The Pricing of Natural Gas:
A Discussion of Pricing Policy in Egypt

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ABSTRACT

This paper is concerned with gas pricing policies and begins by describing the unique characteristics of gas that influence the market and pricing. In Egypt, the upstream and downstream pricing of gas is based on the institutional system which governs the hydrocarbon industry and the multiplicity of objectives the government tries to achieve.

The policy proposals aim to improve consistency and transparency. In gas pricing the basic reference should be the price of the petroleum product displaced. The reference for gas acquisitions from the upstream should be the weighted average price of petroleum products averaged over a short period and should not include crude oil price.

If the government passes the economic gain to gas users, then the price of gas must be set at $1.5/MMBTU. The resulting increases in electricity prices can be mitigated by spreading the rise over a number of years and by designing new tariffs which subsidize the poor and small businesses and tax the rich and large businesses.

ملخـــــــص

تتناول هذه الورقة سياسات تسعير الغاز، وتبدأ بتوصيف الخصائص التى ينفرد بها الغاز، والتى تؤثر فى السوق الخاصة به وكذا فى تسعيره. وترتبط مسألة تسعير الغاز فى مصر - سواء فى مجال إنتاجه أو تسويقه - بطبيعة النظام المؤسسى الذى يحكم الصناعة البترولية، فضلاً عن تأثرها بتعدد الأهداف التى تعمل الحكومة على تحقيقها. وترد بالورقة مناقشة متعمقة لكل من هذين الجانبين .

وتستهدف مقترحات السياسة الواردة بالورقة تحسين كل من الإتساق والشفافية فى قضية تسعير الغاز. ويتحدد المبدأ الحاكم بهذا الصدد فى أن المرجع الرئيسى لعملية التسعير ينبغى أن يكون سعر المنتج البترولى الذى يتم إحلاله. فبالنسبة للحصول على الغاز من جانب الإنتاج، يكون المرجع هو المتوسط المرجح لسعر المنتجات البترولية، والمأخوذ متوسطها على مدى فترة قصيرة، ودون تضمين سعر البترول الخام.

وإذا ما رغبت الحكومة فى نقل المكاسب الإقتصادية إلى مستخدمى الغاز، فإنه يتعين أن يتحدد سعره عند مستوى قدره ١،٥ مليون وحدة حرارية بريطانية (MMTBU)، وأن تجرى مراجعة هذا السعر كل عام على أساس التغيرات التى تحدث لمتوسط أسعار الوقود على مدى ثلاث سنوات. كما يكون بالإمكان التخفيف من حدة زيادات أسعار الكهرباء التى تترتب على ذلك عن طريق توزيعها على عدد من السنوات، وذلك من خلال صياغة نظام جديد لتعريفة الكهرباء ينطوى على توفير الدعم للفقراء والمشروعات الصغيرة، وفرض الضريبة على الأغنياء والمشروعات الكبيرة.

List of Acronyms and Abbreviations

fob	free on board
cif	cost, insurance and freight
EGPC	Egyptian Petroleum Corporation
LNG	liquefied natural gas
LPG	liquefied petroleum gas
CNG	compressed natural gas
VLCC	very large crude container
ULCC	ultra large crude container
BG	British Gas
NERA	National Economic Research Associates
MMBTU	million British thermal unit
PT	piaster (Egyptian)
TCF	trillion cubic feet
BCF	billion cubic feet
$MCF	$/million cubic feet
BTU	British thermal unit
PPC	Petroleum Pipeline Company
IEOC	International Egyptian Oil Company
ENPPI	Engineering for the Petroleum and Process Industries

I. Introduction

The main purpose of this paper is to propose gas-pricing policies for Egypt. It begins, however, with some comments on the economic characteristics of natural gas compared to crude oil and petroleum products. These preliminary remarks are relevant to an analysis of gas pricing. These are followed by a section on natural gas in Egypt which gives some essential information on natural gas reserves, production and consumption and describes the institutional structure under which the gas industry operates in Egypt. The paper also discusses the production-sharing agreements and the pricing of gas upstream and downstream. The discussion then turns to different gas-pricing approaches, offers policy proposals for gas pricing in Egypt and assesses their implications for both the downstream and the upstream, electricity prices, and pricing under an alternative institutional structure, namely opening of power generation to private investors. The paper also addresses issues that may arise if and when Egypt begins to export gas.

II. Relevant Characteristics of Natural Gas

Natural gas is a natural, non-renewable resource. The owner of such resources, generally the state, is entitled to a rent for the simple reason that the resource itself is a factor of production in the process that yields it as an economic commodity. Natural gas belongs to a particular class of primary commodities: it is a fuel. But classifications are not as simple as we would like them to be. Natural gas is not only used as a fuel, but as a feedstock for petrochemicals and fertilizers, albeit in a much smaller proportion. As a fuel, it is a substitute for other fuels; and as a feedstock, much less perfectly, for other feedstock. The important point regarding substitution is that it does not refer to a similarity between the full set of physical/chemical characteristics of two commodities, but to their respective roles in a specific use.

Gas is a fuel, like petroleum products, nuclear or coal, but has characteristics different from oil, petroleum or coal. It is a hydrocarbon and as such belongs to the same family as oil with which it is often associated in petroleum reservoirs. But as a hydrocarbon it is as physically remote from nuclear as any material can possibly be. Natural gas, fuel oil, gas oil, nuclear power and coal all generate electricity. They have different physical and chemical characteristics, but they are all substitutes in this particular use. As a hydrocarbon, gas emits CO_2 in combustion. In this way, it is similar to oil and coal but only in a general sense, because it emits less CO_2 per calorific unit than oil and much less than coal. Nuclear power does not emit CO_2, but waste and accidental releases from a plant may emit nefarious radiation. The externalities caused by varying degrees of CO_2, sulfur and particle emissions, or by nuclear radiation, raise fiscal and price-differential issues. The physical state of a fuel—which may be a gas, a liquid or a solid—and its possible transformations—gas can be liquefied and solids gasified—also have economic importance. They have an impact on transport costs, on economies of scale in transportation and on the nature and financing of the investments required to shift the commodity either domestically or in international trade.

Often gas and oil are considered similar commodities, and analytical concepts applied to oil are extended to natural gas. This can be extremely misleading. First, as mentioned before, gas is a gas and oil is a liquid. This means that gas can only be transported economically in pipelines up to a certain distance. Over very long distances gas must be liquefied (LNG), transported under pressure in dedicated vessels and re-gasified at the point of destination. Transporting gas on trucks in smaller parcels as compressed natural gas (CNG) is very costly. The advantage of oil over gas is that it can be easily transported in small parcels and, with the benefit of economies of scale, in large volumes (in a VLCC or an ULCC). It also moves in pipelines and, most importantly, the transport of oil never requires transforming its physical state.

Secondly, in upstream production, oil and gas have different characteristics and a complex relationship with one another. Gas is sometimes associated with oil in the field and sometimes found in an unassociated form. Exploration for oil and gas is not a different activity. When a company decides to explore it is never sure of the outcome: a disappointing dry hole, an oilfield rich or poor in gas, or a field with unassociated gas that may be either dry (methane mixed with small amounts of higher order molecules) or wet (methane mixed with higher amounts of condensates). For this reason, exploration/development/production contracts usually have the same structure for all hydrocarbon activities. And this fact has important economic implications for the development of the oil and gas industries.

In an associated field, oil and gas are joint products. Oil is always in demand, but this is not necessarily the case for gas. When associated gas happens to be in excess supply in relation to its final market (where demand may be small or, in some places, non-existent) it will be either flared (a common practice in the past now prohibited in most countries for environmental reasons) or re-injected in the oilfield.

Third, oil has a much wider range of energy uses than gas. The most immediate overlap between oil and gas is that both fuels generate heat when burned under a boiler, be it a modest central-heating boiler or one in an industrial plant or a thermal power station. Gas has the edge over oil in combined-cycle power plants, but even there gas oil—a petroleum product—is a close substitute. Petroleum products reign supreme in relation to gas in the transport sector—cars, ships and aircraft. True, gas is used in the form of CNG in trucks and taxis in many parts of the world, including Egypt; but gasoline and diesel remain the more effective and convenient fuel to power a car engine.

Fourth, oil and gas have different characteristics in international trade. Although very close substitutes in an important use such as power generation, oil and gas are not similarly tradable; they are not perfect substitutes in international trade. Oil, whether as crude or in the form of refined products, is eminently tradable. It can be easily exported or imported in parcels of different sizes. It can be moved from any location to any destination when the trade is seaborn. There is a world market for oil where regional segmentation is not very rigid because of the opportunities for arbitrage. This world market is very liquid, with daily supplies exceeding 30 million barrels a day. It generates prices for spot, physical forward and futures contracts. There are trading instruments which enable hedging and speculation linking different elements of the term structure of prices. For these reasons it is possible to speak of international oil prices.

For natural gas, the situation is fundamentally different. The main difference is the high transport cost of gas. Significant transport costs translate into a large gap between the free on board (fob) price and the cost, insurance and freight (cif) price of a tradable commodity. One must then distinguish between the international price of this commodity for the exporter and for the importer (when transport costs are small, this distinction can be ignored). Consider a country which can export both oil and gas because production is in excess of domestic demand. Because they are substitutable the potential importer will be prepared to pay a price for gas per calorific unit close to that for the same unit of the relevant petroleum product at the importing country's border. But the potential exporter will receive a higher price (often much higher) per calorific unit of oil than of gas because of the enormous difference in transport costs. The implication is that natural gas has priority on the domestic market, and it should be allowed to penetrate this market fully wherever it can displace oil. The displaced oil is perfectly tradable and generates higher unit revenues as an export (has a higher opportunity cost as an import) than the imperfectly tradable gas which displaces it. This is the 'golden rule' of the international gas trade.

The related problem in the gas trade is the economic size of the export (or import) parcel. An LNG export project is rarely viable unless the operation requires two or three trains of 2 million ton capacity each (this is a necessary, not a sufficient condition)[1]. Because the gas trade is still in its infancy, the number of LNG export and import terminals in the world is exceedingly small. Due to the minimum size requirement and the dearth of terminals equipped with liquefaction facilities, the international trade in LNG essentially consists, for the moment at least, of a finite number of bilateral contracts.

There is thus considerable rigidity in LNG trade in sharp contrast with the flexibility that characterizes oil trade. The bilateral LNG deals yield different prices for the producers at their respective borders, because of differences in distance between the exporting and importing country and because of differences in bargaining power, a factor which plays an important role in the negotiation of bilateral contracts. The implication of this is that we cannot talk meaningfully about an international price for gas. There are different prices in different regions both at the importing (cif) and at the exporting point (fob)—in other words, different international prices. And for the potential exporter, the opportunity cost of his gas, if international trade is to be considered, is the fob price or the corresponding netback that exports would generate.

We derive from this analysis a number of propositions relevant to a discussion of gas pricing:

- The government is entitled by virtue of ownership to a fiscal revenue per unit of natural gas produced in its territory.
- Natural gas is a close substitute for petroleum products in a range of energy uses (power generation, central heating, industry), but a fairly poor substitute in other important sectors, namely transport.

[1] 'Ton' implies a metric ton.

- Crude oil and petroleum products are as perfectly tradable as any commodity can be. The international trade in natural gas is beset by several rigidities. Furthermore, international trade in gas (measured as a proportion of world production) is much less developed than in oil.
- Transport costs constitute a critical factor in gas trade (and for the domestic use of gas when long distances separate the field from the market). High transport costs are sometimes an economic impediment to trade. Another important implication is that they create a large gap—the longer distance involved—between fob and cif prices. Because of transport costs and rigidities it is not meaningful to speak of an international price of gas. Arbitrage between world regions (Asia, Europe and North America) is virtually non-existent for gas at present.
- Gas has environmental advantages. Thus, there is a case for a premium on the equivalent oil price paid by an importer.

III. Natural Gas in Egypt

Petroleum has a long history in Egypt, which was one of the first Middle Eastern countries where the exploration, development and production of oil took place (first exploration in 1885, first discovery in 1908 and production in 1909, as in Iran). But the volume of petroleum in Egypt remained small for several decades during which several other Middle Eastern countries became large oil producers and exporters.

Associated gas was inevitably extracted with crude oil, but until the second half of the 1970s there was no domestic market for gas produced in very small quantities. There were no attempts to re-inject this back into the oil fields and, according to the general practice, gas was simply flared. The situation changed following the discovery of important fields of non-associated gas in Abu Madi, Abu Qir and Abu Gharadeeg between 1967 and 1971. The initial estimates of recoverable reserves were 1 TCF at Abu Madi, 0.6 TCF at Abu Gharadeeg, 1.2 TCF at Abu Qir and 3.0 TCF at Abu Qir North (Ikram 1980, 276). These discoveries justified the development of a domestic market for natural gas which emerged in 1975, on a very modest scale, when gas accounted for 0.4 percent of Egypt's energy consumption. But initial growth was rapid with gas accounting for 12 percent of energy use in 1980 (Hertzmark 1993, 11). These early discoveries of gas fields were followed by several others. One of the most exciting was the discovery of numerous fields off-shore of the Nile Delta in an area extending from approximately the mid-point between Rosetta and Damietta to the East of Port Said. The 25 fields in this area constitute, according to Amoco and ENI, ‘a world-class basin’ (*MEES* 23/6/97, DI). Whether the potential reserves (usually estimates which are a significant multiple of the proven recoverable reserves) are as large as suggested by the two oil companies, that is of the order of 36TCF, is impossible to determine from an outsider’s point of view at this stage.

Estimates of Egypt’s proven gas reserves are continually being revised and increased. In 1990, the conventional estimate was 11.5 TCF; in 1992, 12.2 TCF; in mid-1997, 23 TCF (this estimate had already been made in mid-1994 suggesting that it now understates the exact reserves). Ultimate reserves may turn out to be twice as large as the mid-1994 estimate of proven reserves. It is unwise, however, to hazard a forecast which depends on uncertain and unknown factors. What is certain is that Egypt is well-endowed with natural gas resources. It is not a giant in this area like Russia (proved reserves 1,717 TCF), Iran (746 TCF) or Qatar (250 TCF), but is in the bracket which includes the UK, Oman, Australia and China. Thus, we will assume that Egypt’s gas reserves are sufficient to meet growing future domestic requirements for quite a long period of time. In 1995, gas consumption in Egypt was approximately 1.22 BCF/day. Power generation used 0.78 BCF/day or about 64 percent; fertilizers 0.16 BCF/day; industry, 0.1 BCF/day; cement and petroleum about 0.08 BCF/day each; and the domestic sector a very small amount of perhaps 0.02 BCF/day. There are different projections for the growth in gas consumption in Egypt between now and 2010. The Donald Hertzmark (USAID) study of 1993 estimates an increase of gas consumption to 2 BCF/day in 2010; Amoco and ENI estimate an increase to 3.2 BCF/day in 2010 (*MEES* 23/6/97). The range is very wide indeed.

The institutional structure of the natural gas industry in Egypt is as follows. In the upstream sector a number of foreign companies have contracts for the exploration/production of petroleum, which includes gas. These contracts belong to a well-known class, used extensively in the oil industry, known as a production-sharing agreement. In these agreements, the contractor carries all the exploration risks, which means that he gets nothing if there is no commercial discovery. If oil and/or gas are discovered, and the decision is made to develop the resource and produce it, the contractor is entitled to recover quarterly “all costs and expenses in respect of all the exploration, development and related operations . . . to the extent and out of *x* percent of all petroleum produced and saved . . . and not used in petroleum operations" (Petroleum Law 26/10/1995 Art. VII(a1)).

Cost recovery begins with production. The limit on how much can be recovered every period is equivalent to a percentage of the petroleum produced that varies from contract to contract. In most cases, *x* is set at 40 percent, but there are exceptions as some contracts stipulate an annual ceiling for cost recovery of 30 or 35 percent. These limits may be reached during several years in the early period of production depending on the sums initially spent on exploration and development and the production levels attained. Once the initial investment costs (exploration and development) are recovered, cost recovery mainly consists of operating costs, and unless more investments are undertaken later on, it will then often amount to much less than the 30 or 40 percent limit. The cost recovery formula is usually defined as follows, although there are exceptions:

25 percent of exploration costs + 25 percent of development costs + 100 percent of operating costs,

provided that this sum does not exceed the specified *x* percent (30 to 40 percent depending on the particular contract) of the volume of the relevant production in the given year. If this sum exceeds this limit, the excess is carried over to the next year and beyond until costs are fully recovered.

One implication of this formula is that the contractor cannot recover more than, say, 25 percent per year of either development or exploration expenditures even if the recovery formula yields a sum that falls short of the specified *x* percent limit on the volume of production. Recovery of investment expenditures under these conditions cannot take less than four years. There are therefore (a) stipulated shares of exploration and development costs that can be recovered in any year which affect the length of the recovery period for investment costs, and (b) a limit on the share of production that can be taken for recovery in any year. How long it takes the contractor to recover his investment costs depends therefore (subject to a minimum of four years) on the aggregate value of these costs in relation to the value of production in the relevant years.

The production in excess of the recovery entitlement as defined above is divided between the contractor and Egyptian General Petroleum Corporation (EGPC) in proportions which vary from contract to contract. The EGPC share of production in excess of recovery varies between 55 and 81 percent, and the contractor's share varies accordingly between a high of

45 percent and a low of 19 percent. The value of the gas taken under cost recovery and production sharing is determined by a price formula in dollars per thousand cubic feet. The formula links the price of gas to that of crude oil (specifically Gulf of Suez blend fob at Ras Shukheir) on the basis of thermal equivalence between oil and gas. It involves a 15 percent discount "to enable EGPC to finance and maintain the portions of the pipeline distribution system to be provided by EGPC"(Petroleum Law 26/10/95 Article VII(c2I)). Thus, the price of gas ($/MCF) is equal to:

$$\frac{\textit{0.85 price of the relevant ton of oil}}{\textit{BTUs per tone of oil}} \quad x \quad \textit{BTUs per MCF of gas}$$

BTUs per ton of oil is considered 42.96×10^6, and BTUs per MCF of gas is approximately 1.019×10^6. Surprisingly, there is no cap on the oil price in this formula or a graduated discount should oil prices rise above a certain level. Taking the average prices published by Platts for Gulf of Suez blend fob Ras Shukheir for January to May 1997 we derive the following gas prices:

	Suez Blend Price		*Gas Price*
	$/barrel	*$/ton*	*$/MMBTU*
January 1997	21.14	154.03	3.05
February 1997	18.39	134.25	2.66
March 1997	16.41	119.79	2.37
April 1997	14.70	107.31	2.12
May 1997	16.41	119.79	2.37

(Assuming 1 ton = 7.3 barrels)

The government, as distinct from EGPC, collects the corporation tax at a rate of 40 percent on the profits of the contractor. It also receives from EGPC a 10 percent royalty on gas produced. This is a transfer from EGPC to the government for which the contractor is not liable.

The institutional structure of the downstream gas industry in Egypt is an EGPC monopoly which includes a number of specialized subsidiaries. Thus, the Petroleum Pipeline Company (PPC) covers transmission, Petrogas markets natural gas and LPG in Egypt, and Egypt Gas, a joint venture with an EGPC majority participation, has a monopoly on gas installations, connections and maintenance. The recent formation of two companies involving EGPC through Egypt Gas and private companies (Amoco and IEOC in one case and Amoco and ENPPI in the second) is opening the downstream sector to foreign participation in investments. The first is the Egypt Trans Gas Company which will be responsible for new transmission pipelines, and the second is the Natural Gas Vehicle Company which is concerned with gas utilization in the form of CNG in transport (mainly taxis).

EGPC acquires gas from the contractors in two forms: (a) production-share entitlement and (b) purchase of the cost-recovery gas and the contractors' production share. By definition, gas is acquired at zero price under (a) and at the price determined by the oil-linked formula presented and illustrated with examples here above under (b). EGPC then acts as a seller and markets the acquired gas to electrical, industrial, commercial and household customers. The prices at which gas was sold to various types of customers in April 1997 were as follows:

Sector	*Price in PT/cubic meter*	*Equivalent US$/MMBTU*
Industry, cement, power, bakeries	12.25	1.02
Foreign investors	25.49	2.11
CNG for cars in service stations	15.76	1.31
Household consumption:		
• *less than 30m^3*	10.00	0.83
• *30-60m^3*	20.00	1.66
• *greater than 60m^3*	30.00	2.49

The price of gas to industry, power, etc. was recently raised to 14.1 PT/cubic meter, in other words $1.17/MMBTU. We can see that EGPC bought the unit of gas paid for at a much higher price than the price at which it sold to various domestic customers; this is a significant discrepancy. Since EGPC receives its production share at zero price, there is a further discrepancy: a possible difference between the marginal and the average cost of gas acquisition by EGPC. Finally, there is a discrepancy between the average acquisition cost during the stage of high cost recovery and the stage when recovery mainly involves operating costs. These instances can be illustrated as follows:

(a) A representative acquisition price for the quantities for which EGPC pays is about $2.2/MMBTU (which roughly corresponds to a price of $17.50-$18.00 for the Brent blend of crudes),[2] the selling price for the largest component of gas demand was $1.02/MMBTU until recently and is now $1.17/MMBTU. The acquisition price of the gas bought for cash varies continually with the price of crude oil. The selling price remains constant over a long period

[2] We consider $17.50-$18.00/barrel of Brent as an average price of oil during large parts of the period 1987-97. Occasionally, during the Kuwait-Iraq War of 1990/1 and in 1996 for example, oil prices were much higher. At $30/barrel EGPC would pay $4/MMBTU. In 1988 and 1994, the Brent price fell to about $14/barrel which means that EGPC then only paid $1.73/MMBTU. Even then, this purchase price was higher than the selling price.

of time until changed administratively by a discrete amount, after which it remains constant at a different level for another long period.

(b) As EGPC pays a price p for a proportion x of its acquisition and nothing for $(1-x)$, the average price is: $px + (1 - x) \times 0$. So, if EGPC purchases 55 percent of the production, for example, and obtains 45 percent free, the average price is $0.55p$. In the example above (purchase at $2.2/MMBTU), the average cost incurred by EGPC is $1.21/MMBTU, still higher than the old selling price of $1.02/MMBTU (the new $1.17/MMBTU selling price eliminates most of this discrepancy). But what is the marginal price? At first it appears to be p, as this is the accounting difference between the payment made for any n and $n + 1$ units. But this ignores the fact that a proportion of incremental production is shared and another proportion goes towards cost recovery. So when production increases by one unit (and assuming that the cost recovery proportion is 0.4, the share of the contractor is 0.15 and the EGPC free production share 0.45), EGPC would acquire the additional unit at $0.55p$. This is because every unit it purchases is associated in this example with a free acquisition of 0.82 units.

The situation would be different under alternative institutional arrangements. For example, assume that the contractor has the right to keep his share of production for his own use, for selling to any customer of his choice or for export. Assume further that production is constant. EGPC would acquire the 45 percent in the previous example at zero price. The average cost of acquisition would be zero but for a reduced volume. If EGPC were then to buy from the contractor an additional unit, the marginal cost would be p, which is different from the average cost of zero. If EGPC, which receives n unit at zero price, decides to buy m units from the contractor regularly, the average price would be:

$$\frac{0 \times n + pm}{m + n}$$

that is less than p; but the marginal price for an additional unit beyond $n + m$ would still be p. When production is increasing, or the share of recovery oil decreasing, EGPC will acquire additional units free. But the decision to buy or not to buy additional units is a separate one in this hypothetical institutional structure. So the marginal acquisition cost for EGPC remains p, while the average cost declines because of the rise in n for any given m.

This hypothetical case becomes actual should liberalization—in this context the break-up of the EGPC monopoly—take place or should gas be exported. The implications would be significant. The contractor, for example, would be unlikely to sell his gas domestically at the price p as defined by the current formula, because this price exceeds that of the substitute petroleum products assumed at present to be fuel oil. (The introduction of combined-cycle power plants could change this situation). And, more importantly, the contractor would be unlikely to get p as the fob price of gas exports if these were to go ahead.

(c) In the current institutional system, the average acquisition cost of EGPC, for any given p, would vary with the share of recovery cost. In the early stage, while exploration and development costs are being recovered, this share would be 30 to 40 percent depending on the particular production-sharing contract. At a later stage it might be much smaller, say 5 or 10 percent. In the first stage, EGPC average acquisition cost (assuming a 75 percent production share and a 40 percent maximum recovery) would be $0.55p$ while at a later stage (assuming recovery falls to 5 percent) it could be as low as $0.2875p$.

All this obscures the important question: how much rent is accruing to the government (in this context government and EGPC should be considered as one entity), and how is it used? Currently, EGPC is acquiring gas at a price p which varies with the price of oil while the selling price is constant. EGPC paradoxically benefits, in so far as gas is concerned, from a fall in the price of oil and sees its profits fall (or its losses increase) when the price of oil rises.

It is correct to argue that the rent element is in the production share, and the lack of transparency regarding the actual rent arises from the price structure. Greater transparency would be achieved if the acquisition price were altered to reflect an accurate relationship with the selling prices. An adverse effect on the producers' incentives can be avoided by introducing a compensating change in the pricing formula. The exact nature of the required changes in contractual arrangements upstream partly depends on the pricing policies that the government will adopt for the downstream, on the institutional changes that are introduced in both gas and electricity, and whether gas export projects are implemented or not.

IV. Gas Pricing

Before making any decision on gas-pricing policy it is necessary to determine what constitutes the opportunity cost/benefit of gas for a given country. Consider two different cases: the first is that gas is used only in the domestic market; the second is that it is both sold domestically and exported abroad.

The opportunity benefit of gas used domestically is the value of the equivalent unit of the petroleum product displaced. This may be fuel oil and/or gas oil in the power sector (disregarding coal and nuclear), LPG and/or kerosene in the household sector, gasoline and/or diesel in transport and so forth. Petroleum products are highly tradable, and both their fob and cif prices are regularly assessed. For the determination of the opportunity benefit, it is important to know whether the country is a net exporter or a net importer of the petroleum product displaced because of differences between fob and cif prices. For example, the average price of fuel oil (3.5 sulfur) in the Mediterranean in May 1997 was $77.65/ton fob and $86.80/ton cif. The price difference was approximately $9/ton or $1.36/barrel. Further, the exporting country's net realization is lower than the fob price because of refining and transport costs (from refinery to export terminal), and the importing country's total cost is higher than the cif price because of transport costs from the harbor to the power station.

Let us assume that Egypt is a net exporter of petroleum products, that gas displaces heavy fuel oil (3.5 S) in both the power sector and for boiler uses in industry (including cement), and that these uses dominate the gas market to a very high percentage (say 80 percent or more). We can then assume that the export price of fuel is the opportunity gain to the economy arising from using gas.

A million BTU of fuel oil would have fetched $77.65/41.875 = $1.85 in May 1997 in exports. Theoretically, the net opportunity gain is the difference between $1.85/MMBTU and the real resource cost of producing the equivalent unit of natural gas. The difficulty is that we do not know what the number is. There are estimates made by British Gas and apparently confirmed by the World Bank of the long-run marginal cost (LRMC) of producing gas of PT 13.65/cubic meter or $1.14/MMBTU. If this is the case, then the net gain is:

$$\$1.85 - \$1.14 = \$0.71/\text{MMBTU}.$$

If we allow an additional $0.15/MMBTU for transport cost to the burner tip (it is unclear whether the BG study includes this), then the gain is reduced to $0.56/MMBTU. But in the current institutional structure gas is purchased from the contractor at a price related to the crude oil price in a formula. In May 1997, Suez Blend cost $16.41/barrel which gives a purchase price of $2.48/MMBTU and an acquisition price of $1.36/MMBTU when recovery is at its maximum. Add $0.15 for transport to the burner tip which brings costs to $1.51/MMBTU, and what remains is a potential gain (resulting from the displacement of fuel oil) of $1.85 - $1.51 = 0.34/MMBTU. This is less than the minimum rent of $0.50/MMBTU which Persian Gulf countries expect from their LNG exports. When recovery is at its minimum, say 5 percent of the value of production, the acquisition price in this example is $0.71/MMBTU. Add $0.15 for transport and the benefit of displacing fuel oil will be about $1.0/MMBTU.

The fact that the opportunity gain of using a unit of gas instead of an equivalent unit of fuel oil is the export value (or a proportion) of this unit of gas does not necessarily mean that gas should be sold to the user at the price of the displaced fuel. This is a different issue which will be addressed later. If the country exports gas, or is in a position to do so, there is another opportunity gain for gas, that is the netback at the border of the exporting country. The net gain is the difference between this netback and the real resource cost of producing gas and transporting it to the border. Exporting gas through the Mediterranean to a suitable European destination in the form of LNG may, in today's conditions, yield a price of $2.50 - $2.60/MMBTU cif. Allowing $1.25 for liquefaction and 35 cents for transport, the fob realization would be $0.90 - $1.00/MMBTU.

In this example, the gross gain from export is lower than the gain from displacing fuel oil domestically by $0.85 - $0.95/MMBTU. But it would be wrong to argue, as consultancy and international agency reports often do, that in the case of exports it is the export realization that define the opportunity gain. There are two different values for this gain, one arising from exports and one from domestic use. They are both related to trade, directly in the case of exports and through the displacement of a tradable in the domestic case. In our example, the former is lower than the latter. The policy implication is that gas should be sold first to the market which generates the highest gain and the surplus production that this market cannot absorb to the other market. In practice, gain equalization does not take place because the LNG export market is lumpy and the domestic market tends to grow in a continuous, albeit variable, manner.

It is a fairly safe generalization that the domestic gas market has priority in Egypt. The problem, however, is that supplies do not move in harmony with domestic demand. This means that at a certain point in time supply may exceed the requirements of the domestic market, thus making a case for exports. But at another point in time supply may no longer be sufficient to meet both the increased requirements of the domestic market and the variable export commitments made when a temporary surplus emerged previously. In this case, the benefits derived from exporting early on must be compared to the future opportunity costs of having to export far less than would have accrued in the domestic market.

With these preliminaries in mind, we can now address the pricing issue. Heretofore, the advice given to Egypt on this issue has been almost exclusively concerned with the pricing of gas downstream. There is a dearth of studies which also concern themselves with pricing upstream and with the relationship between the various parts of the price structure. There are three schools of thought on the pricing of gas downstream in Egypt. The first advocates a price for the power-generation sector close to the price of the fuel displaced. The second advocates the use of LRMC pricing for gas. The third school of thought calls for domestic prices to reflect the international price of gas.

The logic of the first recommendation, the gas price to the power sector is similar to the price of displaced fuel, is that the substitute determines the opportunity cost. If the power section pays x for a unit of fuel oil, it will be willing to pay x minus an inducement discount to use an equivalent unit of gas instead. This approach shows that fuel oil sets a ceiling for the price of gas, and that the gas seller should get the full value of the benefit arising from the displacement of fuel oil. If gas is sold at less than the inducement price, and this discount from the fuel oil price is passed on to the electricity consumers, the gains will be appropriated by them rather than the gas producer. Whether the gas seller, the power generator or the electricity consumers should be allowed to appropriate a gain is a political, not an economic decision.

There is, however, another aspect to this pricing approach. If the price of gas is to be linked to that of oil downstream, does consistency require their linking upstream? (And one must ask also which is the oil price—crude or product—that is relevant for both the upstream and the downstream?) But why should the gas and oil prices be linked upstream? Are oil and gas, which are substitutes in a range of uses, also substitutes in production? If they were, the case for linking their prices upstream would be unassailable. The answer to these questions is complex.

Associated gas is a joint-product of oil and for this reason not a substitute in production. Non-associated gas is a substitute in the sense that it competes with oil for exploration and development capital expenditures by an oil company. In deciding to explore and develop a gas resource the company will use in its decision algorithm the same expected rate of return as for oil on its projected incremental investment. This is correct but does not imply that the price of gas at the source should be equal to the price of crude oil adjusted for thermal equivalence and the difference in the costs of shifting gas and oil from the well to the delivery point. There are reasons why the price link is not a necessary condition for equalizing expected returns. Development and operating costs are likely to be different for gas and oil. Non-associated gas is often itself a joint-product with condensates. There are cases where condensates on their own come close to justify the economic exploration of a field.

Even if we were to accept the 'substitute' principle for pricing gas both upstream and downstream with oil we would still find that this is not applied consistently in Egypt, where crude oil provides the reference upstream and fuel oil is the reference proposed by a number of consultants and international organizations for pricing downstream.

The second approach to gas pricing advocated by BG and NERA, for example, is to use the long-run marginal cost (LRMC). This is again an opportunity-cost approach which focuses on the second element of the net opportunity gain equation which we defined as:

net opportunity gain = export or import price of the fuel displaced - real cost of producing gas or LRMC.

Instead of pricing according to the substitute-in-use, this approach prices according to the resources used to produce gas as these have an opportunity cost. They can be used indeed to produce instead something else. In a perfectly competitive market the prices of these resources are equal to their opportunity costs. Both approaches (fuel equivalent and LRMC) have defendable analytical foundations. There are four main differences between the two approaches, however. The first relates to distribution considerations; the second is practical; the third relates to the stability of price signals given to the power sector and other users of gas and electricity; and the fourth to the implications for gas pricing upstream.

First, the distribution point is relevant. Pricing gas to the downstream on the basis of the displaced fuel allocates to EGPC the economy's gain from using gas. Pricing on the basis of

LRMC transfers the gain to the electricity sector, the industrial users, and others who may or may not pass this on to the buyers of their products (electricity consumers and other industries). In both cases, however, the government may be able to or may wish to appropriate these gains through taxation and spend the money to benefit the same or different constituencies.

Second, the practical difficulty relates to the estimation of LRMC. While fuel oil prices can be read every day on the tickers of price assessment agencies, LRMC has to be computed on the basis of a host of assumptions. One will always find reasons to question the reliability of given estimates. Furthermore, LRMC is likely to change over time as a result of new discoveries, changes in factor and input markets and several other reasons.

Third, fuel oil prices fluctuate continually. If gas is to be priced accordingly, electricity prices will either have to follow similar fluctuations or to be stabilized with a recourse to financial trading instruments such as swaps (if the power stations are privately owned) or through a fiscal cushion (if they are in the public sector). Although the prevailing economic ideology treats utilities as commodities, there are differences which favor stable tariffs for electricity for example. Furthermore, fluctuating prices which reflect changing market conditions of another fuel in the short and very short term are not a good sign for long-term lumpy investments that must be carefully planned. One may argue in response to this point that other industries—oil, petrochemicals, and others—have to invest without the help of stable prices. True, but investments in oil are cushioned by a huge gap between costs and prices, and the petrochemical industry has often been battered by pronounced and troublesome cycles. There is no significant 'rent' cushion in electricity and no sober person would want electricity to be subjected to a cycle like that of petrochemicals.

Finally, what are the implications of these gas-pricing approaches downstream for pricing upstream? We have qualified the notion that fuel-equivalence pricing downstream necessarily implies the application of an identical principle upstream. The LRMC approach is unlikely to work upstream in an institutional structure which involves foreign private investors. Oil companies which are the upstream investors insist on formulae that capture the 'upside potential' of the oil market. That oil prices may rise or fall is a risk they are willing to take. Given the institutional structure in Egypt, the gas-pricing dilemma is that two different pricing principles seem to be required; one that involves incentives for the operator upstream and one that provides some stability to the power sector downstream.

The third approach to gas pricing is that it should relate to the international price of gas. We have indicated earlier that this does not exist at this stage of development in the international
gas trade. Consider the following data for 1996 which show considerable differences in the prices of internationally traded gas:

LNG Japan (cif)	*$3.7/MMBTU*
Europe (cif)	*$2.4*
UK (Heren Index)	*$1.8*
USA (well head)	*$2.2*
USA (imports)	*$1.9*

Egypt is now considering export projects. Some will undoubtedly argue that the netback price of gas in such projects is the appropriate pricing standard. But we have already seen earlier in this section that this netback is one of (at least) two opportunity gains arising from producing and disposing of gas in the domestic and various external markets. I have also suggested that equalization is unlikely to occur.

In all these pricing approaches, the allocation and distribution issues are intertwined. The ideal policy system attributes the allocation function to prices and distribution to taxes and subsidies. But for a variety of reasons governments prefer to conceal taxes/subsidies under prices and thus end up with systems which lack transparency and fail to fulfill adequately both the economic allocation function and the sociopolitical distributive objective. This is a significant problem with gas-pricing policy in Egypt.

V. Gas Pricing Policy Proposal

A gas-pricing policy for Egypt must reconcile a number of objectives. First, it must encourage exploration and development by foreign companies and therefore provide the upstream sector with adequate incentives. Secondly, it must provide industry and power generation with an essential input at fairly stable prices. Thirdly, it must yield a rent to the government. Governments sometimes use energy pricing policy to foster other goals such as energy conservation, environmental protection and redistribution of income. By definition, such a structure cannot be perfect because the number of objectives is greater than the number of instruments. Inevitably, compromises have to be made.

Let us restate the options. First, a gas policy which is not about prices but markets. The development priority is the domestic market, as the net opportunity gains arising from the displacement of fuel oil in power generation and heat-raising in industry, kerosene and LPG in the commercial/household sector and gasoline or diesel in the transport sector are likely to be higher than the net opportunity gain from exports. This proposition assumes that gas export prices are related to cif oil prices, but that they are affected at the fob point by high transport costs. The qualification is that costs of gas distribution for households, commercial and institutional establishments, and of CNG distribution to service stations may prove to be high in certain locations. This would lower the opportunity gain from using gas instead of petroleum products in certain domestic sectors below the gain from gas exports. In this case the expansion of gas markets should not be encouraged in areas where costs of transmission and distribution are high. The implication is not that gas should not be exported (as surpluses may arise in certain periods), but that export contracts take into account, as much as possible, future domestic requirements.

Secondly, there is a distribution decision to be made by the government. There is a potential gain to the economy from using gas. The government may decide to appropriate these gains, which will be then redistributed according to the pattern of incremental government expenditures, pass them on to consumers or share them with consumers. Those who trust governments and their spending plans may advocate the first option; those who do not, will advocate the second. But even if governments are to be trusted, one may still argue that a redistribution of benefits to electricity consumers has the advantages of (a) reaching a large proportion of the population, (b) helping industry and other productive sectors, and (c) generating some external economies of modernization. The drawback is that lower electricity prices to domestic consumers benefit the rich more (as they use more power) than the poor, but even this can be remedied by designing progressive electricity tariffs. It is also true that more electricity will be demanded if its price is lower than it would be without the allowance for new opportunity gains. But the incremental costs of supplying this additional demand can be included in the electricity cost. The system will thus find a new equilibrium reflecting a set of adjustments.

For pricing gas (given any particular decision made on the distributive issue) one needs next to choose a reference. If the whole of the gas —electricity sector was under public ownership, the problem would be simple. The reference would be the LRMC. The solution of the pricing issue would involve the following steps:

1- Evaluate, as best as possible, the LRMC of producing gas.
2- Evaluate all costs of transmission to the point of use.
3- Compute the LRMC of electricity accordingly.
4- Compare (1) and (2) with the value of the fuel displaced.
5- The government should then decide on how or to whom the gains are allocated.
6- Add to the LRMC of electricity any proportion of (4) that the government wishes to appropriate.
7- Establish electricity tariffs that are consistent with (6).

Broadly speaking, this is straight forward, but there are hidden problems. First, LRMCs are difficult to estimate, as mentioned before. Second, the prices of fuels displaced (Step 4) are extremely variable. Take for example the price of Brent from 1994 to 1997. It hit a trough at $13.05/barrel on March 8, 1994 and a peak of $24.96/barrel on January 9, 1997. The range between trough and peak in a period of three years was 31 percent below and 31 percent above a mid-range price of $19/barrel. During the same period heavy fuel oil prices in Rotterdam varied between $54/ton and $125/ton. This gives a range of variations of 39 percent both below and above the mid-point. At $54/ton for fuel oil, the thermal equivalent price is $1.29/MMBTU, and at $125/ton it is $2.98/MMBTU. If we take the LRMC of gas at $1.14/MMBTU and add something for transport costs to the power-station gate—say 15 cents/MMBTU—the low price of fuel oil ($1.29) turns out to be the same as the LRMC in this example. There is no gain. In sharp contrast, the high price of fuel oil ($2.98/MMBTU) generates a substantial gain of $1.69/MMBTU.

Fortunately, the extremes of the range do not seem to hold for long periods. A sensible approach to this problem of fluctuating fuel oil prices is to take as reference a three- or four-year average. This reference can be computed once a year at a given date and applied accordingly. However, the institutional structure in Egypt is different. There are private investors upstream. There will be private investors in electricity downstream. And gas exports may take place in the foreseeable future. How, then to price gas given this structure? Let us begin with the upstream sector.

Since production-sharing agreements upstream are well established, the LRMC is not the relevant parameter for pricing gas upstream. The pricing question in the upstream sector is one of the relevant reference price, relative production shares and gas sales agreements. The value of gas to Egypt is that of the tradable petroleum product displaced at the burner tip. At the well-head, it is this value minus the gas transport cost. At present, the petroleum product displaced is fuel oil under boilers. Combined-cycle generation plants, which now account for 20 percent of installed capacity, increase the opportunity gain of gas because of the higher thermal efficiency of these plants.

The relevant parameters for assessing the upstream pricing system under production sharing agreements follow:

Production shares. In the initial production stage, the contractor is entitled to recover costs for up to 40 percent of the value of production in most existing agreements (in some instances the recovery is limited to 30 percent or 35 percent). The remaining production is divided between EGPC and the contractor in ratios which, depending on the contract, vary from 55 percent to 85 percent for EGPC and 15 to 45 percent for the contractor. Assuming 40 percent maximum recovery and a 75/25 split for the remainder gas, the EGPC share would be 45 percent of the production initially but could rise in later stages to 73.75 percent.

Opportunity gains of using gas. Under current circumstances this is the traded price of fuel oil minus a transport cost of gas to the burner tip of, say, $0.15/MMBTU (this is an assumption made for illustrative purposes which should be modified according to actual costings). With combined-cycle plants, the fuel oil price should be increased by at least 30 percent to take into account higher thermal efficiency.

Acquisition cost. This is the price at which EGPC purchases gas as given in the formulae of contracts with the companies investing upstream.

The concealed rent element. We calculate this as the difference between the benefit derived from using gas (which is related to the value of the displaced fuel adjusted in various ways as mentioned above) and the acquisition cost.

Let p_f be the MMBTU price of the displaced fuel and p the MMBTU price at which EGPC acquires gas from the contractor. In Stage 1, when the EGPC share may be as little as 0.45, the hidden rental element per MMBTU is:

$$(p_f - \$0.15) - 0.55p.$$

In Stage 2, when the EGPC share may be as high as 0.7375, the hidden rental element is:

$$(p_f - \$0.15) - 0.2625p.$$

Now consider two extreme cases where (a) the price of a ton of fuel oil is \$54/ton and that of Suez Blend is \$11.5/barrel and, (b) the price of a ton of fuel oil is \$125/ton and that of Suez Blend is \$22/barrel. The respective values of the hidden rental element are then as follows:

Stage 1/Case (a): \$0.18/MMBTU
Stage 1/Case (b): \$0.99/MMBTU
Stage 2/Case (a): \$0.71/MMBTU
Stage 2/Case (b): \$2.00/MMBTU

But these cases are not very meaningful, because prices do not hold for long periods at the extreme points of the range. Let us take instead actual average annual prices for Suez Blend and fuel oil (3.5 S) fob:

Year	*Suez Blend* ($/barrel)	*Fuel Oil* ($/ton)	*Rental Element* ($/MMBTU)
1991	16.79	69.82	0.12
1992	16.50	74.00	0.25
1993	13.81	59.39	0.13
1994	13.94	75.55	0.49
1995	15.54	87.94	0.66
1996	18.74	93.90	0.53

We see that there are still significant variations in the values of the rental element even when we consider only one case: the 45 percent share for EGPC, which is the least favorable.

We have now elements which enable us to propose pricing policies for the upstream sector given the current institutional structure. Ideally we would like to recommend that the terms of current production-sharing agreements be renegotiated to let the acquisition price formula be linked to fuel oil rather than crude oil prices. This would harmonize price variations upstream and downstream. Fuel oil prices do not display a constant relationship with crude oil prices as the data presented above for 1991-1996 show. The ratio fuel oil price/ton over Suez Blend price/barrel (on an average annual basis) has varied from a low of 4.16 (1991) to a high of 5.65 (1995). The latter coefficient is 36 percent higher than the former. Should such a change in reference prices be agreed upon, some other contractual terms (namely the production shares or the 0.85 coefficient in the pricing formula) would have to be altered to compensate the contractor for the use of a lower reference price. However, such a recommendation would be highly unpopular. If the crude oil price is retained as the reference for gas pricing upstream, then I would recommend imposing a progressive coefficient that reduces the impact of price rises beyond $23/barrel for Suez Blend and a cap if oil prices rise beyond $30/barrel.

Turning to the downstream, the pricing proposal is to use the price of fuel oil (3.5S) fob for exports in the Mediterranean as the reference. For combined-cycle plants this reference may be increased by 30 percent. The reference should be computed as a three year average for application in the fourth year (the reference for 1997 would thus be the average of 1994-1996).

Finally, the government will have to decide how much of the hidden rental element *d* on gas it wishes to pass on to electricity consumers. This would be a proportion of *d*, anywhere between zero and one, set according to the government preferences. Because of the variability of both the fuel price (even when averaged over three years) and of *d* , the discount on the price of gas to the electricity sector must be made to vary directly with the price of fuel oil. Such a direct relationship is displayed to some extent by the actual price data (see table p. 22). The purpose is to stabilize electricity prices as much as possible.

VI. Implications of the Gas-Pricing Proposals

Some of the main implications of the gas-pricing policy proposals are as follows:

(a) In the upstream the proposed change (the use of fuel oil instead of crude prices as reference) need not alter the contractors' expected rate of returns, because the change is to be compensated for either by increasing production shares or, and perhaps this is more acceptable to the parties involved, by increasing the coefficient 0.85 which figures in the price formula.

At present the acquisition price of gas per MMBTU is equal to: (0.85 x price of a barrel of oil) / 5.616. If this is replaced by the following, coefficient *a* x price of a ton of fuel oil/41.875, we derive the following equivalence condition:

$$a = \frac{0.85 \times 41.875}{5.616} \times \frac{\text{Price of crude/barrel}}{\text{Price of fuel/ton}}$$

$$a = 6.34\ \underline{\text{Price of crude/barrel}}$$

Price of fuel/ton

We have seen that the ratio of the price of fuel/ton over the price of crude/barrel has varied from 4.16 to 5.65 (taking annual average price data). This gives a range of values between 1.52 and 1.12 for a. A point within this range may be negotiated. For example, if a is set at 1.32 (the mid-point between 1.12 and 1.52), the acquisition price of gas per MMBTU would be $1.32p_f/41.875$. These would give acquisition prices of gas as follows:

Fuel Oil Price ($/ton)	*Gas Price* ($/MMBTU)
60	1.89
70	2.20
75	2.36
80	2.52
85	2.68

(b) The prospects of gas exports raise interesting pricing issues upstream. At present the upstream contractors sell their production share to EGPC at 85 percent of the price of Suez Blend on a thermal equivalent basis (BTU for BTU). If export markets open up, they will sell some of their production share in the from of LNG (say, to Turkey, Cyprus, Greece or Italy) and, perhaps, as pipeline gas to neighboring countries.

Assume a world market in which the Brent price is $18/barrel. At this price the cif gas price in Europe tends to converge at $2.50 - $2.60/MMBTU. The Suez Blend price, when Brent is at $18/barrel, falls within $15.50 - $16.50/barrel range. The upstream contractor would be facing two very different sets of prices: high ones for domestic sales and low ones for exports. The ranges are:

(i) Domestic sales to EGPC for Suez Blend at $15.50 - $16.50/barrel would be in the $2.35 - $2.50/MMBTU range.

(ii) Export realization on LNG ($2.50 - $2.60) - ($1.25 for liquefaction + $0.35 for transport) = $0.90 - $1.00/MMBTU

The LNG market is unattractive. The realization of pipeline exports may be slightly lower than from domestic sales, but exports are predicated on supplies exceeding domestic requirements. By definition, the option to sell domestically the gas committed for exports does not exist, at least for a while (the length of the export contract). If the contractors decide to go ahead with exports and accept the lower realizations, they would indicate to EGPC that acceptable rates of return can be achieved at lower prices than obtained from EGPC. How would EGPC then react? If the contractors maintain that the sales price to EGPC is at the levels required to generate an acceptable return on their investment, they will seek to negotiate for new fields —

assigned to export projects —contracts that would give them a much higher production share. Would that be acceptable to EGPC? Their third option, complementary rather than alternative to the second, is to link the proposed export to a power plant investment in the importing country. This raises the value of gas by about 30 percent. Even taking these options together would not bridge the gap between the export netback and the price at which gas is sold to EGPC.

The reason why contractors may be interested in export projects is to hasten the development of, and production from, new fields whose supplies may be in excess of domestic requirements at the moment. EGPC has the option to delay purchases from the contractor for a few years. The contractors may thus argue that they are not preferring the low export netback to the higher selling price to EGPC, but rather the export netback to no sales at all for some years. For the Egyptian government, however, the problem is to ensure that future supplies to the growing economy are not preempted by export contracts entered into presently.

(c) In the downstream, gas prices would rise under our proposal. We have seen that in early 1997, the power sector obtained gas at $1.02/MMBTU. This has now been raised to PT 14.1/cubic meter, that is about $1.17/MMBTU. In our proposal, the reference price of gas is the three-year average of fuel oil price which may fall anywhere between $65/ton and $85/ton if the six-year period 1991-1996 can be taken as representative. This means that the corresponding reference price per MMBTU would range between $1.60 and $2.05/MMBTU. We have also seen that the rental element *d* has varied between $0.12 and $0.66/MMBTU. If a graduated discount, ranging from $0.10/MMBTU when the fuel price is low to $0.55/MMBTU when it is high, is introduced then the selling price would be stabilized at around $1.50/MMBTU.

(d) The implications for electricity prices of an increase of 47 percent in the price of the input (comparing with the early 1997 gas price of $1.02/MMBTU) or even 28.2 percent (comparing with the new gas price of $1.17/MMBTU) are significant. Assume that the LRMC of electricity consists of 40 percent fuel and 60 percent non-fuel costs. An increase of

28.2 percent in fuel costs would increase the LRMC of electricity (non-fuel costs held constant) by 11.3 percent. Considering also that non-fuel costs are affected by inflation and that the tariff yield is at present probably lower than the electricity LRMC, a policy that will raise both the price of gas and eliminate the gap between the tariff yield and the electricity LRMC will result in a much larger hike in electricity prices than indicated above.

Given this situation, a sensible policy will include transitional and compensatory elements. The required price rises of electricity can be mitigated by measures (including investments, improved management, greater attention to maintenance) which further increase the efficiency of the power system. Although much progress has been achieved on this front, there is always more that can be done. Price rises can be spread, say, over a four- or five- year period. It would be sensible to announce them from the outset to enable users to plan and implement their response. A small subsidy, in addition to *d* and to the five-year transitional subsidy arising from the spreading of price increases, may be envisaged.

(e) The question of subsidies and concern for the budget of poor households are important. This paper does not contest subsidies as a fiscal instrument which governments can use to promote distribution objectives but rather the right of governments to tax. Subsidies should be transparent and directed to the poor. Ideally, subsidies should be in the form of income support, not price reductions, but this is not always feasible. If subsidies on gas and electricity must be given in the form of small reductions from 'economic prices' to poor households (not through prices fixed for innumerable years as for bread, bus fares, etc. after the 1940s), there is no particular cause for concern.

At present subsidization is not transparent as it is hidden under the pricing of fuel oil and natural gas to electricity and the pricing of electricity itself. We propose instead 'economic' pricing of the relevant petroleum products by the oil sector, pricing of natural gas as explained previously, and an explicit subsidy to electricity. Financing would be partly covered by the resulting increases in the profit tax yield from the oil and gas industry. Electricity tariffs for households may be graduated as follows:

(i) Very low KWH prices for the amount of electricity necessary to light to three small rooms and to use a radio and a small television set.

(iii) A moderate tariff for the additional amount required for the lighting of a fourth room and use of a refrigerator.

(iii) A much higher tariff for any additional electricity consumption. This may involve an element that helps financing (i) and (ii).

Small workshops and factories may also be given a preferential tariff. All other commercial and residential users would pay rates consistent with the LRMC of electricity.

(f) There are financial implications for EGPC as buyer—*cum*—seller of gas. EGPC would be buying gas at an average price between 0.33*p* and 0.55*p*, say 0.44*p* selling at a stabilized price of $1.50/MMBTU, and incurring a transmission cost assumed to be $0.15/MMBTU. The relevant crude oil price *p*, which is 0.85 of the thermal equivalent of a barrel, may vary from $1.80/MMBTU (crude oil at $12/barrel) to $3.48 (crude oil at $23/barrel). The average acquisition price may thus vary between $0.79 and $1.53/MMBTU.

The net realization of $1.35/MMBTU leaves a cash surplus of $0.56 per unit at the low oil price and a loss of $0.18 per unit at the high oil price. In fact, the highest annual average crude oil price in the period 1991-1996 was $18.74/barrel for Suez Blend. This implies an average acquisition price of $1.25/MMBTU involving a small margin of $0.10 per unit. This data supports the use of a cap on the pricing formula of a sales agreement associated with the production-sharing agreement.

(g) Opening the electricity sector to private investors also raises pricing issues, but these are closely related to the institutional structure that will be put in place. Private investment may be restricted to power generation with the distribution entirely in the public sector. Alternatively, the privately-owned power station may have its own exclusive market, say a particular industry. Another possible structure would involve private interests in both generation and distribution. The implications of these alternative arrangements go well beyond the scope of this paper; however, there is an important point to be made regarding pricing of gas to new power stations which will presumably use combined-cycle technology. As mentioned earlier, it is legitimate to charge a higher price for gas to these plants given their greater thermal efficiency. The proviso, of course, is that some of the benefits of greater efficiency should accrue to the investors in order to induce them to enter the field and use the preferred technology.

(h) The final point is about the use of heavy fuel oil (3.5 S) for power generation. This fuel is used as a reference because natural gas has actually been displacing it in Egypt's electricity sector. But this heavy fuel oil is environmentally unfriendly. If Egypt has little or no gas resources, heavy fuel oil (3.5 S) would eventually be replaced by heavy fuel oil (1.0 S) in conventional power stations and by middle distillates in combined-cycle plants. One could therefore argue that these other petroleum products should provide the reference for pricing gas given that environmental concerns will bring them into use sooner or later.

If we were to take the price of fuel oil (1.0 S) as the reference for gas pricing downstream, the price of gas downstream would rise by the ratio p_l/p_f (where p_l is the price of fuel oil (0.1 S) if no discount *d* is given for the rental element. Taking annual averages for the prices of fuel oil (3.5 S) and (1.0 S) fob Mediterranean in 1991-1996, we find that the highest p_l/p_f ratio was 1.50 in early 1993, and the lowest, 1.14, in 1995. There has been a tendency for the ratio to be low in the past three years (1.19 in 1994, 1.14 in 1995, 1.18 in 1996). Taking these figures as representative would still lead to gas prices higher by 15 to 20 percent (if no discount is given). But if the discount *d,* representing the hidden rental value is allowed, the gas price would be the same whether p_f or p_l is taken as the reference. This is shown as follows:

In the first case, the gas price is:

$$p_f - [(p_f - \$0.15) - 0.44p] = 0.44p + \$0.15,$$ where p is the price of Suez Blend

In the second case, the gas price would become:

$$p_l - [(p_l - \$0.15) - 0.44p] = 0.44p + \$0.15$$

In our proposal, however, we suggest a stabilization of the gas price at around \$1.50/MMBTU by smoothing changes in fuel oil prices and varying the discount *d*. This remains unaffected when fuel oil (1.0 S) is the reference.

VII. Conclusions

Our main policy conclusion can be summarized as follows:

1. The development of the domestic market for gas has priority over exports in all sectors where this development yields a higher opportunity gain for gas than the export netback.

2. Although Egyptian gas reserves appear to be very large, export commitments made at a time of surplus production should be checked against the expected gas supply/domestic demand balance in future years. This is simply because export contracts are entered into for a long period.

3. The price netback at the border of the exporting country does not provide a relevant measure for the opportunity gain of gas utilization if this is higher in the domestic sector. The gas market is best considered as segmented with the proviso stated in the previous recommendation.

4. The LRMC approach is not suitable for pricing gas upstream in the current institutional structure of the industry which involves private foreign contractors. It is also not appropriate to purchase gas at crude oil related prices. Our proposal is to use fuel oil as a reference for gas purchases upstream and alter the price coefficient 0.85 to compensate the contractor.

5. If the crude oil reference is to be retained for upstream pricing, it is advisable to negotiate a gradual capping of the relevant crude oil price when it rises above a certain level. There is a case to be made for allowing the contractor to enjoy the benefits of the upside potential; but there is not reason for allowing him to appropriate the full marginal gains. Furthermore, a form of capping is necessary to ensure that a measure of price stabilization downstream can be achieved without EGPC incurring huge financial losses when crude oil prices are high.

6. We prefer a price of $1.50/MMBTU for gas sales to the power sector (conventional thermal generators). The supporting argument and the associated computations are presented in this text. Essentially, the argument is to take the fuel oil price as the relevant reference and reduce it by a discount reflecting the opportunity gain that accrues to the economy from using gas instead of fuel oil.

7. Prices of gas to combined-cycle plants should reflect some of the thermal efficiency advantages.

8. This proposal results in higher electricity prices. These may be mitigated by further programs of reorganization, maintenance and waste reduction. The price rises may also be spread over a few years. Small subsidies may be adopted if necessary.

9. Subsidies, whenever provided, should be as transparent as possible and benefit poor households and small labor-intensive industries.