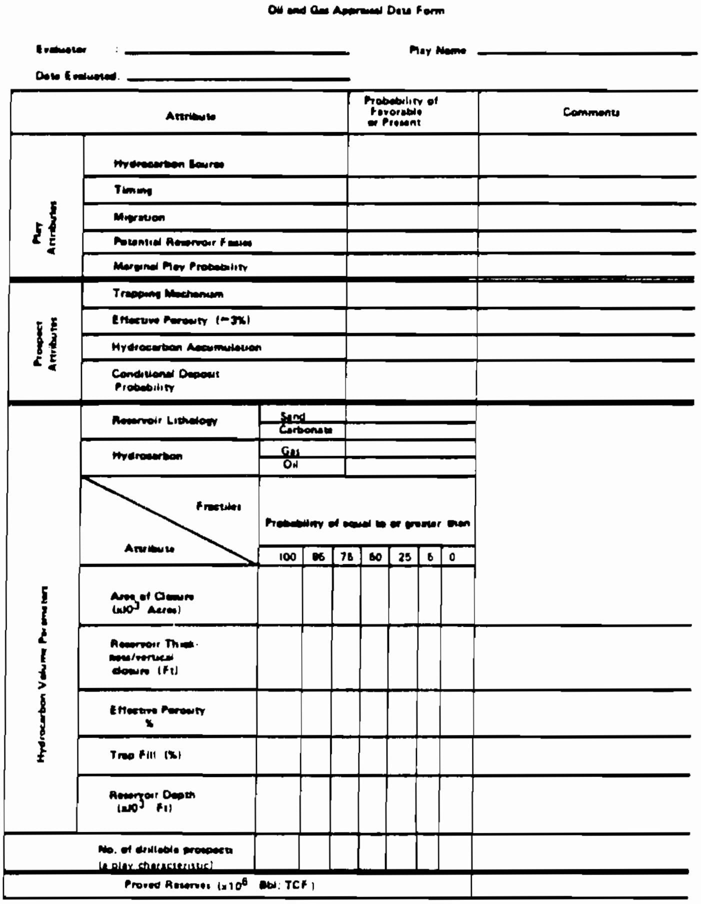
Play-analysis methods are usually applied to smaller areas of appraisal than are the previously described methods, areas such as a geologic trend consisting of a reef-play or a channel or bar sand. However, in some studies the play-analysis procedure has been applied to an entire geologic horizon or stratigraphic unit, such as the total Cretaceous within a basin. Although the estimator may have called the procedure a "play-analysis," the basic concepts are no longer those of the original definition.

The basic technique requires more detailed data than the volumetric-yield methods, utilizing all the data used in the finding-rate approach and additional data concerning the individual fields within a play, plus the basic information on the reservoir characteristics in these fields.

An estimate of conventional petroleum resources is usually expressed as an equation relating a series of geologic and reservoir variables to the amount of potential oil or gas within the reservoir. Probability values may be assigned to the favorability of a play and usually to the probable success of the prospects within the play. The geologic and reservoir variables are described by subjectively derived probability functions based upon the judgment of the estimators or by use of selected analogs for many of the variables. The data formats are usually designed for sophisticated computer processing, probability distributions being assigned by the geologist for each variable. The estimates of the resource are derived for each play by means of the equation relating the variables to the potential resource by Monte Carlo methods. The procedure for processing the numerous variables evaluated by the geologist, and the accompanying probability distributions, is to use computer models that can rapidly process thousands of random samplings of the values of the variables needed for determining the resource appraisals which are shown as probability distributions. The total resource estimate for the area or basin is determined by aggregating the potential of all plays by using Monte Carlo simulation techniques. The output is in the form of a probability distribution for the total resource assessment.

Figure 6 shows an example of a simplified data format being used in a play-analysis technique currently under investigation by the U.S. Department of the Interior, Office of Mineral Policy and Research Analysis (OMPRA), and the USGS in a joint study to evaluate the petroleum resources of the National Petroleum Reserve of Alaska (NPRA). Geologic variables such as source rock, trapping mechanism, size of trap, thickness of reservoir bed, and porosity are described by probability distributions. A Monte Carlo technique is used to determine the size of the prospect or field and to solve the equation relating the geologic and reservoir variables to the resource assessments.

Table 2 shows the probability distributions for the resource estimates, completed in September 1979, of the undiscovered oil and gas


Oil and Gas Appraisal Data Form

Evaluator :

Play Name

Date Evaluated.

Attribute		Probability of Favorable or Present	Comments
Play Attributes	Hydrocarbon Source		
	Timing		
	Migration		
	Potential Reservoir Facies		
	Marginal Play Probability		
Prospect Attributes	Trapping Mechanism		
	Effective Porosity (~3%)		
	Hydrocarbon Accumulation		
	Conditional Deposit Probability		

Hydrocarbon Volume Parameters

Reservoir Lithology	Sand	
	Carbonate	
Hydrocarbon	Gas	
	Oil	

Fractiles / Attribute	100	95	75	50	25	5	0
Area of Closure ($x10^3$ Acres)							
Reservoir Thickness/vertical closure (Ft)							
Effective Porosity %							
Trap Fill (%)							
Reservoir Depth ($x10^3$ Ft)							
No. of drillable prospects (a play characteristic)							

(The Fractiles columns are headed "Probability of equal to or greater than".)

Proved Reserves ($x10^6$ Bbl; TCF)

Figure 6. Oil and gas appraisal data form.

in-place in the National Petroleum Reserve of Alaska (NPRA). The mean value of the total resources in-place for NPRA were estimated to be 7.10 billion barrels of oil and 14.12 trillion cubic feet of gas. These estimates were derived from the geology model in the play analysis system developed by the U.S. Department of the Interior. The basic geological input was provided by the USGS to OMPRA which, in turn, used the play-analysis technique for the resource appraisal and as the basis for the exploration, development, production, and economic evaluations for the NPRA studies published in the "Final Report of the 105(b) Economic and Policy Analysis" (U.S. DOI-OMPRA, 1979).

Table 2. Preliminary distribution of estimated national petroleum reserves of Alaska oil and gas resources in-place and barrels of oil-equivalent, as of September 1979.

(%) Probability That Quantity is at least Given Value	Oil In-Place (Billions of Barrels)	Gas In Place (Trillions of cu. Ft.)	Barrels of Oil Equivalent in Place [1/] (Billions of Barrels)
95	1.04	3.51	2.08
90	1.35	4.25	2.66
50	6.03	12.52	8.57
25	10.01	17.54	13.26
10	13.72	28.29	17.33
5	16.45	34.97	20.35
1	24.80	40.17	30.00
Mean	7.10	14.12	9.60

1/ Barrels of oil equivalent are obtained by converting the estimated gas in place to the energy equivalent in oil and adding the resulting value to the estimated oil in-place. The values in this table are estimated independently, therefore, oil and gas estimates may not be added across percentiles to obtain BOE (DOI/OMPRA, 1979).

A major weakness of the play-analysis models is the assumption that all the variables assessed in each play, as used in the Monte Carlo simulation, are independent. Many of the geologic and reservoir variables are not independent, and this creates some confusion in the minds of the geologists who are to assign the values for each variable, for the degree of risk or success for the occurrence of a favorable play, and for a favorable prospect in that play.

One advantage of the play-analysis approach is that it simplifies, or appears to simplify, the geologist's task in evaluating the resources of an area by providing a fixed format for the variables he must evaluate; the actual resource assessment is determined by statistical and mathematical methods through the use of computer models. This method may also reduce the amount of time necessary to evaluate an area, provided ample data are readily available. However, such sophisticated computerized procedures do not necessarily mean that accuracy has been increased in the resource assessments resulting from this method over those evaluated using other resource appraisal methods. Geologists concerned over the results of their basic input into these programs must become increasingly concerned over the assumptions and mathematical manipulations within the computer system that are often designed by technical personnel who are not familiar with the basic assumptions and concepts concerning the geology of petroleum occurrence.

One of the most publicized of the play-analysis methods has been that of the Geological Survey of Canada (Department of Energy, Mines and Resources, 1977). Various modified versions of the Canadian approach and some of those used by industry are currently under investigation by the USGS. Ideally, a computerized procedure similar to that used in the play-analysis approach could be the ultimate goal in the idealistic world of resource appraisal. However, we have yet to achieve such a goal.

Unconventional Natural Gas Resources

The successful application of the exploration play-analysis model to the evaluation of conventional petroleum resources led to the experimental application of a modified play-analysis approach for an appraisal of unconventional gas resources for a pilot study of the Devonian black shales in the Appalachian basin.

In 1975, USGS was requested to aid the U.S. Energy Research and Development Administration (ERDA), now the U.S. Department of Energy (DOE), in their investigations for appraising the energy potential of the gas-productive petroliferous black shales of Devonian age in the eastern United States. To assist ERDA in achieving the goals of its program, the USGS was asked to perform a series of stratigraphic, structural, geochemical, and geophysical studies to establish a data bank and data retrieval system over a 5 year period, and to make an appraisal of the energy resources (predominantly unconventional natural gas) of the Devonian black shales in the Appalachian basin. The latter assignment involves the USGS Resource Appraisal Group working with all the groups in the project to evaluate the data at hand and then preparing an independent resource appraisal.

A review of the results of the basic stratigraphic, structural, geochemical, source-bed, maturation, and clay mineralogy studies soon reveals the complexity of the many lithologic units that compose the Middle and Upper Devonian black shale facies in the Applachian Basin, and the multivariate nature of the geologic characteristics that contribute to conditions favorable for the occurrence of producible gas from Devonian black shales. The basic geologic characteristics and degree of uncertainty as expressed by the geologists for explicit identification and substantial detail for each play are very similar to the circumstances encountered in the play-analysis approach used in appraising the petroleum resources of NPRA. Some significant differences may also be found between the geologic characteriation for the conventional occurrence of petroleum and that of the unconventional natural gas occurrence in the black shales.

These similarities and differences can be summed up as follows:

The Devonian shales can be subdivided and delineated as distinct units or plays of approximately homogeneous geological and geochemical characteristics. The extent, geometry, and stratigraphic relations of each play can be defined and mapped the same way that they were in NPRA. Reservoir engineering variables such as porosity, permeability, reservoir pressures and temperatures, and methane compressibility can be measured, and a geochemical analysis can be made of types and amounts of organic matter within the black-shale facies.

One major difference between conventional gas and unconventional gas in shales is that the former occurs in well defined and mappable reservoirs, whereas the latter, when it is in commercial amounts, is usually concentrated in areas where the shales are naturally fractured, jointed, or faulted. The types of porosity in black shales are: 1) effective microporosity due to matrix porosity and microfractures, and 2) porosity due to macrofractures.

The Devonian shale resource appraisal includes only "movable" gas, i.e., gas that can leave the shale under "reservoir" conditions in response to the disequilibrium caused by a well penetrating the shale unit. "Movable" means that the gas can leave a core sample at surface conditions without grinding or heating. "Movable" gas is assessed only when in "black" facies, i.e., shale having an organic-matter content greater than 2% by volume (Schmoker, 1980).

In light of the significant differences between the geologic characteristics that identify the conventional natural gas reservoirs and those that define the unconventional natural gas in black shales, several changes must be made in the geology model for assessing the natural gas resources. The most important change is the basic equation used to calculate the amount of gas within each play and the essential parameters required for the equation.

The basic equation as designed by members of the USGS for assessing the amount of movable gas in the black shales is defined as follows:

$$G_m = (\phi_{e,mi})\,(Th_B)\,\frac{(P_{r1})}{(P_s)}\,\frac{(T_s)}{(T_{r1})}\,\frac{(1)}{(Z_1)} +$$

$$(\phi_{f,ma})\,(Th_f)\,\frac{(P_{r2})}{(P_s)}\,\frac{(T_s)}{(T_{r2})}\,\frac{(1)}{(Z_2)} + (Y_s)\,(TH_{ORG})$$

where

G_m = cubic ft of movable gas at standard conditions/square feet of land surface

$\phi_{e,mi}$ = effective microporosity due to matrix porosity and microfractures

$\phi_{f,ma}$ = porosity due to macrofractures

Th_B = thickness of black-shale facies (ft)

Th_f = thickness of fractured interval

P_r, P_S = reservoir pressure and standard pressure, respectively (PSI)

T_r, T_s = reservoir temperature and standard temperature, respectively (absolute)

Z = methane compressibility (gas-deviation factor)

Y_S = cubic feet of movable gas at standard conditions/cubic feet of organic matter

TH_{ORG} = net thickness of organic matter (ft) in the black shale facies.

The equation that calculates the amount of "movable" gas should be evaluated for each of the geologic plays as defined for the Appalachian Basin. The plays are defined so that within each unit, the geologic and geochemical properties represented by the equation are relatively homogeneous. Values are determined using subjective judgment by the geologists and geochemists for the various probability distributions for the total "movable" gas, and the terms constituting the equation are computed for each play. These distributions when multiplied by the area of the play will give the expected volumes of movable gas. The probability distributions for the resource appraisal for the gas in each play will be aggregated statistically to give the total assessment of gas resources within the black shales of the basin.

In addition, the probability of each play being favorable, in terms of the existence of "permeable pathways" (such as a fracture system) that allow the movable gas to reach a well, is subjectively determined. A subjective ranking of the various plays can be made.

A Pilot Study in Devonian Black Shales of the Appalachian Basin

The modified play analysis approach, incorporating the newly formulated equation and the related assumptions and parameter values, was applied on an experimental basis to a pilot area within the Appalachian Basin. A five-county area within West Virginia was selected for the experimental trial runs to assess the unconventional gas within the black shales. Three plays were distinguished for an appraisal of the gas resources. Figure 7 is a map of the pilot area,

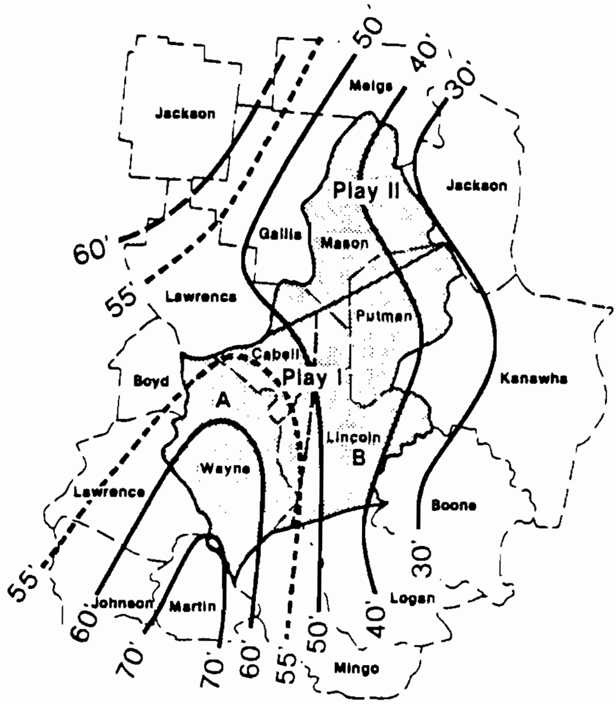


Figure 7. Devonian black shale pilot area - Plays I A&B, II. Average volume % organic content of "black" shales.

showing the mapped boundaries of the plays within that area. Plays IA and IB are geologically defined in part by the structural aspects of the Rome Trough and in part by the characteristics of the organic matter within the black shale. Play II is outside the trough area and has different organic characteristics. Note that the county boundaries of the pilot area arbitrarily cut out only segments of each of the naturally occurring plays for assessment; thus, the resulting estimates do not represent a complete appraisal of any one of the three plays.

Figure 8 is an example of the data formats used to compile the essential information for each play (Miller, 1980). A team of six geologists and one petroleum engineer met to review and interpret available information prior to making the subjective judgments concerning the values for each of the geologic variables shown on the format. The reservoir data were compiled whenever available or analog data were used if specific information

PILOT AREA: DEVONIAN BLACK SHALE

Identify Play: ____________

PLAY FAVORABILITY	PROBABILITY OF BEING FAVORABLE ON A SCALE OF 0 TO 1	COMMENTS
Existance of Permeable 'Pathways'*		

* 'Pathways' which allow the movable gas to reach a well, whether by fracture systems, porous lenses, etc.

GAS VOLUME PARAMETERS	PROBABILITY OF EQUAL TO OR GREATER THAN			MODE
	95%	50%	5%	
Effective microporosity $\phi_{E,MI}$ (%)				
Porosity due to macrofractures $\phi_{F,MA}$ (%)				
Thickness of black shale Facies TH_B (ft.)				
Reservoir Pressure P_R (PSI)				
Reservoir Temperature T_R (absolute)				
Movable gas/organic matter Y_g (cu.ft./cu.ft.)				
Thickness of organic matter TH_{ORG} = ORG* (organic content of Black Shale) X TH_B				
*Estimate ORG (% vol.)				
Depth of Black Shale Units (ft.) Assume mid-point of units				
Area of Play (sq. miles) If boundaries of play are fixed, give one value; if boundaries are uncertain, give range				

Standard Pressure P_S	
Standard Temperature T_S	
Compressibility of Gas, z factor (Tables)	

Figure 8. Data format form for natural gas resources appraisal in Devonian black shales.

was not known within the boundaries of the pilot area.

Preliminary Findings of the Resource Assessment Procedures in the Pilot Study

The play approach was used on each of the three plays for several trial runs to remove the "bugs" from the newly modified geology model. The assessments were reviewed and analyzed in terms of the geochemical and technical information available in the pilot area. The following results should be viewed as preliminary and are shown for comparative purposes for the "gas richness" determined for the segments of each of the three plays.

Preliminary
Resource Estimates of Movable Gas
in Pilot Area, in Trillions of Cubic Feet

PLAYS	Probability that Quantity is at least Given Value: 95%	5%	Mean Value	Probability of Favorable "Pathways" (%)
Play 1A	1.62	4.35	2.95	100
Play 1B	5.90	14.75	9.65	100
Play II	.74	1.77	1.23	100

Conclusions on the Use of the Play Analysis Approach to Black Shale Gas Appraisals

The play-analysis approach, using a modified geology model to determine the amount of unconventional natural gas within the Devonian black shales of the Appalachian basin, is considered by the geologists working on the project to have high merit. Research will continue on refining the method and the computer program and in checking out all the technical aspects related to the basic assumptions in the geology model, in particular, the geochemical concepts of "movable" gas and the relationships of sorbed gas to organic content in the black shales.

The USGS plans to continue the research and development of the play analysis approach for resource appraisal work both for conventional petroleum resources and for the assessment of unconventional petroleum resources.

A strong interest has been expressed by other governbment agencies for the Survey to use the application of the geology model to the play-analysis approach for assessing conventional petroleum resources which would provide input into those agencies various economic models.

A SUMMARY OF THE U.S. GEOLOGICAL SURVEY'S PETROLEUM RESOURCE-APPRAISAL SYSTEM

The resource-appraisal system used at this time by the Resource Appraisal Group within the U.S. Geological Survey is one that will achieve the following:

1. Resource-appraisal methods that emphasize the evaluation of all the available geologic and geophysical data by geologic basins or

provinces.

2. The compilation of a comprehensive information data base containing all of the pertinent geologic and geophysical data, exploration statistics, field and reservoir data, and production and reserve data for each producing and potential petroleum province in the United States.

3. The application of at least two or more resource-appraisal techniques on each area to be assessed as a means of cross checking within reason the resource estimates, if time and conditions permit.

4. The review and analysis of the basic information and appraisal results by a team of geologists applying all the resource appraisal procedures feasible (see Figure 9). This team provides the final subjective probability estimates that are used as input in the various Monte Carlo techniques to aggregate the final resource assessments by basin, region, an entire Nation, or the World.

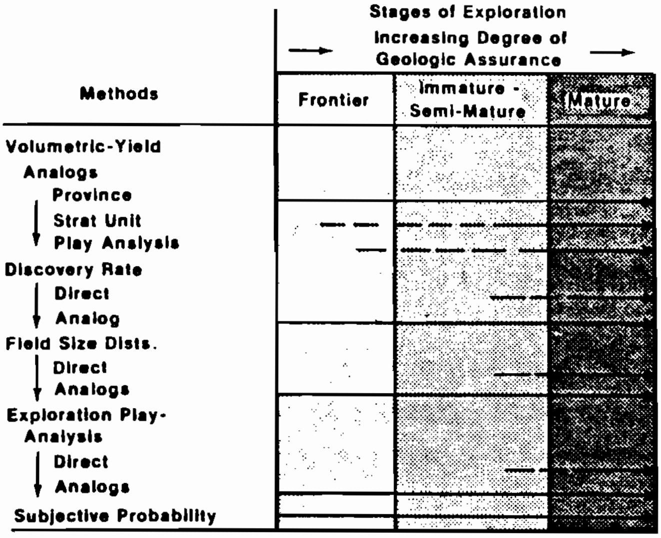


Figure 9. Resource appraisal methods applicable for the various stages of exploration in a petroleum province with an increasing degree of geologic assurance.

CURRENT ACTIVITIES IN THE RESOURCE APPRAISAL GROUP

Activities having priority in the immediate future for the Resource Appraisal Group are: (1) A revised, expanded, and updated version of Circular 725 which is currently in progress; this new assessment of the Nation's petroleum resources is to be completed late in 1980; (2) current updates on the petroleum resources of all Outer Continental Slope (OCS) basins for the United States; (3) continuing research on resource appraisal methods, particularly in the area of play-analysis methods; and (4) the initial development of a world petroleum resource-appraisal system for analyzing petroleum resources on an international basis.

CONCLUSIONS

This review of the evolution in the oil and natural gas resource appraisal methods used by the Resource Appraisal Group in the U.S. Geological Survey since 1975 covers the significant developments in the appraisal procedures for assessing our Nation's resources. We recognize that some major problems related to resource assessments have arisen primarily from a confusion in terminology and in the assumptions, qualifications and limitations related to various resource appraisal methods. These problems have created misunderstandings in the meaning and interpretation of resource information and in the application of resource estimates by the media, government and the public. Scientists making resource assessments must strive to reach some agreement on a system of resource classification, definitions, and basic assumptions for resource appraisal studies.

An understanding of the availability and distribution of the Nation's resources is a fundamental requirement for the formulation of a national energy policy. Great uncertainties are inherent in estimating undiscovered petroleum resources and will continue to plague the geologist trying to make these estimates; However, the limitations imposed by these uncertainties must be recognized, understood, and dealt with realistically. Geologists and other scientists devoting their expertise to making resource estimates must clarify the terms used, improve upon the resource appraisal methods applied to these studies, and keep up to date with the dynamic and everchanging petroleum data bases. Individual scientists, government agencies, and industry must use the best expertise available to estimate the amounts of undiscovered petroleum resources, both domestic and worldwide, that remain available for use, in order to plan for the rational exploration and development of these resources in the future.

The Resource Appraisal Group, as a part of the research program of the U.S. Geological Survey, will continue to meet its responsibilities to develop resource appraisal methods and to apply these methods for assessing the Nation's and the World's petroleum resources.

ACKNOWLEDGMENTS

I would like to acknowledge the work of all past and present members of the Resource Appraisal Group of the U.S. Geological Survey, for without the team effort provided by the Group, this paper could not have been written.

REFERENCES

Arps, J.J., and Roberts, T.G., 1958: "Economics of Drilling for Cretaceous Oil on East Flank of Denver-Julesburg Basin," American Association of Petroleum Geologists Bulletin, v. 42, no. 11, p. 2549-2566.

Day, D.T., 1909, "Petroleum Resources of the United States," in U.S. Geological Survey Bulletin 394, p. 30-61.

Department of Energy, Mines and Resources of Canada, 1977, "Oil and Natural Gas Resources of Canada 1976," Minister of Supply and Services Canada, Report EP77-1, 61-73

Dolton, G. L., Coury, A. B., Frezon, S. E., Robinson, K., Varnes, K. L., Wunder, J. M. and Allen, R. W., 1979: "Estimates of Undiscovered Oil and Gas, Permian Basin, West Texas and Southeast New Mexico," U.S. Geological Survey Open File Report 79-838, 72 p.

Hendricks, T. A., 1965: "Resources of Oil, Gas, and Natural-Gas Liquids in the United States and the World," U.S. Geological Survey Circular 522, 20 p.

Hubbert, M.K., 1962: "Energy Resources - A Report to the Committee on Natural Resources of the National Academy of Sciences - National Research Council," National Academy of Sciences, National Research Council Publication 1000-D, 141 p.

Hubbert, M. K., 1974, "U.S. Energy Resources, A Review as of 1972," pt. 1 in "A National Fuels and Energy Policy Study," U.S. 93rd Congress, 2nd session, Senate Committee Interior and Insular Affairs, Committee Print, Serial No. 93-40 (92-75), 267 p.

Miller, B. M., Thomson, H. L., Dolton, G. L., Coury, A. B., Hendricks, T. A., Lennartz, F. E., Powers, R. B., Sable, E. G., and Varnes, K. L., 1975, "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," U.S. Geological Survey Circular 725, 78 p.

Miller, B. M., Pike, R. S., Powers, R. B., Scott, E. W., Khan, A. S., Carlson, K. H., Vietti, B. T., and Lambert, G. D., 1978, "Task I Interagency Oil and Gas Supply project, Pilot Area: Gulf of Mexico," U.S. Geological Survey, unpublished data, 115 p.

Miller, B. M., 1979, "The Evolution in the Development of the Petroleum Resource Appraisal Procedures in the U.S. Geological Survey and a Summary of Current Assessments for the United States," Proceedings SPE-AIME Symposium on Petroleum Economics and Evaluation, Dallas, Texas, Feb 11-13, 1979, SPE-7720, p. 79-90.

Miller, Betty M., 1980, "Application of Exploration Play-Analysis Techniques to the Assessment of Conventional and Unconventional Petroleum Resources," abstract, American Association of Petroleum Geologists, Bulletin 64, no. 5 and convention program, Denver, Colorado, June 8-11, 1980.

Moore, C. L., 1966, "Projections of U.S. Petroleum Supply to 1980," with appendix entitled "The Gompertz Curve for Analyzing and Projecting the

Historical Supply Patterns of Exhaustible Natural Resources," U.S. Department of Interior, Office of Oil and Gas, 13 p.

National Petroleum Council, 1973, "U.S. Energy Outlook, Oil and Gas Availability," National Petroleum Council, 786 p.

Schmoker, J. W., 1980, "An Approach to Resource Appraisal in the Appalachian Devonian Shale," U.S. Geological Survey, unpublished data, 6 p.

Thomsen, H.L., 1979, "Oil and Gas Resource Appraisal--State of the Art," abstract, American Association of Petroleum Geologists, Bulletin 63, no. 3, p. 540.

U.S. Department of Interior, Office of Minerals Policy and Research Analysis, 1979, "Final Report of the 105(b) Economic and Policy Analysis, Alternative Overall Procedures for the Exploration, Development, Production Transportation and Distribution of the Petroleum Resources of the National Petroleum Reserve in Alaska (NPRA)," 145 p.

Weeks, L. G., 1950: "Concerning Estimates of Potential Petroleum Reserves," American Association of Petroleum Geologists Bulletin, v. 34, 1947-1953.

Zapp, A. D., 1962: "Future Petroleum Producing Capacity in the United States," U.S. Geological Survey Bulletin 1142-H, 36 p.

THE DEVELOPMENT OF MODELS TO STUDY THE NATURAL GAS DEPOSITS OF NORTHWESTERN SIBERIA

G.N. Kuznetsov, M.V. Sidorenko, and I.N. Zimin
All-Union Research Institute for Systems Studies, Moscow, USSR

INTRODUCTION

Gas is one of the main fuels used in the USSR and the gas industry is developing at a rapid rate. The industry's vigorous growth during the period 1960-1970 was caused by the availability of large proven and speculative reserves. Although only 127.7 billion m^3 were extracted in 1965, this figure will exceed 435 billion m^3 in 1980.

According to preliminary calculations, during 1980-1985 and 1985-1990, the Northwest Siberian gas complex (NWS) will be the main source of this increase; its share of gas production will grow from 8.4% in 1975 to 50% in 1985.

The USSR now has the largest gas-supply system in the world, 135,000 km of main at the end of 1980. Total gas production is the second largest in the world and yearly rates of growth exceed those of all other countries. The development of gas production has demanded consideration of supplies as a whole in order to draw up a middle- and long-term strategy, since gas reserves in regions which are well populated and near to the industrial centers of the USSR in Europe are limited.

In the mid-1960s the main proven reserves of natural gas were in the European part of the USSR. At present about 84% of the total Soviet reserves are known to be in the Asian part of the country, more than 70% of this being in the NWS.

The role of the NWS gas in satisfying the demands of the national economy is constantly growing. In 1980, 23% of the demand for gas in the European area was satisfied from NWS resources. In accordance with provisional figures, the NWS gas share will rise to 42% and in 1990 will be more than 50%.

THE NWS REGION

Since the NWS region will become the main base of natural gas resources in the USSR, a policy is required to determine the maximum levels of extraction, taking account of the fact that stocks should be conserved for as long as possible. The development of NWS gas deposits depends on essential capital investments to provide plants for extraction, suitable transport sytems for distribution, and the necessary infrastructure.

The NWS gas complex went on stream in 1965-1970 and is developing at an increased rate. Thus, while during that period capital investments amounted to 4.7 billion rubles, in 1970-1975 this sum was 9.5 billion rubles and in 1975-1980 is expected to grow to 21 billion rubles.

The main proven reserves of gas (more than 60%) are located in the unique deposits of the NWS region--Urengoiskoye, Yamburgskoye, Medvezhye, and Zapolyarnoye--more than 10.5 trillion (million-million) m^3 of natural gas in all (Table 1). At present, industrial exploitation of only the deposits at Medvezhye (since 1972), Urengoiskoye (since 1978), and Vyngapurskoye (since 1977) is being carried out but by the end of 1985 the Yubileinoye, Yamburgskoye, Severo-Urengoiskoye, and other deposits are planned to produce gas.

In 1978 65 billion m^3 of gas were extracted at Medvezhye and 30 billion m^3 at Urengoiskoye. Although the Medvezhye deposit has already reached the efficiency projected in 1976, gas extraction from the Cenomanian stage of the Urengoiskoye deposit should amount to 100 billion m^3 (Orudgev, 1976), though at present this extraction rate is being modified.

The proven natural gas reserves of the USSR total 25.8 trillion m^3--4.2 trillion m^3 in the European area (16.3%) and 18.2 trillion m^3 (70.5%) in the Siberian and Far East regions. The NWS gas reserves total 17 trillion m^3 and probable reserves 73 trillion m^3. Sufficient geological work has now been done to enable development of the resources. Thus, it seems possible to forecast possible extraction levels both from individual deposits, and groups of deposits. However, taking into account the enormous distances between the resources base and the consumers, together with the huge capital investments required for pipeline construction, it is necessary to lay down the following provisions: (a) extraction levels by region must be constant for 30-35 years, according to the pipeline amortization period (33 years); (b) extraction levels must be at this maximum for 10-15 years, according to the size of deposits; and (c) the extraction ratio must be 0.9-0.95, according to actual geological data.

TABLE 1 Characteristics of the main NWS gas deposits (Orudgev, 1976).

Deposit	Productive stage	Depth (m)	Altitude (m)	Reservoir size (km)	Depth pressure (atm)	Reserves (trillion m^3)	Well capacity (thousand m^3 day^{-1})
Urengoiskoye	Cenomanian	1100-1240	211	166x25	118.5	3.9	1000.0
Yamburgskoye	Cenomanian	1000-1200	200	160x45	114.0	3.0	200.0-700.0
Zapolyarnoye	Cenomanian-Turonian	1100-1300	230	50x30	128.4	2.0	150.0-250.0
Medvezhye	Cenomanian	1060-1210	136	120x25	113.5	1.6	1000.0

Taking into account the above considerations and limitations, it is possible to make some calculations about gas extraction and development in NWS.

A CONCEPTUAL BASIS FOR MINERAL RESOURCES DEVELOPMENT AND PRODUCTION MODELING

At present a system of models is under construction at VNIISI* for the development of mineral resources. This is called DYMMIR, and denotes Dynamic Models for utilization of Mineral Resources. The results of the analysis of potential alternatives for the development of natural gas resources in NWS, as presented in this paper, are based on the DYMMIR system.

Before a description of this model is given, the conceptual basis of the complete system will be briefly considered. Analysis of the resources of individual regions is usually related to an assessment of the availability of the potential resources to meet an increasing demand. In general, the supply is considered to be functionally interconnected with the resources and reserves of given minerals as well as with their potential consumption. There is a wide variety of methods in the literature for calculating the availability of resources. These methods are based on various assumptions about the factors which influence reserves and the consumption of resources over a period of time (Orudgev, 1976; Anon. 1979).

Our view was determined by the following major considerations when dealing with the problem: (a) the uncertainty of the present estimates for the availability of resources; (b) the differences in assessing resources when viewed first from the technical then the economic viewpoint in regard to their exploration and extraction; (c) the fuzziness of the criteria for economic efficiency of the above processes; and (d) the interchangability of various mineral resources.

It seems reasonable to concentrate on social, economic, technological, and ecological constraints which directly influence the availability of resources in a given region.

Taking into account the complexity of the research made necessary by the complexity of the above considerations, a decision was made to use a man-machine simulation as the basic tool to attack the problem. This approach was based on multiple, adequately detailed reproductions of the process by a computer, direct access being maintained by experts of all the disciplines involved at all stages of the simulation.

It became clear that the problem could not be dealt with in a single model because of the complex phenomena involved and the presence of nonformalized elements. Hence efforts were made to develop a system of simulation in which both formalized and nonformalized subsystems were represented.

---

*VNIISI denotes All Union Institute for Systems Studies.

The system is designed to give long-term predictions on the availability of resources in a given region, and can also be used as a basis for providing the required inputs to the mineral resources block of a global system of models (Gelovany, 1980) and a system for national optimal forward planning (Danilov-Danilian and Zavelsky, 1975). Thus, the DYMMIR system provides the opportunity to simulate various alternatives to the organizational structure inherent in existing regulations (central planning or local plans) and to the type of regionalization (province, state, or group of countries) best suited for the purpose.

Some basic assumptions were made in designing the system.

(1) A mineral resource was considered to be a natural association of materials. This association yields both a basic raw material and by-products.

(2) The functional demand for a particular mineral resource was considered to be available from external sources for any region under investigation.

(3) Two supply sources, conventional raw materials, and alternatives, were considered for a particular demand. Alternative raw materials could completely or partially substitute conventional raw materials. These are raw materials whose physical and chemical properties are very close to those of the conventional raw materials.

(4) Production cycles for conventional and alternative raw materials were described and simulated separately in the DYMMIR system.

(5) A multiplicity of alternative sources was included in the analysis. For instance, natural gas, coal, heavy oil, tar sands, etc., were considered to be alternatives for conventional oil resources.

(6) Subdivision into conventional and alternative resources was to some extent conditional and depended on a particular problem statement.

The conceptual basis of the system is a precise description of the complete production stages, starting from an assessment of regional resources and ending with their conversion into raw materials. Applying the DYMMIR system to a wide range of various resources, extensive modifications are necessary to particular models or even, in some cases, the building of new models depending on the properties of a specific resource.

A general scheme of interrelation for various categories of resource in the system is shown in Figure 1. The classification of categories is that of McKelvey (1972) with slight modification of definitions when required. Arrows in Figure 1 indicate the direction of resource flows. Factors which control the intensities of flows are process-specific and described individually for each model.

One of the family of models will now be discussed in detail.

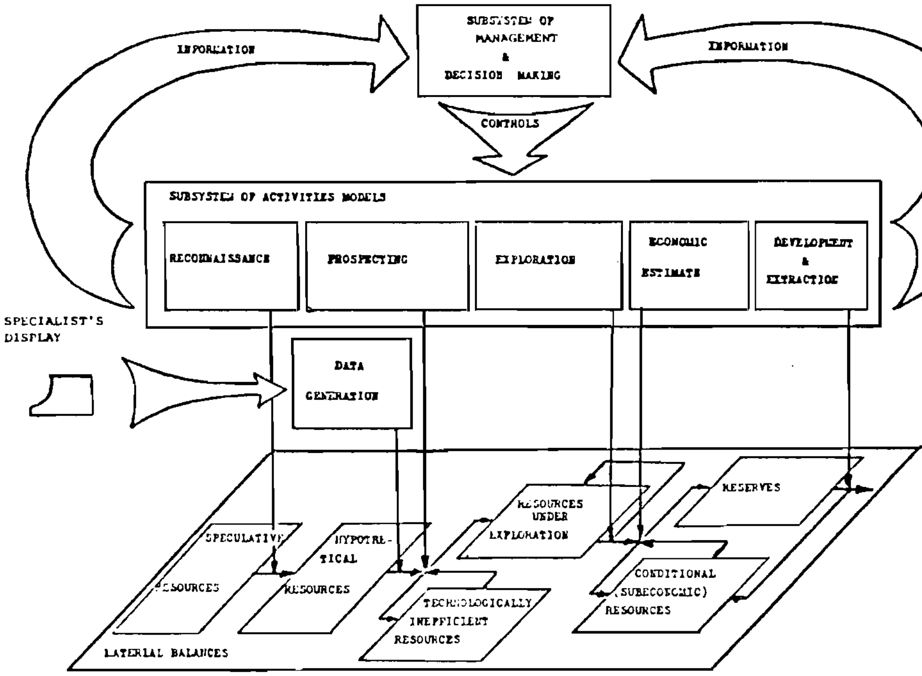


FIGURE 1 General structure of the DYMMIR model.

BRIEF DESCRIPTION OF THE "DEVELOPMENT AND EXTRACTION" MODEL

Consider the production of natural resources in a given region. The following two main problems should be resolved at the modeling stage: (a) a program for the development of resources in the long term, and (b) a sequence for the development of resources, taking into account any possible restrictions and constraints.

The main constraints may be induced, initially, by considering a limited supply of materials and facilities, limited capital investment, regional constraints (for instance, availability of water and land resources, possible concentrations of pollutants, etc.) and, then, considering limitations in the desirable production rates and reserves.

In developing a program for the utilization of regional deposits, a set of possible alternatives was taken into account for each individual deposit, with the following assumptions: (a) only known deposits can be included in the program when it is being planned; (b) utilization plans for deposits must not be changed or modified at the time of program construction; and (c) if priorities are defined for individual deposits, these deposits will be developed in the sequence determined by consideration of these priorities, such priorities being provided either by a simulated management system or by a specialist.

Assuming a constant extraction rate of resources during the lifetime of each individual deposit, which depends in practice on maintaining a working crew of constant size, economic efficiency, and technological feasibility, the typical shape shown in Figure 2 is used for simulating production over a period. Of course, the lifetime and height of the plateau may differ both for different deposits and for different alternative production patterns for any given deposit. These patterns depend on the application of known or hypothetical (but expected) technologies to resource extraction, as well as mixtures of technologies or possible transfer from one technological mixture to another. The latter allows technological progress to be simulated by an analyzer. The possibility of including hypothetical technologies in the model allows one to analyze their influence on all stages of resource production, exploration, and development.

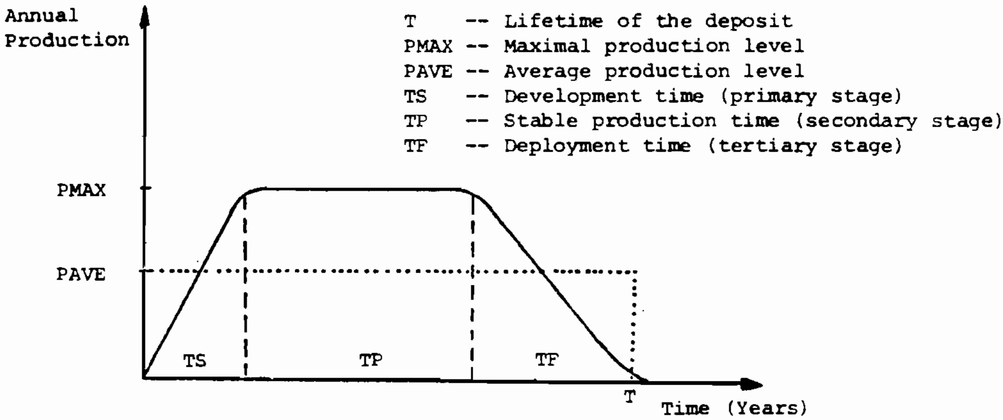


FIGURE 2 Graphical interpretation of a project for development and production of an individual deposit.

In the model each technology is characterized by a set of parameters

$$\{P_i, A_i, F_i, L_i, B_i, R_i, K_i\}$$

where P_i is the productivity of the unitary capacity utilizing the ith technology, A_i is the vector for specific operational costs (for instance, labor, facilities, materials, etc.) in the natural expression*, F_i is the capital stock per capacity unit, L_i is the vector of specific parameters which characterize the influence of a given technology on the environment, B_i is the costs of the infrastructure per unit of production capacity, R_i is the vector of specific capital investment, and K_i is the vector of the geological parameters which limit the applicability of the ith technology (for example, minimal depth pressure, minimal concentration of a given mineral in the earth's crust, maximal depth, etc.).

*A_i can be considered as a vector of the WELMM factors (Grenon and Lapillone, 1976) required to run a given capacity.

The sequence of technological treatments to be applied in production is assumed to be given, determined by the nature of the resource being extracted and the range of feasible technological processes. In the case of crude oil this sequence consists of primary, secondary and tertiary methods.

In the model the sequence of ordering for the technological processes is represented by a graph, whose nodes correspond to technologies and arrows define the order for use in the extraction process. The point of transfer from one node to its successors depends on the values of the geological parameters (K_i). These determine the conditions of applicability of the individual technology, which change during the extraction process. The need to transfer from one technology to another arises in resource extraction when geological conditions change to such an extent that further utilization of the first technology becomes inefficient or cannot maintain the desired production level. In the case of natural gas, the above can be illustrated by initial extraction which does not require pumping, and later stages of extraction where pumping is necessary because of changes in the geological parameters, such as change of pressure with depth.

INITIAL DATA

Data on the various NWS deposits is given in Table 1. In addition the following values (costs are in conditional monetary units) were used for calculations of the model: a compressor station of capacity 7.5 billion m^3 $year^{-1}$; a main pipeline of capacity 33.0 billion m^3 $year^{-1}$; capital investment of 0.6 million rubles for the construction of each well; capital investment of 21 million rubles for construction of each compressor station necessary for additional pressure; operating costs per well of 0.085 million rubles per year; operating costs of each compressor station necessary to provide additional pressure of 3.4 million rubles per year; a selling price of 15 rubles per thousand m^3 of product; a discount ratio of 0.08; a value of 1.4 for the ratio of the pressure increase at the exit of each compressor station necessary to provide additional pressure; and a pipeline working pressure of 70 atm.

In calculating the parameters for the development of each deposit the following variables were used: extraction ratio 0.9-0.95; deposit lifetime 10-30 years; development time 1-7 years; and stable production time 5-15 years.

Possibilities for varying the assessment of the reserves of each deposit and the periods and costs of further exploration are provided in the model. Nevertheless, in the present work, assessment of reserves was assumed to be given and, therefore, further exploration was not considered.

DISCUSSION OF RESULTS

Using this approach more than one hundred alternative methods for working each of the main NWS deposits have been calculated. A selection of the acceptable methods was made in two stages.

The first stage is represented schematically in Figure 3; to be acceptable a variable must first satisfy several criteria which are chosen in advance. The final ten are chosen on the basis of production costs and commercial profit. Only occasionally are variables found which satisfy all the criteria involved.

In the second stage, all the selected information is considered by specialists before a final decision is made. A typical set of variables is shown in Figure 4.

The selection of the specialist is made on the basis of criteria which are not strictly laid down. Such criteria would include the geological structure of the deposit which might affect extraction, availability and level of labor and materials at the deposit site, and the contribution of the project to the development of the NWS region in accordance with the overall strategy for the gas industry of the USSR.

The methods chosen for each deposit now analyzed are shown in Table 2. It is necessary to point out that the given methods are preliminary and will be refined by using more detailed information about both the deposits considered and smaller deposits of the same region.

A number of schedules for the development of each deposit is selected from an economic assessment and from the point of view of the technical, material, and labor resources of the region. Both formalized schedules and informal methods suggested by specialists are considered.

A model schedule for developing the main deposits of NWS is given in Figure 5. When determining a schedule the following factors have been taken into account: (a) attainment of maximal extraction level for a group of deposits by 1990-1995;

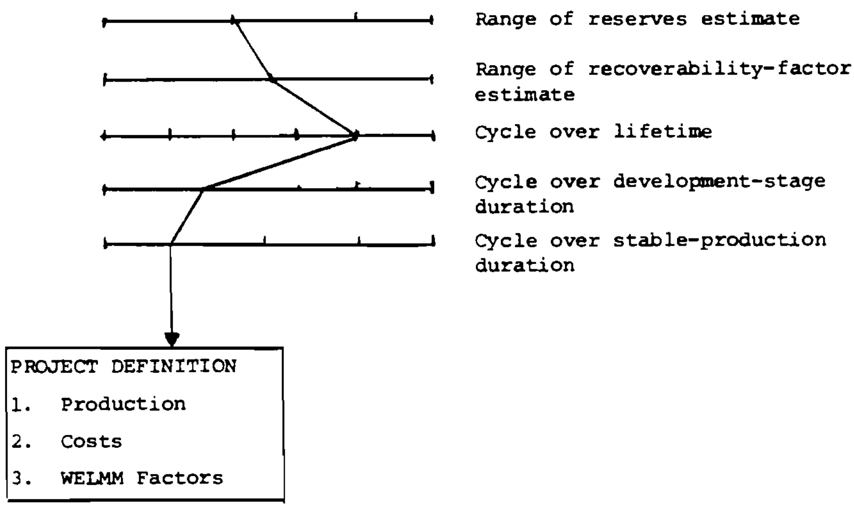


FIGURE 3 Analysis scheme.

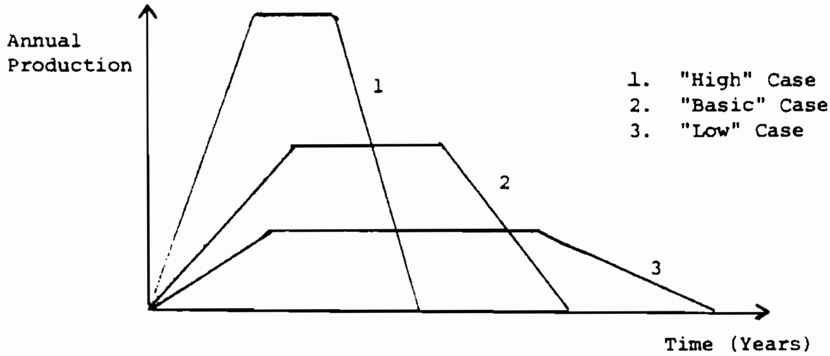


FIGURE 4 Alternative projects for the development and production of a deposit.

TABLE 2 Final variables chosen after analysis of each deposit.

Deposit	Lifetime of deposit (years)			Maximal production level (billion m^3 $year^{-1}$) (PMAX)[a]	Average production level (billion m^3 $year^{-1}$) (PAVE)[a]	Cost of proving (billion rubles)	Cost of product (rubles per thousand m^3)
	Development time (TS)[a]	Stable production time (TP)[a]	Deployment time (TF)[a]				
Urengoiskoye	5.0	11.0	9.0	207.5	148.2	5.6	0.011
Yamburgskoye	4.0	8.0	8.0	206.6	142.5	5.1	0.011
Zapolyarnoye	4.0	9.0	7.0	133.0	95.0	2.9	0.031
Medvezhye	5.0	14.0	14.0	63.8	45.6	1.9	0.0087

[a]See Figure 2.

and (b) the stability of material, technical, and labor resources which are used to develop the deposits in the early stages (maximal extraction level stage).

Factor (b) is the reason why the development periods for each deposit do not cross.

A stable level of extraction in NWS will be maintained by the development of other deposits which have not been mentioned in this paper. The development of the deposits is shown by the dotted lines in Figure 5.

CONCLUSIONS

The potentialities of the model systems constructed at VNIISI has been demonstrated for NWS development projects.

"Development and Extraction" model computations show that from an economic point of view it is most profitable to use a scheme which yields maximal gas extraction from a deposit for a period of 10-15 years--a rather short period of extraction. This is explained by the rapid return of capital investments into deposit development. Nevertheless, such a regime is not always

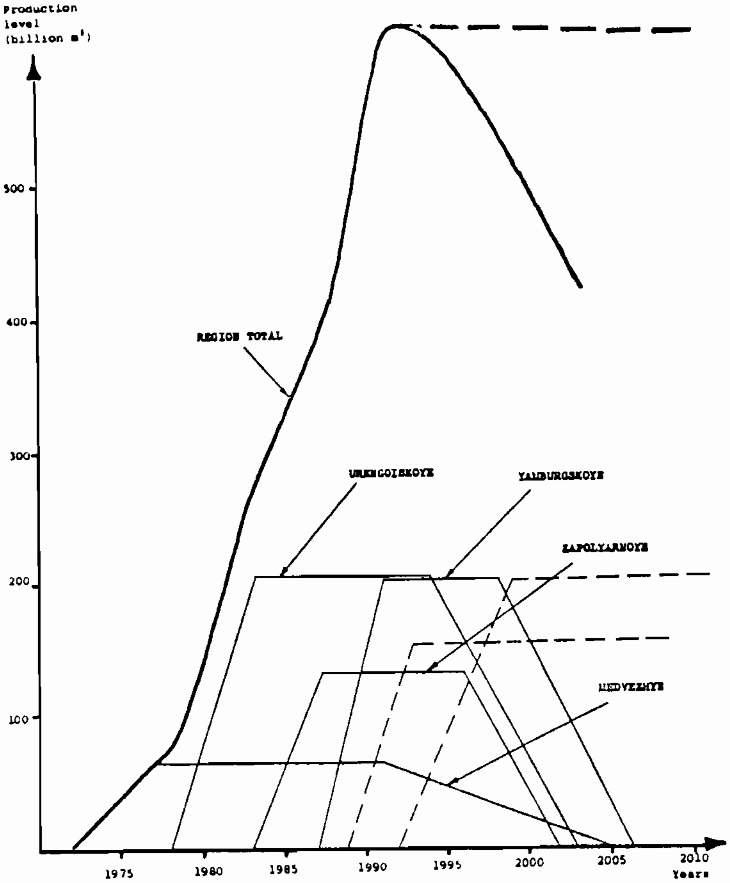


FIGURE 5 A schedule for the development and production of natural gas deposits.

possible because of the geological structure and restrictions of material and labor.

Conventional methods are difficult, sometimes impossible, to apply to the projects discussed in this paper; hence the necessity to use the procedures described to solve the problems involved.

REFERENCES

Anon. (1979). Natural Resources in the National Economy, Issue 5, VNIISI, Moscow.

Danilov-Danilian, V. and Zavelsky, N. (1975). The System of National Optimal Perspective Planning: Problem of Theory and Methods. Nauka, Moscow.

Gelovany, V. (1980). The Global Development System of Models. VNIISI, Moscow, 1978.

Grenon, M., and Lapillone, B. (1976). The WELMM Approach to Energy Strategies and Options. RR-76-19. International Institute for Applied Systems Analysis, Laxenburg, Austria.
McKelvey, V.E. (1972). Mineral resources estimates and public policy. Am. Sci. Also published as Professional Paper 820, US Geological Survey, 1973.
Orudgev, S. (1976). The Gas Economy on Progress Way. Nedra, Moscow.

THE IMPORTANCE OF DEEP DRILLING TO THE NATURAL GAS SUPPLY OF AUSTRIA

A. Kaufmann and A. Kröll
ÖMV Aktiengesellschaft, Vienna, Austria

GEOLOGICAL FEATURES OF AUSTRIA

In order to convey the importance of superdeep exploration to Austria, it is necessary to explain briefly its geological situation. The geological structure of Austria is extremely heterogeneous and of very different tectonics. On top of the crystalline shield of the Bohemian Massif in the north and northeast, there is a 10-15 km wide strip of tertiary sediment of Molasse, with, in part, a thickness of more than 2000 m, formed from erosion products from the Alps. In the northeast and west one finds, covered by these Molasse deposits, autochthonous Jurassic and Upper Cretaceous sediments, with thicknesses up to 3000 m. Adjoining the Molasse zone towards the south, there are Alpine nappes, essentially consisting of Mesozoic sediments and generally to be classified into several zones. Towards the north the Flyschzone, consisting of Upper Cretaceous and Paleogene sediments, has overthrust the Molasse and is itself overthrusted in the south by the northern limestone zone. The limestone Alps consist mostly of Triassic and, to a smaller extent, Jurassic carbonates.

In the central Alpine area, reaching across Austria from west to east, crystalline rocks are found which make up the main chain of the Alps. This Paleozoic deposit, resting on top of the central Alps, as well as the Mesozoic deposit which exists south of the Alps are only mentioned here; neither is of any importance for hydrocarbon exploration.

Covering the Alpine nappe structure and included in the eastern part of the Molasse zone, there are young tertiary deposits on the eastern border of the Alps. These have a thickness of up to 5000 m in the Vienna Basin, which is an area of extension. This region of inner-Alpine subsidence of the Vienna Basin has been of special importance to hydrocarbon exploration, especially for natural gas prospecting. Sediment thicknesses up to 15000 m can be expected, existing in several floors. Floor I consists of the Neogene basin-filling, in which 38 oil and gas fields have been developed to date. Underneath is situated floor II with Mesozoic layers of Alpine nappes, where the gas field of greatest importance to Austria has been developed at a depth of 4600-5900 m (Schönkirchen Superdeep). Floor III, the deepest, is of greatest importance for future exploration. This floor encompasses all sediments situated beneath the Alpine nappes and consists mainly of Mesozoic and Paleozoic deposits. The superdeep wildcat Zisterdorf Übertief reached this floor in the Vienna Basin for the first time and gas was proved at a depth of 7544 m.

A further province for gas exploration is the Molasse zone, where in the past gas-bearing has been proved both in the western and eastern region. The gas is found within the Molasse (Chatt, Eocene) layer, as well as the Mesozoic layers below. In close contact with the Molasse there is a further prospective zone, the overthrust Molasse, where several gas fields have already been found; further finds are anticipated.

NATURAL GAS EXPLORATION IN AUSTRIA

Excluding oil shale and local oil finds in historic times, the first discoveries of oil and gas in Austria were as long ago as 1844 and 1845, while drilling a wildcat within Vienna's city limits. It has been reported that during drilling in the Sarmat at a depth of 207 m, salt water and combustible gas (which most certainly meant natural gas) was discovered. The first economically profitable production of natural gas in Austria was in 1892, within the city limits of Wels at a depth of 250 m. This natural gas comes from sandstones of the Burdigal. Within the Vienna Basin, oil and gas was first proven in 1913 near Eggbell, today in Czechoslovakia. Commercial gas production started with the gas reservoir in the area of Oberlaa near Vienna in 1932. In 1934 the first economically profitable oil production was started near Gösting. Until the mid-fifties, natural gas production came exclusively from the Neogene of the Vienna Basin. Natural gas was found in the eastern Molasse zone (Wildendürnbach area) in 1960. A natural gas industry, in today's sense, was developed only after the formation of the ÖMV Aktiengesellschaft in 1955. The development of natural gas production in the Molasse of Upper Austria took place simultaneously with oil exploration in that area. The first discovery was at Puchkirchen in 1956.

Until the mid-1950s, only the Neogene basin-filling had been explored to any extent. Drilling activities sometimes also reached the floor of the basin which was mainly Flysch at relative shallow depths. With the exception of the St. Ulrich-Hauskirchen reservoir, no hydrocarbon resources worth mentioning were detected on the basin-floor. Technical possibilities for deep exploration have existed only since 1957. During that year, an exploratory drilling (Palterndorf 3) reached a depth of 3000 m for the first time in Austria.

On April 14, 1959, the exploratory drilling *Aderklaa 78* proved gas in the Triassic Hauptdolomit at a depth of 2817.5 m, based on a drill-stem test. This was the first time that gas had been found in floor II, the limestone Alpine body under the floor of the Vienna Basin. Since the sour gas component was about 0.3% H_2S and 1.2% CO_2, a desulfurization plant had to be built to make this gas usable. In addition to the Triassic Hauptdolomit, smaller gas reservoirs were also proven in the limestones of Jurassic-Cretaceous formations. The most important reservoir rock, the Hauptdolomit of the Triassic, forms a relief structure and had an original gas content of about 4 billion cubic meters (Vn), of which roughly 50% was produced. In 1960 gas was also proven in the Triassic layers of a structure underneath the Neogene in Zwerndorf-Baumgarten. In addition to the Schönkirchen Tief oil reservoir, discovered in 1962, and the Prottes Tief oil reservoir (1966), a third sour gas reservoir was found in 1964 (Schönkirchen Tief), situated in a system of the same aquifer. This reservoir had a gas content of about 850 million cubic meters (Vn) and a gas recovery of about 65% can be expected.

Encouraged by this success at depths of 2600-2900 m, within which all of the above described reservoirs were found, the exploration of the internal structures of the limestone Alps was started during 1967. On deep-drilling Schönkirchen Tief 32, sour gas was proven at depths of 4800-5400 m during 1968. The wildcat reached a final depth of 6009 m, a record for Austria at that time. In accordance with today's knowledge about this superdeep reservoir, it has an initial content of about 15 billion cubic meters (Vn) natural gas, 50% of which can be expected to be recoverable. This natural gas has a sour gas component of 14% CO_2 and 2% H_2S; the remaining component is practically pure methane.

Permeabilities of the dolomite body found in Schönkirchen Übertief reservoir average 2 mD. Average porosities are about 4%. In contrast, relief structures show permeabilities of several 100 mD and porosities of 6-9%. In 1971 another reservoir, the Reyersdorf Dolomite, was developed and in 1973 the discovery of Hirschstetten, after exploring to 3000 m, was accomplished. Finally, in 1977, in the area of Gänserndorf, gas was proven in the Schönkirchen Übertief field, reaching down to a depth of 5922 m.

Up to the end of 1979, about 33 billion cubic meters (Vn) of natural gas were produced--27.3 billion cubic meters (Vn) by ÖMV, and 5.6 billion cubic meters (Vn) by RAG. In relation to geological regions, 25.7 billion cubic meters (Vn) originated in the Vienna Basin and 7.3 billion cubic meters (Vn) in the Molasse. The deep explorations described produced mainly sour gas, 6.3 billion cubic meters (Vn) from the Vienna Basin alone. ÖMV's production share in these reservoirs has risen from 10% in 1962 to 50% in 1979. According to the reserve situation, the share of natural gas production of these reservoirs will also be about 50% in 1980. To permit appreciation of the gas production development in the Molasse zone, which is also of great importance, a breakdown of the 1979 production is valuable. The total 1979 gas production was 1.767 billion cubic meters (Vn), of which about 40% originated in the Molasse zone. The balance was produced in about equal parts from the Neogene and from the sour gas reservoirs situated in the floor of the Vienna Basin already described. Encouraged by success in the Molasse zone and the Waschberg zone, both reaching underneath the Vienna Basin, the superdeep drilling Zisterdorf 1 was started at the end of 1977, targeting the autochthonous Mesozoic and Paleozoic deposits. After penetrating the Neogene basin-filling and the Flyschzone, this drilling aims to reach the prospective sediments of the autochthonous Mesozoic. In January 1980 gas was proved at a depth of 7544 m in the Mesozoic layers. During a test run, the daily production rate was above 1 million cubic meters (Vn) and it is assumed that this well is producing from the deepest economically profitable gas reservoir in the world. An estimate of this gas resource will only be possible after further drilling. This and previous successes have encouraged ÖMV Aktiengesellschaft to pursue superdeep exploration with even more determination.

GAS PRODUCTION FROM VERY DEEP RESERVOIRS

Manfred Lorbach and Wolfhart Mohr
Petroleum Engineering Department, Mining University of Leoben, Austria

The importance of natural gas as a primary source of energy has only become apparent in the last few years. Thus statistics on the world reserves of natural gas in conventional and unconventional locations have only recently become available. Conventional gas reserves are gas reserves in reservoirs which contain dry natural gas in situ. Unconventional natural gas reserves are reserves from coal gasification, gas from Devonian shales, from formations with low permeability, geopressured gas, and gas hydrates. Estimates of unconventional natural gas reserves are only available for the USA. Conventional reserves and gas reserves from formations of low permeability are compared in Table 1.

TABLE 1 Natural gas resource estimates (10^{12} m_n^3).

	USA				World
	Nat. Acad. Sci (1974)[a]	Exxon Base exp. (1974)[a]	McCormick et al. (1978)[b]	Meyer (1979)[c]	Mayerhoff (1979)[d]
Reserves	10.08	9.85			66.8
To be discovered	15.01	16.48			--
Total conventional reserves	25.09	26.33			--
Formations of low permeability			15.52	16.88	

[a]Fueling the 80s, J. Pet. Techal, January 1980, Spec. Eng. Report.
[b]World Energy Resources 1985-2020, World Energy Conference, IPC Sciences and Technology Press, 1978.
[c]R.F. Meyer, The Resource Potential of Gas in Tight Formations, 2nd IIASA Conference on Energy Resources, 5-16 July 1976, Laxenburg, p.645. Criteria used for inclusion were (a) the natural gas potential of the Rocky Mountains, (b) production is not feasible with conventional completion technology, (c) conditions of at least 30 m net pay, max. 65% water-saturation, and 5-15% porosity exist, (d) reservoir depth is between 1525 m and 4570 m, and (e) prospective areal extent of reservoir is at least 30 km^2.
[d]In W. Rühl, Petroleum and natural gas resources and reserves worldwide--exploration and harnessing problems, ANEP, 1979, pp.1-11.

Table 1 shows that the conventional "reserves remaining recoverable" are about the same as the reserves from reservoirs of low permeability. It is, however, necessary to note that, according to the criteria used by Meyer to estimate formations of low permeability, reservoirs in ultra-deep formations have not been included. Thus, the figures of Meyer can only be viewed as low estimates. Taking the mean values from the stated figures, a factor of 0.65 is obtained when reserves from reservoirs of low permeability are related to total reserves. If this result derived from estimates of resources in the USA is applicable worldwide, one concludes there is a world reserve of natural gas from formations of low permeability of at least $43.8 \times 10^{12}\ m_n^3$. If it were possible to extract economically all the gas in formations of low permeability, the total world reserves of natural gas would rise from about $67 \times 10^{12}\ m^3$ to about $110 \times 10^{12}\ m^3$.

GENERATION CONDITIONS

According to prevailing opinion about the origin of oil and natural gas reservoirs, these substances are formed when organic material in the earth's crust forms kerogen which then decomposes under appropriate conditions. It is assumed that decomposition actually occurs as the kerogen descends deeper into its host sediments and the temperature increases. This decomposition leads, under specific conditions, to the formation of both oil and gas. The dynamics of the system are not yet understood completely; temperature and possible effects of catalysts can cause further changes to the oil formed.

Figure 1 shows the relationship between the atomic hydrogen/carbon ratio and the atomic oxygen/carbon ratio of organic substances. Three types of kerogens are shown, from marine (I) to limnic (III), all of which lead to an oil-forming state analogous with incoalification (catagenesis), although having different H/C vs. O/C relationships. If the organic substance sinks below some pertinent depth, there is evidence of incoalification for all three types of kerogen; and finally all three types form methane and CO_2 with smaller amounts of H_2S according to the content of sulfur in the kerogens (metagenesis). Time and temperature play important roles because they control the creation of hydrocarbons. In addition, however, the generation of hydrocarbons depends on the depth, as shown in Figure 2.

From Figure 2 it can be seen that the formation of liquid hydrocarbons passes through a maximum at depths of 2000 and 3000 m. The formation of gaseous hydrocarbons, however, increases with increasing depth. Finally, the formation of liquid hydrocarbons declines because of their progressively rising instability or they turn in part into more stable gaseous hydrocarbons and form a residual of higher molecular weight (Welte, 1977; Tissot and Welte, 1978). It should be noted, however, that the temperature-gradient is more important than depth in the hydrocarbon formation process. At constant temperature, increase in pressure retards the transformation of oil into gas, which means that liquid hydrocarbons are more stable at higher pressures. Liquid hydrocarbons therefore are present to a

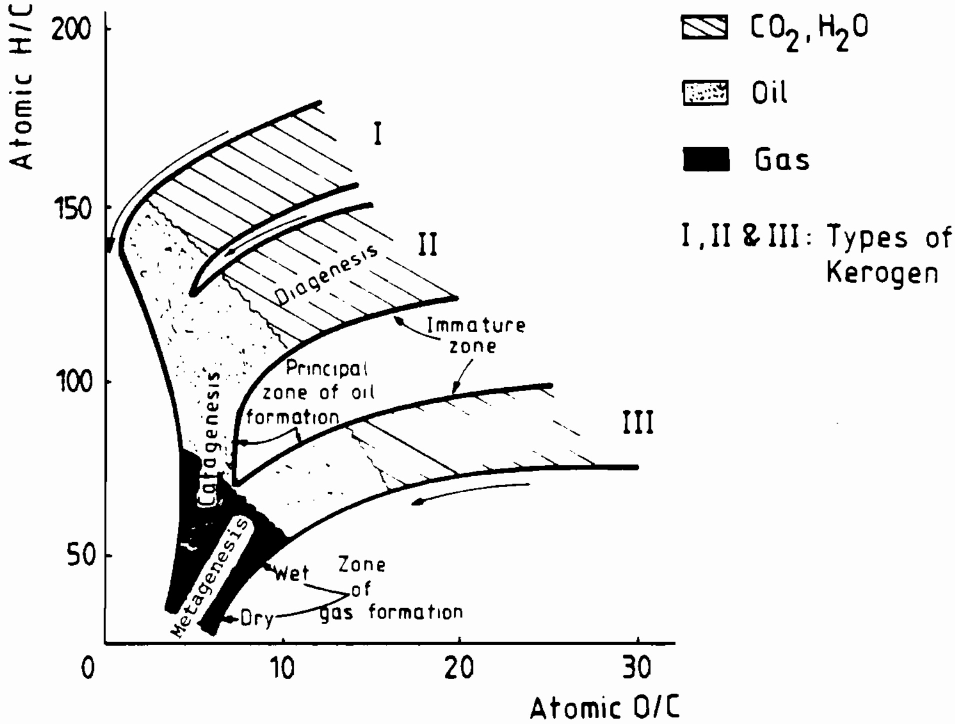


FIGURE 1 General scheme of kerogen evolution, according to Krevelen (Tissot and Welte, 1978).

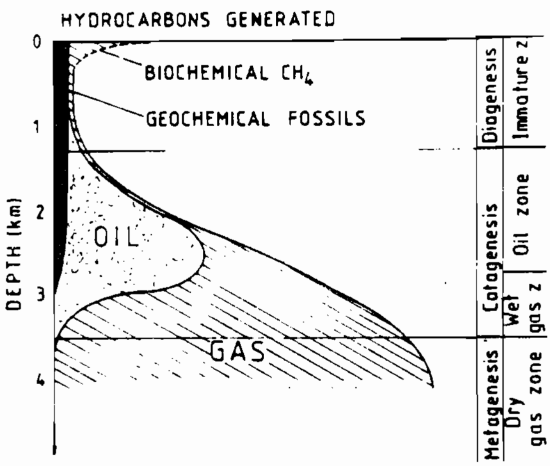


FIGURE 2 General scheme of hydrocarbon formation (Tissot and Welte, 1978).

greater degree where medium pressures and low temperature-gradients coincide (Fertl, 1976). Figure 3 shows how the hydrocarbon state is related to the temperature and pressure of formation.

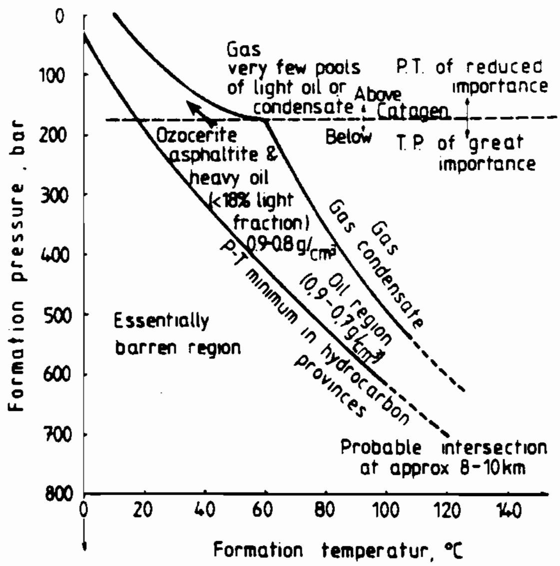


FIGURE 3 Relationship of hydrocarbon state on temperature and pressure of formation (Fertl, 1976).

PERMEABILITY OF RESERVOIRS, PRODUCTIVITY, AND RECOVERY

With increasing depth the voids in the reservoir diminish by mechanical and chemical compaction and processes of cementation. These processes are influenced by the environment, pressure, and temperature. Migrating hydrocarbons hinder compaction whereas increase of temperature intensifies the reduction of voids by strenghening chemical compaction. The overall trend is determined by the pressure-gradient because of its mechanical effect and because, as the pressure increases, the solubility of rock at points of contact also increases. Hence there is an increasing possibility of resegregation of dissolved substances in the voids. This trend is characterized by a great reduction of porosity, particularly in the higher strata, and has an exponential form.

In examining very deep reservoirs, the depth at which the flow of fluids ceases because of the decrease in porosity and permeability is of particular importance. This critical depth for sandstones in the USA is assumed to be about 7000-9000 m at 170-220°C. For clay and carbonatic detritus the critical depth is less than the value for sandstones.

Limestone and dolomite are subject to the same features regarding mechanical compaction as sandstones and clays. Chemical diagenesis however has a greater influence. Therefore, the presence of secondary porosities created by tectonic and compaction-pressure in easily deformable and thus tight limestones or dolomites is significant. Fracture porosities in dolomites are expected to be the same magnitude as those for sandstones at corresponding depths. Strain fissures have also been identified in limestones at depths greater than 4000 m (Wieseneder, 1977).

Voids not only become smaller with increasing depth but also change their form and distribution. This affects permeability and saturation strongly owing to the altered specific surface. Therefore the permeability can range from about 10^4 millidarey (md) to about 10^{-3} md at critical depths. The origin of secondary fissures and fractures from tectonic stresses in sandstones and carbonates can improve the capacity of production without increasing the reserves of the reservoir (Rühl, 1977).

Permeability is also strongly dependent on the distribution of the magnitude of pores or voids. At permeabilities greater than 1 md, almost all the fluid in the pores will be moved, whereas at permeabilities below this value only that part which fills the largest pores will participate in the flow. The water-saturation of this part will be about 50% according to some studies (Denecke, 1964; Thomas and Ward, 1972) because of the high specific surface of small, oval compared to spherical pores.

In evaluating the volume of gas in a reservoir one has to consider that this volume does not increase in proportion to depth. Because of this, at a depth of about 6000 m and a pressure of about 700 bar, for example, only 300-400 m_n^3 gas per cubic meter of void can be expected.

The viscosity of natural gas decreases with increasing temperature. With increasing pressure, however, the viscosity increases. Since the influence of pressure predominates in most cases, only in favorable cases is a considerable increase in viscosity not observed (Rühl, 1977).

From these considerations one can conclude that with increasing depth and lower permeability adequate opportunities exist for storage of gas, but conditions for gas flow, because of the reduced effective permeability, do not exist. Such conditions can be accomplished by special methods of stimulation.

STIMULATION TECHNIQUES

Stimulation techniques developed are acidizing, acid-fracturing and hydraulic-fracturing, for which the last uses proppants to keep the fractures open. Since the success of all the procedures depends on the injection rate and the injection pressure of liquid media, the techniques of stimulation have increasingly involved greater volumes of liquids and greater hydraulic powers. Some years ago, these processes were collectively termed "massive hydraulic fracs" (MHF).

According to theoretical considerations, improvement in the flow, expressed as the ratio of production before and after stimulation, should lie between 4 and 6. Acidizing, however, yields an improvement factor of about 2 (Tunn, 1971). To decide if acidizing or fracturing should be applied, the mineral composition and the plastic or elastic characteristics of the rock must be studied. Limestones, for example, react favorably to acidizing but hydraulic-fracturing, because of the large amount of plasticity (Slusser and Rieckman, 1976), are unsuitable in this case.

STIMULATION BY HYDRAULIC-FRACTURING

In the last few years, research has been carried out to determine the relationship between the volume of fluid and proppants injected and the improvement in flowrates under economical conditions. In the Wattenberg field of the USA, for example, a series of tests was performed with increasing frac-volumes. The results show that with increasing frac-volume both the fracture length and economic conditions improve. There was no evidence of any limitation or change in this trend, so that with the greatest fracturing treatment used (1900 m^3 volume of fracturing fluid), the greatest fracturing lengths and the shortest pay-out time were achieved. The depths of these reservoirs were 2300-2560 m (Fast, *et al.*, 1977).

Comparable successes for MHF treatments have emerged from the Uinta Basin of the USA (Short, 1978). Though the reservoirs treated were not very deep, the permeabilities and porosities had low values. It was shown that, in spite of high water-saturation values, great amounts of gases could be extracted. Another MHF treatment in Texas (Noran, 1975) used 1900 m^3 of frac-fluid and 250 mg of proppant; the production rate increased 8.5 times. The cost of this treatment (1975) was 250,000 US dollars.

Similar success has been reported for test MHF treatments in the FRG (Brinkmann, *et al.*, 1980). Stimulation factors of about 3-12.5 were reported for the treatments at depths of about 4000 m. For better evaluation of the results of fracturing treatments, it is necessary to predict possible future production. This is best accomplished by comparing the production of a fractured and an unfractured reservoir in both transient and steady-state conditions of production.

Figure 4 shows different rates of production, cumulative production, and pressure drop for fracturing treatments used over a period of 20 years. The initial, transient rate of production before treatment was 1.33 x 10^5 (m_n^3/day). If fractures with length about 12% of the radius of the well influx (r_e) are created, a rate of production of about 2.4 x 10^5 (m_n^3/day) can be assumed over a period of 1.9 years according to calculations. This time can be extended to 3.2 years if 42% of r_e can be fractured. Since the radius of well influx is unaffected by the stimulation treatment, the rate will decline over the remainder of a 20-year period.

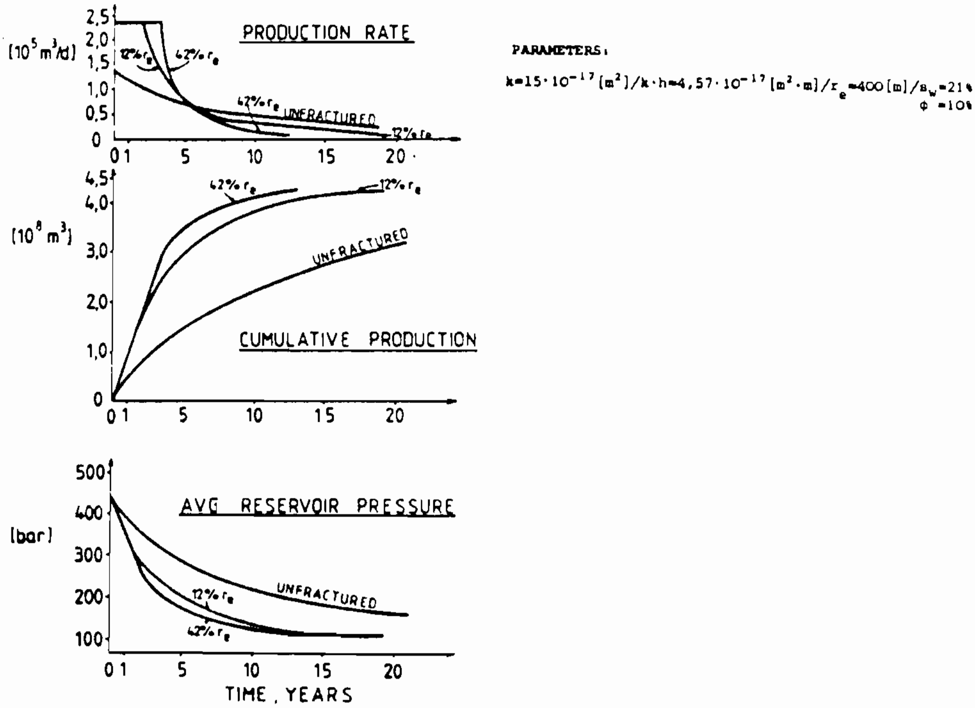


FIGURE 4 Production forecast in a low permeability formation (Slusser and Rieckman, 1976).

The advantage of fracturing treatment is shown by short-term considerations. If, a period of 5 years, for example, is cited for the initial production, a cumulative production of 3.11×10^8 (m_n^3) of gas is yielded if fractures are present with a length of $0.12r_e$ and 3.68×10^8 (m_n^3) of gas if fractures are present with a length of $0.42r_e$. If a shorter pay-out time is achieved this justifies high volume, expensive stimulation treatments in deep formations of low permeability, though such treatment might be judged uneconomical by long-term considerations (Slusser and Rieckman, 1976).

STIMULATION BY ACIDIZING/ACID-FRACTURING

The application of an acidizing treatment to plastic-acting rocks is advantageous if carbonates, which are more easily acidized than treated with frac-fluids and proppants, are present. In this process, acid penetrates deep into the formation as fracturing proceeds and this destructive effect enlarges the paths of flow. Proppants are not then required. In Figure 5, 15% and 28% hydrochloric acid and low-fluid-loss acid emulsion were selected from a variety of possible acids and compared as acid-fracturing fluids at two different well spacings. This comparison was done with a permeability of 0.1 md and a porosity of 10%.

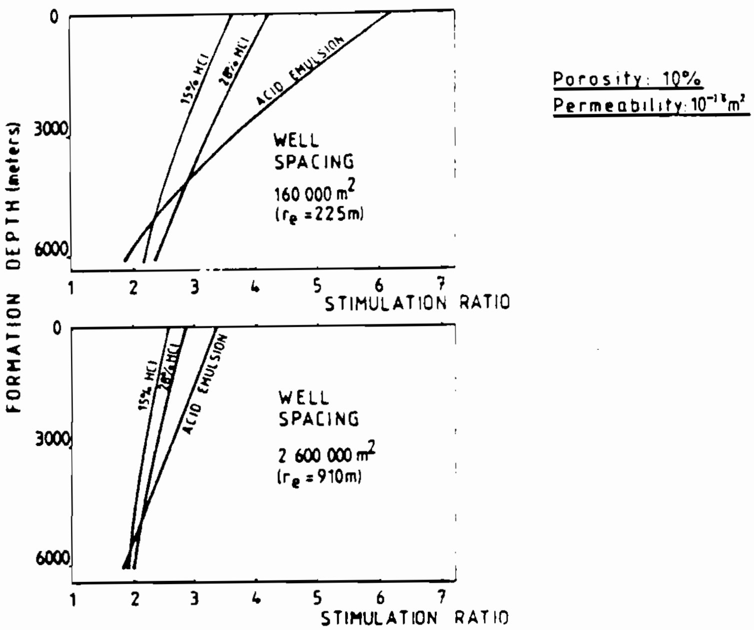


FIGURE 5 Comparison of predicted stimulation ratios (Novotny, 1977).

From Figure 5 one can conclude that the best stimulation is achieved with an acid emulsion in shallow formations with low closure stresses on the acidizing fracture. At low permeabilities and low closure stresses there is good fracture formation and conductivity. Stimulation is strongly dependent on acidized fracture length. The acid emulsion with low fluid-loss yields longer fractures and better stimulation performance. At greater depths, these advantages disappear because the fracture conductivity decreases as closure stresses increase. Under these circumstances, normal acids which produce short but highly conductive acidized fractures achieve better results. It should be noted that, for low closure stresses, the acidized fracture conductivity improves up to depths of 6000 m, especially if the fracture gradient is low and the pressure in the fracture can be increased (Novotny, 1977).

ECONOMIC CONSIDERATIONS

An economic motivation for large-scale stimulation can be demonstrated when the value of a well deduced from production predictions is compared with the cost of drilling the well and of creating the fracture lengths assumed in the production calculations. Figure 6 shows a plot of this relationship.

If the well costs are low and an additional fracturing treatment is performed for a single sandstone, the total costs will be lower than the existing costs of production and therefore such treatment is economically justifiable for any range of fracture length desired. On the other hand, if the assumed pay thickness is distributed in multiple sandstones, a fracture

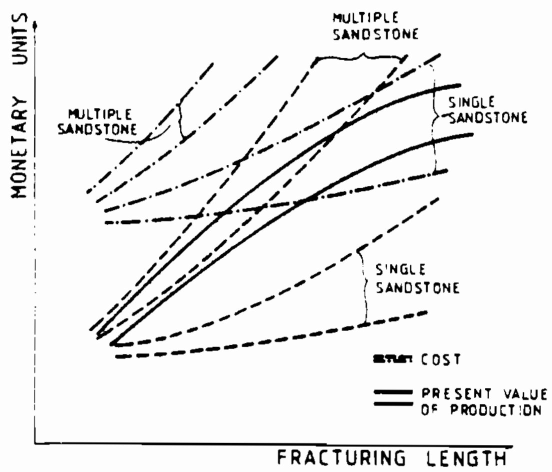


FIGURE 6 Feasibility of fracturing treatment (Randolph, 1978).

length of 250-500 m provides the best possibility for recovering well expenditure from production. For high well costs, the total costs of the stimulated well can be recovered only if the pay is in a single sandstone and fracture lengths of 750-1000 m can be achieved (Randolph, 1978). Considering present economic limits, the additional utilization of very deep gas reservoirs by fracturing can only be justified by a proportional increase in the gas extracted.

SUMMARY

World reserves of gas from deep formations of low permeability have been estimated as 44×10^{12} (m_n^3). These figures are significant when compared with estimates of other gas reserves. Stimulation methods are necessary to extract the gas economically. The stimulation techniques used vary according to rock properties and reservoir potential. For sandstones, MHF treatments are most successful. For carbonates there is no distinct trend but large-scale acid-fracturing with acid emulsion appears as successful as large-scale MHF treatments, at a lower cost. Fractures are created, enlarged, and converted to flow paths by pressure and by acidizing the surface of the fractures, no frac fluid or proppants being necessary.

Development must continue to provide frac-fluids, proppants, and appropriate technologies for each type of stimulation and conditions. Economics and market values will then determine if large additional gas reserves discussed in this paper are worth extracting.

REFERENCES

Brinkmann, F., Fuhrberg, H.D., and Schöber, K. (1980). Frac-Behandlungen in tiefen gering permeablen Gaslagerstätten--derzeitiger Stand und Weitere Aussichten. Erdöl-Erdgas-Zeitschrift, 96, Heft 2, Febr.:37.
Denecke, A. (1964). Gesteinsphysikalische Untersuchung und Bewertung von Speichergesteinen geringer Porosität und Permeabilität. Erdöl-Erdgas-Zeitschrift, 80, Juni:215 ff.
Fast, C.R., Holman, G.B., and Covlin, R.J. (1977). The application of massive hydraulic fracturing to the tight muddy 'J' formation, Wattenberg Field, Colorado. Petro. Technol., January:10.
Fertl, W.H. (1976). Abnormal formation pressures. Developments in Petroleum Science 2, Elsevier Scientific Publishing Company, Amsterdam, p.291.
Noran, D. (1975). Massive frac unlocks gas from microdarcy reservoir. Oil Gas J., 73, No. 38, September 22:112.
Novotny, E.J. (1977). Prediction of stimulation from acid fracturing treatments using finite fracture conductivity. Pet. Technol., September:1186.
Randolph, P.L. (1978). Gas in tight formations. 2nd IIASA Conference on Energy Resources 1985-2020. IPC Sciences and Technology Press, p.657.
Rühl, W. (1977). Lagerstätte--Behandlungen--Wirtschaftlichkeit. Erdöl-Erdgas-Zeitschrift, 93, Sonderausgabe:79.
Short, J.A. (1978). Massive frac treatments tapping tight gas sands in Uinta Basin. Oil Gas J., 76 No. 3, January.
Slusser, M.L., and Rieckman, M. (1976). Fracturing low permeable gas reservoirs, Erdöl-Erdgas-Zeitschrift, 92, März, Heft 3:70 ff.
Thomas, R.D., and Ward, D.C. (1972). Effect of overburden pressure and water saturation on gas permeability of tight sandstone cores. Pet. Technol., February:120.
Tissot, B.P., and Welte, D.H. (1978). Petroleum Formation and Occurrence. Springer-Verlag, Berlin, p.185.
Tunn, W. (1971). Stimulationen bei tiefen Gasbohrungen. Erdöl-Erdgas-Zeitschrift, 87, July:202.
Welte, D. (1977). Grenzbedingung für Kohlenwasserstoffbildung und -umbildung. Erdöl-Erdgas-Zeitschrift, 93, Sonderausgabe:
Wieseneder, H. (1977). Verhalten der Gesteine unter extremen Druck- und Temperaturbedingungen. Erdöl-Erdgas-Zeitschrift, 93, Sonderausgabe:74.

THE STRUCTURE OF NATURAL GAS SUPPLY AND POSSIBLE CONSUMPTION MANAGEMENT

R.Th. Kastner
Vienna, Austria

INTRODUCTION

"The sun shone, having no alternative, on the nothing new."* It is to be hoped that soon the sun will shine, not only upon the poet, but also for the rest of us, in a way that will provide enlightenment and an escape from canalized logic, in the search to find alternatives that will "keep the sun shining." The sun should not only evoke verses and prayers; we also need thorough understanding before we can ensure that we are using its energy fairly and wisely. If we are successful the sun could in future look down, admittedly not on a new, but still on a more humane earth. But the necessary changes will cost time, time that will pass rather quickly as these problems of global energy supply burn toward a solution.

The energy-supply picture will have to change dramatically within the next fifty years, if the path of peaceful coexistence on the planet is not to be left. This will only be possible if energy problems cease to be regarded in isolation and if the need to bring about corresponding changes in their strong interdependence with economic, political, and social structures is also recognized. The complete human logical system, which has increasingly focused on the material world and information-producing and information-handling technologies, will have to turn more toward man himself. But which approaches will help us to reorganize and to replace those functions that are more or less fulfilled by our present institutions? Which sources of energy might be useful and what kinds of economic and social structures do they imply? Will natural gas (afterwards referred to as NG) be able to fulfill our expectations based on present estimates of the amounts available, its geographical distribution, and present patterns of utilization?

It appears that political mechanisms, which have in previous analyses been neglected as "soft" variables because they are very difficult to predict, will assume more and more importance in determining the supply-demand relation on the NG market. One response to this could be a trend towards diversification and independence. However, certain parts of the NG market can only operate effectively if utilization is globally controlled. International solidarity will be needed to oppose narrowly nationalistic and protectionist interests.

This paper describes various approaches to organizing supply and distribution structures and explains them with the help of a partly qualitative phenomenological analysis. These insights into the energy question as a mainly political and social problem make it necessary to leave for a while

**Murphy*, by Samuel Beckett.

the well-trodden paths of quantitative analysis, in order to arrive at methods that adequately portray reality, rather than distorting reality to suit the available methodology.

DIVERSITY IN RESERVES AND SUPPLY

The energy source presently dominant on the international market is oil. The other energy carriers, such as coal, NG, and the so-called "unconventional" forms of energy, are closely linked to oil, and are more or less associated with it on the world energy market. But how does this compare with the global distribution of energy reserves?

The well-known imbalance between the energy producing and consuming regions of the world, and particularly the dominant position of the Middle East, is based on oil reserves and is most clearly manifested in the economic and political union OPEC. About 40% of NG is found associated with oil while about 60% is unassociated (Wilson 1977). This clearly seems to reinforce the present position of the oil-exporting countries, although the geographical distribution of NG reserves is much wider than those of oil. It should be stressed that most oil estimates to date have tended to converge around the 2000 billion barrels figure, but as far as I am aware no such convergence can be seen in estimates of gas reserves. Therefore a still wider distribution of NG may be possible. But it will be shown below that an exact definition of NG reserves is probably not the most important factor in solving the problems of the world NG market.

The gap between the supply and demand of NG between exporting and importing countries is not as large as the corresponding oil gap (for an analysis see Deutsch and Tintner 1979). It might seem that this could lead to a lessening in tension on the energy market, with a simultaneous increase in gas utilization and decrease in oil consumption, and generally toward a more guaranteed supply for the industrialized countries. But the world does not consist only of industrialized zones. The problems of the developing countries may be outlined as follows. First of all, their geographical location is not of particular significance here. In addition to the regional diversity of NG reserves, the uneven distribution of *amounts* of the resource plays an important role. Unevenly distributed reserves imply a great reliance on transport facilities, so that questions of the transportability and transport costs of NG immediately arise. Technical progress in the construction of gas pipelines and tankers makes it increasingly possible to transport NG over long distances. But the use of these transport facilities is limited. The development of large pipeline-networks only pays where both large reserves and a secure demand exist. Big tankers carrying liquefied NG (LNG) require liquefaction and regasification equipment. Both are technically feasible and, based on a certain amount of LNG flow, even desirable from the viewpoint of costs. But how does the method of NG transportation determine distribution structures?

Concentrated reserves make the transport of large amounts an economic necessity and this influences centralized supply structures. This means that only regions having relatively centralized and organized demand can be economically supplied. In countries where the distances to be covered are very great, any completely new development of gas networks is not likely to be profitable, partially because of the prohibitively high investments required, but not for that reason alone. Marchetti and Nakicenovic (1979) have estimated that NG will be replaced by nuclear power in about fifty years: this should make us think about the high structural burden and the importance of adaptability of supply systems, which will be discussed later. One desirable future goal of diversification would be a situation in which NG were no longer flared in the producing countries, but rather consumed locally (e.g. as a feedstock for chemical industries or as energy for household use).

Most industrialized countries are relatively self-sufficient in NG, but the increasing NG demand of western countries will mean relinquishing some independence to the OPEC states and the USSR, which own the lion's share of the global reserves. The existing NG networks in Western Europe and North America are being substantially enlarged, while the supply is being covered by NG from the Netherlands and the North Sea, and through contracts with the USSR and the OPEC states.

Once again, however, the developing countries are not included in this happy picture. They will have to increase their annual economic growth rates to approximately 10% by the year 2000, merely in order to cover their basic needs. This will undoubtedly imply a larger expenditure of primary energy. What this means for the developing countries will be shown later.

Fairly obviously, due to the geographical dispersion of NG and the concentration of giant reserves, as well as the associated transport facilities, a structure of interdependences is created that hardly differs from the well-known interdependences on the oil market. Methods for exploration and the production of NG are similar to those for oil, and even the demand structures are to a certain extent predetermined by the relatively long tradition of oil consumption. For these reasons and also in the face of increasing demand, the market penetration of NG is likely to be more rapid than was that of oil.

Concerning possible transitions to other energy sources such as a more-developed fusion technology or maybe solar energy, adaptation will probably be more difficult than is the case for NG. Here we stress only that the use of traditional logic will probably lead to similar mistakes in the development of the necessary supply structures as have been made with oil, and that these will be intensified by any further centralization.

DIVERSITY IN INSTITUTIONS AND CONSUMPTION

The increasing risks of NG exploration and the high demand for investment in production and distribution means that the big international companies already play the role of pioneers. The investments and risks will continue to increase and the technological requirements will become more and more complex. The exploration of large gas fields and the construction of supply networks more or less demands the involvement of such organizations.

The development of these companies has to be examined carefully. On one hand, the trend to structural diversification of the world energy market will continue with the emergence of new product markets and a wider range of different resources, not only in the oil sector. Some further nationalization of the production and distribution of NG can be expected. Moreover, processing industry and tanker-building capacity is being enlarged with the help of national companies, mainly in the OPEC countries. These seem to be developing nationalization and decentralizing decision-making responsibility, at least as regards the production and transport of oil and NG.

On the other hand the oil companies are showing an increasing tendency to become "energy trusts". According to Bischoff and Gocht (1979), 30% of American hard coal production was controlled by oil companies in 1976. They also hold a big share in the mining of uranium ore and in the building of nuclear power plants. About 50% of the world's uranium reserves are under their control, and their market share of fuel elements for nuclear power plants is also significant. These examples of expansion into various product markets show clearly the tendency to optimize decision making not just over the relatively narrow NG market, but over all forms of primary energy sources.

Even using this approach of concerted exploration, production, and distribution of energy sources, there is an obvious tendency to follow the simple strategy: "What has provided success up to now will also provide it further on." And as Lovins (1977) pointed out, "big organizations needed to develop big technologies." This institutional problem has further implications for the development of the NG market. It demands the application of technology and the entire supporting apparatus to large-scale reserves and with it also the development of widespread consumption networks. This positive-feedback cycle reinforces the development of complex, high-technology supply-demand balances.

The organizational structures described seem to satisfy the conventional energy demands of industrialized nations. But the necessary transformation will still cause difficulties, because it is well known that the greater the complexity of the market, the greater the structural burden. Gas supply within the industrialized countries will possibly be organized by the pioneering approach of the big energy companies. But the question of building up complex NG networks in the developing countries still remains. These countries are facing a period of major technological change and increasing economic growth rates. Their organizational structures for distributing large amounts of energy over long distances are still in no way developed; at present, only the regional utilization of NG has any real meaning or likelihood of attainment.

It seems obvious that the application of normal modes of transport, which presuppose very large amounts of NG and guaranteed consumers, are inappropriate for the energy supply structure of developing countries. On one hand, the energy demand is quite different to that in industrialized countries. Much of the energy consumed in these countries is local and noncommercial in nature. An estimate of Indian energy consumption shows that nearly 60% of energy consumption in 1960 was noncommercial and that this had only fallen to 48% by 1970 (Government of India 1975). This percentage will clearly decrease further in future and commercial energy, especially that required for the generation of electric power, will increase enormously. On the other hand, NG will be substituted by qualitatively different energy sources. Therefore, supply structures should not be burdened by excessive centralization, which reinforces today's oil-supply dependencies. In the developing countries, NG supply structures must be provided that are easily adaptable for potential future decentralized energy forms such as biogas or solar energy. NG consumption strategies need to be developed that are not only determined by central reserves and so do not automatically involve large-scale transport problems and the rest of the traditional logic of the large energy companies. A move to unconventional energy sources is not itself enough; it is also necessary to switch away from overwhelming dependence on inadequate energy-supply structures to help NG penetrate the market as an intermediate source. On this basis a discriminating supply strategy will be possible, which supports not only the centralized structures with their built-in dynamic but also other small-scale energy sources.

Only after elucidation of the institutional situation on the world energy market will rational management of supply structures and consumption become possible. The estimation of reserves and considerations of the feasibility and optimal usage of energy transport facilities are certainly important, but if they receive too much attention they tend to hide the underlying institutional problems.

CONCLUSIONS

Quite obviously, the NG problem is a global one. In working toward a solution, we must look at the long tradition of the development of institutional structures and supply networks. In recent decades market rules have changed in such a way that they show very little similarity to those that figured in our schoolbooks. The established fact of substitution between energy sources must guide us in the direction of adaptable patterns of NG utilization. More generally, the energy problem cannot be reduced to a purely economic question; it is embedded in and interrelated with nearly all political, social, and institutional constraints.

These modest insights lead to the following thesis:

- Dangers in the development of NG supply structures lie in the heritage of traditional institutions.
- The use of NG in industrialized countries must prepare the way for the transition to future unconventional supply structures, with the active support of political independence and social maturity and responsibility.
- In developing countries the application of complex centralized NG networks and the use of LNG with associated long transport distances seems to be inappropriate and ineffective. Diversity of supply and consumption structures, and with it adaptability to other future decentralized energy sources, must be provided.
- Large-scale NG usage is partly caused by a positive-feedback cycle between centralized energy supply and concentrated decision-making hierarchies.
- On analyzing the NG situation it seems that economic structures have an indirect impact on the scientific work involved. Economic interests may in some cases determine the scientific approach used.
- In comparison with the political and social constraints implicit in the energy problem, reserve estimates and purely technological considerations are of marginal importance. The energy problem is in fact mainly a political and social problem.

REFERENCES

Bischoff, G. and W. Gocht (Ed.) (1979). Das Energiehandbuch. Braunschweig.

Deutsch, E. and G. Tintner (1979). Methodische Probleme der Energiefrage (Methodological Problems of the Energy Question). Wirtschaftspolitische Blätter, 3:26.

Government of India (1975). Report of The Fuel Policy Committee. New Delhi.

Lovins, A.B. (1977). Soft Energy Paths: Toward a Durable Peace. Friends of the Earth International, Cambridge, Mass.

Marchetti, C. and N. Nakicenovic (1979). The Dynamics of Energy Systems and the Logistic Substitution Model. RR-79-13. International Institute for Applied Systems Analysis, Laxenburg, Austria.

Wilson, C.L. (Ed.) (1977). Energy: Global Prospects 1985-2000. Report of WAES. New York, St. Louis, San Francisco.

THE IMPACT OF GOVERNMENT POLICY ON NATURAL GAS RESOURCE DEVELOPMENT

Robert B. Kalisch
American Gas Association, Arlington, Virginia, USA

The US government has had a profound effect on the development of the natural gas industry. Regulation of wellhead prices and interstate pipeline charges by the federal government and regulation of most end-user prices by state governments have not only affected the amount of drilling for gas, but more importantly, the type of drilling. This paper illustrates some examples of this influence, and projects possible changes in drilling activity caused by the Natural Gas Policy Act of 1978 (NGPA).

HISTORY

Since 1954 wellhead prices in the United States have been regulated, for interstate sales, under the Natural Gas Act of 1938.

It was this Act, as interpreted by the Supreme Court in the Phillips decision of 1954, which placed interstate gas under the jurisdiction of the Federal Power Commission (FPC). The FPC set just and reasonable rates which they designed to permit recovery of production costs plus a reasonable rate of return. Originally FPC set rates on a case-by-case basis, but later changed to an area rate determination based on average area production costs. In July 1974 a nationwide rate ceiling was adopted for new natural gas and later for several categories of old natural gas.

Intrastate gas was not limited by federal statute until the NGPA. In fact the NGPA sought to balance the production incentives between these two markets by providing a common price ceiling for several categories of natural gas from 1978-1985. After 1985 all new gas becomes deregulated.

Gas well drilling activity is greatly influenced by the allowable wellhead price for natural gas, and this can cause significant distortions in overall national drilling effort. This paper examines gas well drilling statistics from 1955-1979. The emphasis is on the characterization of national drilling patterns under these federally mandated rates for interstate gas, and on the changes which are taking place under the NGPA.

GAS WELL COMPLETIONS AND POTENTIAL GAS ESTIMATES

Gas well drilling activity over the past few years has been characterized by the following:

-- Annual productivity, i.e., reserve additions per foot (MCF/ft) has been steadily declining (since 1967);
-- Drilling costs are steadily rising, resulting in a decline in gas volumes found per dollar of exploration investment;
-- Gas well drilling footage and well completions have increased dramatically starting in 1972, and have reached new record levels each year since 1973;
-- Proved reserves have been declining since 1970.

This pattern, particularly the decline in proved reserves in the face of record levels of drilling, has been interpreted by some as indicating that resources of natural gas are rapidly dwindling, and that wellhead pricing incentives cannot induce significant additional supplies.

The validity of this contention was examined by analyzing 1974-1977 drilling data from the standpoint of the relationship between drilling activity and potential gas resources. Two primary sources of data were used (API; PGA).

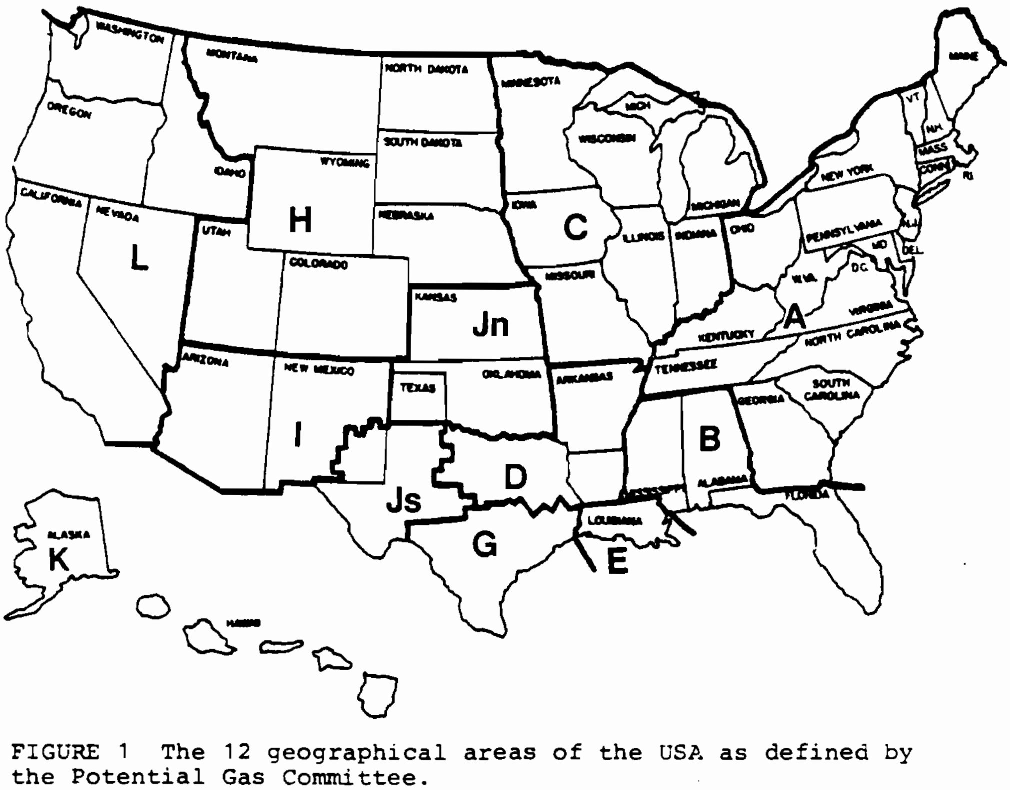


FIGURE 1 The 12 geographical areas of the USA as defined by the Potential Gas Committee.

The analysis considered 12 geographical areas of the USA consistent with the breakdown used by the Potential Gas Committee (Figure 1). These 12 areas were subdivided into onshore, offshore, shallow depth and deep (greater than 15,000 feet) subcategories, resulting in a total of 27 different drilling regions.

Figure 2 shows the range of the percentage of gas well completions for the years 1974-1977 versus the percentage of US potential gas resources contained in those regions. As can be seen, these data generally indicate that about 90% of the gas well completions have occurred in areas with only about 30% of the nation's gas potential (AGA, 1978).

Furthermore, as seen in Figures 3-6, which depict the percentage of gas well completions within a drilling cost category, most of the drilling has occurred in areas where drilling costs have been relatively low. For example, in 1974, about 26% of all gas well completions were in areas where the cost of drilling was between $10 and $20 per foot. While the histograms generally shift to the right with time, reflecting the impact of inflation on drilling, the dominance of low-cost drilling is apparent; e.g., in 1974, 1975 and 1976 over 90% of gas well completions were in areas where drilling costs were less than $50 per foot.

The significance of this pattern of low-cost drilling on exploitation of the nation's potential gas resources is further illustrated in Figures 7-9, which depict the percentage of potential gas resources as a function of drilling costs for the years 1974-1977. As seen, those areas where most of the drilling has occurred--that is, areas where drilling costs have been less than $60 per foot--represent only about one-third of the nation's potential gas resources. The remaining two-thirds are in areas with appreciably higher drilling costs--largely the Gulf of Mexico and Alaska.

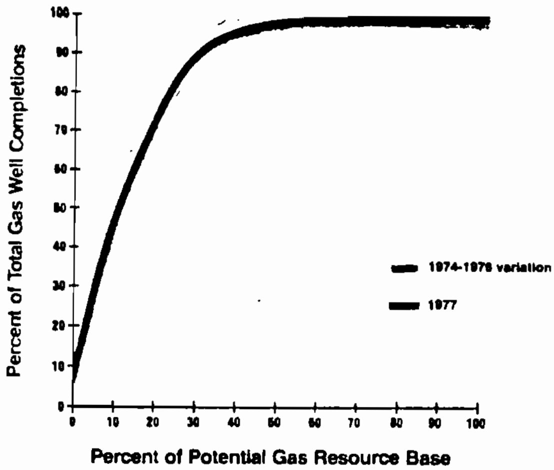


FIGURE 2 Graph of gas well completions vs. potential gas resource base: 1974-1977.

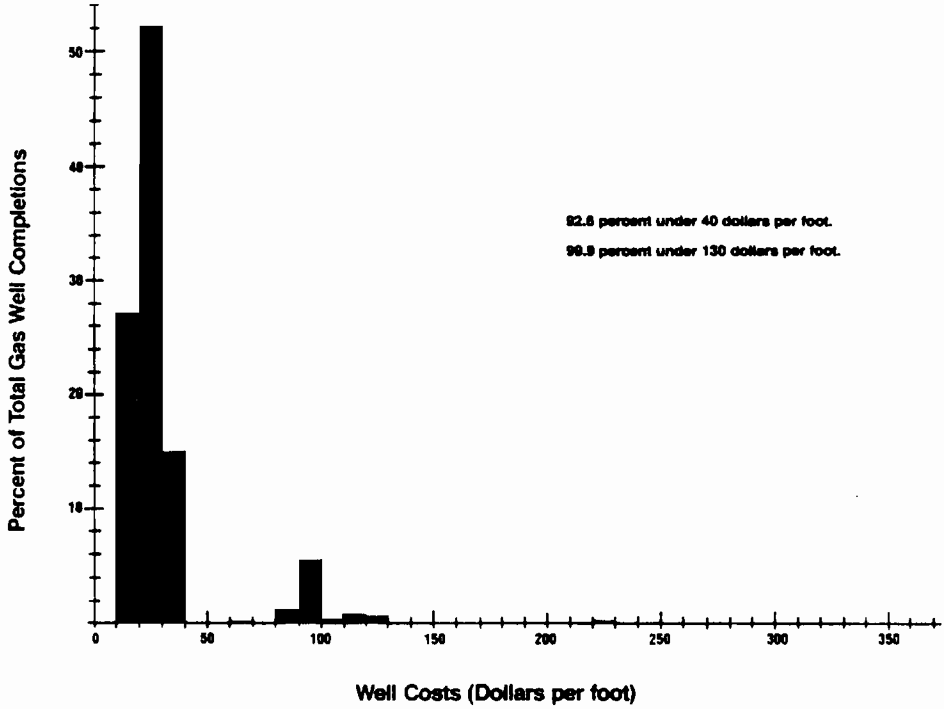


FIGURE 3 Histogram of total gas well completions vs. costs for 1974.

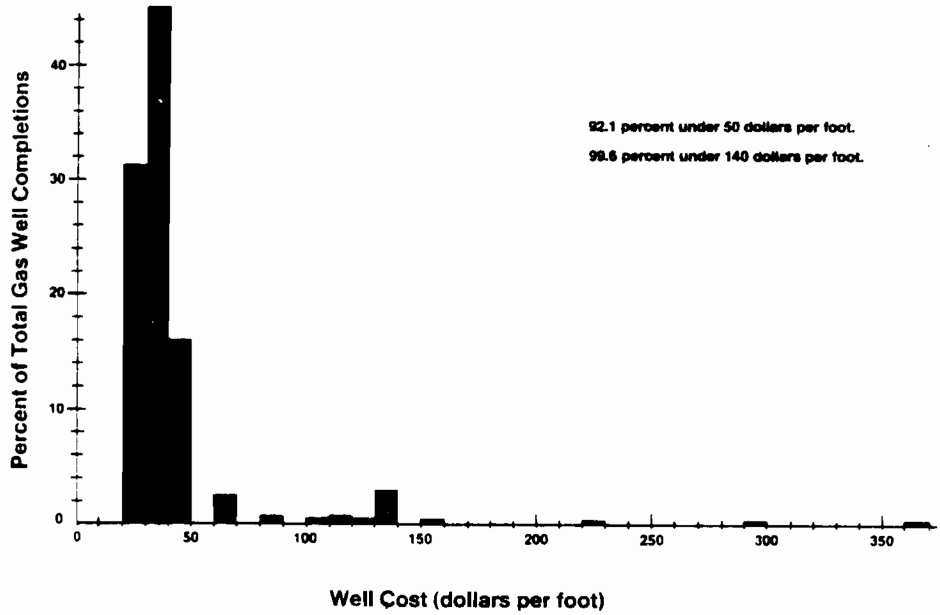


FIGURE 4 Histogram of total gas well completions vs. costs for 1975.

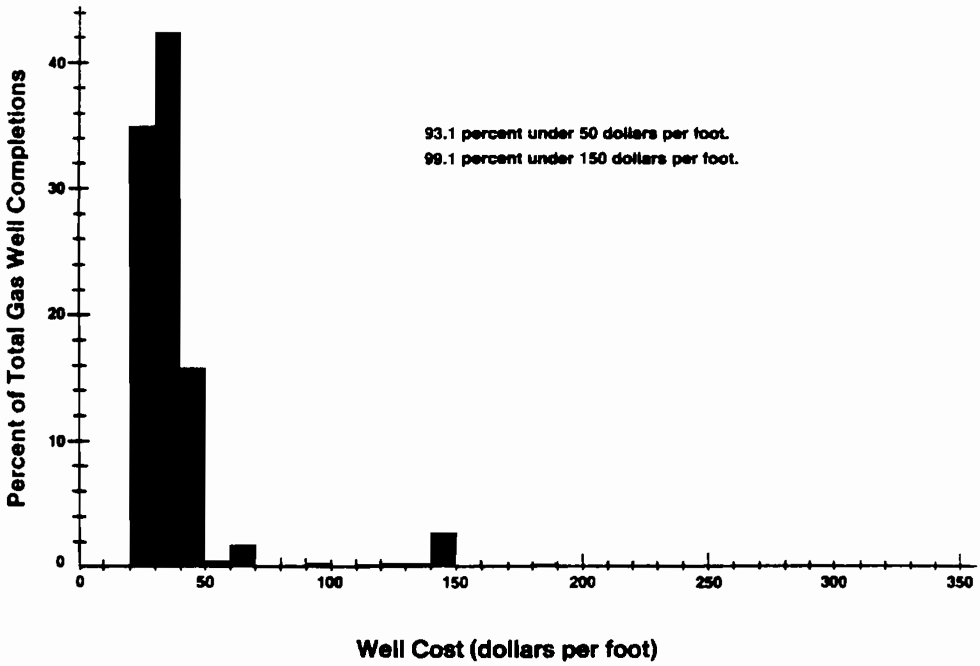


FIGURE 5 Histogram of total gas well completions vs. cost for 1976.

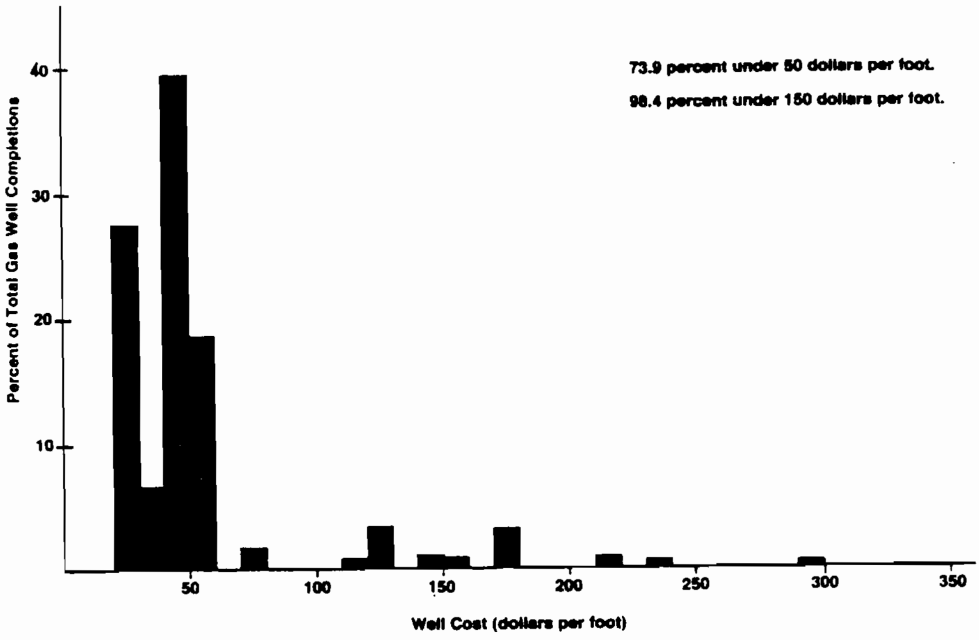


FIGURE 6 Histogram of total gas well completions vs. cost for 1977.

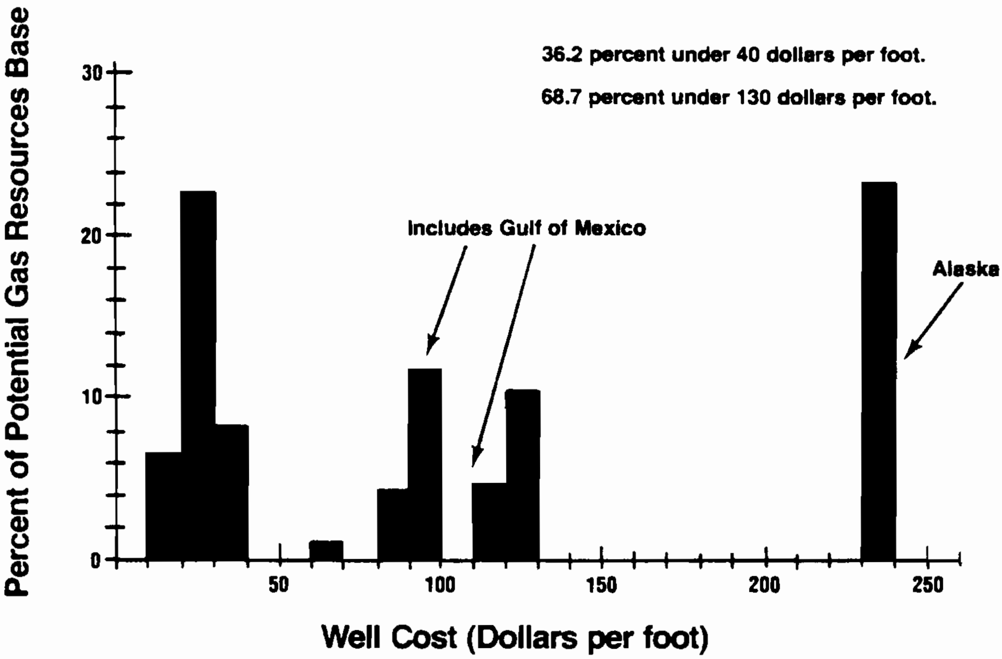


FIGURE 7 Histogram of potential gas resource base vs. cost for 1974.

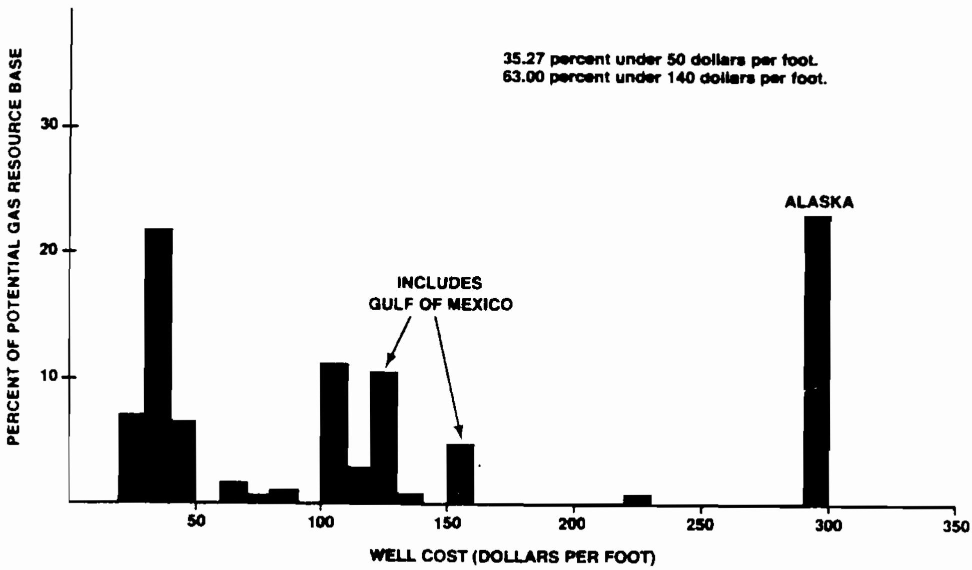


FIGURE 8 Histogram of potential gas resource base vs. cost for 1975.

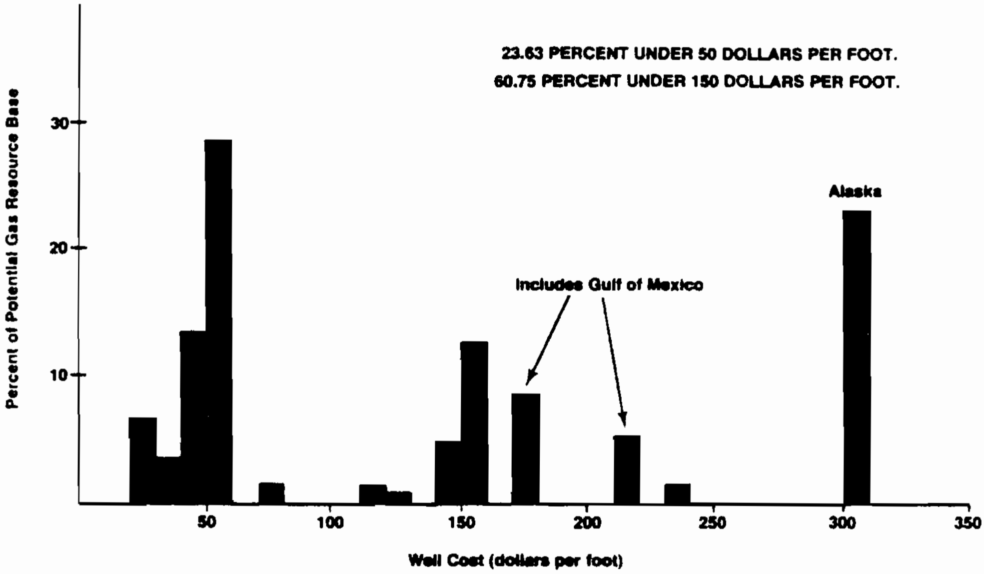


FIGURE 9 Histogram of potential gas resource base vs. cost for 1977.

These histograms show that drilling activity over the past few years has not been concentrated in regions containing the majority of potential gas resources, but rather in the more mature areas where costs are significantly lower. Thus, the more frontier drilling regions, such as offshore and deep onshore, have been largely unexplored and still contain a large percentage of our natural gas resources.

The paradox of large amounts of drilling in the face of dwindling reserves is caused by federal regulation of interstate wellhead gas prices which constrained drilling to the lower cost, mature regions where few large discoveries could be expected.

GAS WELL COMPLETIONS AND RESERVE ADDITIONS

There has been an increasing emphasis on drilling for natural gas in recent years. Figure 10 is a chart of gas well completions and successful gas well footage drilled since 1956. Both parameters display similar general trends, rising sharply in 1972 and setting new records annually since 1973. Figure 11 relates the gas well completions to the wellhead price in real dollars for the interstate and intrastate market. It is, of course, no surprise under such circumstances that the interstate market has an extremely poor record in these years with respect to adding new gas supplies. This graph also shows clearly the rapid drilling response to improved prices.

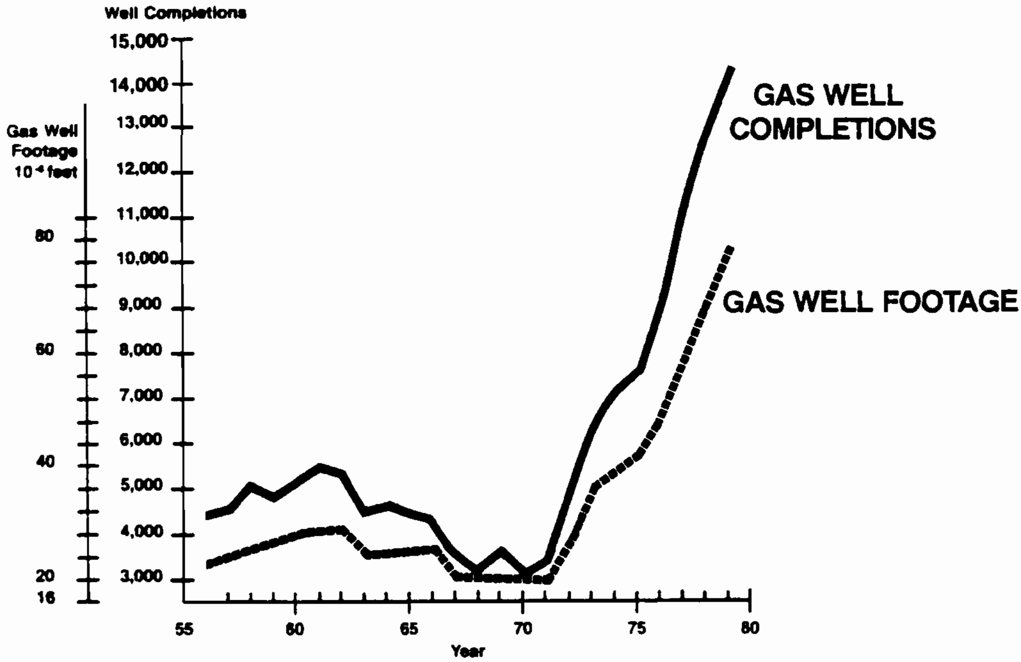


FIGURE 10 Graph of gas well completions and gas well footage from 1956 to 1979.

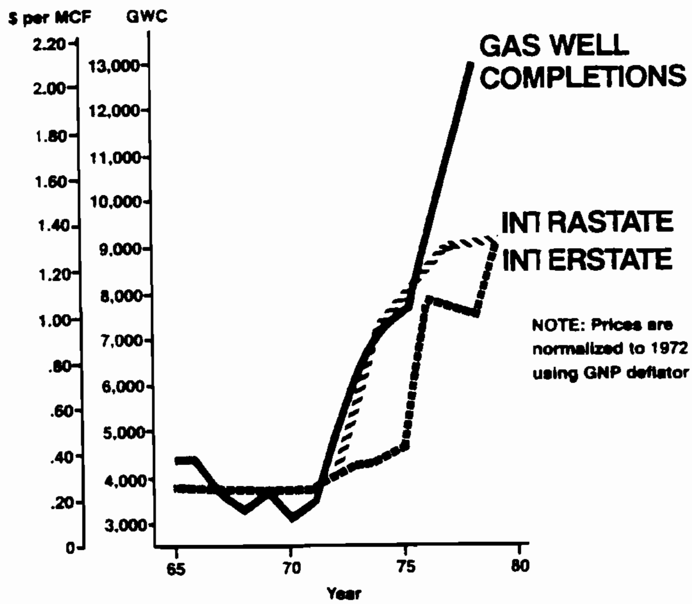


FIGURE 11 Graph of gas well completions vs. new gas prices from 1965 to 1979.

On a national basis, the proved reserves added each year do not correlate well with the number of gas wells completed. As can be seen in Figure 12, there almost appears to be a negative correlation between these two variables. In a limited sense that is true. Low reserve additions do create a need for more reserves to be added, and so more drilling occurs. However, since most wells were drilled in less productive areas, the effect of a large number of wells on reserve figures is relatively low.

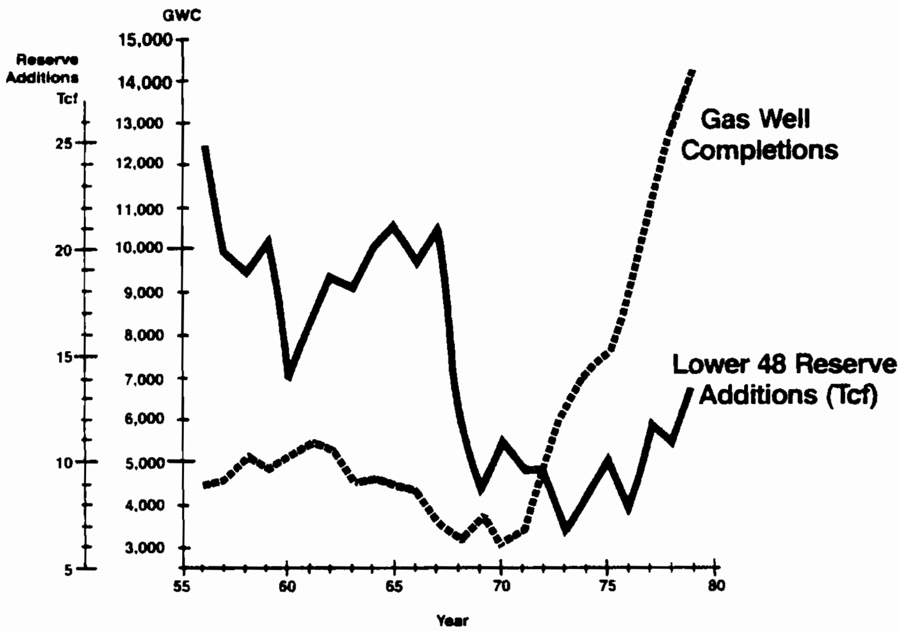


FIGURE 12 Graph of reserve additions and gas well completions for the lower 48 states of the USA from 1956 to 1970.

STATE STATISTICS

Table 1 lists the various regions of the United States in descending order of non-associated additions to proved reserves per gas well completions--an indicator of drilling productivity. By this measure, Alaska shows the highest productivity, followed by South Louisiana, Mississippi, Wyoming, and California.

Despite this relatively high productivity, however, these regions represent only a small share of gas well drilling activity. This is illustrated in Table 2 which shows data on percent of non-associated additions to proved reserves and percent of gas well completions for the various regions--with the regions listed in the same order as in Table 1. As seen, almost half the reserve additions are in areas representing only about 10% of the total gas well completions.

TABLE 1 Non-associated reserve additions and gas well completions in 1978.

Region	Non-Associated Reserve Additions (MMcf)	Gas Well Completions	Non-Associated Reserve Additions Per Gas Well Completion
Alaska	99.0	4	24755
South Louisiana	2682.9	536	5005
Mississippi	214.0	69	3101
Wyoming	484.4	171	2832
California	135.7	68	1995
Texas RRC 3	602.8	330	1827
Texas RRC 5	82.9	68	1220
Texas RRC 10	324.2	267	1214
New Mexico	876.0	818	1071
Alabama	56.6	58	976
Texas RRC 8	149.1	156	956
Michigan	50.8	54	942
Texas RRC 4	527.2	615	857
Texas RRC 6	203.6	276	738
Oklahoma	887.8	1507	589
Arkansas	35.0	67	523
Texas RRC 2	219.0	435	503
Montana	75.0	153	490
Colorado	158.0	328	482
West Virginia	447.2	1148	390
Texas RRC 7C	130.3	363	359
Kansas	301.1	925	325
Texas RRC 7B	117.3	368	319
Texas RRC 1	46.2	155	298
Virginia	8.4	29	290
Pennsylvania	280.4	1106	253
Kentucky	31.8	127	251
Texas RRC 9	40.9	207	198
Ohio	197.0	1390	142
North Louisiana	100.8	750	134
Utah	10.7	91	118
New York	25.3	224	113
Texas RRC 8A	3.3	52	64
Nebraska	.2	12	19
Illinois	0	15	0
Indiana	0	43	0
Florida	0	2	0
US Total	9620.3	13064	736

This non-optimum pattern of drilling activity is felt to be cost-related. Table 3 lists the drilling costs per well for the top five regions in Tables 1 and 2 and several other representative regions. As can be seen, those regions with relatively little drilling activity (but relatively high productivity) generally have the highest average drilling costs per well.

TABLE 2 Percent non-associated reserve additions vs. percent gas well completions.

Region	Percent of Reserves Added	Percent of Gas Wells Completed	Cumulative Percent of Reserves Added	Cumulative Percent of Gas Wells Completed
Alaska	1.03	.03	1.03	.03
South Louisiana	27.94	4.13	28.97	4.16
Mississippi	2.23	.53	31.20	4.69
Wyoming	5.04	1.32	36.24	6.01
California	1.41	.52	37.65	6.53
Texas RRC 3	6.28	2.54	43.93	9.07
Texas RRC 5	.86	.52	44.79	9.59
Texas RRC 10	3.37	2.06	48.16	11.65
New Mexico	9.12	6.30	57.28	17.95
Alabama	.59	.45	57.87	18.40
Texas RRC 8	1.55	1.20	59.42	19.60
Michigan	.53	.42	59.95	20.02
Texas RRC 4	5.49	4.74	65.44	24.76
Texas RRC 6	2.12	2.13	67.56	26.89
Oklahoma	9.24	11.60	76.80	38.49
Arkansas	.36	.52	77.16	39.01
Texas RRC 2	2.28	3.35	79.44	42.36
Montana	.78	1.18	80.22	43.54
Colorado	1.65	2.53	81.87	46.07
West Virginia	4.66	8.84	86.53	54.91
Texas RRC 7C	1.36	2.79	87.89	57.70
Kansas	3.13	7.12	91.02	64.82
Texas RRC 7B	1.22	2.83	92.24	67.65
Texas RRC 1	.48	1.19	92.72	68.84
Virginia	.09	.22	92.81	69.06
Pennsylvania	2.92	8.52	95.73	77.58
Kentucky	.33	.98	96.06	78.56
Texas RRC 9	.43	1.59	96.49	80.15
Ohio	2.05	10.70	98.54	90.85
North Louisiana	1.05	5.77	99.59	96.62
New York	.26	1.72	99.85	98.34
Utah	.11	.70	99.96	99.04
Nebraska	.01	.11	99.97	99.15
Texas RRC 8A	.03	.40	100.00	99.55
Illinois	0	.12	100.00	99.67
Indiana	0	.32	100.00	99.99
Florida	0	.01	100.00	100.00

GAS WELL COMPLETIONS IN 1979

The effect of the NGPA on gas well completions in the USA has been apparent since the start of this year. Figure 11 shows gas well completion statistics from 1956-1979. The data show that the gas well completions have been sharply increasing. Overall, 1979 gas well completions are up 12.4% over 1978. In fact, 1979 had the highest level of gas well completions in the nation's history.

TABLE 3 Drilling costs (dollars) per well for various regions.

Region	Cost Per Well[a]
Alaska	1,721,327
South Louisiana[b]	1,463,488
Mississippi	1,152,965
Wyoming	960,111
California	248,320
Ohio[c]	90,472
Oklahoma	371,768
Pennsylvania[c]	90,472
West Virginia[c]	90,472
Texas RRC 2	277,868
Texas RRC 3[b]	716,363
Texas RRC 4	478,744

[a]The cost shown is the average cost per gas well in that region in 1977 (Joint Association Survey, 1977).
[b]Includes offshore
[c]Cost data combines New York, Ohio, Pennsylvania, and West Virginia.

To analyze the effect of the NGPA on gas drilling, there are four geographical areas which have accounted for about 90% of the drilling increases from 1978-1979. Offshore gas well completions were up 10.2%; gas well completions in those areas producing deep gas were up 10.1%; gas well completions in the Thrust Belt were up 33.9%; finally, in the Appalachian Basin gas well completions increased 19.6%.

Offshore potential gas supplies in the lower 48 states are estimated by the Potential Gas Committee to be 21.2% of the nation's total. Typically, less than 4% of the gas well completions are offshore. This type of imbalance is one of the reasons that reserve additions are not higher. Less new gas is discovered each year because federal pricing policy has ensured that drilling effort does not match the potential in particular geographical regions. The changes in the annual number of offshore gas well completions is one important criterion for judging if the geographical distribution of drilling activity is improving. Completions increased from 266 to 293 between 1978 and 1979, so that 1979 was an all-time record year for offshore gas drilling. The wellhead price for new gas of $2.29 per MMBtu (as authorized by the NGPA) was a major factor in this drilling increase. In fact, when compared to the corresponding 1978 price of $1.52 per MMBtu, the inter-relationship between increased incentives and drilling activity becomes apparent.

Another critical region from the viewpoint of its large resource is the deep gas found in the lower 48 states at depths of more than 15,000 feet. Approximately 19.5% of the total US potential gas is at these depths; yet the annual percentage of deep gas well completions is less than 5% of the total. In 1979 gas well completions in those areas in which most deep gas well drilling occurs increased 10.1% over 1978. This is a dramatic response to the NGPA deregulation of deep gas.

The third region which is experiencing a major boom in gas well drilling is, of course, the Rocky Mountain Thrust Belt. Exploration in the Thrust Belt has both oil and gas objectives. From the gas well completions alone, it can be seen that this is an extremely active area. Gas well completions have increased by 33.9% from 1978-1979.

Finally, the Appalachian Basin has seen a marked increase in gas well activity. The six major drilling states of this basin are Kentucky, New York, Ohio, Pennsylvania, Tennessee and West Virginia. This increase in drilling activity is especially impressive in light of the fact that the Appalachian Basin historically has been only a minor factor in gas production and only a minor contributor to proved reserves, as shown in Table 4.

TABLE 4 Appalachian Basin production and reserves in 1978 as a percentage of US total.

Region	Production	Proved Reserves
Kentucky	0.3%	0.4%
New York	0.1%	0.1%
Ohio	0.6%	0.8%
Pennsylvania	0.5%	1.0%
Tennessee	--	--
West Virginia	0.8%	1.3%
Total Basin	2.3%	3.6%

Undoubtedly, one factor accounting for the renewed interest in this area is Section 107 of the NGPA which deregulated the price of gas produced from Devonian shales as of December 1979. Another factor is that the wells in the Appalachian Basin are relatively shallow and inexpensive, as illustrated in Table 5. Partially offsetting these lower costs, however, is the below-average figure for reserves added per foot drilled. The statistic which considers both the cost and reserves-added factors is the volume of gas reserves added per dollar of well cost. By this measure, the Appalachian Basin performs well--values over 3.0 in Kentucky, Pennsylvania and West Virginia in comparison with about 2.4 for the national average.

SUMMARY

The USA still has extremely large volumes of recoverable natural gas despite the consumption of over 500 Tcf in the past forty years. Development of this remaining gas is an economic problem. Adequate pricing incentives will intensify the search for gas and drilling of wells. During the period of wellhead price regulation for interstate gas, some regulators believed that realistic production levels could be maintained with a federally established wellhead price. These regulators did not

TABLE 5 Comparison of Appalachian and US gas well reserves and costs.

Region	Cost[a] per well ($)	Cost[a] per foot drilled ($)	Reserves Added per foot drilled (CF per ft.)[a]	Reserves Added per $ of well cost (CF per $)[a]
Kentucky	78,473	40.02	120	3.00
New York	90,472[b]	24.44[b]	39	1.60
Ohio	90,472[b]	24.44[b]	34	1.39
Pennsylvania	90,472[b]	24.44[b]	74	3.03
West Virginia	90,472[b]	24.44[b]	108	4.42
US Average	313,537	57.58	137	2.38

[a]Cost data are for 1977 and reserves data for 1978.
[b]Data from Joint Association Survey (1977) which used a single category to describe drilling costs for these four states.

understand the inadequate effect of minor changes in incentives. Nor did they understand that cost-based pricing caused exploitation of the easy-to-develop resources, while the more difficult resources were neglected. In 1978 the passage of the NGPA was a genuine effort to increase the volume of the resources which could be economically developed. So far, the response has been vigorous and enthusiastic.

REFERENCES

American Gas Association (1978). Energy Analysis: Drilling Activity and Potential Gas Resources.

API. Joint Association Survey on Drilling Costs. American Petroleum Association.

PGA. Potential Supply of Natural Gas in The United States. Potential Gas Agency.

INSTITUTIONAL AND ECONOMIC CONSTRAINTS ON THE UTILIZATION OF NATURAL GAS RESOURCES, WITH SPECIAL REFERENCE TO WESTERN EUROPE AND LATIN AMERICA

Peter R. Odell
Economic Geography Institute, Erasmus University, Rotterdam, The Netherlands

1. INTRODUCTION

Both the figures for the world's proven reserves of natural gas and the most conservative estimates of ultimate resources indicate that natural gas provides an energy potential of roughly the same order of magnitude as that of crude oil. Some observers anticipate the ultimate resource bases of both conventional oil and conventional natural gas to be higher - or even much higher - than the approximately 2000 x 10^9 barrels of oil equivalent of the conservative view of the volumes likely to be recoverable. Beyond these enhanced volumes of the conventional resources of the two energy sources, however, there are also the so-called unconventional occurrences. In the case of these potential world energy resources, it is the outlook for natural gas rather than for oil which provides the mind-boggling figures. In spite of this, however, natural gas has failed to develop as an energy source at the global level to anything like the same extent as oil.

By 1973, at the end of the period of almost 25 years of an exponential rate of growth of 7½% per annum in the use of oil, the world's total oil consumption had reached a level of 20.9 x 10^9 barrels, and oil then supplied about 42% of total world energy use. At that time, the world use of gas was the equivalent of 7.9 x 10^9 barrels of oil: a mere 16% of world energy use. Since then, under the impact of the changed world of oil power and of oil prices, the use of oil has increased much more slowly. By 1979 it had grown to no more than 23.6 x 10^9 barrels at an annual rate of growth of a little over 1.5%. In spite of the uncertainty during most of this period over oil supplies and the disincentive generated for its use by the order of magnitude real increase in the price of oil, alternative energies, including natural gas, have made little impact. Natural gas use in 1979 can be estimated at the energy equivalent of approximately 9.5 x 10^9 barrels of oil, an increase of 20% over 1973, giving an annual rate of increase in use since 1973 of about 2.5% per annum.

Overall in the global energy situation, natural gas thus remains relatively unimportant. Indeed, outside North America, the Soviet Union, and a few other countries it is not unreasonable to suggest that natural gas remains a relatively unknown source of residential, commercial, and industrial energy and/ or a little exploited energy resource.

The international oil industry's lack of interest, until very recently, in exploiting gas resources and their unwillingness or inability to market it provides one important institutional reason for this situation. The relatively very much higher transport costs involved in getting gas to market - compared with oil, even in circumstances in which the transport of gas was technically possible - reduced the international oil companies' enthusiasm for trying very hard to market the gas resources they had discovered in their search for oil; and the same factors generally eliminated their motivation to search for gas *per se*.

Moreover, governments in many parts of the world have played a much more interventionist role in the gas sector. Gas supplies, originally derived from the gasification of coal and the local distribution of coal-gas production, were usually treated as a national or a municipal utility, leading to a requirement that any replacement supplies of natural gas should enter the energy system through the same institutional framework. The consequential lack of oil-industry control over the marketing of gas was a constraint on its interest in the resource. Moreover, much more so than in the case of oil, governments have sought to control gas prices at the well head and often argued that its value should reflect either the fact that natural gas was a by-product of oil production and thus have only low direct costs attributed to it; or, in the case of non-associated gas production, the long-term supply price of the operation. Such considerations have undoubtedly led to restraints on the exploration for gas; and thus to limitations on its discovery and production.

2. RESTRAINTS ON THE DEVELOPMENT OF NATURAL GAS IN WESTERN EUROPE

These constraints on the evolution of the supply of natural gas as quickly as the geological and technical circumstances allowed have been important in Western Europe over the past 20 years. Moreover, their impact is still apparent so that the potential role of natural gas in the Western European energy economy remains as perplexing as throughout the last two decades.

More than 11 years ago I published a study, 'Natural Gas in Western Europe' (Odell, 1969), which drew attention to the availability of a potential for gas production far exceeding the plans of the operators and the expectations of governments in a situation in which there was no possible element of demand constraint on the gas supply. The restraining element that could then be identified in the European gas market was the existence of a monopoly supplier seeking to achieve the highest possible monopoly rent from developing the largest non-associated gas field in the non-Communist world, viz. the Groningen field in the Netherlands.

I then suggested that the strategy of the monopoly would necessarily be undermined by competition from alternative suppliers - both by the development of the gas fields in the natural gas province of the southern part of the North Sea, and by the attraction provided by a high-price market in Western Europe for the supplies of gas which would become available from the Soviet Union via pipelines from the massive West Siberia fields, as well as from other oil-producing countries via the rapidly developing technology of liquefied natural-gas transport. I made a forecast of the size of the West European gas market by 1975 which reflected these hitherto unconsidered factors. This forecast was in marked contrast to that made at the same time by the energy planners in the OECD, the EEC, and in various Western European countries. This contrast is shown in Table 1, together with the situation as it had actually developed by 1975.

The purpose of this introductory note on the history of natural gas developments in Western Europe is not to allocate 'marks' for the degree to which the forecasts were right or wrong, but simply to indicate the tendency on the part of official bodies to make their estimates of the future supply of natural gas based on an extrapolation of specific commercial and state policies which stand in danger of being undermined at any time by the forces of competition and/or by changes in the general energy and economic environment.

Table 1. Western Europe: 1969 estimates of natural gas production by 1975

Country/region	1968 Production	Official estimates for 1975	Author's estimate for 1975	Actual 1975 (approximately)
		($m^3 \times 10^9$)		
The Netherlands	25.1	55	118	98
(of which Groningen)	(25.1)	(55)	(100)	(92)
West Germany	5.8	15	25	20
(of which on-land)	(5.8)	(15)	(20)	(20)
South North Sea (British/Danish Sectors)	2.3	30	38	37
Italy	10.4	12	20	15
France	8.7	6	10	11
Rest of Europe	<1	2	5	2
Total	53	120	217	183
(Estimates as % of actual)		(65%)	(117%)	

Source: 1969 estimates from Odell (1969). Actual figures for 1968 and 1975 from EEC and national statistics.

This is as true today as it was a decade ago. Indeed, perhaps even more so, given that more governments and more companies have become involved in the natural gas sector, so making the situation even more complex to analyze. Unhappily, even more of the actors are now pursuing policies and taking decisions which, in essence, try to limit the scale and speed of development of the resource. There is now, moreover, an additional factor which isolates even more the evolution of the natural gas market in Western Europe from considerations of supply and demand schedules as determined by competition in the energy market place. This is the existence of a very general belief that natural gas is such an inherently scarce commodity that its discovery must be viewed in the context of a 'need' to save it for the 21st century when, it is argued, it will be required to provide a little residual light and warmth in a world then otherwise devoid of readily available and usable sources of energy - in brief, the scarcity syndrome. No one today would advocate profligacy in the use of a fossil fuel, especially natural gas with its many advantages over the alternatives. It is, however, a far cry from such advocacy to a plea for a rational view on the development potential of the Western European natural gas market based on the following considerations:

(a) The continent needs to reduce its dependence on oil imported from OPEC countries in the interests of security, both economic and political. Indeed, energy policies of individual countries as well as of organizations like the EEC and the IEA are designed to push Western European economies and societies in that direction. Yet the existence of known natural-gas resources in and around Western

Europe could, on their being developed effectively, slice 50 million tons a year off the region's oil imports within the short space of time needed to develop the infrastructure to get the gas into the transmission systems.

(b) Western Europe is still at the beginning of its search for hydrocarbons. To date, in relation to the total potential, very little has been achieved. It is thus inappropriate, to say the least, for Western Europe to approach the question of natural-gas resource exhaustion in the same way as may now be necessary for the United States, where the continent's resources have been so thoroughly explored and exploited over the past 50 years. A more appropriate lesson to be drawn from the US is to note how quickly and over how long a period reserves of gas can be built up in the initial phase of an effective exploration effort. Even from the use of analogy it is possible to extrapolate a continuing rapid development of Western Europe's gas resource base. This enables depletion rates to be planned against reasonable expectations of reserves' discoveries, rather than simply against the knowledge of the amount of gas already discovered.

(c) An appropriate approach to the evolution of Western Europe's gas reserves' figure does not, however, have to be based on analogy from United States' experience. It can, instead, be much more soundly based on current knowledge of the resource base in Western Europe itself and on what can, with a high degree of confidence, be extrapolated from the successes to date of the exploration effort. This shows a high probability that the currently declared proven and probable reserves of gas understate the prospects even for the near term, and that available reserves will go on increasing over the forseeable future at a rate sufficient to allow for a continuing rising demand curve. This is illustrated in Table 2, which also sets out the elements of controversy in contemporary crystal-ball gazing on the future supply of, and demand for, natural gas in Western Europe by the mid-1980s.

Within the context of OPEC oil at continuing high prices, there is no chance that any natural gas produced in Western Europe would fail to find markets. Obviously a collapse of the OPEC oil price would significantly alter this assumption as many customers - in a continued free-choice economy in the energy sector - would then prefer to use imported lower-cost oil, rather than pay the price necessary to cover the costs of producing and transporting some of the more expensive Western European off-shore gas to market. Such a development would limit natural gas markets, especially in industry and in power generation throughout the continent and would clearly be most important in the consuming regions furthest away from the main sources of supply. This supply is, as shown in Figure 1, essentially North-west European. For the moment, however, it is difficult to envisage such a fundamental change in the world oil outlook. We can thus assume, except locally and in particular circumstances of gas saturation of specific markets (e.g. the residential sector market in the Netherlands or, increasingly, in large parts of the UK), that there are unlikely to be effective demand restraints imposed through economic factors on the expansion of the natural gas industry: in the absence, that is, of a long-lived economic depression in Western Europe.

Neither is it reasonable to conclude that there will be significant political/environmental constraints, except for limitations of gas use in

Table 2. Western Europe: its currently 'proven' and possible natural gas resources and an estimate of their development by the mid-1980s

Region	Remaining recoverable reserves			Mid-1980s annual production potential	Millions of tons of coal equivalent* (approximate)
	Declared 'proven' + 'probable' in 1979 ($x10^9m^3$)	Proven + probable + possible ($x10^9m^3$)	As likely by mid-1980s ($x10^9m^3$)	($x10^9m^3$)	
On-shore Netherlands	2025	2150	1900	105	110
South North Sea - British Sector	520	650	900	50	65
South North Sea - Other Sectors	450	850	1050	55	70
On-shore West Germany	250	500	450	25	30
Austria, France, Italy, Spain	400	450	500	35	45
Northern North Sea Basin - UK/Norway	1000	2500	3000	115	145
Rest of European continental shelf (Ireland, Spain, etc.)	50	150	250	15	25
Total	4695	7250	8050	395	478

*Conversion to coal equivalent based on known or estimated calorific values of the various gas supply sources.

Source: For 1976, various national and EEC/OECD estimates. Estimates for the 1980s are the author's own.

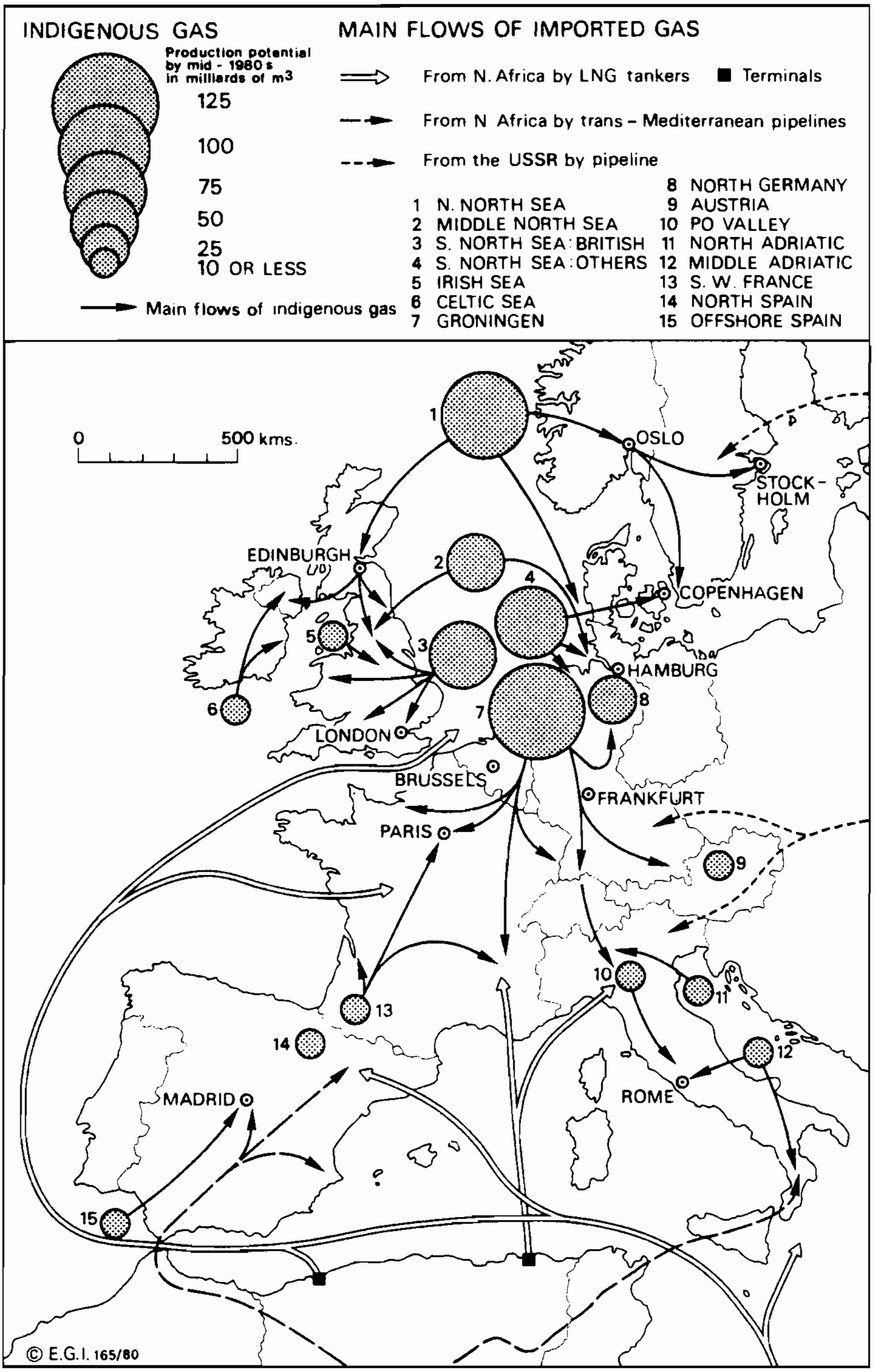


Figure 1. The geography of Western Europe's potential supplies of natural gas by the mid-1980s.

electricity power stations*. And finally, neither is there a very high probability that the necessary infrastructure to transport and distribute gas could not be built. In this respect, however, one approaches much closer to the question of production limitations, particularly as far as associated gas from oil fields is concerned. We shall return to this issue when considering the supply side of the equation.

Overall, it is thus difficult to foresee any necessary demand limitation on the use of natural gas in Western Europe for at least the next 10 years. Its advantages as a source of energy are well-known and generally recognized. Its incorporation into the energy economy, at as high a rate of development as the expansion of the production potential allows, remains, political and institutional constraints excepted, a function of the geography of its supply and the location of energy demand. This is illustrated in Figure 2, which I first used in my 1969 study, with the following note of explanation:

> "In both the US and the USSR the main energy consuming areas are remote from natural gas supplies and, despite these facts of geography, gas has become a preferred fuel in both countries. Within Western Europe, on the other hand, the major supplies of natural gas are in the heart of the areas of heaviest energy consumption. Other things being equal, this situation should ensure the most rapid development and utilisation possible of Western European gas with consequent enhanced economic advantages for the continent's energy users." (Odell, 1969, p. 9).

The continuing basic validity of this earlier observation made on the attractiveness of natural gas for Western Europe is not in doubt. There are, however, still constraints on its implementation because, in the Western European context, other things have not been equal. At the beginning of this paper the institutional (monopolistic) restraints on the production of Dutch natural gas in the late 1960s were mentioned. Now, over a decade later, one notes a major difference between the production potential, which the resource base development appears to indicate should be possible by 1985, and the figures which official sources (this time in the shape of recent OECD figures for energy supply and demand in Western Europe to 1985) (OECD, 1977), believe will be achieved. These are set out in Table 3. These OECD estimates of a 1985 gas production of 229-258 $\times 10^9$ m^3 should be compared with the potential for a production of almost 400 $\times 10^9$ m^3 which emerges from analysis of the reserves shown in Table 2.

It is not that the OECD figures for the 1985 production of natural gas are <u>very</u> pessimistic compared with the 1974 base. As Table 3 shows, within the context of an expected 47% increase in energy use from 1974-1985, the OECD 'reference case' envisages an increase of Western Europe's natural gas production of 45% and an increase of over 63% in its 'accelerated policy' case. However, the expectation of 1985 production levels of 229 and 258 $\times 10^9$ m^3, in the two cases, respectively, contrasts strongly with the estimated production potential from the still rapidly developing resource base. Indeed, as shown in Table 4, the difference between what is now officially expected and what appears to be possible, with the full development of the resource base, is of the same order of magnitude as the difference which existed between the estimates made in 1969 for production levels by 1975 (Table 1). In both

---

*This restraint is related to the fact that it is very wasteful to use gas as the energy input into centralized electricity generating stations, where only a net 30% of the input fuel is converted into useful energy. Even this restraint could, however, be eliminated were gas to be used for electricity production in CHP plants (Odell, 1976).

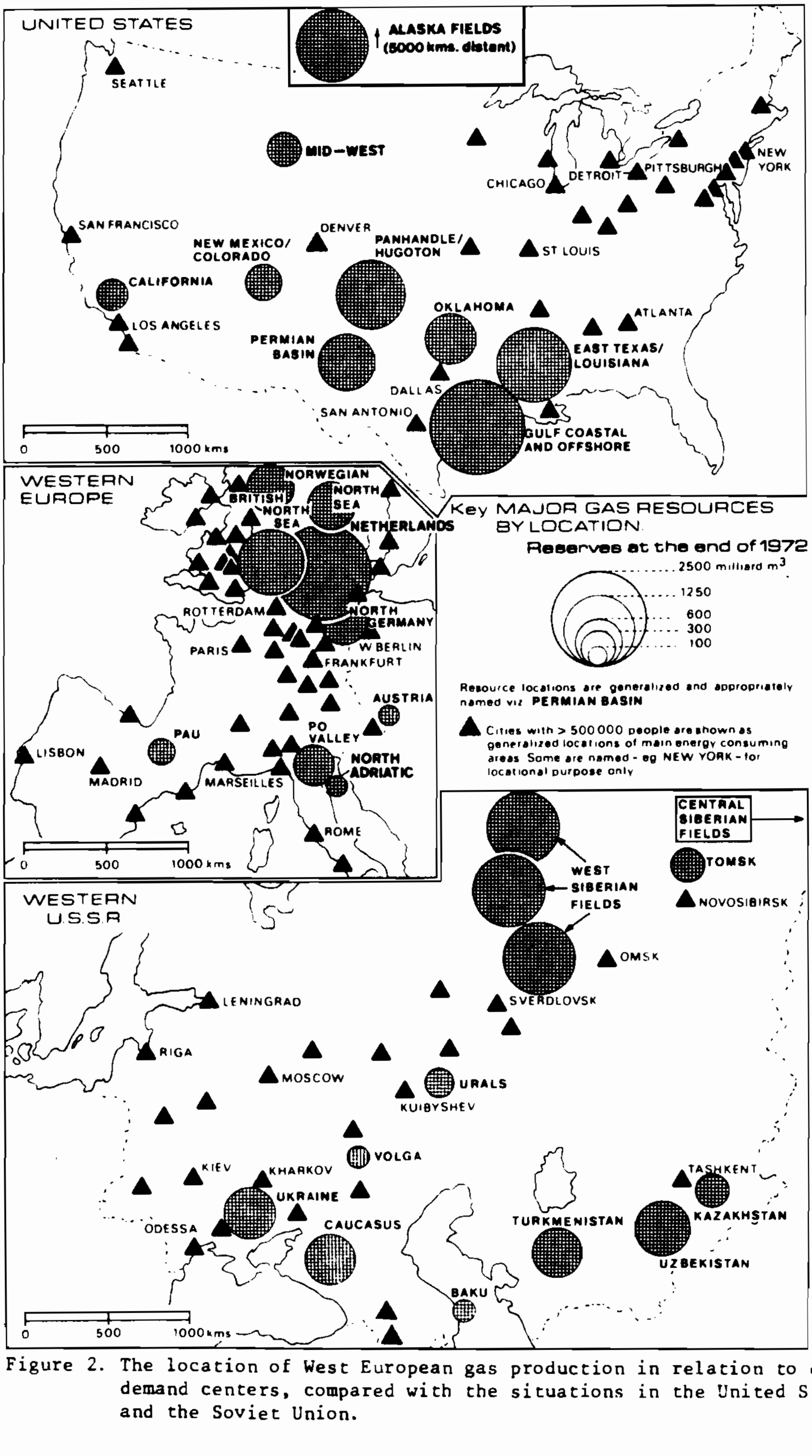


Figure 2. The location of West European gas production in relation to energy demand centers, compared with the situations in the United States and the Soviet Union.

Table 3. OECD forecasts of changes in energy consumption in Western Europe, 1974-1985

	1974 Energy Use		1985 Reference Case			1985 Accelerated policy case		
	Quantity	% of total energy	Quantity	% of total	% Increase over 1974	Quantity	% of total	% Increase over 1974
Oil (mill.b/d)	13.3	56	18.0	53	36	14.6	45	10
Natural gas ($m^3 \times 10^9$)	174.4	13	311.8	15	79	341.9	18	97
(of which West European production)	(157.7)	(11)	(228.9)	(11)	(45)	(257.9)	(13)	(63)
Coal (mill.tons)	467.9	27	516.0	20	10	552.6	23	18
Primary electricity (Twh/yr)	1426.3	4	2593.0	12	82	2528.0	14	77
Total energy use (mill.tons oil equiv.)	1159	-	1704.4	-	47	1619.2	-	39

Source: OECD (1977).

cases the official view indicates an increase in indigenous production which equals only 40% of the increase which could be sustained by full exploitation of the resources.

It would be tempting to speculate that history in this respect is simply being given a chance to repeat itself. Indeed, one can argue that the same behavioral characteristics of 'official' forecasters of the natural gas sector of the West European economy are again at work, viz. their unwillingness to think in dynamic-enough terms about the development of a gas resource base under the stimulus of an open-ended demand. Alternatively, it could simply be that OECD, as a multi-national energy planning agency, is influenced most of all in its published forecasts by the reticence of the member governments to commit their countries to maximize their production of natural gas. This is because such a commitment implies either too large a rate of export to neighboring countries or, even more simply, too high a rate of production when set against other national energy policy decisions. Such decisions may simply seek to curb the rate of development of hydro-carbons as a matter of principle, or they may be related to firm plans for other sectors of the national energy economy (viz. coal, nuclear power), which are supported by powerful pressure groups. Such groups would not wish to see the sectors they support undermined by the prospect of too much gas.

It is, indeed, to one or other of these considerations that one must turn in order to find an adequate explanation for the continued underestimating of the potential contribution of indigenous natural gas to the Western European economy, rather than to really serious doubts over the size of the resource base which could be developed, or over the ability of the industry to produce and to deliver the commodity even from the adverse environments of the northern parts of the North Sea.

Table 4 summarizes, country by country, the differences between the OECD 'Reference' and 'Accelerated' cases, on the one hand, and the production potential estimates previously listed in Table 2, on the other. The Netherlands, the UK, and Norway are in all cases the dominant suppliers and the differences in the estimates for these countries are thus critical in analyzing the overall situation. Before dealing with these in detail, however, it must be pointed out that in no other country is there any element whatsoever in the official figures that 1985 production levels will owe anything to discoveries which have not yet been made (other than for developments in reserves which will be necessary to maintain production levels in countries like France and Austria). This is truly remarkable given that every country plans an active exploration program for natural gas in its potential petroliferous regions. In each of these there must be some hope of success, for otherwise no company or state entity would be willing to invest. An outlook in which none of the hopes for successful exploration are realized is basically unbelievable - but it illustrates nicely one of the basic points made earlier concerning the failure of governments in Western Europe to respond to the well-known dynamics of natural gas exploration and exploitation. However, for all these minor producers taken together the difference between the estimates amounts to less than 30 x 10^9 m^3 by 1985. However, for the Netherlands, the UK, and Norway the difference between the estimates is, in each case, at least that great.

As far as the Netherlands is concerned, the discrepancy between the estimates is largely a function of contrasting expectations concerning the off-shore potential - though there is also a component related to the decision to allow a decline in production from the giant on-shore Groningen field and an expectation that this will not be made up by the exploitation of newly discovered on-shore resources resulting from an active exploration effort. The 'gap' in the interpretation of the off-shore situation appears, however,

Table 4. Western Europe: 1977 estimates of natural gas production by 1985

Country/region	1978 Production	OECD estimates		Author's estimates
		Reference Case ($10^9 x m^3$)	Accelerated Case ($10^9 x m^3$)	
Netherlands	90.2	92	111	146
United Kingdom	39.15	50	50	105
Norway	13.50	30	40	65
West Germany	20.03	20	20	30
Italy	12.5	17.5	17.5	20
France	7.87	8	8	12
Spain/Portugal	0.01	6.5	6.5	8
Denmark	-	2.5	2.5	5
Ireland	0.10	1.3	1.3	5
Austria	2.18	1.3	1.3	2
Total	c. 185.9	229	258	398

Sources: OECD estimates are from OECD (1977). The author's estimates are based on production potential from gas reserves already discovered or likely to be available by 1981/82, so that there is time for the necessary production/transportation infrastructure to be built. See Figure 1 for a map of the author's estimate of supply patterns by the early 1980s.

to be more important and emerges from the information in Table 3 and Figure 3. These show that the south North Sea is full of gas fields. Over 60 discoveries are shown in the Dutch sector alone. Thus, the official figure for off-shore production of only about 10^9 m^3 a year is unnecessarily low, even when related, as it appears to be, only to gas from the much smaller number of officially declared fields. Yet exploration for new gas fields in the Dutch sector of the North Sea has recently expanded with companies responding to the opportunity of a market for gas at prices which are generally closely related to oil equivalent prices. Indeed, given what is known of the situation - and that is little enough given the high degree of secrecy maintained in respect of Dutch gas reserves - coupled with what one can reasonably extrapolate, then a level of production of less than 40-45 x 10^9 m^3 per year from the Dutch off-shore by 1985 will only be possible in the context of governmental unwillingness to allow reasonable developments to go ahead. The supply of Dutch gas in the 1980s will, in other words, be constrained by an even more powerful institutional force than the NAM monopoly over Groningen production in 1969.

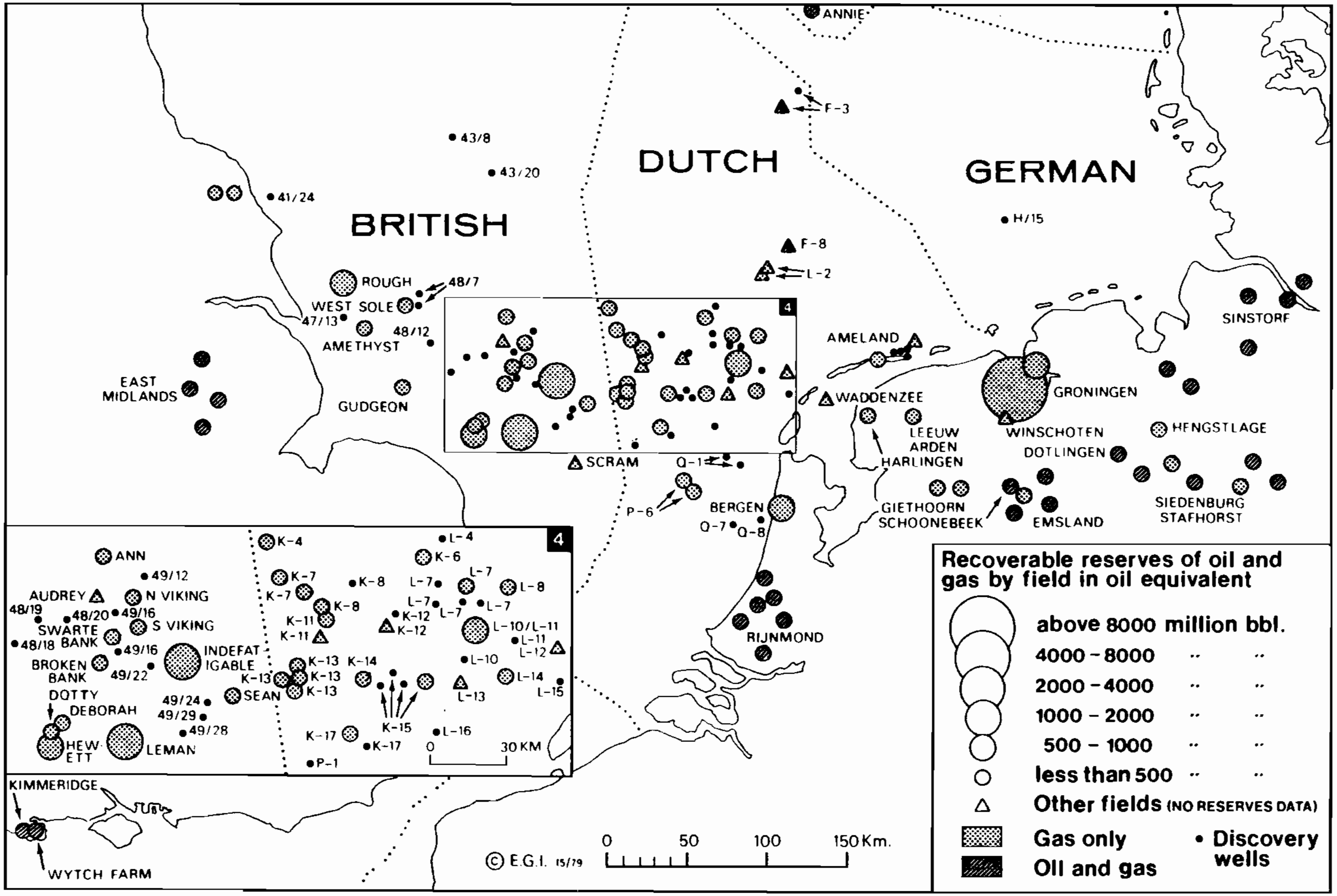


Figure 3. The Southern North Sea: discoveries and developments to mid-1979.

For the UK the situation is rather different, and somewhat more complex, with three main factors involved. First, south North Sea developments in the British sector (see Figure 3) are curtailed by the lack of incentives to the companies which have discovered many fields there. All gas from these fields has to be sold at the English coast to the British Gas Corporation and as it is not prepared, or not allowed, to pay a price which enables the companies to meet the opportunity costs on the investments required for the development of new fields (or even for the development of additional reserves from fields already in production), exploitation is not taking place and so reserves remain unproven and unused. This gas, together with that under the adjacent Dutch sector of the south North Sea, currently constitutes Western Europe's lowest-cost energy resource potential and by particular provisions of Dutch and British policies towards natural gas, the benefits to be gained from its development are being foregone.

Secondly, the UK Gas Corporation tied itself, a few years ago, to an open-ended commitment to buy natural gas from the large Frigg field in Norwegian waters* (see Figure 4). Both the cost of this new gas and its total annual availability (at least 15×10^9 m^3 per year), adding about 35% to the present level of supply, has created concern over the ability of the Gas Corporation to market any more gas successfully. This arises because the Corporation knows it will not be allowed to sell any gas for electricity generation, where its use would upset the one secure market for British coal. Thus, in having to concentrate on the marketing problem for Frigg gas, it cannot be fully enthusiastic about the too rapid development of the even greater new production potential from the northern part of the British sector of the North Sea. Here a number of new oil fields with high gas/oil ratios have been discovered, so opening up the possibility of high annual rates of associated gas production by the mid-1980s.

This leads to the third factor involved in creating an apparent unwillingness by the UK to declare its production potential for 1985 at a higher figure than the 50×10^9 m^3 designated in the OECD study. This is the expensive question of the development of a multi-user pipeline system for collecting associated gas from the 30 or so north North Sea oil fields with collectable quantities of natural gas (see Figure 5). This is partly a matter of expensive technology <u>per se</u>, but has also been, until recently, a matter of politics, given the previous government's insistence that the operation should mainly be in the hands of state enterprises. Thus private-sector companies involved could not be certain of being able to achieve an adequate return on the investment required. Detailed studies on the project have now been completed and proposals have been made. Final agreement is, however, still awaited so that the Gas Corporation retains a breathing space for the marketing efforts which will be required to take UK gas consumption to a level 50% higher than that achieved to date. Time may, however, turn out to have been expensively bought because of the cost of oil production which has had to be foregone,

---

*The reason for accepting such a commitment on the part of the BGC - in the light of the availability of lower-cost gas from the south North Sea basin and a high expectation of gas reserves being discovered in British waters further north (as has now happened) - has never been satisfactorily explained. It seems to lie in the belief by the former Chairman of the Corporation that he was dealing with a scarce commodity and was frightened that it would not be possible to cover forward sales. This reasoning also explains why the BGC stopped trying to sell gas to new customers - indeed, even refused to supply new customers - at the same time. These mistakes have cost the BGC dearly in respect of its supply costs.

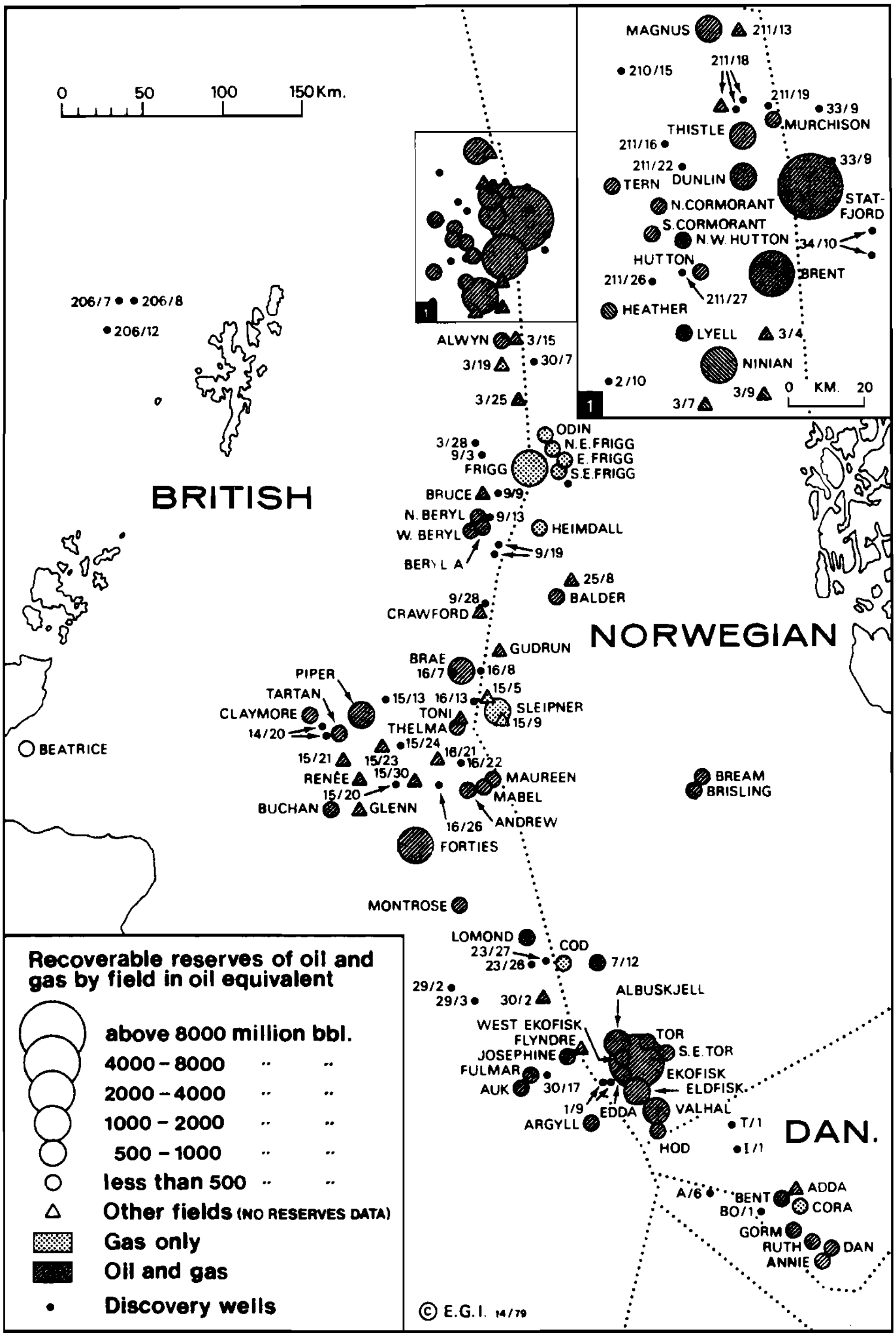


Figure 4. The Northern North Sea: discoveries and developments to mid-1979.

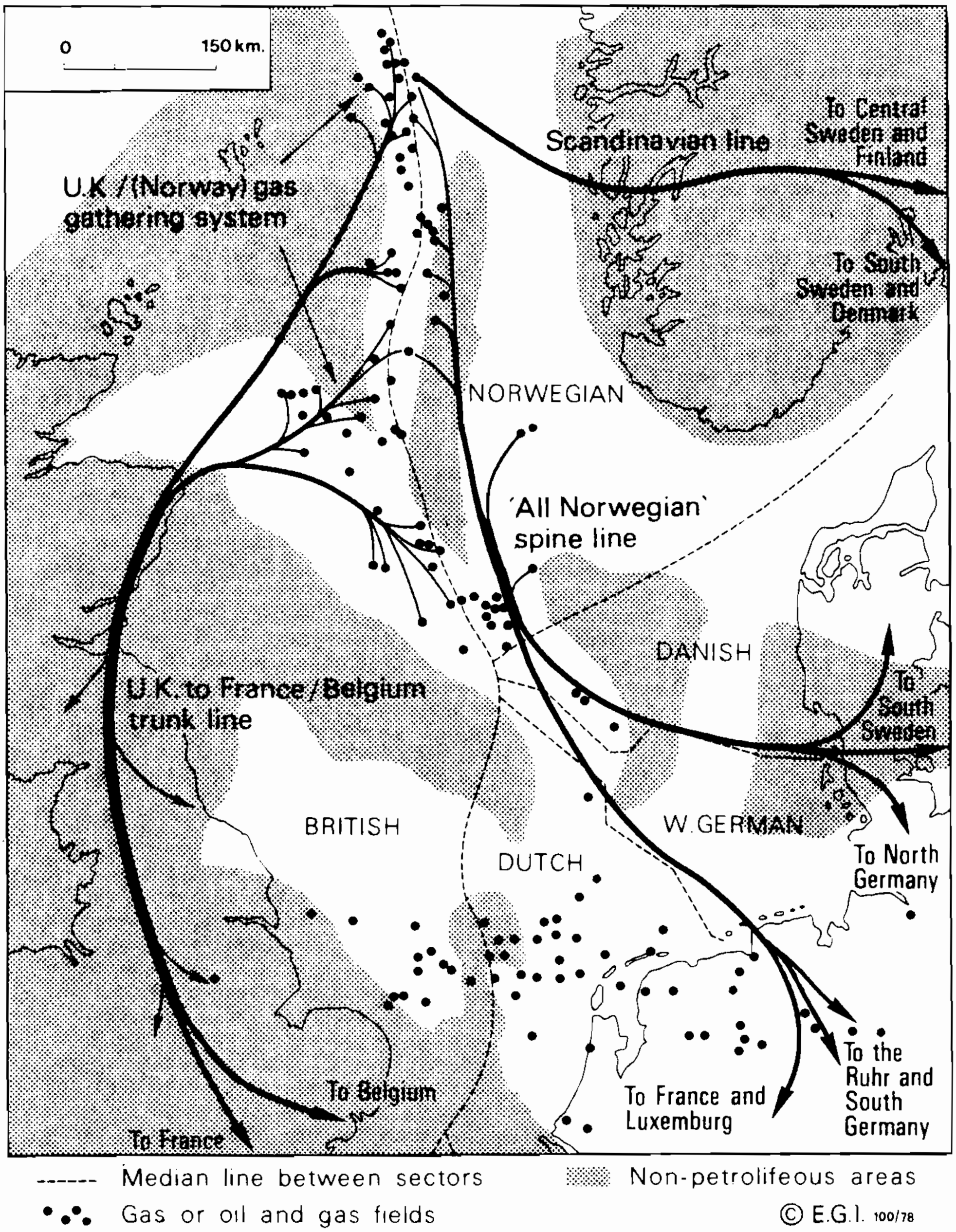


Figure 5. The North Sea oil and gas province. Fields and discoveries, etc., and alternative possibilities for natural gas collection and delivery systems from the Northern and Central Basins. (Note that the gas transport systems shown are hypothetical only; they do not represent definite plans in general or in detail as of June 1980.)

or of associated gas which has had to be flared in the meantime*.

Indeed, so great are the gas collection and transportation difficulties involved when the potentially large new supplies of British North Sea gas are evaluated solely in a British context, that it is almost self-evident that the solution lies in the UK linking its gas transmission system to that of the mainland of Western Europe, across the Channel into France and/or Belgium. Yet this solution is in itself a problem because of the widely held view that the UK should not commit itself to long-term gas supply contracts with other member countries of the EEC. The British government once before, in 1971, refused to allow British gas (from the Viking field in the southern part of the North Sea) to be sold to West Germany and even now, in spite of EEC legislation which formally forbids discrimination between EEC customers for any product from a member country, it still seems more likely than not that a similar decision would again be taken. Meanwhile, the potential for natural gas production from the UK seems likely to be restrained, again, as in the Netherlands, largely for institutional rather than good economic and strategic reasons.

In respect of the Norwegian natural gas potential the OECD forecasts specify the greatest proportional difference between the 'Reference' case and the 'Accelerated policy' case - the latter indicates a 33% higher gas production than the former. Even so, the 'Accelerated policy' specifies so low a figure that it will take deliberately negative policies in relation to the potential available for it not to be exceeded. But it is, of course, precisely such policies in respect of hydrocarbon production levels which mark Norwegian attitudes towards its North Sea resources. If all possibilities have to be evaluated in the context of a general principle that the total production of hydrocarbons must not exceed the equivalent of 90-100 million tons of oil per year then, given what has been found already and what is under development on both the oil and gas fronts, new natural gas developments cannot supply more than 30×10^9 m^3 per year. The rest of the allowable hydrocarbon production 'quota' will be provided by oil from Ekofisk, Statfjord and other fields in production or development.

In the context of a Western Europe whose political and economic future is bound up with greatly reduced dependence on oil from the Middle East, this is an institutional attitude to the development of gas resources with serious consequences (Odell, 1974). However, the internal Norwegian reasons for taking the policy decision so to restrict production have long been overtaken by events, particularly in respect of the no longer valid assumption, as used in the initial calculations of the optimal level of Norwegian hydrocarbons production, that all the country's resources would be fully employed in other economic activities. Though the decision on production limitation has not been formally reversed, there are indications that it is not being treated with quite the same degree of firmness as it was, say, up to 1976. The change is reflected, for example, in the licensing of a relatively large number of new blocks in the North Sea and in the recent deci-

*The new British government announced its decision to proceed with a multi-field gas gathering pipeline system on June 19, 1980. This decision reflects a major change in policy, as private-sector companies will provide most of the investment and will thus control the system. It also opens up the possibility of gas sales in the UK outside the monopoly exercised by the Gas Corporation, and could thus push total sales to higher levels than hitherto written into the British estimates of the future availability of gas. The system is expected to deliver its first gas in 1984/85 and may thus alter the OECD's forecasts.

sion to allow exploration north of latitude 62° to begin in spite of misgivings on the part of a large section of Norwegian opinion. This change in attitude opens up the possibility of a reappraisal of the level of natural gas production which could be achieved by Norway by the mid-1980s. Fields which have been discovered but not yet evaluated could contribute to the enhanced potential which, quite conservatively, may be put at the level of 65 x 10^9 m^3 shown in Table 4.

As much of the potential is in respect of associated gas, the gas production decision is often a joint one involving oil as well. Thus technical, rather than marketing, considerations are often paramount: and if the gas 'has' to be sold (rather than being reinjected or flared) then transport considerations, particularly in respect of the pipeline distance under water and of the scale of the operation, may well be an overall determining factor for the volume which has to be involved. Given the location of possible contributing fields to an enhanced supply of Norwegian gas (see Figure 4), the quantities seem likely to have to be bigger rather than smaller.

If a 'Norwegian' solution to the Norwegian North Sea gas potential is to be achieved - through the development of the Scandinavian line or the All-Norwegian Spine-line, which would link a series of fields from north to south in Norwegian waters with Germany and/or Denmark (see Figure 5) - then a delivery system with a capacity of at least 20 x 10^9 m^3 per year seems likely to be required in order to keep the unit investment cost down to a level which ensures the marketability of the gas. This, when added to existing contracts, would take Norway's contribution of gas to the European market above the 'Accelerated policy' figure in the OECD report in one move. Such a system is attractive not only because of the Norwegian-ness of the solution, but also because it ensures entry for the gas to the West German and other mainland energy markets, where an oil equivalent price would be an acceptable formula for determining the gas price.

This is not true for the alternative solution, viz. the building of a system of collector pipelines from the Norwegian fields to tie in to the proposed multi-user trunk gas lines running from fields in the British sector of the north North Sea to the UK mainland. In this case, Norway would only be required to undertake a more limited scale of development. This could be achieved, however, only as a result of difficult negotiations with the UK over charges to be made for the use of the British lines and for using the UK as a transit country, in order to get the Norwegian gas delivered to the mainland of Western Europe via the UK.

Such a development would have considerable benefits for the UK itself; first, in terms of the general added value in the British economy from this service function; second, the Norwegian throughput of gas through the British trunk lines to the coast would guarantee the viability of the multi-user line project; and third, in terms of the political opening the transhipment of Norwegian gas to France or Belgium would give for a British government to 'sell' the idea that some British gas could also move across the Channel - at low cost and high value in terms of foreign exchange earnings to the UK economy.

Such international co-operation might thus enable Norway to restrict its supply of natural gas to a level lower than that required to ensure the profitable development of Norway's gas resources if Norway were to build a separate off-shore transportation system. A decision on the gas transport system may thus well be the main element in determining whether Norway does nothing more than expected by the OECD energy analysts, or whether it chooses to move to a level of supply of the commodity by 1985 which will take its total production of gas to a higher level.

This choice by Norway also depends on its own institutional response to the challenge and opportunities presented by the natural-gas markets of Western Europe. This is the same sort of gas policy choice which we have already shown to be the case in respect of the Netherlands and the United Kingdom, the other two main suppliers of natural gas in Western Europe. The three countries thus have much in common as far as their decisions on their natural-gas policies are concerned. Indeed, their policy decisions in this respect will determine just how independent Western Europe can become from OPEC oil by the mid-1980s, with obvious important implications for the future of the region's economy in general. If we assume that all three decided to pursue policies to maximize, rather than to restrict, the production of their large natural-gas reserves, and further assume that all the additional natural gas they produce will substitute oil that the OECD currently expects to be imported from the OPEC countries, then, within the context of the figures in the 1977 OECD report on West Europe's total energy demand by 1985, the use of oil would fall by the latter date by about 2.5 x 10^6 barrels/day from the calculated 14.6 x 10^6 barrels/day shown in the 'Accelerated policy' case. This additional gas production would, however, also enhance the possibilities of indigenous oil production (given that much of the new gas will be from oil fields as associated gas), so that oil import requirements of Western Europe could then fall sharply from the OECD expected level. The continent would, in that

Table 5. Natural gas resources of the Southern North Sea Basin
(excluding associated gas)

	Dutch sector	British sector	German sector
Total number of gas discoveries	62	36	3
Number of discoveries declared as gas fields	20	15	-
Governments' declarations of remaining proven gas reserves ($10^9 m^3$)	322[a]	460[a]	-
Number of fields in production	13	8	-
Other fields with announced production plans	5	1	-
Current (1979) annual production ($10^9 m^3$)	approx. 8	39	-
Likely remaining reserves[b] for all fields in each sector at summed 90% probability ($10^9 m^3$)	1000+	950+	50+
Mid-1980s production potential with full exploitation[c] of the already discovered reserves ($10^9 m^3$)	45+	50+	2-3

[a]Arithmetic total of 'proven' reserves of declared fields.

[b]Based on all discoveries made and not just on declared fields.

[c]Based on 20-25 year depletion periods for the fields.

case, become much more independent of OPEC for the supplies of energy essential to its continued development. This much is at stake in respect of decisions on the development of the natural gas resources that have to be taken in Western Europe over the next few years, where even in the wealthy and sophisticated socio-economic systems of this part of the world, economic and institutional factors still constitute effective constraints on the maximum possible use of the region's natural gas resources.

3. RESTRAINTS ON NATURAL GAS DEVELOPMENT IN LATIN AMERICA

In the Third World - outside the member-countries of OPEC - there are equally important and even more effective constraints on natural gas exploration, production, and use. The geographical location and patterns of energy use, as well as the overall pattern of energy demand, inhibit the incorporation of natural gas into Third World countries' energy systems. Distant resources, for example, are not perceived as being relevant to energy policy decisions, even in circumstances in which the increasing amounts of energy required by developing countries have increasingly originated in the even more-distant oil producing and exporting countries. In the capital-short countries of the Third World, however, the development of gas resources has to compete with alternative high capital-cost energy provision - notably hydro-electricity and, increasingly, nuclear power. All too often the cost effectiveness of natural gas development seems not to be seriously considered because of pressures for expenditure on the alternatives: hydro-electric power because it is a familiar, reliable source for which international financing is usually readily available; and nuclear power, because the search for Third World markets for atomic power stations by competing supplying countries of the industrial world ensures that the necessary studies of the nuclear option are made, and that the capital required is offered as part of a package deal.

Table 6 shows the evolution of energy use in Latin America between 1950 and 1975. In the context of a 340% increase in energy use over these 25 years, and a dramatic decline in the relative contribution of vegetable fuels, the continent's energy economy became increasingly dominated by oil. Natural gas use, however, increased by over 10 times in oil equivalent terms and by over three times in percentage terms. Despite this growth in the contribution of natural gas to the continent's energy economy, most natural-gas production in Latin America was still wasted in 1975. Total gas production in that year amounted to more than 80 million tons of oil equivalent, but almost 58% of that total was flared at well-head. Utilization of the flared gas could have substituted 35% of the continent's use of 134.4 million tons of oil! The geographical distribution of gas production and utilization in the 14 most important energy-using countries of Latin America (collectively accounting for almost 95% of all energy used in the continent) is shown in Table 7. From this Table it can be seen that three countries - Venezuela, Mexico, and Argentina - account for over 76% of total gas production and for no less than 86% of total natural gas use. Even so over 30 x 10^6 tons oil equivalent of natural gas is flared in these important oil and gas producing countries - wasted gas equal to almost 14% of their total energy use of 220 million tons oil equivalent.

Thus even in respect of the continent's relatively limited exploitation of its natural-gas resource potential (to be discussed later in the paper), there has been a less than fully successful incorporation of the gas produced into the expanding energy sector of the economy. The background to this situation indicates the nature of the restraints on a more rapid development of natural gas' contribution to the energy needs of developing countries. Natural gas in Latin America is usually a by-product of oil production, so that the geography of its production is a function of decisions on oil develop-

Table 6. Energy use in Latin America, 1950 and 1975

	1950		1975	
	m.t.o.e.[a]	%	m.t.o.e.[a]	%
Total energy use	68.0	100	231.1	100
Of which:				
Vegetable fuels	29.2	42.9	41.4	17.9
Oil	28.8	42.4	134.4	58.2
Natural gas	2.9	4.3	33.7	14.6
Coal	5.5	8.1	11.0	4.8
Hydro-electricity	1.6	2.4	10.6	4.6

[a]m.t.o.e. = million tons oil equivalent.

[b]Calculated on the basis of heat value of electricity produced. 1kWh = 3412 Btu = 860 kcals.

ments for which the subsequent transport requirements and costs are very different from those of natural gas.

Natural gas demands a capital-intensive transportation system from its point of production to energy consuming areas and a sophisticated, and even more capital-intensive distribution system if it is to be used in urban residential, commercial, and small industry sectors as well as in large-scale energy-intensive industries. In that most Latin American countries have economies in which the former are collectively much more important than the latter in their total energy needs, this acts as a disincentive for gas use.

The fact that most of Latin America's oil production has been developed in locations remote from energy demand centers means that most of the associated gas production cannot quickly be incorporated into the energy economy so that it has to be flared and/or re-injected into the producing reservoir. Given time, pipelines can be built, industries can be located in areas of gas availability (as in Argentina, Venezuela and, most especially, Mexico), and the gas delivered for energy use. However, even with such developments 100% use of the gas produced is unlikely to be achieved, and in many cases in Latin America even these efforts to make gas available for use have been long-delayed or have proved impossible to implement for both economic-geographical and political reasons; producing, as shown in Table 7, the inevitably low ratio between gas production and use in most Latin American countries. As shown later, whilst the prospects for the production of natural gas in much of Latin America could improve, the prospects for its effective use in greatly expanded quantities in the 1980s are much less good - basically because of the types of constraints on its utilization that have already been noted.

Since 1975 (the last year for which comprehensive and comparable data for the whole of Latin America is available) there have been important infrastruc-

Table 7. Aspects of energy, oil and natural gas developments in 14 Latin American countries, 1950 and 1975

Country		Energy (excl. veg. fuels)[a]			Oil			Gas			% of oil and gas in total energy use
		Production for use[b]	Use	% Self suff.	Production	Use	% Self suff.	Production	Use	% used	
Argentina	1950	3.86	9.04	42.7	3.36	7.31	46.0	0.66	0.46	69.7	85.9
	1975	28.20	28.06	100.5	20.67	19.85	104.1	8.93	6.64	74.4	94.4
Bolivia	1950	0.11	0.16	68.8	0.08	0.12	66.7	-	-	-	75.0
	1975	2.04	0.94	217.0	1.92	0.82	234.1	3.38	0.06	1.7	93.6
Brazil	1950	1.73	6.47	26.7	0.05	4.32	1.2	neg.	-	-	66.8
	1975	16.71	45.05	37.1	8.58	35.83	23.9	1.41	0.44	31.2	80.5
Chile	1950	1.65	2.70	61.1	0.08	1.13	7.1	0.17	-	0	41.9
	1975	3.74	6.42	58.3	1.17	3.99	29.3	6.17	1.09	17.7	79.1
Colombia	1950	5.70	1.92	336.8	4.70	0.93	505.4	1.04	0.18	17.3	57.8
	1975	12.34	11.01	112.1	7.92	6.60	120.0	2.95	1.53	51.9	73.8
Cuba	1950	0.02	1.78	1.1	0.02	1.72	1.2	-	-	-	96.6
	1975	0.23	7.10	3.2	0.23	7.00	3.3	-	-	-	98.6
Ecuador	1950	0.35	0.24	145.8	0.35	0.23	152.2	0.12	-	0	95.8
	1975	7.86	2.09	376.1	7.75	1.99	389.4	0.26	0.05	19.2	97.6
Jamaica	1950	neg.	0.09	zero	-	0.91	zero	-	-	-	88.9
	1975	0.03	1.90	2.7	-	1.89	zero	-	-	-	99.5
Mexico	1950	12.52	9.36	133.8	10.57	7.38	143.2	1.61	1.14	70.8	91.0
	1975	59.52	48.71	122.2	42.12	30.97	136.0	19.36	12.81	66.2	89.9
Peru	1950	2.10	1.22	172.1	2.01	1.10	182.7	0.71	neg.	0	90.2
	1975	4.55	6.73	67.6	3.51	5.65	62.1	1.65	0.43	26.1	90.3
Dom. Rep.	1950	-	0.13	zero	-	0.13	zero	-	-	-	100
	1975	0.01	1.39	0.7	-	1.38	zero	-	-	-	99.3
Trinidad	1950	3.03	0.30	1010.0	2.90	0.17	1705.9	0.40	0.13	32.5	100
	1975	14.30	2.47	574.9	11.25	1.32	852.3	1.31	1.15	87.8	100
Uruguay	1950	0.06	0.87	6.9	-	0.73	zero	-	-	-	83.9
	1975	0.09	1.70	5.2	-	1.59	zero	-	-	-	93.5
Venezuela	1950	79.24	3.52	2251.1	78.24	[illegible]	3129.6	13.72	0.97	7.1	98.6
	1975	132.80	19.71	673.8	122.55	9.29	1319.2	33.04	9.50	28.1	95.3

[a]Hydro-electricity has been included on the basis of the heat value of the electricity produced, viz. 1kWh = 3412.1 Btu = 859.9 Kcals.

[b]Excluded from this figure is that part of the production of natural gas which is neither used nor exported, i.e. the gas produced as a by-product of oil production and then flared or reinjected.

tural developments of new pipelines for the long-distance transmission of additional gas, both within countries and, in a few cases, between countries. Some steps have also been taken to ensure that new markets can be secured for gas - such as the recent Argentine decision that gas will replace oil in industrial, commercial and residential sectors through the Buenos Aires Metropolitan Region. This, of course, is a project which implies a high level of expenditure over many years on the construction of an extensive gas distribution system. In this kind of development there is a parallel with what has happened over the last three decades elsewhere in the world; first, in North America, and more recently in the Soviet Union and Western Europe. In each of these continents the attractiveness of relatively low-cost gas - particularly that produced in association with oil and that available from gas fields in close proximity to centers of urban/industrial energy use - was, once the opportunity was recognized, the basis for a very rapid expansion in its use.

Indeed, in both North America and in Western Europe the rate of increase in gas use, once the necessary infrastructure had been built, generally exceeded the forecasts as natural gas substituted oil across a broad range of uses. Many of the large and rapidly-growing urban areas in Latin America offer similar, though not identical, conditions and their conversion to the use of natural gas from the use of oil products could become one of the marked features of Latin America's energy economy over the last 20 years of the century.

Three additional points need to be made concerning the medium-term future of natural gas in Latin America. First, except in Mexico to some degree and in Argentina to a small degree, there has been no deliberate search for reserves of natural gas as such: the supplies already achieved are a consequence of the search for oil. Non-associated natural gas resources are, however, a common phenomenon in other parts of the world where large-scale gas-using economies have provided the motivation for hydrocarbon exploration specifically orientated to the discovery of natural gas. There is no reason to believe that Latin America will be any different in this respect. Indeed, both Grossling and the USSR Ministry of Geology indicate that potential natural gas reserves in Latin America are likely to be of the same order of magnitude (in oil equivalent terms) as the continent's oil reserves (viz. 410-1060 x 10^9 bbls. oil equivalent) (Grenon, 1976). In this context it seems reasonable to suggest that efforts to find some of these gas reserves should be an energy policy objective during the 1980s.

Second, natural gas developments in the Latin American context have much in common with the development of primary electricity. This is true in respect of the substitutability of gas and electricity in many uses, and it is also true in respect of the generally remote locations of the production of the two energy sources relative to centers of demand. Transmission facilities for both are capital intensive but, dollar for dollar, expenditure on gas lines is at least three times as cost-effective as investment in long-distance electricity transmission by overhead cables. Hitherto, the development of the latter has, nevertheless, gone ahead more quickly than the former, partly as a consequence of a greater appreciation of the opportunities for hydro-electricity developments and partly because the hydro-electric sector was one for which international funds (particularly from the World Bank) were readily available. Lack of knowledge of the gas potential and lack of funds for its development in a situation in which it was overshadowed by oil have thus ensured a priority for hydro-electricity and, more recently, for nuclear electricity which, similarly, may be viewed as an alternative to the expansion of the natural gas sector of many Latin American countries' energy economies. To a large degree natural gas developments in the 1980s could offer an alternative option to the even more capital-intensive development of the primary electricity system.

Third, increasing concern for environmental pollution in the cities of Latin America presents another plus point for natural gas: its direct substitution of the use of oil products and its indirect substitution of the use of fuel oil for electricity generation would contribute significantly to the containment of atmospheric pollution problems in the continent's very rapidly growing urban areas, some of which, in the absence of such changes in energy use patterns, are certain to become increasingly unpleasant places in which to live and work.

Thus, a combination of resources, economic and environmental considerations indicates that Latin America's energy plans for the 1980s and the 1990s ought to involve a rapid expansion in the degree to which associated gas is used and the beginning, at very least, of a systematic search for large-scale

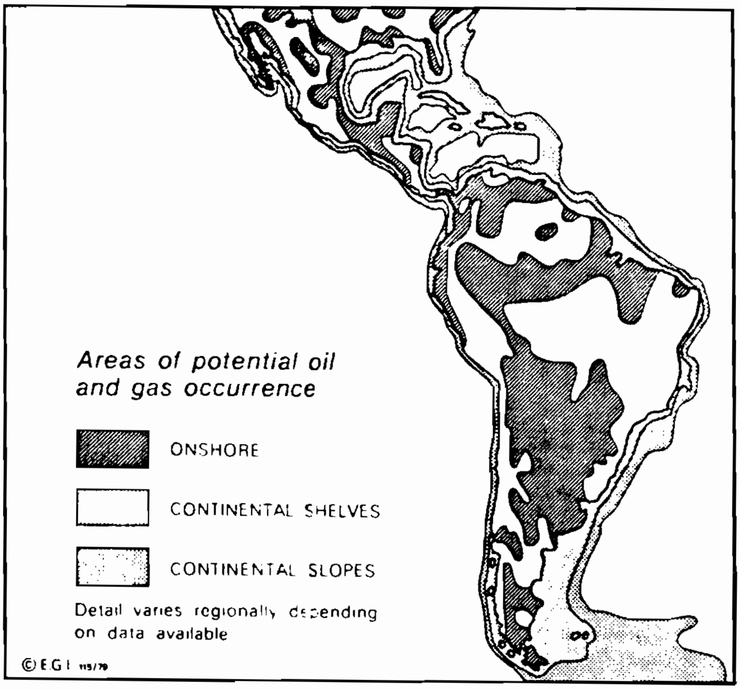


Figure 6. Latin America. The continent's potential oil- and gas-rich regions - onshore and offshore.

new supplies of non-associated gas from the large regions of potential. These are defined, geographically, in Figure 6, while Figure 7 presents Grossling's by now well-known diagram showing the imbalance between the extent of Latin America's potentially petroliferous areas and the degree to which there has to date been a search for its oil and gas resources. There is, indeed, not a single country in the whole of Latin America without areas of potential for hydrocarbons occurrence. This may be compared with the fact that only 11 countries of the continent currently have some degree of gas production - and in four of these it is small or very small (of less than two million tons oil equivalent per year).

A much intensified effort for the exploitation of the continent's resources would thus seem without doubt to represent the best objective for energy policy makers and the main sector of the energy economy into which investment should be directed. Herein, however, lie the constraints - both of finance and of appropriate institutional arrangements - which restrict the short-term development of a high level of exploration activity.

The high-risk expenditure of tens- or even hundreds-of-millions of dollars on the initial exploration of new provinces and basins implies the need to spread the risks over many countries and regions. Thus, to persuade companies to undertake exploration activities in one particular location necessarily means that they must be certain that they will be allowed to proceed into the oil development and production phase at that location, should the exploration efforts prove to be successful, and to take high profits from it. It is the unlikelihood of most Latin American governments accepting the need for a high profit regime from gas exploitation by private enterprise that makes most companies reluctant to undertake really intensive

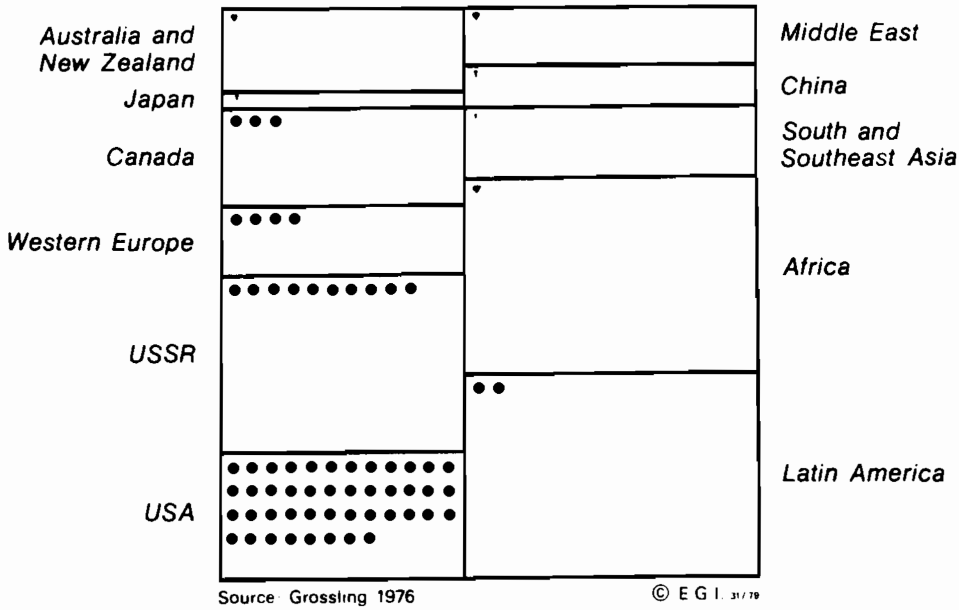


Figure 7. The regional distribution of the World's potentially petroliferous areas - shown in proportion to the world total and also showing the number of exploration and development wells drilled in each region; each complete dot represents 50,000 wells.

exploration work, even in those parts of Latin America where there have been no political restrictions on their involvement. In the many countries of Latin America where there have been such political inhibitions, the limited financial and other resources available to the state oil entities have inhibited the level of their exploration efforts so that resources have remained undiscovered.

Recently, a number of somewhat convoluted arrangements have been worked out to enable the international companies to participate in exploration, even in countries where such petroleum-sector activities have for long been the monopoly of the state. The consequential enhanced level of activities is a move in the right direction, but the total effort remains low and the speed of exploration is slower than it need be. It is, moreover, still the responsibility of a very small number of companies often awarded exclusive rights over large areas when, as experience from many parts of the world has shown, what is really required is an input of exploration activities based on as many different views on the prospects for oil and gas in a given location as it is possible to achieve. The learning process is much enhanced in that way and many contrasting interpretations of the seismic data (and this is still something of an art as well as a science) can be tested. Progress in this direction in Latin America threatens to be slow - as it goes against the grain of developments over the past 40 years during which oil exploration and production activities have become increasingly centralized, not only in terms of monitoring and control, but also in terms of actual operations. There is, thus, clearly a political problem of large dimensions to be overcome before the proliferation of exploration enterprise will become acceptable to governments and, thereafter, a level of confidence will still need to be built up before much of Latin America could become a preferred, high priority area for exploration activities on the part of a large number of oil companies. Yet if the next two decades are to bring the development of indigenous production to levels which eliminate energy constraints on economic progress in as many Latin American countries as possible, the proliferation of exploration ventures is required in the short term.

Let me reiterate that this is not purely, or even primarily, a question of money. Rather it is one of attitudes, of policies, and a revised appreciation of the risks involved on the part both of governments and of companies. As this is an effective barrier to the rapid development of the potentially very large gas resources of Latin America, the involvement of third parties to depoliticize the whole issue might well be appropriate. At relatively small cost to such third parties - such as the World Bank, the OPEC investment fund, funds channeled through SELA or another Latin American organization - the necessary expertise could perhaps be made available under, first, 'no-obligation' conditions as far as the countries of the continent are concerned and where the initial steps towards hydrocarbons' exploration might otherwise be impossible or else long delayed; and, second, under guaranteed adequate reimbursement conditions for the exploration enterprises themselves.

I have dwelt at some length on this point because it seems to be the key to ensuring the most cost-effective way of providing Latin America with the energy that it will require over the rest of this century. If gas and oil exploration can be stimulated to many times its present level, then the continent seems likely to achieve sufficient indigenous reserves of the type of energy to which it is used and this will thus constitute a cost minimization objective on both the supply and demand sides of the equation. If not, then many countries of Latin America will be obliged to follow much higher-cost energy options, the impact of which will be to divert financial and managerial resources away from other desirable ends - both in directly productive and in the welfare sectors of Latin America's economies and societies.

4. CONCLUSION

In the two contrasting world regions whose natural gas prospects have been considered in this paper, one can conclude very firmly that the degree of development to date and the outlook for their future bear very little direct relationship to the regions' natural gas resources or to the energy needs of the countries concerned. In the context of both economic and strategic considerations, the advantages which would accrue from the utilization of the maximum possible quantities of indigenous gas appear self-evident, especially in situations in which new gas-producing potential could be developed at a lower investment cost than most alternative sources of energy. Yet in both regions more attention is being given, and more resources devoted to, the development of inherently higher cost alternatives, such as nuclear power and hydro-electricity, whilst, in the case especially of Western Europe, there appears to be more interest in securing energy imports which are less risky than OPEC oil - including the import of natural gas both through pipelines from North Africa and from the Soviet Union and as liquefied natural gas from more distant supply sources - than there is in the expansion of the indigenous natural gas industry. Such apparently irrational, even perverse, behavior arises out of the institutional and other constraints which appear to epitomize the present-day energy policy attitudes towards natural gas development. A number of these have been described and analyzed in this paper. In concluding I wish to summarize and to emphasize two of the central issues which appear to be involved.

The first is a difficulty, on the part of energy policy makers and of other opinion formers, associated with their perception of natural gas resources. The absence, in most of the countries of the two regions, of a significant history of oil and gas developments has produced a short-fall in knowledge and understanding of the processes involved in the very long-term evolution of major hydrocarbon provinces. Consequently, the validity of the concept of undiscovered but discoverable gas reserves is not acceptable for planning the expansion of the natural gas industry. Instead, the maximum volume of offtake, for periods as long as 30 years, has been related to the volume of proven reserves. This essentially undermines the dynamic nature of the industry by eliminating the inherent expansionist capabilities of major gas provinces in their initial stages of exploitation. In other words, the inappropriate planning of future gas demand schedules has inhibited production and exploration - and so has thus taken the dynamics out of the sector.

Second, there are constraints which arise from the reactions between international considerations and certain specific characteristics of natural gas' occurrence and transportation. The almost inevitable mis-match between the geography of gas production potential and that of gas demand potential, coupled with the requirement for high-cost fixed transportation links to connect the potentials, represents the essence of the problem and is specific to natural gas in the range of possible energy developments. To date, most natural gas utilization has taken place within the boundaries of two of the world's largest countries - the United States and the Soviet Union - within which these specific characteristics of natural gas' development needs could be treated as a national challenge and opportunity. Elsewhere, they pose problems of conflicting national preferences even in respect of bi-lateral opportunities and, very often, third, fourth, and even fifth countries are involved to complicate the situation still further. There are examples in both Western Europe and Latin America of natural gas potential which remains frustrated by such international considerations, and these bode ill for the prospects for the rational development of natural gas - in spite of its considerable advantages of generally low-cost production compared with other energy sources and the general preference for it over other sorts of energy by many types of energy users.

REFERENCES

Grenon, M. (1976). Energy Resources. IIASA Energy Resources Conf., 1975. International Institute for Applied Systems Analysis, Laxenburg, Austria.

Odell, P.R. (1969). Natural Gas in Western Europe: A Case Study in the Economic Geography of Energy Resources. De Erven F. Bohn, Haarlem.

Odell, P.R. (1974). Norway's Oil and Europe's Energy Needs; Basis for a Mutually Advantageous Development Policy. Financial Times Conf., Scandinavia and the North Sea, 29 April, Oslo.

Odell, P.R. (1976). Europe and the cost of energy: nuclear power or oil and gas. Energy Policy, 4 (2).

OECD (1977). Outlook for Energy 1985. Paris.

GEOPRESSURED FORMATION PARAMETERS OF THE ARMSTRONG AND CORPUS-CHRISTI FAIRWAYS, FRIO FORMATION (OLIGOCENE), CENTRAL AND SOUTH TEXAS

Myron H. Dorfman

Center for Energy Studies, The University of Texas at Austin, Austin, Texas, USA

INTRODUCTION

The growing need to produce more energy, combined with higher prices as an incentive, has led to research into new alternative forms of energy. One of these forms is geopressured geothermal energy, which involves use of water from deep aquifers in sedimentary basins of great thickness (over 25,000'), contained under high pressure and temperature. In addition, the waters within these aquifers are believed to contain methane at saturated conditions, thus three forms of energy are present; the kinetic and thermal energy of the waters and the methane which may be extracted from these waters.

During the past seven years, the Center for Energy Studies and the Bureau of Economic Geology of The University of Texas at Austin have intensively investigated the parameters associated with geopressured-geothermal energy in the Northern Gulf of Mexico Basin of the United States, concentrating on the tertiary sandstones of the Texas Gulf Coast. This basin is one of several geopressured basins within the United States, and contains the greatest quantity of information due to the many thousands of wells drilled for hydrocarbons within it; other geopressured basins of similar type are found throughout the world. It has been estimated that over sixty such basins are known, and others may be present. Thus, this work may have applicability not only in the Gulf Coast of the United States, but also in similar geologic environments worldwide.

Initially, the investigations were concentrated on the geothermal energy that might be extracted from the waters for electric power generation and various process heat applications. However, recent increases in the price of natural gas has led to increased emphasis on the methane dissolved in the waters. Estimates of recoverable methane range from 150 Tcf to 2,500 Tcf in aquifers within this basin, without regard to economics of production.

In order to ascertain with some accuracy the amount of methane dissolved in aquifers, it is necessary to quantify the temperature, pressure and salinity of the waters, since natural gas content is directly proporational to the first two, and inversely proportional to the latter. This study will concentrate on pressure determinations in two fairway areas in Texas where pressure gradients may be determined with considerable accuracy.

Geology

The geology of Kenedy County and the Armstrong Fairway is dominated by the great Tertiary deposits of the Texas Gulf Coast. Vast quantities of sand and mud were carried across a wide fluvial plain during this period and deposited along the shores of the Gulf of Mexico. These sediments prograded toward the gulf as a series of wedge shaped deposits which dip and thicken gulfward, with the younger wedges being displaced basinward from the proceeding wedge (Figure 2). At the thin landward end the wedges are mostly shale with scattered, discontinuous sand bodies. The sands are thickest in the central portion accompanied by thin shales. In the downdip portion the shales are thick with thin, relatively continuous sands (Bebout, Dorfman, and Agagu, 1975). The thickening of sand-shale bodies was aided by the numerous down to the coast growth faults in the region. A study by Bruce (1973) concluded that these contemporaneous fault systems were mainly the result of differential compaction of adjacent sedimentary masses during time of shoreline regression forming structural features characterized by thickening of sediment on the downthrown side where rollover is common. These are predominately normal faults which appear to die out with depth. Some gravitational faults were also formed in this region where subsidence exceeded the rate of deposition. The geological formation of prime interest is the Frio formation of Oligocene series in both the Armstrong and Corpus Christi fairways. The Frio outcrops approximately

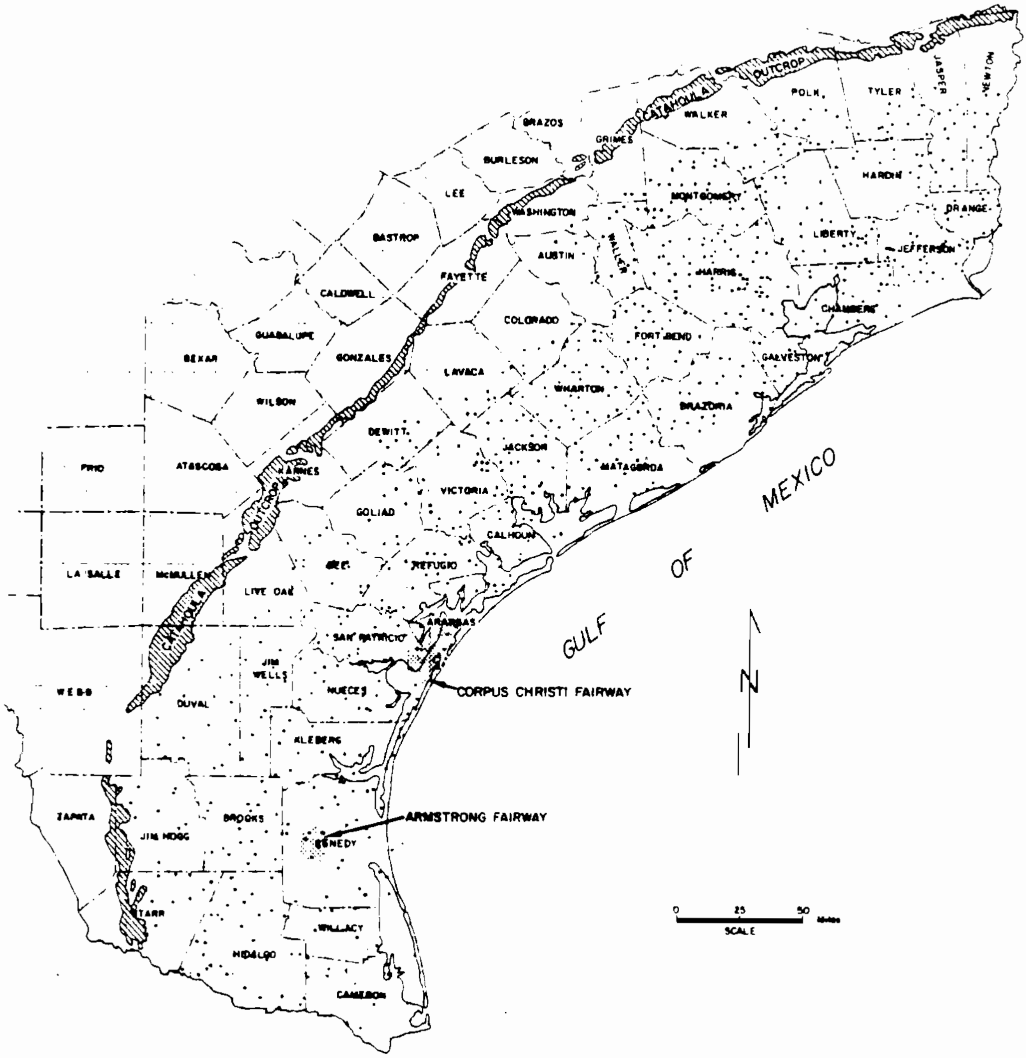


FIGURE 1 Study areas.

100 miles inland along a band parallel to the coast. Thickness ranges from 200' near the outrcop to 9,000' in the subsurface near the present coastline. The Frio was deposited in four major depositional environments: fluvial, deltaic, strandplain and shelf.

In the Corpus Christi area, both the strandplain and fluvial deposits have fluid temperatures which are too low for geothermal prospects although the strandplain sands are thick and extensive. Most sands in the shelf are thin

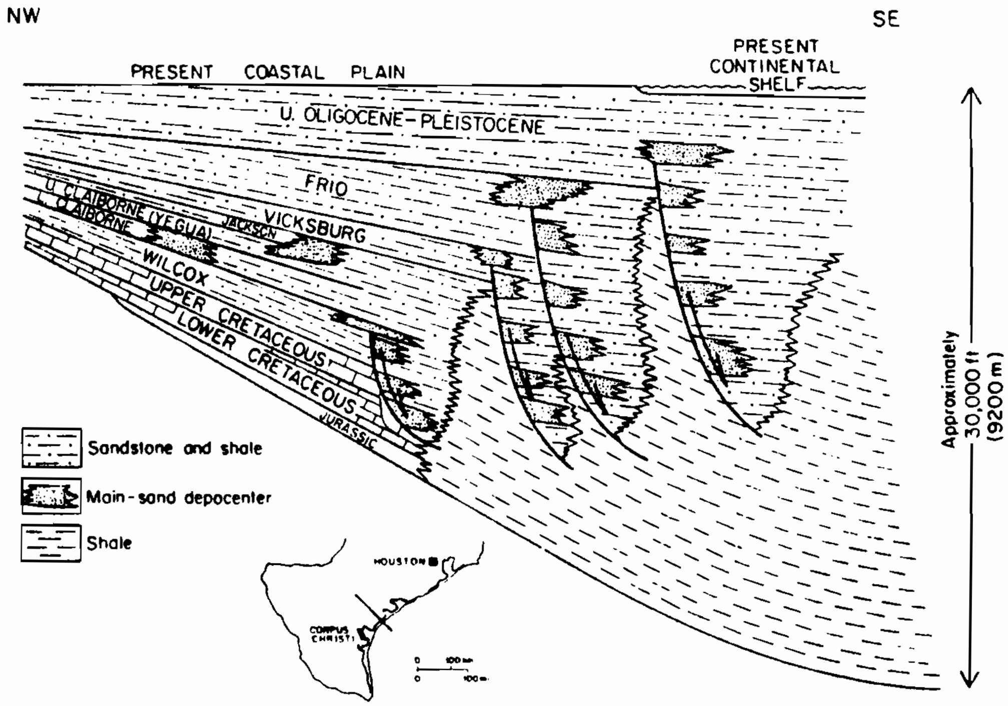


FIGURE 2 Depositional/structural style of the Tertiary along the Texas Gulf coast (Bebout et al., 1978).

and lateral extent is unknown, although some sand bodies are thick enough and do contain high temperature fluids. Prospective sand bodies were isolated in the Middle Texas Gulf Coast Frio Study (Bebout, Agagu and Dorfman 1975) where the best known development of sandstone was found in the Corpus Christi Bay in the basal portion of the Frio formation. A net sandstone map of the two lower genetic units of the Frio indicate a strandplain environment where as much as 800 to 1000 ft. of sand occur.

In the Armstrong Fairway area, a net sandstone map of the area reveals the shape of a lobate delta composed of up to forty percent sandstone with two areas where more than 700' of sandstone occur. The area is defined by a growth fault of approximately 1,100' of displacement. On the downthrown or coastal side of this fault the sand-shale section is about 1,500' thick, and in the Caldelaria Field area individual sandstone units range up to 200' in thickness (Figure 1).

Formation Pressure

As sand and mud are deposited along prograding delta fronts, interstitial formation waters are trapped during burial and subsidence. If the formations are open to the atmosphere, a column of water from the ground surface to the subsurface formation depth would balance the formation pressure. These formations are said to be normally pressured and experience has shown the normal pressure gradient on the Texas Gulf Coast is approximately 0.465 psi per foot of depth (Hottmann and Johnson, 1965). If formation waters are sealed off during burial and contained water cannot be squeezed out because of restricted fluid movement, compaction of sediment grains will not occur and formation water will begin to carry part of the overburden load. When this occurs, formation fluid pressures significantly greater than normal hydrostatic pressure develop and the formation is said to be undercompacted and geopressured (Dorfman and Kehle, 1974) (Figure 2).

The occurrence of geopressure can be identified by various methods. These include when a sudden increase in drilling mud weight to over 13 pounds per gallon (ppg) becomes necessary, the reduction of shale resistivity, an increase in the temperature gradient and the reduction of negative self-potential deflection. A method for estimating formation pressures from shale resistivity readings of electric logs has been developed by Hottmann and Johnson (1965) and was used extensively in this study to identify the occurrence of geopressure.

Estimation of Formation Pressure

Formation pressure gradients (FPG) for a particular region can be determined from electric log data by measurement of shale resistivities from the 16 inch short normal curve. This method, developed by Hottmann and Johnson (1965), consists of establishing a normal compaction trend for the area of interest by making a semilog plot of shale resistivity versus depth for numerous wells in the area of interest as well as the well in question. Observed shale resistivities in geopressured zones diverge from the normal trend toward lower values (Figure 3). The ratio of the extrapolated normal shale resistivity to the observed shale

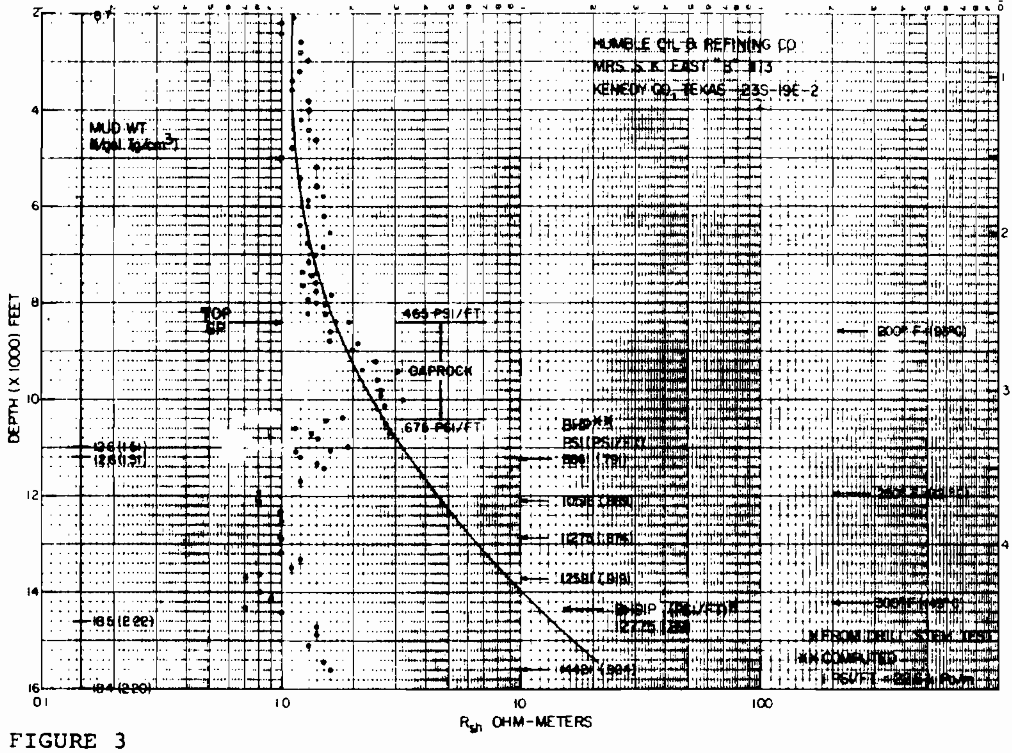


FIGURE 3

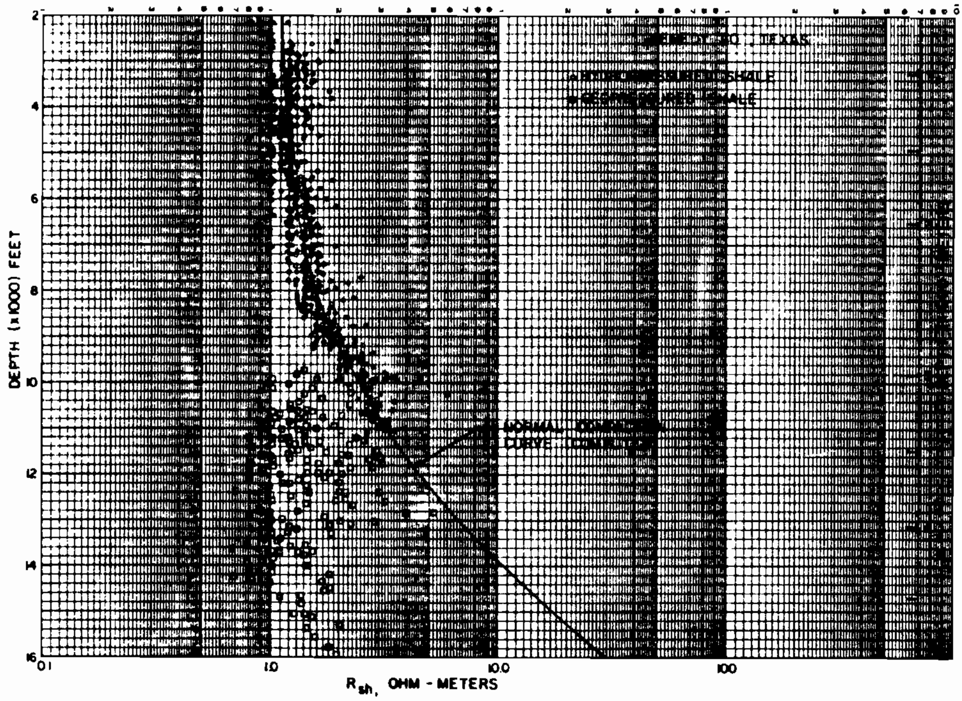


FIGURE 4

resistivity is next determined and then related to the fluid pressure gradient empirically by using shut-in bottom hole pressure data from drill stem tests.

Shale resistivity values read from the amplified short normal curve were accumulated from over forty wells in Kenedy County at depths ranging from 2,000' to total depth. The amplified short normal curve was used because of its resolution, negligible borehole corrections in the range of resistivities considered and because this device was run on almost all of the wells and has remained essentially unchanged for the last twenty-five years. Only data from clean shale zones at least thirty feet thick were chosen in areas of low SP deflection where the resistivity was uniform. Silty, limey or washed out shales were avoided as well as shales near highly resistive fresh water formations at shallow depths. A composite plot of the logarithm of shale resistivity versus depth was made after eliminating the data from geopressured zones. The normal compaction trend was established by fitting the best curve through these points and then extrapolating this curve to the necessary depth (Figure 4).

Shut-in bottom hole pressure data from drill stem tests in thirteen producing wells in Kenedy County was used to empirically relate shale resistivity at any depth to the fluid pressure gradient. Fluid pressure gradients were calculated from BHP and the depths of the zones tested and plotted against the logarithm of the ratio of the extrapolated normal shale resistivity to the observed shale resistivity of the clean shale nearest to the tested zone. A curve was next fitted through these 14 points (Figure 5).

Fluid pressure gradients for any depth between 2,000' and 16,000' can be calculated for an individual well by drawing the normal compaction line on the individual shale resistivity plot (Figure 6), determining the ratio of normal to observed resistivity and finding the corresponding FPG .

A similar procedure was used to determine compaction trends, deviation of Rsh in the geopressured regime, and plots of pressure gradient vs. ratio of normal to observed resistivity of shale for the Corpus Christi Fairway (Figs.7,8,9).

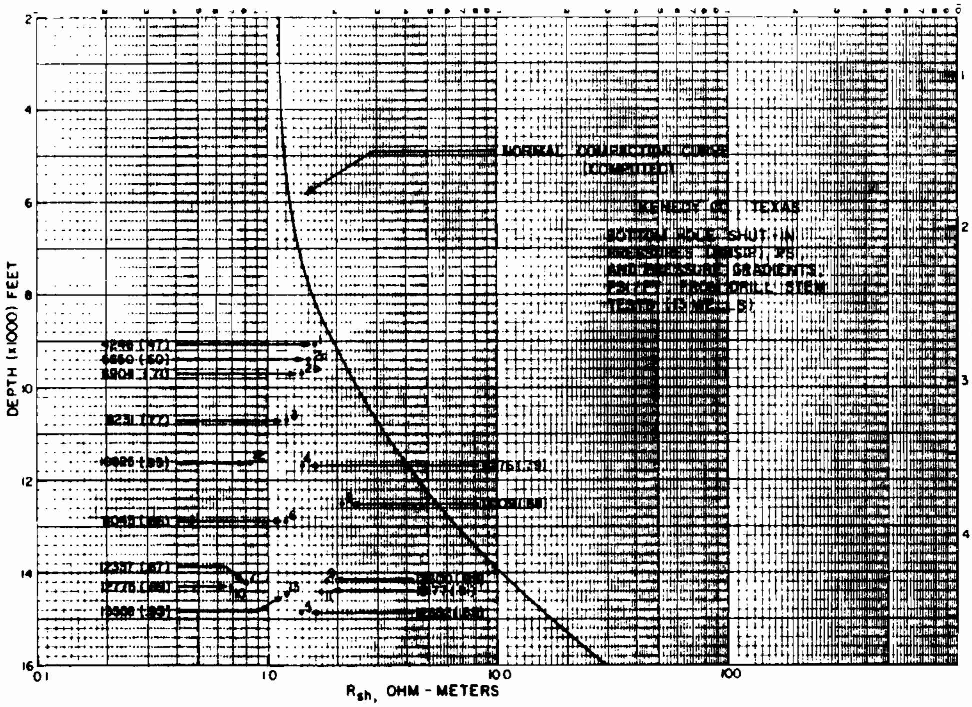


FIGURE 5

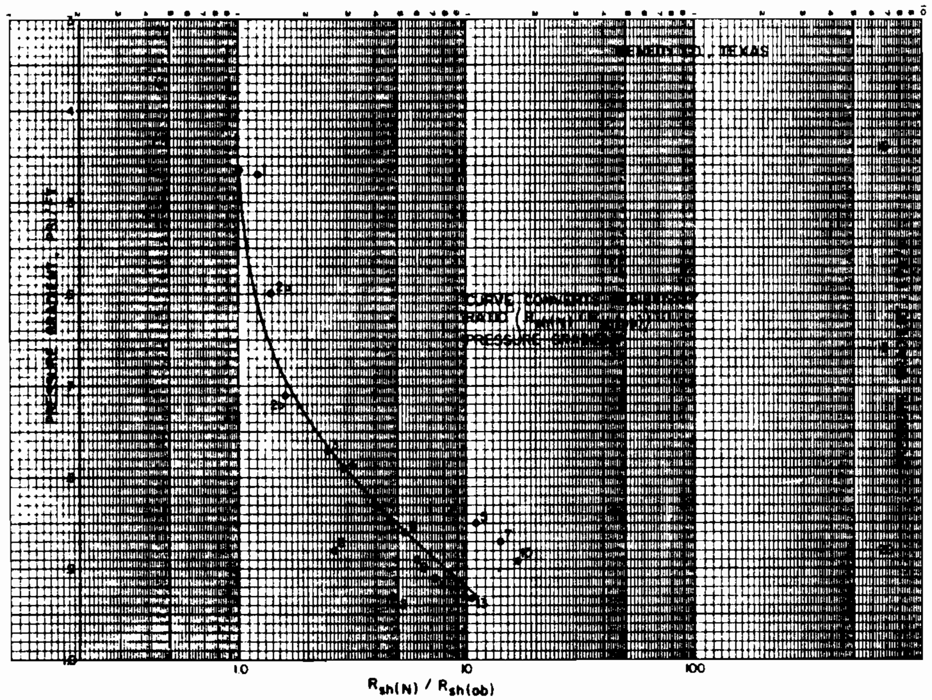


FIGURE 6

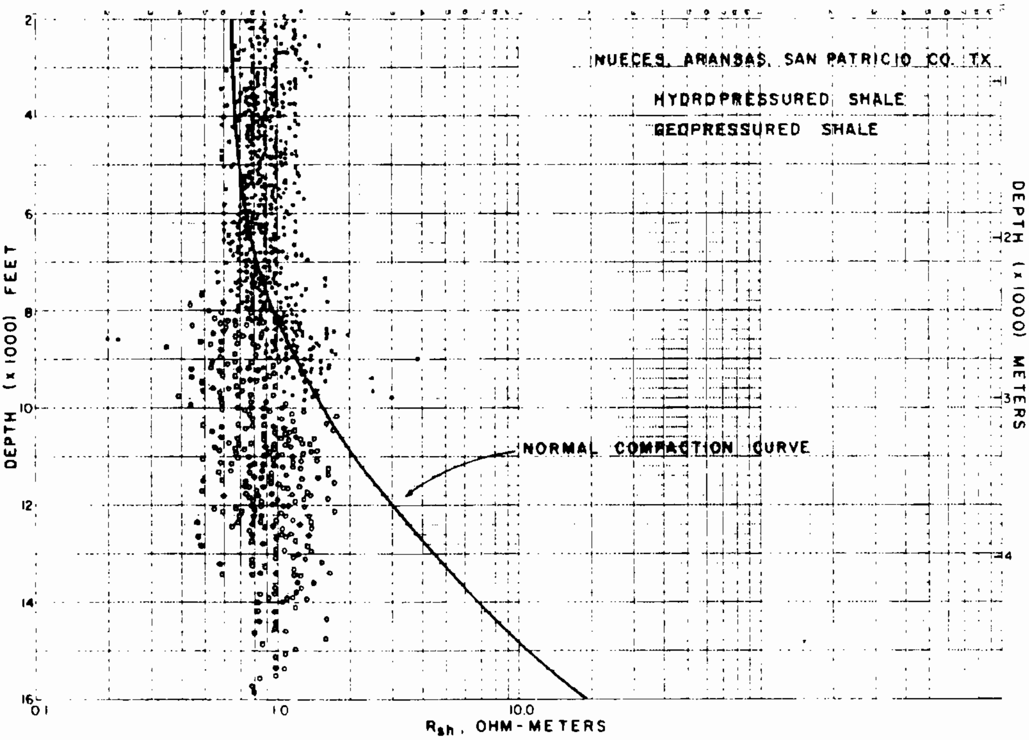


FIGURE 7

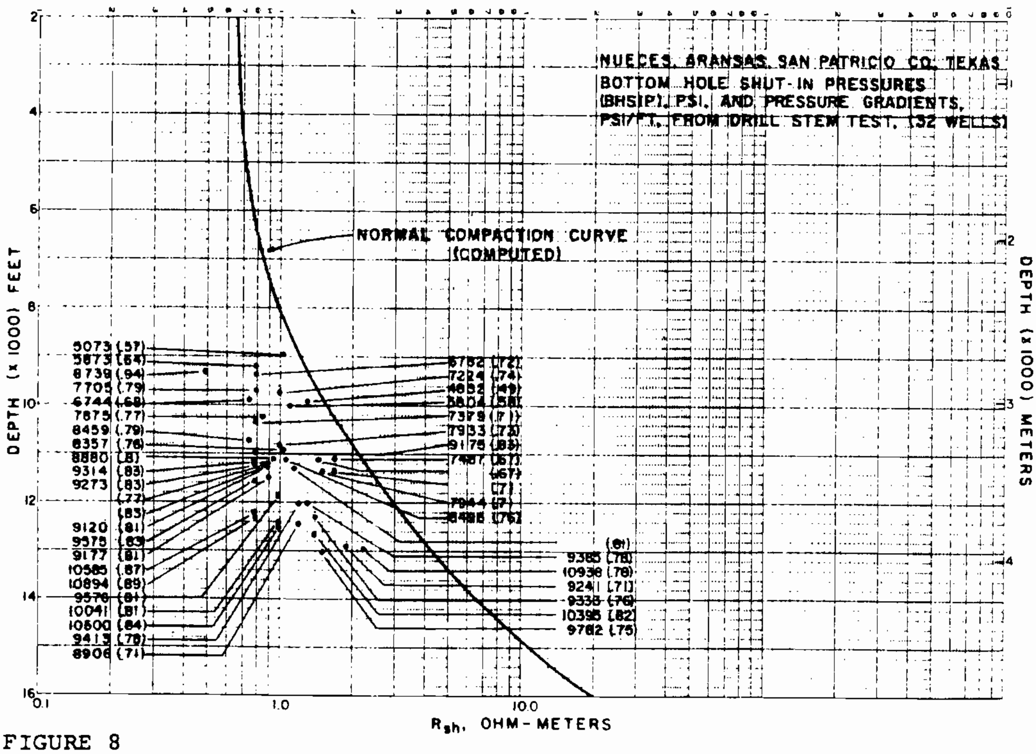


FIGURE 8

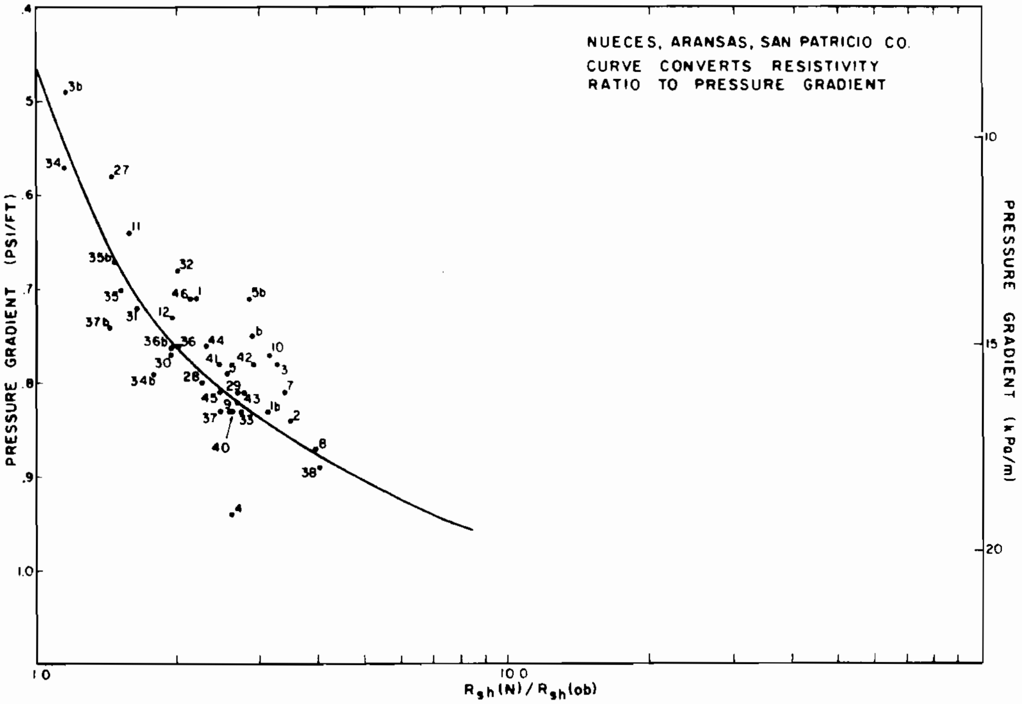


FIGURE 9

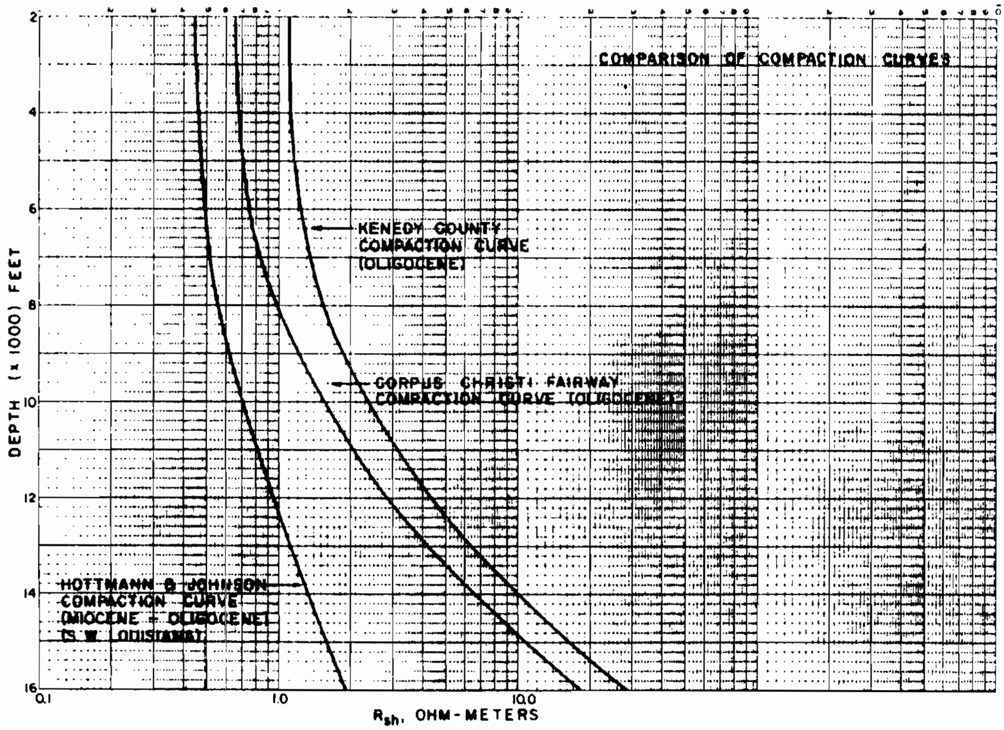


FIGURE 10

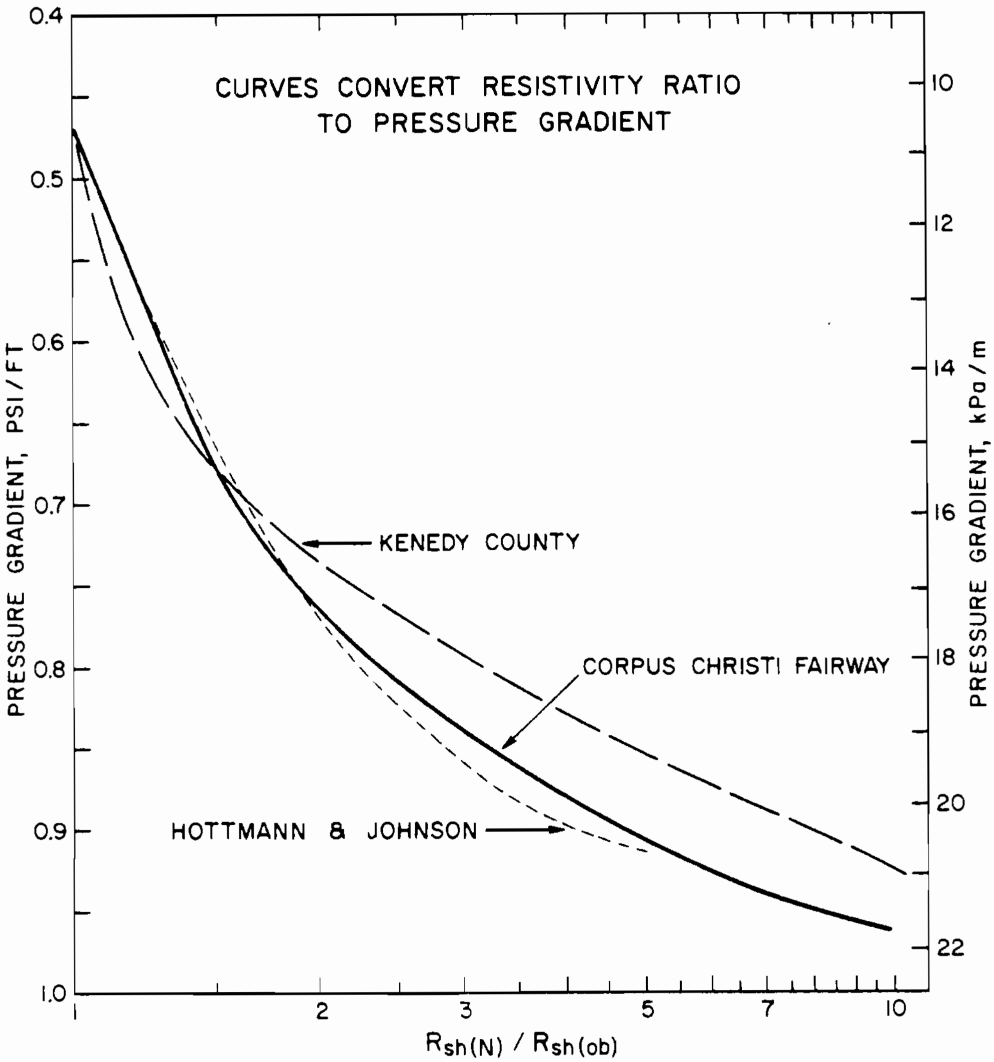


FIGURE 11

Discussion

It will be noted that compaction trends within both the Armstrong and Corpus Christi Fairways show considerable divergence from that previously published by Hottmann and Johnson (1965). The older work was done primarily from well logs in Louisiana in both the Miocene and Oligocene Series, whereas these areas in Texas are concerned with only Frio (Oligocene) age sediments(Fig.10). A combined plot of pressure gradients vs. Rsh ratio shown in Fig.11 also shows differences in each of the areas studies, as well as divergence from the Hottmann and Johnson study. This work does not attempt to define the reasons for such divergence, but it may be noted that environment of deposition is somewhat different in each area which may account for some of the differences. One may suspect, as a result of this work, that discrete areas of study will result in gross differences in rock characteristics, which will affect log interpretations; one cannot rely on generalized interpretations of areas as large as the Gulf Coast for specific interpretation of a given area.

Another point that appears to be important is the fact that divergence of Rsh does not occur at the top of geopressure; i.e., .465 psi/ft. as shown in Fig. 3 . Throughout both the Armstrong fairway and the Corpus Christi fairway, it was found that the first deflection of Rsh occurred at a pressure gradient of approximately .7 psi/ft. Based on the early work, researchers have assumed that the top of geopressure corresponded with the first occurrence of increase in pressure gradient, but this does not appear to be the case in central and south Texas. It is assumed that the first deflection of Rsh occurs at this higher pressure gradient in these areas as a result of a thick wedge of marine shale overlying the Frio, which forms the cap for geopressure. Again, generalizations of first deflection of Rsh from the computed curve cannot be assumed to correspond to generalized pressure gradients throughout the entire Gulf Coast basin. This information could be extremely important to those drilling wells into the geopressured regime, since location of specific pressure gradients by well logs will affect mud density while drilling, and also affect the point where intermediate casing must be set in order to isolate hydropressured sediments from the geopressured regime.

Conclusions

It has been found that compaction of sediments in the central and south Texas areas, known as the Corpus Christi and Armstrong geothermal geopressured fairways, shows divergence from each other and from previously published data.

This affects relationships of pressure gradient vs. Rsh ratios in each of these areas. It has also been shown that first divergence of resistivity of shale does not occur at the top of geopressure in central and south Texas but at an average pressure gradient of .7 psi/ft.

REFERENCES

1. Bebout, D.G., M.H. Dorfman and O.K. Agagu. 1975. Geothermal Resources Frio Formation, South Texas; Bureau of Economic Geology, University of Texas, Circ. 75-1.

2. Bebout, D. G. O.K. Agagu, M. H. Dorfman. 1974. Geothermal Resources Frio Formation, Middle Texas Gulf Coast; Bureau of Economic Geology, University of Texas, Circ. 75-8.

3. Bebout, D. G., R. G. Loucks, A. R. Gregory. 1978. Frio Sandstone Reservoirs; Bureau of Economic Geology, University of Texas, RI-91.

4. Bruce, C. H. 1973. Pressured Shale and Related Sediment Deformation: Mechanism for Development of Regional Contemporaneous Faults; AAPG Bulletin, v.8, p.7-32.

5. Dorfman, M. H. and R. O. Kehle. 1974. Potential Geothermal Resources of Texas; Bureau of Economic Geology, University of Texas, Circ.74-4.

6. Hottmann, C.E. and R.K. Johnson. 1965. Estimation of Formation Pressures from Log-Derived Shale Properties; Journal of Petroleum Technology, v.21, #7, p.803-810.

UNDERGROUND DISPOSAL OF WATER PRODUCED FROM GEOPRESSURED ZONES

B.H. Caudle
The University of Texas at Austin, Austin, Texas, USA

The use of geopressured aquifers as a source of energy will require the continous production of large quantities of water. This water, which will usually have a mineral content above that of surface waters, must often be injected into the saline aquifers that lie below the fresh water table. As an example, the well which has been drilled into the geopressured aquifer in Brazoria County, Texas[1] for the purpose of evaluating the resource, is expected to require the re-injection of 40,000 barrels per day of saline water into a normally pressured aquifer at the 7,000 foot level.

The pressure at the sand face of an injection well will be well above the initial (and the average) aquifer pressure. At a constant rate of injection, the sand face (well bore) pressure will continue to increase with time even if the aquifer is unbounded. The maximum pressure which can be tolerated in the well bore is limited - usually by the breakdown pressure of the formation. Thus the life of any injection well in continous use will be limited. A sand face pressure equivalent to 0.5 psi per foot of depth (1130 newtons per square meter per meter) is generally considered to be a safe level.

The expected well bore pressure during injection may be estimated using the superposed line source solution for slight by compressible fluids.[2] For this paper the equation may be written as:

$$P_w = P_i - \frac{q\mu B}{4\pi kh} \, Ei \, \frac{-\phi\mu c r_w^2}{4kt} \tag{1}$$

for a single well in an infinite - acting aquifer and as:

$$P_w = P_i - \frac{q\mu B}{4\pi kh} \left[Ei \, \frac{-\phi\mu c r_w^2}{4kt} + \sum_{j=0}^{\infty} Ei \, \frac{-\phi\mu c r_j^2}{4kt} \right] \tag{2}$$

for a single well in a bounded aquifer. Figure 1 illustrates the way in which a square aquifer is simulated for use with equation (2). Since the exponential integral function decreases as the argument increases, the summation terms for image well that lie far away from the real well may be neglected. Figure 3 shows a solution for equation (2) for a bounded aquifer 7.5 x 10^9 ft^2 in areal extent. The properties indicated on the figure correspond to those expected for the brine disposal well of the Pleasant Bayou geopressure-geothermal test site. The curve shows that the sand face pressure will quickly rise to 3300 psi but nearly 15 years of continuous injection can be supported before this pressure reaches 3355 psi (equivalent to 0.5 psi per foot of depth).

From the basic equation we can see that the sand face pressure curve is a function of the well bore size as well the reservoir and fluid properties. This could easily lead to a trial and error set of solutions to design a properly sized injection well to be used for water disposal. We can, however, obtain a better equation for design purposes by combining the parameters of equations (1) and (2)

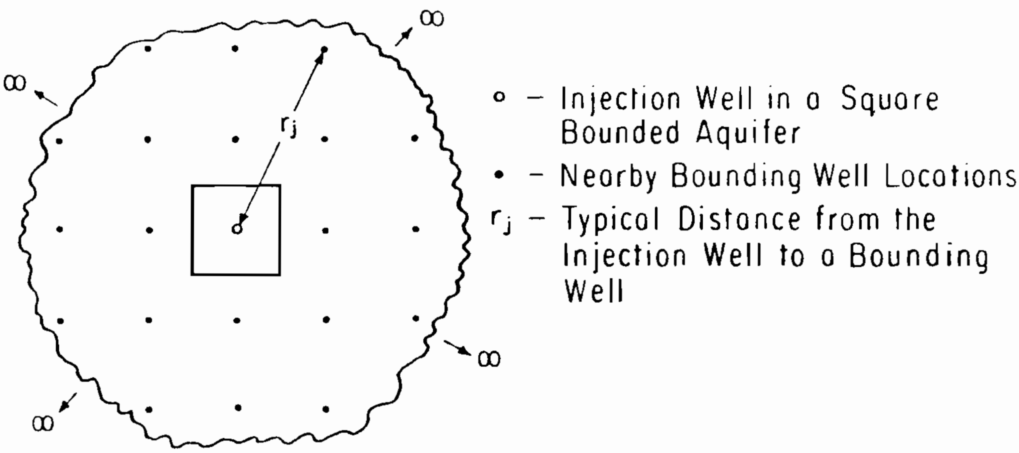


Figure 1. Creating a bonded aquifer by the use of image well terms.

into dimensionless groupings. We will define a dimensionless sand face pressure as:

$$P_{wD} = \frac{4\pi(P_w - P_i)kh}{q\mu B}$$

and a dimensionless time as:

$$t_{wD} = \frac{4kt}{\phi\mu c r_w^{\,2}}$$

Equation (2) then becomes:

$$P_{wD} = -\,Ei\left(-\frac{1}{t_{wD}}\right) - \sum_{j=o}^{\infty} Ei\left(-\left(\frac{1}{t_{wD}}\right)\left(\frac{r_j}{r_w}\right)^2\right) \tag{2a}$$

In this last equation the ratios r_s/r_w are direct functions of the aquifer area if the injection well is reasonably well centered in the aquifer. We will define a dimensionless aquifer area term as:

$$A_o = \frac{\sqrt{A}}{r_w}$$

From equation (2a) a single curve will be obtained for a fixed dimensionless aquifer area.

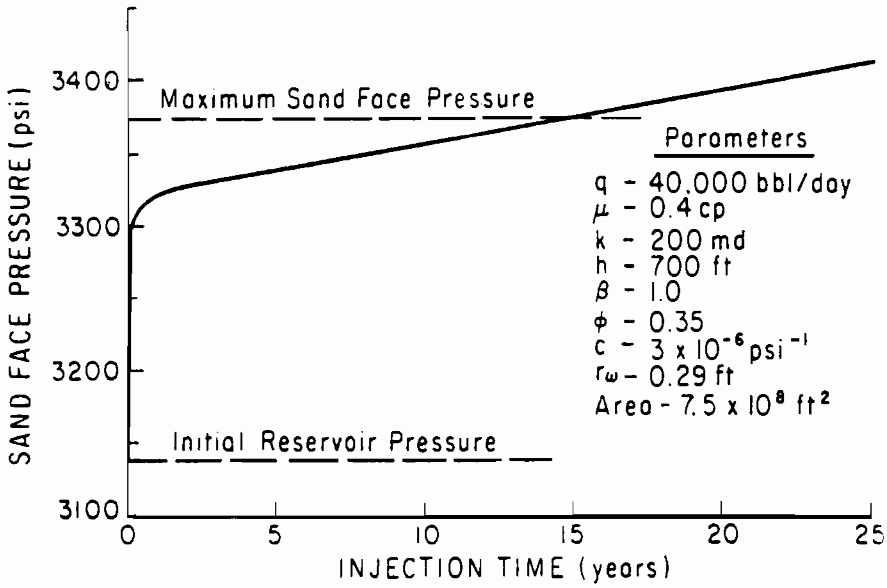


Figure 2. Injection well pressure - Pleasant Bayou.

An injection well design chart has been developed as shown in Figure 3. In this chart the dimensionless well pressure (p_{wd}) is plotted as the logarithm of the dimensionless time (t_{wd}) for a number of dimensionless area ratios. The other two lines show the effect of splitting the total injection between two or three wells only a short distance apart (100 feet) in an unbounded system. Bounded aquifer curves could be plotted for these multiple well cases but they have been omitted for clarity.

The way in which the chart may be used will be illustrated using the basic data for the Pleasant Bayou injection well as shown in Figure 2. In the field units shown the dimensionless pressure is:

$$P_{wD} = \frac{(P_w - P_i)kh}{70.6 q \mu B} = 29.4$$

while the dimensionless aquifer area is:

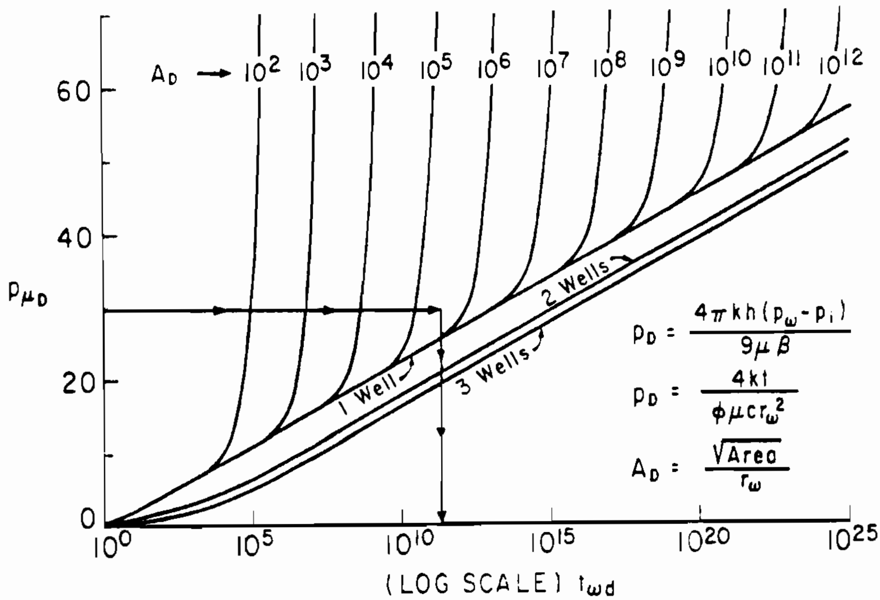


Figure 3. Dimensionless injection pressure chart.

$$A_o = \frac{\sqrt{75}}{.29} \times 10^4 = 3 \times 10^5$$

This leads to a dimensionless time valve of 2 x 10". In the field units of Figure 1:

$$t_D = \frac{.000264kt}{\phi \mu c r_w^{\ 2}}$$

Therefore:

$t = 6.7 \times 10^{-7}\ t_D$ (hours) $= 1.34 \times 10^5$ hours for the well bore radius of 0.29 feet. This is equivalent to 15.3 years and is quite close to the time prediction shown in Figure 1. It should be noted that the time is very dependent upon the well bore radius. For instance, doubling the well bore radius would increase by a factor of 4 the time to reach the designated maximum sand face pressure. Because of this dependency the dimensionless time term may be used to determine the well bore size that would be necessary to continue injection for a specified period of time.

It should also be noted that the chart (and the equation) are valid for an open well bore that completely penetrates the aquifer. Since most wells have casing through the formation, the perforations should be evenly and closely spaced (about 1 per foot) to get the effect of an open hole. The effects of deviations from an open hole pressure may be treated as a "skin effect" as outlined in works on transient pressure analysis such as reference 2.

A further use for the chart shown in Figure 3 might be in the determination of aquifer size after some period of production. Measured pressures - when converted to the dimensionless unit, p_{wd}, should plot along a straight line until the effect of the boundary causes an upward swing. At this point, the dimensionless area term may be estimated.

The use of a dimensionless chart like that in Figure 3 should be helpful in determining the bore size and placement of wells that are to be used for the disposal of waste water by injection into normally pressured aquifers.

References

1. D. G. Bebout, R. G. Loucks, and A.R. Gregory,(1978), Frio Sandsone Reservoirs, Report of Investigations No. 91.

2. C. S. Matthews and D.G. Russell,(1967), Pressure Buildup and Flow Tests in Wells, Volume 1.

NOMENCLATURE

A_D - dimensionless area - $\frac{\sqrt{\text{aquifer area}}}{\text{well bore radius}}$ - dimensionless

B - formation volume factor - $\frac{\text{aquifer volume}}{\text{surface volume}}$ - dimensionless

C - liquid compressibility - 1/pressure

h - aquifer height

k - permeability

q - injection rate - surface volume/time

p_i - initial aquifer pressure

p_w - well or sand face pressure

p_{wD} - dimensionless injection pressure

r_w - well bore radius

r_j - distance from injection well to the j th image well

t - time

t_o - dimensionless time

ϕ - porosity

μ - viscosity

$$Ei(-x) = \int_{-\infty}^{x} \frac{e^{-y}}{y} dy$$

RESERVOIR MECHANICS OF GEOPRESSURED-GEOTHERMAL AQUIFERS: PLEASANT BAYOU WELL

H. Ohkuma,[1] K. Sepehrnoori,[1] J.T. Lewis,[1] R.M. Knapp,[2] and R.C. MacDonald[1]
[1] *The University of Texas at Austin, Austin, Texas, USA;*
[2] *University of Oklahoma, Norman, Oklahoma, USA*

Introduction

Prior to the production testing of the Pleasant Bayou #2 geopressured geothermal well, an analysis has been made of the possible effects of reservoir production parameters on well productivity and resource recovery. The purpose of this preliminary study is to determine those factors that will have the greatest effect on the observed production behavior and therefore have the most importance in the reservoir characterization process.

This paper describes the potential sensitivity of well production behavior and resource recovery to formation heterogeneities, the selected completion interval for the well, and the potential effect of an immobile gas phase buildup around the wellbore.

Well Model

To conduct these sensitivity studies, a gas-water finite difference reservoir simulation model was employed. The model accounts for two-phase flow of gas and water in which gas is allowed to dissolve in water according to prescribed constitutive relationships. In addition the model accounts for shale dewatering. The model assumes uniaxial compaction. The assumption of uniaxial compaction is only a first order approximation. Work is currently underway to implement methods which will account for a more realistic triaxial compaction within the reservoir system as well as a treatment of transient or creep behavior of the formations adjacent to the reservoir [1].

For this study a cylindrical coordinate system was used so as to concentrate the reservoir definition about the wellbore. A schematic representation of the model geometry is shown in Figure 1. For purposes of this study it was assumed that the reservoir was symmetric about the well and that the shale/sand sequence could be described in 50 foot intervals. In general, the sand/shale sequence alternated over the 50 foot zones; however, a single 100 foot sand zone was used in the middle of the formation to more closely represent the actual case. During the course of this study the communication between the sand zones through the shales was varied to simulate differing heterogeneous configurations within the reservoir.

Figure 1 shows the well perforated in the upper sand layer as an approximation to the actual completion of the Brazoria County well. However, during our study, completion over all sand intervals was assumed in some cases for comparison purposes.

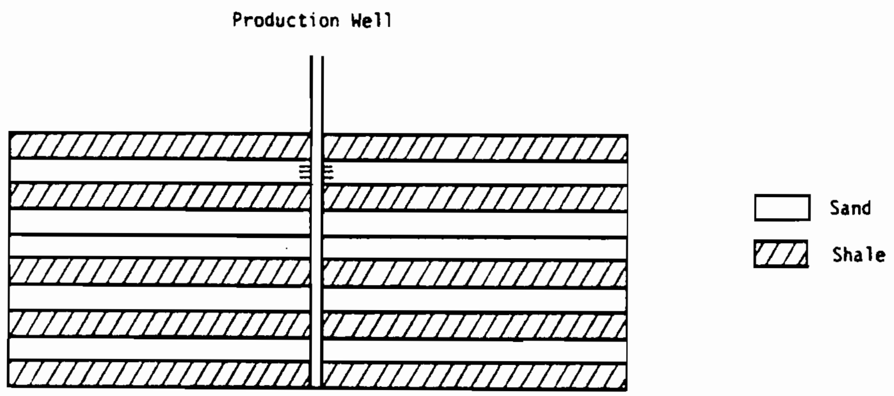


Figure 1 CROSS-SECTIONAL VIEW OF A SAND-SHALE ALTERNATING AQUIFER

The Brazoria County reservoir was assumed to cover a 4 square mile drainage area centered upon the Brazoria Pleasant Bayou #2 well. The initial pressure of the reservoir was taken to be 11,500 psia at depth of 14,600 feet. There was initially no free gas present within the aquifer. The fluid properties were estimated as functions of pressures at the expected aquifer temperature of 325°F. An initial solution gas/water ratio of 45 SCF/STB was employed, based on the assumed aquifer salinity between 50,000-70,000 ppm. Subsequent data indicate a somewhat higher salinity with the associated lower solution gas/oil ratios than were used in the study. The actual temperature was approximately 10-15° lower than used in the study. As shown in Figure 1, a total sand thickness of 250 feet within an overall gross thickness of the reservoir of 500 feet was assumed. All of the basic reservoir parameters and conditions are summarized in Table 1. Table 2 shows the various values of the parameters that were used for each simulation.

In order to handle certain aspects of the single well problem studied here, it was necessary to modify the reservoir model to treat both production and two-phase flow transmissibilities about the wellbore implicitly. These model modifications are similar to the semi-implicit treatment used in the study of coring and gas percolation problems encountered in the petroleum industry [2].

Compaction Parameters

Earlier studies used optimistic values of compaction coefficients of 0.5 X 10^{-5} psi^{-1} for sand and 10^{-5} psi^{-1} for shale [3]. Recent laboratory analysis conducted at The University of Texas Center for Earth Sciences and Engineering on cores taken from both the Brazoria County Pleasant Bayou #1 and #2 wells indicates compaction coefficients on the order of 10^{-6} psi^{-1}, a tenfold decrease in value [4]. As shown in

Table 1

BASIC RESERVOIR PARAMETERS AND CONDITIONS

Drainage Area	4 square miles
External Radius, r_e	5,958 feet
Well Radius, r_w	0.208 feet
Aquifer Depth	14,600-15,100 feet
Aquifer Facies	5 x 50' sand 5 x 50' shale
Initial Pressure	11,500 psia
Aquifer Temperature	325^oF
Porosity	$\phi_{sd} = \phi_{sh} = 20\%$
Permeability	$K_{xsd} = 20\text{-}500$ md $K_{zsd} = 2\text{-}250$ md $K_{xsh} = 10^{-4}$ md $K_{zsh} = 10^{-5}\text{-}10^{-4}$ md
Uniaxial Compaction Coefficient	$C_{msd} = 0.5\text{-}5 \times 10^{-6}$ psi^{-1} $C_{msh} = 1.0\text{-}10 \times 10^{-6}$ psi^{-1}
Initial Gas Saturation	0.%
Critical Gas Saturation	0.%
Maximum Allowable Production Rate	20,000 BWPD
Minimum Bottom Hole Pressure	7,000 psia

Figure 2, this reduction in compaction coefficient has a substantial effect on the projected behavior of the well and ultimate resource recovery. In the run #1 entitled Large Compaction shown on Figure 2 a shale compaction coefficient of 10 X 10^{-6} psi^{-1} and a sand compaction of 5 X 10^{-6} psi^{-1} were employed. The uniaxial compaction coefficients used for the case #2 labelled Measured Compaction Coefficients, are a factor

Table 2

SUMMARY OF SIMULATIONS

Run No.	Compaction Constant (psi^{-1})		Horizontal Permeability Sand Layer (md)					Shale (md)	K_x/K_z Ratio	Producing Zone	Sand Layer Communication
	C_{msd}	C_{msh}	1	2	3	4	5				
1	5×10^{-6}	10×10^{-6}	20	20	20	20	20	10^{-4}	2	All Sands	None
2	0.5×10^{-6}	1×10^{-6}	20	20	20	20	20	10^{-4}	2	All Sands	None
3.1	0.5×10^{-6}	1×10^{-6}	20	20	20	20	20	10^{-4}	10	Sand - 1	External
3.2	0.5×10^{-6}	1×10^{-6}	20	20	20	20	20	10^{-4}	5	Sand - 1	External
3.3	0.5×10^{-6}	1×10^{-6}	20	20	20	20	20	10^{-4}	2	Sand - 1	External
3.4	0.5×10^{-6}	1×10^{-6}	20	20	20	20	20	10^{-4}	1	Sand - 1	External
4.1	0.5×10^{-6}	1×10^{-6}	20	20	20	20	20	10^{-4}	10	Sand - 1	Near Well
4.2	0.5×10^{-6}	1×10^{-6}	20	20	20	20	20	10^{-4}	5	Sand - 1	Near Well
4.3	0.5×10^{-6}	1×10^{-6}	20	20	20	20	20	10^{-4}	2	Sand - 1	Near Well
4.4	0.5×10^{-6}	1×10^{-6}	20	20	20	20	20	10^{-4}	1	Sand - 1	Near Well
5	0.5×10^{-6}	1×10^{-6}	500	20	20	20	20	10^{-4}	2	Sand - 1	External
6	0.5×10^{-6}	1×10^{-6}	50	22	6	50	22	10^{-4}	2	Sand - 1	External
7	0.5×10^{-6}	1×10^{-6}	11	200	110	200	50	10^{-4}	2	Sand - 2	External

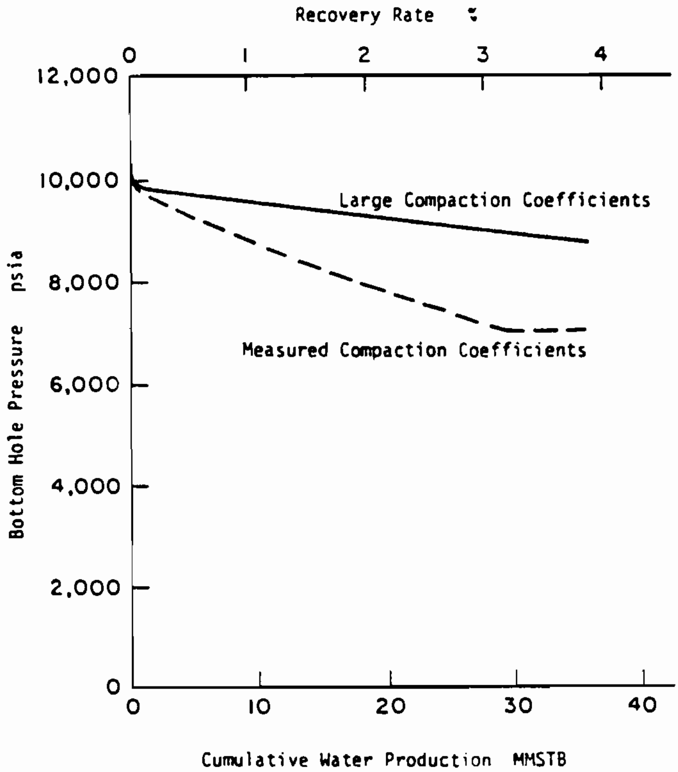


Figure 2 EFFECTS OF UNIAXIAL COMPACTION CONSTANTS

of ten less or for shales, 1 X 10^{-6} psi^{-1} and for sand 0.5 X 10^{-6} psi^{-1}. In each of these cases the well was produced at a rate of 20,000 BWPD with a bottom hole pressure limitation of 7,000 psia. This bottom hole pressure limitation was used to approximate the minimum bottom hole pressure at which the 20,000 BWPD rate would be sustained without artificial lift. When the bottom hole flowing pressure reaches 7,000 psia, the producing rate is reduced accordingly so as to maintain this minimum bottom hole pressure.

In these two runs, the producing well was completed in all of the five producing sands. Each of the sand layers was assumed to have a permeability of 20 md. The interbedded shales were assumed to have a horizontal permeability of 10^{-4} md. In each case there was no sand layer communication through the shale zones. Referring to Figure 2, we note that the larger compaction coefficient allows a continuous production of 20,000 BWPD through 15 producing years for a resource recovery of almost 12%. In this case, it was assumed that the well would be shut-in when the reservoir bottom hole flowing pressure reached 7,000 psia. Using the measured compaction coefficients, a recovery of 3% is computed at the 20,000 BWPD rate before the limiting bottom hole flowing pressure is reached. Figure 3 shows the water production rate versus time for the case of the smaller compaction coefficient. The well is able to produce at 20,000 BWPD for 4 years, after which the rate declines rapidly from 20,000 BWPD to approximately 12,000 BWPD after 5 years.

Effects of Communication through Shale and Completion Interval Location

The effects of the completion interval location relative to the

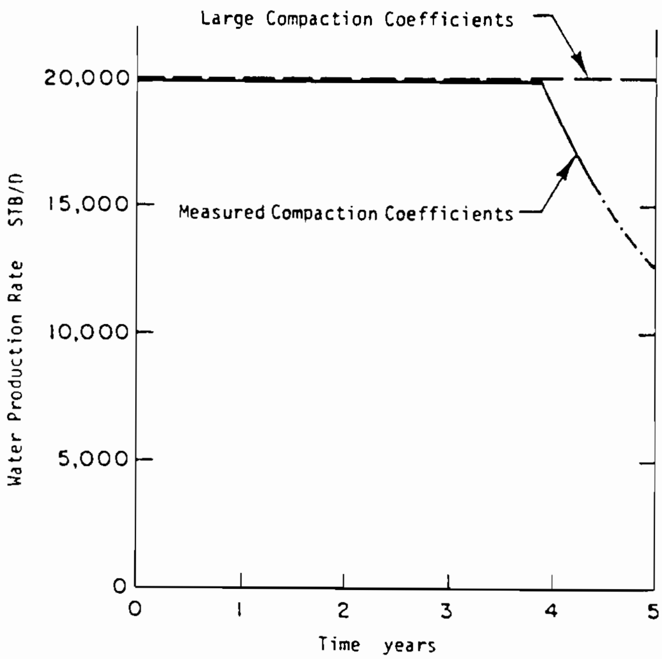


Figure 3 WATER PRODUCTION RATES OF FULLY PENETRATED WELLS

sands in the producing reservoir have become more important since the completion of the Pleasant Bayou #2. This well has been completed over only 50 feet of the total net sand interval. Production of the resource now will depend upon the degree of communication among the various sands in the reservoir with the completed sand interval. Several simulation runs were made to evaluate the effects of this partial completion interval on the production capability and ultimate resource recovery from the reservoir. In each of the cases described we have employed the most recent compaction data. Figure 4 presents a comparison between three of the cases run. The sands were allowed to communicate through the shales at some distance from the wellbore. In our model this was the outermost grid block. The results for a fully penetrated well in

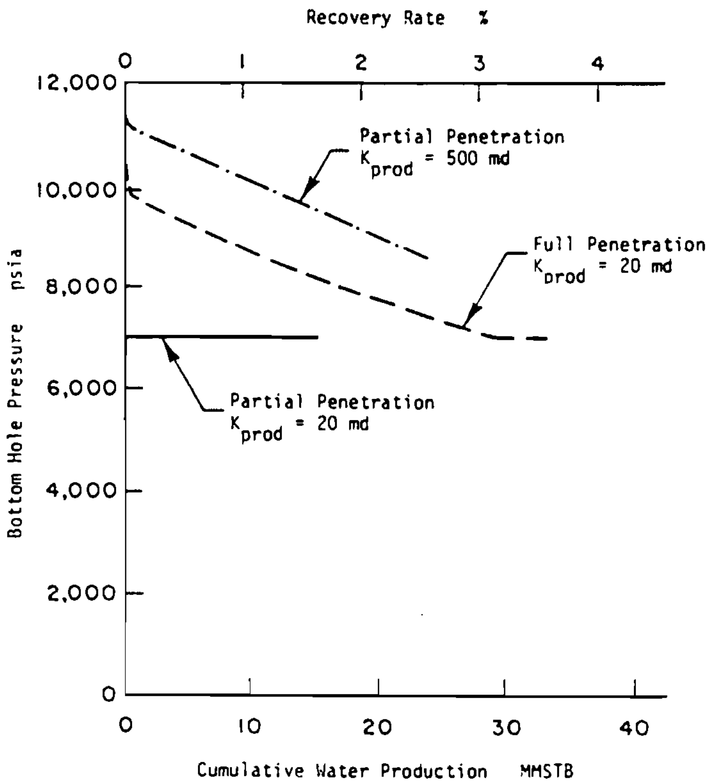


Figure 4 EFFECTS OF WELL PENETRATION AND PRODUCING SAND PERMEABILITIES

which each of the sands has a permeability of 20 md serves as a base case. If the 50 foot completion zone has a horizontal permeability of only 20 md, we see that it is unable to produce at the desired 20,000 BWPD rate. In fact, for this case, the well could only produce 10,000 BWPD against the 7,000 psia limiting flowing bottom hole pressure. This rate declines to 7,000-8,000 BWPD over a 5 year period. On the other hand, a well completed in the same interval but assuming a fairly high horizontal permeability of 500 md was able to produce at 20,000 BWPD for a long period of time. In this situation, it was possible to produce the well at 20,000 BWPD for 6.3 years for a recovery of 5% of the resource. This compares to a sustained rate over 3.8 years and a 3% recovery for the base case. The horizontal permeability of 500 md is, of course, opti-

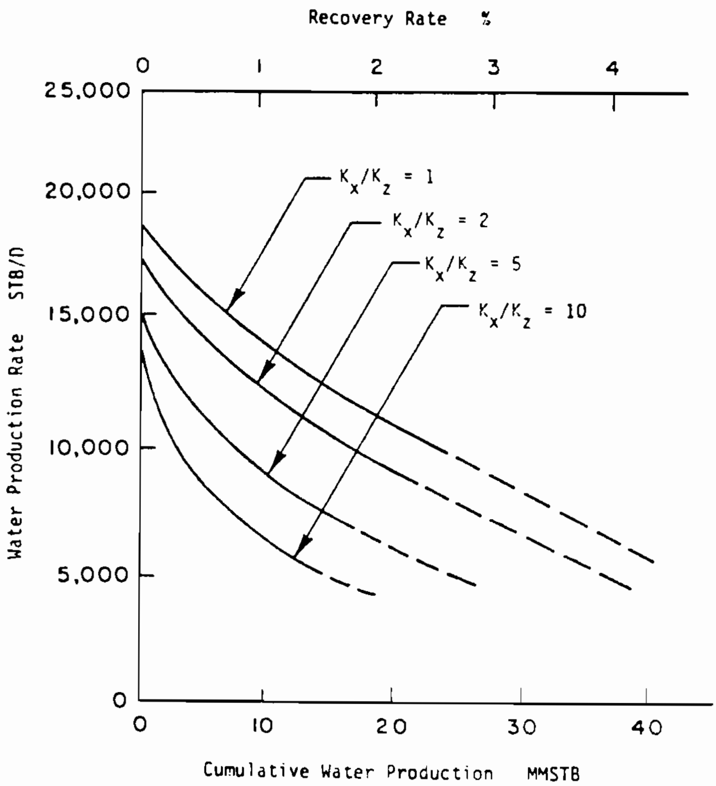


Figure 5 EFFECTS OF DEGREE OF SAND COMMUNICATION

mistic and represents the highest value that we might expect. Also, it was assumed that the 500 md extended outward over the entire areal extent of the reservoir.

Several runs were made to determine the effect of sand layer communication. In these runs, the effect of vertical sand permeability, assuming communication occurs near the wellbore, was investigated. Figure 5 shows the water production rates that might be expected from the well if the horizontal-to-vertical permeability ratio varied from 1 to 10. The permeability of each of the zones, including the producing zone, was 20 md. It is not possible to produce at the desired 20,000 BWPD rate at this level of permeability through a partially completed well. As indicated on Table 3 (Runs 4.1 through 4.4), the recoveries expected

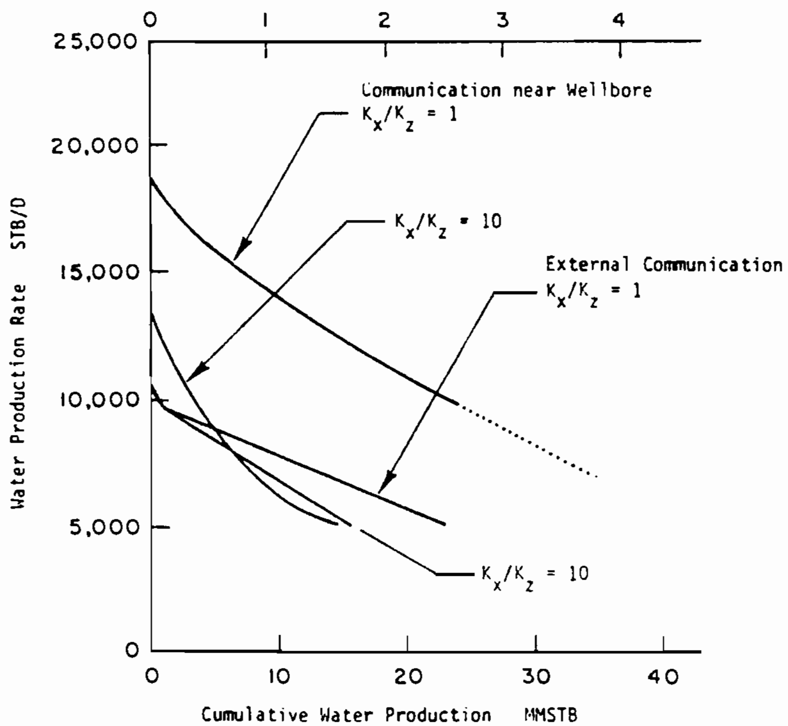


Figure 6 EFFECTS OF LOCATION OF SAND LAYER COMMUNICATION

Table 3 AQUIFER'S PRODUCTIVE LIFE AND RECOVERY RATE FOR CONSTANT RATE PRODUCTION

Production Rate / Run No.	20,000 STB/D		10,000 STB/D		5,000 STB/D	
	Life Years	Recovery %	Life Years	Recovery %	Life Years	Recovery %
1	14.9	11.8	29.7	11.8	59.5	11.8
2	3.8	3.0	11.1	4.4	25.9	5.1
3.1	---	---	0.07	0.03	10.5	1.7
3.2	---	---	0.07	0.03	12.3	2.0
3.3	---	---	0.07	0.03	14.4	2.4
3.4	---	---	0.07	0.03	15.3	2.5
4.1	---	---	0.85	0.34	8.0	1.6
4.2	---	---	1.84	0.73	13.8	2.7
4.3	---	---	4.55	1.8	20.3	4.0
4.4	---	---	6.36	2.5	22.7	4.5
5	6.3	5.0	12.5	5.0	25.0	4.2
6	1.2	0.94	2.4	0.94	4.7	0.78
7	6.0	4.8	12.1	4.8	24.1	4.0

for these reservoir configurations are disappointing.

A more interesting study was made comparing the sensitivity of production rates for variations in location of communication through the shales. Figure 6 shows that the degree of communication for shale windows near the wellbore has a significant effect on the productive capability of the well, whereas the degree of communication of shale windows some distance from the wellbore has very little effect on the producing capabilities of the well.

Effects of Completion Sand Permeability on Performance

Simulation runs listed on Table 2 as Runs 3.2, 5, 6 and 7 are presented in Figure 7. The basic difference between each of these runs is the permeability of the producing (i.e., completion) layer. For these cases, there was no constraint placed upon the minimum flowing bottom hole pressure. In each case, the well was produced at 20,000 BWPD. As might be expected, the run which utilized a 20 md permeability producing sand resulted in a very low producing bottom hole pressure almost immediately as shown in Figure 8. A 50 md sand assumption maintained the 20,000 BWPD rate out to a 1% recovery. A 200 md sand was quite comparable to the 500 md assumption. This is significant since a more realistic production or completion interval sand permeability appears to be 200 md. Indeed it is reasonable to expect a 100 md permeability could result in a 20,000 BWPD production rate out to a 3 or 4%

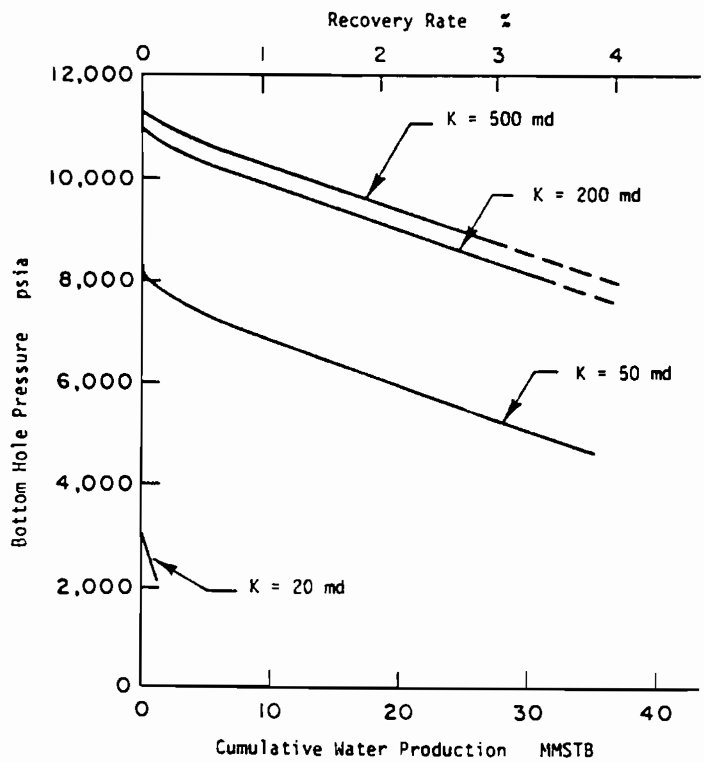


Figure 7 EFFECTS OF PRODUCING SAND PERMEABILITIES

recovery of the resource provided of course that the 100 md average sand permeability would be continuous areally over the entire reservoir.

Effects of Immobile Gas Saturation on Well Productivity

Figure 8 shows a typical set of water and gas/oil permeability relationships for a sand. Our concern in studying this problem is summed up in the difference between the residual gas saturation, denoted by S_{gr}, and the critical gas saturation, denoted by S_{gc}, on the figure. A critical gas saturation occurs when gas displaces water (normally referred to as drainage) whereas the residual gas saturation is usually found when water displaces gas (normally referred to as imbibition). The problem in the production of the geopressured geothermal aquifer is to determine whether the evolved gas in the reservoir will behave as if imbibition occurs, or as if drainage were occurring.

At the pressures that will be experienced in the geopressured

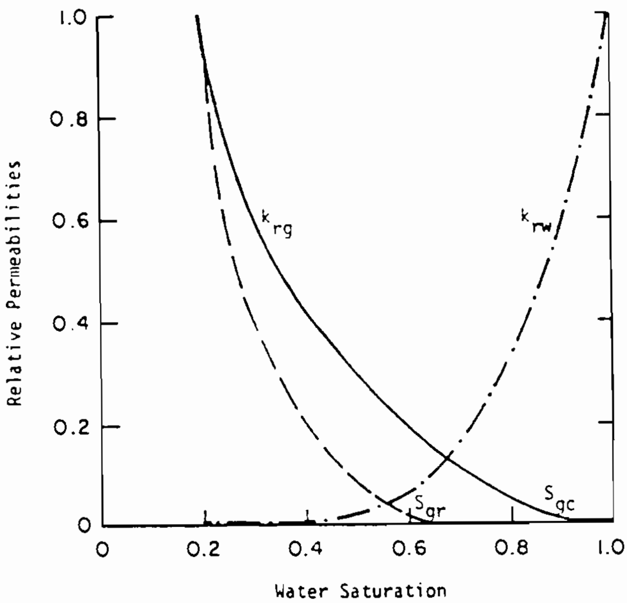


Figure 8 WATER AND GAS RELATIVE PERMEABILITIES

aquifer and for the amounts of gas that may be evolved from the water in the aquifer, it is expected that the gas saturations will be on the order of not more than 1 or 2% throughout the reservoir except near the wellbore. Near the producing well, gas will continually be evolved as water is produced to the wellbore due to the pressure drawdown in the near wellbore region. This gas will not move towards the well until such time as a critical or residual gas saturation has accumulated and been exceeded. This gas buildup of course will interfere with the ability of the well to produce water due to relative permeability effects. If the gas which is evolved from the water in the near wellbore region behaves as if drainage is occurring, then the critical gas saturation will only be in the neighborhood of 1-5% and the associated relative permeability effects to the water will be minimal. On the other hand, if the gas behaves as if imbibition is occurring, it is quite possible that the immobile gas saturation will reach upwards of 30-50% of the pore space, having a significant effect on the relative permeability of the water as demonstrated in Figure 8. It is this effect that we have studied with the geopressured geothermal reservoir simulation model.

The simulation model was altered for this series of studies to have a much more detailed grid about the well. This would enable the reservoir to predict a more detailed saturation profile. The immobile gas saturation is believed to affect the well productivity in an area not more than 50 feet away from the wellbore.

Figure 9 shows the dramatic effect that gas saturation buildup would have on the bottom hole pressure of the producing well. In this case, the well is being produced at only 10,000 BWPD. The curve labelled "No Solution Gas," i.e., the case in which the critical gas saturation is taken as zero, shows very little pressure decline over the first 600 days of production. However, when a residual gas saturation of 36% is used in the computation, we see a steady decline in the flowing bottom hole pressure over the first year of production, resulting in a final bottom hole pressure after one year of approximately 9,000 psia, some 2,000 psi less than the case in which no immobile gas effects are considered. The reason that the bottom hole pressure becomes more or less constant after one year is that the immobile gas saturation has been attained around the wellbore and the additional gas that evolves flows to the wellbore and is produced. In the two cases presented in Figure 9, we have assumed that the reservoir would be completed in all the sand intervals.

A more germane problem is to consider the same effects for a well that is completed over a limited interval such as the Pleasant Bayou #2 well. Figure 10 shows the expected behavior of the well assuming no

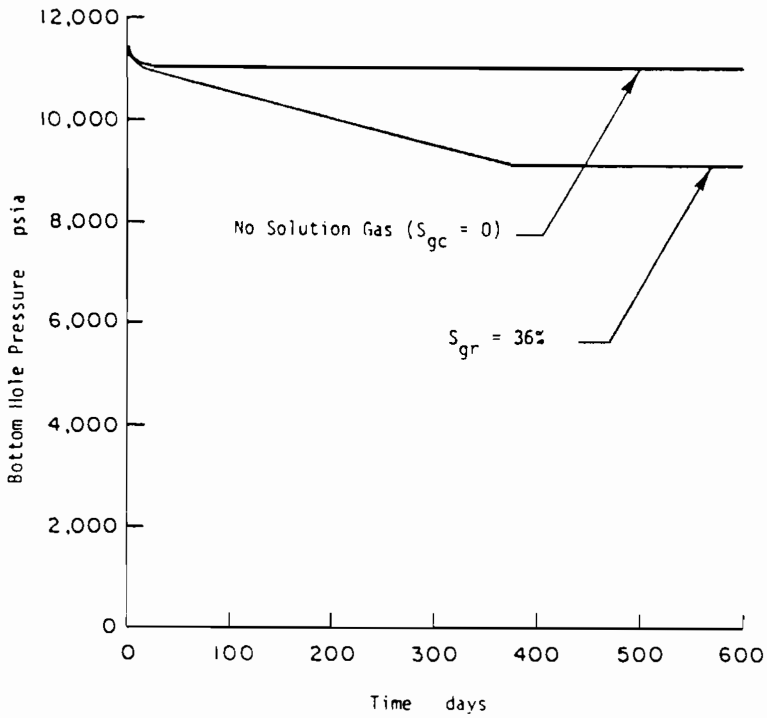


Figure 9 EFFECTS OF GAS SATURATION BUILDUP NEAR FULLY PENETRATED WELL

gas saturation and again a residual gas saturation of 36%. As we see, there is a dramatic reduction in the bottom hole pressure of the well. The pressure drawdown in the completion layer itself is sufficient to cause this significant immobile gas saturation buildup about this well.

We have demonstrated by these runs that an immobile gas saturation buildup around the wellbore would have a substantial effect on the productivity of the well and, thus, on the ultimate recovery of the resource. It must be emphasized, however, that it is not clear that this immobile gas saturation would indeed occur about the well. The question that has to be answered experimentally is, What is the immobile gas saturation that would occur when gas evolves in situ rather than through a purely displacement mechanism? These results are of course pessimistic with respect to well productivity. However, it might be

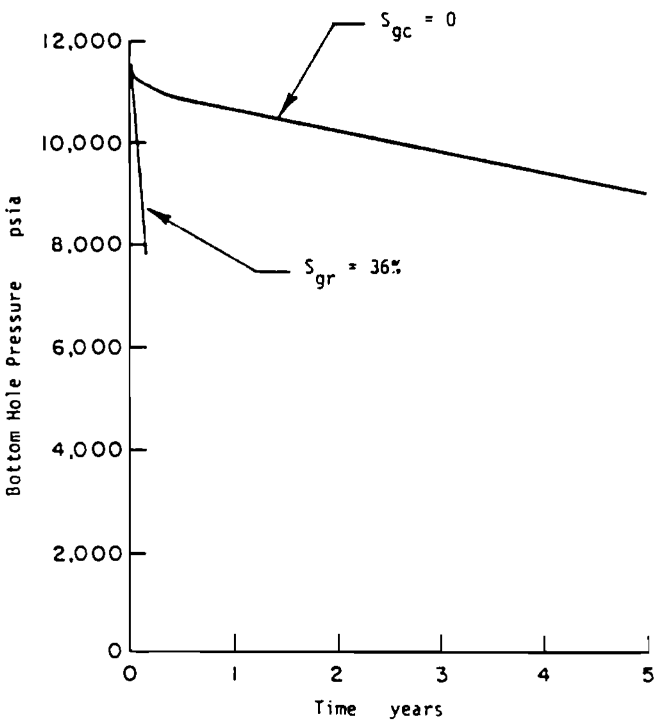


Figure 10 EFFECTS OF GAS SATURATION BUILDUP NEAR PARTIALLY PENETRATED WELL

possible through completion technique to avoid the relative permeability, immobile gas, or skin effects that would be apparent if this phenomenon occurs.

Conclusions

1. Reservoir intercommunication will have a significant effect on the well production behavior as well as the total resource recovery to be expected from the reservoir. This is particularly significant for a well completed over a small interval of the reservoir thickness.
2. The extent of high permeability across the reservoir will have a significant influence on the well's productivity.
3. The effect of immobile gas accumulation around the wellbore may substantially reduce the well's production capability. It is strongly recommended that work be done to better define the relative permeability characteristics and immobile gas saturation that might be expected upon the completion of a well in a geopressured geothermal aquifer.

Acknowledgment

This work was performed under DOE Contract number DE-AC08-79ET 27112.

References

1. Thompson, T. W.; Gray, K. E.; MacDonald, R. C.; and Jogi, P. N.; "A Preliminary Creep Analysis of Rocks from the Pleasant Bayou Wells," Proceedings, Fourth United States Gulf Coast Geopressured Geothermal Energy Conference, Austin, Texas, October 29-31, 1979.
2. Aziz, K., and Settari, A., Petroleum Reservoir Simulation, Applied Science Publishing Ltd., London, 1979.

3. Ohkuma, H.; Knapp, R. M.; and Sepehrnoori, K., "An Analysis of Reservoir Mechanics of Geopressured Geothermal Aquifers," Proceedings of Geothermal Resources Council Annual Meeting, Reno, Nevada, 1979.

4. Gray, K. E.; Jogi, P. N.; Morita, N.; and Thompson, T. W., "The Deformation Behavior of Rocks from the Pleasant Bayou Wells," Proceedings, Fourth United States Gulf Coast Geopressured Geothermal Energy Conference, Austin, Texas, October 29-31, 1979.

THE US DEPARTMENT OF ENERGY PROGRAM IN GEOPRESSURED RESOURCES

Keith Westhusing
Department of Energy, Washington, D.C., USA

Introduction and Summary

The geopressured gas resource along the U.S. Gulf Coast is projected to be substantial, but no reservoir has been developed commercially as yet because of uncertainties about the reservoir characteristics, recovery technology, and economics. Since industry is not expected to address this resource on its own, the U.S. Department of Energy initiated a program in 1974 to determine the resource potential and whether the resource could be produced economically. These two goals are expected to be attained by 1986.

The primary focus of current activities is on methane recovery because of the greater value of this energy source. However, effort is also being directed at developing the thermal and kinetic energy for production of electricity or for local use.

Should it be technically and economically possible to produce the formation waters, extract the methane, utilize the thermal and kinetic energy, and dispose of the spent water in an environmentally sound way, these reservoirs could make a substantial contribution to the nation's gas supply.

The Recoverable Resource

The geopressured resource is projected to be substantial, but its exact size and recoverability is highly uncertain. Estimates of the technically recoverable methane in solution in the geopressured waters have varied by two orders of magnitude -- from 50 to 5,000 trillion cubic feet. These differences arise from uncertainties about the geographic area, the size of the reservoirs, and the volume of methane that may be dissolved in the geopressured brines.

The U.S. Geological Survey published an estimate in 1979 for the methane and thermal energy. This assessment is summarized on Exhibit 1. The methane and thermal resource in sandstone formations is estimated at 6 thousand quads of natural gas and 11 thousand quads of heat and is evenly divided between onshore and offshore areas. (In comparison, the U.S. consumes about 20 quads of gas annually). A larger thermal and methane resource is estimated to be held in the shale formations (97 thousand quads of thermal energy and 56 thousand quads of methane). However, recovery of water and methane from the shales would be difficult because of their low permeability.

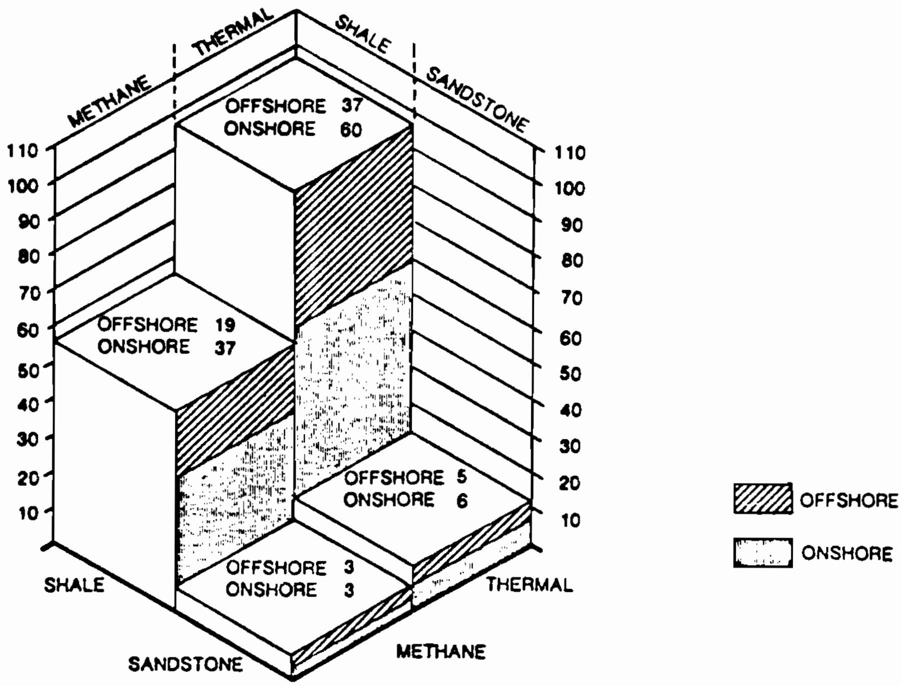


EXHIBIT 1 Methane and thermal energy in geopressured aquifers (thousands of quads). SOURCE: U.S.G.S. CIRCULAR 790

The geopressured-geothermal program of the U.S. Department of Energy (DOE) focuses on the sandstone formations beneath the onshore coastal areas of Texas and Louisiana for the following reasons:

- o Geologic studies have identified large onshore fairways that may contain substantial quantities of water and dissolved methane because of their high pressures, high temperatures, and proximity to source rock;
- o The resource is reasonably close to existing pipelines and industrial centers; and,
- o Considerable data on the geological, geophysical, and geochemical properties of this area are available from previous oil and gas drilling.

Need for a DOE Program

Although the in-place geopressured resource is clearly large, numerous historical perceptions limit industry's interest in pursuing this resource:

- o Previous drilling has been upstructure, in areas where oil and gas could be trapped; thus, the reservoirs found to date have been relatively small. By extension, industry assumes that the geopressured aquifers will also be small.
- o Production from these wells involves large rates of water and low rates of gas. Consequently, these resources have been perceived to be economically marginal in comparison with conventional natural gas.
- o Subsidence, water disposal, mineral rights, and other issues pose serious environmental uncertainties that could potentially have large economic consequences to any single company.

Given the high front-end RD&D costs required to better understand this resource, resolve the environmental uncertainties and reduce the risks, no single company on its own has been willing to sponsor the essential resource assessment and basic research. An important aspect of the DOE role is therefore to gather sufficient and reliable information on the resource to overcome industry's historical perceptions.

DOE Program Goals and Objectives

Since 1974 the Department of Energy or its predecessor agencies have had an RD&D program to determine the potential of the geopressured-geothermal resource.

The main goals of the current program are to narrow the range of uncertainty on the resource potential to demonstrate whether the resource is economically recoverable, and to ensure the timely development of this domestic energy source if the potential is proven.

To meet these goals, the Department of Energy has established the following six objectives:

1. Assess the size of the in-place and recoverable resource;
2. Determine the technical feasibility of reservoir development, including downhole, surface and disposal technology;
3. Establish the economics of resource production;
4. Conduct supporting research on reservoir and fluid characteristics;
5. Identify and mitigate adverse environmental impacts; and
6. Promote commercialization.

The results obtained in this program may also be of benefit to the understanding and development of other resources that require technology for producing and disposing of high rates of water; improved characterization of the geopressured-goethermal zones; and downhole and surface technology to handle hot, briny waters and extract energy from them.

Program Activities and Accomplishments

Major efforts have been sponsored by DOE since 1974 at the University of Texas and Louisiana State University to prepare regional assessments of the Gulf Coast geopressured resources. These assessments have begun to define the geopressured "fairways" and to delineate optimum areas that can be developed as sites for long-duration testing.

In addition to the resource assessment, geological research, such as compaction measurement and sandstone consolidation analysis, is being done to define specific reservoir properties that will lead to improved estimates of the in-place and technically recoverable resource. Two well testing programs are underway to obtain this basic data:

Wells of Opportunity

To reduce uncertainties associated with reservoir characteristics, DOE initiated its Wells of Opportunity program where wells previously drilled by industry in the search for oil and gas can be recompleted in geopressured zones. Recompleting these wells in the zones of interest allows DOE to test wells at a lower cost than by drilling new wells. However, the wells may not be in optimal locations and they may only be used for short-term testing of the fluid properties and reservoir characteristics around the wellbore.

The location of the six Wells of Opportunity obtained as of mid-1980 are shown in Exhibit 2.

Design Wells

Design wells are wells drilled for DOE by contractors at sites selected from geologic studies. These wells are more expensive than the Wells of Opportunity, but they permit long-term testing in optimal geopressured fairways and reservoirs. These tests can obtain data on the area and thickness of the reservoir, reservoir

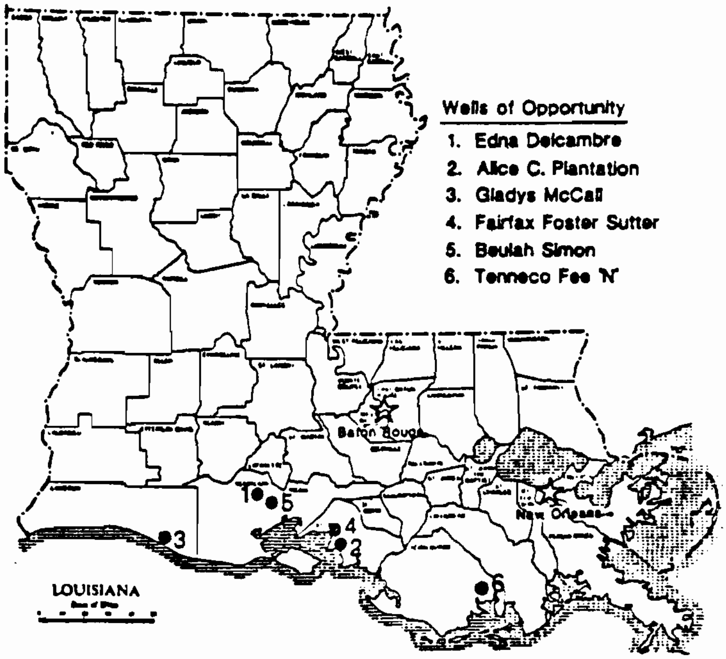


EXHIBIT 2 Location of DOE wells of opportunity.

characteristics throughout the reservoir, and long-term production effects.

The one design well drilled and tested to date has been the Pleasant Bayou #2 in Brazoria County, Texas.

Development of the necessary production technology is an integral part of the well testing programs. In addition to the resource assessment and well drilling activities, research and development is directed toward developing production technology and overcoming economic, institutional, and environmental barriers that might impede commercialization.

Program Priorities and Milestones

To implement this program, the RD&D program has been organized according to the following priorities:

- Near-Term Priorities (1981-82). Preliminary Assessment of the Resource. By the end of 1982, sufficient data will have been gathered from geological studies, from industry, and from DOE well tests to complete a preliminary confirmation of the size and technical viability of the resource.

- Mid-Term Priorities (1983-86). Economic Assessment of the Resource. By the end of 1986, enough data will be available to conduct a full economic assessment of the resource. In addition, appropriate downhole and surface technology will have been developed and some advanced recovery technology will be available from the hydrothermal program for adaption. Substantial progress will also have been made toward resolving or mitigating environmental, legal, social, and institutional constraints.

- Long-Term Priorities (Beyond 1986). Commercialization and Total Energy Systems. After 1986 it is expected that industry will develop the potential resource. DOE will assist this development by working to resolve constraints that might impede the effort and by developing technology for extracting kinetic and thermal energy to provide a total energy system, including the design and construction of a pilot plant if warranted.

The first major program milestone is at the end of 1982, as shown on Exhibit 3. By this time, testing of the first four Design Wells and twelve Wells of Opportunity should have produced detailed resource data, and some critical RD&D projects and regional resource assessments will have been completed so that a report of the technical feasibility of developing the resource can be prepared.

A second major milestone occurs in 1986 when the data from the twenty-four Wells of Opportunity and twelve Design Wells have been gathered and evaluated. By then, sufficient data will have been collected to allow a comprehensive assessment and report on the potential of geopressured-geothermal energy.

Implementation Strategy

To achieve its stated objectives, the implementation strategy of the Geopressured-Geothermal Program is organized around three activities. The major components of these activities are shown on Exhibit 4.

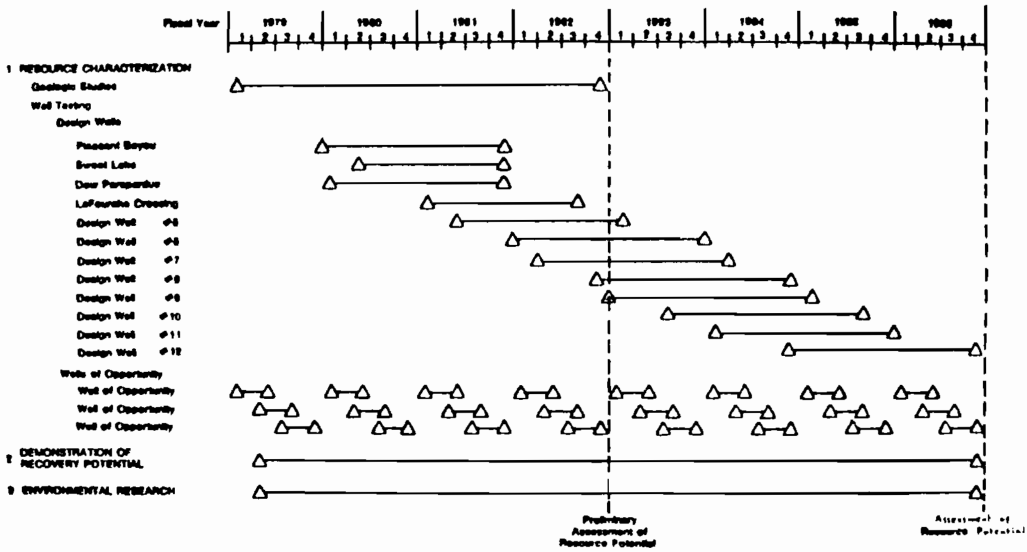


EXHIBIT 3 Milestones for recoverable resource estimates.

Activity 1. Resource Characterization

The purpose of the first technical program activity is to build a base of geologic and engineering data, use this data to reduce the uncertainty associated with the size and recoverability of the resource, and establish the location of aquifers suitable for development.

The Resource Characterization activity is further detailed on Exhibit 5. Data on the resource will be acquired by:

- o Geologic Studies. Regional geologic studies will be conducted by the U.S. Geological Survey, industry, or universities for DOE.
- o Well Testing. Key reservoir and fluild data will be obtained from specific sites, either from industry or the DOE sponsored Wells of Opportunity and Design Well programs.

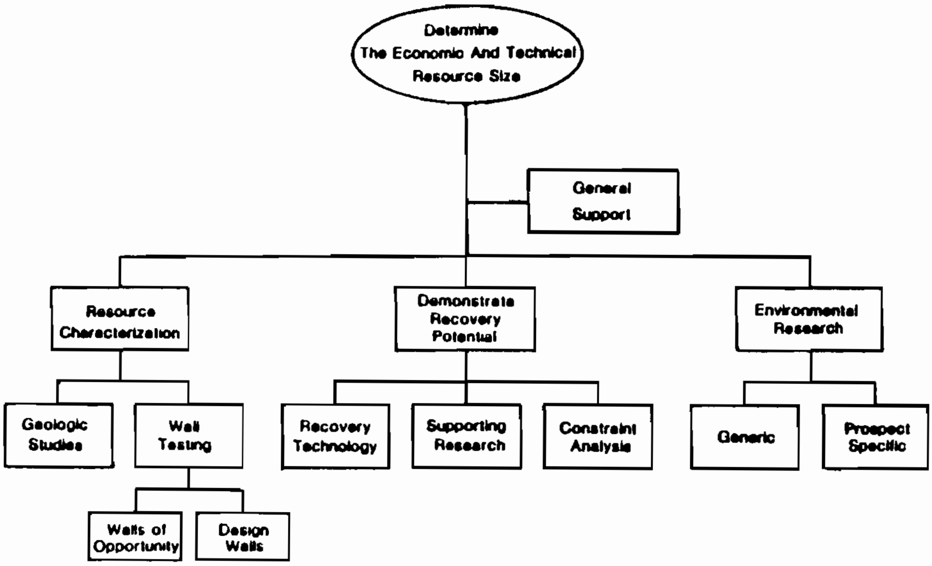
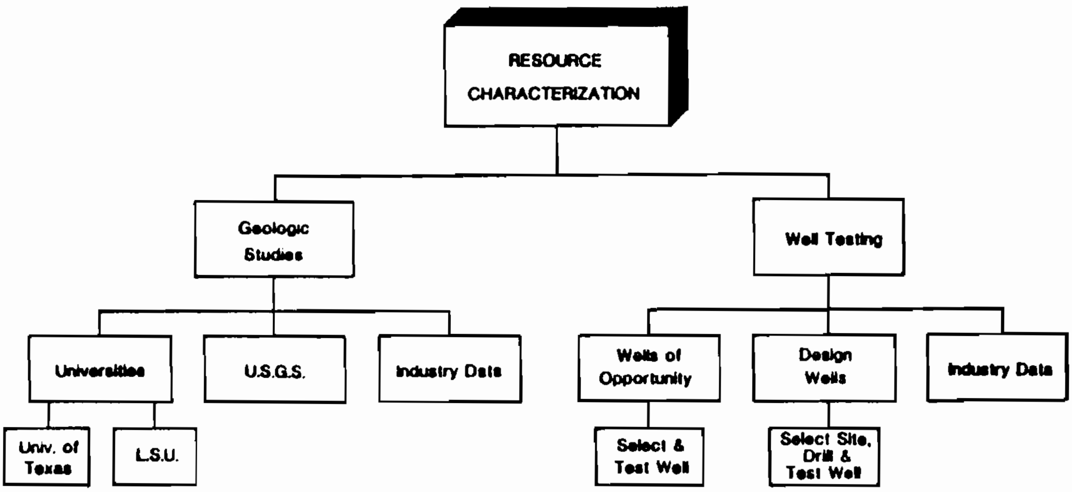


EXHIBIT 4 Major components of implementation strategy.



Goals:	Prepare Resource Assessment of U.S. Gulf Coast	Collect Site Specific Reservoir and Fluid Data
Strategy:	Detailed Geologic and Geophysical Studies of the Texas and Louisiana Gulf Coast to Identify Fairways and Favorable Prospects	Obtain Wells Drilled by Industry for Short-Term Testing and Drill Wells in Best Locations for Long-Term Testing

EXHIBIT 5 Resource characterization activity.

Activity 2. Demonstration of Recovery Potential

The purpose of the second technical activity is to demonstrate whether the geopressured-geothermal resource can be technically and economically recovered. This requires demonstrating the technology of high volume brine production, disposal, and energy recovery; obtaining an improved scientific and mathematical understanding of the resource; and resolving any institutional and legal constraints that may impede timely development.

The approach to this activity consists of the three components:

- Technology. Demonstrate the technical feasibility of producing geopressured aquifers by developing technology as part of the well drilling program, and adapt existing technology to the greatest extent possible.
- Supporting Research. Develop an improved understanding of geopressured reservoir and fluid characteristics through laboratory work and reservoir models.
- Constraint Analysis. Identify legal and institutional constraints and work with local and state sources to resolve them.

In addition to the work being done under the geopressured program, applicable experience and technology from the hydrothermal program will be drawn upon for the geothermal component of the resource.

Activity 3. Environmental Research

The primary purpose of the Environmental Research activity is to anticipate, understand, and develop methods to control the environmental problems associated with the development of the geopressured resource.

The two main components of the Environmental Research activity outlined in Exhibit 6 are discussed below.

- o Prospect-Specific Activities. This work focuses on individual development sites and includes regional baseline studies, environmental data collection, analyses of the environmental impact of site development, and monitoring of the environment at the site.

- o Generic Activities. The environmental consequences addressed by the generic activities are expected to be observed at all sites where geopressured development is undertaken and include the issues of subsidence, induced seismicity, hydrologic alterations, release of toxic gases and surface discharge of the spent brine.

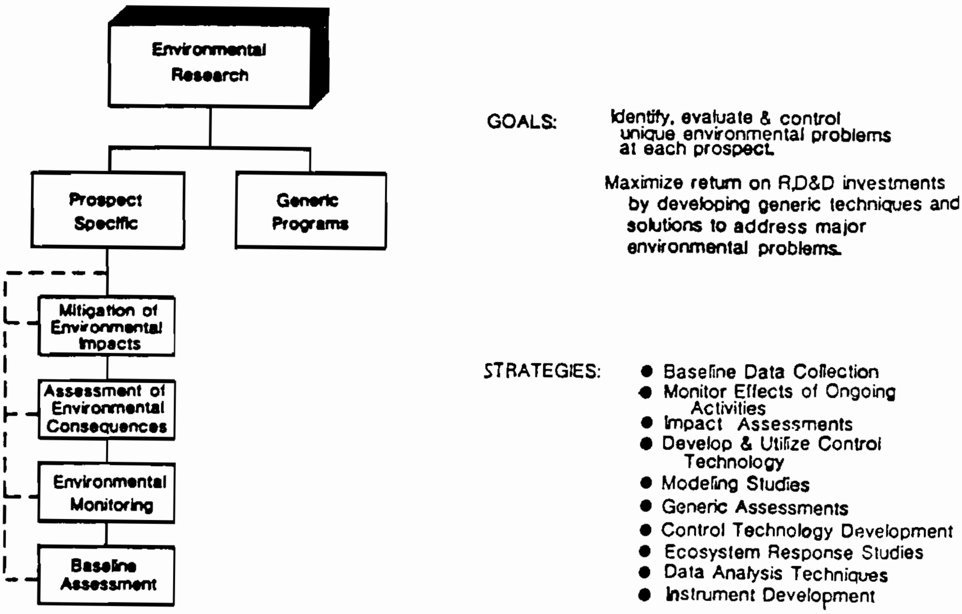


EXHIBIT 6 Components of the environmental research activity.

METHANE ENTRAINED IN GEOPRESSURED AQUIFERS, TEXAS GULF COAST

Robert A. Morton
Bureau of Economic Geology, The University of Texas at Austin, Austin, Texas, USA

ABSTRACT

Throughout the Gulf Coast region, substantial quantities of methane are contained within Tertiary sediments that exhibit abnormally high temperature and pressure gradients. Some of the methane occurs as dispersed free gas and some is dissolved in the hot overpressured brines. Laboratory measurements under saturated conditions indicate that methane solubility is directly related to formation temperature and fluid pressure and inversely related to salinity of formation waters. However, methane concentrations estimated from these theoretical considerations are higher than actual field measurements. Six tests of geopressured aquifers have yielded between 3.6 to 4.5 m^3/m^3 (20 to 25 scf/bbl) of gas. These low gas concentrations are attributed to high salinities, that in all tests exceeded 100,000 mg/l, but undersaturated conditions cannot be ruled out completely.

During the Cenozoic Era, rapid sedimentation, basin subsidence, and growth faulting resulted in thick accumulations of sand and shale. The thickest sandstones were deposited in deltaic and strandplain environments

---

Publication authorized by the Director, Bureau of Economic Geology, The University of Texas at Austin.

and presently serve as potential geothermal reservoirs. In contrast, the overlying thick shales of prodelta, shelf, and slope origin act as caprocks or permeability barriers that retard vertical migration of fluids. Reservoir quality and caprock distribution are governed partly by rock properties inherited from the environment of deposition and partly by diagenetic alterations that accompanied burial. Reservoirs that were subjected to late-stage leaching and the formation of secondary porosity are ideal for producing gas saturated brines at high rates for extensive periods of time.

At present, research efforts are designed to delineate the geographic and stratigraphic variations in salinity and to recognize regional and local trends so that zones of lower salinity and higher gas concentration can be identified. Moreover, well logs and seismic data are being used to develop methods of detecting low concentrations of free gas in watered-out gas sands and in thin sands that were considered as noncommercial prior to renewed interest in unconventional gas supplies.

INTRODUCTION

Over the past decade significant progress has been made toward delineating and describing alternate energy sources associated with geopressured sediments of the Gulf Coast region. Research efforts have recently led to the identification of several areas that appear favorable as sites for production of geothermal resources, including methane dissolved in hot brines. One deep well, the General Crude Oil/Department of Energy Pleasant Bayou No. 2, was drilled in Texas to a depth of 5,000 m (16,500 ft) and is undergoing long-term tests of reservoir performance and time-dependent changes in fluid characteristics. Preliminary results from this well are encouraging because they indicate that some geopressured aquifers are capable of sustaining high rates of production, over 3,200 m^3/day (20,000 bbl/day), for extensive periods of time.

As the geopressured-geothermal program was evolving, natural gas prices in the United States were increasing dramatically. The short-term energy shortage and economic climate subsequently translated to shifts in research direction and in the site selection process. Geopressured-geothermal test sites initially were selected using criteria established for electric power generation. These requirements included reservoir temperatures greater than 149°C (300°F), and pressure gradients in excess of 15.8 kPa/m (0.7 psi/ft). At present, methane entrained in the formation waters offers the greatest potential for short-term economic payout; therefore, the search for test sites has shifted to areas where methane solubility is greatest.

Calculated in-place methane resources for the Gulf Coast region vary widely, but even conservative estimates of 5,700 Tcf (Dorfman, 1977) represent a substantial target for new gas supplies from an area where the infrastructure for exploration and marketing is well developed. Moreover, the geopressured energy resources have direct industrial applications where moderate temperatures and methane are used for drying and refining processes.

Geologic Setting

Depositional and structural styles of the Gulf Coast region are typical of sedimentary basins where deltaic systems are fed by drainage of continental proportion. These basins receive enormous volumes of clastic detritus, mainly as wedges of sand and mud, that are characterized by thick sequences comprising three major lithofacies (interbedded sand and shale, massive sandstone, and massive shale). Within each clastic wedge, time correlative units as well as vertically stacked sequences exhibit an orderly succession of lithologies (fig. 1) related to depositional environment. The upper interbedded sands and shales, massive sandstones, lower interbedded sands and shales, and massive shales closely correspond to fluvial, proximal delta/strandplain, distal delta/shelf, and prodelta/shelf and slope environments that are found progressively farther from shore and in deeper water.

When deposited, the massive shales of deep-water origin have low densities and are water saturated. These properties together with sediment loading cause unstable conditions that initiate and sustain movement of faults, slumps, and diapirs. Such features are prominent where rapid deposition occurred along shelf margins. Most major growth faults were formed contemporaneously with rapid deposition and were located near the depocenters, thus causing substantial thickening of the sedimentary sequence (fig. 1). Both progradational and aggradational processes were

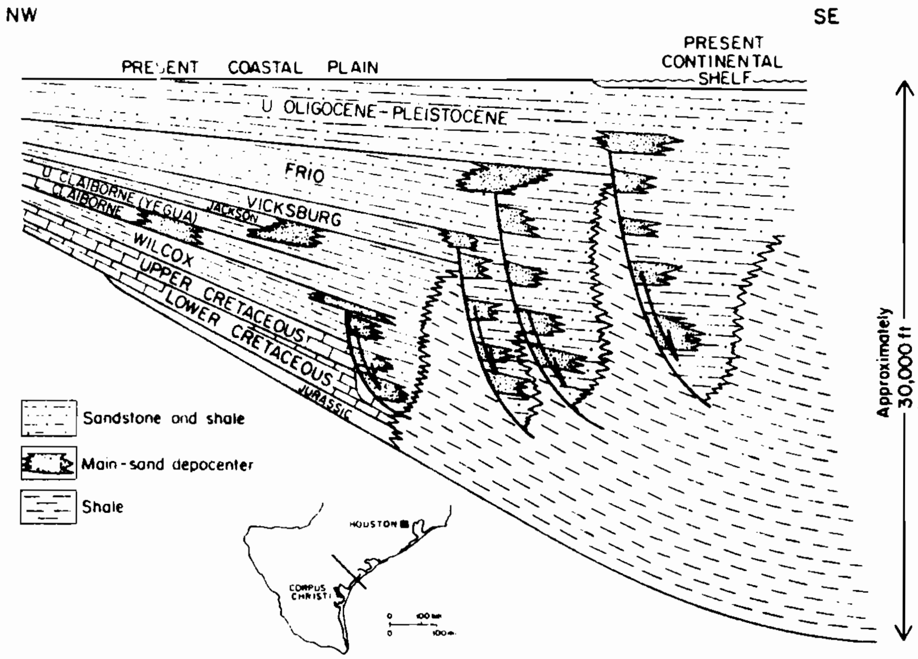


Figure 1. Generalized geologic cross section for Cenozoic strata, Texas Gulf Coast basin. Modified from Bruce (1973).

responsible for infilling the basin; however, thickest deposits formed during regressive (progradational) episodes. Regional transgressions of considerable duration were also important in basin development because they record periods when deltaic sedimentation was minor while marine deposition, primarily shale, was widespread.

With increased time and depths of burial, the sediments were subjected to increased temperatures and pressures; they also underwent diagenetic alterations that included stages of compaction, cementation, and commonly, leaching. The thick shale sections formed permeability barriers that retarded or prevented the migration of fluids normally expelled from the compacting sediments. Pore waters trapped beneath these permeability barriers became overpressured by the weight of the overburden. These same pore waters also produced thermal barriers by reducing heat flow through the sediments.

REGIONAL TRENDS

Although most Tertiary sediments of the Texas Gulf Coast are geopressured at great depths (4 to 5 km) and contain some gas in solution, the Wilcox Group (Eocene) and the Frio Formation (Oligocene) are the two primary candidates for exploration of entrained methane. These geothermal corridors (fig. 2) are prolific oil and gas producers owing to the vast number of sandstone reservoirs that have structural and stratigraphic closure.

Reservoir Continuity

The sandstone reservoirs that produce hydrocarbons also serve as potential geothermal aquifers. Massive sandstones that occur stratigraphically throughout the Tertiary section mark the positions of former nearshore deposition. Most of these sand bodies were originally deposited in distributary channel or delta-front environments. Some of the sands were buried in-place, and some were reworked to form strandplains and barrier islands in interdeltaic areas. The vertical thickness and areal extent of the sand bodies were controlled by rates of sedimentation

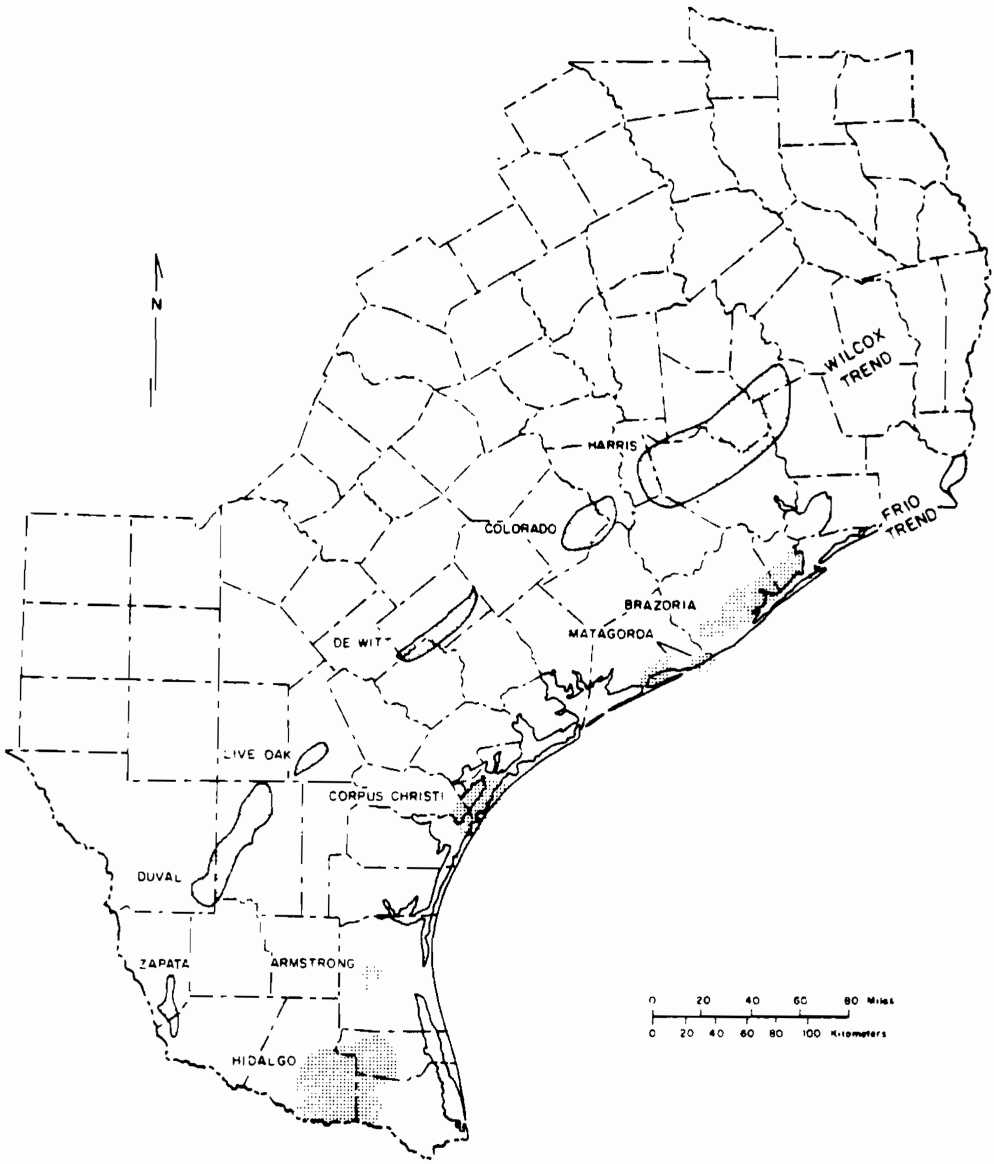


Figure 2. Geopressured-geothermal prospect areas in the Wilcox Group and Frio Formation, Texas Gulf Coast. After Bebout, *et al.* (1978, 1979).

as well as by environments of deposition and their orientation, either strike or dip aligned.

Reservoir continuity is also controlled structurally by growth faults that are ubiquitous along the Gulf Coast. The density of these faults and resulting structural complexity vary from area to area. The largest fault blocks are generally found between regional flexures and are characterized by synclines or salt withdrawal basins. These areas offer the greatest potential for laterally persistent sandstones, but they also offer limited subsurface data because they are downdip of known hydrocarbon accumulations.

Reservoir Quality

Flow characteristics of methane-bearing aquifers depend mainly on porosity and permeability; rock compressibility can also affect production after reservoir pressure declines. Primary porosity and permeability are inherited from the depositional environment; however, these primary properties are altered as the rock compacts and is cemented. Subsequent stages of leaching and cementation as well as fracturing ultimately determine the size and interconnectedness of interparticle spaces.

To some degree, porosity and permeability are related to age, but more importantly, they are related to depth of burial (fig. 3), degree of compaction, and consolidation history. Perhaps the most important of the known processes is secondary leaching, which can significantly improve the porosity of geopressured reservoirs (Loucks, *et al.*, 1979).

Reservoir quality is also affected by sandstone composition. Along the Texas Coast, sandstones of the Frio Formation contain more volcanic and carbonate rock fragments and feldspar than Frio sandstones of the upper Texas Coast, which contain more quartz and less feldspar. In contrast, sandstones of the middle Texas Coast are intermediate between the

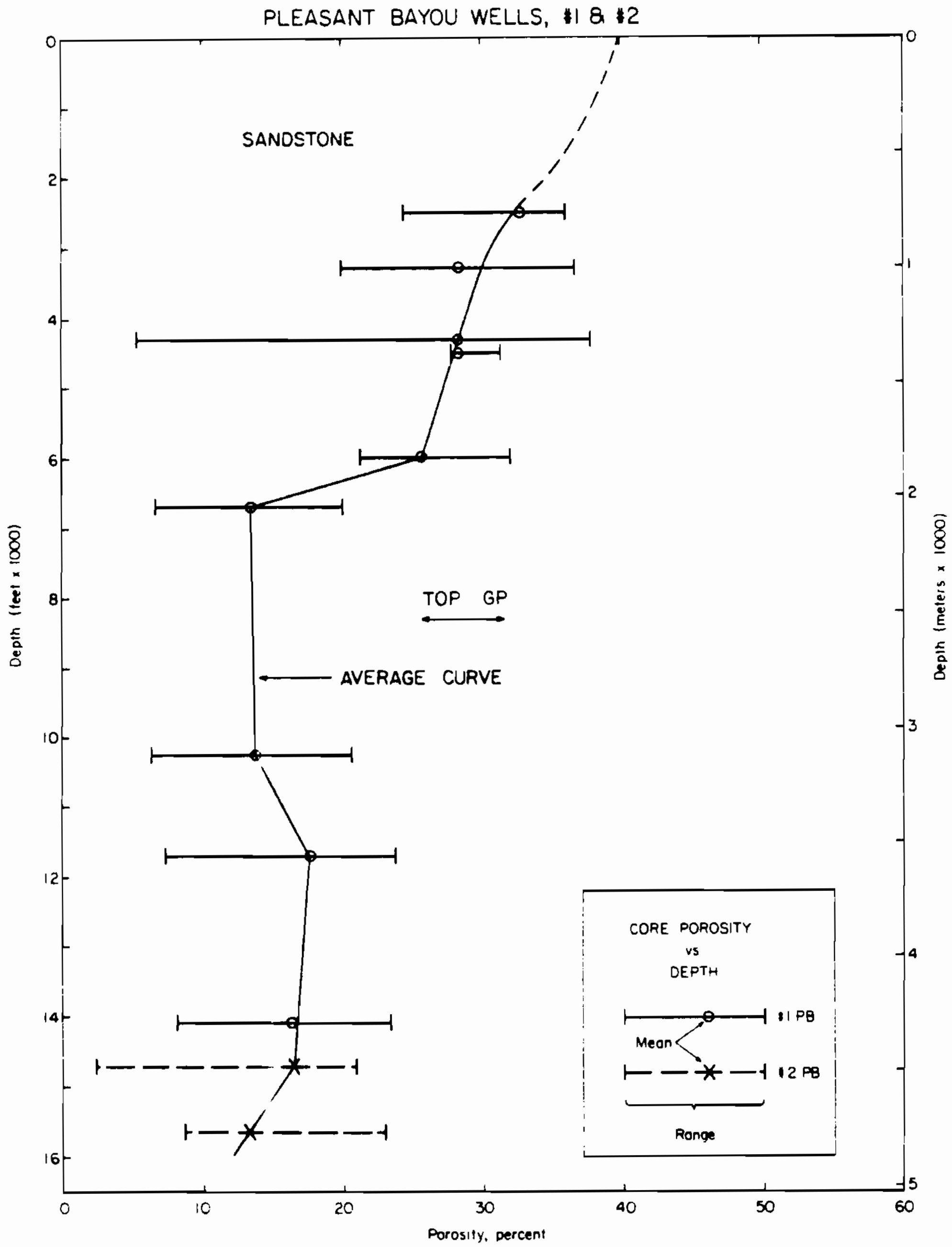


Figure 3. Relationship of whole-core porosity to depth, Pleasant Bayou No. 1 and No. 2. After Gregory, *et al.* (1980).

other two extremes (Bebout, *et al.*, 1978). Because of the abundance of unstable rock fragments and the regional thermal gradient, geopressured sandstones along the lower Texas Coast generally exhibit low porosities and permeabilities. Analyses of whole cores indicate that permeabilities are higher elsewhere, especially along the upper Texas Coast.

Fluid Properties

The solubility of methane in geopressured aquifers depends chiefly on formation temperatures, fluid pressures, and formation water salinities (Blount and others, 1979). The regional distribution of each parameter is independent of the others, but each depends at least partly on regional and local geological conditions.

Subsurface temperatures and temperature gradients for the Wilcox and Frio reservoirs generally increase Gulfward and southwestward along the Texas Coast. Temperature gradients are greatest in the structurally active Rio Grande Embayment; elsewhere, temperatures are nearly uniform for a particular depth. For example, temperatures of 149°C (300°F) occur at depths of 3,940 m (13,000 ft) over much of the central and upper coast.

Field measurements from thousands of wells indicate that fluid temperatures in the geopressured zone range from 93° to 149°C (200° to 300°F); bottom-hole temperatures greater than 175°C (350°F) are rarely encountered even at present drilling depths. Temperature and depth relationships established from the field measurements (fig. 4) not only reveal the thermal gradient for the region, but also provide reasonable approximations of temperatures in untested areas.

Geopressures, or pressure gradients, in excess of 10.5 kPa/m (0.465 psi/ft) are controlled more by facies changes than by depth of burial. The top of geopressure occurs near the base of the massive sandstones and within the underlying sands and shales. Because pressure gradients are

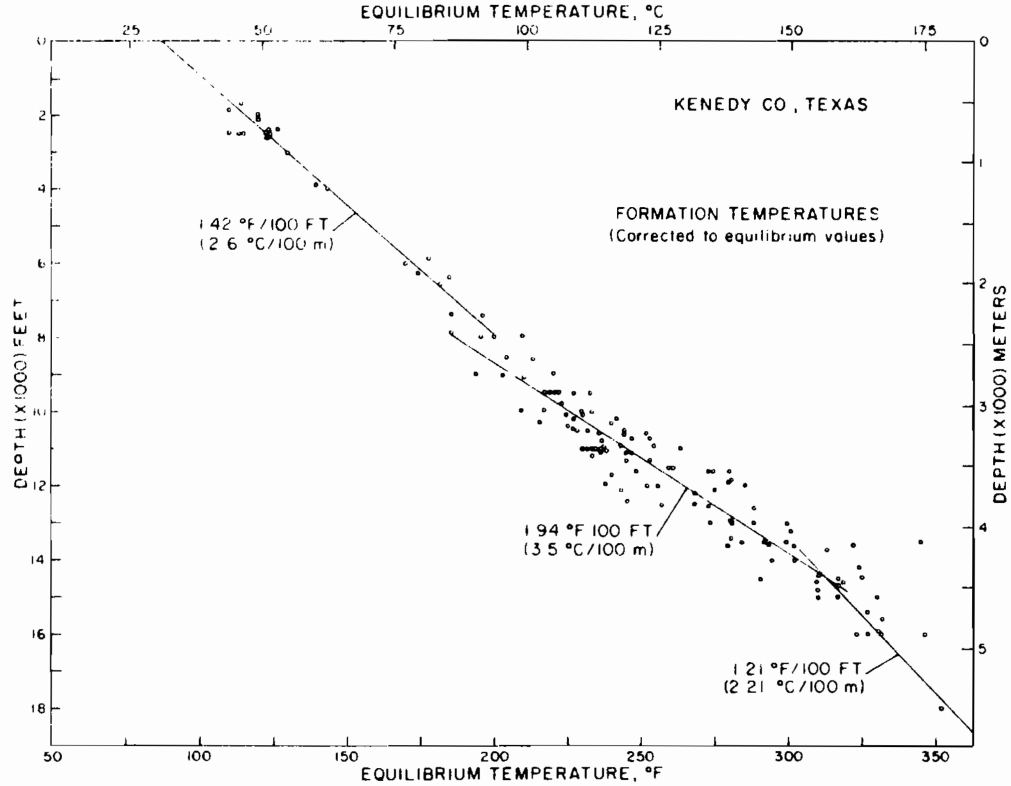


Figure 4. Well log temperatures corrected to equilibrium values versus depth for wells in Kenedy County, Texas. After Gregory, *et al.* (1980).

related to these lithologic changes, depths to the top of geopressure progressively increase to a maximum and then decrease in a seaward direction. Depths generally range from 1,800 to 3,600 m (6,000 to 12,000 ft) in older onshore sediments (Bebout, *et al.*, 1978; 1979), whereas depths as great as 5,450 m (18,000 ft) and as shallow as 900 m (3,000 ft) are encountered in younger sediments beneath the Louisiana shelf (Wallace and others, 1979). Deepest occurrences are usually associated with sandstone depocenters that are downthrown along regional growth faults (fig. 1).

These repetitous patterns of increasing and decreasing depth to geopressure across the coastal plain and continental shelf are associated with each major depositional cycle except the Wilcox Group. For Wilcox sediments, the top of geopressure progressively decreases from 3,900 to 2,400 m (13,000 to 8,000 ft) in a downdip direction (Bebout and others, 1979). Pressure gradients below the top of geopressure (fig. 5) range from hydrostatic (10.5 kPa/m) to near lithostatic (22.6 kPa/m) depending on the depth of interest and the local geological conditions.

Formation water salinity is probably the least understood but most important factor that governs methane solubility. Despite numerous con-

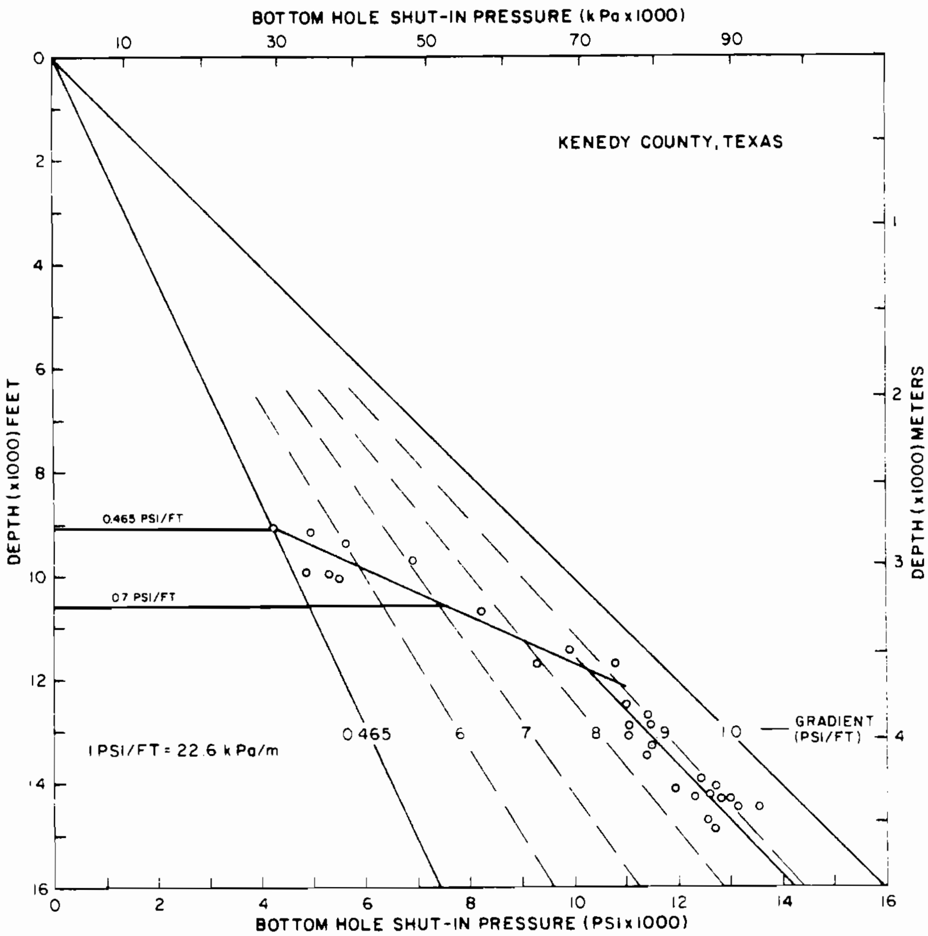


Figure 5. Bottom hole shut-in pressures from drill stem tests for wells in Kenedy County, Texas. After Gregory, *et al.* (1980).

ceptual models, a hypothesis explaining salinity patterns has not emerged. According to log calculations, salinity variations are extreme even within an area and at most depths (fig. 6). Systematic changes in salinity with depth or within a stratigraphic unit have been explained by dissolution of buried evaporites, membrane filtration by clay minerals, or gravity separation induced by tectonic stresses. Because of these and other reports, low salinities were generally expected below the top of geopressure; however, just the opposite has been found. Indeed, geopressured sands specifically tested for geothermal resources have yielded waters with salinities greater than 100,000 mg/l. Moreover, salinities calculated from electric logs for each test interval have consistently underestimated the actual salinities of produced waters.

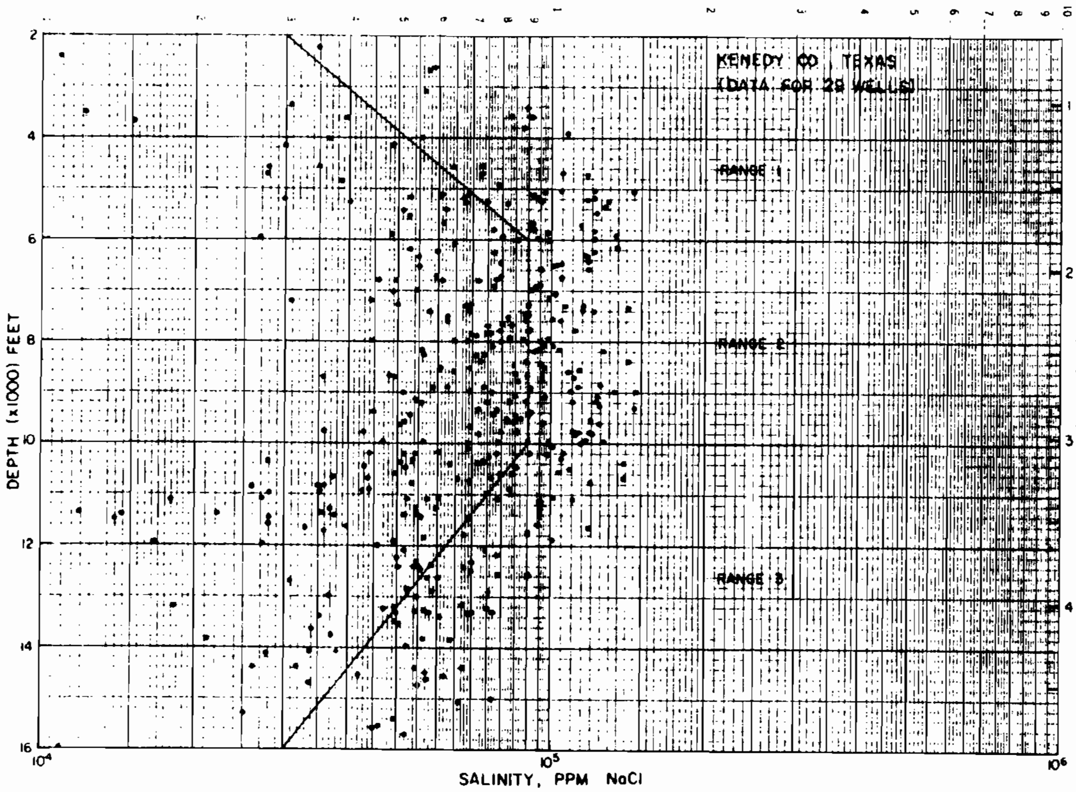


Figure 6. Salinity computed from well logs versus depth for 29 wells in Kenedy County, Texas. After Gregory, *et al.* (1980).

Unrepresentative data from field tests may be responsible for the inaccurate predictions. For example, salinities determined from drill stem tests may be contaminated with mud filtrate. Furthermore, water produced in association with hydrocarbons, especially gas, is subject to dilution by water of condensation or by special treatment such as acidizing or hydraulic fracturing. In each of these cases, the measured salinities could be considerably less than the actual salinities of formation waters. Because of these uncertainties and the immediate need for more accurate prediction, additional studies of brine concentrations are planned.

PRELIMINARY TEST RESULTS

Design Well Program

The first well specifically designed and drilled to test geopressured-geothermal resources is the General Crude Oil/Department of Energy Pleasant Bayou No. 2 in Brazoria County, Texas. The well penetrated 200 m (660 ft) of sandstone with temperatures greater than 149°C (300°F). Additional geopressured sandstones with lower temperatures above the objective interval were also penetrated but await further testing. Perforation depths of the producing well range from 4,463 to 4,482 m (14,644 to 14,704 ft). This interval coincides with the massive portion of a relatively thick sandstone interpreted as a bed-load fluvial channel (Bebout, *et al.*, 1980). In situ properties of this geothermal reservoir are as follows: temperature, 149°C (300°F); formation pressure, 78.6 kPa x 10^3 (11,275 psi); pressure gradient, 17.6 kPa/m (0.8 psi/ft); salinity, 132,000 mg/l NaCl; average porosity, 18 percent; and permeability, 150 to 175 md.

The reservoir was tested for ten days at rates up to 3,500 m^3

(22,000 bbls) of water per day with only a minor pressure decline. Pressure drawdown and buildup curves indicate that no permeability barriers were encountered with 4.8 km (16,000 ft) of the well bore. Gas content for this large aquifer ranged from 3.78 to 5.04 m^3/m^3 (21 to 28 scf/bbl) of water. Methane solubility for the producing sand was considerably less than predicted because formation water salinities were greater than expected. Furthermore, composition of the gas may have contributed to lower methane content. Although methane is the primary gas constituent (88.5 percent), carbon dioxide volumes are not insignificant (10.5 percent).

Wells of Opportunity

In addition to the design well, short-term tests have been obtained from five sands in four wells in Louisiana. These wells were originally drilled for hydrocarbons and abandoned as noncommercial prior to testing for gas production from geopressured aquifers. The objective sands ranged from Lower to Upper Miocene in age; temperatures ranged from 112° to 140°C (234° to 285°F); pressures ranged from 74.8 to 89.7 kPa (10,850 to 13,015 psi); and salinities ranged from 98,860 to 190,904 mg/l. Despite the great distances between wells and the vast differences in reservoir conditions, the ratio of gas to water in these sands was remarkably similar. Without exception, the tests indicated that the wells were capable of producing gas in concentrations ranging from 3.6 to 4.5 m^3/m^3 (20 to 25 scf/bbl).

FUTURE RESEARCH

The search for methane in geothermal aquifers could be enhanced substantially by utilizing data developed for other geothermal prospects. Generic studies requiring more detailed work include (1) delineating areas with low salinity, and (2) identifying reservoirs containing dispersed free gas.

Salinity Predictions

Two distinctly different but complementary approaches can be used to improve predictions of salinities of formation waters. The first method involves comparing calculated salinities from electric logs with measured salinities of waters produced from the same intervals. At present, empirical relationships between salinity and SP response are based on data from the hydropressured zone. Because these equations tend to underestimate salinities in the geopressured zone, log calculations are not reliable. Hence, improving the accuracy of log-derived salinities would permit mapping of relatively low salinity trends.

The second approach, also designed to identify aquifers with low salinity water, involves compilation of field data for various regions and subsurface formations. When placed in a geologic framework, the geographic and stratigraphic distribution of salinity data should provide an adequate method for predicting salinity trends and interpreting the vertical and lateral variations using hydrodynamic models.

Free Gas Detection

Exploration risks could be significantly reduced if zones containing appreciable quantities of methane were easily identified. Abandoned reservoirs with low concentrations of free gas in addition to gas in solution are prime targets for producing unconventional gas. Similarly, thin gas sands that were noncommercial because of water production would also qualify for future consideration. Combined data from well log analyses and seismic processing could be used to develop methods of gas detection from known reservoirs. Velocity reductions from sonic logs and amplitude anomalies from seismic data would establish responses to known conditions. After refinement and allowances for natural variations, these responses could indicate other areas where methane concentrations might be adequate for testing both the concepts and the methodology.

Other research efforts designed to improve our understanding of gas accumulations involve studies of petroleum generation and fluid migration and their relationship to geopressured sediments. Theories of thermal maturation, efficiencies of source rock generation, and regional pathways of primary migration are being examined to ascertain whether solution gas and free gas may be present in sufficient quantities to warrant further research.

ACKNOWLEDGMENTS

This paper summarized results of projects conducted by the Bureau of Economic Geology and funded by the United States Department of Energy, principally under contracts DE-AS05-76ET28461 and DE-AC08-79ET27111.

REFERENCES

Bebout, D. G., Loucks, R. G., and Gregory, A. R. (1980), Geological aspects of Pleasant Bayou geopressured geothermal test well, Brazoria County, Texas: Proc. Fourth U.S. Gulf Coast Geopressured-Geothermal Energy Conference, University of Texas, Austin, Texas (in press).

Bebout, D. G., Loucks, R. G., and Gregory, A. R. (1978), Frio sandstone reservoirs in the deep subsurface along the Texas Gulf Coast: University of Texas, Austin, Texas, Bureau of Economic Geology, Report of Investigations 91, 92 p.

Bebout, D. G., Weise, B. R., Gregory, A. R., and Edwards, M. B. (1979), Wilcox sandstone reservoirs in the deep subsurface along the Texas Gulf Coast, their potential for production of geopressured geothermal energy: University of Texas, Austin, Texas, Bureau of Economic Geology, Contract Report no. DE-A505-76ET28461 for the U.S. Department of Energy, 219 p.

Blount, C. W., Price, L. C., Wenger, L. M., and Tarullo, M. (1979), Methane solubility in aqueous NaCl solutions at elevated temperatures and pressures: Idaho State University and U.S. Geological Survey, Contract Report no. ET-78-5-07-1716 for the U.S. Department of Energy, 38 p.

Bruce, C. H. (1973), Pressured shale and related sediment deformation: mechanism for development of regional contemporaneous faults: Am. Assoc. Petroleum Geologists Bull., v. 57, p. 878-886.

Dorfman, M. H. (1978), Evaluation of natural gas from geopressured zones: Special Issue Am. Gas Assoc. Gas Supply Review, v. 7, p. 1-4.

Gregory, A. R., Dodge, M. M., and Posey, J. S. (1980), Progress report on evaluation of entrained methane in deep reservoirs, Texas Gulf Coast: Proc. Fourth U.S. Gulf Coast Geopressured-Geothermal Energy Conference, University of Texas, Austin, Texas (in press).

Loucks, R. G., Dodge, M. M., and Galloway, W. E., 1979, Sandstone consolidation analysis to delineate areas of high quality reservoirs suitable for production of geopressured geothermal energy: University of Texas, Austin, Texas, Bureau of Economic Geology, Contract Report no. EG-77-05-5554 to the U.S. Department of Energy, 98 p.

Wallace, R. H., Jr., Kraemer, T. F., Taylor, R. E., and Wesselman, J. B., 1979, Assessment of geopressured geothermal resources in the northern Gulf of Mexico Basin, in Muffler, L. J. P. (ed.), Assessment of geothermal resources of the United States - 1978: U.S. Geological Survey Circ. 790, p. 132-155.

REVIEW OF WORLD RESOURCES OF UNCONVENTIONAL GAS

Vello A. Kuuskraa and Richard F. Meyers
Lewin and Associates, Inc., Washington, D.C., USA

INTRODUCTION

As the world reserves of liquid hydrocarbons peak and begin to decline, an increasingly important energy supply role will need to be assumed by natural gas. The current world natural gas reserves are large, estimated at 2,600 trillion cubic feet (Tcf) as of 1980, as shown on Exhibit 1. However, as the use of gas grows, additional supplies will be needed.

One means for obtaining additional natural gas supplies, particularly in countries with otherwise limited indigenous energy sources, is to develop the unconventional gas sources that are often overlooked in the search for conventional oil and gas.

This paper examines the background, geology, and historical uses of five of these unconventional gas deposits, and speculates on their potential overall distribution, size, and recoverability. The five unconventional gas sources examined are:

- Tight gas sands
- Gas from fractured shales
- Methane from coal seams
- Methane in geopressured aquifers, and
- Gas hydrates

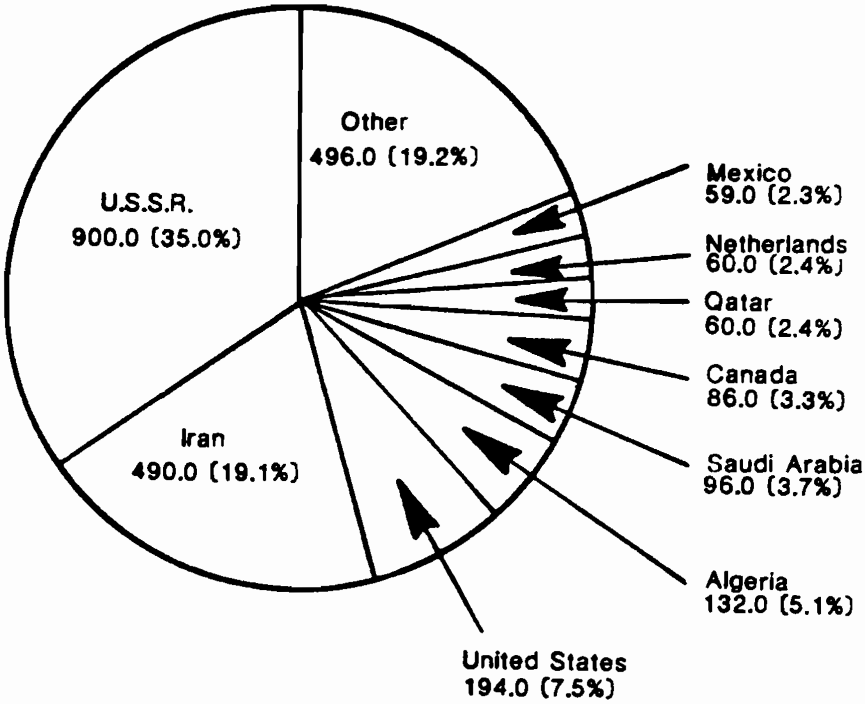
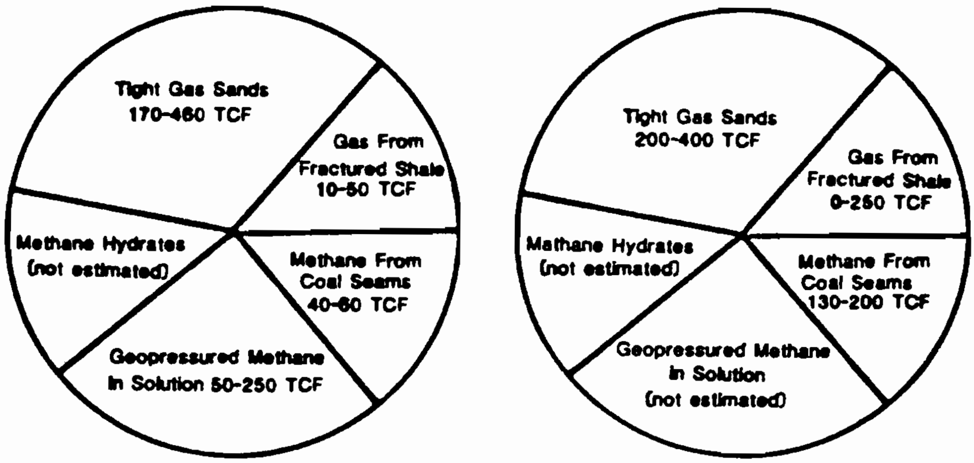


Exhibit 1. Estimated international conventional natural gas proved reserves, 31 December 1979. (Natural gas world total: 2573 trillion cubic feet.)

The critical issue for these resources is not their size - as a focus on the unarguable massive size of the in-place resource is neither relevant nor productive. The principal issues are: how much of this resource can be recovered, with what investment in new recovery technology, and at what economic costs? For example, under natural conditions, only 2 to 3 percent of the large methane resource in geopressured aquifers will flow to the surface; and, unless a natural fracture system exists in the deposit, the gas in fractured shales cannot be considered a physically or economically viable natural gas resource.

The potential amount of technically recoverable gas from worldwide unconventional resources is estimated at 270 Tcf to 820 Tcf in the identified deposits, and an additional 330 Tcf to 850 Tcf in gas deposits speculated to exist by extrapolation from identified areas, as shown below and on Exhibit 2.



(a) Technically recoverable gas from identified deposits total: 270-820 TCF.

(b) Technically recoverable gas from speculative deposits total: 330-850 TCF.

Exhibit 2. Estimated international unconventional natural gas resources.

	TECHNICALLY RECOVERABLE	
	Identified Deposits (Tcf)	Speculative Deposits (Tcf)
TIGHT GAS SAND	170-460	200-400
GAS FROM FRACTURED SHALES	10-50	0-250
METHANE FROM COAL SEAMS	40-60	130-200
GEOPRESSURED METHANE IN SOLUTION	50-250	Not estimated
GAS HYDRATES	-	Not estimated
TOTAL	270-820	330-850

These numbers will surely change since only a fraction of the worldwide unconventional gas resources have been identified or studied to date and the technology for recovering this gas is still emerging. While 270 Tcf of unconventional gas is recoverable with current technology, major advances in technology will be required to extract the upper end of the range of 820 Tcf. The target is large and well worth serious research and inquiry.

The remainder of the paper examines in more detail each of the five unconventional gas resources.

I. TIGHT GAS SANDS

INTRODUCTION

Large quantities of natural gas exist in tight (low permeability) formations in which the gas flow is too low to support economic recovery under conventional technology. Wells drilled into such tight gas formations are generally considered dry holes. In light of an increasing demand for natural gas, higher gas prices, and the advent of new recovery technologies, the tight gas sands may become an economically attractive and substantial energy source.

DEFINITION AND CHARACTERIZATION OF TIGHT GAS SANDS

While tightness, or low permeability, is a basic property of these formations, the term "tight gas sands" encompasses a wide range of sub-marginal natural gas deposits that are characterized by:

- -- Low in-situ gas permeabilities of 0.001 millidarcy (1 microdarcy) to 0.1 md (100 microdarcies).
- -- Low porosities of 7% to 12% and low gas saturations of 50% or less.
- -- A series of thin and discontinuous (lenticular) sand bodies, occasionally over- or underlain by more uniform, blanket deposits.
- -- Low Pressure, shallow gas deposits, where a combination of low pressure (e.g., 500 to 600 psi) and moderately low permeability (e.g., 0.01 md to 1.0 md) lead to low rates of natural (unstimulated) production.

At the present time, there has been no thorough examination of what set of depositional variables and minerology causes a formation to become "tight". The major determinants appear to be:

-- The depth of the deposit, where the higher overburden pressures have led to formation compaction. The relationship of depth to formation permeability and porosity is shown on Exhibits 3A and 3B.

-- The minerology of the deposition, where a combination of clay and fine sediment have formed a dense, non-porous deposition.

HISTORY OF TIGHT GAS PRODUCTION

The only documented production of tight and shallow gas is from the United States and Canada. However, there is strong evidence that tight and shallow gas exists in the Soviet Union. The vast Siberian gas field at Tyumen is shallow and low pressured, although little data is available as to the permeability of this formation. In addition, the Orenburg gas field appears to have streaks of tight gas, with permeabilities less than 1 md, based on general discussions with local Soviet geologists and an examination of cross-sections of this gas field.

1. The U.S. Tight Gas Resources

• Nature of the Resource. A massive belt of tight and shallow gas deposits stretches from the Southwest, through New Mexico, and north through the Rocky Mountain states (See Exhibit 4). The U.S. has 18 deep tight gas basins in this belt that covers an area of 25,000 square miles. These reservoirs are characterized by low permeability, thick pay, and a mode of deposition that ranges from lenticular channel conglomerates to blanket marine beaches. All were formed during the Cretaceous Age (primarily Upper Cretaceous). In addition, the U.S. has a large land area of approximately 120,000 square miles underlain by a shallow gas deposit in the Williston Basin and the Northern Great Plains, of Montana and the Dakotas.

• Production and Reserves. About 0.8 Tcf of gas per year, or about 4% of total U.S. gas production, is provided by tight gas. Most of the development to date has been concentrated in four basins - the

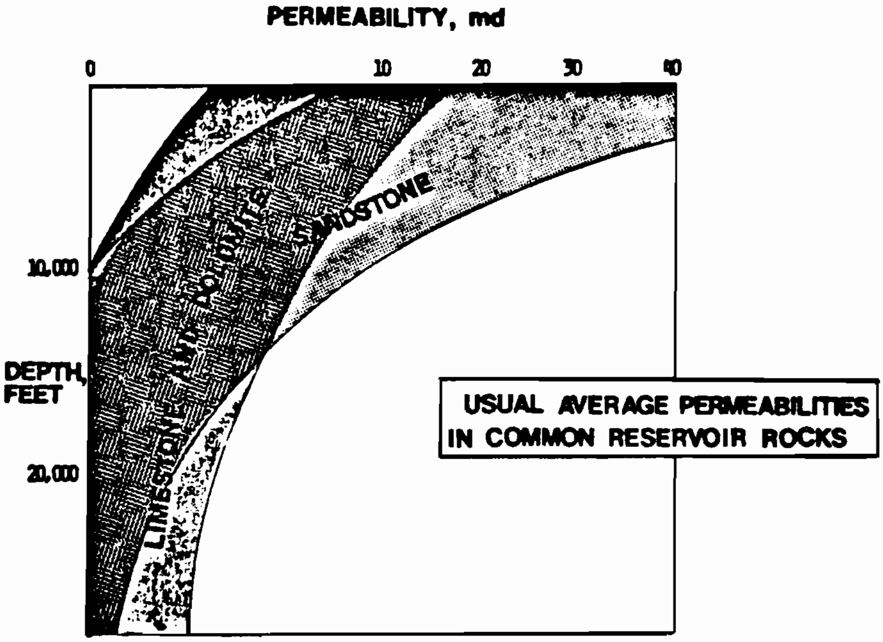


Exhibit 3. (a) Relationship of permeability to depth in common reservoir rocks.

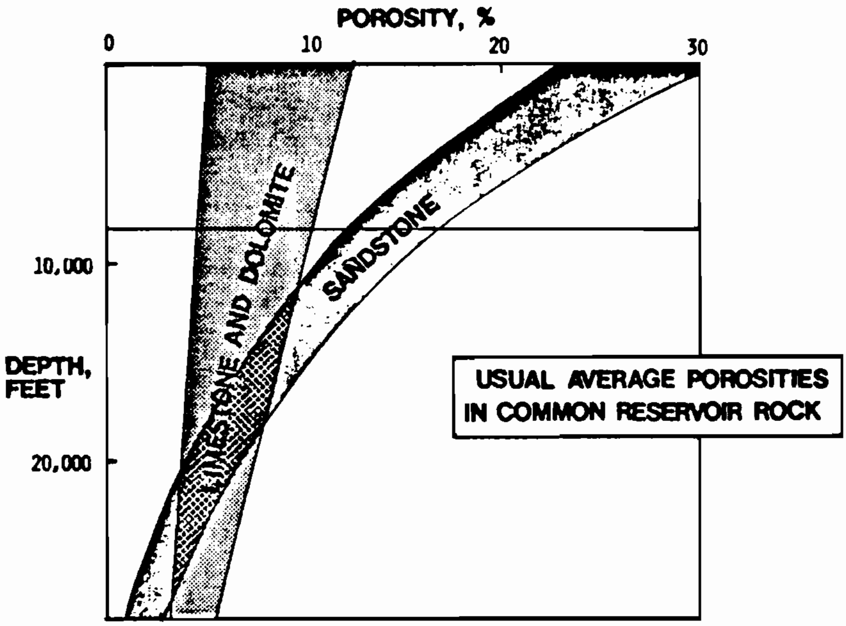


Exhibit 3. (b) Relationship of porosity to depth in common reservoir rocks.

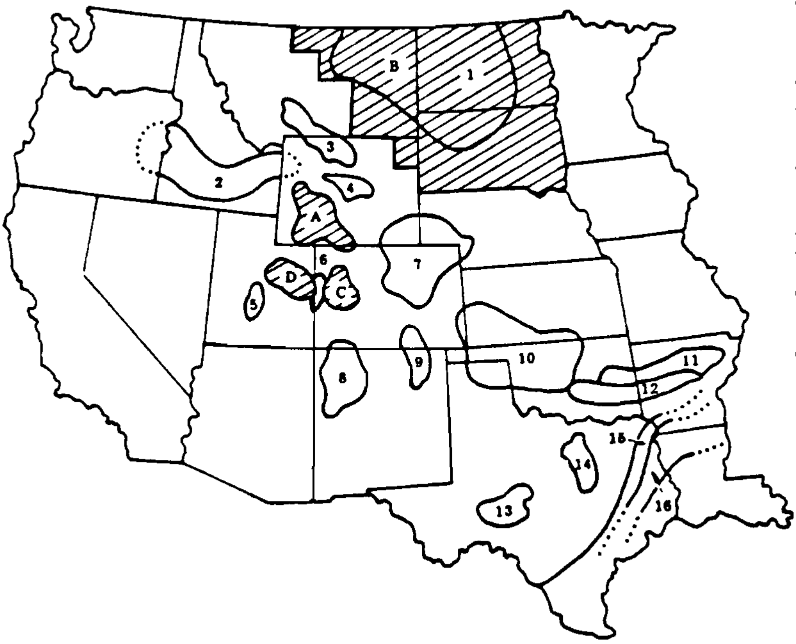


Exhibit 4. Western North American sedimentary basins, gas fields, and tight gas sand areas.

Cotton Valley Trend (0.2 Tcf), the Denver Basin (0.1 Tcf), the San Juan Basin (0.2 Tcf), and the Sonora Basin (0.1 Tcf). These basins have broad, continuous blanket reservoirs (or large sand lenses) that favor hydraulic stimulation. Little development is yet underway in the other tight, lenticular or shallow gas basins. Estimated proved reserves of tight gas, at the end of 1977 was 15 Tcf.

• Estimates of Future Potential. Four major studies of tight gas have been completed to date, as shown in Exhibit 5A.

The Federal Power Commission (FPC) Task Force examined three basins (Greater Green River, Piceance, and Uinta) and added two others, the San Juan and Northern Great Plains, in their updated study. The Lewin study analyzed thirteen basins, but excluded areas regarded as too speculative to support detailed engineering estimates. The report by the DOE Tight Sands Working Group includes estimates for the speculative areas excluded by the Lewin study. Currently, the National Petroleum Council is conducting a study of the

Exhibit 5A

Estimates of Tight Gas Resources

Source	Gas In-Place (Tcf)	Technically Recoverable (Tcf)
• FPC Task Force, National Gas Survey (1973)	240-600	100-300
• Update to FPC Study (1976)	790	-
• Lewin and Associates (1978)	424	108-202
• DOE Tight Sands Working Group (1978)	700-1110	

Exhibit 5B

In-Place and Technically Recoverable Gas - Tight Gas Basins

TARGET/BASIN	Estimated Gas In-Place (Tcf)	Estimated Technically Recoverable* (Tcf)
WESTERN TIGHT		
Green River	90	
Piceance	36	
Uinta	50	
SUBTOTAL	176	11-66
SHALLOW GAS		
Northern Great Plains	53	
Williston	21	
SUBTOTAL	74	22-35
OTHER TIGHT, LENTICULAR		
Big Horn	24	
Douglas Creek	3	
Sonora	24	
SUBTOTAL	51	15-24
TIGHT, BLANKET GAS		
Cotton Valley (Sweet)	67	
Denver	19	
Ouachita	5	
San Juan	15	
Wind River	3	
SUBTOTAL	109	51-67
OTHER LOW-PERMEABILITY		
Cotton Valley (Sour)	14	9-10
TOTAL	424	108-202

* The numbers reflect a range of performance in the technology used for recovering the gas.

potential of the tight gas sands at the request of the Secretary of Energy. The details of the Lewin estimate of the gas in-place and technically recoverable gas are provided on Exhibit 5B. The range in the technically recoverable gas, 108 to 202 Tcf, reflects two views on the efficiency of future gas recovery technology.

2. Canadian Tight Gas Resources

Two major tight gas deposits are located in Canada - the shallow, moderately tight gas in the Medicine Hat area and the very tight gas of the Deep Basin.

- Medicine Hat. The Medicine Hat gas field, with approximately 5 Tcf of marketable reserves, is currently Canada's largest natural gas deposit. Although discovered just after the turn of the century, lack of gas markets and technology constrained the development of this shallow, low pressure gas until recently. Current gas production is 0.3 Tcf per year. Geologically, the Medicine Hat area is similar to the Northern Great Plains of the U.S., as the geologic depositions in the two areas are similar, as shown on Exhibit 6A.

- Deep Basin. A much larger potential for tight gas production in Canada is from a region in western Alberta and eastern British Columbia called the Deep Basin. This area of approximately 20,000 square miles is considered to be underlain by a thick sequence of Cretaceous age gas-saturated sands. While development of the Canadian deep, tight gas deposits has been recent, 400 wells have been or are scheduled to be drilled. Estimated production in 1979 was less than 0.1 Tcf, and proved reserves were 2 to 3 Tcf.

The tight gas resources of Canada may constitute a major gas resource, with 100 to 600 Tcf of gas in-place estimated for the Deep Basin and 20 to 30 Tcf in-place for the shallow gas, as shown on Exhibit 6B. Of this, 60 to 260 Tcf may be recoverable, depending on future gas recovery technology.

Exhibit 6A

Selected Cretaceous Age Rocks of North America

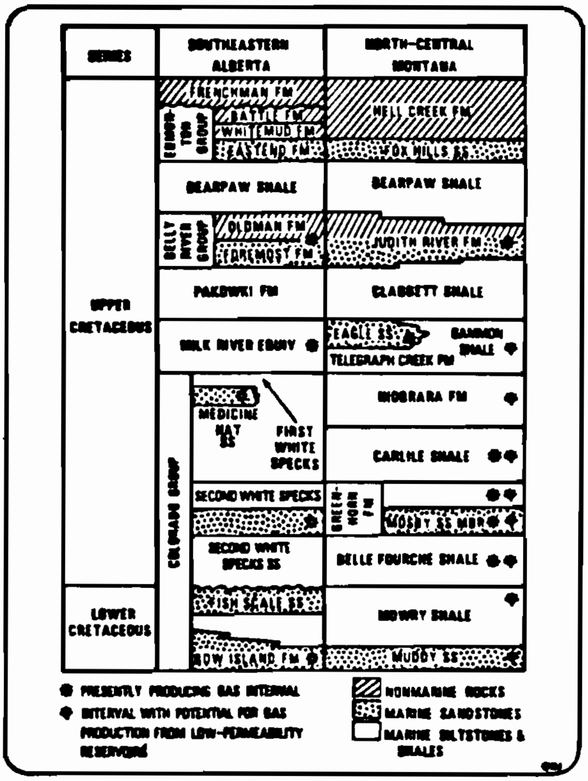


Exhibit 6B

Estimates of Canadian Tight Gas Resources

Source	Gas in-Place (Tcf)	Technically Recoverable (Tcf)
Deep Basin		
Canadian Hunter (1978)	600	50-250
Amoco (1978)	80	50
Lewin (1980)	300	50-150
Shallow Gas		
Dome Petroleum (1979)	23	12-14
Pan Canada Petr. (1978)	Not estimated	10
Total	100-600	60-260

ESSENTIAL RECOVERY TECHNOLOGY

In the late 1960's and early 1970's, three attempts were made to stimulate tight formations by the use of nuclear explosives. Disappointing results and environmental controversy ended these tests.

In 1972, it was proposed that massive hydraulic fracturing (MHF) - the use of fluids and proppants at volumes an order of magnitude larger than conventional - could stimulate production from these tight formations. A joint government-industry test of MHF was conducted in the Piceance Basin in 1974, demonstrating that improvements could be achieved in the rate of gas flow. Other applications of MHF followed in certain of the geologically favorable "sweet spots" of these tight gas basins.

The purpose of MHF is to create and prop an artificial fracture far into the reservoir to enlarge the effective wellbore and provide a high permeability conduit for gas flow to the well. In massive applications, up to two million pounds of sand may be injected along with several hundred thousand gallons of gelled water, foams, and polymer-emulsions. The required fracture length to achieve productive flow from these tight gas sands is shown as a function of the in-situ gas permeability on Exhibit 7.

A pictorial of the essential technological advances required to commercialize tight gas deposits is shown on Exhibit 8.

SPECULATION ON WORLD TIGHT GAS RESOURCES

The U.S. and Canadian tight gas sands are located in basins classified by Klemme as cratonic intracontinental - composite basins (Type 2 Basins) typical of settings where structural traps and many stratigraphic variations lead to the presence of numerous small fields. One-quarter of the world hydrocarbon reserves have been found in the intracontinental basins. As shown on Exhibit 9, these basins are extensive in the West Siberian part of the U.S.S.R., in North

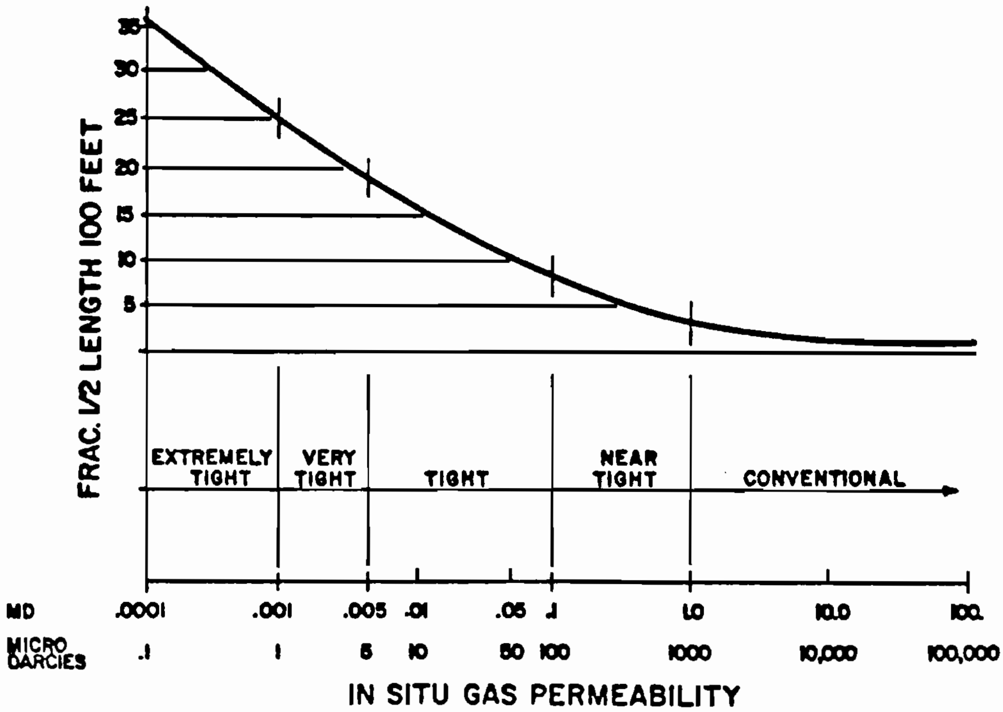


Exhibit 7. Approximate fracture 1/2 length desired for different permeabilities.

Africa, and along the Andean trend of South America. Smaller accumulations appear in northern Europe, Australia, and in the highly structured areas along the northern border of China. Thus, the tight gas sands of North America may be indicative of more widespread geological deposition of this type of resource.

The total worldwide tight gas resource may be over 3,000 trillion cubic feet, as tabulated below:

Geographic Location	Gas In-Place (Tcf)	Technically Recoverable (Tcf)
Identified Areas		
• United States (Lewin/DOE)	400-1,000	110-200
• Canada (Lewin/Canadian Hunter)	300-600	60-260
Sub-total	700-1,600	170-460

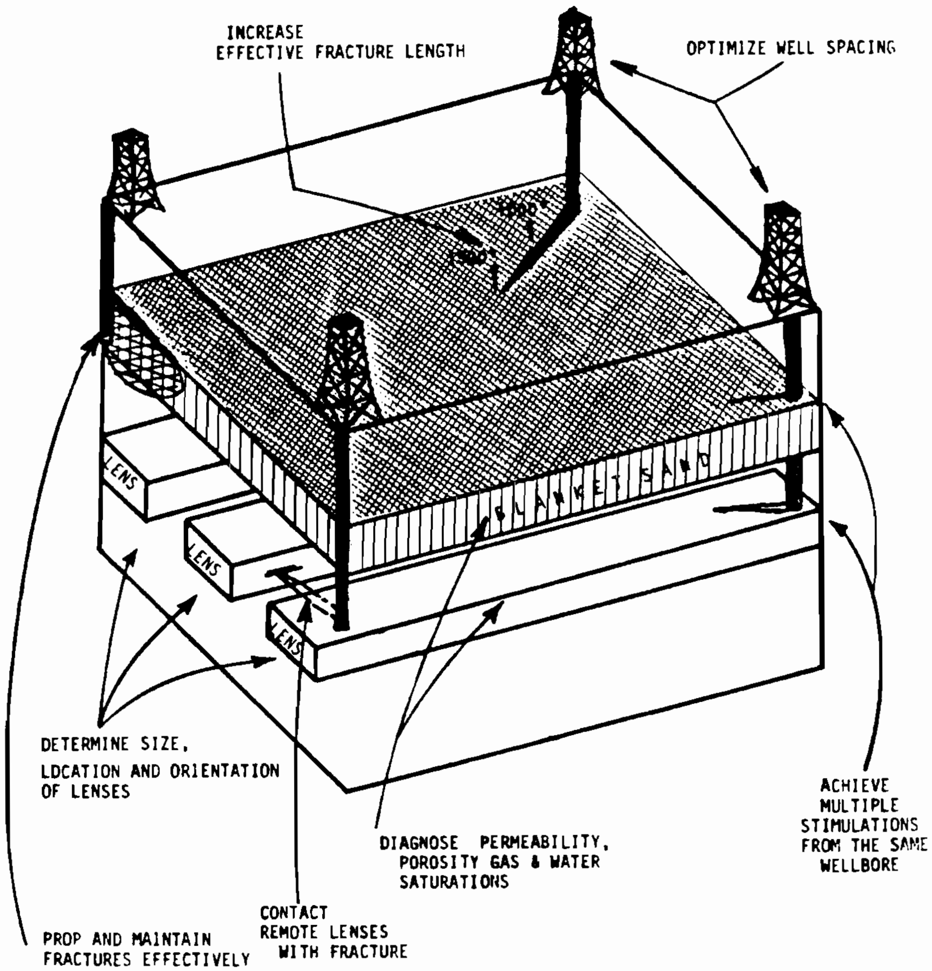


Exhibit 8. Technological advances needed to fully exploit western tight gas sands.

Speculative Areas

• Other (Meyer, 1979)	2,000	200-400

The two identified areas (in the U.S. and Canada), have from 700 to 1,600 Tcf of gas in-place, of which 170 to 460 Tcf appear to be technically recoverable. The speculative portion of the resource, as estimated for the remainder of the world by Meyer (1979), is 2,000 Tcf of gas in-place. Using the ratios for technically recoverable tight gas from the identified locations, an additional 200 to 400 Tcf may be technically recoverable.

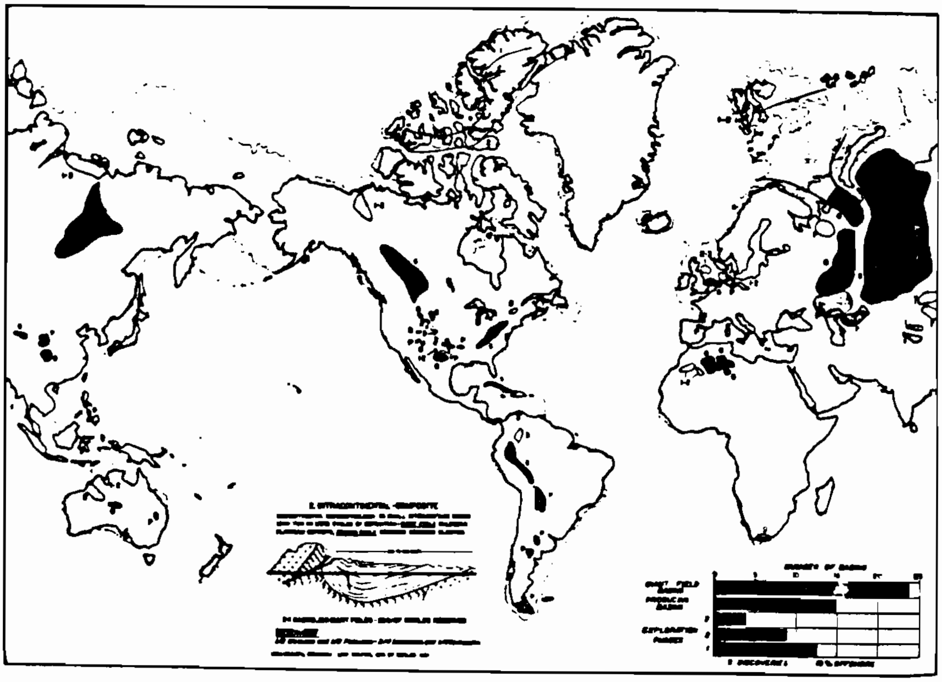


Exhibit 9. Map of cratonic intracontinental-composite basins. (Source: Klemme, 1975).

II. GAS FROM FRACTURED SHALES

INTRODUCTION

Major land areas across the world are underlain by organic shales. These shales contain an immature organic substance, called kerogen, that emits methane when brought to the surface and crushed. It has been speculated that these shales are potentially a massive natural gas resource. In addition to the kerogen, methane is adsorbed in the shales and free gas may exist in areas where sufficient tectonic activity formed a reservoir composed of natural fractures.

Whether the gas resource is the gas adsorbed in the shale matrix, the free gas in the fracture system, or both, the shales can be an important source of natural gas, particularly for local regions. The major issues are, just how much of this resource can be recovered economically and whether any technology can be developed to release the significant amounts of adsorbed gas in the shales.

ORIGIN AND CHARACTERIZATION OF DEVONIAN SHALES OF THE UNITED STATES

• Origin of Devonian Shales. In the United States, the gas bearing Devonian shales underly approximately 200,000 square miles of the Appalachian Basin and major portions of the Michigan and Illinois Basins. The shale in this area is gray, brown, or black - depending on the richness of the organic matter imbedded in the shales.

Shale is a fine textured laminated rock formed by the diagenesis of muds, clays, and mineral particles. The brown shale is the younger shale and has more hydrocarbons in the organic material; in black shale the organic material is closer to elemental carbon.

The Devonian shales were deposited over 350 million years ago in a shallow sea that covered much of the eastern United States. Organic matter settled into this sea, forming sediments, and eventually black, rich organic mud. In the centers of the basins, the sediments were several hundred to over a thousand feet thick and with compaction were altered to shale.

The presence of almost pure methane in the shale fracture system suggests that these reservoirs have been subjected to a low temperature pyrolysis that selectively converted the kerogen to methane and a bitumen. Such decomposition products have been observed in laboratory low temperature conversion of the oil shales of the Green River formation in the Piceance and adjoining basins.

• Distinctive Geological Features. Shales are usually the trapping sediments for oil and gas occurring in porous sandstones and carbonates. However, the Devonian age shales serve as both the reservoir and the seal for the oil and gas deposits.

The surface structure of the Appalchian Basin is characterized by a vast area of broad surface folds, many of which formed during the late Paleozoic time, although additional basement deformation occurred in early Cambrian time. The most notable region that correlates with major tectonic activity is around the Big Sandy Field, accounting for over 80 per cent of all gas production from Devonian shales.

In summary, the special features of the Devonian shales in Kentucky, West Virginia, and Ohio (as shown on Exhibit 10) are a temperature history that led to the decomposition of kerogen into gas and a tectonic history that fractured the brown shales sufficiently to create fracture porosity, and thus a reservoir for the accumulation of gas.

- Estimate of Production and Future Potential. To date, approximately 4 Tcf of natural gas has been proven in the Devonian shales of the U.S. and annual production is approximately 0.1 Tcf.

Because of different interpretations as to the dominant source of the produced gas, widely varying resource estimates have been made for the future potential of U.S. Devonian shales (see Exhibit 11).

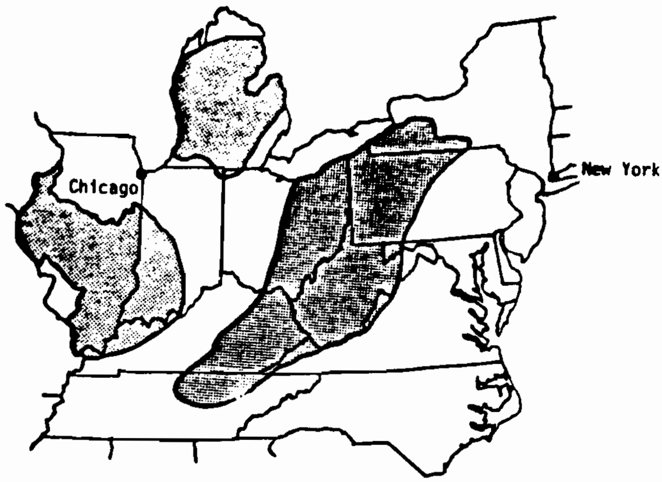


Exhibit 10. Geographic location of Eastern gas shales. Source: Wise, R.L. (ed.) (1979) Semi-annual Report for the Unconventional Gas Recovery Program, DOE/METC, METC/SP-79/8.

Exhibit 11 Estimates of the Devonian Shale Resource

	Gas In-Place (Tcf) Adsorbed Gas	Free Gas	Total	Technically Recoverable (Tcf)
DOE/Morgantown Energy Technology Center (1979)	--	--	780	--
Lewin and Associates (1978) -- Appalachian Basin Only	--	80	--	46
Office of Technology Assessment (1977)	(Not estimated)			25-35
National Petroleum Council (1979)				
-- Appalachian Basin			220-1860	50
-- Other Basins			160	-

Sources:
1. Semi-Annual Report for the Unconventional Gas Recovery Program, METC/SP-79/8, August 1979.
2. Enhanced Recovery of Unconventional Gas, Lewin and Associates, Inc., October 1978.
3. Gas Potential from the Devonian Shales of the Appalachian Basin, Office of Technology Assessment, November 1977.
4. Devonian Shale Task Group, National Petroleum Council Committee on Unconventional Gas Sources, NPC, Sept. 1979.

REVIEW OF GAS PRODUCTION MECHANISMS

Two basic hypotheses have been formulated to identify the dominant mechanisms of gas production from the Devonian shales:

-- The bulk of the recoverable gas desorbs from the matrix, with the fractures providing the flow paths to the well; and

-- The bulk of the recoverable gas is free gas in the natural fractures of the shale, with the contribution of desorption from the matrix being unimportant during the life of the well.

This issue of whether the free gas in the fracture system or gas desorption from the matrix is responsible for the produced gas has been debated for many years.

While the amount of actual gas production may be approximately the same under either mechanism, from a resource and scientific viewpoint it is essential to resolve whether any matrix gas can be recovered. If the matrix gas can be recovered the resource is massive, several thousand Tcf of gas in-place. If this matrix gas cannot be recovered the resource is an order of magnitude smaller.

Whichever the mechanisms, an intense system of natural fractures is required to provide the permeability and the reservoir for the free gas.

SPECULATION ON WORLD RESOURCES OF GAS FROM FRACTURED SHALES

The principal oil-shale deposits of the world are shown on Exhibit 12, with a tabulation of the deposits shown on Exhibit 13. Beyond the 4,000 quads of in-place resources in the high organic content shales an additional 20,000 quads is contained in leaner grade (5% to 10% organic content) deposits. However, a much smaller amount would be expected to be free gas in the fracture system.

The amount of potential gas resource depends on whether any other world basins have experienced the special geological occurrences of:

-- A temperature history that has led to the decomposition of the kerogen to gas, and

-- A tectonic history that has created sufficient natural fracture porosity to provide a reservoir and permeability for the gas

U.S.-based studies of the highly naturally fractured Appalachian Basin, indicate that 10 to 50 Tcf of gas may be technically recoverable from the 2,300 to 3,900 Tcf of in-place resource.

Extrapolating from the U.S. findings, it is possible that the technically recoverable world natural gas resource in fractured shales could range up to 250 Tcf, as shown below. However, this is a highly speculative estimate awaiting further geological appraisal and study.

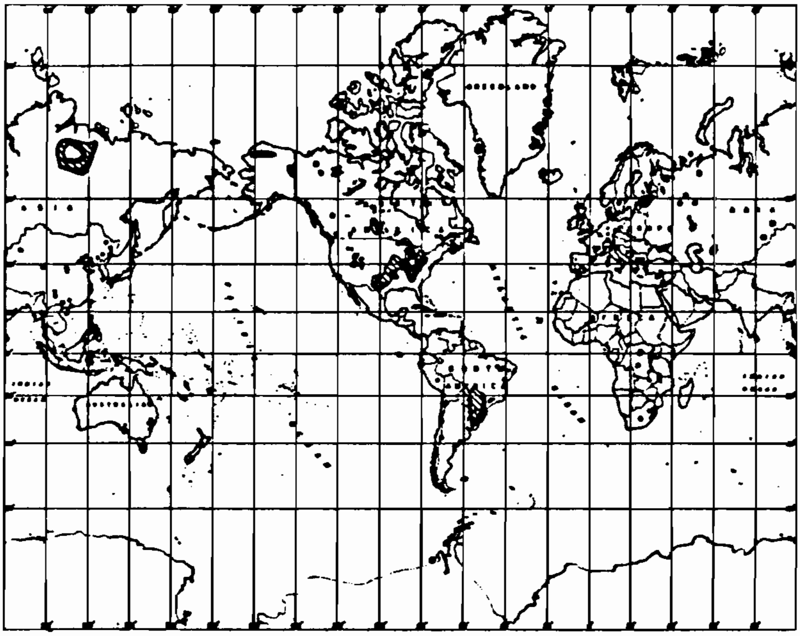


Exhibit 12. Principal reported oil-shale deposits of the world.

	In-Place (Tcf)	Technically Recoverable (Tcf)
Identified Areas		
• Appalachian Basin		
--Free gas only	80	10-50
--Adsorbed and free gas	400-2000	10-50
• Other Basins	1,900	-
• Subtotal	2300-3900	10-50
Speculative Areas (Ex. U.S.)		
• Rich Shales	3,700	0-50
• Lean Shales	18,400	0-200
• Subtotal	22,100	0-250

III. METHANE FROM COAL SEAMS

INTRODUCTION

Since the inception of underground coal mining, the release of methane from coal beds, or "coal gas", has posed a hazard to mining

Exhibit 13 Order of Magnitude of Total Stored Energy in Organic-Rich Shale of the United States and Principal Land Areas of the World

(Estimates and totals rounded)

Continent or country	Approximate area underlain by sedimentary rocks (millions of square miles)	Shale containing 10–65 percent organic matter: Shale in deposits (trillions of short tons)	Shale containing 10–65 percent organic matter: Minimum organic content (trillions of short tons)	Shale containing 10–65 percent organic matter: Combustion energy content Q (10^{15} Btu)	Shale containing 5–10 percent organic matter: Shale in deposits (trillions of short tons)	Shale containing 5–10 percent organic matter: Minimum organic content (trillions of short tons)	Shale containing 5–10 percent organic matter: Combustion energy content Q (10^{15} Btu)
United States	1.6	120	12	210	1,200	60	1,600
Africa	5.0	370	37	980	2,700	190	4,900
Asia	7.0	600	60	1,300	5,000	250	6,500
Australia	1.2	80	9	230	800	45	1,200
Europe	1.6	120	12	210	1,200	60	1,600
North America (including United States)	2.0	220	22	570	2,200	110	2,900
South America	2.4	180	16	470	1,800	90	2,300
World total	20	1,500	150	4,000±	15,000	750	30,000±

operations. Recovering this new vented methane could provide an important augmentation to local supplies of natural gas. Furthermore, under certain favorable conditions it may be feasible to drill into the deeply buried coal seams to recover the trapped methane.

ORIGIN AND COMPOSITION OF COAL BED METHANE

The methane associated with coal seams was formed as part of the subsequent thermal maturation process of the coal. Here, the accumulation of gas may be found in three sources:

- -- Adsorbed on the internal surfaces of the micro-porous structure of the coal.
- -- In the natural fracture system of the coal bed.
- -- In adjacent strata or sand lenses that serve as a reservoir for the desorbed gas.

Methane (CH_4) is the primary component of coal gas, comprising over 90% of the volume. Carbon-dioxide, nitrogen, and other hydrocarbon gases account for the remainder of the volume. In general, the heat content of the gas is 900 to 1,000 Btu per cubic foot.

The evidence for adsorbed methane being the primary source of the gas is compelling. For example, assuming an average of 300 standard cubic feet of gas per ton of coal (12 scf/cf), a seam pressure of 500 psi and a temperature of $80^{o}F$, a voidage or porosity of 42% would be required. Because coal is generally not very porous, the habitat of the methane in coal seams must be gas adsorbed to coal faces or held as adsorbed "liquid" in the coal itself.

HISTORY OF COAL GAS PRODUCTION AND USE

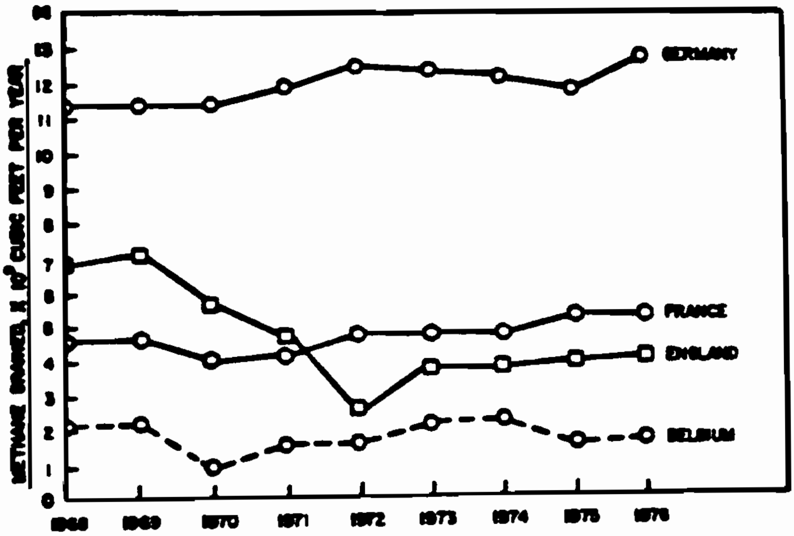
The most thorough documentation of the capture and use of coal bed methane, in association with mining, is from the European countries. Much of the recent U.S. effort is being focused on attempts to recover methane from deep, unmineable coal seams and methane pre-drainage ahead of mining.

1. European Experience

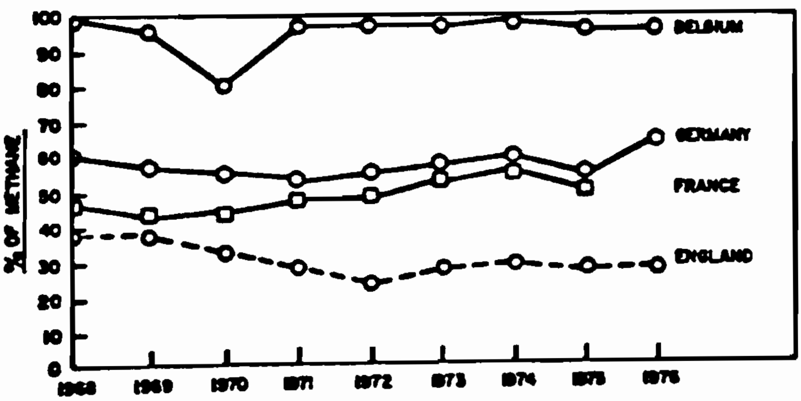
Four European countries, Germany, France, England, and Belgium have been actively capturing and using coal bed methane for the past decade. The amounts of methane drained and the percentages of drained methane recovered for use from these four countries in 1976 were as follows:

	Captured Methane Bcf/yr.	% of Captured Methane Used
Germany	13	65
France	5	50
England	4	25
Belgium	2	95

Additional detail, by year, is provided on Exhibit 14.



TOTAL METHANE DRAINED IN GIVEN YEAR
(AFTER V. TRESKOW, 1977)



PERCENTAGE OF DRAINED METHANE RECOVERED FOR USE
(AFTER V. TRESKOW, 1977)

Exhibit 14. Methane recovery from coal seams in Europe. Source: von Schonfeldt, H. (1979) Methane revocery from deep mines, Proceedings of the 2nd Annual Methane Recovery from Coalbeds Symposium, US DOE, METC/SP-79/8.

• Capture of Methane from German Coal Mines. Germany has an active program of methane drainage from mines, as evidenced by the following 1976 data:

-- 3,653 wells were drilled, averaging 160 feet (48 meters) each.

-- 43% of all methane emissions were captured, amounting to 13 Bcf, of which two thirds were used.

-- Old, unused mines were drained of their methane and accounted for one third of the total methane captured.

• Utilization of Methane Gas from Coal Beds in the United Kingdom. Methane drainage for gas use is practiced in 60 mines in the United Kingdom. The lower quality (30% to 40% concentration) captured methane is used on site for generating steam and power. Higher quality methane (of 60% and higher) is transported to various energy-intensive industrial sites and involves the use of stand-by fuels (such as LPG) that can be mixed to ensure an adequate heating value.

2. United States Experience

While the U.S. has historically viewed coalbed methane as an undesirable by-product of coal mining, numerous efforts are now underway for capturing coalbed methane.

Approximately 80 Bcf per year (217 mmcf per day) of methane is emitted from U.S. coal mines, with 20 coal mines accounting for nearly one-half of total emissions, as shown on Exhibit 15. However, very little of this methane is recovered for use.

The longest sustained production of gas from a 1,000 foot deep coalbed has been in the Big Run Field in Wetzel County, West Virginia, where 23 vertical, unstimulated wells have provided nearly 2 Bcf in the past 30 years.

The largest degasification test conducted by the United States Bureau of Mines involved the drilling of two large (18 foot) diameter shafts into the 600 foot deep Pittsburgh coal seam. A series of horizontal drain holes averaging 600 feet in length were drilled into the coal seam from the bottom of the shaft. These two efforts recovered 0.9 and 0.8 Bcf respectively, in a period of four to five years.

Exhibit 15. Methane emissions from US coal mines (20 largest methane emission coal mines). Source: Irani, M.C., Janasky, J.H., Jeran, P.W., and Hassett, G.L. (1977) Methane Emissions from Coal Mines in 1975, A Survey. US Bureau of Mines, IC 8133.

	Mine Name	Location	Coalbed	Methane Emission, MMcfd
1.	Loveridge	Marion Co., West Virginia	Pittsburgh	11.6
2.	Humphrey No. 7	Monongalia Co., West Virginia	Pittsburgh	9.3
3.	Federal No. 2	Monongalia Co., West Virginia	Pittsburgh	8.1
4.	Blacksville No. 2	Monongalia Co., West Virginia	Pittsburgh	6.3
5.	Osage No. 3	Monongalia Co., West Virginia	Pittsburgh	5.9
6.	Beatrice	Buchanan County, Virginia	Pocahontas #3	5.6
7.	Concord No. 1	Jefferson County, Alabama	Pratt	5.1
8.	Olga	McDowell Co., West Virginia	Pocahontas #4	5.0
9.	Robena	Green County, Pennsylvania	Pittsburgh	4.9
10.	Blacksville No. 1	Monongalia Co., West Virginia	Pittsburgh	4.5
11.	Bethlehem No. 32	Cambria County, Pennsylvania	Kittanning	4.5
12.	Robinson Run No. 95	Harrison Co., West Virginia	Pittsburgh	4.3
13.	Arkwright	Monongalia Co., West Virginia	Pittsburgh	4.0
14.	Federal No. 1	Marion Co., West Virginia	Pittsburgh	4.0
15.	Virginia Pocahontas No. 1	Buchanan County, Virginia	Pocahontas #3	3.9
16.	Cambria Slope No. 33	Cambria County, Pennsylvania	Kittanning	3.9
17.	Virginia Pocahontas No. 2	Buchanan County, Virginia	Pocahontas #3	3.4
18.	Virginia Pocahontas No. 3	Buchanan County, Virginia	Pocahontas #3	3.3
19.	L. S. Wood	Pitkin County, Colorado	Basin B	3.3
20.	Gateway	Green County, Pennsylvania	Pittsburgh	2.7
			TOTAL - Top 20	103.6
			TOTAL - Top 20% of U.S.	47.8

REVIEW OF RECOVERY TECHNOLOGY

1. Recovery Mechanism

The release of methane from the coal seam and its subsequent flow to the wellbore is controlled by three primary variables:

-- The diffusion coefficient of the coal seam.

-- The intensity of the natural fracture system and its effect on surface and slab thickness.

-- The permeability of the fracture system.

The first mechanism, the diffusion of the methane out from the coal matrix is governed by the equation:

$$\frac{dq}{dt} = D \times A \times \frac{dc}{dx}$$

Where dq/dt is the flow rate of gas from the matrix, D is the diffusion constant, A is the surface area from which gas is diffusing, and dc/dx is the concentration gradient of methane from the surface into the coal matrix.

Assuming a uniform fracture system and a rectangular geologic configuration for the coal seams, the equation can be solved using the basic derivation of heat flow by Carslaw and Jaeger. Here, the recovery efficiency R_e (at 0 fracture pressure), for desorption can be expressed as a function of D (the diffusion coefficient), t (time) and L (one-half of the slab thickness), as follows:

$$R_{(e)} = f\ (Dt/L^2)$$

The solution to this equation is shown graphically in Exhibit 16.

The second mechanism governs the flow of the desorbed methane from the coal face toward a pressure sink (the wellbore). A radial-flow, unsteady state equation assuming constant terminal pressure, can be used to estimate recovery.

An example of using these equations to calculate expected recovery from two Pennsylvania (U.S.) coal seams is shown on Exhibit 17.

2. Applicable Recovery and Conversion Technology

Capturing the methane now produced in association with mining requires a highly permeable interconnection through the plane of the major fracture system (the face cleats) and involves:

-- Drilling vertical wells from the surface and using hydraulic fracturing to intersect the natural face and butt cleat fracture system.

-- Drilling deviated wells from the surface into the coal seam to intersect the planes of the face cleats.

-- Drilling horizontal holes perpendicular to the face cleats, either from the mine face or from large vertical bore holes.

All three methods have produced gas, but none, as yet have demonstrated economic feasibility as a stand-alone project. Economically, all depend on the benefits of more rapid and efficient mining and improved mine safety for their justificaton. Exhibit 18 is a pictorial of several of the recovery techniques being tested.

SPECULATION ON WORLD RESOURCES OF METHANE IN COAL SEAMS

The amount of gas in-place per ton is governed by two variables - the rank of coal and its depth of burial (as a proxy for pressure).

1. Gas Content of Coals

• Effect of Rank. The methane content of Bituminous coals is a function of moisture content as defined by the equation (Ettinger):

$$Vd/Vw = C_o m + 1$$

where: Vd & Vw are the volumes (cm^3/gm) of methane adsorbed in dry and moist coal, respectively, C_o is an empirically determined constant, 0.31 for Bituminous coals, and m is the moisture content of the coal (wt. pct.). Thus, for Bituminous coals, the equation becomes:

$$\frac{V_w}{V_d} = \frac{1}{1 + 0.31m}$$

Using the following mean moisture contents for various ranks of coals,

Rank	Mean Moisture Content (wt. pct.)
Bituminous	4.53
Sub-Bituminous	16.01
Lignite	37.64

the resulting gas content of wet Bituminous, Sub-Bituminous, and Lignite then become 41.6%, 16.8%, and 7.9% of that for dry Bituminous coals, respectively. For example, if the gas content of wet Bituminous coals is 250 cubic feet per ton (cf/t), then Sub-Bituminous and Lignite would contain 100 and 50 cf/t, respectively.

• Effect of Pressure. The second variable affecting the amount of gas in-place is depth and thus the pressure of the coal seam. A laboratory isotherm for the Blue Creek Coal, (Alabama) (see Exhibit 19), shows that the gas content is an exponentially decreasing function of pressure. For example, a gas content of 250 cf/t at 250 psi would equate to 150 cf/t at 250 psi.

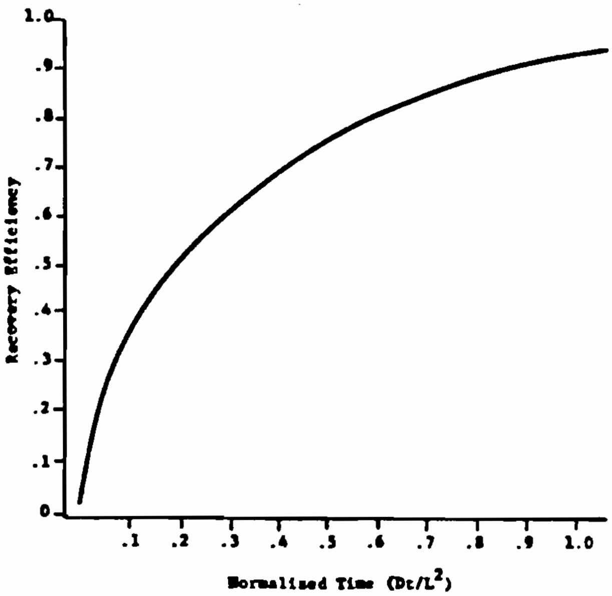


Exhibit 16. Diffusion recovery efficiency. Source: Derived from Carslaw and Jaeger (1959) Conduction of Heat in Solids, 2nd edn (Oxford UP) Ch.III, pp.92-102.

Exhibit 17

Ten-Year Recovery of Methane from Pittsburgh and Pocahontas Coal Using Vertical Wells

Pittsburgh

	Gas Recovered, Percent of Total					
	r_{we} = 1 foot			r_{we} = 10 feet		
Permeability, mds.	80 acres	160 acres	640 acres	80 acres	160 acres	640 acres
1	9	4	1	13	7	2
2	16	9	2	22	13	3
5	27	20	5	35	27	8

	Gas Recovered, MMSCF					
	r_{we} = 1 foot			r_{we} = 10 feet		
Permeability, mds.	80 acres	160 acres	640 acres	80 acres	160 acres	640 acres
1	14	14	14	23	25	28
2	28	28	28	39	46	43
5	48	71	71	62	96	114

Pocahontas

	Gas Recovered, Percent of Total					
	r_{we} = 1 foot			r_{we} = 10 feet		
Permeability, mds.	50 acres	160 acres	640 acres	50 acres	160 acres	640 acres
1	31	17	4	42	23	6
2	49	33	8	59	40	12
5	66	53	18	74	64	25

	Gas Recovered, MMSCF					
	r_{we} = 1 foot			r_{we} = 10 feet		
Permeability, mds.	50 acres	160 acres	640 acres	50 acres	160 acres	640 acres
1	85	93	93	113	126	128
2	134	180	180	162	216	265
5	180	289	395	202	351	543

Pittsburgh Coal:

Gas Content	180 SCF/Ton
Pressure	176 psia
Depth	607 feet
Thickness	8 feet
Temperature	80°F
Pseudo-porosity	34%
Gas Content in 80 acres	178 MMSCF
Producing Well Pressure	50 psig
Compressibility	7.83×10^{-3} psi^{-1}

Pocahontas Coal:

Gas Content	435 SCF/Ton
Pressure	588 psia
Depth	1600 feet
Thickness	54 inches
Temperature	100°F
Pseudo-porosity	38%
Gas Content in 50 Acres	273 MMSCF
Producing Well Pressure	50 psig
Compressibility	2.95×10^{-3} psi^{-1}

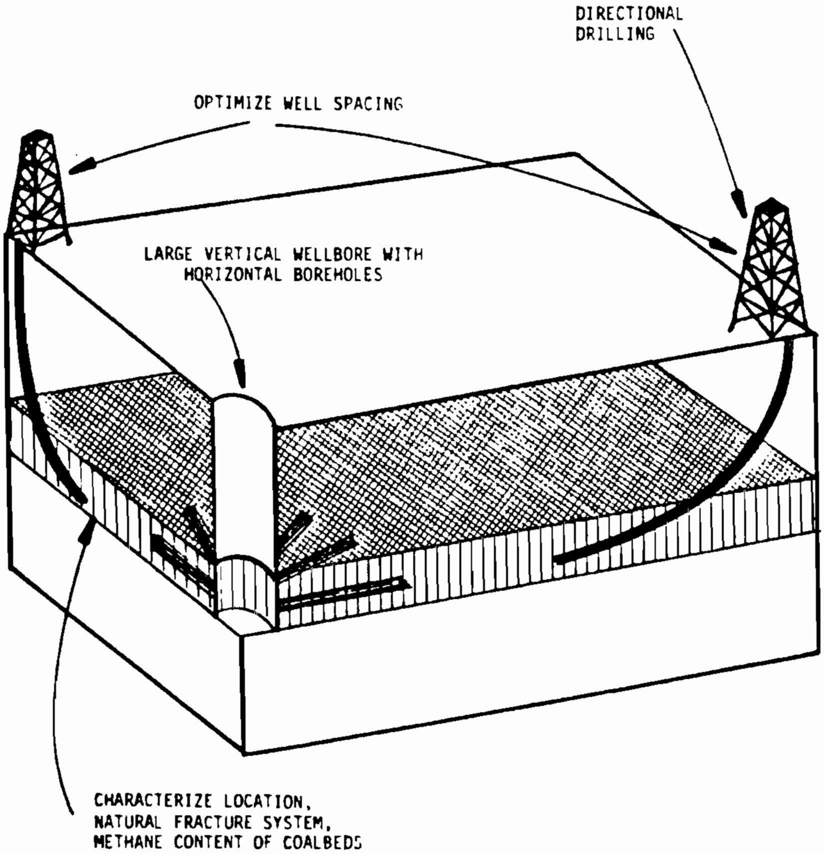


Exhibit 18. Technology advances needed to fully exploit coal seams.

2. Calculation of Total Methane in Coal Seams -- U.S.

Using data on the rank, depth, and gas content of coal, it is possible to develop an estimate of the amount of methane in-place in U.S. coal seams. The following data and assumptions are used:

- Total U.S. coal resources, identified and hypothetical-4,000 billion tons

- Distribution of U.S. coals by rank
  - -- Anthracite and Bituminous - 44%
  - -- Sub-Bituminous - 28%
  - -- Lignite - 28%

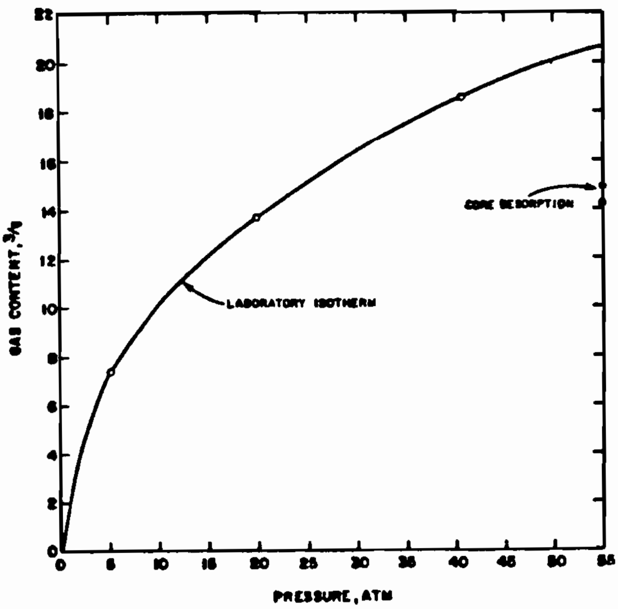


Exhibit 19. Gas content of Blue Creek coal Tuscaloosa Co., Alabama.

- Distribution of U.S. coals by depth (overburden)
  - -- Less than 1,000 feet - 48%
  - -- Between 1,000 and 3,000 feet - 42%
  - -- Greater than 3,000 feet - 10%

- Gas content of U.S. coals by rank and depth, in cubic feet of gas per ton of coal:

	Depth		
Rank	Under 1,000' cf/t	1,000-3,000' cf/t	Over 3,000' cf/t
Anthracite and Bituminous	150	250	500
Sub-Bituminous	60	100	200
Lignite	30	50	100

Using this data, it is possible to develop a distribution of the total U.S. coal resource by rank and depth, and from that to estimate that 550 Tcf is the gas in-place in coal seams, as follows (in Tcf):

Rank	Depth (Overburden) less than 1,000' (Tcf)	1,000-3,000' (Tcf)	more than 3,000' (Tcf)	Totals by Rank (Tcf)
Anthracite and Bituminous	127	184	88	399
Sub-Bituminous	32	47	22	101
Lignite	16	23	11	50
Totals by Depth	175	254	121	550

The calculation for one of the cells is as follows for Anthracite and Bituminous at less than 1,000':

(0.44 x 0.48) x 4,000 Billion tons x 150 cf/t = 127 Tcf

Using the same ratios for the rest of the world as for the U.S., 2,280 Tcf of gas in-place is estimated for the total world coal resources, as shown below by continent:

Continent	Estimated Total Resource (10^9 tons)	Estimated Gas In-Place (Tcf)
Asia	11,000	1,510
United States	4,000	550
Other North America	400	60
Europe	800	110
Africa	250	30
Oceania and South & Central America	170	20
TOTAL	16,620	2,280

(Source: Averitt, U.S.G.S. Bulletin 1412, January 1, 1974.)

However, a considerable portion of this gas in-place is in coal seams that are too thin or too lean (because of rank or depth) to be a viable target. In general, the favorable resource is in the anthracite and bituminous coals, in the thick beds and at sufficient depths.

Using the U.S. distribution of coal thickness of:

-- Thick (bituminous coal more than 42 inches thick; sub-bituminous more than 10 feet thick) - 33%

-- Intermediate (bituminous coal 28 to 42 inches thick; sub-bituminous 5 and 10 feet thick) - 25%

-- Thin (bituminous coal 14 to 28 inches thick; sub-bituminous less than 5 feet) - 42%

The favorable U.S. target becomes 135 Tcf, as shown below:

	300-1,000' & Thick (Tcf)	1,000-3,000' & Thick (Tcf)	over 3,000' & Thick (Tcf)	Total By Rank (Tcf)
Anthracite and Bituminous	22 Tcf	61 Tcf	29 Tcf	112
Sub-Bituminous	-	16	7	23
Total by Depth/Tcf	22	77	36	135

The technical recovery efficiency, using the desorption equations discussed above, will range from 30% to 45% of the in-place resource. Thus, the amount of technically recoverable methane from U.S. coal seams will range from 40 to 60 Tcf.

As a point of comparison, two separate studies of potentially recoverable methane, by the NPC and by Lewin, determined that 30 to 40 Tcf of the in-place resource in the United States could be recovered at prices of $5 to $9 per Mcf.

Using the U.S. data on coals as a sample, the total worldwide favorable target is approximately 570 Tcf, of which 170 to 260 Tcf may be technically recoverable, as shown below by continent:

Continent	Favorable Target (Tcf)	Potentially Recoverable (30-45%) (Tcf)
Asia	380	110-170
United States	135	40-60
Other North America	15	5-10
Europe	30	10-15
Africa	10	5
Oceania and South & Central America	-	-
	570	170-260

Categorizing the methane in U.S. coal deposits as identified and the remainder of the world as speculative, the distribution of the total methane in coal seams resource is as follows:

	Gas In-Place (Tcf)	Favorable Target (Tcf)	Technically Recoverable (Tcf)
• Identified	550	135	40-60
• Speculative	1,730	435	130-200

IV. GEOPRESSURED AQUIFERS

INTRODUCTION

The potentially massive supplies of clean, natural gas held in solution in geopressured aquifers has been posed by many as the answer to the energy crisis. Projections of 1,000 years of natural gas supplies in popular publications and papers such as Fortune and The Wall Street Journal further spark the public interest.

Clearly, a large resource exists in-place, estimated from 1,000 to 50,000 Tcf in the U.S. alone. However, only a fraction of this large resource is recoverable, although no one yet knows with confidence just how much and at what costs.

DEFINITION OF THE GEOPRESSURED RESOURCE

The term "geopressured aquifers" characterizes subsurface reservoirs containing methane dissolved in water under high pressures and temperatures. Such water-bearing aquifers have been identified onshore and offshore in the Gulf Coast areas of the United States and along the Caspian Sea in the Soviet Union. While these geopressured zones and aquifers have been known to exist for some time, they have generally been considered a hazard in drilling for oil and gas. The recognition that important quantities of methane are dissolved in the waters of the geopressured zones has led to the current efforts to better characterize and understand this unconventional gas resource.

The initial interest in geopressured aquifers was for thermal energy resources. Thus the target consisted of large, high temperature reservoirs that met the following criteria:

-- Reservoir volume of 3 cubic miles

-- Permeability of at least 20 millidarcies

-- Fluid temperature of 300°F or greater

With the recognition that methane was the dominant energy resource in the waters, the ideal reservoir criteria began to emphasize methane content and fluid production capacity, such as:

-- Methane saturation of at least 30 cubic feet per barrel of water

-- An initial bottom hole pressure greater than 12,000 psi

-- Reservoir volume of 1 cubic mile or greater

-- Thick highly permeable reservoirs

Beyond the geopressured resource, large quantities of natural gas may exist in shallower hydropressured aquifers. Should the brines in these aquifers be developed for other purposes, important quantities of by-product methane could be recovered.

HISTORY OF RECOVERY OF GAS DISSOLVED IN WATER

1. U.S. Experience

The U.S. experience in recovering gas dissolved in water includes a highly focused program designed to recover methane from geopressured brines, and smaller industrial efforts for recovering by-product methane from water produced for other purposes, such as iodine extraction or waterflooding.

• Geopressured Aquifers. To date, four major tests have been conducted for solution gas in geopressured aquifers - three of these were in wells drilled (unsuccessfully) for oil and gas (the Edna Delcambre No. 1, the Fairfax Foster Sutter No. 2, and the Beulah Simon No. 2 in Louisiana); and one as part of a highly instrumented test into a major geopressured fairway (the Pleasant Bayou No. 2 in Texas). The preliminary results showed much lower gas in solution because of the higher than expected (100,000 to 200,000 ppm) dissolved solids. These results are shown below:

Opportunity Tests	Gas Contact (cf/bbl)	Permeability (md)
Edna Delcambre No. 1	20-25	364
Fairfax Foster Sutter No. 2	21	14
Beulah Simon No. 2	24	12
Designed Tests		
Pleasant Bayou No. 2	22	150

• By-Product Solution Gas. Two projects in the U.S. capture solution methane as a by-product of other activities:

-- As part of its iodine extraction project in Oklahoma, Amoco collects approximately 10 to 12 cubic feet of solution methane per barrel of water for input into a local pipeline.

-- As part of its offshore waterflood project in the Gulf Coast, Exxon collects approximately 10 cubic feet of solution methane per barrel of water.

2. Central African Experience

In Lake Kivu, situated in Central Africa, dissolved methane is held in the bottom layers of the lake by a stable density stratification. Recent geological studies place the amount of methane dissolved in these waters at approximately 2 Tcf (63×10^9 m^3). However, the concentration of methane per barrel of water is low, 2 cf/bbl (0.3 to 0.4 m^3 water), because of the shallow 1,500 feet (480 meter) depth of the lake.

3. Japanese Experience

In the Southern Kanto gas region (Chiba Prefecture), near Tokyo, and in the Niigata area of northwestern Honshu, natural gas is produced from waters in shallow, 3,000 to 4,000 foot wells as part of the production of iodine. The estimated gas in-place in these two areas is 0.3 tcf and 0.4 tcf respectively.

The amount of gas dissolved in the water is low, on the order of 4 to 6 cubic feet per barrel, as is the annual (1977) production rate of 6 Bcf. The Geological Survey of Japan estimated that from 21 to 31 Tcf of this low saturation gas may exist in-place in Japan.

THE TECHNOLOGY OF GEOPRESSURED ENERGY PRODUCTION

1. Total Energy Systems

Three forms of energy are contained in geopressured aquifers:

-- Methane - the dissolved methane could be extracted from geopressured waters and transported by pipelines.

-- Thermal - the high temperature of the waters could be used directly, or for the production of electricity.

-- Hydraulic - the high pressure of the waters could be used to drive turbines or positive displacement machines.

Conceptually, in a total energy recovery system, the geopressured water would be used to drive a turbine and deliver hydraulic energy to produce electric power. The water would flow through separators, where the methane would be extracted. Finally, thermal energy could be recovered by using a binary-cycle plant to generate electric power. The hydraulic and electric power could be used on-site to furnish energy for the pumps and other equipment.

2. Methane

Estimates for the recovery of methane can be calculated using basic engineering flow equations or a two-phased reservoir simulator, once the methane content of the brine and the basic reservoir properties that govern the flow of the geopressured fluids are established. The equations used for calculating brine flow are shown on Exhibit 20.

The estimated reservoir properties of prospective fairways in Texas and Louisiana are shown on Exhibits 21-A and 21-B, respectively. The critical parameters that have the most influence on the recovery of methane and the total amount of dissolved methane are discussed below:

- Methane Content. The volume of methane dissolved in a barrel of water is a function of the pressure, temperature, and salinity of the geopressured brines. Assuming full saturation, Exhibit 22 shows the relationship of temperature and pressure and the effect of salinity on solubility of methane in water.

- Reservoir Volume. Economic operations will require producing large volume reservoirs. The pay thickness of the producing formation influences the initial production rate and the slope of the production-decline curve. The areal extent influences how much water and methane will ultimately be recovered from the prospect. Exhibit 23 shows the effects of pay thickness and reservoir area on gas recovery.

FLOW EQUATIONS

$$p_w = p_i - \frac{70.6\, q\mu}{kh} \ln(A/r_w^2) + \ln(2.2458/F_A)$$

$$+ 2s - \frac{5.6146qt}{\phi chA} \quad \text{(1)}$$

$$J/\phi c = 21.3k(t/A + 18.97\, P_{DO}/\eta) \quad \text{(2)}$$

$$I = \frac{0.00708k}{\mu \ln\left[\frac{25250A}{r_{we}^2}\right]} \quad \text{(3)}$$

$$p_{wh} = p_w - \rho gh - fhq^2 \quad \text{(4)}$$

Nomenclature

A = drainage area per well, acres
c = compressibility, psi^{-1}
F_A = shape factor for drainage area
I = Injectivity, B/D/psi/ft
k = permeability, md
p_i = initial reservoir pressure, psi
p_w = flowing well pressure, psi
P_{DO} = a dimensionless function
$= \frac{1}{2}\left[\ln\left(\frac{A}{r_w^2}\right) + \ln\left(\frac{2.246}{F_A} + 2s\right)\right]$
q = B/D
r_w = well radius, ft
$r_{we} = r_w F_A e^{-s/F_A}$
s = skin factor
t = time, years
η = hydraulic diffusivity, sq ft/D
ϕ = porosity, fraction
μ = viscosity, cp

Exhibit 20. Equations used for calculating flow rates.

A

Prospect Area	Temperature (°F)	Pressure (psi)	Dissolved Solids (ppm)	Permeability (md)	Net Pay (ft)	Area of Individual Sand Body (mi²)	Areal Extent (mi²)	Average SCF/bbl	In-Place Dissolved Gas (Tcf)
1. Hidalgo	300+	11,000	20,000*	1.5	300	50	800	45	3.3
2. Armstrong	250	10,000	20,000*	20	300	50	50	35	2.6
3. Corpus Christi	300	10,000	20,000*	5	350	4	200	40	0.3
4. Matagorda	350	12,000	20,000*	35	30	4	100	55	-
5. Brazoria									
- Austin Bayou	325	12,000	60,000	50	300	60	60	45	4.1
- Pleasant Bayou	300	11,000	60,000	30	300	60	140	40	3.0

*Estimated for Fairways 1-4

SOURCE: Adapted from Bebout, et al.

B

Prospect Area	Temperature (°F)	Pressure (psi)	Dissolved Solids (ppm)	Permeability (md)	Bulk Volume, ft.^{3} x 10^9	Avg. SCF/bbl	In-Place Dissolved Gas (Tcf)
1. Atchafalaya Bay	220	11,400	107,000	95	1,051	23	1.1
2. Johnson's Bayou	300	9,800	95,000	200	1,600	20	1.8
3. Lafourche Crossing	240	12,900	45,000	70	332	35	0.5
4. Rockefeller Refuge	290	14,200	86,000	80	946	46	1.8
5. S.E. Pecan Island	270	13,000	70,000	98	1,342	42	2.3

Source: Evaluation of Five Potential Geopressure-Geothermal Test Sites in Southern Louisiana, Louisiana State University, 1979.

Exhibit 21. Reservoir properties of geopressured-geothermal prospect areas: A, in Texas; B, in Louisiana.

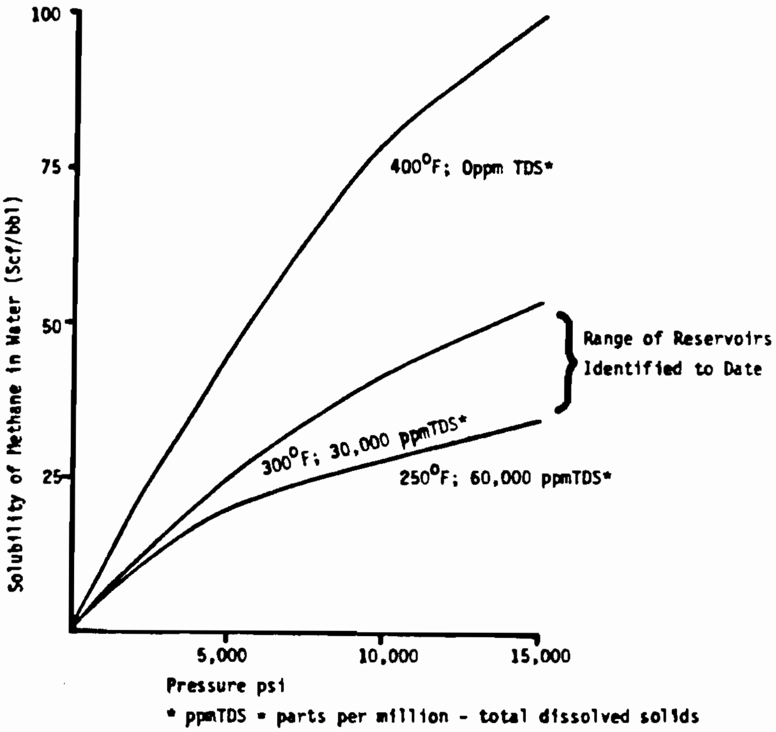


Exhibit 22. Gas solubility in brine.

• Permeability and Compressibility. The permeability and compressibility of a selected geopressured-geothermal interval determines the deliverability of the system, and thus its economic feasibility.

An example analysis shows that the ideal combination of high compressibility (16×10^{-6} psi^{-1}) and high permeability (60 mds) leads to recovery of 8.6 Bcf of methane and 3.4% of the resource in-place over 30 years. Low permeability (5 mds) and a low compressibility (6×10^{-6} psi^{-1}) reduces the recovery to 3.4 Bcf of methane, equal to a 1.4% recovery of the in-place resource.

SPECULATION OF WORLD RESOURCES OF GAS IN SOLUTION

While the global occurrence of abnormal formation pressures (geopressures) is considerable, as shown on Exhibit 24, it is

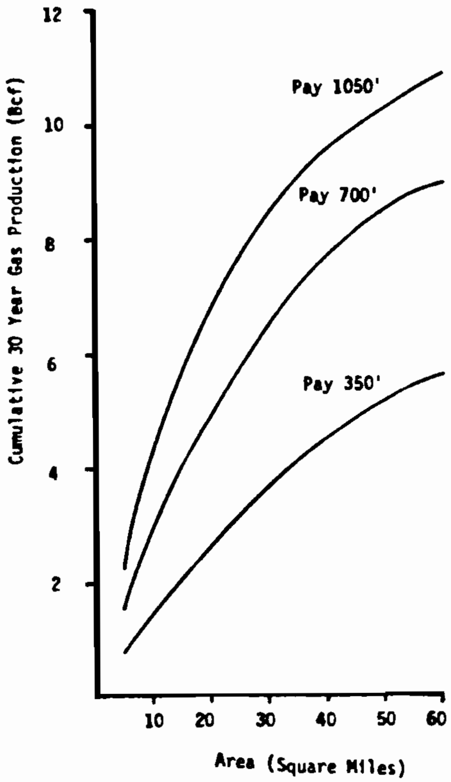


Exhibit 23. Effect of pay thickness and reservoir area on gas recovery from a geopressured aquifer.

virtually impossible to estimate the world resources of geopressured methane and other forms of gas in solution.

1. U.S. Geopressured Resources. The geopressured methane in solution is generally estimated to range from 1,000 to 6,000 Tcf in place (a larger estimate by Jones, 1977 places the total at 50,000 Tcf). The technically recoverable U.S. geopressured resource estimates range from 50 to 250 Tcf, as shown on Exhibit 25.

2. World Geopressured Resources. While initial data on major geographical over-pressured areas is available, and is briefly reviewed below, further inquiry is required to establish whether geopressured aquifers of sufficient size may be found in these areas:

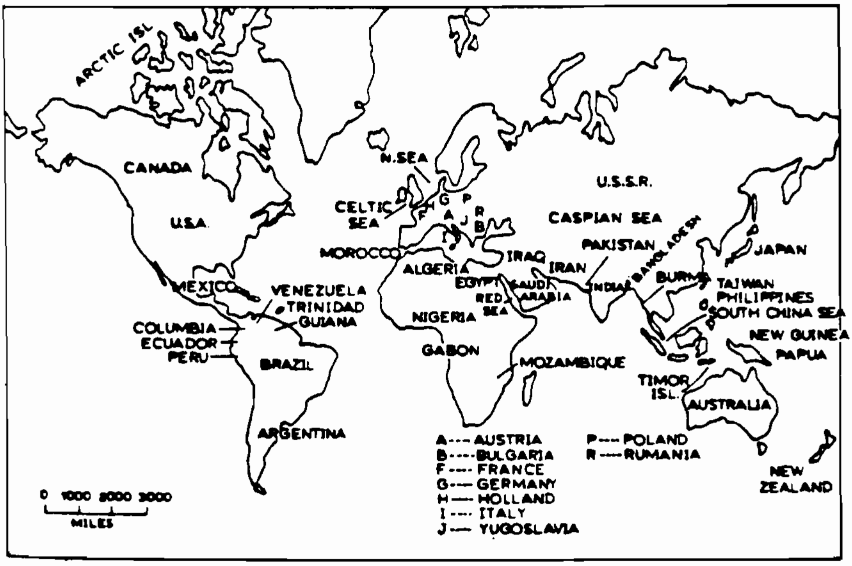


Exhibit 24. Worldwide occurrence of abnormal formation pressures.

• Europe. The over-pressured areas of Europe include the Aquitaine Basin, France (0.78 psi/ft.) and the forelands of the Alps; including the Rolanse Basin in Germany, the Vienna Basin in Austria, the Po basin in Italy, and the Transylvania Basin in Hungary (0.86 psi/ft.).

• Soviet Union. The major land area, labeled the Russian Platform (in the Saratov and Kuybyshev regions), appears to be at hydrostatic pressure, except for the Mesozoic Age formations. Abnormal pressures approaching lithostatic levels (1 psi/ft.) were measured in Dageston and Checkeno (Ingushian regions, A.S.S.R.).

• Africa. Drilling operations in Nigeria and the Nile delta, Egypt, reportedly have found over-pressured areas similar to those in the Gulf Coast.

• Far East. Wells drilled near the north coast of Hawke Bay (New Zealand) have encountered pressures of 0.8 psi/ft. Additional potential appears to be in the South China Sea, near Taiwan and the Nagaoba Plain near Honshu, Japan.

Substantially more geological and reservoir engineering analysis is required before even an initial speculative appraisal can be made for the geopressured methane resources of the world.

Exhibit 25

Estimates of Natural Gas in Geopressured Aquifers
(Trillions of Cubic Feet)

		Total Resource In-Place			Technically Recoverable Resource ***		
Date	Source	Texas	La.	Total	Texas	La.	Total
1977	Jones			50,000			5,000
1977	Dorfman (UT)			5,700	82		257
1977	Hise (LSU)			3,000			150
1978	Lewin & Assoc.*	300	800	1,100	10	40	50
1978	Bernard				40	14	54
1979	USGS, #790						
	• Onshore**	1,800	1,300	3,100	72	25	97
	• Offshore			2,800			53

Sources: Jones, P.H. (1969), Hydrology of Miocene Deposits in the Northern Gulf of Mexico Basin. Louisiana Water Resources Research Institute, Bulletin GT-2, Baton Rouge, La.: Louisiana State University.

Dorman, M.H. and R.O. Kehle (1974), Potential Geothermal Resources of Texas. Bureau of Economic Geology Circular 74-4. Austin, Texas: The University of Texas at Austin.

Hise, B.R., 1976, Natural gas from geopressured zones, in Natural Gas from Unconventional Sources: The National Research Council, Board of Mineral Resources, Comm. on Natural Resources, National Academy of Sciences.

Lewin and Associates, Inc., Enhanced Recovery of Unconventional Gas, NTIS No. HCP/2705-02.

Bernard, W.J., "Reservoir Mechanics of Geopressured Aquifers," contained in Proceedings of First Geopressured Geothermal Energy Conference, University of Texas at Austin, June 2-4, 1975.

Assessment of Geothermal Resources of the United States--1978, USGS Circular 790.

* The Lewin estimate for Texas includes only the Frio formation below the 200°F isotherm (revised in 1979).

** USGS estimate for on-shore portion of resource is for sandstone only. The estimate of recoverable resource assumes sufficiently high wellhead pressure to limit subsidence to 1 meter.

*** Assumes no reinjection into the produced aquifer. Reinjection could increase the technically recoverable resource by five to six fold.

V. GAS HYDRATES

INTRODUCTION

Gas hydrates are solids which resemble ice (Katz, 1971), in that gas molecules are incorporated in the molecular structure of the water. The formation of gas hydrates is dependent on and sensitive to temperature, pressure, and salt content of the water. For example, at 30°F., methane in pure water forms hydrates at 350 psia, whereas at 30°F in water with 20 weight-percent NaCl, a pressure of 1000 psia is required.

Gas hydrates are well known to the natural gas industry because their formation can plug high pressure flow lines if the gas is not dry. Aside from such practical problems, gas hydrates are known to occur widely in the upper layers of sediment beneath the sea floor and in permafrost areas.

SEA FLOOR GAS HYDRATES

The phenomenon of gas hydrates appears to be almost universal below the sea floor outside the equatorial region, having been determined from deep sea cores and inferred in numerous studies based upon ocean seismic profiling (Tucholke, Bryan, and Ewing, 1977--in the western Atlantic; and Grantz, Boucher, and Whitney, 1976--in the Beaufort Sea). While it is very difficult to visualize and construct a means to exploit such deposits at this time, the resource appears to be so large as to justify extensive study. At the same time, Trofimuk, (1973) makes the very significant observation that, because hydrates render sediments impermeable to natural gas, the upper sedimentary layers of the ocean floors, with their gas hydrates, may form a cap rock beneath which oil and gas could be trapped.

PERMAFROST AREA GAS HYDRATES

The occurrence of natural gas hydrates in permafrost areas is well-documented (Mines Magazine, 1971; Trofimuk et al., 1977; Bily and Dick, 1974; Dobrynin et al., 1979; McIver, 1979), but the means of exploiting them are not clear. Trofimuk et al. (1977) have suggested a definite correlation between areas of continental glaciation and the presence of large natural gas accumulations. Bily and Dick (1974) describe the presence of gas hydrates in the permafrost of northern Canada, in particular drawing attention to the drilling problems the hydrates present when warmed by the drilling fluid. They point out the production problems that may be encountered in attempting to exploit the hydrate resource, specifically the heat requirement and consequent water release during decomposition. In the Soviet Union, the Messojakha field resources are being produced by the injection of methyl alcohol into the hydrate reservoir (Dobrynin et al., 1979). These authors suggest that injection of heat into the reservoir may be most useful where the gas hydrate deposits are underlain by high-temperature water reservoirs.

ESSENTIAL TECHNOLOGY

The dissociation of hydrates to gas and water can be represented by

$$n_H H_2O \cdot CH_4 \text{ (hydrate solid) -- n } H_2O \text{ (water) } + CH_4\text{(gas)}$$

where n_H has a value approaching 6 for hydrates of natural gas. The enthalpy change associated with the transition is about 63 kJ per mole of methane dissociated.

The energy for hydrate dissociation has to be supplied by an external source and at maximum theoretic efficiency representing about ten percent of the heating value of the gas produced. The exact ratio of the energy recovered to the energy input will depend on the composition of the gas recovered and on the efficiency of transferring the dissociation energy to the hydrate phase.

A recent paper by Holder, John, and Yen (SPE/DOE 8929) shows that with 60% energy efficiency and a 90% gas recovery efficiency, the majority of the gas hydrate formations could be produced at a positive net energy ratio.

SPECULATION OF WORLD GAS HYDRATE RESOURCE

Exhibit 26A shows the relationship between ice coverage by continental galciation of different ages and extent of zones of gas hydrate formation. Exhibit 26B relates the distribution of glaciation to present-day oil and gas accumulation. It has been estimated that such deposits occur over one-half the area of the U.S.S.R. and may represent presently uncounted reserves of as much as 350 Tcf (Mines Magazine, 1972).

Estimates of the total gas hydrate resource vary widely. Meyer (1979) uses a figure of 500 Tcf for permafrost areas. McIver (1979) quotes a figure of 535 Tcf for the Soviet Union and, on a volumetric basis, calculates 200 Tcf for the USA-Canada areas of permafrost. Dobrynin, et al. (1979) estimate 53 million tons of coal equivalent (about 1.2 million TCF of gas) on land and 11,300 billion tons of coal equivalent (about 270 million TCF of gas) on the sea floor as the world gas hydrate resource.

These estimates are tabulated below:

Geographic Area	Resource In-Place (Tcf)
• USA - Canada (McIver)	200
• USSR	
McIver	535
Dobrynin	
--land	1
--sea floor	270
• Total (Meyer)	500

Exhibit 26A

Hydrate Formation Zones and Ice Sheet Distribution on the Earth
(average thickness of HFZ on continents--700 m.; on ocean floor--300m)

	Continental Glaciers			Hydrate Formation Zones — Continents (Northern Hemisphere)		
	Area ($10^6 km^2$)	Area (%)	Volume ($10^6 km^3$)	Area ($10^6 km^3$)	Area (%)	Rock Volume in HFZ ($10^6 km^3$)
Permo-Carboniferous period	70	--	175	--	--	--
Quaternary (temperature minimum)	45	30	60	75	50	52
Recent	15	9	24	40	27	28

Exhibit 26B

Distribution of World Oil and Gas Resources Relative to Quaternary Glaciation
(from Trofimuk et al., 1977)

	Continental Glaciation	Hydrate Formation Zones	Percentage of Oil and Gas Associated with Glaciation — Oil	Gas
North America	38-46°N. Lat.	35°N. Lat.	95	40
West Europe	49°N. Lat.	50°N. Lat.	95	90
East Europe	--	47°N. Lat.	--	40
West Siberia	59°N. Lat.	56°N. Lat.	80	98
Total Northern Hemisphere	50°N. Lat.	45°N. Lat.	60*(8**)	60

* - excluding the U.S.S.R.
** - excluding the U.S.S.R. and Athabaska.

(Source: Trofimuk et al., 1977)

I. REFERENCES

Gidley, John R., Mutti, D. H., and Nierode, D.E., "Tight Gas Stimulation by Massive Hydraulic Fracturing - A Study of Well Performance," SPE Paper 6867, presented at the 52nd Annual Fall Meeting of the SPE on Denver, Colorado, Oct. 9-12, 1977.

Klemme, H. D., "Giant Fields Related to their Geologic Setting -- A Possible Guide to Exploration," Bulletin of Canadian Pet. Geol., Vol. 23, No. 1, March 1974, pp. 30-66.

Lewin and Associates, Inc., Enhanced Recovery of Unconventional Gas, Vols. 1-3, (HCP/T2705), Washington, D.C., October 1978.

Leutkehans, Gerald R., "Gas in Tight Sands," Chapter 12 in Gas From Unconventional Sources, National Academy of Sciences, Washington, D.C., 1976.

U.S. Department of Energy, Tight Sands Working Group, draft studies.

U.S. Department of Energy/Federal Energy Regulatory Commission, National Gas Survey - Unconventional Natural Gas Resources, Washington, D. C., June 1978.

U.S. Energy Research and Development Administration, Western Gas Sands Project Plan, Washington, D. C., August 1, 1977.

U.S. Federal Power Commission, National Gas Survey, Washington, D.C., 1973.

II. REFERENCES

American Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1978, API, Vol. 33, June 1979.

Carslaw, H.S., and Jaeger, J.C., Conduction of Heat in Solids, Oxford, 2nd Edition, 1959.

deWitt, W., Perry, W.J., and Wallace, L.G., "Oil and Gas Data from Devonian and Silurian Rocks in the Appalachian Basin," U.S. Geological Survey Map I-197B, Washington, D. C., 1975.

Holditch, S.A., Devonian Shale Production Analysis, Sovereign Engineering International, Inc., College Station Texas, January 1978.

Hunter, C. and D. Young, "Relationship of Natural Gas Occurrence and Production in Eastern Kentucky (Big Sandy Gas Fields) to Joints and Fractures in Devonian Bituminous Shale," Bulletin of American Association of Petroleum Geologists, Vol. 37, No. 2, February 1953.

Lewin and Associates, Inc., Enhanced Recovery of Unconventional Gas, Vols. 1-3, (HCP/T2705), October 1978.

National Petroleum Council Committee on Unconventional Gas Resources, Devonian Shale Task Group, Sept. 1979.

Office of Technology Assessment, Gas Potential from the Devonian Shales of the Appalachian Basin, Washington, D. C., Nov. 1977.

Smith, Eric C., "A Practical Approach to Evaluating Shale Hydrocarbon Potential", in Second Eastern Gas Shales Symposium, (DOE/METC/SP-78/6), v.II, Washington, D. C., pg. 73-88, October 1978.

Wise, Robert L., Ed. Semi-Annual Report for the Unconventional Gas Recovery Program, (DOE/METC/SP-79/8), Washington, D.C., August 1979.

III. REFERENCES

Averitt, P., "Coal Resources of the United States, January 1, 1974," U.S. Geological Survey Bulletin 1412, Washington, D. C., 1975.

Booz, Allen and Hamilton, ERDA's Underground Coal Gasification Program, Vol. III - Resources, May 1977.

Carslaw, H.S. and Jaeger, J.C., Conduction of Heat in Solids, Oxford, 2nd Edition, Chapter 3, 1959, pp. 92-102.

Ettinger, I.L., Lidin, G.D., Dmitriev, A.M., and Zhupkhina, E.A., Systematic Handbook for the Determination of the Methane Content of Coal Seams from the Seam Pressure of the Gas and Methane Capacity of the Coal, National Coal Board Translation No. 1606/SEH, Moscow, 1958.

Irani, M.C., Jeran, P.W., and Duel, M., Methane Emissions from Coal Mines, U.S. Bureau of Mines, R.I. 8659, Washington, D. C., 1974.

Irani, M.C., Jansky, J.H., Jeran, P.W., and Hassett, G.L., Methane Emissions from U.S. Coal Mines in 1974, A Survey, U.S. Bureau of Mines, I.C. 8133, Washington, D. C., 1977.

Kim, A.G., Estimating Methane Content of Bituminous Coal Beds from Adsorption Data, U.S. Bureau of Mines, I.C. 8133, Washington, D.C., 1977.

Lewin and Associates, Inc., Enhanced Recovery of Unconventional Gas, Vols. 1-3 (HCP/T2705), Washington, D.C., October 1978.

National Petroleum Council, Coal Seams Task Groups, Draft Report, December 1979.

Slider, H.C., Practical Petroleum Reservoir Engineering Methods, Petroleum Publishing Co., Tulsa, Oklahoma, 1976.

vonSchonfeldt, Hilmar, "Methane Recovery from Deep Mines," in Proceedings of the Second Annual Methane Recovery from Coalbeds Symposium, U.S. DOE, METC/SP-79/9, 1979.

IV. REFERENCES

BeBout, D.G., Loucks, R.G., and Gregory, A.R., Geopressured Geothermal Fairway Evaluation and Test - Well Site Location - Frio Formation, Texas Gulf Coast, prepared for the U.S. Energy Research and Development Administration, Washington, D. C., May 1977.

Bernard, W.J., "Reservoir Mechanics of Geopressured Aquifers," in Proceedings of the First Geopressured-Geothermal Energy Conference, University of Texas at Austin, June 2-4, 1975.

Brown, W.M., "A Huge Reserve of Natural Gas Comes Within Reach," Fortune, October 1976, pp. 219-222.

Dorman, M. H., and Kehle, R.O., "Potential Geothermal Resources in Texas," Bureau of Economic Geology, Circular 74-4, The University of Texas at Austin, 1974.

Hise, B.R., "Natural Gas from Geopressured Zones," in Natural Gas from Unconventional Sources, The National Research Council, Board of Mineral Resources, Comm. on Natural Resources, National Academy of Sciences, Washington, D.C., 1976.

Jones, P..H., "Hydrology of Miocene Deposits in the Northern Gulf of Mexico Basin," Louisiana Water Resources Institute Bulletin, GT-2, Louisiana State University, Baton Rouge, 1969.

Lewin and Associates, Inc., Enhanced Recovery of Unconventional Gas, Vols. 1-3 (HCP/2705), Washington, D. C., October 1978.

Randolph, P.L., "Natural Gas from Geopressured Aquifers?" SPE Paper 6826, presented at the 52nd Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME, Denver, Colorado, 1977.

White, D.E., and Williams, D.L., Eds., "Assessment of Geothermal Resources of the United States -- 1975," U.S. Geological Survey Circular 721, U.S. Dept. of the Interior, Arlington, Va., 1975.

Wilson, T., and Osborne, R., The Likely Sizes and Reservoir Parameters of Geopressured Aquifers, University of Southern California, 1977.

V. REFERENCES

Bily, C., and Dick, J.W.L., "Naturally-Occurring Gas Hydrates in the Mackenzie Delta, N.W.T.," Canadian Petroleum Geological Bulletin, v. 22, 1974.

Dobrynin, V.M., Korotajer, Yu. P., and Plyuschev, D.V., "Gas Hydrates: A Possible Energy Source," Paper presented at the UNITAR Conference on Long-Term Energy Resources, Montreal, November 26-December 7, 1979.

Grantz, Arthur, Boucher, Gary, and Whitney, O.T., "Possible Solid Gas Hydrate and Natural Gas Deposits Beneath the Continental Slope of the Beaufort Sea", U.S. Geological Survey Circular 733, 1976, p. 14.

Katz, D.L., "Depths to Which Frozen Gas Fields (Gas Hydrates) May Be Expected", Journal of Petroleum Technology, v. 23, 1971, p. 419

McIver, R.D., "Gas Hydrates", Paper presented at the UNITAR Conference on Long-Term Energy Resources, Montreal, November 26-December 7, 1979.

Meyer, R.F., "Speculations on Oil and Gas Resources in Small Fields and Unconventional Deposits," Paper presented at the UNITAR Conference on Long-Term Energy Resources, Montreal, November 26-December 7, 1979.

Mines Magazine, Oil and Gas Production Problems in Siberia: Mines Magazine, November 1971, p. 14-16.

Trofimuk, A. A., "Accumulation of Natural Gases in Zones of Hydrate-Formation in the Hydrosphere," Doklady Akad. Nauk SSR, v. 212, 1973, p. 931-934.

Trofimuk, A.A., Chersky, N.V., and Tsaryov, "The Role of Continential Glaciation and Hydrate Formation on Petroleum Occurrence," in Meyer, R.F., ed., The Future Supply of Nature-Made Petroleum & Gas, Pergamon, 1977, p. 919-926.

Tucholke, B.E., Bryan, G.M., and Ewing, J.J., "Gas-Hydrate Horizons Detected in Seismic-Profiles Data from the Western North Atlantic," Amer. Assoc. Petroleum Geol. Bull., v. 61, 1977, p. 698-707.

POSSIBLE GAS RESERVES IN CONTINENTAL AND MARINE DEPOSITS, AND PROSPECTING AND DEVELOPMENT METHODS

A.A. Trofimuk, N.V. Tchersky, U.F. Makogon, and V.P. Tsariov
USSR Natural Gas Research Institute, Branch of the USSR Academy of Sciences, Yakutsk, USSR

INTRODUCTION

The intensive industrialization of some modern societies has led to a drastic increase in energy consumption which, in turn, has resulted in an alarming demand for hydrocarbon fuel relative to known reserves. At the beginning of 1979, world known reserves of oil were 88.1 x 10^9 tons, and of natural gas 71.5 x 10^{12} m^3. During 1979, world consumption of oil rose to 3.1 x 10^9 tons, and natural gas to 1.4 x 10^{12} m^3. Oil and gas satisfy two-thirds of the total world energy demands at present.

In spite of the development of new processes for energy production, hydrocarbon fuel will remain the basic source of energy throughout the 20th century. The increase in the rate of energy consumption over the rate of growth of known oil and natural gas reserves requires an intensification of the search for new sources of raw materials, and the development of more advanced methods of energy production. Hence, the property of natural gases to combine with water and form gas hydrate deposits in the earth's crust under specific thermodynamic conditions has received widespread attention. Such hydrates are formed by practically all known gases except hydrogen, helium, and neon. The equilibrium conditions for the hydrate formation of methane and some other gases are shown in Figures 1 and 2.

CLASSIFICATION OF GAS HYDRATE DEPOSITS

Gases which are generated and migrate in the earth's crust form hydrates under specific thermodynamic conditions. Accumulation leads to gas hydrate deposits (GHD). These GHD contain gas which is partially or completely in the hydrated phase according to the thermodynamic conditions and the stage of formation.

The bottom and sides of gas hydrate deposits can come into contact with water reservoirs, and the bottom with free gas, gas condensate, or oil deposits. The upper surfaces can contact free gas deposits or gas-tight beds. Offshore deposits of hydrate can also, of course, make contact with free water. Three types of continental gas hydrate deposits are shown in Figure 3.

The mechanism of formation of GHD differs significantly from that of free gas deposits because of the low diffusion

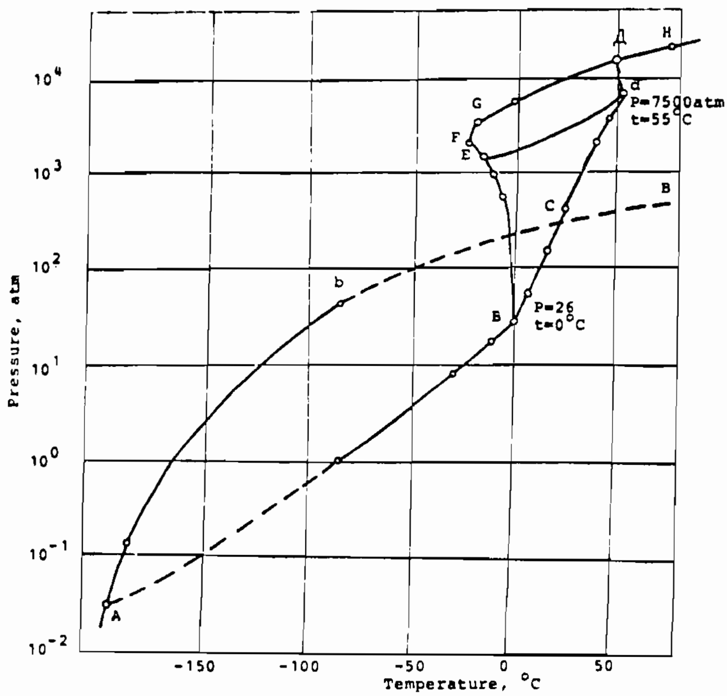


FIGURE 1 Conditions for methane hydrate formation.

permeability of the hydrate, the low concentration of gas in the reservoir water in contact with the GHD, and the low gas hydrate pressure.

Accumulation of the separate components of natural gas in the solid phase can begin during the first stages of the conversion of the original matter by biochemical transformation, provided these transformations occur in the hydrate formation zones (HFZ). In the HFZ, free gases which enter those regions of the earth where the temperature is higher than the equilibrium temperature for formation are also converted into the hydrate.

Those GHD which exist under the present thermodynamic conditions of sedimentory cover of the earth's crust can be classed as primary or secondary deposits. Primary GHD are deposits which, after formation, were not subjected to a cyclic change in thermodynamic conditions accompanied by a phase transition of the gas and water into separate deposits. Usually such GHD occur well offshore and often possess no lithological layers. Primary GHD have existed unchanged since their formation, a period which coincides with the last great fall of temperature on earth. Primary GHD are characterized by three factors: generated hydrocarbons do not migrate into the bottom of sediments which are diffused in the bottom waters, as was previously assumed,but accumulate as hydrates in the immediate vicinity of the bottom boundary; GHD accumulation occurs from waters

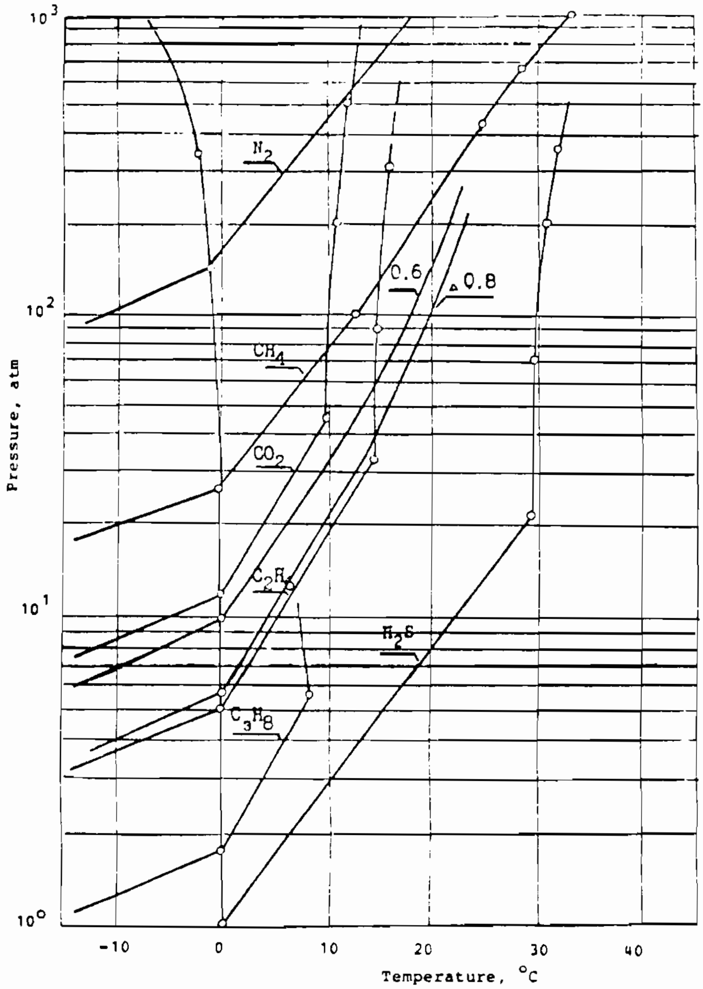


FIGURE 2 Conditions for the formation of some gas hydrates.

undersaturated with gas; lithological layers are not necessary for GHD conservation. Secondary GHD are formed from free gas deposits as thermodynamic conditions change. Usually they lie under an impermeable lithological layer. The age of secondary GHD is defined by the last period when stable equilibrium thermodynamic conditions existed in the deposit for such hydrate formation.

A diagram which shows how the three types of deposit in Figure 3 are formed as the average temperature of the earth's surface changes is given in Figure 4. It should be noted that 15°C is the critical conversion value for deposits of type I and II, while this value is 12°C for deposits of type II and III. An average annual temperature of the earth's surface which exceeds 15°C would cause the destruction of all the glaciers

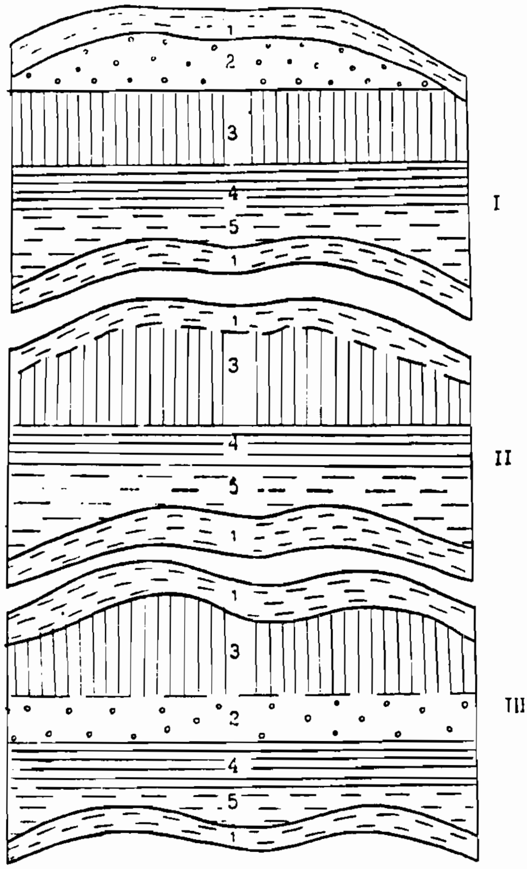


FIGURE 3 Three types of gas hydrate deposits: 1, lithological layers; 2, gas deposits; 3, gas hydrate deposit; 4, oil deposit; 5, bottom water.

and permafrost regions of the earth. Temperatures below 15°C would lead to intensive formation of glaciers and permafrost zones on continents, while temperatures below 12°C would cause the progressive formation of thick ice in the oceans.

The average annual temperature on the Earth's surface during the period of its existence is given in Figure 5. The first glaciers formed on the present continents occurred in the Lower Proterozoic age, 2.3-2.5 times 10^9 years ago. Falls in temperature were then repeated cyclically several times. The last large glacier formation began 11 times 10^6 years ago and reached its maximum 5-6 times 10^6 years ago. Estimation of offshore gas hydrate reserves should therefore be based on the accumulation period of HFZ in bottom sediments during the last 5.5 million years.

The process of hydrate formation has significantly affected the concentration and conservation of hydrocarbons in the sedimentary cover of the earth's crust and contributed, to a

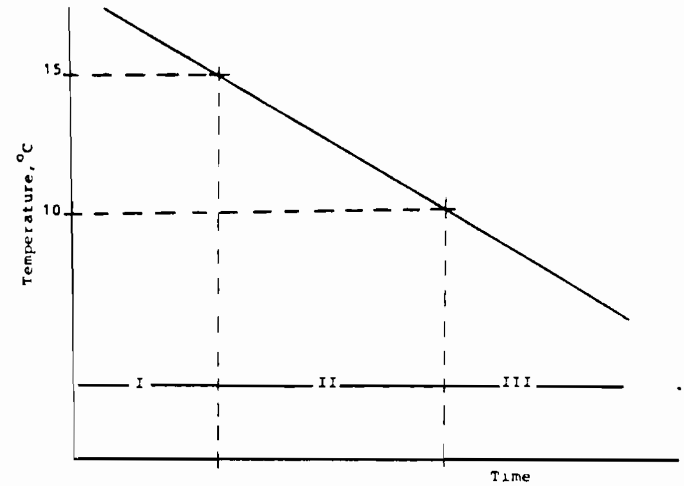


FIGURE 4 Formation of the three types of deposits in Figure 3 with change of surface temperature.

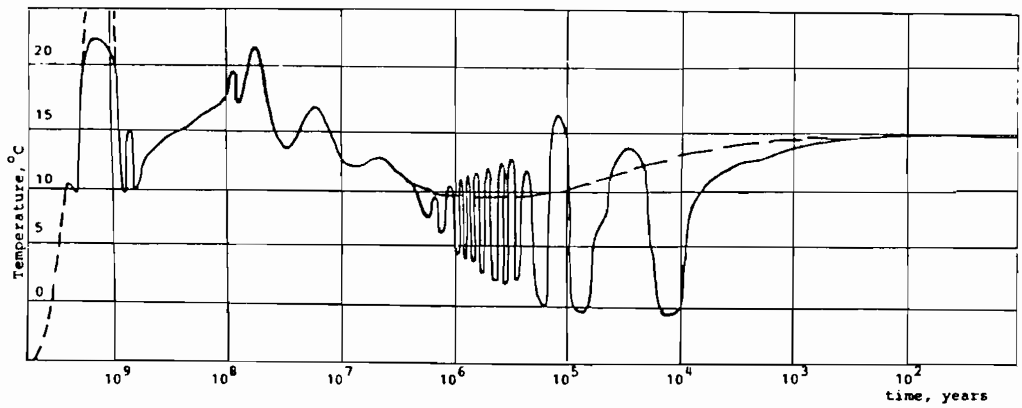


FIGURE 5 Average temperature changes on the earth's surface.

large extent, to the accumulation and conservation of the present natural gas and oil reserves.

HYDRATE FORMATION ZONES

The present thermodynamic characteristics of the sedimentary cover of the earth's crust for 25% of the land and about 90% of the marine surface of the world comply with the conditions necessary for accumulation and conservation of natural gases in the solid hydrated state.

The HFZ thickness on land is 700-1500 or more meters, and under offshore conditions 100-400 m. The maximum thickness of the continental HFZ is related to the most cooled section of the sedimentary cover of the earth's crust, characterized by freshened reservoir waters. Offshore the HFZ fall within that zone of the continental shelf which is connected to the oceanic slope; this is characterized by a moderate value of geothermal gradient, maximum thickness of sedimentary rock, and intensive generation of hydrocarbons. Mineralization of reservoir waters in marine HFZ shifts the equilibrium curve for hydrate formation by no more than 1-2°C. An oceanic bed which is characterized by a small thickness of sedimentary cover, a high geothermal gradient, and weak generation of hydrocarbons is distinguished by a comparatively low hydrate saturation coefficient in the HFZ.

Profiles for which the thermodynamic conditions comply with those for hydrate formation on land and offshore are given in Figures 6 and 7. Mineralization of reservoir waters in the continental section of some regions shifts the equilibrium curve by 5-10°C, thus decreasing the HFZ thickness by some hundreds of meters.

Of particular interest for GHD prospecting is that zone of the Arctic shelf which is connected to continents by zones of polar extension. In coastal regions on land the thickness of this zone decreases under the influence of the ocean. The depth of the HFZ beds also decreases, i.e. the impermeable "crystalline" cap moves to the north along any particular latitude. In contrast, the thermodynamic conditions of the bottom of the Arctic Ocean corresponds to those for hydrate formation practically over the entire area. The lower boundary of the HFZ becomes even lower as the ocean deepens.

On the coast, zones of hydrate formation on land and at the bottom of the Ocean join, forming a thick dome-shaped screen. This screen extends all along the coast.

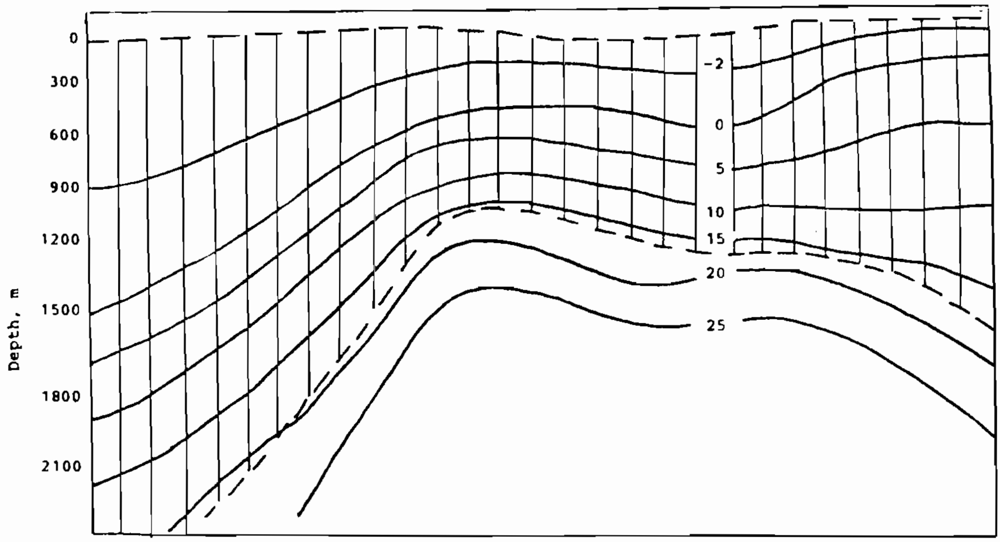


FIGURE 6 Profile of the hydrate formation zone on land.

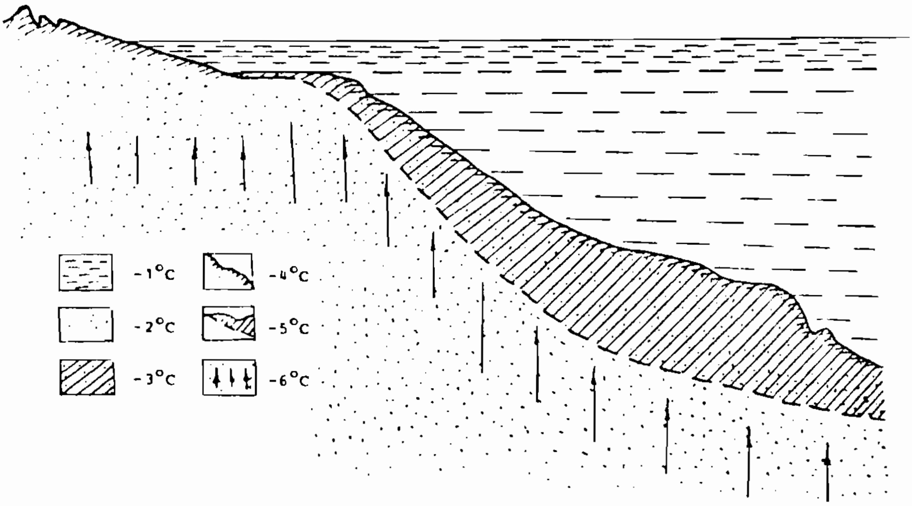


FIGURE 7 Profile of the hydrate formation zone offshore.

The profile of this polar zone, the thickness of which reaches 800 m on the continent, is given in Figure 8. The boundaries of the HFZ on land and at the bottom of the Ocean are also shown. The lower boundary of the HFZ forms the roof of a unique reservoir which extends along the coast of the Arctic Ocean.

The thick sedimentary cover and low geothermal gradient in the Arctic shelf zone show the likelihood of large gas hydrate accumulations in this area.

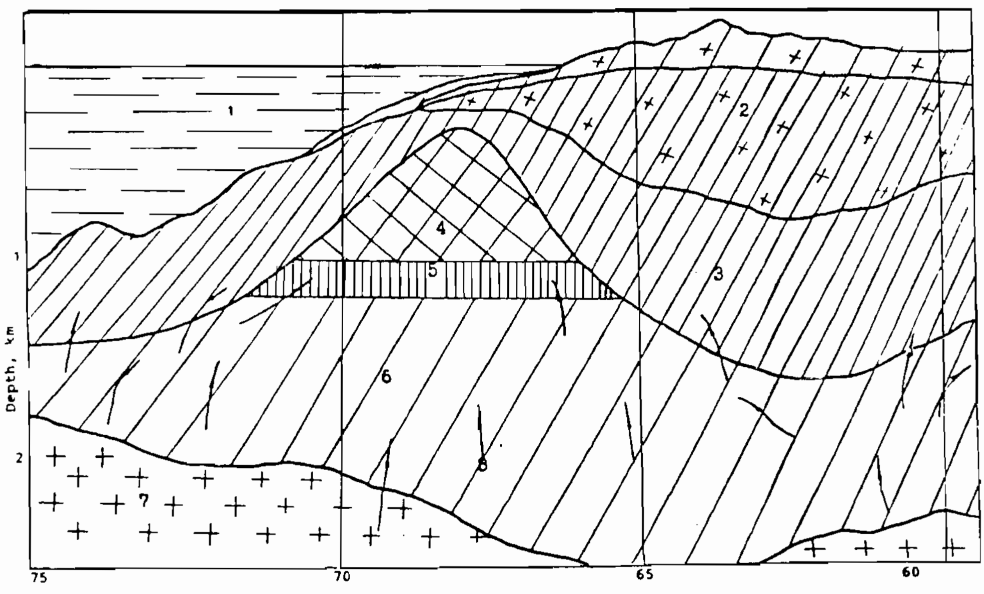


FIGURE 8 Profile of the connection between the Arctic Ocean and the polar continental zone.

GAS HYDRATE RESERVES

Estimation of the world's gas hydrate reserves is as difficult as the development of effective means for their recovery. Such an estimate requires regional and total values of existing and earlier temperatures, sediment thickness, concentration of organic compounds in sediments, and information about conversion and conservation as the thermodynamic parameters of the sedimentary cover suffer cyclic changes.

We have estimated the gas reserves in the continental GHD as 57 times 10^{12} m^3. McIver has given a figure of 31.1 times 10^{12} m^3 for the GHD on land of which 5.4 times 10^{12} m^3 are located in Canada.

Offshore, the HFZ begins at a depth of 100-250 m for polar zones, 200-300 m for temperate zones, and 400-600 m for torrid zones (Figure 9). We estimate the gas reserves concentrated in the hydrated phase within the shelf and continental slope as 5-25 times 10^{15} m^3.

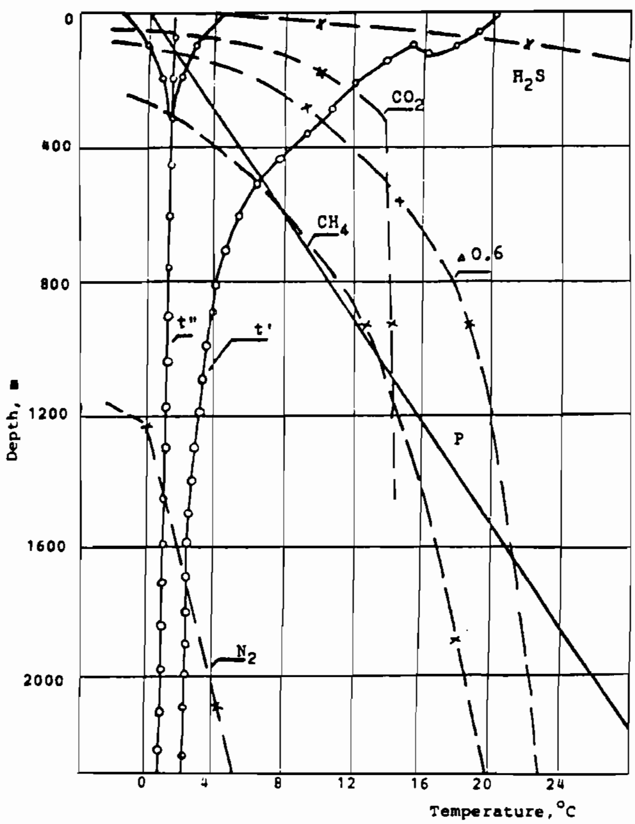


FIGURE 9 Depth—temperature relation for hydrate formation offshore.

METHODS OF GHD PROSPECTING

The following properties of hydrates, which are found in the porous medium, are used in GHD prospecting: the low electric conductivity and permeability; the increased velocity of acoustic wave which pass through a thickness of sedimentary rock saturated with gas hydrates; the anomalous values of diffusion gas flows over GHD, the temperature of the deposit decreasing during recovery; the gas composition change; and the reservoir water freshening during GHD recovery.

Regional GHD prospecting both on land and offshore can be performed with the help of seismoacoustic equipment at a frequency of 0.1-10 kHz, together with gas thermometry. These methods allow the area, thickness, and depth of the top and bottom of the GHD to be estimated and the hydrate and gas saturation of the deposits to be evaluated. Improvement in determining the GHD parameters is possible by using combined geophysical methods and core samples taken from the GHD themselves. The large hydrate fields on the north-west coast of the USA, the north coast of Canada, and the east coast of Africa were reveald from seismoacoustic measurements of the sedimentary cover.

ESTIMATION OF GAS RESERVES IN THE GHD

Estimation of the gas reserves in the GHD has been considered by Makogon. It should be noted that gas in the GHD lying at depths of up to 1500 m always exceeds the volume which would be recovered from an identical free gas deposit. In deeper GHD, the free gas concentration per unit volume of deposit exceeds that of the gas hydrate. For example, at a pressure of 80 kgf cm^{-2}, in 1 m^3 there are 100 m^3 of free gas and about 160 m^3 of gas hydrate, and at a pressure of 200 kgf cm^{-2}, in 1 m^3 there are 165 m^3 of gas hydrate and 250 m^3 of free gas.

TECHNIQUES FOR WORKING GHD

In principle, suitable techniques already exist to make possible GHD working. However, the thermodynamic parameters of the hydrate degradation process in GHD require, in practice, radically new, highly effective methods which can be used both on land and, especially, in deep-water environments.

A general technique is used for land-based GHD working: conversion of hydrates in the GHD into free gas directly in the deposit followed by traditional methods of recovery. Conversion of hydrates into free gas can be accomplished by pressure reduction relative to the hydrate degradation pressure in the deposit and by thermochemical or electroacoustic, etc., action on the GHD.

When drilling and working the GHD, it is necessary to take account of some specific properties of hydrates, such as the sharp increase in gas volume when the hydrate is converted into the free phase, the constancy of reservoir pressure necessary to provide the definite isotherm needed for GHD working, and the release of large volumes of free water during hydrate degradation, etc.

Marine GHD working has some distinctive features compared to working on land. These are: (1) the absence of impermeable lithological layers over the GHD; (2) the small depth of the deposit bed from the bottom surface--from a fraction of a meter to some hundreds of meters; (3) the large area of spread of the GHD; (4) the relatively low mechanical strength of overlying and hydrate-containing loose deposits; (5) the main component which holds the GHD in the bottom sediments is the hydrate itself; (6) the presence of a thick water cover over the GHD surface in a marine environment; (7) the GHD are worked always at constant hydraulic pressure, whatever the method of hydrate degradation; (8) the degree of supercooling with GHD depth is a variable which is determined by the depth of the upper surface of the HFZ in the water, the GHD thickness, and the geothermal gradient in the GHD section; (9) the GHD forms an impermeable cover for the underlying free gas and oil deposits; and (10) if there is free gas or oil deposits under the GHD, it is necessary, first, to extract the oil and free gas and then to work the gas hydrate deposits.

CONCLUSION

Natural gases concentrated in the earth's crust in the form of hydrates must be regarded as sources of hydrocarbon fuel. However, they require new methods of recovery.

The presence of hydrate formation conditions both under the seas and on land have provided a very extensive concentration of deposits of hydrocarbon fuel on earth. The tremendous gas reserves in the hydrate phase, which amount to tens of trillions of cubic meters on land and tens of thousand trillions of cubic meters offshore, require a thorough investigation and the development of effective means for locating, GHD prospecting, and working.

METHANE IN COAL BASINS OF THE USSR

M.V. Tolkachev and B.M. Zimakov
Academy of the National Economy of the USSR, Moscow, USSR

INTRODUCTION

Given the current world energy situation, which is characterized by a deficiency of some traditional fuels (oil, natural gas), an effective long-range plan for optimal utilization of natural resources must consider all possible energy sources. It is therefore necessary to make an inventory of all traditional and nontraditional energy resources.

Over the past 40 years the pattern of fuel usage in the USSR has significantly changed (Table 1). Coal, oil, and natural gas production has increased 4.3-, 18.8-, and 127-fold, respectively, during this period (Melnikov and Shelest, 1975; *Pravda*, 1980). The use of natural gas as a fuel in world terms increased over the period 1950–1972 from 9 to 20.4% (Melnikov and Shelest, 1975).

An extensive study of natural energy resources has shown that after traditional natural gas fields, the potential resourcs of which in the USSR comprise more than 25% of the world reserves (Melnikov and Shelest, 1975), coal can be regarded as the next

TABLE 1 Pattern of fuel usage in the USSR over the past 40 years.

Fuel	Annual production					
	1940	1950	1960	1970	1979	1980[a]
Oil and NGL (million tons)	31.1	37.9	147.9	352.6	586	620–640
Natural gas (billion m^3)	3.2	5.8	43.3	198.0	407	400–435
Coal (million tons)	165.9	261.1	509.6	624.1	719	790–810

[a]From Proceedings of the XXV Congress of the CPSU. Politizdat, Moscow, 1976, pp. 177–179.

most important source of energy. The USSR holds about 57% of the total world coal reserves (Melnikov and Shelest, 1975). Production and processing techniques now enable a nontraditional energy source--methane in coalbeds--to be utilized.

The methane in coalbeds forms the most accessible reserve of all known nontraditional fuel gases. The latter include all the other gases above or inside coal and oil shale, methane dissolved in water (in zones of hydrostatic and abnormal pressure), gas in brines, methane from organic-rich oil shale, biogas, gas from urban and industrial waste, gas hydrate, etc.

The utilization of methane obtained from coalbeds has another important aspect apart from energy considerations--extraction will increase the safety of coal mining.

GAS CONTENT OF COAL DEPOSITS

The natural gases in coalfields are mostly methane and its homologs (80–100%), with some nitrogen, hydrogen, and carbon dioxide/carbon monoxide, and small amounts of hydrogen sulfide, helium, argon, neon, and other gases. The ratio of some of these gases is significant. In hydrocarbons the ratio of methane to its homologs is generally controlled by the degree of metamorphism of the organic matter. Heavy methane homologs almost invariably characterize the gases of medium-rank coals (from fat to coke). In the gases of high-rank anthracites the carbon dioxide content rises to 40–50%. Carbon dioxide and nitrogen usually occur in the upper layers of fields during natural degassing and gas-water exchange takes place with the atmosphere and hydrosphere. The hydrogen concentration depends on the coal rank and increases from long-flame coals to anthracites.

With increase in coal rank, absorptive capacity grows, reaching maximum values for anthracite. The natural methane content of coalbeds systematically increases up to low-rank anthracites, and then sharply decreases in higher-rank anthracites.

According to their habitat and migratory ability, natural gases of coal basins can exist in the sedimentary layers as absorbed, free, and crystallohydrate forms, or dissolved in water. Other things being equal (lithology, organic matter content, degree of metamorphism), the quantitative parameters of gas-saturated permeable zones and the natural methane content of coals and host rocks are controlled by the dynamics of the gas system--the availability of gas from deep sources, and hydrodynamic conditions of the lithosphere, which differ in zones subjected to hydrostatic pressure or high pressures caused by product formation

Coal deposits have a specific lateral and vertical gas zonality, which is controlled by the geology of the coal basin, the coal rank and the tectonic setting of the coal field, by the thickness and permeability of the overlying strata, and by hydrogeological and geothermal conditions, and other factors.

In the upper sections of the coal basin, changes usually occur in the gas zones--gas weathering and demethanization (forming zones of air or air containing various products). The amount of methane increases with depth and eventually becomes the predominant gas. For instance, in the Donets basin five successive gas zones have been defined (1978): nitrogen—carbon dioxide (CO_2 >20%, nitrogen <80%, no methane), carbon dioxide—nitrogen (CO_2 <20%, nitrogen >80%, traces of methane), methane-nitrogen (methane <20%, nitrogen >80%), nitrogen-methane (methane 20-80%, nitrogen <20%, traces of CO_2), and methane (methane >80%).

The distinctive feature of the Pechora basin is the absence of the two upper zones, the nitrogen—carbon dioxide and carbon dioxide—nitrogen zones, known to be present in the Donets, Kuznetsk, and other basins. The Pechora basin lacks any zone of complete demethanization (Table 2) and two main gas zones only are present--a zone of gas weathering and a methane zone.

Within the zone of gas weathering (which occurs between the methane-nitrogen and nitrogen-methane zones), the methane content in coalbeds does not vary significantly, usually not exceeding 1-2 m^3 ton^{-1} for long-flame and gas coals, 3-4 m^3 ton^{-1} for fat and coking coals, and 4-6 m^3 ton^{-1} for lean coals and anthracites. Because of such insignificant methane contents, the gas reserves within the zone of coalbed gas weathering have no practical value. The underlying zones containing methane gases are characterized by increasing methane content (that is the volume of methane in m^3 ton^{-1} contained in unit mass of coal under standard conditions, see *Nedra*, 1977).

The most rapid growth in methane content is recorded at a depth of 400-600 m from the boundary of the methane zone. Further down, as the depth increases the rate of growth of methane decreases markedly (there is a slow growth to 800-1000 m). At

TABLE 2 Zones of coalbed gas weathering in the Pechora and other basins of the USSR[a].

Basin/field	Thickness (m)	
	Zone of gas weathering from surface	Including zone of complete demethanization
Donets	200—500	100—400
Kuznetsk[b]	200—300	80—150
Karaganda[c]	60 (90)—250 (300)	60—100
	80 (120)—300	
Pechora	30—200	0—50 (100)
Including the fields of:		
Inta	100—150	To 10
Usá and Seida	To 50	Absent
Vargashor	20—100	Absent
Vorkuta	30 (100)—50 (200)	0—20
Khalmeru	100—250	To 30
Yunyaga	To 250	50—100

[a]Kravtsov (1979). Vol. 1, p. 389.
[b]Kravtsov (1979). Vol. 2, p. 69.
[c]Kravtsov (1979). Vol. 2, pp. 69, 80.

a depth of 1000-1500 m the rate of growth does not usually exceed 1 m^3 ton^{-1} of coal per 100 m and can even drop as low as 0.02 m^3 ton^{-1} per 100 m. Because of these negligible variations in methane content, these depths are regarded as an area of the coalbed where stabilization has occurred. The intensity of methane growth increases with coal rank in the methane zone: from long-flame (<8–10 m^3 ton^{-1}) to high-rank (lean) coals (30–35 m^3 ton^{-1}), reaching a maximum (40–45 m^3 ton^{-1}) for low-rank anthracites. High-rank anthracites (superanthracites) differ greatly from all fossil coals in that they have a very low methane content (2–5 m^3 ton^{-1}).

The above variations in methane content with depth for the various coal ranks can, in our opinion, be sued as the main geological criterium for assessment of coalbed gas reserves.

EVALUATION OF THE AMOUNT OF COALBED GAS IN THE KUZNETSK, DONETS, AND KARAGANDA BASINS

At minable depths, about half of the methane present is confined within the coal seams, which usually comprise 2–5% only of the total thickness of the coal-bearing strata. It is concluded that coalbed methane is mostly a product of the coalification of coalbed organic matter and of particulate organic matter of the coal-bearing strata.

Many attempts have been made to calculate the amount of methane produced by coals over the entire geologic history of sedimentary basins, and to evaluate the quantity of methane which has escaped to atmosphere and that retained in the coal-bearing strata.

According to Mott (1943), 83 m^3 of methane is formed as a result of the transformation of one ton of bituminous coal (the content of the fuel, C^g, is 85%) into semianthracite (C^g = 92%). Molchanov and Tyzhnov (1961) believe that in the course of transformation from gas to lean coals, one ton of coal generates some 110 m^3 of methane. Lidin and Petrosyan (1962) hold that the amount of methane generated in the course of metamorphism from brown to long-flame coal reaches 30–40 m^3, to fat coal 70–80 m^3, to lean coal 120–150 m^3, and to semianthracite 200 m^3 per ton of coal formed.

An attempt to apply the materials balance approach to the processes taking place during the metamorphism of Donets coals was undertaken many years ago by Uspenskiy (1954). He concluded that about 105 m^3 of methane is generated during the formation of one ton of medium-rank coal; when transformed into anthracite one ton of coal generates some 170 m^3 of methane.

By evaluating the balance of methane generation in coals of the Donets basin, Kozlov and Tokarev (1961), using the former work of Lidin (1949), concluded that some 15 trillion m^3 of methane have escaped from coal-bearing strata throughout the geologic history of the Donets basin. They evaluated the total volume of methane generated by the coals (now lying at depths up to 1800 m) as 36 trillion m^3. Thus, according to these workers, the amount of methane retained in the coal-bearing strata is about 21 trillion m^3.

Ermakov (1972), following the work of Uspenskiy (1954), and taking into consideration the additional studies of Kozlov and Tokarev (1961), assessed the amount of methane (m^3) generated during the formation of one ton of coal from peat for various coal ranks, as follows:

brown coal (B)	68
long-flame coal (D)	168
gas coal (G)	212
fat coal (Zh)	229
coking coal (K)	270
lean-coking coal (OS)	287
lean and semianthracite (T-PA)	333
anthracite (A)	419

Assuming the average thickness of the gas weathering zone to be 300 m, Bagrintseva et al. (1968) assessed the distribution of coalbed hydrocarbon gas reserves of coal basins according to depth (see Table 3). Taking into consideration the coal seams of unminable thickness, they set the total amount of methane in USSR coal basins as 150-160 trillion m^3. Ermakov (1972), in his later, more optimistic assessments believes that gas reserves in minable and thin seams to a depth of 1800 m in USSR coal basins total 240-250 trillion m^3.

TABLE 3 Distribution of hydrocarbon gases in coalbeds.

Depth (m)	Average gas content of coal (m^3/ton^{-1})	Coal reserves (trillion tons)	Gas reserves (trillion m^3
0-300	3	2,3	6,9
300-600	10	1,8	18,0
600-1200	20	2,8	56,0
1200-1800	25	1,7	42,5
Total	58	8,6	123,4

The above values can be regarded as prospective scientific assessments, obtained on the basis of generalized hypothetical notions of methane generation during the formation of sedimentary coal basins and on average values of coalbed gas content.

The following evaluation of the amount of gas in the coal seams of the major USSR coal and anthracite basins is based upon geological data, that is the intrabasinal distribution of coal reserves according to rank and the present natural content of gas with its quantitative dependence on coal rank and depth. See Table 4 for the ranking of coal according to a Russian

National Standard. To evaluate the amount of methane, the coal reserves of the Kuznetsk, Pechora, Donets, and Karaganda basins, according to rank, were subdivided into three groups which differ significantly in average methane content. The evaluation was carried out to a depth of 1800 m in two ways: for coal in place (Table 5) and for commercial reserves of coals and anthracites (Table 6).

The average values used for the natural methane content of the various coal ranks, which vary greatly with depth and for different basins (Table 7), were determined using published graphs and tables compiled from the results of explorations (Kravtsov, 1979) in the Donets (Vol. 1, pp. 98,99,134,284,299), Pechora (Vol. 1, pp. 319,436-39), Kuznetsk (Vol. 2, pp. 177,191, 265,269,274), and Karaganda (Vol. 2, pp. 50,53,61,69) basins.

Because of the varying thicknesses of the coalbed gas weathering zone (demethanization) and the very low gas content within this zone, the evaluated amounts of methane have been reduced in proportion to the coal reserves of these zones; that is, by 10% for the Pechora, Kuznetsk, and Karaganda basins, and by 15% for the Donets basin (Table 8).

The calculated total amounts of methane in coals of the Pechora basin to a depth of 1800 m (Table 8) generally agree with the results of previous studies (Zimakov, 1966; Kalimov, *et al.*, 1969; Kravtsov, 1979). The evaluated methane reserves of the entire sedimentary regions of the basins is obviously only a theoretical value. To assess the potentialities of an integrated program to extract both methane and coal from a field,

TABLE 4 Ranking of coals for calculation of methane reserves.

Rank	From Russian standard 21489-76			Coal type (USSR system)	Volatile content, V^g (%)
	Rank Number	Vitrinite-reflectance in air, $10R^a$, conventional units)	Vitrinite-reflectance under oil immersion, R^o, (%)		
First (low)	I, I-II (coals)	70-82	0.5-0.84	D,G	>35-37
Second (medium)	II-III, III, III-IV, IV, IV-V, V (coals)	83-107	0.85-1.99	G-Zh, Zh, K, K-Zh, OS, SS	35 (37)-15
Third (high)[a]	VI (coal) VII-VIII VIII-IX, IX (anthracite)	108-150	2.0-5.5	T A	<15-17 (V^g-vol >110

[a]Excluding the highest rank of anthracites (superanthracites), designated X in Russion standard 21489-76, with $10R^a$>150, R^o>5.5%, and V^g-vol<110 mg^{-1}

TABLE 5 Calculation of the methane reserves in coal in place to a depth of 1800 m.

Rank	Basin				All four basins
	Kuznetsk	Pechora	Donets	Karaganda	
I. First (low)					
Coal reserves (billion tons) (Nedra, 1978)	300.8	122.5	71.1		
Average natural methane content (m^3 ton^{-1})	8-12	10-15	8-12		
Gas reserves (billion m^3)	2406-3610	1225-1837	569-853		
II. Second (mean)					
Coal reserves (billion tons) (Nedra, 1978)	183.0	32.4	15.3	49.0	
Average natural methane content (m^3 ton^{-1})	16-21	23-28	14-18	18-23	
Gas reserves (billion m^3)	2928-3843	745-907	214-275	882-1127	
III. Third (high)					
Coal reserves (billion tons) (Nedra, 1978)	227.3	18.9	15.7		
Average natural methane content (m^3 ton^{-1})	20-30	20-30	20-30		
Gas reserves (billion m^3)	4546-6819	376-567	314-471		
Total coal reserves (billion tons)	711.1	173.8	102.1	49.0	987.0
gas reserves (billion m^3)	9880-14272	2346-3311	1097-1599	882-1127	14207-20309

TABLE 6 Calculation of methane reserves in minable coal seams to a depth of 1800 m.

Rank	Basin				All four basins
	Kuznetsk	Pechora	Donets	Karaganda	
I. First (low)					
Coal reserves (billion tons) (Nedra, 1978)	268.0	30.6	58.8		
Average natural methane content (m^3 ton^{-1})	8-12	10-15	8-12		
Gas reserves (billion m^3)	2144-3216	306-459	470-705		
II. Second (mean)					
Coal reserves (billion tons) (Nedra, 1978)	156.6	9.52	12.53	29.90	
Average natural methane content (m^3 ton^{-1})	16-21	23-28	14-18	18-23	
Gas reserves (billion m^3)	2504-3286	219-266	175-225	538-688	
III. Third (high)					
Coal reserves (billion tons) (Nedra, 1978)	205.1	2.44	10.53		
Average natural methane content (m^3 ton^{-1})	20-30	20-30	20-30		
Gas reserves (billion m^3)	4102-6153	49-73	210-316		
Total coal reserves (billion tons)	629.6[a]	42.56	81.8[b]	29.90[a]	783.90
gas reserves (billion m^3)	8750-12655	574-798	855-1246	538-688	10717-15387

[a] High-rank anthracites excluded.
[b] Brown coals excluded.

TABLE 7 Comparison of coalbed natural methane conent in the methane zone of the Pechora and Donets basins.

Field/shaft (structure)	Coal type (USSR system)[a]	Coalbed methane content ($m^3 ton^{-1}$) of fuel components at depth of					
		100 m	200 m	300 m	400 m	500 m	600 m
Pechora basin							
Vorkutsk (eastern limb of syncline)	Zh[b]	9-12	17-20	20-24	23-27	27-32	23-35
Vorkutsk (western limb of syncline)	Zh[c]	8-10	13-15	16-19	18-22	21-26	
Usa	Zh[b]	13-16	17-21	19-23	21-25	24-28	
Vorshagor	Zh[c]	9-11	12-14	14-16	15-18	20-23	
Seida	G	6-7	8-9	9-10			
Inta	D	3-4	4-5	--	5-6	6-7	
Donets basin							
Millerov area	D	2-3	3-4	--	4-5	5-6	6-7
West-Donets shaft	G[d]	4-5	6-7	8-9	9-10	--	10-12
Shafts "North-Isvarin 1", "South-West 1"	K, Zh	5-6	7-9	10-11	12-13	14-15	16-18
Bystryan syncline	OS	11-13	15-17	18-20	19-21	20-22	22-24
S-Kamensk 1 shaft	T-PA	9-11	13-15	16-18	19-21	22-24	25-28
Krasnodonets syncline	PA-10/A	20-24	26-29	28-31	29-33	30-34	33-37

[a] Zh denotes fat, G gas, D long-flame, K coking, OS lean coking, T lean, PA semianthracite, and 10/A low-rank
[b] Uspenskiy (1954)
[c] Lidin (1949)
[d] Zimakov (1966)

it is better to evaluate the amount of methane in developing and prospective fields as a function of actual depth and coal mining area. Research is necessary to determine gas recovery ratios before the practical significance of methane resources can be adequately assessed.

UTILIZATION OF COALFIELD METHANE

The total world production of natural gas over the period 1976-2000 has been tentatively estimated at not less than 40-50 trillion m^3 (Sidorenko, *et al.*, 1979). This amount is 2-2.5 times more than the cumulative world production of natural gas over the 100-year period 1896-1975. In view of the considerable increase in coal production planned over this period, greater utilization of coalfield natural gases should follow automatically.

TABLE 8 Evaluated amounts of methane corresponding to coal reserves.

	Basin				Total
	Kuznets	Pechora	Donets	Kara-ganda	
I. Coal reserves (billion tons) (Nedra, 1978)					
in place	711.1[a]	173.8	102.1[b]	49.0[a]	987
minable	629.6	42.5	81.8[b]	29.9[a]	784
II. Methane resources (billion m^3)					
in coal in place	10870	2550	1150	900	15470
in minable coal reserves	9630	620	890	550	11690

[a]High-rank anthracite excluded.
[b]Brown coal excluded.

In the coal mines of the world some 26-28 billion m^3 of methane is evolved annually (Burchakov, *et al.*, 1979). Of this, about 10-12% (2.8-3.0 billion m^3) is captured and piped to the surface. The methane content of this captured gas normally does not exceed 40-50% and only half is utilized as fuel (see Table 9). In some countries (Poland, FRG, Belgium, and Japan) more than 80% of the captured methane is utilized.

The existing total potential natural gas reserves in the USSR are sufficient to ensure a prolonged and steady development of industry. However, more than 70% of these reserves is in the poorly accessible and almost undeveloped northern areas of Siberia and the Middle Asian deserts, which markedly increases gas production and supply costs. The average cost of natural gas production in the USSR for the period 1964-1972 per unit volume increased 4.6-fold, and transportation costs 1.4-fold (Melnikov and Shelest, 1975). From 1971 to 1975 the growth in capital expenses for natural gas production and transportation compared to the period from 1966 to 1970 averaged

TABLE 9 Calorific values of coalfield methane.

Methane concentration (see test) in mine gases (%)	30	40	50	60	70	80	90	100
Gas calorific value (kcal m^{-3})[a]	2500	3400	4250	5100	5950	6800	7650	8500

[a]Burchakov, *et al.* (1979)

60% per unit of gas production growth (Melnikov and Shelest, 1975). Under these circumstances improvements in the utilization of coalfield methane, apart from the safety aspect, has important economic significance.

Low methane contents of gas mixtures and variability in concentration are the main obstacles to improved utilization. Unfortunately not all captured methane can, at present, be utilized as fuel.

Gas-recovering installations in the USSR daily produce 3.2-3.5 million m^3 of methane. Degassing is carried out in 189 mines, mainly in the Donets (108), Kuznetsk (35), Karaganda (22), and Pechora (13) basins. In 60 of the above-mentioned mines the methane concentration in the recovered gases exceeds 30% (Burchakov, *et al.*, 1979). This makes it possible for the gas to be burned in commercial boilers. For 25 mines of the Donets basin the methane concentration in pipelines is 30-50%, and for 18 mines this value is more than 50% (Burchakov, *et al.*, 1979). In 1980 degassing will be carried out in 195-200 mines. The amount of methane produced will reach 3.8-4.2 million m^3 per day (Burchakov et al. 1979). Utilization of 85% of the above-mentioned volumes of methane is equivalent to only 700-800 thousand tons of coal per annum, which is about 0.1% of the planned annual coal production.

The amount of methane contained in the developed coal basins of the USSR, on the basis of the above calculations, indicates that the natural methane of coalfields can be used as a steady supplementary, though somewhat limited, energy resource, especially for projects involved with the coal industry itself.

REFERENCES

Bagrintseva, K.I., Vasil'ev, V.G., and Ermakov, V.I. (1968). Coal-bearing sediments in generation of natural gas. *Petroleum geology*, N6.

Burchakov, A.S., Ayruni, A.T., Kuznetsov, S.K., and Sleptsov, E.I. (1979). Techno-economic Evaluation of Coal Mines Degassing. Nedra, Moscow.

(1978). Geology of the USSR Coal and Shale Deposits, Vol. 12, Nedra, Moscow.

Ermakov, V.I. (1972). Peculiarities of Coalbed Natural Gas Generation and Accumulation. ONTI VIEMS.

(1977). Manual on Determination and Prediction of Gas Content in Coalbeds and Enclosing Rocks in Course of Exploration. Nedra, Moscow.

Kalimov, Y.I., Esipov, P.T., Stolyarman, S.S., and Zaytsev, A.N. (1969). Experience in Degassing the Pechora Basin Coal Mines. Komi Publishing House, Syktyvkar.

Kozlov, V.P., and Tolkachev, L.V. (1961). Volumes of gas generation in sedimentary sequences (examples from the Donets basin). *Sov. Geol.*, N7.

Kravtsov, A.I. (Chief Editor) (1979). Gas Content of the USSR Coal Fields and Basins, Vols. I and II. Nedra, Moscow.

Lidin, G.D. (1949). Factors predetermining gas content in coal mines. Gas Content of the USSR Coal Mines, Vol. I. USSR Academy of Sciences, Moscow.

Lidin, G.D. (1978). Prediction on exploration evidences of sudden methane blowouts in coal mines. In "Okhrana i ozdorovlenie vozdushnoiy sredy v shakhtakh". Nauka, Moscow.

Lidin, G.D. and Petrosyan, A.E. (1962). Gas Content of the USSR Coal Mines, Vol. II. Gas content of coal mines in the South-west part of the Donets basin. USSR Academy of Sciences, Moscow.

Makogon, Yu.F., Trebin, F.G., Trofimuk, A.A., Tsarev, V.P., and Cherskiy, N.V. (1971). Discovery of a gas accumulation in the solid (gashydrate) state. Dnevnik of the USSR Academy of Sciences, N196.

Melnikov, N.V. and Shelest, V.A. (1975). The USSR fuel energy complex. Planned Economy, N2.

Molchanov, I.I. and Tyzhnov, A.V. (1961). Early metamorphism of sedimentary rocks and its importance in the search for fuel fossils. Razvedka i okhrana nedr, N5.

Mott, R.A. (1943). The origin and composition of coals. Fuel in Science and Practice, Vol. XXII.

Sidorenko, A.V., Arbatov, A.A., and Mirlin, G.A. (1979). Mineral resources: reserves problem. "Prirodnye resursy i okruzhayushchaya sreda. Dostizheniya i perspektivy". Proceedings N7, Moscow.

(1980). The results of the fulfillment of the USSR economic and social plan development in 1979. Newspaper *Pravda*, January 26.

(1976). Brown coals, coals and anthracites. Ranks on the evidence of vitrinite-reflectance values. Russian standard 21489-76. Publishing House for Standards, Moscow.

Uspenskiy, V.A. (1954). Experience on materials balance processes taking place during coalbed metamorphism. Izv. Akad. Nauk USSR, *Ser. Geol.*, N6.

Zimakov, B.M. (1966). On tasks and stages of gas content study in coal field exploration. Proceedings of the State Committee of Reserves on Exploration Methods, Commercial Evaluation and Reserves Estimate of Mineral Deposits, Vol. 4, Nedra, Moscow.

BIOMASS AND BIOGAS – PRESENT AND POSSIBLE FUTURE

David O. Hall
King's College, University of London, London, UK

ABSTRACT

Biomass today provides about 15% of the world's annual energy--this is equivalent to about 20 million barrels of oil per day. Most of this use occurs in developing countries, especially in rural areas, where heavy dependence on biomass is resulting in agricultural and ecological problems. This large-scale use is seldom thoroughly considered, and in particular consumption of wood-fuel is probably three times that officially estimated.

One method of conversion of biomass to a useful fuel is biogas production. Biogas comprises the gaseous fermentation products of organic matter and consists of about 60% methane and 40% CO_2. It has an energy content of about 20 MJ/m^3; about 0.4-0.5m^3 of biogas are produced per kg of dry volatile solids over a 5-30 day anaerobic fermentation period. The process was introduced in Europe in the last century for sewage disposal but it is only in the last decade or so that it has been seriously considered as an effective energy system--mostly in Asia but increasingly now in Europe and North America. Other regions of the world are also becoming very interested in assessing the potential of biogas production.

The current worldwide government-sponsored research and development and incentives for solar energy in 1980 approaches $2½ billion. More than four-fifths of this is allocated to expenditures in the Americas (Brazil, USA and Canada) where important biomass programs have been implemented over the last four years--the result of the realisation that biomass can provide liquid and gaseous fuels, besides solid fuel and chemicals, at a cost and with socio-economic benefits that look surprisingly favorable even in these early days. Biomass for energy programs are currently being implemented and are under assessment in many countries of the world including nearly all those in Europe and also the EEC. It is important that each country and region assess its own requirements and potentials, train the people required for implementation, and develop the necessary infrastructure.

The biomass resource will be described, as will conversion technologies and how they are being implemented in various countries. The possibility of mimicking the basic process of photosynthesis, viz., water splitting (for H_2), C- and N-fixation, and charge separation across membranes (for electricity) will be discussed with a view to possible future practical implementation.

INTRODUCTION

(Calvin, 1977 and 1980; Coombs, 1980; Eckholm, 1979; Hall, 1979 and 1980; Parikh, 1979; Revelle, 1979; St. Pierre and Brown, 1980; Slesser and Lewis, 1979; Smil and Knowland, 1980; UKISES, 1976 and 1979, World Bank, 1979).

Hardly a day goes by without there being a news item warning us of the impending shortage of oil and what it is going to cost us--if we can get it! This belated realisation that non-renewable liquid fuels are going to increase in price, and possibly even be rationed, is one of the main reasons why biomass is being looked at so seriously by so many of the developed countries. Possibly even more important, for the developing countries of the world, is the so-called 'wood-fuel crisis' which may be even more serious since the problems of deforestation have such long-term detrimental agricultural, social, and economic consequences.

The oil/energy problem of the last five years has had three clear effects on biomass energy use and development. Firstly, in the developing countries there has been an accelerating use of biomass as oil products have become too expensive and/or unavailable. Secondly, in a number of developed countries large research and development programs have been instituted which have sought to establish the potential and costs of energy from biomass. Estimated annual current expenditure is approaching $100 million in North America and Europe. The work is still in its early stages but results look far more promising than was thought possible even two years ago. Demonstration projects and small-scale commercialisation are being rapidly implemented. Thirdly, in at least one country, viz., Brazil (which currently spends over half of its foreign currency on oil imports) large-scale biomass energy schemes are being implemented as rapidly as possible--the current annual investment is over half a billion dollars. In addition, in the field of biogas conversion there has recently been rapid progress. China has constructed 7 million units (single-family size) over the last few years and continues construction at 1 million a year; India has 70,000 units (community size mostly) while units have recently been constructed in Europe and the USA for animal manure use from 300-cow to 100,000-cattle farms and feeding lots. Research, development, and design, and commercial construction is progressing rapidly.

There is no doubt that the majority of the people in the world live by growing plants and processing their products. The main issue in developing countries is that of scarcity and the problem of trying to maintain, or possibly even to increase, the present level of use without harming agricultural, forestry, and ecological systems. More efficient use of existing biomass and possible substitutes for biomass use, e.g., solar and wind-based technology, should be considered and implemented as quickly as possible to reverse the trend of excessive biomass use, as is already occurring in many countries. In the developed world the expertise exists and is already being used to implement biomass energy programs. Biomass can provide a source of energy now and in the future; just how much it can contribute to the overall provision of energy will very much depend on existing local and national circumstances, and thus it is imperative that each country establish its own energy-use patterns and potential of biomass energy. This is not very easy to accomplish quickly, but needs to be done as soon as possible.

Not many people need reminding that our fossil carbon reserves, whether for fuel or chemicals, are all products of past photosynthesis. Photosynthesis is the key process in life and as developed by plants can be simply represented as:

$$H_2O + CO_2 \xrightarrow[\text{solar energy}]{\text{plants}} \text{organic materials} + O_2$$

In addition to C, H, and O, the plants also incorporate nitrogen and sulfur into the organic material via light-dependent reactions--this latter point is often not appreciated. Thus the basic processes of photosynthesis have determined life as we know it (dependent on organic materials and oxygen) and will continue to play the major role in the integration of bioenergetic systems in the future.

In the past photosynthesis has given us coal, oil and gas, fuel-wood, food, fiber and chemicals. The relative use of these fixed carbon sources has varied over the years and will undoubtedly do so in the future. It seems necessary now to look at how photosynthesis fits into the biosphere and how we could possibly use biological solar-energy conversion in the future as a source of raw materials--and not necessarily in the traditional ways.

What most people do not realise is the magnitude of present photosynthesis--it produces an amount of stored energy in the form of biomass which is about ten times the world's annual use of energy. Table 1 also shows that the total amount of proven fuel reserves below the earth is only equal to the present standing biomass (mostly trees) on the earth's surface, while the total fossil fuel resources are probably only ten times this amount. This massive capture of solar energy and conversion into a stored product occurs with only a low overall efficiency of about 0.1% on a world-wide basis, but because of the adaptability of plants it takes place, and can be used, over most of the earth.

It is not widely appreciated that one-seventh of the world's annual fuel supplies are biomass (equivalent to 20 million barrels of oil a day--the same as the US consumption rate) and that about half of all the trees cut down are used for cooking and heating. Because this use is mostly confined to developing countries, it has until recently been sadly neglected and the effects of overuse of biomass are having serious and long-term consequences. In the non-OPEC developing countries, which contain over half of the world's population, non-commercial fuel often comprises up to 90% of their total energy use. This non-commercial fuel includes wood, dung and agricultural wastes and because of its nature is seldom thoroughly considered. Total wood-fuel consumption is probably three times that usually shown in statistics, and about half of the world's population relies mainly on wood for their cooking (four-fifths of total household energy use) and heating. Furthermore, supply statistics of non-commercial energy can be in error by factors of 10 or even 100.

In my estimation a rural person in the developing countries uses on average about 15 GJ of biomass-derived energy every year. This is the equivalent of 1 tonne or 1.4 m^3 of air-dry wood. Local and regional differences in annual use abound, as do the

TABLE 1. Fossil Fuel Reserves and Resources, Biomass Production and CO_2 Balances. (Hall, 1979).

Proven reserves	Tonnes coal equivalent
Coal	5×10^{11}
Oil	2×10^{11}
Gas	1×10^{11}
Total	8×10^{11} t = 25×10^{21}J
Estimated resources	
Coal	85×10^{11}
Oil	5×10^{11}
Gas	3×10^{11}
Unconventional gas & oil	20×10^{11}
Total	113×10^{11} t = 300×10^{21}J
Fossil fuels used so far (1976)	2×10^{11} t carbon = 6×10^{21}J
World's annual energy use	3×10^{20}J (5×10^{9} t carbon from fossil fuels)
Annual photosynthesis	8×10^{10} t carbon
(a) net primary production	(2×10^{11} t organic matter) = 3×10^{21}J
(b) cultivated land only	0.4×10^{10} t carbon
Stored in biomass	
(a) total (90% in trees)	8×10^{11} t carbon = 20×10^{21}J
(b) cultivated land only (standing mass)	0.6×10^{11} t carbon
Atmospheric CO_2	7×10^{11} t carbon
CO_2 in ocean surface layers	6×10^{11} t carbon
Soil organic matter	$10\text{-}30 \times 10^{11}$ t carbon
Ocean organic matter	17×10^{11} t carbon

relative proportions of wood, dung and agricultural wastes. The developing countries have a population of about 3 billion, of which about 70% are rural. Biomass energy in rural areas usually supplies more than 85% of the energy--and this is mostly used in the household for cooking. There is also an urgent need to supply more local energy for agriculture and small industry. We can thus calculate an annual worldwide rural biomass energy use of about 2.3×10^{10} GJ. In Africa about 65% of the total energy consumed is biomass-derived, in Latin America the figure is about 45%, while in India and the Far East it is about 50%. Including the urban population of developing countries, who often use large quantities of biomass-derived energy (say, an average of 8GJ/year) and the use of biofuels by small-scale industries, we can easily come up with a total biomass energy use in developing countries of about 4×10^{10} GJ; this is about one-seventh of the world's total energy use--equivalent to about 20 million barrels of oil per day. A recent study (World Bank, 1979) states that by the end of 1981, 1.5 billion of the world's 4.5 billion people will be relying principally on wood-fuels for their cooking, and a further one billion will be relying on agricultural residues, including dung, for their cooking fuels.

In this paper I would like to present some evidence that fuels produced by solar-energy conversion are a very important source of energy now and will continue to be so for the foreseeable future--probably even to an increasing extent. We should re-examine and if possible, re-employ the previous systems; but, with today's increased population and standard of living, we cannot revert to old technology, but must develop new means of utilising present-day photosynthetic systems more efficiently. Solar biological systems could be realised to varying degrees over the short and long term. Some, such as the use of wood, biological and agricultural wastes, and energy farming, could be put into practice immediately, whereas others may never become practicable. Photobiological systems can be tailored to suit an individual country, taking into consideration total available energy, local food and fiber production, ecological aspects, climate and land use. In all cases the total energy input (other than sunlight) into any biological system should be compared with the energy output and also with the energy consumed in the construction and operation of any other competing energy-producing system.

Solar energy is a very attractive source of energy for the future, but it does have disadvantages. It is diffuse and intermittent on a daily and seasonal basis, thus collection and storage costs can be high. However, plants are designed to capture diffuse radiation and store it for future use. Hence the serious thought (and money) being given to ideas of using biomass as a source of energy--especially for liquid fuels, but also for power generation and other end uses (see Table 7). I am aware of biomass programs in the UK, Ireland, France, Germany, Denmark, Sweden, USA, Canada, Mexico, Brazil, Sudan, Kenya, Zimbabwe, Australia, New Zealand, India, Philippines, Thailand, Israel, South Korea and China. The biggest difficulty with implementing them seems to be the simplicity of the idea--the solution is too simple for such a complex problem. Fortunately for us, plants are very adaptable and exist in great diversity--they could thus continue indefinitely to supply us with renewable quantities of food, fiber, fuel and chemicals. If the serious liquid fuel problem which is predicted within the next 10 to 15 years comes about, we may turn to plant products sooner than we expect.

What I am definitely not proposing is that any one country will ever be able to derive all its energy requirements from biomass--this is highly unlikely except in especially favorable circumstances. What each country (or even region) should do is to look closely at the advantages and problems with biomass energy systems; these are summarized in Table 2.

TABLE 2 Some Advantages and Problems Forseen in Biomass for Energy Schemes. (Hall, 1980)

Advantages	Problems
1 Stores energy	1 Land use competition
2 Renewable	2 Land areas required
3 Versatile conversion and products; some products with high energy content	3 Supply uncertain in initial phases
4 Dependent on technology already available with minimum capital input; available to all income levels	4 Costs often uncertain
5 Can be developed with present manpower and material resources	5 Fertilizer, soil and water requirements
6 Large biological and engineering development potential	6 Existing agricultural, forestry and social practices
7 Creates employment and skills	7 Bulky resource; transport and storage can be a problem
8 Reasonably priced in many instances	8 Subject to climatic variability
9 Ecologically inoffensive and safe	
10 Does not increase atmospheric CO_2	

With a biogas conversion system the advantages are significant: it operates at ambient temperatures to produce a readily utilizable gas, the sludge by-product retains most of the organic fertilizer value of the original biomass and is thus a valuable product, pathogens are destroyed, pollution is abated, and it produces a local energy source. The main problems currently are cost, maintenance, and social acceptance; the first two are being adequately tackled, but sociological changes do not occur rapidly. The long-term advantages are considerable, but implementation of significant programs will take time and require important economic and political commitments. The programs will vary in their emphasis and thus most of the research and development should be done locally. This represents an ideal opportunity to encourage local scientists, engineers and administrators in one field of energy supply. One should always be fully aware of the assumptions involved in any energy cost projections (especially if they are more than 6 to 12 months out of date) before extrapolating or drawing firm conclusions.

Even if biomass systems do not become significant suppliers of energy in a specific country in the future, the spin-off in terms of benefits to agriculture, forestry, land-use patterns and bioconversion technology are, I think, significant.

EFFICIENCY OF PHOTOSYNTHESIS (UKISES, 1976; Hall, 1979)

Plants use radiation between 400 and 700 nm, the so-called photosynthetically active radiation (P.A.R.). This P.A.R. comprises about 50% of all sunlight which has an average normal-to-sun daytime intensity totaling about 800-1000 W/m^2 on the earth's surface.

The overall practical maximum efficiency of photosynthetic energy conversion is approximately 5-6% (Table 3) and is derived from our knowledge of the process of CO_2 fixation and the physiological and physical losses involved. Fixed CO_2 in the form of carbohydrate has an energy content of 0.47 Mj/mol of CO_2 and the energy of a mole quantum of red light at 680 nm (the least energetic light able to perform photosynthesis efficiently) is 0.176 MJ. Thus the minimum number of mole quanta of red light required to fix one mole of CO_2 is 0.47/0.176 = 2.7. However, since at least eight quanta of light are required to transfer the four electrons from water to fix one molecule of CO_2, the theoretical CO_2 fixation efficiency of light is 2.7/8 = 33%. This is for red light, and obviously will be correspondingly less for white light. Under optimum field conditions values of 3% conversion can be achieved by plants:

TABLE 3 Photosynthetic Efficiency and Energy Losses (UKISES, 1976; Bolton and Hall, 1979)

	Available light energy
At sea level.	100%
50% loss as a result of 400-700 nm light being the photosynthetically usable wave lengths.	50%
20% loss due to reflection, inactive absorption, and transmission by leaves.	40%
77% loss representing quantum efficiency requirements for CO_2 fixation with 680 nm light (assuming 10 quanta/CO_2)[a].	9.2%
40% loss due to respiration.	5.5%
	(Overall photosynthetic efficiency)

[a] If the minimum quantum requirement is 8 quanta/CO_2, then this loss factor becomes 72% instead of 77%, giving a final photosynthetic efficiency of 6.7% instead of 5.5%

however, these values are often for short-term growth periods, and when averaged over the whole year they fall to between 1 and 3% (see Table 4).

In practice, photosynthetic conversion efficiencies in temperate areas are typically between 0.5 and 1.3% of the total radiation when averaged over the whole year, while values for sub-tropical crops are between 0.5 and 2.5%. The yields which can be expected under various sunlight intensities at different photosynthetic efficiencies can be easily calculated from graphical data.

IMPLEMENTATION OF BIOMASS ENERGY SCHEMES

The main factors which will determine whether a biomass scheme can be implemented in a given country are (a) the biomass resource, (b) the available technology and infrastructure for

TABLE 4 Average-to-good annual yields of dry matter production (UKISES, 1976).

	Yield in tonnes/ hectare/yr	Yield in $g/m^2/day$	Photosynthetic efficiency (percent of total radiation)
Tropical			
Napier grass	88	24	1.6
Sugar cane	66	18	1.2
Reed swamp	59	16	1.1
Annual crops	30	-	-
Perennial crops	75 - 80	-	-
Rain forest	35 - 50	-	-
Temperate (Europe)			
Perennial crops	29	8	1.0
Annual crops	22	6	0.8
Grassland	22	6	0.8
Evergreen forest	22	6	0.8
Deciduous forest	15	4	0.6
Savanna	11	3	-
Desert	1	0.3	0.02

conversion, distribution and marketing, and (c) the political will combined with social acceptance and economic viability. These points will be considered.

The Resource Base (Anon., 1980; Coombs, 1980; FAO/ECE, 1980; Hall, 1980; van der Wal, 1979)

The total annual production of biomass (net primary production), the amount of wood produced (including natural forest and managed plantations), and the harvested weight of the major starch and sugar crops are shown in Table 5. In addition, there is a worldwide availability of crop residues and other organic wastes (Table 6 and below). Although the amounts of such wastes have been calculated in some detail for the USA, Canada and some European countries where they have been identified as the major short term biomass-resource, such figures are not generally available for the developing countries. Such data that are available are often questionable and cannot, at present, form a basis for any energy planning discussions. In addition to established sources of wood and food, a wide range of other land and aquatic cultivation systems have been proposed for the future. Both established and future options are summarized in Table 6.

It is easy to do 'envelope-type' calculations to show what the maximum potential is for biogas, but it is impossible at this stage to say what is even remotely feasible. Animal manures generated every year in the world are about 1.8×10^9t, cellulosic residues from agriculture (e.g. straw) are about 0.6×10^9t. The energy content of these residues is about 62×10^{18}J, of which about half could be recovered as energy equivalent to about $1.7 \times 10^{12}m^3$ biogas--this would provide about 10% of the world's current energy use. The world's forests have a net annual primary production of about 8×10^{10}t which could theoretically give $3.2 \times 10^{13}m^3$ of biogas with an energy content of 6.4×10^{20}J, equivalent to twice as much energy as the world currently uses.

TABLE 5 Annual Biomass Production in Tonnes (Coombs, 1980; Hall, 1980).

Net primary production (organic matter)	2×10^{11}
Forest production (dry matter)	9×10^{10}
Cereals (as harvested)	1.5×10^9
Cereals (as starch)	1×10^9
Root crops	5.7×10^8
Root crops (as starch)	2.2×10^8
Sugar crops	1×10^9
Sugar crops (as sugar)	9×10^7

TABLE 6 Sources of Biomass for Conversion to Fuels (Coombs, 1980; Hall, 1980).

Wastes	Land crops	Aquatic plants
Manures	Ligno-cellulose	Algae
Slurry	Trees	Uni-cellular
Domestic rubbish	Eucalyptus	Chlorella
Food wastes	Poplar	Scenedesmus
Sewage	Firs, Pines	Navicula
Sewage residues	Leuceana	Multi-cellular
Wood residues	Casuarina	Kelp
Cane tops	Starch Crops	Water weed
Straw	Maize	Water hyacinth
Husks	Cassava	Water reeds/rushes
Citrus peel	Sugar crops	
Bagasse	Cane	
Molasses	Beet	

More realistically, India presently derives 15% of its energy from dung and 10% from agricultural wastes. The USA obtains 2% of its energy from biomass and recent projections (OTA, 1979) claim that 10 to 17 quads (10^{18}J) are attainable by the year 2000. Sweden derives 10% of its energy from biomass and could reach 50% if it was politically decreed. In Europe a recent EEC (Brussels) calculation shows that agricultural and forestry wastes and surpluses which are reasonably obtainable could provide 25 x 10^6t oil equivalent per annum; an equivalent amount could also be provided from energy crops and plantation schemes. Thus 50 x 10^{16}t oil equivalent could be derived from biomass--this is 4% of the estimated 1985 energy demand, which is nearly the same as energy used by agriculture. An FAO/EEC study of 29 European countries claims that 45-50 x10^{16}t oil equivalent could be produced from agricultural wastes--this represents 3% of total energy requirements of these countries.

Two usually neglected resources will be mentioned briefly.

Aquatic Plants and Algae (Benemann et al., 1977; Goldman, 1979; Richmond et al., 1979; NAS, 1976; Seshadri, 1977; Chin and Goh, 1978)

The potential yield of biomass from fresh-water and marine plants is great. However, the extremely high water content of many of these plants as harvested, and the difficulty in drying them in the sun, may preclude their direct use as a fuel. Anaerobic fermentation of aquatic plants and wet agricultural wastes appears to be a most appropriate technology for the processing of such biomass into fuel, fertilizer, and feed. Waterweeds thrive on sewage, they clean the water effectively and grow rapidly in the process. Thus they may serve a dual role of improving the environment and providing a significant source of energy.

The production of biogas from water hyacinth, for example, has been carried out in a number of countries--this species was selected because of its prolific growth rate and because it floats, so can be easily harvested. Alternatively, algal ponds which use organic wastes (often polluting and/or costly to dispose of) seem promising in many of the sunnier parts of the world where there are often problems with liquid waste disposal.

Thoughts of using algae and bacteria in biological solar-energy systems are not new, but have received more attention over the last few years. One advantage of such microbial systems is that they can be technologically sophisticated or simple, depending on local conditions. The choice of the most suitable species will also depend on local occurrences and preferences, e.g., taking into account salinity and temperature. The species selected can then be fitted into the environmental requirements quite easily.

Many liquid and semi-solid wastes from houses, industries and farms are ideal for the growth of photosynthetic algae and bacteria. Under good conditions rapid growth with about 3-5% solar conversion efficiency can be obtained. The harvested algae may be fed directly to animals, fermented to produce methane, or burnt to produce electricity. Simultaneously, waste can be disposed of and water purified; it is estimated that such algal systems are 0.5-0.75 times as expensive as conventional waste disposal systems in California. The main economic problem is harvesting costs, but the development of new techniques and the use of different, easily-harvested species of algae are proving important. Two-stage algal ponds for complete liquid waste treatment are being tested. Algae which can be harvested by straining are grown in the first pond, while nitrogen-fixing blue-green algae (also easily harvested) grow in the second pond, deriving their nutrients from the first treatment ponds. Utilization of CO_2, e.g., wastes from industry, also increases productivity. Harvested biomass can be fermented to produce methane (equivalent to 500 Btu/lb algae) while the residues would contain virtually all the N and P of the algal biomass, providing a good agricultural fertilizer--one acre of algal ponds could supply the fertilizer required by 10-50 acres of agricultural land. By optimization of yields and including energy inputs and conversion losses, a net production of 200 million Btu per acre per year of methane seems feasible--at a 30° latitude this would represent a 1.5% annual photosynthetic conversion efficiency. The cost of the methane so produced is calculated to be \$2.75-4.10/million Btu, depending on land costs and the size of the pond. These costs are high, but do not take into account the benefit value of waste treatment (which is becoming increasingly expensive) and any by-products, e.g., fertilizers and organic chemicals.

In California average yields of algae in excess of 100kg dry weight/ha/day are obtained, with peak production in summer reaching three times this figure. Yields of 50-60 tonnes dry weight/ha/yr would produce 74,000 kW hr of electricity. Oswald has constructed algal ponds of 10^6 liters which give a 2-3% photosynthetic efficiency on a steady-state basis. Large feeding systems for cattle and chickens have now been provided with algal ponds fed directly with animal waste; about 40% of the nitrogen is recovered in the algae, which is subsequently re-fed to the animals. The green algae presently grown have 50-60% protein but blue-green algae are being tried which contain 60-70% of extractable protein. Algal ponds for oxidation of sewage are operating in at least 10 countries of the world and the interest in these systems as possible net energy and fertilizer producers, and as water purifiers is increasing rapidly. They will obviously never provide major portions of any country's primary energy requirements, but these algal systems have many advantages not the least of which is their energy-conserving characteristics.

Arid Lands (Calvin, 1977 and 1980; Campos-Lopez, 1980; Hall, 1980; Johnson and Hinman, 1980; Parente, 1980.)

A large percentage of the world's land can be classified as arid or semi-arid. Such areas often have serious energy, fuel-wood, and ecology problems. With proper management the vegetation of such areas could provide a renewable resource of energy, food, fiber, and chemicals in the future. A few research institutes devoted to work in such areas do already exist but they need to be considerably strengthened and their scope broadened.

There are many plants which have a CAM-type photosynthetic metabolism which enable them to thrive in arid zones, e.g., Euphorbia and Yucca. Such plants make optimum use of water such that their dry matter production per unit of water used is high compared to other plants. They can also function well at high temperatures and light intensities, as well as under other types of physiological stress. The sustainable yields in such environments is an important question mark. The production of oils, rubbers, waxes, energy, etc., on a sustainable basis from plants able to grow in stress environments may become important in the future.

Many species of plants produce hydrocarbons which can be used as fuels and chemicals--probably the best known is natural rubber from the Hevea rubber tree. Such hydrocarbons are chemically more reduced than carbohydrates, so can be used more directly, whereas carbohydrates require a microbiological or thermochemical conversion before use as a fuel. Currently Hevea rubber provides about one-third of the world's rubber requirements, but with the increasing costs of synthetic rubber (derived from petroleum) and increasing yields from the rubber trees, the proportion is starting to rise again. Natural rubber can also be produced from the desert shrub guayule (Parthenium argentatum) and large quantities have been so produced in the past in Mexico--about 20 million pounds in 1910 and again in 1944 in response to economic conditions prevailing at the time. This possibility of indigenous natural rubber production is being seriously examined again both in Mexico and the USA.

Concurrently, serious efforts are being made to select and establish trial plantations of plants which produce hydrocarbons of lower molecular weight than rubber. The idea is to extract liquids which will have properties very close to those of petroleum. The best known work is that of Calvin (1980) in California using Euphorbia species, with the aim of producing the equivalent of about 20 barrels of 'oil' per hectare per year in semi-arid (desert-type) environment. Additionally, trees have been identified in Brazil (Cobafeira sp. and Croton sp.) which produce 'oils' which can either be used directly or require some processing before being used in engines.

These examples have been discussed to show that there are alternative means of obtaining renewable quantities of oils. However, it must be emphasised that the amounts which can be produced at an economic price will vary tremendously from country to country. Thus the proportion of any country's liquid fuel requirements which can be produced by 'hydrocarbon plants' may never be very large, but it is one way of providing liquid fuels in the future. Also of importance is the fact that such plants need not necessarily use food-producing land.

Vegetable Oils (Brown, 1980; Hall, 1980)

Oils from sunflower, soy bean, palms, etc., can be used in diesel engines or can be mixed with diesel fuel in various proportions. There are some problems with contaminants in the oil that can affect the engine but there is renewed interest, e.g., in Brazil, the USA and South Africa, in using plant-derived oils and fuel extenders, especially for 'on-farm' use; the suggestion has been made that planting 10% of a mechanized maize farm to sunflower would ensure complete fuel self-sufficiency for the farmer. The net energy ratios also appear very favorable. The possibilities of using tropical oil-producing plants, such as oil palm, as a fuel resource deserve more attention because their possibilities for extraction and direct use offer advantages over sugar and starch crops, which involve fermentation and distillation processes before use as fuel. Moreover, inter-cropping or agroforestry is ideally suited for palm plantations.

The question of whether oil crops should be used as a fuel or as food will, of course, have to be a local decision--whether it is economically or politically based, a question which also encompasses other biomass-for-energy crops where there is direct food/fuel competition. It is a very important and contentious point at this time and one that cannot be easily resolved. Undoubtedly it would be best to use marginal lands and agricultural residues for fuel, but local social and economic criteria may well be overriding in the decision processes.

Technology for Conversion (Barrett et al., 1978; Bente, 1980; Coombs, 1980; Department of Energy, 1979; NAS, 1977; Nyns et al., 1980; Stafford, 1980; Watt Committee, 1979.)

Biomass as it stands in the field or collected as wastes is often an unsuitable fuel since it has a high moisture content, a low physical and energy density and cannot be used in internal combustion engines. Established conversion technology can be divided into the biological and the thermal (Table 7). The great versatility of biomass energy systems is one of their most attractive features - a range of conversion technologies is already available (and being improved) yielding a diversity of products, especially liquid fuels on which most world economies have recently been based.

Plant materials may be degraded biologically by anaerobic digestion processes or by fermentation, the useful products being methane, ethanol and possibly other alcohols, acids, and esters. At present the established technologies are the anaerobic digestion of cellulosic wastes to form methane, or the fermentation of simple sugars to form ethanol. The most suitable feedstocks for anaerobic digestion are manures, sewage, food wastes, water plants, and algae.

Biomass, especially woody material, can also readily be converted to gases using thermochemical means such as gasification. This technology is compatible with coal conversion and thus provides similar products which can be used as gases or further processed to liquid fuels and chemicals. Such gasification routes may be preferable to fermentation in certain instances and must be carefully analyzed. The most suitable materials for thermal conversion are those with low water and high lignocellulose contents, for example wood chips, straw, husks, shells of nuts, etc. The most likely

TABLE 7 Solar Energy for Fuels: Simplified Scheme of Conversion Processes and Products (Hall, 1979).

Resource	Process	Products	Users
Dry biomass (e.g. wood, residues)	Combustion	Heat, electricity	Industry, domestic
	Gasification	Gaseous fuels, methanol, Hydrogen, ammonia	Industry, transport, chemicals
	Pyrolysis	Oil, char, gas	Industry, transport
	Hydrolysis and distillation	Ethanol	Transport, chemicals
Wet biomass (e.g. sewage, aquatics)	Anaerobic digestion	Methane	Industry, domestic
Sugars (from juices and cellulose)	Fermentation and distillation	Ethanol	Transport, chemicals
Water	Photochemical/ photobiological catalysis	Hydrogen	Industry, chemical, transport

process to be adopted will use part of the material to produce a mixture of carbon monoxide and hydrogen (synthesis gas) needed for the subsequent catalytic formation of alcohols and hydrocarbons. During gasification oxygen or steam may be introduced to enhance the degree of conversion to synthesis gas and to increase its purity.

Two basic routes of catalytic conversion of synthesis gas to further products can be recognised. This gas may be converted directly to hydrocarbons via the Fischer-Tropsch synthesis, or may be used for the formation of methanol. Both routes are well established, using gas produced from coal, in countries such as South Africa and Germany. Some plants using sorted domestic rubbish are operating and considerable research is being carried out on gasification of wood. On a smaller scale, commercial wood-fuelled gasification plants have been available for some time, the gas produced being suitable for use in stationary engines.

Hence the technology exists for the production of heat, steam, electricity, gas, and liquid transport fuels from biomass. In addition, alcohols are the conventional starting point for a wide range of low molecular weight chemicals, plastics, and fibers. Implementation of such schemes depends on local requirements, economics, energy balances, etc. This great versatility of biomass conversion technologies is one of its distinct advantages.

Energy Ratios and Economics (Coombs, 1980; Jawetz, 1980; OTA, 1979; Leach, 1976; Pimental and Pimentel, 1979; Slesser and Lewis, 1979.)

Ideally the main factors to be considered in adopting a specific biomass route would relate to the energy gain and the economics. The benefit to be derived by converting plant material to ethanol can be expressed in terms of the net energy ratio (NER) which is obtained by dividing the final yield of energy in useful products, by the total energy inputs derived from sources other than the biomass itself. In computing the inputs, in addition to fuel, fertilizer, and irrigation, a value has to be assigned to the farm and process machinery and to on-going maintenance. In general a net energy gain is seen where the fermentation and distillation is powered by burning crop residues, as in the case of sugar cane, or by burning wood obtained locally--as for a cassava alcohol-distillery powered using *Eucalyptus* wood. Reported NER values for such systems vary from about 2.4 to over 7. For most starch crops and sugar beet, the values are close to or below one, i.e., more energy is used than is produced. However, this may still be worthwhile if the fuel source is for instance cheap coal or poor quality wood or residues, etc., which are in effect converted to a high quality fuel.

For the thermal conversion routes an efficiency can be calculated as the ratio of energy in the end product to the energy content of the starting material. Since part of the feed is completely burned to power the conversion, this value must be less than one. Here the justification is again related to the production of a high quality, higher energy-density liquid fuel; from a bulky, wet biomass source.

At present the efficiency of methanol production from wood is probably about 25%, however efficiencies of around 60% are theoretically feasible.

The estimates of the cost of producing alcohol by fermentation of biomass vary enormously from US 10¢ per liter to over 60¢ per liter. However, many of these estimates are based on paper studies. Realistic figures from Brazil (1979) are as follows: 30.5¢ per liter of sugar cane alcohol, and 31.7¢ for cassava-derived alcohol, as compared to gasoline at an ex-refinery selling price of 23¢ per liter and a retail price of 39.6¢ per liter. The alcohol prices are f.o.b. distillery selling prices, calculated for alcohol produced by autonomous distilleries computed to yield the investor a 15% annual return on investment, calculated according to the discounted cash flow method, and on PROALCOOL funding of 80% of the fixed investment. Ethanol production, from farm crops, in the USA is profitable at present due to the tax structure. The Federal Government has passed an exemption of gasoline tax on GASOHOL (a 10% ethanol/gasoline blend) equivalent to $0.4 per gallon. Various states have further tax incentives so that, in Iowa for instance, the combined subsidies work out at over $1 per gallon. The justification for this lies in the fact that in order to maintain corn prices the government subsidises each bushel of corn not produced with one dollar. A bushel of corn can produce 2.5 gallons (US) of ethanol for making 25 gallons of GASOHOL.

Most paper studies indicate that methanol produced by gasification of wood and catalytic resynthesis will be considerably cheaper than ethanol produced by fermentation. The only problem is that no production plants are operating at present. A detailed analysis for a methanol plant in New Zealand can be summarised as follows. At an efficiency of 50% for a 2500 oven-dry tonnes per day plant at 1977 prices, using New Zealand national cost benefit economics (10% on capital, discounted cash flow over 30 years, no tax or depreciation), the product price was $214 per tonne using wood at $55 a tonne or $146 a tonne for wood at $25 a tonne. These values are equivalent to product costs of between 17 and 19¢ a liter, comparable with those summarised recently by the US Solar Energy Research Institute (SERI) where methanol costs from wastes or fuel crops varied from 11¢ to 35¢ per liter at raw material costs from a negative value for waste to about $50 a tonne, with assumed efficiencies of methanol production of between 25 and 50%.

Implementation (Brown, 1980; Commission of the European Communities, 1979; Eckholm, 1979; Hall, 1980; King and Chandler, 1978; Makijani, 1976; Parikh and Parikh, 1977; Vergara and Pimentel, 1978.)

The assessment and implementation of biomass energy programs in individual countries is an excellent opportunity for a country to develop its own research, development, and demonstration capabilities in this area. The types of biomass available for conversion to energy (and the competition with food production) are very much region-dependent, e.g., sugar cane and cassava in hotter climates, cellulose in temperate areas, and hydrocarbon shrubs in arid zones. No one country has a monopoly on biomass-for-energy expertise and indeed it is widespread--not the ethanol program in Brazil, the biogas plants in China and India, gasifiers in Germany, straw burners in Denmark, agro-forestry in East Africa, village wood-lots in Korea and parts of India, and so on. It is also an opportunity to develop collaboration between scientists, engineers, foresters, agronomists, sociologists, economists, and administrators within a country, within regions and between countries. Biomass conversion has a wide appeal because it has both immediate practical and also longer-term basic research and development requirements.

It is imperative that good energy assessments be made in individual countries (with or without outside help), identifying the energy flows, limitations in data, and opportunities. The priority needs must be matched with the available resources. The practical importance of biomass energy must be made very clear and proposals to implement such systems clearly spelt out to ensure the full co-operation of all concerned.

STATUS OF VARIOUS BIOMASS PROJECTS THROUGHOUT THE WORLD (Hall, 1980)

In Table 8 a short summary of biomass and energy costs of some schemes around the world are listed. Further details are given below for a number of these schemes.

Brazil (Gochnarg, 1979; Goldemberg, 1978; Yang and Tindade, 1979)

By far the most ambitious biomass program which has been planned is that in Brazil for the production of alcohol from sugar cane, sorghum, and cassava. This National Alcohol Program (PNA or PROALCOOL) was established in November 1975. The alcohol will be used to blend with petrol--a mixture of up to 20% (by volume) requires no adjustment to the engine (over the past 10 years the State of Sao Paulo with over 1.3 million cars has varied the alcohol content of its petrol up to 18%, depending on the availability of alcohol and price of molasses). In 1977, 141 new alcohol distilleries were authorised by PROALCOOL, requiring an investment of about $900m and able to supply 3.2×10^9 liters of alcohol by 1980, about a fifth of the projected gasoline requirement. By 1985 total production of alcohol could reach 10×10^9 liters with a huge total investment of billions of dollars. An economic analysis of the production of alcohol from sugar cane and cassava calculated selling prices of fuel, ex-distillery, of $0.33/liter, 81% of the present retail price of gasoline on a volume basis. Brazil is clearly embarking on an ambitious program of fuel import substitution using the natural advantages of land and climate which it has--and it may be a very useful demonstration to other countries and provide exportable technology and expertise. The indirect benefits such as saving foreign exchange, creating new employment, encouraging domestic technology and industry, and reducing pollution, are great.

USA (Bente, 1980; Department of Energy, 1979; Electric Power Research Institute, 1978; Flaim and Witholder, 1978; Lipinsky, 1978; Weisz and Marshall, 1979.)

TABLE 8 Estimated Biomass and Energy Product Costs (Hall, 1979)

Country	Product and Source	Cost
Brazil (1977)	Ethanol from sugar cane (ex-distillery)	US$16.7/$10^6$BTU (US$ 0.33/litre)
	Gasohol (retail)	US$13.18/$10^6$BTU
Australia (1975)	Ethanol from Cassava	AU$250/t
	Industrial ethanol	AU$275/t
Canada (1975 and 1978)	Methanol from wood	CAN$0.35-0.70/gallon
New Zealand (1976)	Ethanol from pine trees (500 t/day capacity; credits from byproducts)	NZ$260/t (13% return on capital)
New Zealand (1977)	Biogas from plants	NZ$3.45-5.57/GJ
	Natural gas production cost	NZ$1.09/GJ
	Coal gas production cost	NZ$6.33/GJ
Upper Volta (1976)	Fuelwood from plantations	US$0.09/KWh (t)
	Kerosene (retail)	US$0.13/KWh (t)
	Butane gas (retail)	US$0.19/KWh (t)
Philippines (1977)	Electricity from Leucaena fuelwood-fired generating station (same cost as oil-fired station)	US$0.014-0.018/KWh
Tanzania (1976)	Biogas from dung (for cooking and lighting)	US$0.012/KWh
	Electricity	US$0.113/KWh
India (1978)	Casuarina fuelwood to replace coal-fired electricity generating station (competitive with coal: 15-30 year pay back)	US$12/t (dry)

The USA has a very large research, development and design program on biomass which had a budget of $56m for 1979 and will be even greater for 1980. The 1975 US use of energy was 71×10^{18}J; the total standing forest inventory, however, has an energy content three times this figure. The biomass which could be used to produce energy and is being looked at very carefully includes forests, specifically grown crops and plantations, and agricultural, industrial, and urban wastes of all types. The total annual biomass growth of commercial forests is 9.3×10^{18}J of which 6.6×10^{18}J is potentially collectible. Cropland agriculture produces energy totalling about 12×10^{18}J annually of which about 40% is represented by residues left on the land. A detailed analysis of 'potentially usable biomass residues' shows that of the residues currently collected, 2.1×10^{18}J could be obtained from urban solid wastes, 1.0×10^{18}J from animal feedlots canneries, wood manufacture, and so on. Uncollected residues such as cereal straw, cornstalks, and logging residues could contribute 5×10^{18}J per annum. It is interesting that 60% of US cropland is dedicated to the production of livestock--and this excludes the contribution that 282 million hectares (38% of mainland US area) of pasture and rangeland make to livestock support. There are thus large areas of land which could be used in the future for the production of biomass.

Flexible plant systems are also being considered--thus biomass intermediates (besides food) are processed into fuels and sugar cane production. It is theoretically possible to reorganise the present US corn biomass system to permit the production of $10\text{-}18 \times 10^{9}$ l of ethanol (or its equivalent in other fermentation products) while obtaining the same quantity of end-use food products in the form of beef, poultry and pork. The ethanol could be blended at 10% with a quarter of the US gasoline. GASOHOL is currently widely available at over 2000 gasoline stations and is cheaper than gasoline. Sugar cane produces numerous by-products such as molasses, alcohol, and bagasse which can be used for power generation, and as fermentable substrates or substitute wood.

The concept of intensive silviculture biomass farms or energy farms has been one subject of detailed analysis. Fast-growing deciduous trees which coppice have been examined, as have numerous other trees, including those which fix nitrogen to ammonia.

Table 9 summarises one of many existing studies of biomass products and their costs to give an idea how close some technologies are to economic reality. The assumptions implicit in all these calculations must, however, be recognised and carefully analysed.

TABLE 9 Biomass Energy Products Costs Compared to Conventional Methods (for the USA, 1981). (Flaim and Witholder, 1978).

Product	Cost from Biomass ($\$/10^6$ BTU)	Conventional Cost ($\$/10^6$ BTU)	Biomass / Conventional
Methanol	8.4 - 15-9	8.4	1.0 - 1.9
Ethanol	15.0 - 36.3	19.6	0.8 - 1.9
Medium BTU gas	4.7 - 7.4	3.0 - 5.0	0.9 - 2.5
Substitute natural gas	4.8 - 7.3	3.0 - 5.0	1.1 - 2.4
Ammonia	5.8 - 11.4	7.4	0.8 - 1.5
Fuel oil	3.6 - 7.9	3.2	1.1 - 2.5
Electricity	0.03- 0.14 ($/KWh)	0.03- 0.06 ($/KWh)	0.5 - 4.5

Canada (Bente, 1980; Marshal, 1979)

Canadian studies on the large-scale production of methanol from biomass show that by the year 2025 up to 42% of the transport fuels could be provided by such means. Methanol represents a unique fuel combining the portability of liquid petroleum products and the clean, even-burning characteristics of natural gas. The Federal Government recently announced a $180m program on biomass resource and development and also provided economic incentives to industry to use wood and forest residues to provide energy.

Europe (UKISES, 1979; Anon., 1980; Chartier and Meriaux, 1980)

In Europe a number of countries and the EEC are conducting extensive feasibility studies of the potential of biomass as a source of energy and fuels in the future. Trial plantings of alder, willows, poplars, etc., are being undertaken in addition to assessing energy yields from agricultural residues, urban wastes, techniques of conversion, waste land and forest potentials, and algal systems. Biological and thermal conversion equipment is available and is in great demand for use in Europe and overseas.

A recent study by the European Commission (Brussels) shows that in the nine EEC countries biomass could provide 4% of their total energy requirements in the year 2000 (equal to 50 million tonnes oil equivalent or 2 million barrels of oil per day)--this equals the use of energy by the agricultural sector and could be achieved with the use of residues and wastes and by utilizing some marginal land with minimal disturbance to conventional agriculture. With a great effort and disturbance to agriculture and forestry, the EEC countries could provide 20% of their total energy requirements from biomass, if they so wished.

Sahel Region (Brown and Howe, 1978; Floor, 1977 and 1978; Openshaw and Morris, 1978 and 1979; SEMA, 1978)

The problems of deforestation and enlargement of deserts has highlighted the lack of fuelwood in most countries of this region. It is a scarcity which is reaching crisis proportions in large parts of South Asia, the Sahel, Andean countries, Central America, and the Caribbean.

The per capita requirement for cooking alone is about 0.5 m^3 of wood/year. Total fuelwood requirement is probably about 1 ton which is equivalent to about 400 kg coal per person per year. Demand from urban areas and industry to use charcoal instead of the more expensive kerosene and oil is diverting wood-fuel from rural areas, resulting in increasing forest and scrub destruction (often long distances from villages) and use of dung as a fuel instead of as a fertiliser. A recent Dutch study of the Sahel region points out two possible solutions: decreasing fuelwood demand by using stoves which reduce consumption by 70%, and increasing the supply of fuelwood by establishing 'forest plantations'. Costs of reforestation and fuelwood production have been calculated for the tree species suggested, and the conclusion is that 'under the conditions assumed it is an economically feasible activity'. Naturally there are institutional problems which impinge on agriculture and other practices of the society, but if such countries are to achieve even a modicum of internal fuel production they should seriously consider such biomass systems and set up fuelwood plantations as soon as possible.

India (Eckholm, 1979; Seshadri et al., 1978)

India has a long-standing biogas program and is rapidly implementing new approaches to biomass utilisation. A study in Tamil Nadu, South India, on the possibility of growing *Casuarina* (a nitrogen-fixing tree) as a source of fuel for a power plant generating 100MW electricity has shown favorable economic and social benefits. In direct competition with coal, a payback period for such an energy plantation would be from 15-30 years. An equivalent of 110 hectares is required to generate 1 MW electricity; about 11,000 labourers would be required, and the overall energy output/input ratios are high.

In the state of Gujarat, one of the poorest in India, a social forestry program has been implemented with village plantations schemes and roadside and canal-bank plantings. Free extension services and seedlings and the involvement of local councils, farmers, schools, etc., have helped reverse the worsening fuelwood problem of only a few years ago.

Philippines (Terrado et al., 1978)

A feasibility study has shown that a 9100 hectare fuelwood plantation 'would supply the needs of a 75 MW steam power station if it were not more than 50 km distant'. The investment requirements and cost of power produced look favorable and competitive with oil-fired power stations of similar capacity. The best species of fast-growing tree seems to be the 'giant ipil-ipil' (*Leucaena leucocephala*) which fixes nitrogen to ammonia--a highly desirable trait.

China (Smil and Knowland, 1980; Van Buren, 1979)

During the 1970's biogas plants were perfected and installed at a rapid rate. It is estimated that there are now (1980) about 7 million in operation (about 1 million a year are being constructed) and the methane so produced is used for cooking, crop drying, power generation and various other purposes. In Szechwan province alone, 17 million people use biogas for cooking and lighting; in some areas 80% of all rural households are served by biogas. In addition, over the last two decades a massive reforestation program has increased the proportion of national land under forest from 5-13%--implying an increase of 72m hectares.

Australia (McCann and Saddler, 1976; Stewart et al., 1979)

In Australia, *Eucalyptus*, cassava (*Manihot*), *Hibiscus*, napier grass (*Pennisetum*) and sugar cane were selected as potentially the most desirable high-yielding crops which can be harvested over the whole year. It was shown that alcohol produced from cassava (starch-rich) is an economically viable system, but that if processing to destroy cell walls is required the costs become too high. The cost of alcohol from cassava is calculated to be $A 250/tonne from a 100,000 tonne/year batch-process plant which compares favorably with the 1975 market price of alcohol $A 275/tonne) as an industrial solvent. Recent studies show that over half Australia's liquid fuel requirements could be produced from agricultural residues and specifically-grown crops.

New Zealand (Stewart, 1977; Harris et al., 1979)

With its very efficient agriculture, low population density and the fact that it uses a large proportion of its foreign exchange for petroleum purchases, it is natural that New Zealand is considering biomass as a source of fuels. Current work shows that fodder beet for ethanol and wood for methanol may be economic sources of liquid fuels. Proposals have been made that New Zealand could convert from a petrol to an alcohol liquid fuel economy--half provided by methanol from indigenous natural gas, and the other half by alcohols from trees and agricultural crops.

South Korea (Eckholm, 1979)

'The dramatic forestry success story of the seventies' is how the six-year-old South Korean reforestation scheme has been described. Since 1973, in the face of severe timber and fuelwood shortages, a community-based forestry program has been implemented with priority being placed on meeting the needs of the rural population. Government statistics claim that one-third of the land is now stocked with trees less than 10 years old. A network of village forestry associations has been established providing a link between government organisations and villagers--these associations establish, manage, and harvest the plantations. Through profit-sharing mechanisms the Koreans have managed to co-opt private land for public forestry purposes. It has been calculated that a switch from coal purchases to locally grown fuelwood has meant a 15% increase in income for many families.

There is a resemblance between South Korea's and China's reforestation programs. Central government in both cases had made a strong political commitment to community forestry with back-up technical assistance and local-level participatory institutions. Such patterns could be usefully examined in other so-called 'hopeless situations'.

FUTURE PHOTOSYNTHESIS (Bolton and Hall, 1979; Calvin, 1977 and 1980; Hall, 1980; Hall et al., 1980; Mitsui et al., 1977; Wittwer, 1980)

Whole Plants

One of the 'problems' with photosynthesis is that it requires a whole plant to function--and the problem with whole plant photosynthesis is that its efficiency is usually low (less than 1%) since many limiting factors of the environment and the plant itself interact to determine the final overall efficiency. Thus a task for photosynthesis of the far future is to try to select and/or manipulate plants which will give higher yields with acceptable energy output/input ratios. We need much more effort placed on studies of whole plant physiology and biochemistry and their interactions with environmental factors. Already such studies are being increasingly funded by both industrial and government organisations--in marked contrast to the neglect of this type of research in the past.

Examples of the type of research which is being done or needs to be done are: photosynthetic mechanisms of carbon fixation; factors in bioproductivity; genetic engineering using plant cell tissue cultures; plant selection and breeding to overcome stresses (drought, temperature or salinity); selection of plants and algae with useful products such as oil, glycerol, waxes, or pigments; nitrogen fixation and metabolism, and its regulation by photosynthesis.

Artificial Photosynthesis

Also to be seriously considered is long-term basic, directed research on artificial photobiological/chemical systems for production of fuels and chemicals (H_2, fixed C, and NH_3), and this needs sustained funding if these exciting future possibilities are to be realised.

Since whole-plant photosynthesis operates under the burden of so many limiting factors it is interesting to speculate about artificial systems which mimic certain parts of the photosynthetic processes and so produce useful products at higher efficiencies of solar-energy conversion. (A 13% maximum efficiency of solar-energy conversion is considered a practical limit to produce a storable product). I think that this is definitely feasible from a technical point of view, but it will take some time to discover whether it could ever be economic. Note must also be taken of other light-driven chemical and physical systems which are presently being investigated and may come to fruition before biologically-based systems.

A number of proposals have been made to mimic photosynthesis *in vitro* or to use *in vivo* photosynthesis in an abbreviated form in order to overcome the inefficiencies and instability factors that seem to be inherent in whole plant (or algal) photosynthesis. The state of the art is still very rudimentary, but it gives some idea of what may be achieved in the future--the scope is enormous, but it may well take ten years or longer to discover whether any of these systems has any practical potential. Fortunately, the quality of the work, the wide interest, and the wide range of disciplines being attracted augurs profitable results.

Plants perform at least two unique reactions upon which all life depends, viz., the splitting of water by visible light to produce oxygen and protons, and the fixation of CO_2 into organic compounds. An understanding of how these two systems operate and attempts to mimic the processes with *in vitro* and completely synthetic systems is now the subject of active research.

In vitro systems which emulate the plant's ability to convert CO_2 to organic compounds are a very attractive proposition.

Recent reports claim the formation from CO_2 of methanol, formaldehyde and formic acid. These are very interesting and important studies since it is the first time that light has been used outside the plant to catalytically fix CO_2. There has also been one report of the photochemical reduction of nitrogen to ammonia on TiO powder using UV light.

A recently published idea is the photosynthetic reduction of nitrate to ammonia using membrane particles from blue-green algae. This process seems to occur naturally by light reactions which are closely linked (via reduced ferredoxin) to the primary reaction of photosynthesis, i.e., not involving the CO_2 fixation process. However, it may be possible to use intact blue-green algae (possibly immobilised) to continually fix N_2 to NH_3--the cells would have to be genetically derepressed and this is now certainly possible with the recent advances in genetics.

The term 'biophotolysis' is applied to photosynthetic systems that split water to produce hydrogen gas. This applies to both living systems, such as algae, and to *in vitro* systems comprising various biological components such as membranes and enzymes. We also discuss the so-called 'artificial' systems which seek to mimic the photosynthetic systems by the use of synthetic catalysts. Our bias tends to lean heavily towards this last approach.

The great interest in biophotolysis-type systems probably derives from the fact that they are the only energy systems currently known to have the following three attributes: (a) the substrate (water) is ubiquitous, (b) the driving force is unlimited (sun), and (c) the product is stable and non-polluting (hydrogen). At present, the biological system is the only one that is able to use visible light catalytically to split water to H_2 and O_2; we hope that other systems will be found soon.

The production of H_2 gas by light-activated water splitting using components from plants (chlorophyll-membranes and ferredoxin) and bacteria (hydrogenase), was reported in 1972/3. The rates of H_2 evolution were low, the system only ran for 15 minutes, and there were questions as to whether the protons did indeed come from water. Since then our laboratory and others have increased the rates and longevity of H_2 production tenfold in each case, besides convincingly showing that water is the ultimate source of H_2. The ultimate object of our line of research is to understand how the biological system operates and then construct a completely synthetic system mimicking the algal or plant-bacterial systems. In this case an Fe-S catalyst could be used instead of ferredoxin or a hydrogenase; a chlorophyll layer membrane or vesicle instead of the chloroplast, and a manganese catalyst to evolve the O_2 from water. A two-stage system has been constructed where O_2 is evolved in the light and H_2 in the dark. A single-phase system evolves H_2 and O_2 simultaneously which could then be separated by semi-permeable membranes, or the gas mixture burnt directly. There are problems of stability in the living systems which would need to be overcome before any biologically-based system could be practical. Progress has been made in identifying stable hydrogenase enzymes from photosynthetic bacteria.

We have also reported the substitution of the ferredoxin (electron carrier from the membranes to the hydrogenase) by two different synthetic Fe-S compounds and two different synthetic Fe-S-Mo compounds--we think this is the first report of such substitutions. A synthetic hydrogenase seems too difficult at present but active research is being pursued with synthetic Fe-S clusters. We have, however, been able to replace the hydrogenase with colloidal platinum and also found oxygen and temperature-stable hydrogenases for use in the chloroplast systems. The water-splitting component in the chlorophyll--containing membrane is an Mn-containing enzyme. A number of laboratories are working on synthetic Mn compounds to split water, and one laboratory at least is very optimistic of success.

At present the main limiting factor we detect is the poor stability of the membrane towards light and oxygen. Even though we have found some chloroplast membranes which are much more stable than others, we do not as yet know the reason for this--I suspect we must wait until membrane technologists come up with a suitable membrane. We have had some success in embedding the membranes and enzymes in calcium alginate gels (spheres or films supported on nylon or steel mesh), as a step towards the construction of a demonstration device for H_2 production.

The chloroplast system of Haehnel et al. seems an important step forward in constructing a device that generates both a photovoltage and photocurrent. The system comprises two half-cells containing chloroplasts separated by an ultrafiltration membrane which enables exchange of protons and ionic conductance but prevents irreversible changes by diffusion of larger components. By the use of appropriate dyes as catalysts, the potential difference between the endogenous donor and acceptor of photosystem I of chloroplasts is 'harnessed'. Such a 'chloroplast battery' was shown to generate a voltage of about 200 mV and a small current is thought to have been obtained. The inherent resistance of the present cell is high, but this is being improved. It is also hoped to incorporate hydrogen-evolution catalysts into the right-hand half-cell. In such a mode, oxygen would be evolved in the left-hand half-cell and hydrogen in the other.

This work on H_2 production from water is going ahead as basic research, since this single-stage system is unique. The only other system which emulates this is the two-stage photovoltaic solar cell-plus-electrolysis system. Of course, a purely photochemical system to split water with visible light may be discovered and found to be stable--this would then solve all our problems. Lastly one must mention that certain algae produce H_2 continuously under specific conditions and contain the enzyme hydrogenase. This system is being experimented with in a number of laboratories, in some cases in conjunction with growing algae on wastes--thus having a three-stage system of growth, then H_2 production, and finally harvesting. Photosynthetic bacteria have been shown to grow directly on wastes producing H_2 gas.

Economics of Photochemical Systems

There have been very few studies of the economics of photochemical solar-energy conversion and storage, possibly because the field is quite new and also because as yet very few systems have been shown to work with reasonable efficiency and longevity. Harrigan has made a limited study and concludes that the photochemical production of fuels could be economic only in a hybrid system that also provided thermal energy. Mattox has examined some of the material costs that are applicable to almost any kind of collector, but he does not consider photochemical systems specifically.

It is possible to put some limits on the capital costs of a photochemical collector. Depending on the location, the average (365 day, 24 hour) solar irradiance on a south-facing collector at the optimum angle for the latitude will be 200-400 W/m^2. If the energy conversion and storage efficiency is assumed to be 10%, then such a collector will store energy as a fuel at a rate of 20-40 W/m^2. If the fuel is hydrogen, this corresponds to 60-120 m^3 of hydrogen produced per m^2 of collector per year. The 1978 price of hydrogen is about \$80 per 1000 m^3. Thus, the value of solar-generated hydrogen that might be produced per m^2 of collector per year is \$4.80-\$9.60. This could perhaps justify a capital cost of \$20-\$40 per m^2 of collector but not much more. This analysis agrees with one carried out by Pearlstein in 1974 when an inflation factor is built in. This crude economic analysis points out that the system must be simple and should operate as a single unit producing H_2 and O_2 separately. A photolysis system can be envisaged to meet these requirements (whereas the photovoltaic or concentration system plus electrolysis cannot) but the stability problem of photolysis has yet to be overcome. If thermal collection is combined with fuel production, then a capital cost of perhaps \$200-\$300 per m^2 might be permitted. This emphasises the importance of considering hybrid systems. It is very difficult to make economic assessments in the absence of systems that work with reasonable efficiency in the laboratory. Clearly, the first priority must be to establish scientific feasibility for photochemical conversion and storage systems, and then to assess critically the economic questions.

In conclusion, photochemical conversion and storage of solar energy is a field replete with new papers, most of them of a very high quality; (nearly 70% of the papers referred to in this review have been published since the beginning of 1977). It is too early to tell where this intense activity will lead, but if past experience is any guide, society will benefit immensely and indeed photochemical conversion and storage may well become a significant use of solar energy in the not too distant future.

CONCLUSION

Photosynthesis is the key process in the living world and will continue to be so for the continuation of life as we know it. The development of photobiological energy conversion systems has long-term implications. We might well have an alternative way of providing ourselves with food, fuel, fiber, and chemicals in the next century.

Suggested Timetable for Biomass-for-fuel Programs

Next 10 years:	Fuels from residues, trees and existing crops; use of existing biofuels; demonstrations and training.

10-20 years: Increased residue and complete crop utilisation, local energy crops, and plantations in use.

After 20 years: Energy farming; improved plant species; artificial photobiology and photochemistry.

ACKNOWLEDGEMENT

Parts of this article are derived from studies done by the author for a UNESCO study on 'Fundamental World Energy Problems', a UNEP project on 'Photosynthesis in Relation to Bioproductivity', and a UN Biomass Panel paper. In addition, various research contracts and reviews by the author have been incorporated (see Hall, 1979 and 1980).

REFERENCES

Anon. 1980. Overview of Opportunities for Energy from Biomass in the European Communities. Commission of the European Communities, Brussels; Elsevier, Amsterdam. (in press).

Barnett, A., L. Pyle, and S.K. Subramanian. 1978. Biogas Technology in the Third World: A Multidisciplinary Review. IDRC, Ottawa, 132 pp.

Benneman, J.R., J.C. Weissman, and B.L. Koopman. 1977. Energy production by microbial photosynthesis. Nature. 268: 19-23.

Bente, P. Editor. 1980. Bio-Energy Directory, Vol. 3. Bio-Energy Council, Washington, D.C.

Bolton, J.R. and D.O. Hall. 1979. Photochemical Conversion and Storage of Solar Energy. Annual Review Energy, 4: 353-401.

Brown, N.L. and J.W. Howe. 1978a. Solar Energy for Village Development. Science, 199: 651-657.

Brown, N.L., and J.W. Howe. 1978b. Energy for the Village of Africa. National Academy of Sciences. Washington, D.C.

Brown, J.R. 1980. Food or Fuel: New Competititon for the World's Cropland. Worldwatch Paper 35, Worldwatch Institute. Washington. D.C.

Calvin, M. 1977. Hydrocarbons via Photosynthesis. Energy Resources. 1: 299-317.

Calvin, M. 1980. Petroleum Plantation and Synthetic Chloroplasts. Energy. 4: 851-870.

Campos Lopez, E. 1980. Renewable Resources: A Systematic Approach Academic Press, New York, 410 pp.

Commission of the European Communities. 1979. Solar Energy for Development. Martinus Nijhoff, The Hague, 240pp.

Chartier, P. and S. Mermaux. 1980. Biomass for France. La Recherche, 11. 766-787.

Chin, K.K. and T.N. Goh. 1978. Bioconversion of Solar Energy: Methane Production from Water Hyacinth. In J.W. White and W. McGrew (Editors). Energy from Biomass and Wastes. Institute of Gas Technology, Chicago, Illinois, 215-228.

Coombs, J. 1980. Renewable Sources of Energy (Carbohydrates). Outlook on Agriculture (in press).

Department of Energy (USA). 1979. Mission Analysis for the Federal Fuels from Biomass Program. Vol. 1. Summary and Conclusion. Department of Energy Publication No. SAN-0115-72.

Electric Power Research Institute. 1978. Biofuels: A Survey. Special Report ER-746-SR, Electric Power Research Institute, Palo Alto, California.

Eckholm, E. 1979a. Planting for the Future: Forestry for Human Needs. Worldwatch Paper 26, Worldwatch Institute Washington, D.C.

Eckholm, E. 1979b. Forestry Success of the Seventies. New Scientist, March 8, 764-765.

Flaim, S.J. and R.E. Witholder. 1978. Policy Aspects of Biomass Utilisation. In K.W. Boer and G.E. Franta (Editors). Proceedings of Annual Meeting AS of ISES. Solar Diversification, Vol. 2.1, pp. 56-60.

Floor, W.M. 1977. The Energy Sector of the Sahelian Countries.

Floor, W.M. 1978. Energy Options in Rural Areas of the Third World. Policy Planning Section, Ministry of Foreign Affairs, The Hague.

Goldemberg, J. 1978. Brazil: Energy Options and Current Outlook. Science, 200: 158-163.

Goldman, J.C. 1979. Outdoor Algal Mass Cultures. Water Res., 13: 1-18; 119-136.

Gochrarg, I. 1979. See ref. UKISES 1979, pp. 30-50

Hall, D.O. 1979a. Solar Energy Use through Biology--Past, Present and Future. Solar Energy, 22: 307-328.

Hall, D.O. 1979b. Biological Solar Energy Conversion for Fuels. Nature, 278: 114-117.

Hall, D.O. 1980. Solar Energy through Biology--Fuel for the Future. In J.T. Manasseh and E.J. Briskey (Editors), Symposium on Advances in Food Producing Systems for Arid and Semi Arid Land. Kuwait Foundation for Advancement of Science (in press).

Hall, D.O., M.W.W. Adams, P.E. Gisby and K.K. Rao. 1980. Plant Power Fuels Hydrogen Production. New Scientist, 86: 72-75.

Harris, G.S., M.L. Leoury, T. Frazer, J.B. Dent, W.A.N. Brown, W.B. Earl, T.W. Fookes, and J. Gibert. 1979. The Potential of

Energy Farming for Transport Fuels in New Zealand. Report No. 46 of New Zealand Energy Research and Development Committee, University of Auckland, Auckland, New Zealand.

Jawetz, P. 1980. Economic Realities of Alcohol Fuels. Sugar Journal. January: 13-15.

Johnson, J.D. and C.W. Hinman. 1980. Science, 208: 460-463.

King, K.F.S., and M.T. Chandler. 1978. The Wasted Lands: The Programme of Work of ICRAF. International Council for Research in Agroforestry, Nairobi, Kenya.

Leach, G. 1976. Energy and Food Production. IPC Press, Guildford, U.K. 180pp.

Lipinsky, E. 1978. Fuels from Biomass: Integration with Food and Materials Systems. Science, 199: 644-651.

Marshall, J.E. 1979. See ref. UKISES 1979, pp. 51-60.

Makijani, A. 1976. Energy Policy for the Third World. International Institute for Environment and Development. London.

McCann, D.J., and H.D.W. Saddler. 1976. Photobiological Energy Conversion in Australia. Search, 7: 17-23.

Mitsui, A., et al. (Editors) 1977. Biological Solar Energy Conversion. Academic Press, New York.

National Academy of Sciences. 1976. Making Aquatic Weeds Useful: Some Perspectives for Developing Countries. National Academy of Sciences, Washington, D.C., 175pp.

National Academy of Sciences. 1977. Methane Generation from Human, Animal and Agricultural Wastes. National Academy of Sciences, Washington, D.C.

Nyns, E.J., H.P. Naveau, R. Chare, and Y. Bertrand. 1980. Digesters--a Worldwide Review. In D.A. Stafford (Editor) Energy for Agriculture in Europe. FAO, Rome (in press).

Openshaw, K., and J. Morris. 1978. Woodfuel--a Time for Reassessment. National Resources Forum, 3: 35-51.

Openshaw, K., and J. Morris. 1979. The Socio-economics of Agroforestry. Proceedings of Conference International Cooperation in Agroforestry, ICRAF, Nairobi, Kenya.

OTA. 1979. Gasohol: A Technical Memorandum. Office of Technology Assessment, United States Congress, Washington, D.C., 71pp.

Parikh, J.K. 1979. Renewable Energy Options: What could Developing Countries Expect from Them? Energy, 4: 989-994.

Parikh, J.K., and J.K.S. Parikh. 1977. Mobilization and Impacts of Biogas Technologies. Energy, 2: 441-455.

Parente, G.J.S. 1980. Marmeleiro--the Oil Tree. Federal University of Ceara, Fortaleza, Brazil.

Pimentel, D., and M. Pimentel. 1979. Food, Energy and Society, Arnold, London, 165pp.

Revelle, R. 1979. Energy for Rural Development. Energy, 4: 969-988.

Richmond, A., A. Vonshak, and S. Arad. 1979. Environmental Limitations in Outdoor Production of Algal Biomass. Institute of Desert Research. Ben Gurion University, Sde Boker, Israel, 17pp.

SEMA. 1978. Energy in the Development Strategy of the Sahel--Situation, Perspectives and Recommendations. SEMA, Montrouge, France, 57pp.

Seshadri, C.V. 1977. A Total Energy and Total Materials System using Algal Cultures. MC Research Centre, Madras, India.

Seshadri, C.V., G. Venkataramani, and V. Vasarth. 1978. Energy Plantations--a Case Study for the Coromandel Littoral. MC Research Centre. Madras, India.

Slesser, M. and C. Lewis. 1979. Biological Energy Resources. Spon, London, 192pp.

Smil, V., and W.E. Knowland. 1980. Energy in the Developing World: the Real Energy Crisis. Oxford University Press, Oxford, 300pp.

Stafford, D.A. (Editor). 1980. International Symposium on Anaerobic Digestion, CRC Press, Boca Raton, Florida (in press).

Steward, G.A., H.A. Nix, G. Gartside, W.H.M. Rawlins, R.M. Gifford, and J.R. Siemon. 1979. The Potential for Liquid Fuels from Agriculture and Forestry in Australia. CSIRO, Canberra, Australia, 146pp.

St. Pierre, L.E., and G.R. Brown. (Editors). 1980. Future Sources of Organic Raw Materials: Chemrawn I. Pergamon Press, New York, 651 pp.

Terrado, E.N., P.V. Bawagan, and J.A. Semana. 1978. In F. de Winter (Editor) Sun: Mankind's Future Source of Energy. Pergamon Press, New York, 101-105.

UKISES. 1976. Solar Energy: A U.K. Assessment. Ch. 9 UK-ISES, London.

UKISES. 1979. Biomass for Energy. Proceedings of Conference. C20, UK-ISES, London.

van Buren, A. 1979. The Chinese Biogas Manual. IIED, London.

van der Wal, P. 1979. Perspectives on Bioconversion of Organic Residues for Rural Communities. United Nations University, Tokyo, Japan. pp.3-8.

Vergara, W. and D. Pimentel. 1978. A Study of the Energy Potential of Fuels from Biomass in Five Countries.

Advances in Energy Systems and Technology, Vol. 1, Academic Press, New York, pp. 125-173.

Watt Committee. 1979. Energy from the Biomass. Report No. 5 Watt Committee, London.

Weisz, P.B., and J.F. Marshall. 1979. High-grade Fuels from Biomass Farming: Potentials and Constraints. Science, 206: 24-29.

Wittwer, W.W. 1980. Future Challenges and Opportunities for Agricultural and Forestry Research. In L.E. St. Pierre and G.R. Brown (Editors). Future Sources of Organic Raw Materials: Chemrawn I. Pergamon Press, New York, pp 401-412.

World Bank. 1979. Prospects for Traditional and Non-conventional Energy Sources in Developing Countries. Working Paper No.346. World Bank, Washington, D.C.

Yang, U., and S.C. Trinidade. 1979. Brazil's Gasohol. Chemical Engineering Progress, April 11-19.

DEVELOPMENT OF A SYNTHETIC GAS FROM COAL INDUSTRY IN THE UNITED STATES

William T. McCormick, Jr. and P. Chrisman Iribe
American Natural Service Company, Detroit, Michigan, USA

I. Introduction

Coal gasification is increasingly being recognized as an efficient and environmentally acceptable technology that can help alleviate the energy problem in the United States by reducing its dependence on imported oil through increased utilization of large domestic coal reserves. When compared with other coal utilization options, coal gas offers significant economic and environmental benefits from a national perspective. It has been estimated that a high Btu coal gasification facility would generate less than one-tenth the pollutants, consume five to ten times less water, at only half the cost (accounting for end-use efficiencies) of a coal-to-electricity generating facility producing equivalent amounts of end-use energy (see Table I)[1]. In the case of coal-to-liquids production, the synthetic product is roughly 25-50% more costly than high Btu coal gas on a Btu basis. Furthermore, relative to the rising price of gas from conventional sources, the cost of coal gas over the life of the plant is expected to remain essentially flat due largely to the sizeable fixed investment.

---

[1]A Comparison of Coal Use for Gasification Versus Electrification, American Gas Association, Energy Analysis, April 26, 1977.

The technology for coal gasification has been under development since the early 1600s. Commercial use of low Btu coal gas was prevalent during the early industrialization of the U.S. By the 1920s, some 11,000 small gasification units were in use throughout the country. After natural gas was discovered in sizeable quantities in the 1950s, continued U.S. research into gasification technology virtually ceased. In the meantime, a utility transmission and distribution network over 1 million miles in extent representing $50 billion of investment was constructed (Figure I shows the interstate transmission system). This industry delivers natural gas to over 40 million homes, offices, and industries where an additional $50 billion has been invested in appliances, furnaces, and other gas consuming equipment. In the early 1970s, however, U.S. reserves of conventional natural gas began declining (see Figure II) and the industry began exploring alternatives to natural gas production. Recognizing the vast domestic resource represented by U.S. coal reserves, proposals for initiation of a high Btu gas from coal industry were developed.

The following discussion focuses on the development and potential growth of a U.S. coal gasification industry that will produce substitutes for natural gas. Although reference is made to the production of low Btu coal gas, the focus of this paper is on medium and high Btu gas which can be delivered through existing distribution systems. The paper addresses not only the present state of technology, but also potential market applications, the necessary research and development to achieve these goals, and the major financial and regulatory problems that must be overcome for large-scale commercialization.

II. Overview

Production of synthetic gas from coal requires both chemical

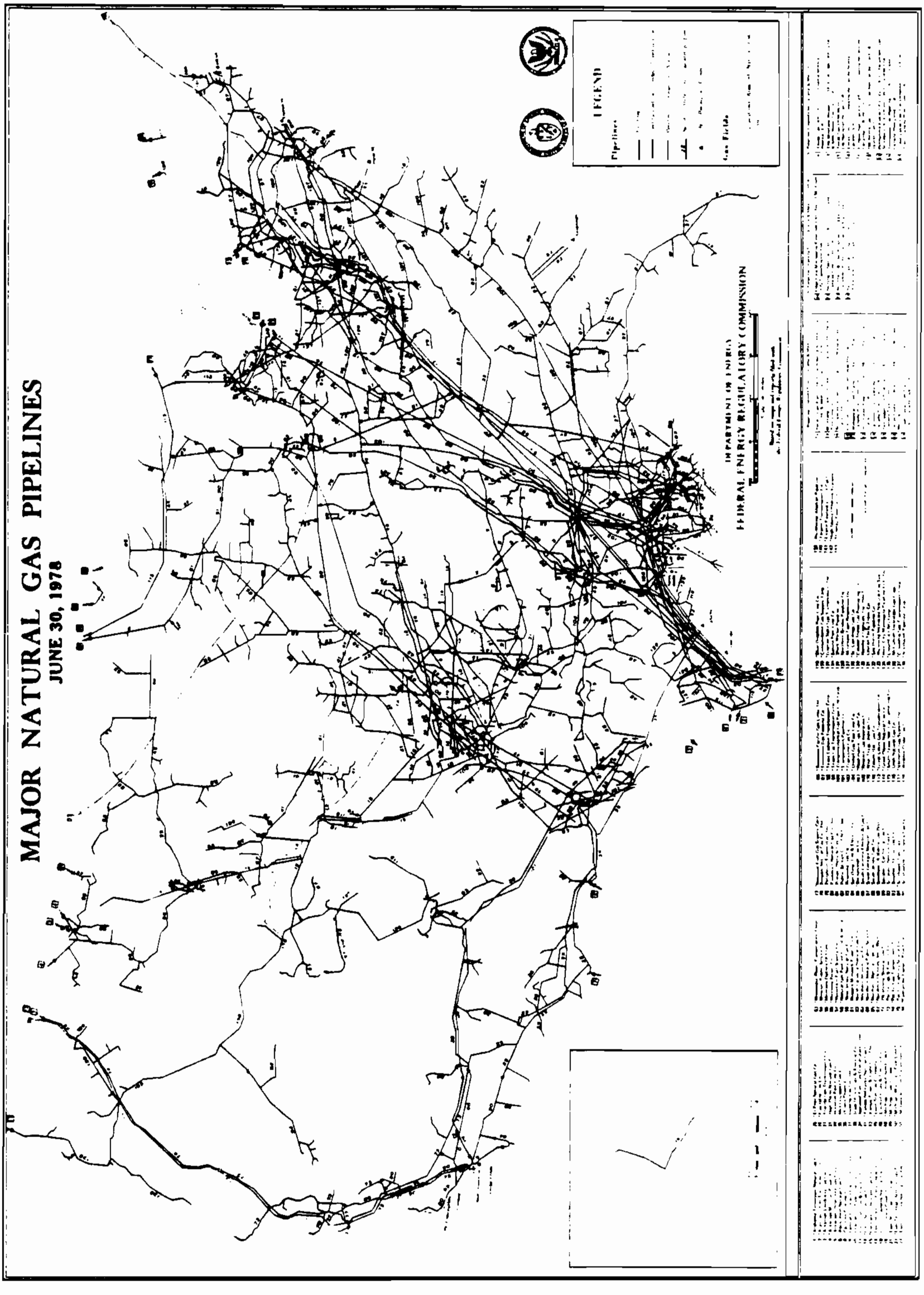

MAJOR NATURAL GAS PIPELINES
JUNE 30, 1978
LEGEND
DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

FIGURE 1

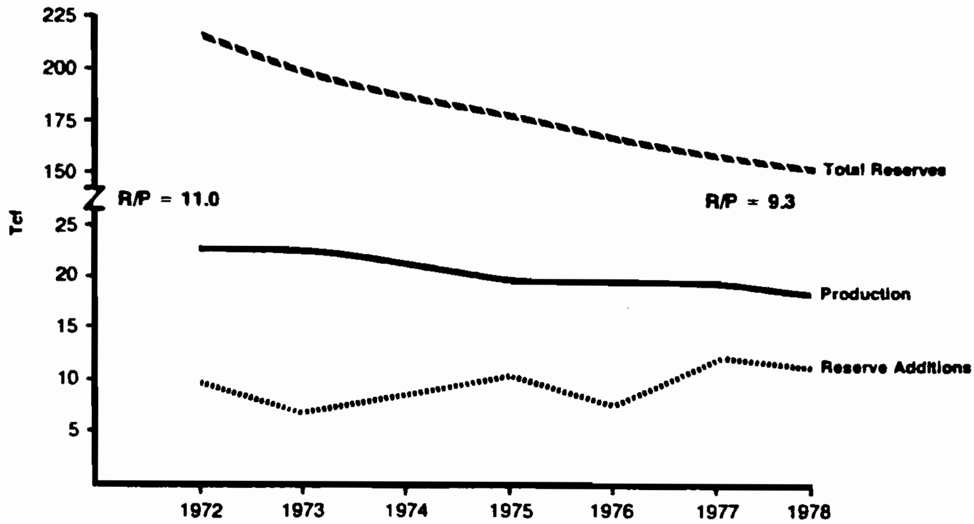


FIGURE II U.S. Natural Gas Reserves and Production (Lower 48 States)

and physical transformation. The high Btu coal gasification processes that already exist or are currently under development share five major steps: coal preparation and pretreatment, gasification, shift conversion, gas purification and methanation. For Medium Btu gas production, only the last step "methanation" is omitted, while for low Btu gas, the purification step is also generally omitted.

Synthetic natural gas can be produced from coal either by mining and then processing through gasification plants or using in-situ (i.e., underground gasification techniques). Depending upon the degree of processing, the resulting Btu content of gas produced through coal conversion ranges between 100 and 1,000 Btu per cubic foot (cf) of gas. In comparison, pipeline gas from conventional sources typically contains approximately 1,000 Btu per cubic foot.

Consequently, only the high Btu (950-1,000 Btu/cf) synthetic natural gas product (SNG) is considered pipeline quality and perfectly substitutable for conventional gas in present transmission systems. The ability to make pipeline quality SNG is particularly important given the size of domestic coal reserves, the broader base of gas applications and the relative beneficial environmental impacts of coal gasification compared to direct combustion of coal.

While underground coal gasification has the potential to significantly expand the economic extraction from coal seams which are unrecoverable with conventional mining techniques, the gas tends to be of low quality. In underground coal gasification, burning is initiated at a primary bore hole with the product gas flowing through a physical linkage to another bore hole for recovery. When air is used to supply oxygen to the burning coal-front, low Btu gas results. However, if pure oxygen is used, the nitrogen content of the product gas is greatly reduced and the medium Btu product gas can be cleaned and methanated to produce SNG.

Although low and medium Btu gas are generally only suitable for on-site combustion or short distance transportation because of economic considerations, they could become an important part of gas utility operations in the future. In particular, medium Btu gas offers gas utilities the opportunity to provide gas to industrial customers where the use of conventional natural gas may be prohibited by regulatory constraints. It is estimated that the industrial market potential for medium Btu gas could be as much as 3 Quadrillion (10^{15}) Btu per year. This estimate includes both single-user plants with energy requirements of 7-10 billion Btu per day as well as multiple-user plants requiring at least 30 billion Btu. Market penetration could be further enhanced by the addition of methanation facilities to a medium Btu plant. Under these circumstances, both medium and high Btu gas could be produced to serve separate markets and improve coal gas plant efficiency through load balancing.

Based on optimistic projections of commercialization assistance through Federal risk sharing and/or other Federal programs, an estimated 90 billion cubic feet of equivalent high Btu SNG could be produced by 1985. With the necessary research and development funding, the appropriate regulatory environment, there could be as much as 3.5 trillion cubic feet of SNG production per year by the year 2000 (see Table I).

TABLE I Conversion of Coal to Electricity or SNG

	Coal Gas	Electricity
PLANT CAPACITY		
For equivalent amounts of useful end-use energy considering furnace and appliance efficiency	250 MMcf/d	3,000 Mw w/Scrubbers
UNIT PLANT CAPITAL REQUIREMENT (billions of 1978 $)	$ 1.6	$ 3.1
DELIVERED RESIDENTIAL COST (1978 $/MMBtu)	$ 6.00	$ 14.00
TOTAL SYSTEM EFFICIENCY	36%	25%
END-USE RESIDENTIAL ENERGY COST ($/MMBtu)	$ 9.20	$ 14.10
KEY ENVIRONMENTAL RESIDUALS (lbs/hr)		
Particulates	180	1,596
SO_2	450	3,300
NO_x	1,780	21,900
WATER REQUIREMENT (acre-ft/yr)	6,300	33,300
ANNUAL COAL REQUIREMENTS		
Trillions of Btus	140.4	201.4
Millions of tons — Western coal	8.0	11.5

III. Resource Size

The United States is estimated to have coal reserves of some 438 billion tons[2] (10,000 quads), one-half of which can be recovered under present technical and economic conditions. In total, this is enough potential energy to satisfy total U.S. energy requirements (78 quads in 1979) for 130 years. Relative to this resource base, a single high Btu commercial scale coal gas facility (250 MMcf/d of production) is estimated to consume only 0.2 billion tons of coal during its entire 20-year life. Consequently, at current rates of natural gas consumption, 500 years of SNG could be produced.

---

[2]The Demonstrated Reserve Base of Coals in the United States as of January 1, 1976, U.S. Bureau of Mines, Department of the Interior, August 1, 1977.

Although not all coals are suitable for any given coal gasification technology (currently available processes are principally suitable for gasifying western U.S. coals), alternative conversion technologies can accept different types of coal. However, through continued research and development efforts, the breadth of coal feedstock that specific conversion methods can accept will increase and make possible utilization of virtually all types of coal. In particular, R&D efforts on second generation processes suitable for handling eastern caking coals (agglomerating) would greatly expand the usable resource base.

IV. Coal Gasification Technology

Coal gasification relies on both chemical and physical transformation of coal. Although the actual order in which these processes occur may vary from process-to-process; there are five major steps: coal preparation and pretreatment,[3] gasification,[4] shift conversion,[5] gas purification,[6] and methanation.[7] The heart of the gasification process is the gasifier where coal, water and air are reacted under heat and pressure to generate a gas stream which can then be further treated to produce the desired product.

Currently, there are three principal gasifer systems including: fixed/moving bed, fluidized-bed, and entrained-bed gasifiers. Each of these systems have advantages and disadvantages depending on the proposed coal type, product gas requirements, plant scale and in-

---

[3]Cleaning, washing, grinding to appropriate size.

[4]Coal or carbon reacts with steam (H_2O) at high pressure to produce methane (CH_4), carbon monoxide (CO) and hydrogen (H_2).

[5]CO reacts with H_2O to produce CO_2 + H_2 to adjust the H_2/CO ratio to optimize.

[6]The product gas which in addition to H_2/CO contains other impurities including acid gases and CO_2 which are removed.

[7]H_2 reacts with CO to produce additional CH_4 plus H_2O.

vestment levels. Consequently, a number of process alternatives and technological improvements are being studies, and in some cases, commercially demonstrated for each of these generic gasifier systems. Following is a short discussion of the currently proposed technologies in order of their likely commercial availability and in terms of their gasification efficiency (i.e., the percentage of methane -- CH_4 -- produced in the gasifier)[8]. See Figure III for a generalized representation of these processes.

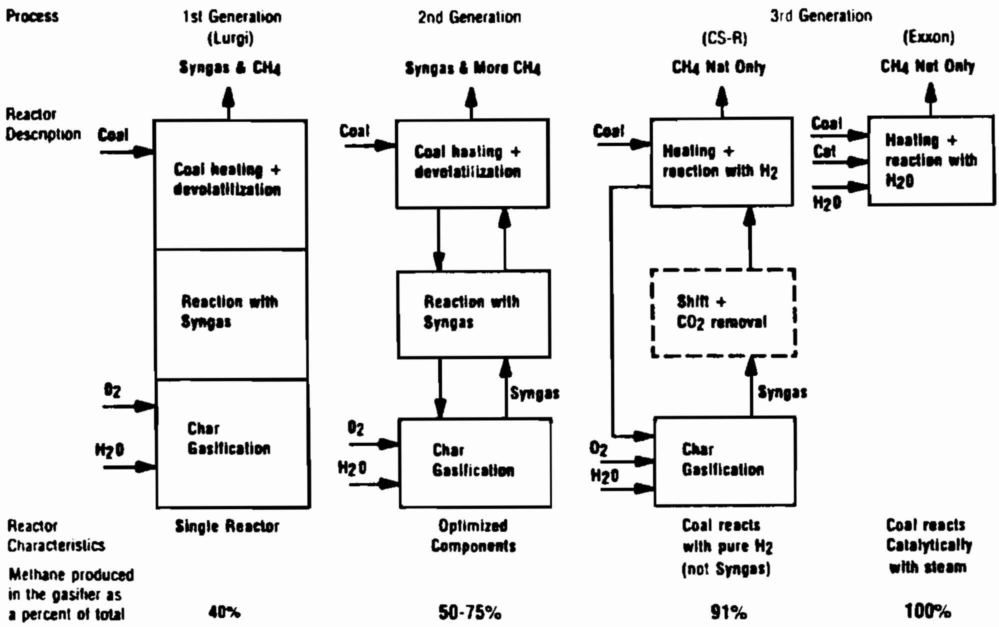


FIGURE III Coal Gasification Technology Development

First Generation Technologies - These are state-of-the-art systems that are currently operational and available for purchase. Examples of these gasifiers include Lurgi, Koppers-Totzek, Wellman Galusha, Stoic, Woodall Duckham. In the Lurgi fixed bed reactor,

---

[8]For a detailed review of coal gasification technology and individual systems, see Coal Gasification Technology Overview, W.W. Bodle and F.C. Schora, Institute of Gas Technology, 3424 S. State Street, Chicago, IL 60616, USA.

for example, coal enters the reactor at the top and moves slowly downward counter-current to the gas stream moving upward. The reactor has three distinct areas. In the top of the reactor, the coal is heated by the hot product gases and the coal is partly devolatilized. In the middle section, the coal reacts with the hot gases coming from the bottom of the reactor to produce volatile products and char. The char is gasified in the bottom section with oxygen and steam, leaving ash behind. Overall, the product gas from the reactor contains 40 percent of the total methane produced in the plant. Lurgi is the most common gasifier system in present use and would be used in the Great Plains project[9] currently proposed for a site in North Dakota.

Second Generation Technologies - Those gasification systems currently in the pilot plant stage of development or soon ready for commercial demonstration. Included in this group are the HYGAS, BIGAS, Synthane, Slagging Lurgi, Texaco, COGAS and pressurized Koppers-Totzek gasifiers. These processes use essentially the same gasification techniques as first generation technology except the reactions are performed under conditions which maximize methanation in the gasifier. To achieve these conditions, the reactor is divided into separate sections, which makes it possible to optimize each section, often by means of fluidized or entrained bed reactors. As a result, the methane generation in the gasifier is increased to 50-75% of the total methane produced.

Third Generation Technologies - These are the newer advanced concepts that are either at the bench scale level of development or in the early process development (PDU) phase. For pipeline gas applications, there are several basic technology options being developed including: flash hydropyrolysis, catalytic gasification

[9] Partners in this project are American Natural Resources, Peoples Energy Corporation, Columbia, Tenneco, and Transasco.

and direct hydrogasification. The third generation reactors are substantially different from first or second generation process. In the hydropyrolysis reactor, the top and middle sections of the second generation reactor have been combined. The coal is now reacted with pure hydrogen (not a syngas as before) to produce only methane. The remaining char is gasified in a char reactor as before. The shift and carbon monoxide removal section in this system generates and separates the process hydrogen from the gases coming from the char gasifier. In the catalytic reactor, all three reaction sections are combined into a single fluidized bed. In this bed, the coal is heated and reacted directly with steam rather than hydrogen or syngas in the presence of a catalyst to produce methane and carbon dioxide.

V. Current Research, Development and Demonstration Programs

A. High Btu Surface Gasification

1. Research & Development - Over the past several years, major research and development efforts have been undertaken to improve the existing coal gasification processes in order to utilize coals not suitable for the conventional Lurgi fixed-bed process, as well as to lower the cost of the product gas. One of the major efforts has been the co-sponsored Department of Energy/Gas Research Institute (DOE/GRI) coal gasification program, which is the successor to work started in 1971 by the Office of Coal Research and the American Gas Association. As of 1979, pilot plant activity on second generation technologies were completed. In addition to the DOE/GRI program, other R&D by private industry has also resulted in a number of promising new technologies. At present, three of these second generation processes ready for demonstration are British Gas Corporation/Slagging Lurgi,

COGAS, and HYGAS.

The BGC/Slagging Lurgi has been developed with private funding and tested at a pilot plant in England. The process uses an advanced Lurgi gasifier designed to overcome some of the problems associated with a conventional dry-bottom Lurgi gasifier.

COGAS utilitizes a fluidized-bed reactor with indirect heat supply by combustion of char with air at low pressure. The COGAS process has been tested in a pilot plant at Leatherhead, England, to produce a synthesis gas that can be converted to methane. An integrated COGAS plant would make oil and gas in about equal amounts on a Btu basis.

The HYGAS process also utilizes a fluidized-bed, multiple state reactor. The process uses coals of any rank or sulfur content. Feasibility of operation has been demonstrated with lignite, sub-bituminous and Illinois basis high-sulfur bituminous coal at a 3 ton/hour pilot plant in Chicago.

Because of the promising potential, DOE has contracted for separate engineering design studies on these three processes and is considering construction of demonstration plants based on one or more of the processes.

Continuing work in industry and government on third generation processes is being conducted by Exxon on its Catalytic Conversion process, by Westinghouse on its two-Stage Fluidized Bed, by Bell Aerospace on its High-Mass Flux, and by Rockwell International on its Short-Residence Time Hydro-gasification process. However, it is still too early to determine whether the development of these technologies should be expanded beyond the small scale pilot plant facility.

2. Commercial Demonstration - In recent years, a number of commercial both full- and half-scale (250 MMcf/d and 125 MMcf/d, respectively) high Btu coal gasification projects have been proposed (see Appendix). While no U.S. project has, however, yet obtained financing due to large financial risks, one has received regulatory approval.[10] Moreover, the gas utility industry has, to date, invested over $130 million in equity capital in various coal gasification projects.

B. Medium Btu Surface Gasification

A wide variety of projects to manufacture low and medium Btu gas are underway in the United States. The largest program is the demonstration plant to be built in Memphis, Tennessee, that will supply medium Btu gas to local industries. Funding is to be provided by the DOE and Memphis Light, Gas & Water. Process engineering and construction management will be handled by Foster Wheeler and operation provided by Delta Refining Company. The IGT U-Gas process will be used. The plant will produce approximately 50 billion Btu per day of medium Btu gas with a coal feed rate of 3,000 tons per day. Operation is expected to begin in 1985. Based on recent economic studies for the Memphis plant, the delivered cost of medium Btu gas from coal will be about $4.25/million Btu in fourth quarter 1979 dollars.

---

[10] The Great Plains Gasification Associates, North Dakota facility, received authorization for construction early in 1980. The Federal Energy Regulatory Commission decision to provide for rate-payer guarantee of the debt has been challenged in the US Court of Appeals. The appeal has not yet been decided.

C. In-Situ Gasification

In underground coal gasification, the USSR efforts far exceed total efforts of other countries. Reportedly, in-situ gasification plants have been operated for many years. In Canada, the Alberta Research Council, in association with other energy-related agencies, performed field tests in 1976. Early trials with underground gasification of coal were also made in the United Kingdom in the 1950s as well as in Belgium. At the present time, Belgium and the Federal Republic of Germany are studying pressurized underground gasification under a cooperative agreement. After extensive laboratory research, full-scale linkage trials are to be made in Belgium. Italy has carried out trials on gasification but has no operational sites presently. Experiments have also been made in Poland, Czechoslovakia, and Morocco.

The U.S. Department of Energy has four funded projects: the western low Btu trials at Hanna, Wyoming; the Western medium Btu trials at Hoe Creek, Wyoming; the eastern coal technology trials near Pricetown, West Virginia; and a project to gasify a steeply dipping bed near Rawlins, Wyoming. According to a DOE spokesman, the Hoe Creek test using oxygen injection was completed. The test duration was 47 days and the heating content of the produced gas was 210 Btu per cubic foot. The results are considered encouraging although the test was not a total success. The test with the steeply-dipping bed near Rawlins, Wyoming, is currently underway with steam/oxygen injection. Gas heating value is averaging 300 Btu per cubic foot.

In addition to governmental efforts, there are at least three active projects in the U.S. being explored by private industry. The most advanced are the efforts by Texas Utilities

Company which has purchased underground coal gasification technology from the Soviet Union and is running tests using Texas lignite. The Atlantic Richfield Company is testing sub-bituminous coal in the Wyoming Powder River Basin. In addition, the University of New Mexico, in conjunction with the Public Service Company of New Mexico, is planning a field test on bituminous coals in the San Juan Basin.

VI. Production Problems

A. Technical

1. Surface Gasification - From a technical point of view, no significant production problems exist for high Btu gasification of western U.S. coals using existing Lurgi fixed-bed technology. Although the types of western American coals that would be used in potential synthetic gas projects have been tested in similar gasifiers in Westfield, Scotland, and Sasolburg, South Africa, commercial scale methanation (necessary for high Btu gas production) has not yet been demonstrated over extended periods of time. Other first and second generation processes which are applicable to eastern coals are not yet commercially available. No significant technical problems exist for medium Btu gasification of all coal types given the wide variety of available processes.

2. In-Situ - Underground coal gasification has yet to resolve the many technical problems including:

- Demonstration of reliable cost-effective linking near the bottom of the coal seam;
- Determination of process efficiencies and sweep efficiencies in multi-well systems;

- Development of process control techniques to achieve reliable product gas composition and flow rates and to operate multiple modules;

- Control of water influx to end gas losses from the reaction zone;

- Evaluation of coal seam limitations, including thickness, depth, rank, shale stringers, dip, permeability, hydrology, continuity, overburden and floor rock characteristics; and

- Gasification of swelling coal.

Major environmental uncertainties associated with underground coal gasification are subsidence causing aquifer disruption, water quality effects caused by contamination of ground water with organic and inorganic materials, surface disruption, water usage, possible health and safety problems, and waste and atmospheric emissions.

B. Non-Technical

A number of institutional and economic factors could limit the growth of both underground and surface coal gasification.

For high Btu gasification in addition to commercial demonstration of the methanation step, total investment and production costs are uncertain, since no U.S. commercial scale plant exists. Capital and operating costs are difficult to predict accurately due to the uncertainties of: (1) inflation over the construction period; (2) availability of required labor skills, equipment and raw materials; and (3) the costs of compliance with existing and potential government regulations and laws.

Since the capital costs for a single commercial scale plant are comparable to the net worth of the largest pipeline company,[11] potential lenders are requiring that the debt be guaranteed for these "first-of-a-kind" commercial scale demonstration plants.

Medium Btu gas, although it cannot be shipped long distances (i.e., through the interstate transmission system), can be moved over distances up to 10-20 miles from the production site. This makes it suitable for use in heavily industrialized areas where many industries are located in close proximity with each other. Again, the technology has yet to be proven commercially feasible in the U.S. Moreover, there continues to be significant concern on the part of potential customers on the comparative economics of medium Btu versus direct consumption of coal oil or natural gas.

With regard to in-situ coal gasification, non-technical problems include pricing, regulatory policies, environmental, health and safety permits, land-use policies, and the lack of firm economic data on produce costs. The large capital requirements for demonstration and initial commercial development will be difficult for gas utilities to finance unless direct Federal support or loan guarantees by the Federal government are available.

VII. Needed Programs and Financial Support

In order to accelerate development of a coal gasification industry in the U.S., government efforts to resolve many of these non-technical problems, especially the regulatory and commerciali-

[11] The Great Plains gasification project, a half commercial scale facility, is estimated to generate 125 MMcf/d (950 Btu/cf) at an estimated cost of approximately $1.1 billion (1980 US dollars). This is roughly comparable to one-third the net worth of the largest natural gas utility in the US - the Columbia Gas System.

zation risks must be forthcoming. These efforts include government funded R&D programs, clearly defined environmental requirements, providing loan guarantees, and allowing utilities to initially "roll-in" the higher cost of synthetic high Btu coal gas with conventional gas supplies in their customer gas prices.

Several Federal risk-sharing programs have been proposed over the last five years to reduce commercialization uncertainties and risks to an acceptable level for private financial sector participation in surface coal gasification.

The Federal Energy Regulatory Commission has recently approved a number of special incentives for the Great Plains Coal Gasification Project. The most important of these rate provisions are: a consumer guarantee of the debt by means of an abandonment tariff, interest and DOE surcharges during construction, rolled-in pricing and a full cost of service tariff. Also, the Congress is considering two separate legislative initiatives which address the principal production problems.

- An Energy Mobilization Board or "fast track" agency which would ensure that important national energy projects would receive expeditious treatment through the regulatory approval process including the limitation of unnecessary regulatory requirements during the construction and initial operation period (assisting both capital cost and price containment).

- A Synthetic Fuels Corporation which could make available Federal loan guarantees of up to 75% of initial estimated project costs and 60% of cost overruns. This corporation is to proceed in two phases. Phase I would have authorized funding for $20 billion in Federal financial incentives to be used on a one-for-one basis (i.e., $1 of authorization for $1 of project guarantee). Phase II, depending on the success of Phase I, would be expanded by an additional $68 billion in authorization.

VIII. Production Estimates

The production and marketability of pipeline and near-pipeline quality coal gas will be determined by a large number of interrelated factors including the investment capabilities of the gas transmission and distribution companies, financial support from the Federal government, conducive treatment from regulatory agencies, energy demand, and the price of alternative fuel including the direct use of coal. Estimates for total coal gas production between now and 2000 are presented in Table III. The potential contribution

TABLE II

Range of Production Estimates for Coal Gasification
(Annual Bcf - 1,000 Btu/cf)

	Low	High
1985	45	90
1990	200	1,000
1995	800	2,000
2000	1,500	3,500

TABLE III

Range of Production Estimates for Coal Gasification
(Annual Bcf - 1,000 Btu/cf)

	High Btu Gasification		Medium Btu Gasification		Underground	
	Low	High	Low	High	Low	High
1985	45	90	20	20	0	0
1990	180	760	70	180	0	45
1995	720	1890	150	360	25	90
2000	1260	2970	220	510	50	180

of high Btu coal gas to the U.S. gas supply picture through the year 2000 is shown on Figure IV.

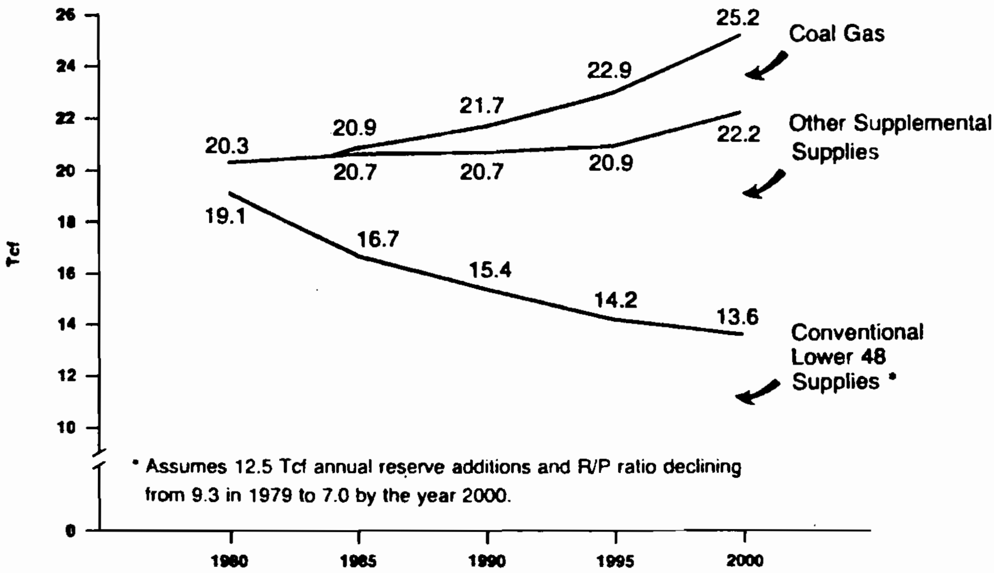


FIGURE IV U.S. Gas Supplies

A. High Btu Surface Gasification

1. High Case - Assuming action on the pending Federal loan guarantee program and passage of "fast track" legislation, an initial phase of commercial high Btu gas demonstration projects could be under construction by the early 1980s. Totaling roughly 450 Bcf annually, production from these first phase plants could be on-stream by 1987 (in 1985, production from the Great Plains project in North Dakota and one other half-scale plant could be expected to total 90 Bcf). With continuation of a Federal loan guarantee program during the middle and late 1980s, an additional 15 full-scale plants could be under construction by the end of the decade -- some in the form of additions to facilities at existing sites, some at new sites. With the termination of Federally-assisted commercial

demonstration projects around 1992, 1.3 Tcf of synthetic gas could be produced annually. Thereafter, an average of two to three commercial scale facilities are estimated to go into construction annually with total production by the year 2000 of some 3.0 Tcf. This seemingly rapid growth of a high Btu gasification industry was mirrored during the 1960s and 1970s with the growth of nuclear electric generating industry in the U.S. For comparison purposes, Figure V depicts the growth pattern for the nuclear industry versus that proposed in the high growth situation for the high Btu coal gasification industry. It is interesting to note that were these industries launched today, they would cost roughly the same in terms of total investment costs.

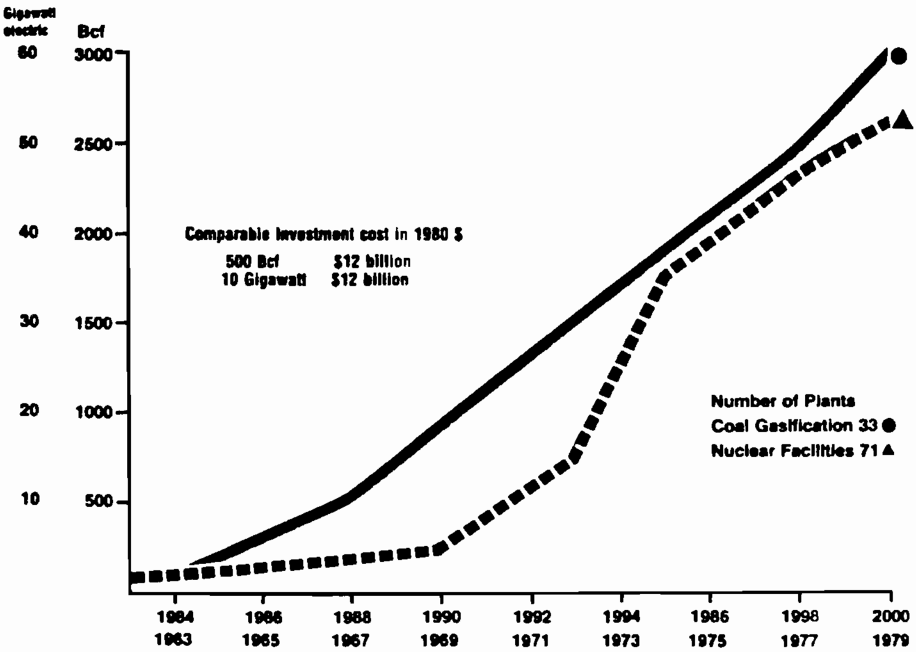


FIGURE V High Btu Coal Gasification Industry Growth vs. Comparable Nuclear Industry Growth

2. Low Case - Alternatively without loan guarantees or

"fast track" programs, only the half-scale Great Plains plant would be producing gas by 1985. With expansion of this facility to full-scale by 1990 and an additional two half-scale facilities at other sites, a total of only 0.2 Tcf of high Btu coal gas would be produced by 1990. Expansion of these two plants to full-scale plus one additional full-scale plant per year in the 1990s could result in 14 full-scale plants by the year 2000 producing 1.3 Tcf annually.

B. Medium Btu Gasification

1. High Case - The maximum potential production from medium Btu gas in 1990 is approximately 180 Bcf. This includes 37 Bcf from the demonstration plant proposed by Memphis Light, Gas & Water (which will actually begin producing 18 Bcf in 1985) as well as other plants totaling 143 Bcf. By the year 2000, total production could reach an estimated 550 Bcf.

2. Low Case - The low case estimate reflects limited market penetration of medium Btu gas use due to industry resistance. On this basis, likely 1990 annual production would be limited to the scaled up Memphis demonstration plant and one additional full-scale plant. Additional plants would be added by the year 2000 for a total annual production of 220 Bcf.

C. In-Situ Gasification

1. High Case - The maximum production potential for underground gasification, including methanation, is based on one demonstration plant (125 million cubic feet per day) on-stream by 1990, upgrading to a full-scale installation (250 million cubic feet per day) by 1995, and an additional full-scale operation by the year 2000.

2. Low Case - The low estimate assumes reduced effort on

underground gasification technology development and fewer demonstration facilities in the later years. In this situation, operation of a smaller demonstration plant (75 million cubic feet per day) by 1995, and upgrading of the demonstration plant to a 125 million cubic feet per day facility by the year 2000 is expected.

NATURAL GAS RESOURCES IN COAL DEPOSITS

A.I. Gritsenko, Y.I. Yermakov, and I.P. Zhabrev
Academy of Sciences of the USSR, Moscow, USSR

Numerous reports in the literature show that fossil coal formation is usually accompanied by an abundant evolution of gases, methane being the basic component. Carbonification dates from the initial burial of a floral material. In the course of geological time this material, mainly cellulose and lignin with smaller amounts of resins and waxes, is gradually changed into peat, brown coal (lignite), and hard coal.

Two main stages of carbonification are usually distinguished: (a) diagenesis (lithification) which includes biochemical processes, this process occurring at normal temperatures and pressures, and (b) metamorphism, which occurs at ever-increasing temperatures and pressures (as the peat bogs overlap more and more with younger sediments and submerge deeper and deeper).

Diagenesis terminates with the formation of soft brown coal. Lustrous lignites, hard coals, and anthracites develop during metamorphism, and this completes the process of carbonification. This overall and stage-by-stage process of coal formation from peats to hard coals and anthracites is accompanied by complete transformation of the coal structure.

According to today's concepts, coal is a polymer composed mainly of aromatic units with various degrees of condensation. The units are united into a single macromolecular system by means of hydroaromatic bridge compounds and linearly polymerized hydrocarbons. During metamorphism this complicated substance loses its functional groups and the side-chains of hydrocarbons decrease in number while the bridge bonds branch out and the aromatic units condense.

The early stages of carbonification result in the formation of oxygen-containing compounds and methane. During the middle stages of metamorphism (which correspond to an increase in the condensation of aromatic units following the destruction of linearly polymerized hydrocarbonic bonds and side-chains) heavy homologs of methane are formed together with methane itself. In the later stages of metamorphism, when the aromatic units become highly condensed and the content of linearly polymerized hydrocarbon radicals diminishes, the yield of methane homologs decreases while liberation of methane and, perhaps, hydrogen increases.

At each stage of carbonification the amount of generated gas exceeds that of the initial coal substance by many times. The bulk of the gas so formed migrates into the environment. Some of the gas is retained in the coal seam which forms the gas generator. The amount of retained gas depends upon the thermobarometric conditions and the properties of the coal. Coal is a highly porous, natural sorbent with a great capacity for reversible adsorption. According to Airuni (1970), the pores and cracks in coal seams vary in size from 10^{-6} to 10^{-2} cm or even more. Ultrapores and micropores occur with a size $<10^{-6}$cm, intermediate pores with a size from 10^{-6} to 10^{-5}cm; submacropores and macropores are also present with a size from 10^{-5} to 10^{-2}cm, and visible cracks and pores of size $>10^{-2}$cm. There are also typical enclosed pores which can liberate gas only upon intensive coal contraction. The total coal porosity reaches 12-13%, the cumulative specific surface of coal being 100-200 m^2 g^{-1}.

The gas accumulating within the body of the coal is present in two phases--a free, compressed phase, and an adsorbed phase. The high sorptivity of coal probably explains why the bulk of gas in coal seams is usually in the adsorbed phase.

Ettinger (1966) studied the specific features of methane adsorption by the coal and found the following: (a) as the content of volatile components in the coal decreases, methane adsorption increases, from weakly metamorphosed coal towards anthracites; (b) adsorption increases with increase in pressure from 0 to 200-400 atm but any further growth of pressure does not significantly affect the amount of methane adsorbed; and (c) increase in temperature decreases the sorptivity of the coal.

Coal porosity depends upon its degree of metamorphism; it diminishes in coals with a volatile content of 40% from 11-12% to 4-5% in lean coals and anthracites.

These specific features of coal as a collector permit the conclusion that, at pressures up to 100 atm, the bulk of the methane accumulated by the coal seam is in the adsorbed state. At pressures above 100-200 atm when no further adsorption is possible, the methane accumulation in vacant pores becomes more important. In weakly metamorphosed coals the amount of free gas is only 10% of the total bulk at 20 atm, 30% at 200 atm, and 80% at 1000 atm. In strongly metamorphosed coals at the same pressures the total porosity decreases and the share of free gas drops to 2, 8, and 47%, respectively.

Because the sorptivity decreases at pressures of 100-200 atm and because the increase in temperature and the vacant porous space are lowered at elevated pressures, the amount of gas which can be held in coal does not seem to change down to a depth of 3-5 km. On average, the gas reaches 25 m^3 ton^{-1} and only at pressures of about 1000 atm does the presence of gas in coal reach 30-40 m^3 g^{-1}.

At present, all basic coal regions of the USSR have been investigated with respect to the gas geology of coal seams. As a result many data are now available on gases in coal seams of all degrees of carbonification. This is of particular importance because gases from each previous stage of the metamorphism are not retained in the coals but replaced by the newly formed gases of the next metamorphic stage. Therefore, coal seams chiefly contain only those gases which were developed at the end of the carbonification stage reached, when tests are carried out.

The upper levels of coal mines are, as a rule, found to be in the zone of gas weathering (the thickness of such zones depends upon the actual geological conditions of the coal deposit in question). The gas composition within a gas weathering zone undergoes considerable changes owing to gas exchange with the atmosphere. This is why the initial gas composition can be established only in those levels which are below the zone of gas weathering.

The nitrogen content in coal gases varies from 0 to 99%, the concentration increasing regularly as the surface is approached. This feature points to the aerial origin of the component discussed, a fact which is confirmed by the argon-nitrogen ratio (0.0102-0.0129) which is close to the atmospheric value (0.0118).

Higher contents of carbon dioxide (up to 80-90%) have been found only within the gas weathering zone; maximum concentrations are confined to outcrops of coal seams on the surface or shallow beds. This shows that the bulk of carbon dioxide is a product of biochemical and oxidation processes occurring in the zone of gas exchange with the atmosphere. Above the gas weathering zone the carbon dioxide content decreases sharply, its value varying from 0.1 or 0.2% to several percent.

Methane has been observed in gases of coals in all degrees of metamorphism, from brown coals to anthracites. Its content increases with depth (in proportion to the decreasing intensity of gas exchange with the atmosphere), reaching 90-100% below the gas weathering zone of coal seams.

Extensive investigations of the gases in coal carried out with the help of modern gas-analytical devices have shown that heavy hydrocarbons are frequently components of the gas evolved during coal metamorphism. They have been found in concentrations ranging from negligible to several percent in gases from the Soviet coal basins of the Donets, Kuznetsky, Karaganda, Kizel, Pechora, and Lvov-Volyn, as well as others in the USA, Western Europe, and Japan.

Ethane, propane, butane, as well as pentane and hexane which are much heavier, have been detected in gases from coal.

Methane homologs make up a continuous series, the ethane content varying from 0.01 to 15-23%, the propane content from 0.001 to 13%, the butane content from 0 to 9%, and the pentane content, as a rule, being <1%; the amount of hydrocarbons is generally higher.

The hydrocarbon content has been found to be in direct proportion to the degree of coal metamorphism, the maximum coal percent being observed during the fat and coke stages of metamorphism.

Liquid hydrocarbons have been frequently found in coal-bearing seams alongside gaseous methane homologs. The occurrence of oil and bitumens has been detected in the coal-bearing deposits of the Kuznetsky, Donets, Kizel, Karaganda, Tkibuli-Shoara, Pechora, Chelyabinsk, and other coal basins of the USSR.

So far no unequivocal conclusions have been made about the origin and content of the hydrogen in the free sorbed and dissolved gases of sedimentary rocks. This is basically because of the considerable discrepancies in the data on these hydrogen concentrations cited by various authors, and also because the hydrogen often "disappears" on repeated testing.

Today the presence of hydrogen has been definitely fixed in the gases of the Donets, Kuznetsky, Pechora, Kizel, Suchanov, Karaganda, and other coal basins of the USSR, as well as in some coal-bearing deposits of Western Europe and North America. The observed hydrogen content varies from some tenths of one percent to 20-25% or even more. For example, the coal gases of the Kuznetsky basin contain up to 20-87% of hydrogen while the mines in Georgia have only 5% of hydrogen in their ore-bearing beds. High hydrogen concentrations have been found in the coals of the Norilsk region (80%). The Kizel coal gases have shown a high frequency of hydrogen-containing gases. The local concentrations of hydrogen vary from 1.0 to 87%, the average values being 0.01-1.2 m^3 ton^{-1} of coal.

It is typical that free gas emissions reveal free hydrogen concentrations which sharply decrease with time since hydrogen is extremely mobile.

Knowing the basic features of the coal basin structure and the discovered regularities in gas distribution, one can reliably determine the resources of hydrocarbon gas contained in coal seams. It is feasible first to evaluate the total quantity of gas in commercial coal-bearing strata.

According to Shabarov and Tyzhnov (1958), the total bulk of coal in coal seams of working thickness only (over 0.4-0.5 m) down to 1800 m in depth has been estimated to be 8.6 trillion tons in all Soviet coal basins. Table 1 shows the ratios between coals of different metamorphic degrees, from data obtained for the USSR as a whole.

The quantity of coal in commercial coal-bearing strata which occurs in seams of non-workable thickness and in scattered states can be assessed as follows, with certain approximations of course. According to Lidin and Petrosyan (1962), the total coal capacity of the productive carboniferous beds in the Donets basin is characterized by a coefficient of about 0.04, the value for seams of workable thickness being 0.007 and that for non-workable thicknesses 0.008; scattered coal constitutes a value of only 0.026. Hence, there is somewhat more than 1 m of non-workable coal and 3.7 m of scattered coal per 1 m of workable seam.

Making the same kind of calculations for the Pechora basin one can see that there is 0.6-1.7 m of non-workable coal, which is about 1.1 m on average. For the scattered coal content of about 2%, the cumulative thickness will be 60-86 m, the total thickness of coal-bearing deposits in the Vorkuta and Pechora series being 3.0-4.4 km. This considerably exceeds the total

TABLE 1 Ratios between coals of various metamorphic degree for the USSR as a whole.

Degree of coal metamorphism in the Donets mark classification	Total geological resources (billion ton)
Anthracites and lean coals (A+L)	1080.45
Steam-baking, coking, and steam-fat coals (SB+C+SF)	1952.71
Gas coals (G)	819.32
Long-flame coals (L+LB)	1804.11
Brown coals (B)	3012.91
Total	8669.51

thickness of the workable seams (24-36 m) by practically 150-200% or more. With some approximation, one may say that the coal content in thin beds is on average equal to their commercial reserves.

When calculating gas resources the following factors were taken into account.

(a) The gas present in coal seams below the gas weathering zone at calculable depths is chiefly assessed by the capacity to retain gas in the sorbed state.

(b) With growing degree of coal metamorphism, the gas content of coal seams increases (from 10 to 15 m^3 ton^{-1} in brown coals to 30 m^3 ton^{-1} or even more in anthracites).

(c) At maximal depths the gas content of "average coal" is about 25 m^3 ton^{-1} since brown coals mainly occur at small depths.

(d) With increasing depth the gas content of coal seams increases, upper values being observed at a depth of 600 m when the utmost thickness of the gas weathering zone was 300 m.

Considering these factors the gas distribution at different depths of coal seams of workable capacity is shown in Table 2.

Considering thin coal beds in the USSR, all the gas resources in coal seams down to depths of 1800 m only have been estimated as 240-250 trillion m^3. Hence, despite the "residual" content of methane, such coal seams are still very effective gas accumulators.

We regard coal basins which are only being developed today as the most interesting for the potential evaluation of gas contents. Such coal basins can then be exploited to maximum advantage in the future when the technical problems of gas utilization are largely overcome. Of equal interest are the deep layers of intensively exploited deposits with extremely high gas contents in their coal beds. Among the latter the deep

TABLE 2 Gas distribution with depth.

Depth intervals (m)	Average gas content of coals (m^3 ton^{-1})	Coal reserves (trillion ton)	Methane content (trillion m^3)
0-300	3	2.3	6.9
300-600	10	1.8	18.0
600-1200	20	2.8	56.0
1200-1800	25	1.7	42.5
Total			123.4

layers of the Donets basin must first be mentioned; these were the first for which calculations have been made in the history of Russia. The basic plans of gas utilization from its coal seams and enclosing rocks were calculated for depths of 600-1800 m or even more. The carboniferous coal-bearing deposits at these depths are practically untouched by gas weathering processes. With this in mind, one can expect these coal seams to be very rich in gas, and gas evolution to be higher here than in other places.

According to some forecasts (Kravtsov, 1966), it is quite possible that many regions at 650 m depth in the Donets basin may give up to 60 m^3 of gas per ton of coal or even more. It has been observed already that some mines in the north-western area of this basin provide over 100 m^3 of gas per ton of coal.

It is rather specific for the Donets basin that many effective gas deposits are related to both the coal seams and their enclosing beds. Zones of coal-bearing rocks subject to crushing develop all kinds of disjunctive dislocations which can also act as effective gas accumulators.

Several scores of boreholes made during prospecting are known today which revealed short-term gas bursts within the depth interval of the coal-bearing bed, as well as long-term gas and gas-water fountains. For example, gas fountains with yields of 10-50 thousand m^3 or more per day have been noted in the north-western regions of the Donets basin at hole-mouth pressures of 30-60 atm. These gas fountains fade after a time or change into pulsating gas-water fountains. Some of the most intensive gas fountains were terminated because the well wall collapsed.

Some south-western wells of the Donets basin, producing from 1 to 30-60 thousand m^3 day^{-1}, exhibited gas fountains for many years. In the same regions, gas deposits of a rather small size have been discovered in the sandstones of coal-bearing beds, the gas reserves here being from scores to hundreds of millions of cubic meters.

The above shows that when excessive volumes of gas result from coal metamorphism, the coal-bearing rock becomes saturated with gas which then accumulates, via collectors and screening beds, into gas veins which are so far difficult to assess. However, the gas potentially retained by the coal seams themselves can be calculated rather accurately. The total geological coal reserves at depths of 600-1800 m have been estimated as 150-160 billion tons (in seam of 0.3 m or thicker), the minimal gas content of the coals being 25-30 m^3 ton^{-1} and the hydrocarbon gas reserves about 4.0-4.5 trillion m^3. This result should be considerably increased by gas accumulations inside the enclosing coal seams of the rocks and inside the fractured zones. One should also bear in mind that coal-bearing deposits are well developed at depths over 1800 m. In view of all this, the potential gas content of the basin must be much higher than that estimated so far.

High gas contents are typical for coal deposits of the Pechora basin. Some of these deposits have practically no gas weathering zones owing to the highly developed permafrost conditions here. Although permafrost enhances the screening properties of the covering and coal-bearing rocks, so preventing their outgassing, it also enriches the gas content of coals which increases as the temperature decreases. Because of this, many coal deposits of the Pechora basin show a sharp growth in the natural gas content of the local coal seams which, even at depths of 200 or 300 m, may constitute 10 or 15 m^3 of gas per ton of coal, and 25 m^3 of gas at depths under 1000 m. Numerous pockets of gas have been found in some deposits of this basin. Their gas yield is steady at 500-1000 m^3 of gas per day. Some gas fountains occurred while cutting the zones of fractured coals.

The total geological reserves of the Pechora basin coals down to a depth of 1800 m have been estimated as 300 billion tons. Since the average gas content of the coal is about 15 m^3 ton^{-1}, the reserves of hydrocarbon gas in these coal seams is at least 4.5 trillion m^3.

The Tungusky basin is the least studied of all the Soviet coal basins. Its exploitation has only been initiated very recently and hence many problems of its geology and technical conditions for mining are still to be solved.

The coal-bearing strata of the Tungusky basin are at 1500 m or even greater depth. These strata are of the Upper Paleozoic age and extend over one million km^2. The productive beds are broken by numerous inclusions (sills and dykes) which have considerably affected the coal metamorphism. The latter is inferred by the local domination of coal from the middle and higher stages of carbonification. The action of the inclusions logically resulted in a general increase of gaseous hydrocarbons, a situation which was observed under similar conditions in the Suchan basin.

The total reserves of coals in the Tungusky basin to depths of 1800 m, according to careful estimations (with regard to a decreased coefficient of 0.5) are about 2.037 trillion tons. As mentioned above, the bulk of these coals are metamorphosed to a medium-to-high degree. Within the depth intervals of 300-1800 m, i.e. well below the gas weathering zone, coal reserves exceed 1.2 trillion tons. Taking into account the coals in seams under 0.7 m, this estimation can be increased to at least 2.0 trillion tons. Since the average gas content of coals metamorphosed to a medium-to-high degree is about 20-25 m^3 ton^{-1}, the total reserves of hydrocarbon gas (methane) must be about 40-50 trillion m^3.

From simple calculations one can deduce that the gas reserves in the coal seams of individual coal deposits are 500-600 billion m^3 or even more, these figures being quite comparable with those for large gas deposits. In view of this, the seams of such coal fields with high gas contents should be regarded as "gas-and-coal" seams.

It is rather interesting to discuss the estimation of the hydrocarbon gas content in the coal basins of the world. According to the data available today (Matveev, 1973), the world geological reserves of coals had been estimated by the early 1960s as 16.5 trillion tons. As mentioned above, 8.6 trillion tons of this are situated in the territory of the USSR. Bearing in mind that coals in the USSR vary greatly in their geological age, distribution, and bedding conditions, average data on gas contents may be also applied (with certain precautions) to foreign basins as well. As seen in the calculations, there are 1.43 trillion m^3 of gas per trillion tons of medium coal in the USSR in seams of working thickness. Following this, since foreign coals reserves are 7,9 trillion tons, the methane content is about 113 trillion m^3 and, taking thin seams of non-workable capacity into account, the actual value is about 200-220 trillion m^3. In this way, according to preliminary computations, the total world reserves of gas in the coal basins of the globe are 440-470 trillion m^3; excluding thin seams the value is about 230-240 trillion m^3.

The calculations have involved coal seams only. The potential gas content of commercial coal-bearing beds should have a somewhat higher value if the accumulation of gas inside small lens-like and other coal inclusions are taken into account, together with the free gas deposits formed recently. Attention should also be paid to gas generation in cavities during the metamorphism of coal. This gas can be considerable and, according to some authors, this generation exceeds that in coal seams. The gases developing in the enclosing rocks increase the total "gas background" of the coal-bearing beds and facilitate the formation of free gas accumulations in fractured zones and in rocks with satisfactory collecting properties. This form of gas accumulation in coal deposits has not been studied to any extent. Nevertheless, the numerous evolutions of free gas which do not vary with time from practically all coal basins of the world testify to the scale and widespread occurrence of this phenomenon.

An actual problem of today is how to outgas coal seams. This becomes ever more important as coal production steadily increases since coal deposits are being extracted from greater depths, with typically higher associated gas contents. A solution to this problem will further increase gas production and also increase the safety of mining operations in coal deposits of high gas content.

REFERENCES

Airuni, A.T. (1970). Fundamentals of Preliminary Outgassing of Coal Seams at Big Depths. Nauka, Moskow (in Russian).

Ettinger, I.L. (1966). Gas Capacity of Fossil Coals. Nedra, Moscow (in Russian).

Kravtsov, A.I. (1966). Fundamentals of Fuel Mineral Geology. Vysshaya shkola, Moscow (in Russian).
Lidin, G.D., and Petrosyan, A.E. (1962). Gas Abundance of Hard-coal Mines in the USSR, Vol. 2. USSR Academy of Sciences Publishers, Moscow (in Russian).
Matveev, A.K. (1973). World reserves of coals and their distribution in geological systems. In Collective Works: Recent Problems of Geology and Geochemistry of Fuel Minerals. Nauka, Moscow (in Russian).
Shabarov, N.V., and Tyshnov, A.V. (1958). Reserves of Coals and Pyrischists. Gosnauchtekhizdat (in Russian).