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Value of Natural Gas in Power Generation

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VALUE OF NATURAL GAS IN POWER GENERATION

Yves Albouy
and Afsaneh Mashayekhi*/
Energy Department

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ABSTRACT

This paper is one of a series to examine the "netback value" of natural gas in major domestic and export uses. The netback can be compared to the cost of gas to permit a rough estimate of the net economic benefit to gas use in various sectors.

With the help of case studies and simple calculations, the netback value to power generation is found to be fairly high on average even though it diminishes as the use of gas spreads from peak to base load. The paper also highlights the important role of power in the natural gas market and the specific analytical framework in which an assessment of this role can be undertaken for preliminary gas utilization studies.

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SUMMARY AND CONCLUSIONS

For many of the 50 or so developing countries with natural gas resources, the power sector represents the largest potential gas user and can provide the early financial returns necessary to justify the initial infrastructure investment. Because of the sector's size and complexity, however, the analysis of the economic value of gas used to produce electricity and the comparison of that value with those from alternative gas uses are difficult tasks.

This paper is one of a series prepared by World Bank staff to examine the value of natural gas in major domestic and export uses. The papers develop a consistent methodology for calculating the "netback value" of gas -- a summary measure that can sometimes be used to prescreen project alternatives. Under certain circumstances, the netback to gas at the factory gate will also measure consumer willingness to pay. If properly calculated, the netback can be compared to the marginal cost of gas, as estimated by the Average Incremental Cost,[1/] to permit a rough assessment of the net economic benefit to gas use in various sectors. This paper reports on the results of a study to apply the netback concept to gas used for power generation.

The first section of the paper reports on two case studies to evaluate the economic value of natural gas in power generation with the help of the netback approach. The netback value is calculated as the difference in discounted total system cost for two optimised expansion plans with and without a given quantity of gas divided by the discounted stream of gas consumption. This is a more complicated calculation than in other gas uses where this netback can be estimated on a stand alone plant basis. The two cases considered are very different: country A has a small oil-fired thermoelectric system, country B is much larger, has a considerable peak shaving hydroelectric capacity and coal based expansion alternatives.

In general netbacks to the use of gas in the power sector can be quite high particularly if gas is used for peaking. The study indicates that netbacks are larger in country A than in country B. In all cases they tend to decrease as more gas is utilized. They are closely related to the price of the fuel they substitute only in the case of existing plants converted to gas at a small cost. For new gas-fired capacity, the netback is increased by a premium due to the lower capacity related costs of gas-fired units.

The general conclusion is that while it is possible to calculate the netback value of gas for power in a way that is consistent with other sectors, the concept has limited meaning and application in the case of power. This is mostly because the method is an average measure that cannot

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1/ See Energy Department Note No. 10, World Bank, July 1983.

capture the diminishing returns to gas as it moves from peak toward base-load or from fuel to hydro project substitution. The average netback calculated over total gas consumption is higher than the marginal value of gas, which is a measure of the utility's willingness to pay. For the same reason, the gas netback in power will not generally represent willingness to pay, as it will in other sectors where returns are fairly constant over distinct projects. Hence this netback should not be used in setting gas prices in the power sector. Even when applied to the gas requirements of marginal projects the netback concept cannot be safely used to rank such projects: a project with a higher netback could have a greater present value at the going gas price if that price was constant but the present value deteriorates if gas utilization is most heavily concentrated in the periods when prices are highest, for instance in the decade preceding reserves depletion.

Furthermore, the netback approach is a cumbersome method of approximating the demand curve for gas in power. A much better alternative to assess gas demand for power generation is to postulate at the outset a gas price scenario and derive the gas demand with the help of least cost planning models used by power system planners. This approach was used with success in the two country cases. It would certainly be the only possible approach in the case of predominantly hydro systems where gas utilization could be very random and irregular.

The second half of the paper attempts to illustrate all the above findings in a conceptual framework based on power planning methodology. It provides shortcuts to approximate netback calculations. It also suggests a quick way to assess the impact of a large potential gas demand in the power sector on gas depletion as well as on the general price level for other gas utilization projects. This impact is found to be very important for the growth rates of power demand experienced in developing countries even when gas is competing with moderately priced alternative sources of generation such as imported coal.

INTRODUCTION

Natural gas is a major potential source of indigenous energy in over 50 developing countries. Proven reserves of over 30 billion tons of oil equivalent (toe) are about 43 percent of total world reserves and are widely distributed in the Middle East, Asia, Africa, and Latin America. The cost of gas development and transport to major users is usually far below the equivalent value of the liquid fuels that gas can replace.[1/] In developing countries the current level of gas consumption is very low relative to the reserve base and the average share of gas in total primary energy in developing countries is about 7 percent compared to a 19 percent share in OECD countries.

One of the major uses of natural gas is in the power sector. Gas used to displace distillate at peak times and as standby in hydroelectric systems has a very high value. Its low production cost often makes natural gas competitive for base load use as well.

The early use of natural gas for power generation can provide significant benefits both to the power and gas subsectors. For a power utility facing high fuel bills and perhaps energy shortages, gas provides a rapid and economic source of energy. At the same time, to ensure financial viability in the gas subsector, the large initial investments in gas infrastructure must be recouped by large and early gas use. In many developing countries with a limited industrial and residential energy demand, the power sector can provide this initial market. Over the longer term, if there is a gas supply constraint and other higher value markets develop, they will gradually displace gas-based power generation from the base load.

This paper reports on a case study sponsored by the Bank[2/] and on some further in-house analytical work. The study does not address the issue of whether or not an expansion of the power system is economically justified in the first place. It also does not explicitly consider how competing claims on natural gas from outside the power sector might affect gas utilization in power.

The first objective of the case study is to test the applicability of the netback approach to determine the economic value of natural gas in power generation. If such a concept is valid, it could provide a useful summary measure to compare power with other potential users of natural gas. For a given demand forecast, the netback to gas is calculated as the

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1/ "Marginal Cost of Natural Gas in Developing Countries: Concepts and Applications,"Afsaneh Mashayekhi, World Bank, Energy Department Note No. 10, July 1983.

2 "The Economic Value of Natural Gas in Power Generation", Consulting Engineer, Kennedy & Donkin, September 1982.

difference in discounted total system costs over specified planning periods for optimized systems with and without various quantities of natural gas, [1/] divided by the discounted volume of gas consumed over the period. Although the value of gas will be related to the prices of fuels which it displaces, its value cannot be determined simply by reference to these prices. Gas-fired plants may have lower capital costs per kW than alternative plants, lower non-fuel variable costs, and lower maintenance costs. Therefore the value of gas must be assessed in terms of changes in total power system costs. This makes the estimation of netback values in the power sector more complicated than in other sectors (e.g. in a cement plant) where the netback to gas use can be estimated on a plant by plant basis.

This paper is divided into four sections. Following this Introduction, Section I discusses the methodology used to estimate netbacks, and describes two typical power systems of different sizes and with different plant mixes which will be used to measure the sensitivity of netbacks to the growth in demand as well as the volume of gas supply. As an extension to the case study, another method of assessing the demand for gas is considered whereby a price of gas is postulated and the power system expansion and operation are optimized on that basis. The results are the demand curves presented in Section II. Section III summarizes the power planning framework as it applies to gas utilization studies. A final analytical note in Section IV provides several ways to calculate the netback values on an annual cost basis. The last two sections are particularly helpful to the gas analyst in interpreting most of the results of the case studies and in understanding why it is easier to derive gas demand from postulated prices rather than the other way around. The advantage of this second method is even clearer where hydro generation is or could be predominant and wherever the operation of gas-fired plants is difficult to predict and requires simulations. This approach is also used to show that gas demand in power can significantly affect the market and the depletion prospects because even when coal alternatives are available, gas may remain more economic for base load.

1/ Gas production and transport costs are not included since they are very system specific and the netback to gas is measured at the point of its entry into the power plant.

I. CASE STUDY ON NETBACK VALUES

I.1 Methodology

When various projects competing for gas use cannot be ranked directly because the economic value of gas is unknown, it is often useful to find for each project that value of gas which leads to a breakeven between project costs and benefits over the life of the project. This is the netback value to gas at the point of delivery to the project. The netback value of gas for power generation can be estimated by the resource cost savings which would accrue if it were substituted for other fuels on a particular power system. For the power sector, this study estimates the resource cost savings as the difference in discounted total system costs for optimized power systems, assuming a least cost objective, without supplies of natural gas and the same system reoptimized for different volumes of gas supply.

The netback value is partly a function of the inherited plant mix (hydro, oil-fired, coal-fired, gas turbines etc.) and optimal future mixes of plants and fuels which will themselves depend on the capital costs for new plants, costs of converting inherited plants to burn natural gas, the quantities of available gas, estimated future fuel prices, assumed growth rates in demand, and the discount rate. They would also be affected by any differences in the availabilities of gas burning and other types of thermal plant, differences in annual non-fuel variable costs and maintenance costs. Dividing the total discounted savings in system costs when gas is substituted for other fuels by the discounted volume of the gas used gives the netback value of gas per MCF.

The basic idea is to develop least-cost power system expansion plans 1/ with and without given quantities of gas, and then to compare the present value of total costs for each plan. Gas supply costs are not included, so that the breakeven value of gas is measured at the point of entry into the gas-fired power plants. The process models three basic scenarios of gas utilization. First, the power system expansion is optimized assuming a zero supply of gas. Second, the system is reoptimized with a small supply of gas which would be burnt in new gas-fired plants. Third, step two is repeated for progressively larger supplies of gas. This process is repeated allowing for gas use in both new gas-fired plants and in existing plants converted to gas firing. Finally, the benefits of constructing capacity ahead of need in order to speed up the rate of utilization of gas (i.e. overplanting) were estimated. Because the results for the non-conversion and overplanting cases were highly system specific, the following sections of this paper discuss only the general case results in detail.

1/ See Section III for a summary of the basic concepts of power system planning.

The total cost savings from the use of gas include the value of fuel displaced after introducing gas fired power plants and the change in capital, operating and maintenance costs of the plants. The major saving arising from the supply of gas in thermal or mixed thermal/hydro supply systems will be a fuel cost saving.

Capital cost savings due to the use of gas could arise at both the plant and system levels: capacity costs per kW of gas-fired plants may be lower than those of hydro, oil or coal-fired plants and once gas is available the plant mix may change with lower capital cost plants being substituted for those with higher capital costs.

The introduction of gas-fired plants into a power system could also lead to other cost savings besides capital and fuel cost savings. These additional cost savings relate to non-fuel variable costs, labor costs and maintenance. The present value of these costs are estimated on an annual basis for optimized systems with and without gas.

I.2 Power Systems Description and Main Assumptions

Two prototype power systems were chosen for study. Country A is a small system (100 MW maximum demand) with entirely thermal generation. Country B is a medium sized system (2,400 MW maximum demand) with a mix of hydro and thermal options.

For Country A, the power system is entirely thermal with a pronounced peak. The system load factor is expected to be constant over the simulation period at 54.5 percent and no possibility of future hydro projects. The inherited plant mix consists of five 33 MW steam units fired by residual fuel oil, and various diesel units amounting to a total of 70 MW. The steam units are new and are not retired over the simulation period, whereas the diesel units are retired over the period 1988 to 1996. Two different annual load growth rates are assumed, namely 7 and 15 percent with 7 percent as a base case. Country B has a better load factor (70%) and a sizeable amount of peak-shaving hydro capacity. Thermal generation comes from existing or committed lignite fired plants, steam plants on residual fuel oil, gas turbines, and diesel units. The assumed rate of load growth for country B is 7%.

Throughout this study, constant 1982 dollars were used. The fuel price projections are based on mid-1982 levels (Table 1). All petroleum products were projected to increase at an average annual rate of two percent, and lignite prices were assumed to grow at one percent. The generating systems are simulated over 20 years, with an addition of 10 years to eliminate the necessity of calculating residual values; the variable costs incurred in the final ten years of simulation are held constant.

Table 1
Average Real Price of Fuel 1982-2001 in $/MCF

	Country A	Country B
Residual fuel oil	6.4	6.1
Distillate	10.5	10.3
Coal	-	2.9
Lignite	-	4.5

The economic lives assumed for the different types of generating plant were 20 years for steam plants and 15 years for both gas turbines and combined cycle plants. In Country A the only generating plants capable of being converted but at a very high cost of $85/kW, are the 33 MW oil fired steam units [1/]. In Country B the conversion of existing oil fired steam plants and committed gas turbines costs $25/kW and $20/kW respectively. The early retirement dates for all other plants precludes any other conversion possibility.

Gas supply is mapped into MWs of generating capacity at the rate of some 4 MW per million cubic feet per day (MMCFD) [2/]. The position of the generating capacity in the energy dispatch under the load curve is chosen to maximize the fuel savings, just as is done with hydraulic plants without storage and operated in run-of-the-river fashion. This simplified gas allocation tends to underestimate the netback and underutilize the available quantity of gas at intermediate and peak loads.

I.3 Netback Value in Country A Without Conversion

The average netback value of gas for country A without conversion is presented in Table 2 for different assumed supplies of gas and demand growth rates. The maximum value corresponds to the smallest gas supply of 5 MMCFD, which is principally substituted for distillate fuelled gas turbines operating at the bottom of the merit order. The lowest value of gas relates to the 15% growth rate case with a 342 MMCFD supply of gas. In this case gas is mainly substituted for coal. With the exception of peaking needs in the 5 MMCFD supply case, the netback to gas is consistently lower in the 15% growth case than in the 7% case. This is because gas ends up displacing coal in the 15% case, whereas with lower growth the system cannot accomodate the relatively larger coal plants and gas displaces fuel oil and distillate. The netbacks exceed the average price of displaced coal ($3.25 per MCF) because of capital cost savings from substituting gas-fired gas turbines mainly for coal-fired steam units.

1/ This unusually high cost is due to the old age of the steam units.

2/ Throughout this study 1,000 cubic feet (MCF) = 10^6BTU = 1.05 Gigajoules.

At all gas consumption levels the value of gas in the no-conversion case is highest for the 7% growth rate of demand. In this case, because of inherited excess capacity (including capacity under construction) in country A's power system, no new capacity is required until 1992. After 1992, in the absence of gas, optimal additions to the power system are distillate burning gas turbines and oil-fired steam units. When a supply of gas is assumed to be available at either 60 MMCFD or 87 MMCFD, the optimal additions are combined cycle plants, while when the supply is 20 MMCFD the additions are a combined cycle plant, distillate burning gas turbines and new oil-fired steam capacity. In all cases the gas is substituted for fuel oil and distillate. Its value depends on both the prices and the share of the fuels which gas displaces and any discounted capital cost savings or increases which are associated with the introduction of gas.

Table 2
Average Netback Value of Gas - Country A
No Conversion (10% discount rate)

	7% Growth Rate		15% Growth Rate	
Gas Available MMCFD	Gas Used Terminal Year MMCFD	Netback $/MCF	Gas Used Terminal Year MMCFD	Netback $/MCF
5	5.0	10.88	5.0	10.10
20	15.2	8.28	17.9	6.09
60	41.5	8.51	43.1	6.09
87	42.9	8.51	67.0	5.64
342	42.9	8.51	239.7	4.14

In all the 7% growth rate cases the discounted capital costs of the optimal plant additions to the supply system when gas is available are higher than those when there is no gas supply. Thus in all these cases the value of gas is less than the weighted average price of the fuels which it displaces.

For a 5 MMCFD supply, gas is substituted for distillate in gas turbines. Since the cost per kW of the gas turbines has been assumed to be the same irrespective of whether they are gas-fired or use distillate it follows that the value of the gas is determined solely with reference to the price of the displaced distillate.

I.4 Netback Value in Country A With Conversion

Allowing the conversion of existing and under construction plants to gas-firing has the effect of bringing forward the date when the available gas supplies are first utilised. In the 7% growth rate case gas utilization is brought forward from 1982 to 1984. Introducing conversion also has the effect of increasing the proportion of gas used.

Country A is unusual in that the value of gas is much less than the price of the fuel oil which it displaces because of high conversion costs. Conversion costs are so high in country A that they depress the netback for the case with conversion below that for the without-conversion case. This reduction which is very spectacular for 5 MMCFD does not jeopardize the economic justification of conversion as long as the gas price remains well below the netback. In most power systems such as in country B, conversion costs are lower and the netback value with conversion is above the netback with no conversion.

Table 3
Average Netback Value of Gas - Country A
With Conversion (10% Discount Rate)

	7% Growth Rate		15% Growth Rate	
Gas Available MMCFD	Gas Used Terminal Year MMCFD	Average Value $/MCF	Gas Used Terminal Year MMCFD	Average Value $/MCF
5	5.0	6.53	5.0	6.53
20	18.2	7.05	17.9	5.72
60	40.5	7.09	46.6	5.64
87	46.3	7.24	68.2	5.66
342	46.3	7.24	233.4	4.50

In the 7% growth rate case the average value of gas is increased when the supply of gas is increased from 5 MMCFD to 20 MMCFD. The larger supply of gas permits the conversion of three 33 MW oil-fired units. No other changes are introduced to the optimal operating and investment program. This means that, in contrast to the 5 MMCFD supply cases, the costs of conversion are spread over more kWhs and hence the average value of gas is increased.

I.5 Netback Value in Country B

The average netback values of gas with and without conversion are presented in Table 4. With the exception of the 5 MMCFD supply, the values are based on the conversion of inherited steam capacity and the construction of new gas-fired combined cycle units. The study investigated the relative merits of converting steam plants to gas-firing and converting gas turbines to gas-fired combined cycle units. It was found that converting the steam units gave a higher value to gas. For example, with a supply of 60 MMCFD and a 10% discount rate, the value of gas used in gas-turbines converted to combined cycle is $3.55 per MCF compared with a value of $4.14 per MCF if gas is used in a converted steam plant. In this example, country B has excess peaking capacity and does not need additional capacity for many years. In most countries, in contrast to the above example, conversion to combined cycle would generate higher netbacks since combined cycle plants have a higher efficiency than steam plants (42% compared with 30% respectively).

Table 4
Average Value of Gas - Country B
(10% discount rate)

Gas Available MMCFD	Gas Used 1/ Terminal Year MMCFD	Average Value ($/MCF) Without Conversion	Average Value ($/MCF) With Conversion
5	5.0	9.41	9.41
20	16.6	4.65	4.17
60	45.6	3.26	4.14
87	66.1	3.13	3.90
300	228.0	3.20	3.67
1800	1131.0	3.27	3.39

1/ Less gas is used (15.2 MMCFD) in the without conversion case than with conversion when the gas available is 20 MMCFD.

Allowing for conversion, the value of gas declines continuously as the supply of gas is increased. The average value of gas with a supply of 5 MMCFD is the same as in the no conversion case. This is because conversion is uneconomic with this supply and thus gas is used in a new gas turbine to displace distillate.

Total system discounted costs are generally lower (with the exception of the 5 MMCFD case) with conversion than without conversion. The value of gas would always be higher with conversion if gas use were the same in both cases. In Table 4, however, slightly more gas is used with conversion than without conversion when the gas available is 20 MMCFD. This results in a lower netback value for the case with conversion.

I.6 Incremental Netback Value of Gas

Generally conversion costs are not very high, and as in country B the average value of gas computed for power generation decreases as more gas is made available. The netback of the incremental gas supply is lower than the average; and the expansion in gas use should be stopped at the point where this incremental netback falls below the cost of gas. This incremental netback indicates the willingness to pay for gas in power and not the average netback calculated above. Table 5 shows the incremental value of gas in Country B as gas supply is increased from 5 MMCFD to 20 MMCFD, from 20 MMCFD to 60 MMCFD and so on up to 1800 MMCFD [1/]. Additional increments of gas supply beyond 1800 MMCFD lead to a zero incremental netback. In practice, these increments would be defined by the gas requirements of power projects taken one after another from a priority ranking.

Table 5
Incremental Netback to Gas - Country B
With Conversion (10% discount rate)

Gas Available MMCFD	Gas Used in Terminal Year MMCFD	Incremental Value $/MCF
0	0	
		9.41
5	5.0	
		2.44
20	16.6	
		4.13
60	45.6	
		3.36
87	66.1	
		3.55
300	228.0	
		3.20
1800	1131.0	

1/ As indicated in Table 5, gas used in terminal year is in all cases below the quantity of gas available.

I.7 Conclusion

At first glance the netback values appear system specific and little prone to generalization. This is due mostly to the rather arbitrary volumes of gas made available in the different simulations and their interaction with rigidities in new plant sizes and the inherited capacity mix. The changing netback values as more gas is made available illustrate the inherent fragility of the netback approach for measuring the value of gas in power generation.

Some rough comparisons are nonetheless possible. Netbacks are higher in country A where the only alternatives are based on fuel oil than in country B where there is coal and hydropower. The netback is higher than the fuel value in all cases due to capacity savings. The netback on total gas consumption is generally higher than that for incremental consumption at the margin. These results can be easily predicted as shown in Section IV. However, investment lumpiness (or perhaps the MWs mapping method) can produce some unexpected results. For example, a higher growth rate generally increases peak demand and the netback. In country A, however, because higher growth allows bigger and cheaper coal units to be brought on line, the netback falls.

The netback value to gas in power has serious conceptual and practical limitations as a policy indicator. The value of gas in power generation decreases as more gas is used by this subsector; as a result, the average netback value will overstate the willingness to pay of the utility and it cannot be used as a guide to price negotiation. Even when applied to incremental quantities of gas associated with a project, the concept suffers from the same problems as the internal rate of return (IRR). A project A with a higher IRR than project B may indeed yield a lower profit at the actual discount rate. A project with a higher netback would also yield a greater profit at the going price if that price was constant, but this is not true if gas utilization is most heavily concentrated in the periods when prices are highest. The netback cannot be safely used to compare two projects, particularly two mutually exclusive variants of a same one with respect to timing and design.

In calculating the netback value a major practical difficulty is related to the allocation of gas overtime. A simple constant allocation assumes that gas will always play the same role in the power sector. In the framework of depletable resources, gas may be gradually phased out and used more and more for peaking. Because of these limitations, it will generally be better, and easier, to postulate at the outset a profile of gas prices and to derive the gas demand with the help of least cost planning methods used by system planners.

II. CASE STUDY EXTENSION: DEMAND CURVES

As an extension to this study demand curves were calculated in a straightforward and accurate way for various price scenarios with the help of a least cost expansion model, a tool readily available to most power systems planners. The results conform with the static analysis of Section III but investment lumpiness and dynamics have several consequences: the demand curves are broken down into segments with zero or infinite price elasticities, demand may vanish altogether after a plant commissioning if the system is small and demand growth is sluggish. Other seemingly odd results can be explained: in country B converting existing power units to use gas is competitive with distillate use, but in country A conversion investment cost is so high that new units are preferable from the date they are needed (1990); in country B some overplanting is economically justified because the existing oil-fired units are not retired but retrofitted for gas firing.

II.1 Demand Curve for Country A

Simulated demand curves for country A for the years 1985, 1990, 1995, and 2001 are presented in Figure 1. The demand for 1985 consists of a single large step. In this year the only potential use of gas is in converted steam units. The discounted cost of conversion is equivalent to a fuel price of $0.23/MCF in 1985. Hence, when $5.14 is the assumed 1985 price of residual, the demand for gas becomes perfectly elastic at a price of $5.14 - $0.23 = $4.91/MCF. Since conversion is economic for all prices below $4.91/MCF the demand is perfectly price inelastic over the price range 0 to $4.91/MCF.

The demand curve for 1995 consists of a series of steps. The critical price for the use of gas in converted steam plants is $6.28/MCF. For gas prices below this level both the plant mix and the merit order ranking of plants are unchanged and thus the demand is perfectly price inelastic. However, in 1995 a second critical price of gas emerges at $8.13/MCF due to a change in optimal power plant mix. Finally, the demand for gas becomes zero at $10.73/MCF when it is cheaper for gas turbines to use distillate.

II.2 Demand Curve for Country B

For country B, which has an inherited thermal/hydro plant mix, the estimated demand curves for gas in power for the years 1985, 1990, 1995 and 2001 are presented in Figure 2. The demand curve for 1985 consists of two steps with two price ranges over which the demand is perfectly price inelastic. The first step occurs over the price range 0 to $2.41/MCF when gas fired steam units replace coal-fired steam units. The second step occurs over the price range $2.41 to $4.95/MCF, where the latter is the maximum price at which it is financially profitable to convert the inherited oil-fired plants to gas-firing.

Figure 1
COUNTRY A - INSTANTANEOUS GAS DEMAND CURVE

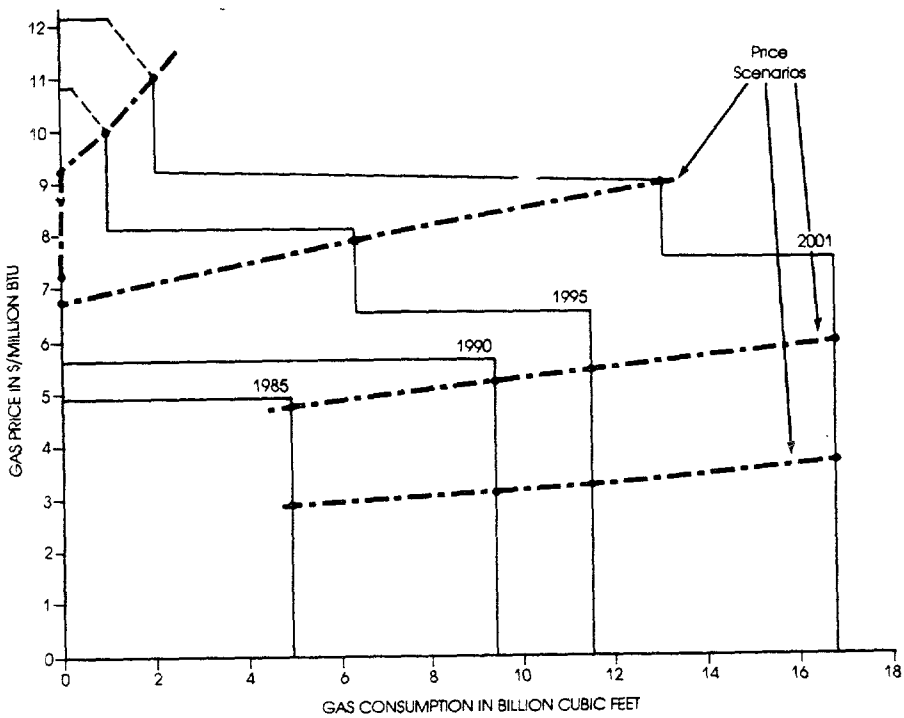
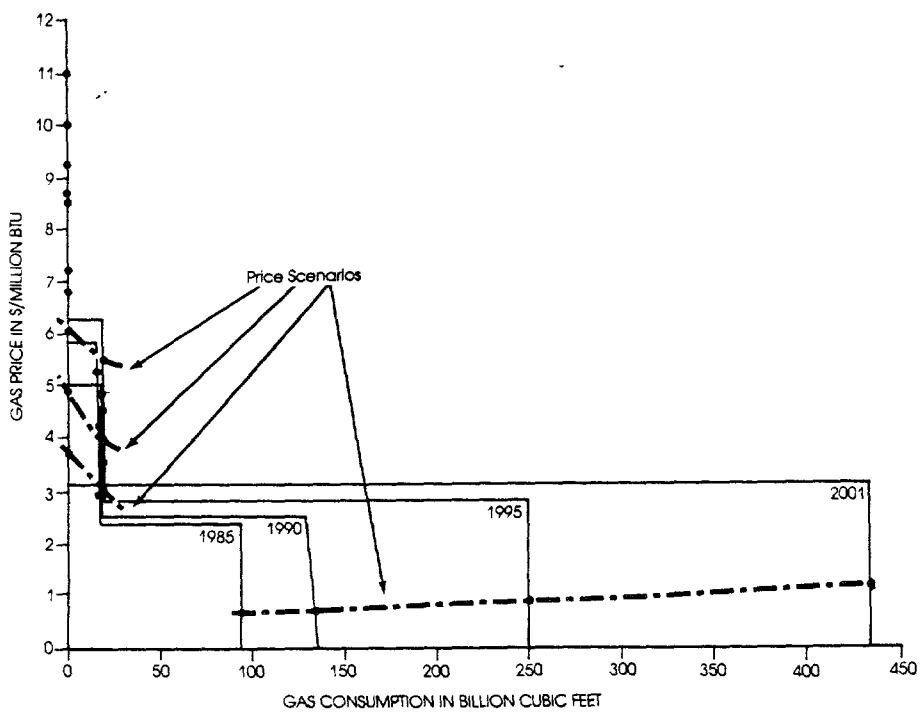


Figure 2
COUNTRY - B INSTANTANEOUS GAS DEMAND CURVE



The demand curve for 1990 and 1995 replicates that for 1985 except that the critical substitution prices of gas are higher due to an increase in real oil prices. The demand for the year 2001 consists of two steps. The first step relates to the price range 0 to $3.05/MCF, where the latter is the critical price of gas where gas-fired power stations replaces coal-firing power station in the least cost investment program. Next, over the price range $3.05 to $11.88/MCF gas is used in gas turbines and at the latter price demand becomes zero. The demand for gas, although small, is perfectly price inelastic over the $3.05 to $11.88 MCF price range.

II.3 Aggregation of Demand Curves Over Time

The problem remains of indicating which price scenarios are compatible with the gas reserves available for power generation. To do so requires an aggregation of gas demands over the years, but these cannot be simply added for a given price since they were determined by postulating a price increase: one point on the 1985 curve leads to another one on the 1990 curve and so on. This common thread must be used in the aggregation and to each scenario corresponds an aggregate. In this study. each price scenario corresponds to a same real price increase of 1.5% a year from 1984 to 2001 but to various discounted averages over the period of analysis in $/MCF: 9, 5 and 3 for Country A, 9, 7, 5, 4, 3 and 1 for Country B.

Cumulative Gas Demand (Billion Cubic Feet)

Price $/MCF	1	3	4	5	7	9
Country A	-	363	-	358	221	29
Country B	8124	275	269	234	8	8

The contrast is striking between country B where gas competes with hydro and coal and the smaller country A where alternative energy sources are relatively expensive. In country B, the demand for gas falls when gas ceases to be competitive in the baseload because hydro is already meeting the peak and intermediate loads. In country A this does not occur and there is demand for gas even as gas prices increase. Also it can be seen that a price of gas under $3/MMBtu has far reaching implications for Country B and that power can strongly affect the prospects of gas reserves depletion. This issue is dealt with in paragraph III.4.

III. POWER PLANNING FOR GAS UTILIZATION STUDIES

Just as it is important for the power planner to be aware of gas as a potential source of energy, it is also necessary that the gas analyst be introduced to the major aspects of power system planning and to the analytical framework recently developed by the Bank to assess the value and role of gas in power generation. This section provides the basic concepts of power planning in a static framework as well as demand curves for various prices of gas. It also provides examples for estimating netbacks based on given quantitites of gas. As illustrated by a case study, least cost procedures currently used by power system planners generate demand curves based on gas price profiles over time.

III.1 Basic Concepts

The commonly used unit of energy in heavy current electricity applications is the kilowatt-hour (kWh) and its multiples, e.g the gigawatt-hour (1 GWh = 10^6kWh). The rate of flow of energy per unit of time is called power which is measured in kilowatts (kW) and its multiples e.g. the megawatt (1 MW = 10^3kW). The load factor is the ratio of average to maximum or peak kilowatts over a given interval of time. The peak demand occurs only over a short period of time and annual load factor typically ranges from 60 to 80%. The cost of electricity basically depends on the plants' running costs and on the size and cost of the capacity required to handle peak demands and severe droughts if hydropower is involved.

The power system planners have to consider the availability and price of fuels, the generating efficiencies and the cost and dependability of the capacity to determine the least-cost operating and expansion schemes. Gas-fired power plant benefit from having access to relatively firm supplies of fuel.

Gas can be burned in a variety of thermoelectric units. The most immediate option is for gas to substitute residual fuel oil (Bunker) in conventional steam plants with an efficiency of about 34% (10,000 Btu or 10 cubic feet per kWh). Gas as well as oil distillates ridden of impurities such as sodium and vanadium may be used to fire gas turbines, the lowest design efficiency of which is 25% (14,000 Btu/kWh) as illustrated in Figure 3a. Exhaust gases are very hot and may be used in an exchanger for process heat and district heating (80% total efficiency) or to preheat the air sent to the turbine (35% generating efficiency). In combined cycle units as in Figure 3-b, the exhaust gases are recycled in the boiler of a conventional steam turbine which provides more than 50% additional power and drives the generating efficiency to about 43% (8,300 Btu/kWh).

Figure 3-a

COMBUSTION TURBINES

GAS TURBINE EFFICIENCY = 25%

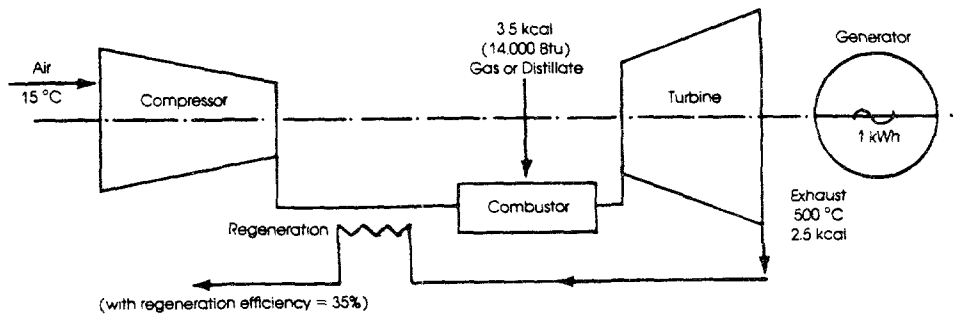
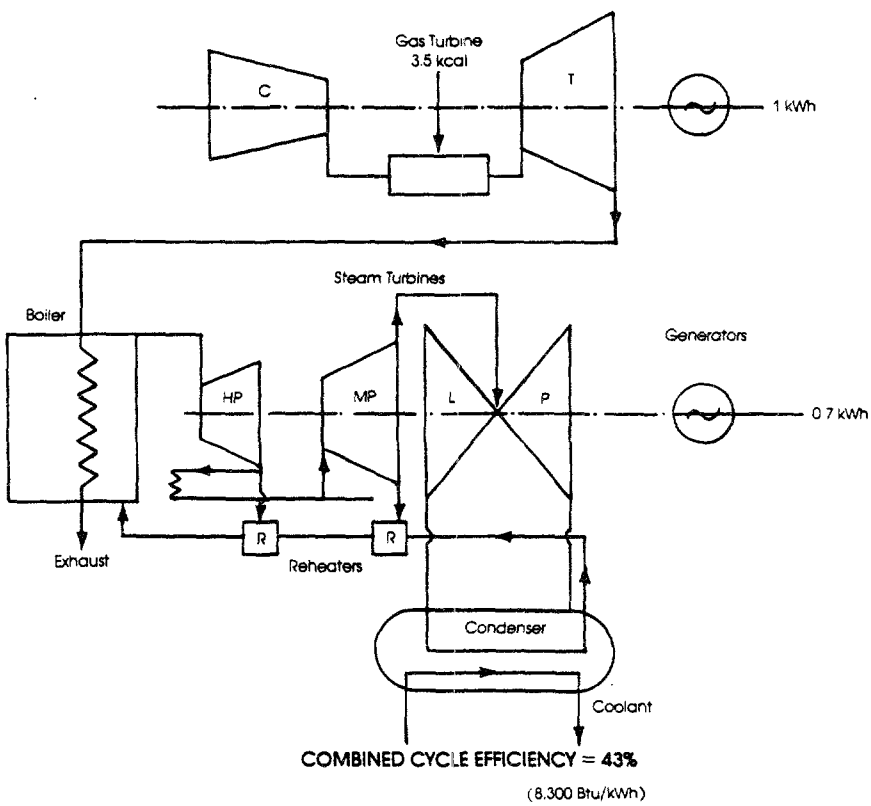


Figure 3-b



Converting a steam plant from fuel oil to gas usually involves little time and money, but the potential for retrofitting is limited. Combustion turbines are the cheapest generating units in terms of operating and maintenance and above all capital costs. Simple cycle units typically sell for $350/kW or less. With a 12% discount rate, 15 years life time and yearly operating and maintenance (O & M) costs of 1.5% of investment, the annuitized cost of a gas turbine is:

$350 x 0.16 = $56/kW

or with a 20% derating for planned and forced outages

56/0.8 = $70/year per kW available round the clock (a.r.c.).

It is often justified to upgrade these turbines into a combined cycle plant by adding a heat recovery boiler and a steam turbine ($950/kW) having 50% of the gas turbine rating. Taking a 30 years life, O & M costs at 2.5% of investment costs, and a 75% availability, the annuitized cost of this upgrading per kW of gas turbine (1.5 kW in combined cycle) is:

0.5 x $950 x 0.15/0.75 = $95/year per kW a.r.c.

The overall annuitized cost of the combined cycle plant is

($70 + $95)/1.5 = $110/year per kW a.r.c.

Annuitized costs for a coal-fired plant of a comparable size are at least $240 and those of an oil-fired plant $160 per kW a.r.c. At international prices the variable operating costs are about 2.5¢/kWh for coal and 5¢/kWh for oil. The all-in costs for base load generation (8,760 hours of utilization per kW a.r.c.) are then 5.25¢/kWh for coal and 6.8¢/kWh for oil. Therefore a gas-fired combined cycle unit is competitive with coal at a 4¢/kWh running cost and with oil at a 6¢/kWh running cost.

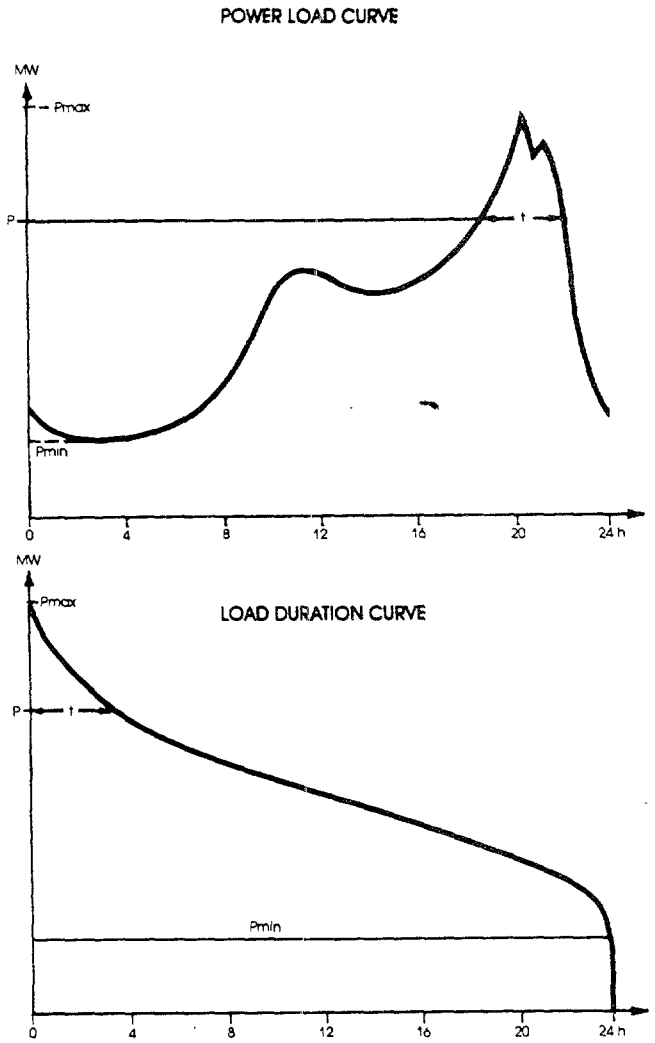
When the average heat rate of gas-fired plants mix is 10,000 Btu/kWh these figures translate into breakeven gas prices of $4 to $6/MCF, which is relatively high. Gas-fired units are even more competitive for shorter periods of use such as peak times since their fixed costs are relatively low or even negligible in the case of existing plants converted to gas.

III.2 Demand for Gas in the Short Run

In most decisions about power generation, cumulated hours of utilization for equipment is an important data whereas dated time is largely irrelevant. For this reason, power system planners generally do not make use of the load curve with its peaks and valleys (Figure 4-a) but rather the System Load Duration Curve (SLDC).

The daily SLDC diagram shown in Figure 4-b (P, t) plots the MW of demand P, against the time t in hours during which this level of demand is equaled or exceeded; it is a nonincreasing curve with peak hours on the left hand side. At the extreme right are night time--or week end hours in the case of a weekly SLDC. Hours for the intermediate or "shoulder" load may be mixed. For instance, in an SLDC for the entire year, nighttime loads of the critical period may be higher than daytime loads outside this period.

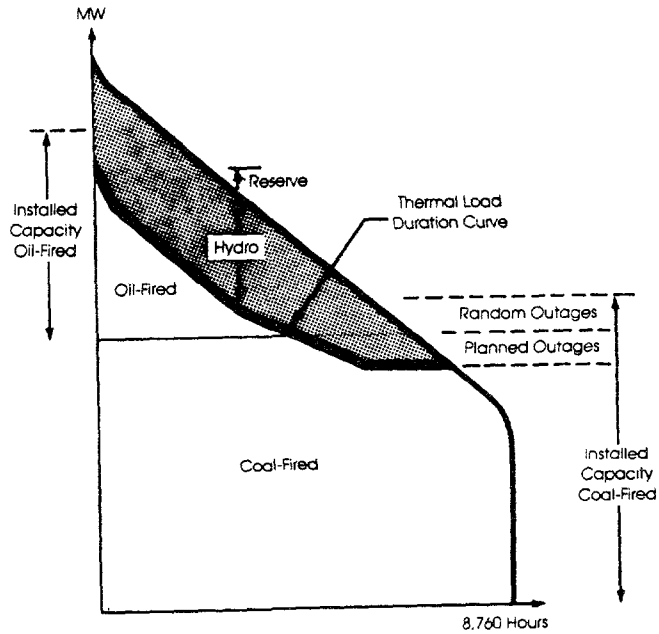
Figure 4(a,b)
POWER LOAD DURATION CURVE



In the short run, generating capacity is known. The generation dispatch seeks to minimize outages and operating costs for the period considered. A first step is to determine the maintenance policy and eventually the discharge in hydraulic plants. The planned outages and the random ones are deducted from the installed capacity net of auxilliaries to determine the dependable capacity.

The discharge in reservoirs is optimum when the level of thermal generation is as low and constant as possible. However, a perfect peak shaving is not always possible as shown in Figure 5 due to turbine capacity limitations, inflows travel time and storage constraints. The residual demand after allocation of hydropower is synthesized into a Thermoelectric Load Duration Curve (TLDC). The TLDC has generally a higher load factor than the original SLDC,and thermoelectric requirements are randomly distributed and quite small on very wet years in systems that are predominantly hydroelectric.

Figure 5
GENERATION DISPATCH



In the short-run, since no capacity is added or deleted, gas can only be used by converting existing plants. Assuming that the price of gas g is between that of coal (c=2.5¢) and fuel oil (5¢), then all the eligible oil-fired plants ought to be converted and utilized more than the nonconverted ones. This reshuffling in the merit order of plants places them in the intermediate part of the TLDC. The value of the operation is all in the fuel savings (net of the conversion annuity A_f); for instance for the first kW to be converted, the annual benefit is:

$$B = (5 - g) \times u_f - A_f$$

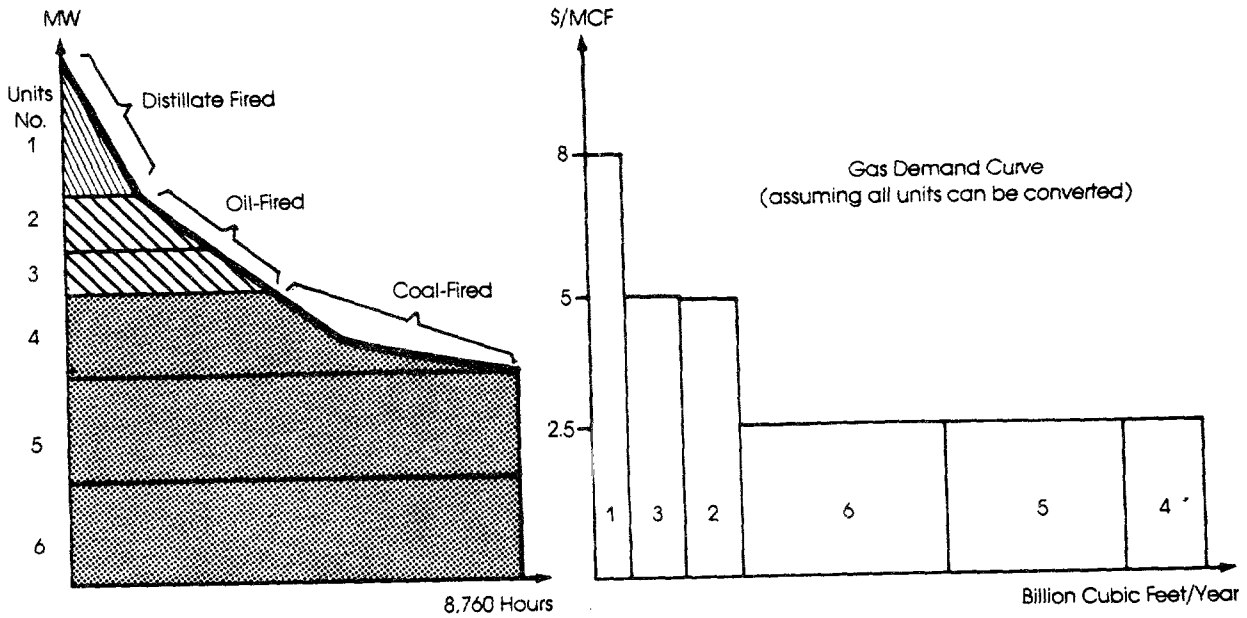
where u_f is the utilization in hours of the most utilized oil-fired unit.

The demand is triggered by a price slightly under the fuel-oil equivalence and depends on new dispatch conditions (such as the size of the coal base and of the intermediate thermal load) and on the stock of eligible plants particularly their age and location.

This demand steps up to a much larger amount if gas prices fall below the price of coal, since gas would then be used in the base load which generally represents two thirds of the load in an all thermoelectric system. In all cases, some oil fired units will remain in the peak because even when possible, conversion would bring only insignificant fuel savings given the small amount of time these units are operated. On the contrary, if the "needle peak" demand was previously met by combustion turbines burn-

ing distillate, these units will be the first ones to be switched to gas; assuming that fuel oil treatment jacks up its cost to some $8/million Btu, a sizable demand for gas will appear at that price level (See Figure 6).

Figure 6
CONVERSION OF EXISTING PLANTS



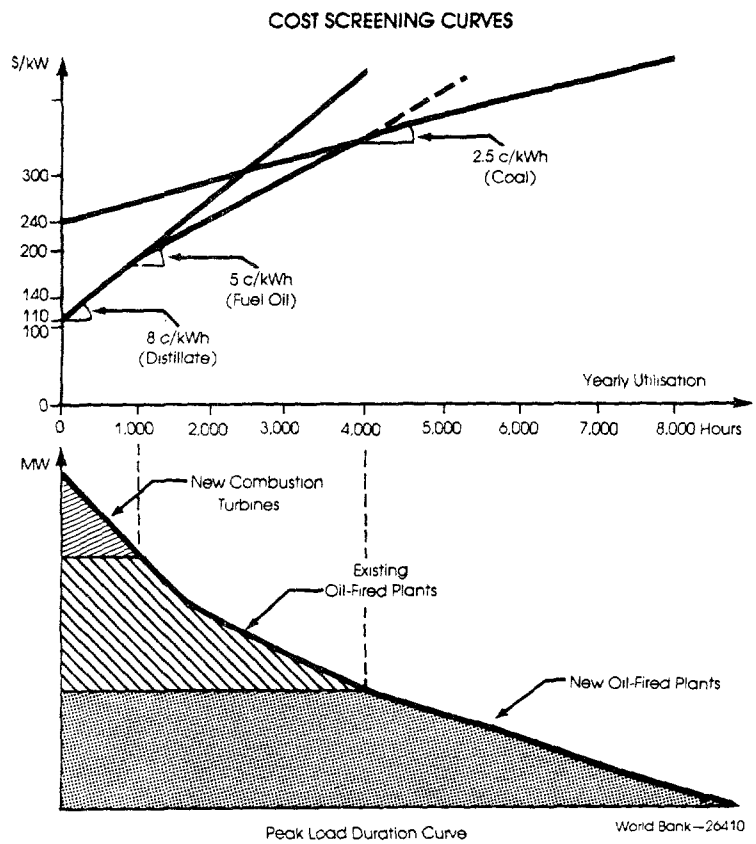
III.3 Demand for gas in the long run

In the long run, capacity may be added and retired. The optimal mix of generating units is determined by the relative prices. A coal-fired plant to be built at a relatively high cost can be competitive because of its lower running costs but only if it generates a large amount of energy. The breakeven utilization is determined by the intersection of the cost curve plotting the fixed and variable costs per dependable kW against the hours of operation as depicted in Figure 7.

In a purely thermoelectric system, the combustion turbines would take the higher part of the load diagram, coal-fired plants the lowest part and the share of oil fired steam plants would be small or nonexistent if they were to be built. However, their main advantage is that they exist and their investment costs are sunk; these oil fired units can resist competition from new coal or distillate fired units in the base and peak loads. Therefore, their role is limited only by the existing capacity stock.

Example. Based on the costs in paragraph IV.1 there is only one annualized value in Figure 7 for which the line with a 5¢/kWh slope (fuel oil costs) intersects the two other cost curves at utilizations of 1,000 and 4,000 hours compatible with the thickness of the load curve "slice" met by the existing oil fired plants. This (shadow) value of oil fired capacity is $140/kW: too low to justify new oil-fired plants but high enough not to accelerate the retirement of existing ones which would save only part of the O & M cost (about $20/kW/yr).

Figure 7
OPTIMAL PLANT MIX IN THE ABSENCE OF GAS

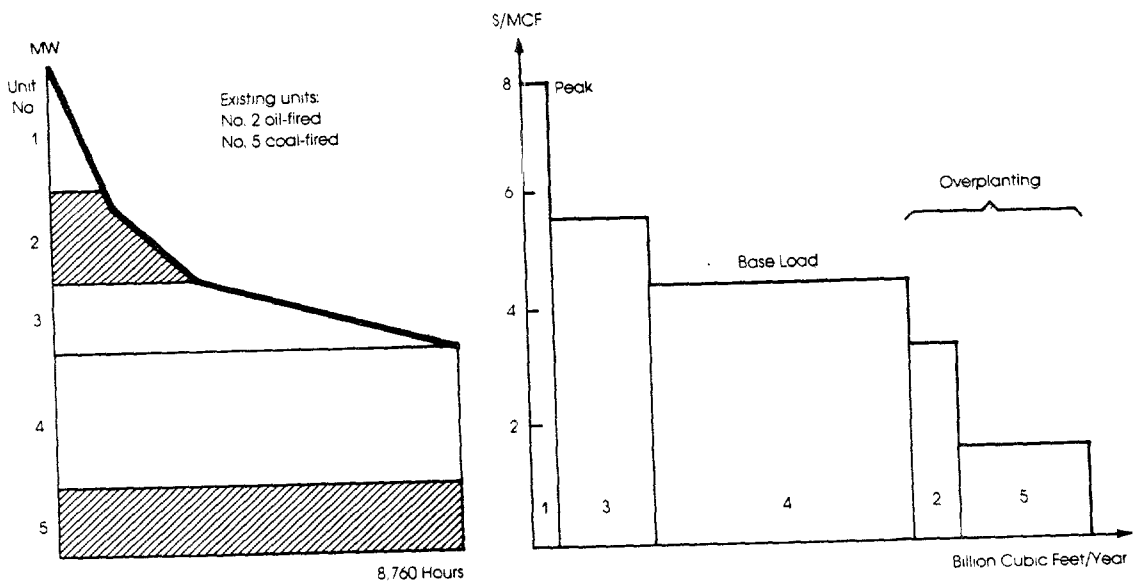


If gas is available at a given price, then in addition to switching existing plants from oil to gas, there may be a case for new gas fired units. First, all the new peaking units are operated on gas instead of fuel distillate for prices that are $8/MCF and below.

New gas-fired plants [1/] have a great fixed cost advantage over new coal-fired plants and can take up the base load for relatively high gas prices. But they have a serious fixed cost disadvantage over existing oil-fired units, and to displace those in the shoulder load requires a low price of gas. Overplanting, in the sense of prematurely retiring the oil-fired plants should be the last option to consider in many cases where this gas could be used to delay capital intensive expansion of generation based on coal or hydropower.

Figure 8 illustrates the order of priority in the use of gas from substitution in plant expansion to overplanting. Any additional fixed outlays, such as pipeline investments increase the annuity and shift this allocation towards the base load. However, in most cases assigning gas fired capacity exclusively to the base load and ignoring peaking and cycling duties can lead to economic losses and to underestimating the value of gas as shown in the next paragraph.

Figure 8
INSERTION OF NEW GAS-FIRED UNITS
(no conversion of existing plants)



1/ The reference gas-fired plant of all the examples in this section has an average heat rate of 10,000 Btu/kWh typical of many real situations and simpler to handle since a gas price of say $8/MCF translates into a running cost of 8¢/kWh. It is associated with a $110/kW annuity equal to that of the combined cycle and in between conventional steam and gas turbines.

III.4 Dynamic Analysis

The above analysis was carried out in a static framework on the basis of annual costs. However, in most cases the operation of a generating plant is bound to vary with time and economic conditions, and a dynamic analysis based on the present value of cost streams is required. This dynamic analysis is also required to assess the feedback impact that power related gas demand may have on the cost of gas to all potential users.

Dual fired plants deserve a special consideration as they may induce a large gas demand even when reserves are relatively limited. The evaluation must focus on the date at which initially gas-fired plants must be switched back to coal or fuel oil and on the fuel savings entailed by gas utilization before that date. Generally, a few years of gas based generation is sufficient to cover the additional cost of dual firing equipment.

Gas dedicated plants must phase out of the base load as gas reserves are depleted and the cost of gas increases. Without an early retirement of these plants, it will take between a few years to a few decades for the most recent plants to be needed for peak and intermediate duties where their economic merit would remain high and their gas requirements relatively low. It all depends on the growth rate of power demand. Thus for a high growth, an expansion based mostly on gas may be sustained many years until the date when gas breaks even with the next best alternative; in this case, the analysis may be carried out on an annual cost basis since shortly after that date fuel requirements will become negligible. By contrast, if power demand grows sluggishly, or if hydro power can meet the peak load, gas-fired plants are confined to base load which is very penalizing in later years and their development must be stopped early on the basis of the discounted average of their fuel costs.

Example

With the data of paragraph 1, coal-fired plants retrofitted to gas firing should be switched back to coal when gas costs are more than $2.5/MCF which is the fuel par value. Development of base load combustion turbines dedicated to gas may still remain justified however since the breakeven price of gas with respect to coal fired plants is $4/MCF.

$$(g = 0.025 + (240-110)/8.760\ h = \$0.04/kWh)$$

For a growth rate of b = 3% the base load phase-out period lasts 20 years and the above (netback) value is compared to the discounted average of gas costs over the next two decades to determine when gas based expansion should be stopped. For a rate of b = 12%, assuming a load factor of 75% for the thermoelectric load duration curve, the stopping rule consists in comparing the gas price with the netback value at this load factor:

$$g = 0.025 + 130/(0.75 \times 8.760) = \$0.045/kWh \text{ or } \$4.5/MCF$$

Hydroelectric systems also may accomodate some kind of gas based complementary generation as load increases. However, this complement is likely to vary seasonally and with the prevailing hydrology; peak day requirements may exceed three times the average intake so that in determining the role of gas, flexibility in the supply is just as important as price. This flexibility is greatest, and the role of back-up fuels is minimum, when the supply to other important users can be easily reduced at short notice. The study of a real case shows that even when gas intake by the utility is allowed to peak at twice the average daily supply, gas can only cover 2/3 of the thermoelectric requirements. The economic comparison between an hydroelectric project and a gas based alternative is difficult. If the hydro plant capacity factor is high then the corresponding horizontal cost curve can be used for a first static comparison as is done with thermal units. However this simplified approach is inappropriate in most cases since hydro generation preempts peak and intermediate load. What is required then is a present value analysis based on the simulation of the system operation over the project lifetime.

The impact of power on gas market conditions also warrants a dynamic analysis. On the one hand an important gas demand for power is particularly helpful in recovering the initial development cost; on the other hand it also accelerates depletion and raises the price used for comparing all gas development projects and this impact must be fed back into the planning process.

A quick check on these requirements is a necessary first step in gas utilization studies. It can be done simply in the analytical framework suggested here. From there, tentative depletion dates and price scenarios can be postulated and a more detailed study may be carried out with the help of least cost planning models used by power engineers. Power related gas demand is largely determined by two factors:

- the competitiveness of gas for base load generation;
- the growth rate of power demand which commands the date when gas-based expansion should stop.

Two rough approximations of gas requirements between now and a postulated depletion date T can be readily obtained once the date for stopping gas based expansion has been determined:

- a maximum estimate by assuming that the future generation of existing plants is negligible or met by gas through plant conversion and/or accelerated retirements (overplanting);
- a lower bound by subtracting from the above the energy generated now.

A comparison of these estimates with noncommitted reserves determines a compatible depletion time to be used in more detailed studies. Reserve uncertainty or the role of existing plants are important factors but the assumed power demand growth rate may make all the difference as

shown in the example below. The example also indicates that in many developing countries gas production costs are low enough and the power demand growth rates high enough to trigger a large demand for gas.

Example

Assume a trapezoidal TLDC with load factor f = 75%, and the same economic data as above; the maximum required gas reserves expressed as a multiple of the first year power load is

$$RM = (Ne^{bs}-1)/b$$
$$\text{with} \quad N = 2f + (1/2f) - e^{b(T-s)}/4f(1-f)$$

For power demand growth rates b = 3%, 6% and 12%, the stopping date s is respectively, 20, 15 and 5 years before depletion date T.

Depletion time T (years)	Range of Required Gas Reserves (in years) Power Demand Growth Rate b=3%	b=6%	b=12%
5	negligible	negligible	0 to 1
10	negligible	negligible	4 to 14
15	negligible	0 to 4	16 to 31
20	0 to 5	0 to 18	42 to 62
25	0 to 11	5 to 30	90 to 115

Assume that the first year power load is 1,500 GWh equivalent to 15 BCF; assume further that non-committed reserves are about 30 times this amount (450 BCF). With a high growth rate (b=12%), the above table indicates that reserves will be depleted in 15 years. However assuming that the present generation is mostly hydro, it will decrease these reserve requirements from 31 to 16 years of the first year load. Can depletion be assumed at 20 years then? Inspection of the same table indicates that the minimum requirements for that depletion time (42 years) would exceed the reserves unless power demand gets to grow at a slower rate.

IV. ANALYTICAL NOTE ON NETBACK CALCULATIONS

IV.1 Static calculations

If a given quantity of gas is available and its price is unknown, the various projects competing for gas use cannot be ranked according to their net worth. Instead, the gas price at which each project's economic costs and benefits breakeven can be calculated. This price is called the netback value. In a preliminary screening of gas uses, those projects with higher netback values are good candidates for further study.

Conversion to gas leads to a netback slightly inferior to the value of the fuels that gas substitutes; the difference covers amortized conversion costs (A_f) over the hours of plant utilization. Where gas substitutes oil based generation with a running cost of 5¢/kWh:

$g = 5 - A_f/u_f$
where u_f = gas consumption of the most utilized oil-fired units.

The netback value includes not only the cost of the displaced fuel but the savings in operating costs due to gas utilization (substantial in the switch from coal to gas). These savings alone may offset the conversion costs.

A new gas-fired unit has a netback with respect to the next best alternative, which is the sum of operating cost and capacity costs differences divided by the hours of utilization of the power plant. The capacity cost difference is positive for new steam or hydro plants and can be referred to as a capacity premium. However, it may be zero or negative for single cycle turbines or existing oil-fired plants.

Example. From paragraph III.3 existing oil-fired units with a (shadow) annuity of $140/kW, are capable of meeting between 1,000 and 4,000 hours/year of the load and enough distillate and coal-fired capacities are developed to meet peak and base load. As shown in Figure 7, the straight cost line of the reference gas-fired unit starts at $110/kW and its slope decreases as gas becomes more abundant and cheaper. When the available quantity of gas exceeds the amount necessary for all the existing and planned peaking units which would otherwise burn distillate, this excess quantity is allocated to more gas-turbines, displacing oil-fired units. The netback value to substituting the first oil-fired kW is:

$g = 0.05 + (140 - 110)/1{,}000\ h = \$0.08/kWh$ or $8/MCF
and that for substituting the last oil-fired kW is:
$g = 0.05 + (140 - 110)/4{,}000\ h = \$0.0575/kWh$ or $5.75/MCF

In practice, since the shadow value of existing capacity is not known, these netbacks of $8 and $5.75/MCF be calculated against the alternative of using distillate with the same kind of plant (g = 0.08) or coal (g = 0.025 + (240 - 110)/4,000 h = 0.0575)

As available quantities of gas increase, so does the utilization of gas-fired capacity and the fixed cost advantage over coal in base load uses diminishes to its minimum ($1.5/MCF which added to the coal equivalent of $2.5/MCF yields $4/MCF).

The netback of the last gas-fired kW is the clearing price in the power market (excluding other markets). Plotting this netback against available quantities of gas results in the same demand curve as the one obtained in Section III where quantities are deduced from prices. In contrast, the netback averaged over a gas utilization program covering peak and base load would overstate the utility's marginal willingness to pay for gas since it includes a higher capacity premium for inframarginal kWs having shorter utilizations.

IV.2 Extension to a Dynamic Framework

The concept of netback value can be extended from one year to the project life cycle. The netback is the price for which the net present worth of the gas project breaks even with that of the next best alternative without gas. This definition is simple enough and consistent with the definition of the long run average incremental cost of gas (LRAIC) which is the price at which gas producers breakeven. Any utilization project with a netback inferior to gas LRAIC will lead to bring an economic loss.

Switching existing generation plants from fuel oil to gas has a netback close to a weighted average of the price of this fuel oil, the weights are the discounted yearly utilizations of the plant. Using the previous notations and the example of combustion turbines switched from oil distillate to gas at a negligible conversion cost, the discounted cash flow is:

$$B = -\sum_t \left[d(t) - g\right] u_d(t)/(1+i)^t$$

where i is the discount rate

$$B = 0 \text{ for } g = \sum_t d(t)\, u_d(t)\, (1+i)^{-t} / \sum_t u_d(t)\, (1+i)^{-t}$$

For a new gas-fired unit, the netback with respect to the next best alternative is the sum of:

- the weighted average of the substituted fuel costs
- the capacity cost premium divided by the sum of these weights

Generally the netback is the weighted average of the marginal fuel costs as explained further. The weights are the discounted volume of gas for each costing period. The capacity premium can be neglected since the peaking units during the period of study have fixed costs that are close to those of gas-fired units.

IV.3 Utilization of Electricity Marginal Costs

Calculating the netback value of gas in a conversion project involves only one difficulty which is to reassess the utilization of the units after retrofitting. Once the generation dispatch has been reviewed, calculating the project cash-flow is straightforward since the benefits are derived from a well specified fuel substitution.

Adding a new capacity has more far reaching consequences. It increases the reliability of service and reduces the fuel costs by amounts that differ with time as dictated by its dispatch merit order. The calculation may be simple if as in the previous example it is possible to define an alternative equivalent plant which would exactly meet the same "slice" on the load diagram. This is not always the case: there is no simple equivalent of a gas-fired combined cycle unit operating off peak in simple cycle mode and at a much higher rating in cold weather; a turbine burning distillate would not be an economical alternative for a long utilization, nor would a steam plant for short and random surges in power or heat demand. The method which has long been followed for the evaluation of cogeneration and hydro projects, consists in valuing the benefits at the power system marginal costs.

Example

With the assumptions of Section III, the marginal fuel costs before gas is introduced are:

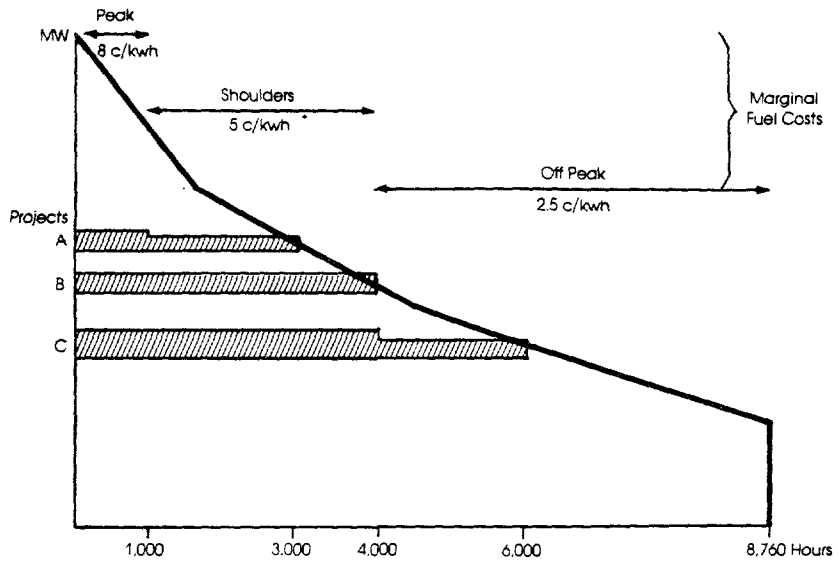
- peak (first 1,000 hrs) 8¢/kWh (Distillate)
- shoulder (next 3,000 hrs) 5¢/kWh (Bunker)
- off peak (remaining 4,760 hrs) 2.5¢/kWh (Coal)

The capacity cost incurred to avoid outages is the lowest annuitized cost of the three screening curves: $110/kW per year corresponding to a new combustion turbine (any additional outlays are reflected in the lower fuel costs of the shoulder and off peak period).

Cashflow and netback calculations for one kW are calculated for various cases depicted in Figure 9.

Case A: Reference plant working 4,000 hours including peak
Value = 110 + 0.08 x 1,000 + 0.05 x 3,000 = $340
Netback = (340-110)/4,000 h = $0.0575/kWh or $5.75/MCF
with a 10,000 Btu/kWh heat rate.

Figure 9
NETBACK CALCULATIONS USING ELECTRICITY MARGINAL COSTS



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Case B: Gas turbines working 3,000 hours/year with 20% improvement in efficiency during peak time (due to colder weather).
Value = 1.2 x (110 + 0.08 x 1,000) + 0.05 x 2,000 = $328
Netback = (328 - 70)/3,000 h = $0.86/kWh or $6.1/MCF
with a 14,000 Btu/kWh nominal heat rate.

Case C: Existing gas turbines repowered for combined cycle at peak and shoulder (50% efficiency improvement) and working at single cycle for another 2,000 hours off peak.
Value = 1.5 x (110 + 0.08 x 1,000 + 0.05 x 3,000) + 0.025 x 2,000 = $560
Netback = (560 - 95)/6,000 h = $0.0775/kWh or $5.5/MCF

This method gives gives the same result as the one in para. IV.1 for Case A, but it is more general and easily applicable when the generating mix includes hydro power. It is also based on marginal costs that are generally available from power system planners.

As is often the case, the gas project entails fixed costs close to the marginal capacity cost--here they are both $110/kW--because combustion turbines are the reference peaking units. As a result the netback is a weighted average of marginal fuel costs, as in Case A:

(0.06 x 1,000 + 0.05 x 3,000)/4,000 = 0.0575

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EGY PAPER No. 6 Energy Efficiency: Optimization of Electric Power Distribution System Losses by Mohan Munasinghe (World Bank) and Walter Scott (Consultant). July 1982. 145 pages, includes appendices.

Discusses the reasons for high existing levels of power distribution losses in developing countries. Identifies areas within a power system where loss optimization would be most effective. Shows that reducing losses is often more cost effective than building more generation capacity.

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

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 noncommerical 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 historical 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 — Guideline for Diesel Generating Plant Specification and Bid Evaluation 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.

EGY PAPER No. 10 — Marginal Cost of Natural Gas in Developing Countries: Concepts and Application by Afsaneh Mashayekhi (World Bank). July 1982. 21 pages, includes appendices.

Defines the concept of marginal cost and average incremental cost. Uses the detailed supply, demand and investment data to apply this concept to estimate the average incremental cost of natural gas supply to major markets in ten developing countries. Demonstrates that the cost of natural gas delivery to the city-gate in many developing countries is far below the cost of competing fuels.

EGY PAPER No. 11 — Power System Load Management Techniques by Resource Dynamics Corp. (USA) Consultant. November 1983. 132 pages.

In recent years, techniques referred to as load management have begun to play an important role in shaping the patterns of electricity consumption in industrialized countries. Along with pricing, a variety of hardware is used to control loads directly and save on energy and peak capacity. This study reviews the state-of-the-art of these so-called "hard" techniques in light of recent technological advances, provides data on cost and manufacturers of this equipment, and identifies controllable loads in developing countries.

EGY PAPER No. 12 — LNG Export Opportunities for Developing Countries and the Economic Value of Natural Gas in LNG Exports by Afsaneh Mashayekhi (World Bank). November 1983. 36 pages, includes appendices.

This paper reviews the LNG export opportunities for developing countries and clarifies some of the issues related to economic costs and benefits of LNG projects from the point of view of an exporting country. It identifies the major technical parameters that affect

costs and analyzes factors affecting the economic size of projects and the effect of scaling them down. Its principal objective is to estimate, given explicit assumptions, the netback values for gas at various stages in the LNG delivery system. It examines three basic scenarios of small and medium scale projects as well as a multi-destination project with several small markets. It also tests the sensitivity of netbacks to the level of infrastructure, discount rates and the price of gas delivered at the importing country.

EGY PAPER No. 13 Identifying the Basic Conditions for Economic Generation of Public Electricity from Surplus Bagasse in Sugar Mills by Syner-Tech Inc. (USA). October 1983. 167 pages, includes appendices.

The study identifies several ways, all using presently available technology, to greatly increase the overall energy efficiency of existing mills, produce surplus bagasse and generate electricity for sale to the grid. These include installing pre-evaporators to conserve steam, drying wet bagasse with flue gasses to improve combustion efficiency, installing high-pressure boilers to increase steam generation efficiency and pelletizing or compressing bagasse to enable it to be stored and used beyond the harvest season.

EGY PAPER No. 14 A Methodology for Regional Assessment of Small Scale Hydropower by Tudor Engineering Company (USA). December 1983. 105 pages.

This paper presents a methodology for regional assessment of small hydropower development potential involving sampling procedures, study execution, energy planning, regional hydrology development, technical site evaluation, cost and economic analysis, environmental and social considerations. Its use should result in reasonably accurate estimates in a short period of time of the viable small-scale hydroelectric projects in a particular region or country. A development program based on such an assessment would be of sufficient reliability to support requests for financing assistance.

EGY PAPER No. 15 Central America Power Interconnection: A Case Study in Integrated Planning English Summary by Fernando Lecaros (Consultant). April 1984. 55 pages.

This paper is a summary of the study, titled "Regional Electrical Interconnection Study of the Central American Isthmus", performed by the Regional Office in Mexico of the United Nations' Economic Commission for Latin America (ECLA) between 1975 and 1979. Its goal was to provide a firm economic and technical foundation to decisions about the interconnection investments in the region. The

purpose of this English Summary is to disseminate the methodology retained by ECLA and to show an example of integrated system planning using models such as WASP developed by the International Atomic Energy Agency. The figures reproduced in this report are limited to the extent necessary for these illustrative purposes.

EGY PAPER No. 16 An Economic Justification for Rural Afforestation: The Case of Ethiopia by Ken Newcombe, World Bank. June 1984. 23 pages, includes appendices. It has proven difficult to quantify the economic benefits of large-scale rural afforestation and to establish the priority for public investment in traditional rural energy supply vis-a-vis investment in the supply for modern fuels (electricity, petroleum) to the urban industrial market. This paper outlines, in simple terms, the biological links between deforestation and agricultural production at the subsistence level, and quantifies the economic benefits of increased food production obtained by replacing animal dung as a fuel with firewood from rural forestry programs.

EGY PAPER No. 17 The Future Role of Hydroelectric Power in Developing Countries by Edwin Moore (World Bank), George Smith (Consultant). June 1984. 59 pages, includes annexes.

The study examines the role of hydroelectricity in the power programs of 100 developing countries in the period 1982-1995. The report indicates that hydro will continue to play a significant role, accounting for 43% of electricity production in 1995. Preparation and engineering expenditures of about $10 billion will be needed in 1982-1990 for the projects required to support this growth. The study concludes that an intensified hydro program would add only 3% to the capacity otherwise planned because the main constraints to hydro development are economic and lack of poor markets rather than lack of knowledge about resources and prospective projects. Nonetheless, the study identifies specific actions that can be taken in many countries to accelerate hydro development.

EGY PAPER No. 18 Guidelines for Marginal Cost Analysis of Power Systems by Yves Albouy (World Bank). June 1984, 31 pages, includes annexes.

These guidelines provide hands-on but state-of-art instructions for conducting a sound and quick analysis that yields the marginal cost structure needed for applications in the power sector and for the review of related studies. These include not only pricing but also the less known marginal analysis of system planning decisions. The paper does not give the detailed theoretical background but draws on the reference literature. It illustrates the basic principles and

calculation methods with the help of many examples going from the simplest to the more complicated system conditions.