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Marginal Cost of Natural Gas in Developing Countries: Concepts and Applications

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Afsaneh Mashayekhi
Energy Department

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ABSTRACT

The uncertain supply and rising cost of petroleum products since 1973 has spurred the development of alternative sources of primary energy. Natural gas is a major source of energy in over 50 developing countries. In these countries natural gas has many applications with a high value in use both as a substitute for other fuels and as a feedstock. Many countries are on the verge of embarking upon gas development and face complex questions of strategy for gas development. The World Bank has addressed these questions in a series of studies on the cost and prices of gas and its optimal allocation among different uses. The results of these studies are expected to be useful to project staff, energy economists, and policy makers concerned with natural gas development in developing countries.

This paper defines the concept of marginal costs and applies it to estimate the economic cost of natural gas in ten developing countries with a wide range of conditions. The marginal cost of natural gas estimated for the ten countries, using the average incremental method, is far below the border price of competing fuels in these countries. The cost of natural gas supply is not expected to rise in these countries within the next two decades as they tap their proven gas reserves. The sample of ten countries includes a variety of natural gas characteristics and these results are representative of costs in many developing countries. These natural gas cost estimates support a strategy of gas development to substitute for petroleum fuels in a large number of developing countries.

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EXECUTIVE SUMMARY AND CONCLUSIONS

The analysis of natural gas delivery costs to domestic markets in developing countries has been limited. This paper uses the information available in the Bank to address the economic cost of natural gas. It defines the concept of marginal cost and applies it to estimate the cost of gas supply to major domestic markets in ten developing countries. 1/ Marginal cost theory has been widely applied by many public utilities such as water and power to set prices for their services. This, however, is a first known attempt to apply a consistent economic methodology to estimate natural gas costs in developing countries. Marginal costs are necessary but not sufficient for setting gas prices due to the exhaustible nature of this resource. They are also useful in interfuel cost comparisons and provide an explicit framework for investment decisions regarding gas supply.

The result of the study is that the long-run marginal cost of gas delivered to the city-gate in these countries is $0.61 to $1.79 per thousand cubic feet (MCF) or $3.59 to $10.54 per barrel of oil equivalent (boe). These figures are far below the economic value of natural gas in many countries as measured by its opportunity cost as a substitute for other fuels or feedstock even with the current depressed oil prices. The sample of ten countries includes a variety of natural gas characteristics. Although costs in some countries may not lie within this range, these sample results are representative of costs in a large number of countries.

Further, the marginal cost of natural gas production and transport is expected not to rise in many countries in the next two decades as they tap their proven stock of reserves and maintain high reserve to production ratios. Potential economies of scale remain to be captured in the supply of gas. This could result in a fall in the marginal cost of gas in some countries over a period of time; as proven reserves decline and diminishing returns set it, if there are no major new discoveries the marginal cost of gas supply may increase in some developing countries. These results support a more rapid program of gas development to satisfy domestic energy needs in developing countries and to alleviate balance of payment difficulties.

1/ The ten countries are Bangladesh, Cameroon, Egypt, India, Morocco, Nigeria, Pakistan, Tanzania, Thailand, and Tunisia.

I. INTRODUCTION

I.1 Background

The uncertain supply and rising cost of petroleum products since 1973 has spurred the development of alternative sources of primary energy. As a group, over 50 developing countries hold almost 43 percent of currently proven reserves which is about 1288 trillion cubic feet and equivalent to 30 billion ton of oil equivalent. Many gas discoveries, often resulting from a search for oil, have not been fully evaluated because of the lack of immediate incentives to invest in their development. Reserves are being reevaluated upward as governments become aware of their potential contribution to energy supply. For many developing countries, even currently proven reserves of gas could supply about half of their long-term commercial energy needs.

Following gas discovery, the immediate concern in many countries has been whether or not the gas is exportable; the domestic market has often not been explored. Recent studies by the Bank indicate that in developing countries natural gas has many applications with a high value in use both as a substitute for other fuels - in industry, power and the residential and commercial sectors - and as a feedstock for fertilizer industries.1/ In many countries gas development to meet domestic uses, as compared to exports, also has a more certain market, lower investment costs that mature more rapidly, and direct linkages to productive sectors of the economy.

Why has natural gas development to meet domestic demand been so slow? The major reasons include a lack of genuine commitment as well as no strong institutional framework to integrate the activities of production, transmission, and distribution companies and consumers. Exploration and development have also often been delayed due to the lack of a pricing agreement with producers. Moreover, the analysis of gas supply, demand, and delivery costs to domestic markets in developing countries has been limited. Few countries have until recently appreciated that natural gas can be supplied to domestic markets at a low cost that competes with other fuels.

The World Bank has supported and financed a number of gas exploration, development, transmission and distribution projects in developing countries. Its experience has generated a substantial and reliable data base that has made this study on natural gas costs possible. One major finding of this work is that there is a large stock of proven undeveloped gas reserves of natural gas in many developing countries that is sufficient to support a significant portion of their long-term energy needs. Another important conclusion is that in a large number of countries potential domestic demand is higher and more diverse than previously believed. As a result the cost of producing and transporting gas to meet the potential demand in many countries is often far below the border price of the fuels it replaces.

1/ See forthcoming papers on the value in use of gas (netback) in power, residential and commercial markets, and LNG export.

I.2 Objectives

This paper uses the information available in the Bank to estimate the marginal cost of natural gas. 1/ Marginal cost theory dates back to Hotelling and Dupuit. In the 1950s, Boiteux also worked on the development of the theory especially for application in the electric power sector. The theory has also been widely applied by other public utilities such as water, and telecommunications to set prices for their services. It provides a framework to analyze system costs and set prices for natural gas which shares many characteristics of public utilities. 2/ Marginal costs, however, are necessary but not sufficient for setting gas prices due to the exhaustible nature of gas and this paper does not address the specific issue of pricing. They can also be used for interfuel cost comparisons to decide whether it is economic to develop natural gas. The LRMC approach is therefore an explicit framework for investment decisions regarding natural gas supply. Most of the gas development costs, following from the technology of gas recovery coupled with the legal arrangements, are incurred at discrete stages. Because of the indivisible and lumpy initial investments to produce and transport natural gas, the average incremental cost method, already widely applied in water supply and power projects, is generally considered to be the appropriate approach to the costing of natural gas. 3/

This study is a first known attempt to apply a consistent economic methodology to estimate natural gas costs in developing countries. It provides a set of comparable cost estimates across countries with a wide range of conditions. This study is part of a larger series of studies on costs, prices of natural gas and its value in different uses. The results of these studies are expected to be useful to project staff, energy economists, and policymakers facing complex questions of strategy for gas development in developing countries. Following this introduction, the paper defines the concept of long-run marginal cost (LRMC) in Part II and applies it in Part III

1/ It excludes profits, taxes, royalties and depletion allowance, which require a separate discussion.

2/ To meet the criteria of economic efficiency, the delivered price of natural gas should not be less than its marginal economic cost of supply. The pricing of gas, however, requires extensions to the LRMC to allow for the exhaustible nature of natural gas and meet financial cost coverage, and income distribution objectives.

3/ The average incremental cost concept described in Chapter II has been widely used in Bank water supply and power projects. See for example, Saunders, Warford and Mann, Alternative Concepts of Marginal Cost for Public Utility Pricing: Problems of Application in the Water Supply Sector, World Bank Staff Working Paper, No. 259, May 1977; also Mohan Munasinghe and Jeremy Warford, Electricity Pricing: Theory and Case Studies, Johns Hopkins University Press, 1982.

to estimate the economic cost of natural gas in ten developing countries.1/ The results as well as comparative analysis of the different countries are presented in Part IV.

1/ It excludes profits, taxes, royalties and depletion allowance, which require a separate discussion.

II. METHODOLOGY

II.1 Technical Characteristics of Natural Gas Production and Transport

Natural gas shares many characteristics of public utilities, e.g. power, water, and telecommunications, such as (i) economies of scale, (ii) lumpy and indivisible capital investments, (iii) need for excess capacity to meet peak demand, reliability standards and future growth in demand, and (iv) diversity and variability of demand.1/ Therefore, the initial capacity for production and transport is both large and long lived, and often designed to meet the growth in demand over a 10 to 20 year period. The measure of costs pertinent to supplying an incremental volume of gas is its long-run marginal cost, namely the change in total costs over the whole production period as a consequence of a small addition in supply.

The rationale for the use of long-run marginal costs (LRMC) is well established and has been widely employed for the evaluation of World Bank water, telecommunication, and power projects.2/ The LRMC of gas is useful in negotiating prices with producers and transmission companies and consumers. It can be compared with alternative fuel costs to decide whether it is economic to develop and use gas. It can also be used to assess the appropriateness of investments in gas system expansion given projected market demand. It is consequently a determinant of actual supply of natural gas. LRMC is also useful in inter-sectoral planning and provides a benchmark by which other social and economic objectives may be evaluated.

II.2 Characteristics of Natural Gas Marginal Costs

In the abstract, LRMC is the incremental cost of optimum adjustments in the gas system expansion plan and gas system operations to meet small increments of demand. This approach estimates marginal costs of serving different consumers at different times in various regions. In practice one of the greatest sources of difficulty in the analysis of gas costs is that the technology of natural gas development and transport is subject to economies of scale and requires large and indivisible investments. Investments in gas infrastructure, following from the technology of gas recovery coupled with prevailing legal arrangements, are incurred at discrete stages. Costs of initial field development such as drilling and equipping gas fields, gas processing facilities, and main transmission lines are a high proportion of the overall lifetime costs.

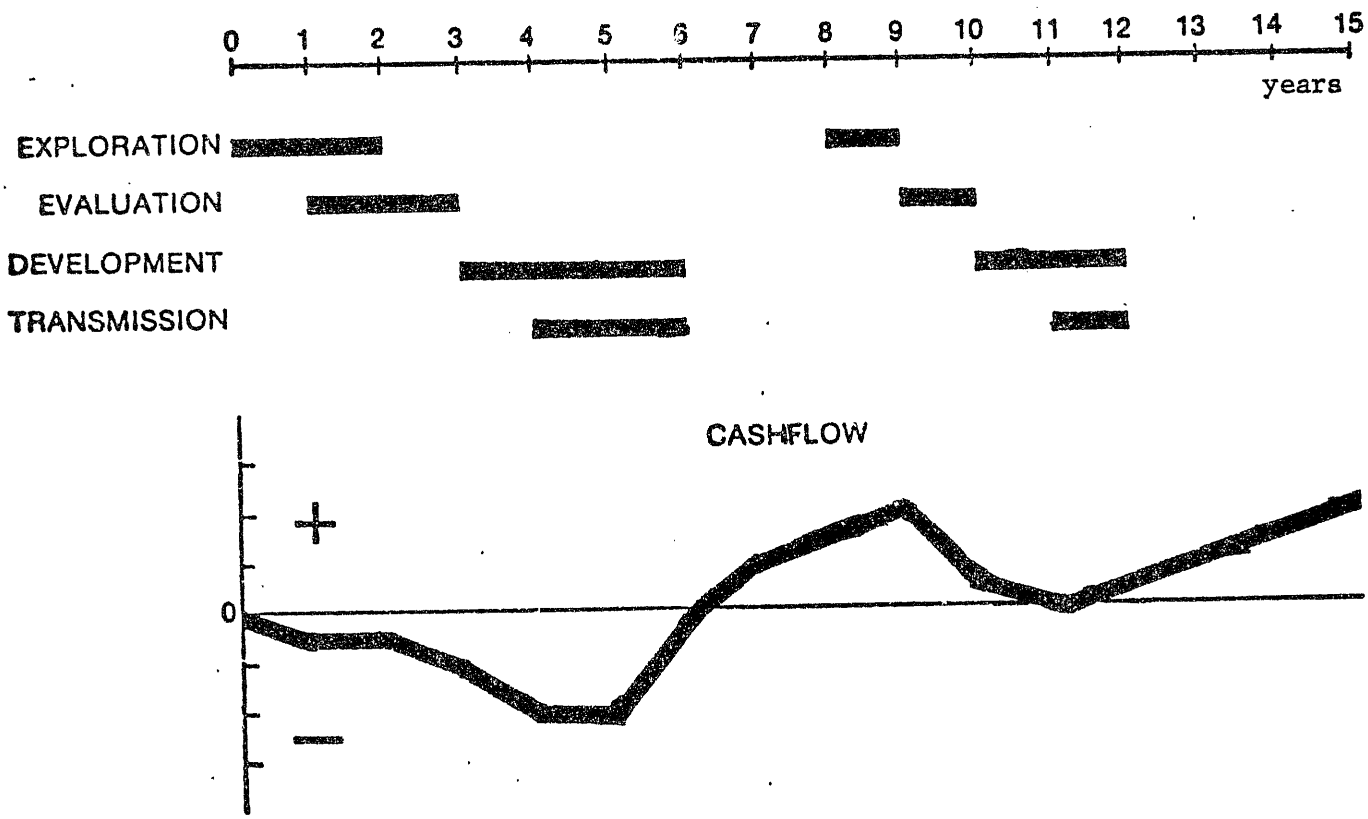
1/ See MacAvoy, Price Formation in Natural Gas Fields, Yale University Press, New Haven, 1976.

2/ See for example, Robert Saunders, Bangkok Water Supply Tariff Study, IBRD, PUN (23), June 1976; also Saunders and Warford, Village Water Supply :Economics and Policy in the Developing world, Baltimore, Johns Hopkins University Press, 1976.

A gas supply system can be divided into four interrelated stages (Figure 1). First, exploration which establishes the level of proven reserves and their commerciality. Exploration costs include an estimate of the finding cost of natural gas.1/ Second, the development and production stage requires large indivisible investments for development drilling, field preparation, field gathering, compression, separation of natural gas liquids and treatment of gas to produce pipeline quality gas to meet contract volume, quality and pressure requirements. The third stage is the transmission of gas from the field or gas treatment plant to the city gate. Investments in transmission facilities are lumpy and costs subject to significant economies of scale until the maximum capacity of pipelines is reached. The fourth stage is distribution to end users. This paper covers the cost of gas up to the city gate excluding distribution costs and assumes most major users lie on or close to the main trunk line.2/

Figure 1

AN ILLUSTRATIVE SCHEDULE OF ACTIVITIES AND CASHFLOW

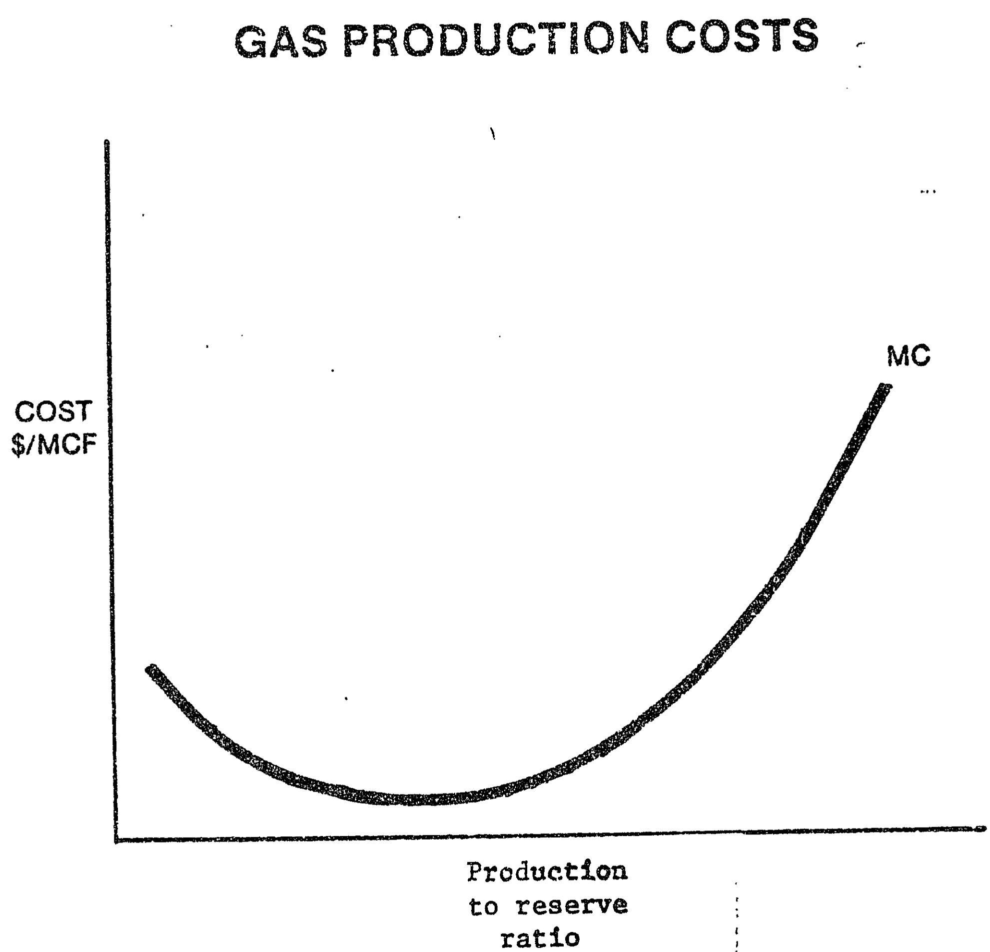


1/ They exclude a depletion allowance for the value of the exhaustible resource.

2/ The additional cost of natural gas distribution to the residential and commercial sectors varies widely between about \$2.5 to \$10.0 per MCF. The results of a study on residential and commercial gas distribution will be available in a forthcoming paper.

Production of the first increment of gas thus requires a large initial expenditure in exploration, development, and transmission. Production of additional volumes necessitates little additional expenditure until maximum capacity is reached. Thereafter indivisibilities and diminishing returns in providing gas to meet demand lead to additional discrete and discontinuous investments and raise the marginal costs (Figure 2). The characteristics of investment in natural gas development and transport for a given field imply that the marginal cost curve falls sharply for relatively low volumes of recovery and rises as cumulative production increases to over 60 percent of estimated recoverable reserves.1/

Figure 2

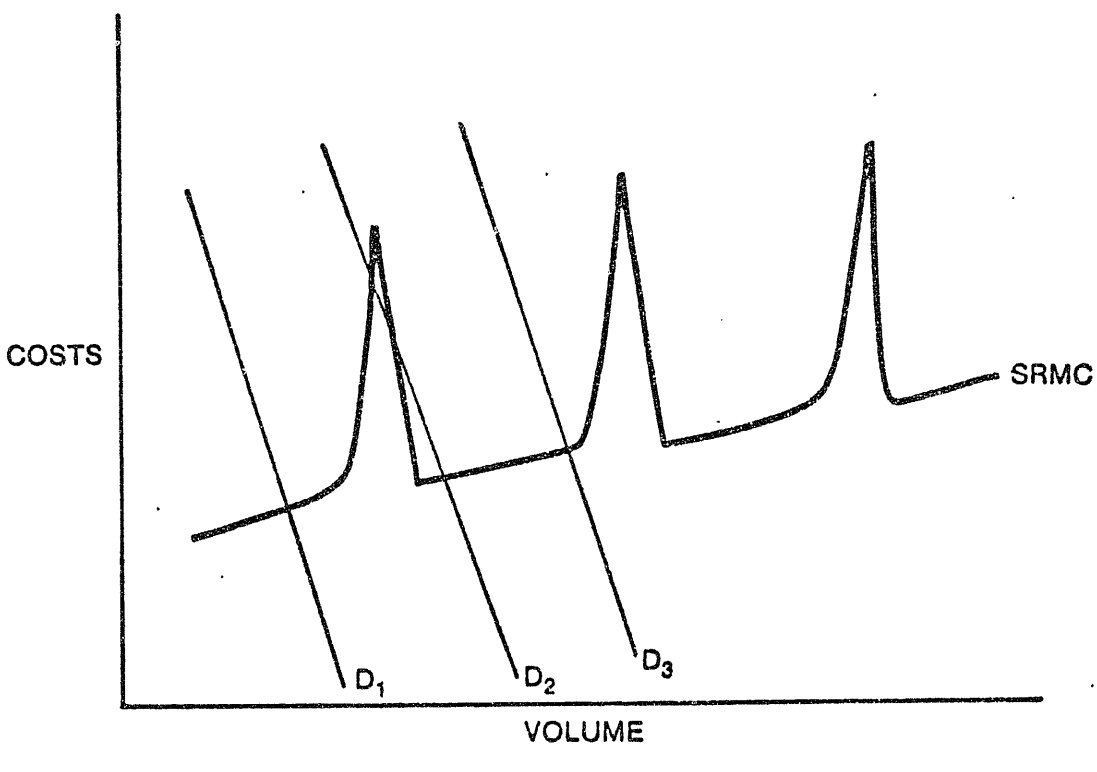


1/ Therefore $\frac{\partial C}{\partial Q} > 0$ for all Q; $\frac{\partial^2 C}{\partial Q^2} \leq 0$ for $Q < Q_1$, where Q_1 is the maximum volume of recoverable reserves before indivisibilities and diminishing returns set in; and $\frac{\partial^2 C}{\partial Q^2} > 0$ for $Q > Q_1$.

Due to the capital indivisibilities, costs will be marginal at some time and non-marginal or discontinuous at others as illustrated in Figure 3. Let us begin with the demand curve D_1, if production from a given gas field is below maximum capacity, the only costs immediately attributable to additional consumption are the incremental operating and maintenance costs, i.e. short-run marginal costs. Once production is at capacity, and the demand curve shifts, gas system expansion requires drilling in existing and new fields, new gathering and perhaps pipeline facilities as well as additional operating and maintenance costs. The resulting large cost fluctuations could cause price changes overtime that would not be acceptable to consumers. Therefore, a definition of long-run marginal costs that fits the structure of investments in gas development and transport is required; costs must be estimated within a sufficiently long-run framework to incorporate the investment process.

Figure 3

COST AND OUTPUT WITH CAPITAL INDIVISIBILITIES



II.3 The Average Incremental Cost (AIC) Concept

The average incremental cost (AIC) definition of marginal cost seems best suited to natural gas technology. The AIC smoothes out the indivisibilities in expenditures. It also reflects the general level and trend of future costs which will have to be incurred as gas consumption increases. The AIC takes a longer view of costs and looks beyond the next increment in capacity. This is particularly important since many developing countries are at an early stage of gas development and expect a large potential shift in demand for gas.

The AIC is estimated by discounting all incremental costs that will be incurred in future to provide and maintain the estimated amount of gas which will be supplied over a specified period and dividing it by the discounted volume of incremental output over this time. The timestream of expenditure for providing, maintaining, and running the system corresponds to a set of outputs over time.[1/]

$$AIC_o = \frac{\sum_{t=1}^{T} [I_t + (R_t - R_o)]/(1 + i)^t}{\sum_{t=1}^{T} (Q_t - Q_o)/(1 + i)^t}$$

I_t - capital costs in year t
Q_t - natural gas production in year t resulting from the investment
R_t - operating and maintenance costs in year t
i - opportunity cost of capital
T - time horizon for development of the project as well as a 20 year production life ($t=o$ is the base year)

To determine the marginal cost of supplying gas the economist must work closely with engineers and follow an iterative process. They must first agree upon the production profile in the denominator based on demand forecasts and supply potential in order to plan the least cost investment plan (See III.3). This analysis is generally carried out for a 10 to 20 year period for which relatively reliable data and forecasts exist.

1/ For producing fields with a declining production profile the formula has to be adjusted so as to estimate the incremental production due to the investment as the difference between the two production profiles with and without the investment (Q_t - Q'_t), where Q'_t is the production without the investment; the operating and maintenance costs should be also similarly adjusted.

The second crucial question is what system of expansion should be designed to deliver gas to the consumer at the least possible cost. The numerator is the present value of the least cost investment stream as well as incremental operating and maintenance costs necessary first to start production and, later, to raise production up to capacity and maintain it at that level. This least cost expansion plan to meet projected demand forecasts is determined assuming a target level of system reliability.1/ Once the price of gas is determined and the gas system begins to operate actual consumption may be different from demand estimates and consequently the costs will have to be revised.

II.4 Pricing of Natural Gas

The discontinuities in supply costs due to the technological indivisibility of gas infrastructure could result in fluctuating prices which might cause political difficulties. The signals provided by such a pricing system can not be adequately interpreted and followed by users and would therefore not encourage optimal investment in gas using equipment.2/ The AIC approach by smoothing out the costs provides a more useful input to the pricing decision.

The AIC, however, is only one of the criteria used to determine the price of natural gas. The appropriate pricing strategy for natural gas must allow for distortions due to externalities, taxes, monopoly practices, duties and subsidies as well as the objectives of financial viability and income distribution. It must also be adjusted because gas is an exhaustible resource and therefore has a depletion value that should be taken into account in its pricing.3/

Marginal economic cost of supply provides a lower boundary to prices. In countries with a large gas surplus, prices would be close to the marginal cost while in gas deficit countries, prices would include a larger depletion allowance. The gas transmission and distribution services are similar to other utility services where use of marginal costs in pricing is prevalent. As applied to natural gas transmission and distribution, marginal cost pricing is a viable approach in the sense of ensuring that the benefits of expenditures in the sector exceed the costs.

1/ Reliability should itself be ideally treated as a variable to be optimized; this is achieved when the marginal cost of adding capacity to improve reliability are equal to the expected value of the cost of savings to consumers resulting from gas shortages averted by these capacity increments.

2/ A similar argument for water supply costs is presented by Robert J. Saunders and Jeremy J. Warford, in Village Water Supply, Johns Hopkins University Press, Baltimore, 1976.

3/ See Dasgupta and Heal, "The Optimal Depletion of Exhaustible Resources", Review of Economic Studies Symposium, Dec. 1974.

III. APPLICATION OF THE AIC METHODOLOGY TO NATURAL GAS

III.1 Country Sample

Exploration, development, and transport costs exhibit considerable variability among different regions. These costs are needed so as to be compared with gas prices and alternative fuel prices to decide whether to produce, transport and distribute gas. In this study the long-run marginal cost of gas production and transport, using the AIC approach, has been estimated for 10 countries. These countries were selected so as to cover a wide spectrum of characteristics such as local geology, size of reserves, offshore-onshore, associated-nonassociated, gas with different compositions, diverse field specifications (shallow and deep structures), as well as different distances to the market. Generally, costs are estimated on a field by field basis for most major fields in each country based on Bank project and assessment work. The quantity and quality of data varies among different countries. In some (e.g. Pakistan) a detailed and reliable data base exists for every field. In others results are based on information on one or two fields.

To summarize, our basic approach, which was to treat output expansion as occuring by discrete increments corresponding to individual fields, is designed to permit analysis of the relation between cost and output for an entire producing region. Field development should ideally proceed starting with the lower cost field and going on to more expensive fields so as to meet growth in demand. In practice, due to certain contractual agreements or incomplete knowledge, this process may not take place. Discovery of new lower cost fields through time may also change the original ordering of fields.

III.2 Costs

The present value of costs of gas production are expressed in constant 1982 dollars and include all capital and operating cost components for exploration, and field development to provide pipeline quality gas over a 20 year production period. The cost of natural gas delivered at city gate is also calculated. It includes all production and transmission costs as well as the costs of compression facilities to maintain pressure where necessary. These costs are close approximations to the cost of gas delivered to major industrial, power, and fertilizer users that are located on or close to the transmission grid. In some cases additional branching costs for secondary lines should be separately estimated for specific users.

Table 1

Cost Build-up for Natural Gas Supply [a/]

	Present Value Exploration	Exploration & Development (in millions of US$)	Exploration Development & Transmission	Gas Volumes (BCF)
Bangladesh	-	93.3	239.4	391.1
Cameroon	80.0	317.5	514.9	287.7
Egypt	220.2	1683.2	1847.4	2641.5
India	115.5	1190.9	2001.8	1870.1
Morocco	45.0	244.1	360.1	210.4
Nigeria	-	1126.7	1889.5	1717.7
Pakistan	211.0	992.2	1273.2	1744.4
Thailand	123.0	1988.9	3716.3	2396.8
Tanzania	104.0	108.5	184.7	175.9
Tunisia	30.0	325.5	773.4	483.3

a/ The net present value figures are discounted at 10 percent.

In this sample the exploration cost category is relatively small compared to the development and transmission costs. Exploration costs are often low since gas is frequently found during the search for oil; moreover, there is often no clear indication of actual expenditure allocated to gas. An estimate of current and future exploration costs is included in all country cases except for Bangladesh, and Nigeria where large reserves to last over 20 years are already proven. These are based on the planned exploration costs during the 20 year planning period. In the absence of planned expenditures historical cost data together with geologists' estimates of success ratios as well as the new estimated probability of a successful play in future, and average expected discovery size are used to determine future exploration costs.

In some countries such as Tunisia and Morocco it was possible to estimate the cost of future reserve additions based on a planned exploration effort. In others, for example Egypt, Pakistan, and Tanzania it was assumed that if the past exploration effort is continued in future in the same basins, statistically the same amount of new reserves would be discovered. After a point in time, due to the limited nature of reserves in a basin, similar exploration investments would lead to a declining rate of discovery. At this point exploration costs increase. Pakistan is a case where exploration costs are expected to increase due to a fall in success ratios. In Pakistan, the estimated exploration cost is based on the estimated success ratio per play, the average discovery size, estimated production profile, and country specific drilling and predrilling costs. In some other countries the reserve to production ratios are higher and exploration costs are often smaller.

For the development and transmission costs in the ten countries a relatively complete and reliable data base exists in the Bank. These costs are based on actual data from project documents, sector work as well as estimates based on unit costs developed for typical installations for specific countries. The ongoing and future development costs for known and proven fields in the ten countries are included in the study. These include field preparation and drilling, flow lines to separator and treatment facilities, as well as gas treatment and separation facilities to provide a pipeline quality gas. The cost of future drilling and field compression to maintain the pressure and volume of gas production during the 15 to 20 year period are also included. Development costs are a function of gas volumes as well as location and specific geological factors and quality of gas, and the rate of production.

The transmission costs include all offshore and onshore pipelines and related facilities (telecommunications, surveying and rights of way), to move the pipeline quality gas to major markets (city-gate). These are based on the country data base or estimates by our engineers. In some cases such as Thailand, Pakistan and Nigeria, compression facilities are needed to maintain pressure requirements at delivery during the twenty year planning period. Costs of this activity depend on the quality and quantity of gas, type of terrain to be crossed, distance to the market, and surveying and right of way.

These costs often overestimate the lean gas costs. Natural gas is generally a composite product that includes lean gas and natural gas liquids (Annex I). It may also be produced in association with oil as in Nigeria. Therefore to the extent that costs are joint, individual products have no objectively determinable separate costs. These joint costs can be allocated on a somewhat arbitrary basis. Once raw gas costs are estimated, the lean gas costs can be calculated using one of several methods.1

III.3 Expected Demand and Production Profiles

In this paper energy demand scenarios for the ten countries were estimated and the share of natural gas determined and used in the denominator

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1/ First, costs can be allocated proportionately according to the heat content (Btu/MCF) of each product. Alternatively, when the market value of each product is known, it can be used as the weight to allocate joint costs. A third method, allocates all costs less the economic value of the by products' at the point of seperation to the main product. The methodology that is chosen should be linked to the purpose of cost allocation and field characteristics.

of the AIC formula.1/ The demand projections are based on the existing natural gas market, its expected growth rate, and a share of the conversion market and future demand taking into account economic and technical constraints in each country. The share of gas depends on the natural gas supply and demand as well as the relative gas and alternative fuel costs. The study of potential demand indicates that gas could satisfy up to about 50 percent of the commercial energy needs in developing countries. In Pakistan which has a gas supply constraint the share of gas in total commercial energy is about 42 percent. This share would increase further if more gas reserves were developed.2/

These projections are adopted as the production profile except where the supply constraint limits production. In the latter case the production profile of gas depends on the potential physical supply of gas. About half of the countries in the group are demand constrained or gas surplus countries; there is a positive gap between their available long-run natural gas supply and domestic demand. Another half of the sample are supply constrained or gas deficit countries. Their long-term demand forecasts exceed their long-run supply potential over the next two decades.3/ The discounted production profiles based on demand projections or alternatively supply constraints is summarized as the present value of gas volumes in Table 1.

1/ These demand estimates are not forecasts of actual consumption; they are potential demand scenarios for natural gas and their realization depends on (i) relative energy prices, (ii) the degree of government commitment to natural gas development, (iii) a natural gas policy consistent with industrial strategy and a general energy plan, (iv) institutional strength of organization in charge of gas development, transport, and marketing (v) financing sources that fit the natural gas investment and cost characteristics.

2/ These demand estimates are based on a static analysis. In a dynamic system, a large gas discovery may affect GDP, and energy elasticity and bring about a shift in the whole demand curve. Once gas is discovered in large quantities, plans to use it in new plants also emerge. Therefore, the estimates used in the study provide a lower boundary to potential future demand. Increased demand would lead to higher production in countries with a demand constraint (gas surplus) and reduce the marginal cost of gas supply until capacity is reached.

3/ This conclusion is based on currently known proven reserves. Further exploration could change this balance in some countries.

IV. RESULTS

IV.1 Average Incremental Costs

The results presented in Table 2 indicate that in all the country cases that were considered, the long-run marginal cost of gas delivered at the city gate is far below its economic value as measured by its opportunity cost as a fuel (e.g., fuel oil replacement) or as feedstock. The sample of ten countries includes a variety of natural gas characteristics; this enables us to conclude that the range of gas costs covers most conditions. Although costs in some countries may not necessarily fall in the range of this sample, these results are representative of costs in a large number of countries. Moreover, the marginal cost of gas production and transport is expected not to rise in most countries in the next two decades as they tap their proven stock of reserves. As the reserve to production ratio becomes smaller the marginal cost is expected to rise.

Table 2

Average Incremental Cost of Natural Gas a/
(in 1982 US$)

	Production Cost		City Gate Delivery Cost	
	($/MCF)	($/boe)	($/MCF)	($/boe)
Bangladesh	0.24	1.41	0.61	3.59
Cameroon b/	1.29	7.60	1.79	10.54
Egypt	0.65	3.81	0.71	4.18
India	0.95	5.60	1.51	8.88
Morocco	1.16	6.48	1.71	10.07
Nigeria c/	0.65	3.83	1.10	6.48
Pakistan	0.36	2.12	0.46	2.71
Thailand	0.80	4.71	1.50	8.84
Tanzania	0.61	3.59	1.05	6.18
Tunisia	0.67	3.97	1.60	9.43

a/ The AICs in this table are estimated at a 10% discount rate; they exclude all profit, tax, royalty and depletion costs.

b/ Production costs for the domestic market; exports would increase the volume of production and reduce costs.

c/ Includes the higher cost associated gas ($0.82/MCF) and lower cost non-associated gas ($0.44/MCF).

IV.2 Comparative Analysis

The cost of gas production and delivery to the city-gate indicated in Table 2 covers a wide range of $0.61 to $1.79 per MCF or $3.59 to $10.54 per barrel of oil equivalent. Since in our sample countries there is a proven stock of gas, the exploration costs are a relatively small proportion of total costs. The most important parameters that influence gas supply costs are (i) field location; (ii) size of reserves and production to reserve ratio; (iii) type of reserves (associated, non-associated); (iv) gas composition; (v) level of demand and (vi) length of production life.

Onshore and Offshore Fields - The production cost of large onshore fields in Bangladesh, and Pakistan lies at the lower end of the cost spectrum. This is because of the relatively low drilling costs attributable to the type of formation, as well as concentration and productivity of wells. The cost of production from onshore fields increases with the depth of wells. In Morocco some wells are over 13,000 feet deep; this together with the high pressure of wells and low recoverability increases the production costs. The reason for these higher costs is due to the greater width of the wells which require specific equipment, the difficulty of operating in greater depth, and the need for blow-out preventors and other equipment to operate under great pressure. Another factor that increases costs is the dispersion of gas fields. Gathering costs depend on the distance and number of wells. In Cameroon the costs of an extensive gas gathering system from a large number of wells over a wide area increase the costs of gas supply.

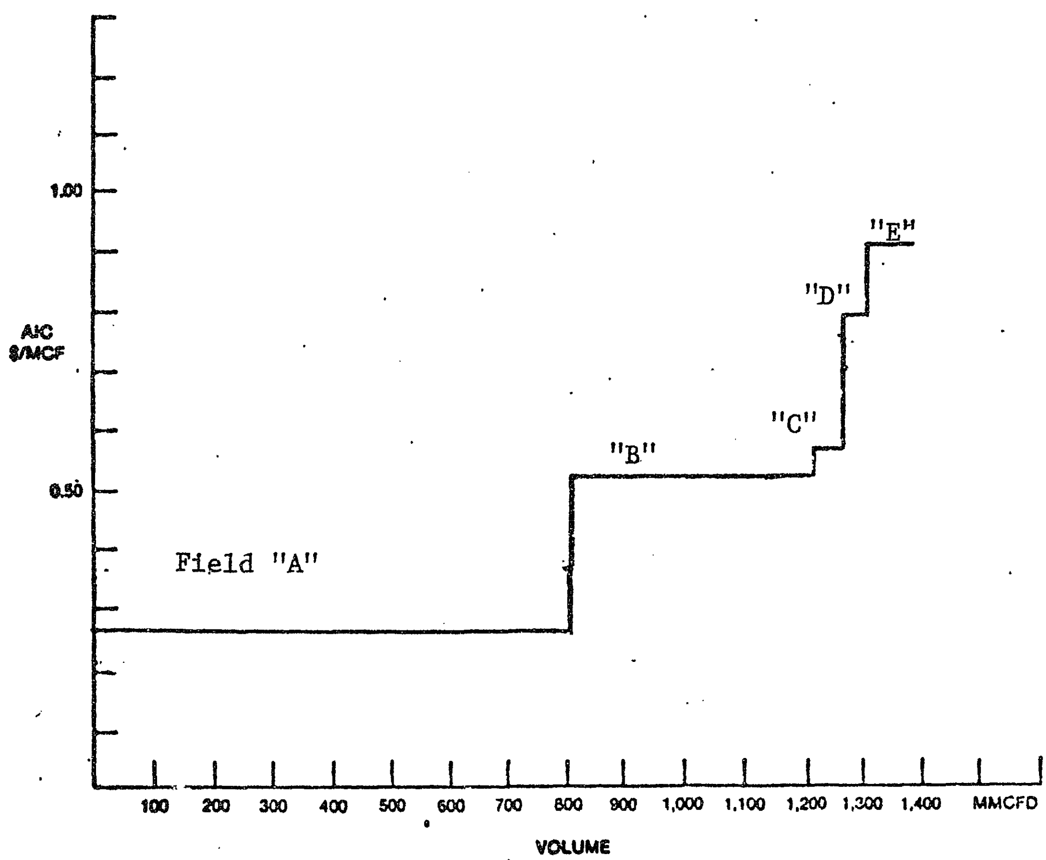
Offshore field production and transmission costs are generally far above comparable onshore fields. The offshore location of some fields in India, Thailand, and Tanzania leads to more expensive drilling and operating costs and a higher AIC of $0.61 to $0.95 per MCF. This is due both to the higher cost of equipment as well as the difficulties in offshore operations. The size of reserves and productivity per well obviously affect costs. Thus, the larger reserves, such as Miskar in Tunisia, benefit from economies of scale in production compared to other smaller offshore fields in Tunisia. Offshore field transmission costs are also higher because of the expensive offshore pipeline. These costs depend on the volume of thoroughput as well as the distance of the field from the shore.

Size of Reserves and Production to Reserve Ratio - With a given size of reserves, once production begins and the production-reserve ratio is low, the marginal cost of production could fall initially (Figure 1). Compression may be required in particular to increase the pressure of the delivery system after the plateau production level has been reached. Compression provides relatively small additions to production and increases the cost of incremental production. Further, as production increase, more expensive fields have to be brought into operation. Obviously, if a large new discovery is made it can reduce costs.

In Pakistan, the large volumes of gas production and economies of scale in production and transmission lead to low supply costs. The marginal cost for different gas fields are presented in Table 4. Pakistan has a relatively mature gas industry, and the production to reserve ratio has been increasing. It is now producing from its lower cost fields. As demand increases and supply from these fields fall, the more expensive fields will have to come under operation.

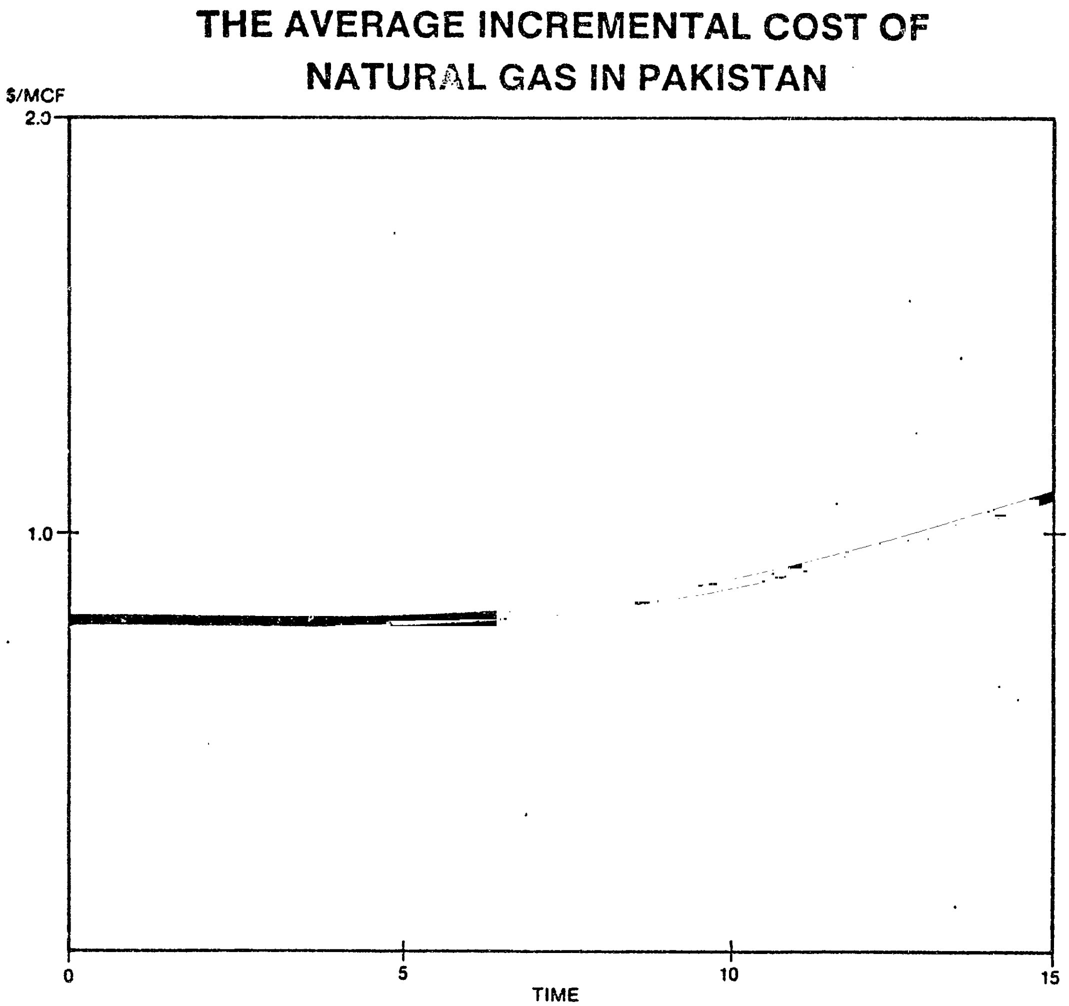
Figure 4

THE AVERAGE COST OF GAS BY FIELD IN PAKISTAN



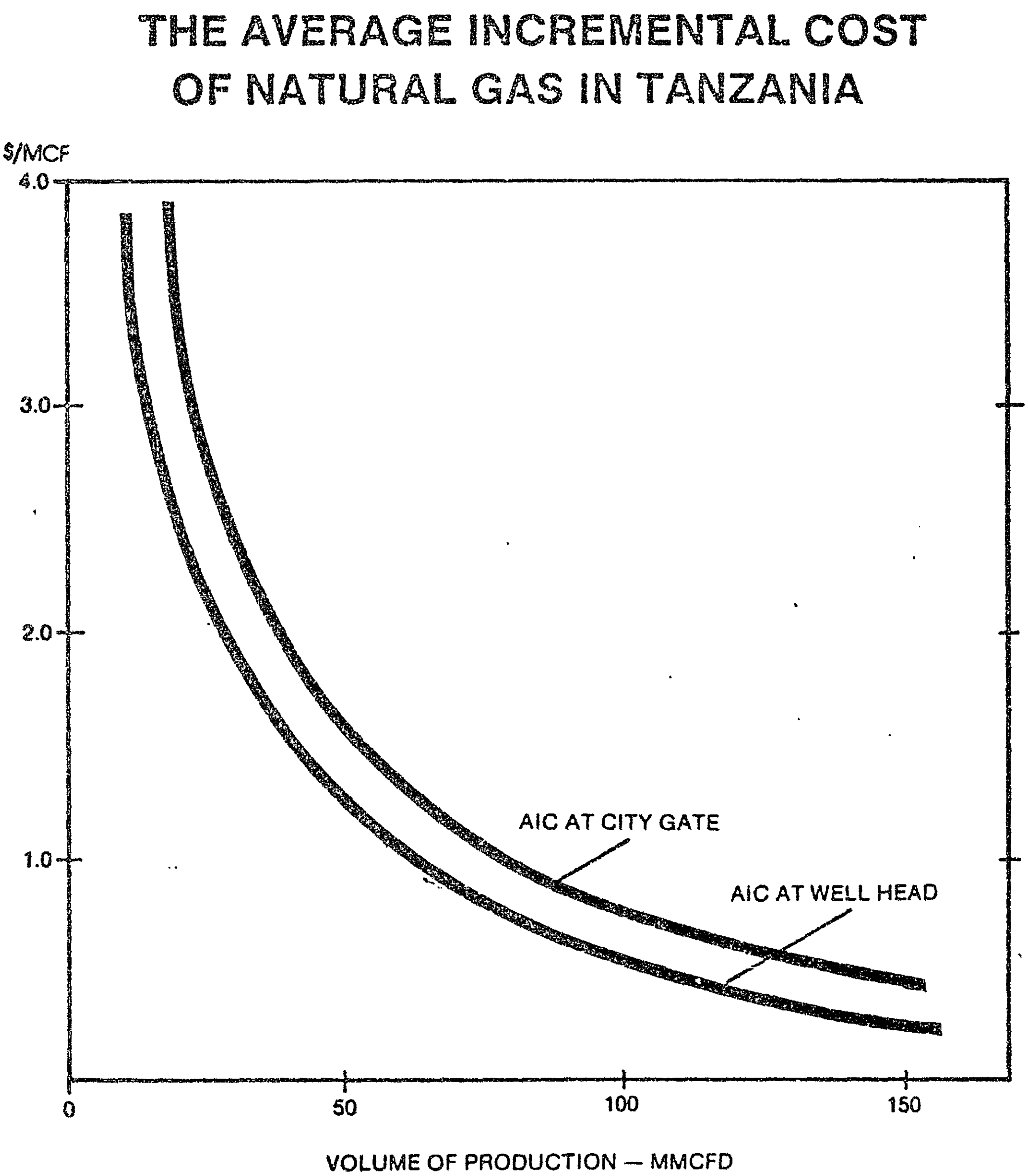
The AIC over the 1982-2000 period is expected to remain low. This is because the presently producing fields, which have a low marginal costs, are expected to have a large share of total production. However, these fields require compression facilities to maintain production which increases the marginal cost of gas production. The production cost of new fields is also higher, and the finding costs of gas is increasing as the success ratio falls. Pakistan is expected to remain in the flat part of the cost curve (Figure 5). Looking through beyond 1990, it will reach the moderately rising part of the cost curve unless a large discovery is made.

Figure 5



In contrast to Pakistan, Tanzania is only beginning to consider gas development and use. It is in the early and falling portion of its cost curve as indicated in Figure 6. This is due to the fact that exploration and development wells already drilled in an offshore field are sufficient to meet a demand up to 100 MMCFD for twenty years with some compression after 1990. The shape of the curve in Figure 6 demonstrates the sensitivity of the AIC to demand. A higher demand and consequent larger production results in a lower AIC. These costs are based on one field; further exploration in other areas such as Mnazi Bay is expected to increase the production potential of gas and reduce costs even further.

Figure 6



Indivisibilities and increasing returns, with a high reserve to production ratio, followed by diminishing returns in providing gas at a uniform rate as the reserve to production declines, give rise to a U-shaped cost curve (Figure 1). Most developing countries are in the initial stages of gas development and therefore in the falling portion of the curve. Pakistan with a relatively mature gas industry is in the flat or slightly rising part of the curve. Looking through the next two decades most countries will be on the falling or flat part of cost curve and will reach the rising costs portion thereafter unless more gas is discovered.

Associated and Non-associated gas - In general the cost of associated gas is presumed to be lower than non-associated gas costs. This is because a large share of the associated gas exploration and development costs are joint costs and are partly allocated to oil. All the cases considered, except for Nigeria, are based on non-associated gas fields. It is obvious that with everything else equal associated gas costs are generally lower due to the joint exploration and development costs. In actual country cases, the associated gas costs may be higher for several reasons. In the case of Nigeria, associated gas is collected at no cost at the flare point if not used by the producer. However, it needs to be gathered from several low volume, widely dispersed supply points, treated, and compressed. Although the non-associated gas requires additional drilling, it costs about $0.44/MCF compared to the associated gas costs of $0.82/MCF. Further, the relative distance of the two types of fields to the market also affects costs. In the evaluation of the supply mix of associated and non-associated gas, however, the cost is only one of the criteria and the depletion premium of each type of gas also needs to be estimated.

Gas Composition - Depending on the gas composition, there may be need for purification, processing, and separation (Annex I). This depends on the richness of the gas as well as the impurities such as hydrogen sulphide, nitrogen, and inerts. In some gas fields in Tunisia, for example, the gas is of a low quality and there are additional costs in processing it before it can be used. The estimates in Table 2 have not been adjusted to take into account the composite nature of the natural gas which includes dry gas as well as natural gas liquids (NGLs) in different proportions. If joint costs were allocated on any basis, the costs of dry gas production would fall. In the case of a dry gas from a specific field in Tanzania, the costs would not require any adjustment. Joint cost issues are more important in some fields in Thailand, Morocco, and Tunisia which have a high NGL content. The choice of a methodology to allocate costs in these countries should be linked to the purpose of cost allocations as well as field characteristics. In the case of a field in Thailand, if costs are allocated proportionately according to heat content of each product, the dry gas costs are about $0.20/MCF below the unadjusted costs in Table 2. Similarly, the lean gas costs in a field in Tunisia are estimated at about $0.15/MCF below unadjusted costs.

Level of demand - In many developing countries with large gas reserves, gas production is constrained by the size of the market. The actual production profile is therefore far below the technical potential of the reserves. The gas system does not benefit from economies of scale compared to, for example, the system in Pakistan that operates close to production capacity. Sensitivity of the costs to the size of the market is a major issue in particular in several small African countries where the industrial market is generally limited. In Tanzania it is estimated that depending on the variation in the market size the delivered gas costs could vary from about

$3.06/MCF for a limited industrial and residential market in or close to Dar Es Salaam to about $1.69 if demand increases to include a portion of the power sector. Costs fall further if a fertilizer plant is also included and production from the field reaches its capacity. Therefore in gas surplus countries as the market expands, the benefit of economies of scale in production and in particular transmission become apparent. In countries that are just starting their gas development, as demand and production increase the costs of gas delivered to the city-gate is expected to fall over a certain period of time due to economies of scale and higher capacity use of the gas infrastructure (Figure 6).

<u>Length of Production Life.</u> Costs are very sensitive to the length of production life. In some fields it is possible to increase annual production rates by large increments through shortening reserve life. Due to economies of scale in gas development and transport, costs may increase less than proportionately with a higher production level. There is no inherent reason to use up gas over a twenty year period rather than a shorter or longer period when there are users who can switch at a low conversion cost to other fuels. The twenty-year period is often used since some users may consider it necessary to make costly investments in gas using facilities with a long life expectancy and high conversion costs to other fuels.

IV.3 Conclusions

The study of the ten countries indicates that the cost of additional recovery declines once the major indivisible investments are made and total production is a small proportion of the volume in place resulting in significant scale economies. Costs may rise sharply when total recovery is a large proportion of the reserves in place. This is due to high compression costs per incremental units, the need to build a new parallel pipeline, or alternatively a rising finding cost to replace the gas that has been produced. Most developing countries are in the increasing returns (falling part of U curve) or constant returns (flat part of U curve) situation.

The level of marginal costs may differ from field to field. Deep, low pressure reserves have higher costs than shallow, high pressure fields. Production from onshore field for a larger market results in lower costs than offshore production for a small market. As far as the actual level of costs are concerned, what can be demonstrated by existing data is that the economic cost of natural gas delivered at the city gate lies between $3.59 and $10.54 per barrel of oil equivalent over the next 15 to 20 years which is far below the border price of most alternative fuels. This is an encouraging result for countries embarking on the development of their gas reserves. Moreover, as systematic exploration proceeds, reserve and production estimates may be revised upward.

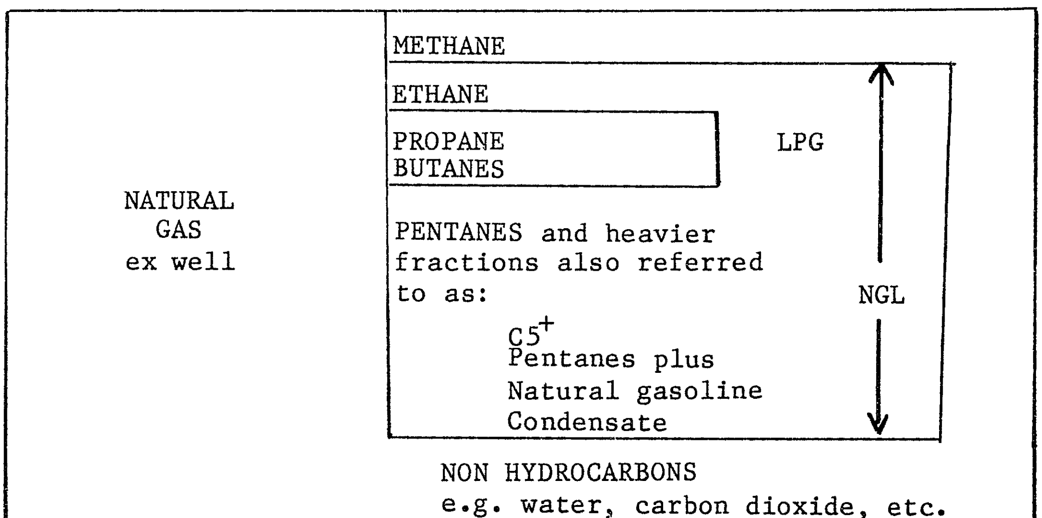
Demand curves may also shift through time as this abundant source of energy becomes available as shown in the case of Pakistan. As a result of higher production levels and capacity utilization, the marginal cost of supply will fall. Once the most accessible and easily exploitable reserves are depleted and diminishing returns set in, the marginal cost of natural gas may increase in some countries. The present estimates of natural gas cost in developing countries therefore need to be used in the context of the dynamics of natural gas demand and supply.

Natural Gas and Gas Liquids

A. Definitions

Natural gas is a simple hydrocarbon that exists in association with oil or separately as non-associated gas. It is generally a composite product. The simplest member methane (C1) is by far the most abundant component, and is always present in a gaseous form. Both associated and non-associated gas often include a high proportion of natural gas liquids (NGLs). These NGLs include ethane (C2) and LPGs, [propane (C3, and butane (C4)], as well as pentanes and natural gasoline condensate (C+5).

Terminology And Constituents Of Natural Gas



LNG = liquefied natural gas
LPG = liquefied petroleum gas
NGL = natural gas liquids
SNG = synthetic (or substitute) natural gas

B. Characteristics

	Calorific Value Kcals/Cu. Metre*	Barrels/Ton	Boiling Point oC at Atmospheric Pressure
Methane	9,495	15.0	- 161.5
Ethane	16,515	13.72	- 88.5
Propane	23,675	12.44	- 42.2
Butane	30,690	10.08	- 0.5
Pentane	35,685	8.53	36.1

C. Conversions

1 bbl crude oil:
= 5.89 million BTU (gross calorific value)
= 5,890 cubic feet = 158 cu metres natural gas

* Measured at 0oC and 760 mm hg dry (Gross).

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EGY PAPER No. 7 — Guidelines for the Presentation of Energy Data in Bank Report October 1982 - 13 pages (incl. 4 Annexes). Masood Ahmed (World Bank).

The growing importance of energy issues in national economic management has led to increased coverage of the energy sector in many types of reports. However, there is still no clear, consistent and standardized format for presenting energy sector information. This paper reviews the problem and proposes guidelines for policymakers and operational staff who deal with energy issues. The paper is divided into three parts: part one sets out the basic framework for presenting aggregated energy data -- "the national energy balance"; part two deals with the use of appropriate units and conversion factors to construct such a balance from raw demand and supply data for the various fuels; and part three briefly discusses special problems posed by: (i) differences in end use efficiency of various fuels; (ii) the inclusion of wood and other noncommercial energy sources; and (iii) the conversion of primary electricity into its fossil fuel equivalent.

EGY PAPER No. 8 — External Financing for Energy in the Developing Countries by Althea Duersten (World Bank). June 1983. 66 pages, includes appendices.

Provides an overview of energy financing in the developing countries. Identifies energy investment requirements and past financing patterns. Discusses the historic roles of multilateral and bilateral assistance programs in helping to mobilize financing, particularly for low income oil importers and in providing economic and sector advice. Examines the role of official export credit, and discusses lending by private financial institutions which has been the predominant source of financing for energy projects in the middle and higher income developing countries.

EGY PAPER No. 9

<u>Guideline for Diesel Generating Plant Specification and Bid Evaluation</u> by C.I. Power Services Inc. (Consultant). December 1982 - 210 pages, includes appendices.

Explains the characteristics and comparative advantages and disadvantages of large low speed two-stroke diesel engines intended for electric generating plant service, and develops a bid evaluation procedure to permit comparing of bids for both types.