Report of Study Group 10.1

<< *Gas in the Less Developped Countries* >>

Rapport du Groupe d'Etudes 10.1

<< *Le gaz dans les pays les moins développés* >>

Chairman / Président

Mourad BELGUEDJ

World Bank / Banque Mondiale

PREAMBLE

Natural gas is expected to be the fastest-growing primary energy source in the world over the next 25 years. According to US Energy Information Administration, total world natural gas demand is expected to more than double the 1995 level of 2,130 $10^9 m^3$ by the year 2020 and most of the growth is expected to occur in advanced economies. In most developing countries, however, natural gas has yet to develop in a way commensurate with the existing resource base, and most of the associated gas produced is being flared whilst non-associated gas is simply left undeveloped. Non-existent gas pipeline infrastructure, undeveloped domestic and regional markets and lack of financial resources to engineer gas-based export schemes have hindered the development and usage of natural gas in the energy sector of most developing countries. Reasons for this lack of forward development have been examined trough the following five case-studies and attempt to show that the potential for development does exist and could materialise in viable projects. The choice of three countries in Africa and two in Asia was motivated by the fact that most of the gas flaring occurs presently in the African continent, where the largest oil and gas finds have been made in recent years. The cases selected in Asia examine countries well endowed with gas resources for which a local market has been developed, including possibilities for exports, wherever feasible and acceptable.

There is growing concern amongst the international community about the environmental hazard gas flaring poses in the long term, as oil production increases in developing countries. These concerns have been further underscored by agreements such as the Kyoto Protocol, which have resulted in consolidating the move towards increased use of natural gas in energy generation and elimination of gas flaring world-wide. Moreover, developing countries are recognising the importance of this abundant resource in diversifying their hard currency export earnings, which are presently over-dependant on oil taxes only or conversely to reduce reliance on petroleum imports, by developing their domestic natural gas reserves.

Few attempts have been made so far to create a domestic market for natural gas. In most of the developing countries, existing petroleum legislation has contributed to the lack of gas development by continuing reference to natural gas as a by-product of oil production. The contractual agreements with the operating International Oil Companies (IOCs) have no explicit provisions for development of natural gas. Under most of the Production Sharing Agreements (PSAs), all the associated gas produced with crude oil, which is not necessary for gas lift operations or for re-injection for reservoir pressure maintenance, belongs to the State, free at the wellhead. In most cases, since the State cannot provide facilities to recover and transport this associated gas, the operators are faced with the alternative of flaring it or shutting down oil production. Since oil production is essential for government revenues, the flaring has been reluctantly authorised in most cases.

One of the most efficient ways to build up a gas market is to identify a sector with large initial absorptive capacity, which points in the direction of the fuel requirements of the power sector. Power sectors are generally the largest consumers of petroleum products and their level of demand, except for peak shaving purposes, is quite stable throughout the year. The power sector in most of the developing countries faces a huge unmet demand for electricity and the supply-demand gap will increasingly widen as industrial activity picks up.

Natural gas is an attractive alternative to oil and coal-fired generation and even to hydropower. Recent technological improvements in the design, efficiency and ease of operation of combined-cycle gas turbines have moved the economics of power generation steadfastly in favour of natural gas. Moreover, carbon dioxide emissions per unit of energy obtained from gas are 80% lower than from coal, making natural gas more environmental friendly. Phased implementation of modular, gas-based power projects, matching field development with market expansion, lower capital costs, along with short construction times are well suited for emerging economies. In addition to power generation, other profitable natural gas development prospects, which the developing countries could explore, include developing energy intensive industrial parks near proven gas fields, the whole gamut of petrochemical and fertiliser industries, extraction of LPG's, export oriented LNG projects and gas to liquid technologies (GTL). Depending on the market absorptive capacity, these options, if developed simultaneously, have the potential of improving the economics of larger projects, as well as the ability to tap new markets, such as regional Gas-to-Wire exports.

Gas based power generation also has a strong multiplier affect on other key sectors of the economy. Since electricity is the basic input for development of industrial as well as domestic and commercial sectors, it has an indirect impact on the social sectors like health, education, telecommunication and information technologies, which are the basic ingredients for improving quality of life. Today, continuous quality electricity supply is pre-requisite to the sustained development of the service sector.

Establishing a proper institutional and regulatory framework is the first step towards lasting development of gas markets. The framework should promote economic development, protect consumer's interests, have a proper monitoring and enforcement mechanism, and it should provide incentives to attract investors. Financial returns to market gas must be made attractive to the operator so there is a disincentive to flare gas or leave it undeveloped. Tax incentive for gas utilisation or re-injection may be a viable proposition along with enforcement of no-flare regulations. Privatisation of energy sector activities and policies to promote competition in energy and other related sectors also have a similar favourable impact.

Promoting viable gas projects is only possible through close co-operation between governments/national oil companies, international oil companies (IOCs) and private investors. Even the development of small-scale gas projects is a complex and capital intensive option. Thus, the initial focus should be on smaller projects, which are easier to bring to fruition and mobilise less scarce resources. These pilot projects have a strong demonstration effect and they generally lead to larger projects. This sector study intends to investigate the feasibility of such projects, through the five interesting cases of Angola, Cameroon and Côte d'Ivoire in Africa and Bangladesh and Vietnam in Asia.

ANGOLA

1 INTRODUCTION AND OVERVIEW OF THE GAS AND OIL SECTOR

The petroleum industry in Angola began in 1955 when oil was discovered in the onshore Kwanza valley by Petrofina, which together with the local government (then under Portuguese rule) established the jointly-owned company, Fina Petroleos de Angola (Petrangol) and constructed a refinery at Luanda to process the oil. Over the years Angola, which became independent in 1975, has emerged as one of the major oil producing countries of Africa and today the petroleum industry is the economic mainstay of the Government of Angola (GoA). With oil, associated gas is also produced and more often than not, flared in huge volumes. This is an attempt to investigate ways to reduce flaring and putting natural gas to productive use.

Three decades of civil war, which erupted soon after independence, have taken their toll on Angola's economy and virtually destroyed its infrastructure leaving GNP per capita at only US$ 312 and a 1998 inflation rate of over 95%. In 1960, oil accounted for less than 8% of gross domestic product, while agriculture contributed about 50%. By 1995, agriculture's share had fallen to 17% and that of oil had jumped to 40%. Today, crude oil accounts for 90% of total exports, more than 80% of government revenues and 42% of the country's GDP. Oil output, which is now nearly 800,000 barrels per day (b/d), is expected to reach one million barrels per day in the near future, making Angola the second most significant oil producer in Sub-Saharan Africa after Nigeria.

The national oil company, Sociedade Nacional de Combustiveis de Angola (Sonangol), was established in 1976, and the hydrocarbon law passed in 1978 made Sonangol sole concessionaire for exploration and production. Associations with foreign companies are in the form of: 1) joint ventures (JVs), where investment costs and production are divided according to the party's share in the venture; and 2) production sharing agreements (PSAs), in which the foreign partners act as contractors to Sonangol. The contractors finance all investment costs, and recover their investments when production begins. The PSAs commit partners to carry out exploration and development within a pre-determined time (usually three years for each phase).

Crude production, which comes almost entirely from offshore fields because of war risks, has doubled in the past ten years from 359,000 b/d in 1987 to an average of 800,000 b/d in 1998. Two thirds of the oil reserves are found off the coastal enclave of Cabinda, in Cabinda and off Angola's northern coast near Soyo, while the few onshore fields are located near Luanda in the Kwanza River Basin and further south in the Namibe Basin. During the past decade, new discoveries have added new reserves at a greater rate than existing reserves are depleted. Angola's total proven oil reserves are estimated at 10 billion barrels at the end of 1998, giving the country a Reserve/Production ratio of 32 years. Following recent further discoveries, its upstream potential is likely to remain extremely positive due to its promising geology, a good record of exploration success, low operating costs and relatively attractive fiscal terms. These factors together with the increasing stability following the ending of its civil war make Angola a key player in Africa's oil industry both as a major producer and exporter.

Meanwhile, oil exploration has resulted in the discovery of significant natural gas reserves, which remained undeveloped and often relinquished by the IOCs to the Angolan State via Sonangol. Up to half of the gas produced in association with oil is flared while the remainder is used for gas lift and injection to boost oil production from declining fields in Cabinda. Under most of the PSAs, the associated gas, which is not necessary for gas lift operations or for re-injection for reservoir pressure maintenance, belongs to the "State" or to Sonangol. Since oil production is essential for government revenues, the flaring has been authorised. It is estimated that in 1998 nearly 15 $10^6 m^3$ per day of associated gas was flared. The lack of gas-based infrastructure is hindering Angola's development and usage of natural gas in its energy sector.

Oil sales, which account for 90% of the country's exports and roughly half of its GDP, are expected to fall to US$ 3.6 billion, compared with US$ 4.9 billion in 1997. Privatisation and the planned establishment of a series of development corridors and energy intensive free-trade zones would help diversify the economy, but these are likely to be an early casualty of fresh conflict - as is the country's IMF reform plan, which is barely in place. It is important that Angola starts giving priority to commercial development of its natural gas reserves in its effort to rebuild its economy and diversify its revenue stream from oil alone.

2 GAS AND OIL POTENTIAL

2.1 Exploration and Production & Future Potential

The main expansion of Angola's upstream oil industry came in the late 1960s when the Cabinda Gulf Oil Co (CABGOC), a Chevron subsidiary, discovered oil offshore of the Angolan coastal enclave of Cabinda. The national oil company (Sonangol) was also established to manage all fuel production and distribution. In the late 1970s, the government initiated a programme to attract foreign oil companies. The Angolan coast, excluding Cabinda, was divided in 13 exploration blocks, which were leased to foreign companies under production sharing agreements. In 1978, the Angolan government authorised Sonangol to acquire a 51% interest in all oil companies operating in Angola, although the management of operations remained under the control of foreign companies.

Three major sedimentary basins favourable to accumulation of hydrocarbons span Angola's entire coastline. The lower Congo basin, which extends from Congo south through Cabinda and into the northern part of Angola, is the only basin from which oil and gas are currently being produced. The Kwanza basin extends from Luanda south to the coastal town of Benguela and the Namibe basin extends from the Benguela area south into Namibia.

Crude production, which has doubled in the past ten years, averaged 800,000 b/d in 1998. Area A, Area B, and Area C, (Block Zero), which are located offshore the enclave of Cabinda, account for nearly 65% of crude production. The Chevron subsidiary, Cabinda Gulf Oil Company (CABGOC), is the operator of the fields located offshore Cabinda, and it has a 39.2% share in the JV. Other partners include Sonangol (41%), Elf (10%) and Agip (9.8%). The largest producing fields are Takula (Area A), Numbi (Area A), and Kokongo (Area B). CABGOC and its partners hope to expand production in the three areas to 600,000 b/d by the turn of the century. The start-up of production from the Lomba (Area B) field was announced in May 1998. Production is currently 15,000 b/d, and is expected to increase to 27,000 b/d by the end of 1998.

The second largest area of production in Angola is Block 3, which is located offshore off Luanda along the northern coast. The largest fields on Block 3 are Pacassa, Cobo-Pambi, and Palanca. Storage and export facilities for the Block are provided by a terminal located on the Palanca field. Elf Aquitaine Exploration Angola (EEA) of France is operator on Block 3 with a 50% interest. Other partners on the block include Sonangol, Agip, Svenska Petroleum, Nis Naftgas, Ina Naftaplin, and Ajoco. The Oombo field, a satellite of the Cobo-Pambi field (1996 production of 54,000 b/d), came on stream in January 1998 producing 9,500 b/d.

Block 2, located offshore of the northern Angolan city of Soyo, is also currently in production. Texaco and Total (France) are both operators on Block 2. Major fields include Lombo, Sulele, and Tubarao. Petrofina (Fina) of Belgium is the operator of Angola's onshore production, centred in two areas, Kwanza near Luanda and the Congo basin near Soyo. Production facilities near Soyo were damaged during the civil war, and a US$ 250 million post-war rehabilitation program is underway.

CABGOC made a significant oil discovery in deeper waters offshore Cabinda in April 1997. The field, designated Kuito, has estimated recoverable reserves of 1-2 billion barrels. Kuito lies in waters 400 m (1,300 feet) deep in Block 14, which is adjacent to Areas B and C. CABGOC is the operator of the PSA working on Block 14 and it has 31% interest in the venture. Other partners in the PSA are Sonangol (20%), Total (20%), Agip (20%), and Petrogal (9%). Initial production from Kuito is expected to begin in 1999 at the rate of 50,000 b/d, eventually increasing to 200,000 b/d.

Chevron also announced a significant oil discovery in deepwater Block 14. The new field has been named Belize and follows its three predecessors - Kuito, Landana, and Benguela. Initial production from Kuito during Phase One is expected to be 75,000 b/d and will reach peak production of 100,000 b/d by 2002. As per Chevron, Kuito will be Angola's first deepwater, zero-flare field. Kuito gas, produced in association with the oil, will be re-injected into the reservoir. Chevron's Nemba and Lomba fields, located in shallower water nearby Block 0, are also zero-flare. Block 14 is operated by Chevron, which holds a 31% interest. The remaining interest is held by Sonangol (20%); Agip Angola (20%);

Total Angola (20%); and Petrogal (9%). Exploration and drilling in Block 14 began in 1996, and the Kuito Field was discovered in April 1997.

Angola's oil industry is an attractive investment opportunity, offering foreign companies favourable geology; low operating costs and; a constructive business approach from the Angolan government. Total foreign investment in oil exploration and production has been US$ 2.7 billion from 1980-86, US$ 2 billion from 1987-90 and was estimated to be US$ 4 billion from 1993-97. Out of the total estimated oil production in 1998, of the major operators Chevron will be producing 450,000 b/d in Cabinda, Elf will expand its production to reach 200,000 b/d in its concessions in Blocks 3/80, 3/85 and 3/91 and Texaco will reach 75,000 b/d.

The recent offshore discoveries in Angola have sparked interest in Angola's unclaimed blocks. Block 19, located in deepwater offshore Luanda, was awarded to a group composed of Fina (30% and operator), Ranger (25%) Sonangol (20%), U.S. United Meridian Corporation (20%), and Israeli firm Naphta (5%). Texaco was named operator of Block 22, and Australian firm BHP was named operator of Block 21 in June 1997. Bids for Blocks 23, 24 and 25 were accepted in 1997, with the possibility of licenses being awarded in the first half of 1998. License awards for Blocks 31-34 may have been granted by the end of 1998. There are plans to establish as many as fifteen new deepwater blocks along Angola's southern coast.

The upstream oil industry has now become key to Angola's war-damaged economy and the country is almost wholly dependent on it for foreign exchange earnings and government revenue. Exports of crude oil earn the country an estimated US$ 5 billion per annum.

2.2 Refining and Downstream

The Fina Petroleos De Angola refinery in Luanda has current nominal capacity of 1.9 million tonnes per annum (38,000 b/d) although current throughput is around 1.6 million tonnes. The refinery is a joint-venture between Sonangol (36%), Fina (61% and operator), and private investors (3%). Angola refines about 50,000 b/d for its domestic market and exports Nafta, bunkering oils and heavy fuel oil. Plans for a second refinery were announced in January 1998. The US$ 2 billion, 200,000 b/d facility, would be located in the central coastal city of Lobito. However, this project depends on raising the US$ 2,000 million to finance its construction as well as improved export prospects and lasting political stability. The proposed refinery could supply the southern part of the country with LPG and petroleum products. It could also run on natural gas, if available at a competitive cost, thus, producing large volumes of liquid fuels for export (estimated natural gas demand would be about 200 $10^6 m^3/y$).

Three firms, Sonangol, Fina, and Sonangalp, a joint venture between Sonangol (51%) and Petrogal (49%), provide product distribution and marketing in Angola. Plans by Sonangol to attract additional foreign companies to the country's downstream market are being hindered by the markets small size and lack of infrastructure.

3 GAS RESERVES AND PRODUCTION

3.1 Natural Gas Resource Base

Angola has estimated reserves of 700 $10^9 m^3$ natural gas, the second largest in Sub-Saharan Africa after Nigeria. Angola's two offshore oil-producing areas have also proved to be bearing substantial gas reserves. Non-associated gas reserves are currently estimated to be more than 500 $10^9 m^3$. In addition to these reserves, which have so far remained undeveloped, the reserves of associated gas are roughly estimated to be 200 $10^9 m^3$.

The offshore Cabinda area has contributed about 70% of the country's total production and contains about two thirds of the total oil and gas reserves. It consists of blocks A, B, and C spread over a total area of about 5,000 km^2. The second offshore area, which consists of blocks 2 and 3, is spread over an area of about 10,000 km^2 and contains about one third of the total oil and gas reserves.

3.2 Current Production and Usage - Gas Flaring

Gas production in 1998 was about 8.0 $10^9 m^3$, of which over 70% (5.6 $10^9 m^3$) will be flared or vented and about 15% (1.2 $10^9 m^3$) re-injected to aid in crude production. However, non-existent gas pipeline infrastructure, undeveloped domestic and regional markets, and lack of financial resources to promote gas-based export schemes have hindered Angola's development and usage of natural gas in its energy sector.

Angola is currently responsible for about 30% of the total gas being flared in Africa and is next only to Nigeria in terms of the total gas being flared. The total estimated energy-related Carbon Emissions as a result of flaring nearly 13 $10^6 m^3/d$ of gas in 1996 were 3.16 10^6 tonnes. At the estimated rates of associated gas production from existing producing fields, Angola's gas flaring may reach about 18 $10^6 m^3/d$. This in addition to being a serious waste of a potentially valuable non-renewable resource has been a significant source of environmental pollution.

Eliminating flaring of about 15 $10^6 m^3/d$ of gas will have substantial environmental benefits. In addition to the benefits derived from gas utilisation (the estimated lost opportunity value as a result of flaring is well over a billion US$ based on equivalent LNG costs), recovering about 15 $10^6 m^3/d$ of gas from flaring will reduce carbon emissions by 6 to 8 10^6 tonnes annually.

4 GAS DEMAND

Current Use

Production of associated gas has been rapidly increasing and the majority of the gas produced is being flared. Limited economic development caused by the prolonged civil unrest has prevented the development of a domestic gas market or gas infrastructure in Angola. This lack of domestic demand means that all the natural gas produced will have to be exported and/or transformed for export, till the time a domestic market is developed and a distribution system put in place.

5 DEVELOPMENT PROSPECTS

Natural Gas development in Angola has been and continues to be hindered by three major factors:

(1) The rate of return on oil investments compared to gas is 3:1 and the contractual agreements with the operating IOCs have no explicit provisions for development of natural gas.
(2) Lack of domestic and regional markets for gas due to minimal economic development.
(3) Increased political risks as a result of over 20 years of civil war. These are more significant for gas projects, which have to be located onshore, while majority of the oil production as well as exportation is done from offshore facilities.

5.1 Power Generation

Angola is especially well endowed with potential sources for the production of electricity, both hydroelectric and thermal (using locally produced oil and gas). As of 1996, the electric generation capacity was 617 megawatts (MW) while electricity generation in 1996 was 1.86 10^9 kilowatthours (1.86 TWh) and the electricity consumed was 1.73 TWh.

Electricity supply in Angola consists of three separate grids and numerous isolated systems. The three main systems are associated with the basins of three important rivers; the Kwanza for the Northern system; the Catumbela for the Central system; and the Cunene for the Southern system. These systems supply the main load centers in Angola; Luanda (in the Northern System); Benguela, Lobito and Huambo (in the Central System); and Lubango and Namibe (in the Southern System). The main isolated systems are those of Cabinda, Uige, and Bie. Another important system in the province of Luanda Norte belongs to the mining company ENDIAMA and was mainly used for diamond mining activities.

The northern system, which covers the capital city of Luanda and its close suburbs, is the biggest consumer and accounts for nearly 80% of the total electricity consumed. Electricity consumption has been severely constrained by the war situation and the unceasing supply interruptions. In spite of the booming population growth in Luanda (estimated to have more than doubled since 1987 to about 4 million people today), the growth in electricity demand has been less than 2% on an annual basis. The stagnation results from the near total collapse of the industrial activity (presently working at around 10% of its theoretical capacity).

Significant portions of the generation and transmission facilities were damaged during the civil war. The central system has been hit repeatedly by UNITA, which in the 1980s put the Lomaum station and a substation at Alto Catumbela out of commission. Many of the power lines in the central area and in the north-west have also been cut by UNITA. As a consequence of the poor reliability of the power supply, self- generation is widespread in Angola. Many businesses have installed their own generators and produce approximately 20% of the total electricity generated in Angola (notwithstanding the fact that the cost of generation is 50-70 ¢/kWh compared to 5-10 ¢/kWh for a conventional hydro/thermal plant). Among the few large consumers relying exclusively on their own power generation is the Fina refinery, which is supplied by a 12 MW naphtha-fired gas turbine.

Of Angola's six dams, only three (Cambambe, Biopo, and Matala) are functioning. Under the recent renovation plan, Cambambe will receive US$ 70 million, Biopo US$ 3 million, and Matala US$ 20 million for renovation and upgrades. The other three dams (Mabubas, Lumaun, and Gove) were severely damaged during the war. Thus, most of the present system urgently requires rehabilitation. The GOA should weigh carefully the feasibility of rehabilitating this hydroelectric capacity against the time and cost it would take to put up cheaper and faster alternatives on stream.

Since the planned US$ 2 billion 520-megawatt (4 x 130 MW) Capanda hydroelectric project on the Kwanza River is not expected to be commissioned before the year 2002, the options for the additional generation capacity, which is urgently required, include setting up new thermal units (gas turbines) or upgrading the existing Cambambe hydro plant (raising of the dam to increase installed capacity by 80 MW). Capanda is located some 200 km East of Cambambe, which is about 360 km from Luanda. In case Cambambe is upgraded, an additional HV transmission line from Cambambe to Luanda will be required and this scenario leads to a very unbalanced system where all generating units would be located far from the main load center (Luanda), and all in the same direction. The dependence of Luanda on the transmission lines from Cambambe would then become very critical.

Recent technological improvements in the design, efficiency and operation of combined cycle gas turbines have moved the economics of power generation in favour of natural gas. Gas fuelled power plants often have lower capital costs per unit of generation (typically, US$ 650 /kW versus US$ 1,300 /kW for a coal fired plant with flue- gas desulphurisation (FGD) and US$ 1,000 /kW for a fuel-oil fired plant with FGD), are quicker to build, are more efficient and emit less air pollutants than other fossil fuel based power plants. The rehabilitation of the dams is expected to require more time and investment than would be necessary to build new gas-fired power plants. The new gas plants could also be used during load-shedding periods. The critical factor here is the availability of cost effective gas supplies in the Luanda area (this scenario will also allow for conversion of the two 56.8 MW gas turbines in Luanda, which currently burn Jet B fuel to gas).

5.2 Conventional Uses

The market potential for natural gas usage in the industrial sector is not particularly promising in the short-/medium-term. Among the most acute problems for industrial rehabilitation are shortages of raw materials, unreliable supplies of water and electricity, and labour instability. The decline in domestic production of many raw materials has been especially critical in the decline in local manufacturing. The deterioration of the water supply system has also damaged many industries, especially breweries, as have cut-offs in electricity supply. Furthermore, labour problems, a consequence of a shortage of skilled workers and disincentives to work for wages in an inflated economy, have depleted the local work force. Foreign exchange constraints have also prevented many industries from importing the necessary raw materials and spare parts to maintain or enhance their production capacity.

5.3 Heavy Industry

The main branches of the heavy industry were the assembly of vehicles; production of steel bars and tubes, zinc sheets, and other metal products; assembly of radio and television sets; and manufacture of tires, batteries, paper, and chemical products.

There have been large investments to rehabilitate steel production. In 1983 the government established a company to process scrap metal. The Northern Regional Enterprise for the Exploitation of Scrap Metal, located in Luanda, had the capacity to process 31,000 tonnes of scrap metal and produced 7,125 tonnes of processed scrap metal in 1985, its first year of operation. The government planned to establish another company in Lobito, with the financial support of the United Nations Development Programme (UNDP) and the United Nations Industrial Development Organisation (UNIDO).

The government also controlled the automobile assembly industry through a company founded in 1978 after a Portuguese firm had been nationalised. The company consisted of a factory that assembled light vehicles; a plant, possibly at Viana, that assembled buses and heavy trucks; and a factory at Cunene that built the chassis for all these vehicles. The light vehicle factory was particularly affected by the cutback in imports in 1982, and its output fell in 1983-84 to only 20% of capacity. Likewise, the bus and truck plant has experienced shutdowns because of a lack of parts.

As the industrial sector recovers from the decline due to civil war, these industrial areas would be potential big gas consuming centres.

In industry the only other consumers who could theoretically switch to gas and absorb enough gas to justify investments in gathering and transport are the cement factory and the Luanda refinery, both located near the Kwanza field. At the 1989 output (720,000 t/y of clinker) the cement plant's consumption of fuel oil is equivalent to 60 $10^6 m^3/d$. With the proposed expansion of the factory to 1.5 million tonnes of clinker in the 90s, the fuel demand would increase to about 150 $10^6 m^3$ annually. However, the cement plant currently uses surplus fuel oil costing only about US$ 67.5 $/10^3 m^3$ (US$ 1.8/10^6Btu) while the gas costs compare at US$ 75.0 $/10^3 m^3$ (US$ 2.0/10^6Btu). The same argument applies to the Luanda refinery whose fuel annual oil requirements are equivalent to approx. 40 $10^9 m^3$.

Other industries, which at present account for only 20% of the country's boiler fuel consumption, might annually demand 20-50 $10^6 m^3$ of gas. Thus, the low potential demand for gas and the availability of cheap alternate fuels make the near term development of non-associated gas reserves for domestic use uneconomic. This scenario can change rapidly once the gas supply infrastructure to feed these areas is set up.

5.4 New large scale projects in the pipeline

So far the only large-scale project which could use a sizeable amount of natural gas as feedstock is an ammonia/urea plant proposed for the Soyo area. The project has been under study since the early 1980s. Economies of scale require a minimum capacity of 1.500 tonnes per day (t/d) of ammonia. World-class plants typically have an installed capacity of 2,000 t/d of ammonia and 500 t/d of urea and cost about US$ 450 to 500 million. Capacity utilisation in these plants typically ranges from 80-90 %. The maximum output would, therefore, be about 480,000 t/y of ammonia and 120,000 t/y of urea (based on 300 days of production and 80% utilisation). Given the very limited domestic demand for nitrogen fertilisers (about 12,000 t/y in 1990), the plant would have to sell most of its output abroad. The plant would potentially require about 500 $10^6 m^3/y$. As the normalisation process continues in Angola and the agricultural production rises, the domestic demand of nitrogen fertilisers coupled with export potential could justify a plant of this scale. The potential for regional demand in these products as well as by large importers like India and China may lay the ground for possible Joint Ventures with Sonangol.

5.5 Other Specific Uses

LPG Extraction Potential: A more promising option for associated gas utilisation is the production of LPG. At present, the only facility in which associated gas is recovered for LPG production is located offshore of Cabinda and stored on a moored LPG tanker, Berge Troll. The output, consisting of a 66:34 mixture of propane and butane, is currently at 2.5 10^6 b/y. In 1986 the output was 177,000 tonnes of LPG of which 168,000 tonnes were exported to Brazil. Revenues amounted to US$ 21.3 million and contributed to about 2% of the country's earnings from energy exports. The sales of LPG in the domestic market have been about 57,000 t/y as the average price was approximately US$ 12.4 per barrel for the last 10 years. A LPG fractionalisation project would add about 30,000 t/y to domestic supplies. This would suffice to eliminate high cost imports (10,000 t/y currently) and add about 20,000 t/y to domestic consumption. At present prices, there is little doubt that this quantity of LPG could be absorbed in the domestic market (provided also that bottles and stoves are available).

A potentially feasible scheme that should be explored by the GOA, is exportation of LPG. LPG mixture extracted from recovered gas could be piped to a LPG tanker moored offshore as floating storage. From there the LPG could be exported without fractionation. There is also potential for producing methanol for exportation, which would use most of the LPG produced.

Potential LNG Export Program: World-wide LNG trade expanded by 44% between 1990 and 1996, rising from 73 $10^9 m^3$ to 100 $10^9 m^3/y$ (75 10^6 t/y). The countries with the largest LNG consumption are in Asia, which imported more than 80 $10^9 m^3$ of LNG in 1996. Japan is by far the largest user of LNG, importing in 1996 almost two-thirds of the world's 100 $10^9 m^3$ of LNG production. South Korea is a distant second with 13% of the total, followed by Taiwan with 3%. Taken together, this region imported more than three-quarters of the total production of LNG in 1996. Despite the success of individual LNG projects and the regional importance of LNG, LNG accounts overall for only 5% of world natural gas consumption.

LNG consumption is expected to increase in the future. Developing Asia, which was expected to experience annual gas consumption increases of almost 8%, has been reviewed downwards due to the "Asian Crisis". Much of this growth would have fuelled electricity generation. Infrastructure projects are also underway for natural gas to displace polluting home heating and cooking fuels in major cities such as Bombay, Shanghai, and Beijing. While the Far East is expected to continue being a major consumer, potential new markets are expected to emerge in Southeast Asia (China, India, Thailand, and Philippines), in West Europe (Greece, Turkey, Spain, and Portugal) and South Africa and Brazil. Total world natural gas demand is expected to reach 4.1 $10^{12} m^3/y$ (3,000 10^6 t/y) by the year 2015. Assuming a conservative 7% share of LNG, LNG demand can be estimated to be about 280 $10^9 m^3/y$ (200 10^6 t/y).

Amongst the regional markets, South Africa is the nearest market, which can absorb significant quantities of gas and support a meaningful gas development program. However, Angola may not be the most cost effective supplier for South Africa's gas needs, since it has to compete with Mozambique's Pande and Namibia's Kudu gas fields, both of which are located much closer to South Africa than Cabinda. Since coal is the fuel of choice in power generation, a need for additional gas for South Africa, which can utilise Angola's reserves, seems highly unlikely in the next ten years.

Therefore, a LNG export scheme is an alternative worthy of consideration by the GOA. A single train 3-4 million tonnes per year capacity LNG plant, which would require about 15-18 $10^6 m^3/d$ of feed gas, would cost approximately US$ 4 billion, not including cost of LNG tankers which would cost approximately US$ 250 million each if constructed anew. A primary source of feedstock for such a project is the associated gas from currently producing, presently developing, and future oil fields from the offshore blocks located south of the Congo River. The gas reserves of the region are sufficient to support a 25-year production plateau even at the rate of 25 $10^6 m^3$. Once a pipeline system joining the plant to the supplying gas fields is in place, it would be very easy to extend the pipeline network to potential high demand cities like the capital Luanda and capture the local gas market there, in the industrial and power sectors and in the planned industrial zone of Viana. Moreover, as the demand for the product stabilises, an expansion could be considered, which would also lead to increased upstream investments by the participants to expand gas production at various supply points. This would result in development of previously discovered but yet to be exploited non-associated gas fields to maintain a reliable source of supply. Such a project, in addition to using up the quantity of gas being flared, would provide an efficient commercial use of Angola's natural gas reserves.

The GOA as well as the IOCs should also study the option of using offshore cryogenic loading technology, for loading LNG. Though the technology is still in the development stage, it is expected to provide a significant breakthrough in production as well as loading of LNG, offshore. Since the production capacity of the LNG production vessel would be substantially less than that of a typical land based liquefaction plant (current estimates are in the range of 3.4-3.6 10^6 t/y), this could give a country like Angola significant marketing advantages, such as being able to sell smaller volumes and still have viable production operations. Typical markets for this gas are Brazil, North America and Western Europe, all within economic range of present day LNG ships. These are also markets where LNG to gas to power sector demand is growing, with Independent Power Producers seeking innovative ways to supply their projects. LNG would also help diversify exports and export revenues for Angola and Sonangol.

New Technologies - Gas to Liquids: Gas to liquid technology (GTL) refers to the conversion of natural gas into synthetic hydrocarbon liquids, particularly middle distillates. With the transportation market, in Africa as well as in Europe, emphasising the use of diesel fuel, rather than Gasoline, this process is an interesting alternative for developing natural gas supplies. Petroleum products are far easier to transport and market than LNG. They can be moved in existing pipelines or products tankers and blended with existing crude oil or product streams. No special contractual arrangements are required to sell them, and there are numerous suitable domestic and foreign markets. Royal Dutch Shell operates a project at Bintu (Malaysia) with a capacity to produce 12,500 b/d of middle distillates from 1.0 $10^9 m^3$ of natural gas per year. Other projects under development include the one being negotiated between Exxon and Qatar, aiming at producing 50,000-100,000 b/d of middle distillates, naphtha, and catalytic cracker feedstock from 5-10 $10^9 m^3$ of gas per year.

By commercialising untapped natural gas reserves, this technology will meet increasing demand for diesel in Angola and the whole South African region and partly displace environmentally less-friendly coal and minimise or eliminate the flaring of natural gas at oil production locations. GOA, in collaboration with IOCs, could study the feasibility of such new technologies vis-à-vis conventional processes, and analyse the commercial potential of projects based on these.

Diversifying their petroleum export base into petrochemicals, LNG, piped gas, LPG,GTL and the like, will help Angola meet its domestic, as well as regional, demand in these products and add to its export revenues, which are currently dependant on oil taxes only. These activities downstream as for the upstream can be financed by private sector investments or other interested parties such as large potential consumers (Brazil, Spain, India, China, etc.) of these products who lack the resource base to produce them domestically.

6 INSTITUTIONAL AND REGULATORY FRAMEWORK

The existing institutional framework, within the Ministry of Petroleum in Angola, is mainly geared towards the development of the upstream oil production, which is closely monitored. Gas production, especially associated gas, is bound to increase in the future with new oil fields being put onstream. The Ministry of Petroleum is looking at the possibility of developing an integrated gas-gathering-system in offshore Angola, south of the Congo River. Such scheme would allow the development of synergies unavailable under individual field approach. These synergies could result in gas development projects including some of the options examined above, and require a close co-operation between Sonangol and the IOC's under the umbrella of the Ministry of Petroleum.

7 CONCLUSION

As the recent moves to bring peace are consolidated, Angola has the potential to emerge as a key player in Africa's oil industry both as a major producer and exporter. Once the operations of the IOCs are no longer constrained by security problems, petroleum exploration activity is expected to extend to other unexplored and prospective sedimentary basins, which are estimated to be four times larger than the current producing areas. However, the current flurry of activity is focused on crude production and natural gas continues to be neglected. Over 70% of the gas production is flared, which in addition to being a serious waste of a potentially valuable non-renewable resource has been a significant source of environmental pollution. The more than twenty years of civil war continues to hinder the development of on-shore facilities, which are the essential base for any capital intensive gas development facilities. The GOA is expected to make sustained efforts to bring back peace and start economic reconstruction and to win the confidence of the international business community to attract private sector investment in the natural gas upstream as well as downstream sector. Gas projects, especially international projects, have a long maturity period from decision time to completion; 5 to 10 years is not uncommon in LNG or similar rigid and capital intensive projects because of the complexity in design, implementation, contract negotiation and commissioning. They do have the advantage, where they are well managed, of providing secure and consistent revenues, albeit lower than for oil. In light of the increasing awareness of the environmental damage resulting from gas flaring and the fact that abundant gas reserves, both associated and non-associated, exist in Angola, gas utilisation has a great potential for growth. In addition to diversifying the petroleum export base and hence the export revenues, this development will also lead to increased upstream investments by the participants to expand gas production at various supply points.

CAMEROON

1 INTRODUCTION AND OVERVIEW OF THE GAS AND OIL SECTOR

The Republic of Cameroon is situated on the Gulf of Guinea and forms part of the West Central African Region. The major cities are Yaoudé, Douala, Nkongsamba and the port of Limbé. In 1998, the estimated population was 14 millions for an area of 475,000 km^2.

Cameroon is one of Africa's oil producing countries contributing about 8 million tonnes per annum or 2% of the continent's oil production. The country also has gas reserves estimated at 110 $10^9 m^3$, which are still unexploited. The upstream oil industry is, thus, the key to the economy.

The downstream oil industry in Cameroon is also an important sector of the country's economy. Consumption of liquid fuel products is currently in the region of 900,000 tonnes per annum, excluding smuggling from Nigeria estimated to be 30% of this figure.

The Ministry of Mines and Energy regulates the industry through its national oil company, Société Nationale des Hydrocarbures (SNH). SNH reports directly to the president and is responsible for promoting the development of the country's hydrocarbon resources and management of the state's interests in any discoveries of oil and gas resources.

Cameroon is well endowed with water resources, it is potentially the second hydropower producer in Africa; it has also vast forests. Petroleum has greatly contributed to the economic and social development of the country from 1978 to 1985. During this period, oil export revenues have provided the necessary financing to sustain economic growth. During 1985-86, when oil production peaked (8.9 million tonnes), oil exports revenues had contributed to 18% of GDP and nearly 53% of the share of goods and services. Following the 1986-drop in oil prices from US$ 24 to US$ 15 per barrel the consequent drop in oil revenues had a negative impact on the economy as a whole and on its financial sector in particular. GNP, which had grown in 1986 by nearly 70% in real terms, dropped to -4% in 1987 and -6% in 1988. The spectacular regression in economic activity led the authorities to initialise and introduce reform in the economy.

Since late-70s, petroleum output, essentially crude oil, emerged as the major determinant of national economy. General government policy is that oil exploration, development, and production activities are carried out by international oil companies (IOCs) under a combination of production sharing and concession contractual terms focusing essentially on crude oil. Oil exploration resulted in the discovery of significant natural gas reserves, which remained undeveloped and often relinquished by the IOCs. The country's oil production reached its peak in the mid-80s and is now declining at a fairly rapid rate. The known natural gas reserves, which are far in excess of the local market's needs but not enough to support an export scheme in the form of liquefied natural gas (LNG), have not yet been delineated. As a result, gas resource base assessment is less mature than that of oil and could be much larger than now estimated. Proposals were made over the recent years to recover liquid petroleum gas (LPG) from associated gas being flared offshore and to develop a medium-size field in the Douala estuary or south of Douala for power generation and local industrial use. These proposals, which would have initiated development of natural gas, were not pursued. With oil production now rapidly declining, the general conclusion is that for the country to continue its economic and social development, which is critically dependent on oil production, priority must be given now to making economic use of existing natural gas resources with the objective of maximising effective substitution of oil based products. Although gas utilisation options are more limited than a few years ago, due to current economic downturn, development of natural gas ought to be initiated and pursued. To ensure a sustainable development, efficiency in economic performance should be the primary objective of any gas development operation. In this regard, the development of a small gas field located near Douala, together with the production of LPG, using gas being flared in offshore fields, would be an economically attractive start-up of Cameroon's gas sector development program, for which participation of IOCs could facilitate project financing and minimise the risk of implementation delays.

Petroleum exploration in Cameroon began in the late 1940s. Exploratory drilling started in 1954 near Douala, where a number of surface oil seeps have been found. The drilling resulted in the discovery of natural gas in 1955 at an average depth of 2,500 m, close to Douala City, in the Logbaba area, where four producing wells were drilled and shut-in since then. The exploration being driven by oil, the Logbaba gas discovery, which appears of a small size, was not delineated and remained unknown with regard to the quantity of gas it really contains. The activity was, then, shifted to the offshore area between Cameroon and Nigeria in the Rio del Rey basin in the Niger delta, where significant oil and gas quantities were discovered since the early 1970s, within water depths of less than 70 m. Nearly all producing fields are about 50 km from the coast.

2 GAS AND OIL POTENTIAL

2.1 Exploration and Production

The first significant oil discovery was made in 1972 with the d'Ekoundou field by ELF. Since, an intensive activity will lead to more discoveries of larger fields as Kole (1974) Kombo and Bravo Marine in 1976 also by ELF, Lokele in 1977 by Pecten/Shell and Moudi in 1979 by Total.

Rio del Rey's oil fields have been put into production since 1978 and have so far been Cameroon's only source of oil production. The production peaked in 1986 with approximately 9.5 10^6 t/y and, then, declined to level off at about 8.5 10^6 t/y from 1987 to 1990. Since 1990, it started declining at an increasing rate, reaching about 10% in 1993 with 6.2 10^6 t/y and more than 14% in 1994 with about 5.5 10^6 t/y . Elf is the largest producer contributing approximately 75% of the country's yearly production, followed by Shell-Pecten with 22% and Kelt, which acquired Total's assets in 1994, with the remaining 3%. Reportedly, proven remaining oil reserves are estimated at about 33.5 10^6 tonnes, implying a reserves/production ratio of only 6 years. Natural gas production has so far been limited to associated gas at an average rate of about 2.5 $10^6 m^3/d$ of which almost one-third is being used within the fields for power generation and in oil production, the remaining being flared. Most of the gas now being flared comes from the western fields of the basin.

Gas flaring has been and continues to be of concern to the Government. Obviously, flaring has always been a costly waste of a potentially valuable resource. Options for recovering Rio del Rey's associated gas for liquid extraction and commercial uses were never effectively assessed. Possibilities of eliminating or minimizing gas flaring, including liquefied petroleum recovery (LPG) and commercialisation of gas were reportedly discussed between government officials, operating companies, and, to some extent, international development agencies, but never pursued. While this report does not imply that a recovery scheme for Rio del Rey's 1.5 to 2 $10^6 m^3/d$ of associated gas (7,500 to 10,000 barrels of oil equivalent) is economically viable, it suggests that a gas utilisation study for such a rich gas, which has been flared for more than 17 years, would not only have addressed the Government's concern but facilitated the start-up of the country's natural gas development program. Such a study would have been highly beneficial if it was carried out at an earlier stage of the production life of the fields. However, with the major oil producing reservoirs now being in their depletion phase, utilisation of currently flared gas, including for an LPG extraction operation, which seems viable given the potential demand for local market and regional exports, needs to be carefully assessed. As more gas will be required for oil production (gas lift), the overall gas flaring will continue to decline, reaching about 1.0 $10^6 m^3/d$ within the next a year and half.

2.2 Future Potential

Following the discoveries made in the Rio del Rey basin, the petroleum exploration was extended to Cameroon's remaining offshore area, which is within the Douala basin, particularly in the Bay of Cameroon. Encouraged by some preliminary results, IOCs intensified their activities along the southern coastal area down to the border with Equatorial Guinea. Exploration activity continued in the Douala basin until the mid-1980s after which it started declining as most of the discoveries made were of small to medium size gas accumulations. Although substantial quantities of gas contain a high level of condensate, none of these discoveries were developed and some of them were simply relinquished.

Most of the operators consider the Douala basin, which is separated from the Rio del Rey basin by a volcanic zone, as a gas prone area with a fairly good potential, but highly unlikely to result in sufficient quantities of gas to support an LNG export scheme in the foreseeable future. As of now, a very limited petroleum exploration activity is being carried out in the Doula basin. The other parts of the country, where some speculative potential exists, would be in the Logone Birni and Garoua basins, which seem to be an extension into northern Cameroon of the rift basins from Chad (Bornu basin) where reportedly promising prospects have been identified. However, no petroleum exploration has been carried out in Cameroon's Birni and Garoua basins for which international oil companies (IOCs) seem to express little or no interest, except for two contract areas held undrilled since 1980 by Elf/Pecten.

According to some IOCs, Cameroon's overall oil and gas potential remains good. Some estimates indicate that future potential oil and gas discoveries could increase the country's reserves by as much as 1 billion barrels and more than 560 $10^9 m^3$ of gas. More than one half of these projected discoveries would be made in the Rio del Rey basin in the Niger delta. Other IOCs are more conservative about the country's future oil and gas potential, saying that both the Niger delta, of which approximately 10% is on Cameroon's side, and the Douala basin have been fairly explored. Based on these IOCs, future discoveries within existing producing areas would be limited and any future potential might be within greater water depths, and, therefore, costly. Most of the IOCs, however, tend to agree that based on past exploration history, Cameroon's future oil and gas discoveries are likely to be made of small to medium size accumulations, requiring, therefore, complex and costly exploration techniques. While no new significant petroleum exploration has started yet, in spite of numerous contractual incentives introduced by the government over the last few years, Cameroon's oil production continues to decline.

3 GAS RESERVES AND PRODUCTION

Natural Gas Resources Base

Based on currently available data, Cameroon's total (initial in place) natural gas can reasonably be estimated at 260 $10^9 m^3$ of which: (i) 200 $10^9 m^3$ would be in the Rio del Rey offshore basin, consisting of up to 165 $10^9 m^3$ of non-associated gas and up to 35 $10^9 m^3$ of associated gas; and, (ii) 60 $10^9 m^3$ in the Douala offshore basin, all of which as non-associated gas. Of the Rio del Rey's 200 $10^9 m^3$ initial gas in place, about 130 $10^9 m^3$ can be considered as proved reserves, consisting of approximately 72 $10^9 m^3$ of non-associated gas, 22 $10^9 m^3$ of gas-cap gas and 35 $10^9 m^3$ of associated gas. Of the 35 $10^9 m^3$ associated gas, about 17 $10^9 m^3$ (48.5%) has already been produced. Rio del Rey's remaining 70 $10^9 m^3$ can be considered as probable and possible reserves consisting of about 65 $10^9 m^3$ of non-associated gas and about 5 $10^9 m^3$ of gas-cap gas. Of the Douala basin's 60 $10^9 m^3$ initial gas place, about 40 $10^9 m^3$ can reasonably be estimated as proved reserves and 20 $10^9 m^3$ as probable and possible reserves. Most of the natural gas reserves so far established in the Douala basin are within the southern coastal area, off Kribi and Sanaga and to a limited extent in the Douala Estuary, at Matanda. Since no oil production has been established yet in the Douala basin, only a fraction (0.6 $10^9 m^3$) of the known reserves can be considered as associated gas.

Except for remaining associated gas estimated at 18 $10^9 m^3$ and gas-cap gas estimated at 22 $10^9 m^3$, Cameroon's natural gas reserves, all of which non-associated, are undeveloped. These reserves consist of about 42 fields of small to medium size, with total proven reserves of about 72 $10^9 m^3$ in the Rio del Rey offshore basin and about 10 fields of small to medium size, with total proven reserves of about 40 $10^9 m^3$, in the Douala basin. Of these 10 fields, one is onshore at Logbaba near Doula and the others are offshore in shallow waters along the southern coast, except for Matanda, which is in the Douala Estuary some 20 km from Douala City. Most of these fields, particularly those in the Douala basin, were discovered and established on the basis of one and sometimes two wells except for Logbaba where 4 wells were completed. Since the exploration was oil driven, most of the gas discovery wells were not fully evaluated, but tested enough to confirm the gas accumulations and establish some broad production parameters. Using conservative recovery factors of 60 to 90%, the recoverable reserves can reasonably be estimated at: (i) 110 $10^9 m^3$ of proven reserves consisting of about 73 $10^9 m^3$ in the Rio del Rey offshore basin and about 37 $10^9 m^3$ in the Douala coastal offshore basin; and (ii) 80 $10^9 m^3$ of probable and possible reserves of which 64 $10^9 m^3$in the Rio del Rey offshore basin and 16 $10^9 m^3$ in the Douala offshore basin.

4 GAS DEMAND

For many industrial activities in Cameroon, natural gas is clearly the best alternative to the various other fuels, particularly given the country's rapidly declining oil production. The main natural gas consumption centre would be Douala where most of the country's industrial activity is located. A residential and commercial market does not appear to be prospective for now, although a demand may develop for it once the distribution system for the industrial sector becomes operational. In fact, experience of gas use in other developing countries has shown a pattern of rapid demand growth, following introduction and availability of natural gas, and this could well be the case in Cameroon.

5 DEVELOPMENT PROSPECTS

The hydraulic resources of Cameroon are concentrated in four major areas irrigated by several streams: the Atlantic Basin in the West (Sanaga, Nyong, and Ntem), the Sanaga and Benoue in the North (Niger River) and the Chad Basin in the extreme North.

Main hydropower capacity is on the Sanaga river and Benoue dam, which provides Sonel with the necessary production and is based on two separate networks and around forty independent thermal power producers in forestry and other economic interests. In 1991, hydropower represented 98% of Sonel, however, thermal power increasingly backs-up or replaces hydropower with lasting drought. Sonel production doubled between 1976 and 1991 from 1,300 GWh to 2,700 GWh.

From 1984 to 1989 crude exports were dominated by IOC with 10% of capacity 6.65 10^6 tonnes in 1989. The rest is refined in Limbe by SONARA with 2 10^6 t/y of installed capacity upon its commissioning in 1981.

5.1 Power Generation

Generation capacity and anticipated growth in demand: The southern interconnected system (where Douala is located) is characterised by an important generation overcapacity, which, considering the limited future demand growth prospects, seems to leave no place for any new power plant before the year 2004. The only significant investments in the coming years will probably concern the transmission network, in order to improve the security of supply to Yaounde and the stability in the western part of the network. The present share of thermal power in the interconnected system is almost negligible. Whatever investment programme, this share will remain very low (below 5%) over the next 15 to 20 years, since the existing hydro infrastructure is sufficient to meet the demand in base and medium load over that period.

Power projects "in the pipeline": Tenders are being called for the 1,050 km Doba-Kribi Oil Pipeline linking the port of Kribi in Cameroon to the oilfields at Doba and Kome in Chad. The capital cost is estimated to US$ 3 billion. The construction has been delayed and production is not expected to start until year 2002-2003. Maximum capacity is 225,000 b/d and duration of production is thirty years. There is also a need to construct a bridge on the Mbere River and rehabilitation of dirt roads is also required.

Potential of converting existing power plants to natural gas: When additional capacity is needed (2004), there is a clear interest in diversifying the system by introducing gas turbines. What the system requires at that time is a means to supply peak power, especially during the dry season, without having to bear high investment costs. Consequently, no hydroelectric scheme appears competitive compared to light thermal units. Even the Lom Pangar regulation dam, which is relatively cheap (no power house) and correctly addresses the problem of hydro power availability during the dry season, still raises the investment costs too high to be economically attractive. All other hydro options, such as Nachtigal or Njock, are definitely too expensive to be considered as relevant options for the next 20 years at least.

Natural gas-fired gas turbines appear as the least-cost option. The first set would be needed in 2004 or earlier to avoid re-inforcing an HV transmission line that would prove more expensive. Other sets would be needed from 2010 onwards. However, yearly load of these gas turbines, and, thus, gas consumption, would remain low, as they would be used for peak shaving. In order to limit the costs of gas production and transportation infrastructure (that would have to be sized for high peak consumption), gas turbines should be constructed as close as possible to the gas source. Conversely to energy demand patterns in most countries of the region, power generation is not likely to become the driving force for gas development, which will have to driven by smaller gas uses.

5.2 Conventional Uses

Industrial activity and industrial areas: The country's industrial activity, mainly concentrated in the Douala's area, continues to rely on fuel oil while natural gas is within its reach. In fact, some 150 to 500 $10^6 m^3$ of rich natural gas reserves discovered and confirmed with four wells some forty years ago at Logbaba, near Douala, remain closed. Another 1.4 $10^9 m^3$ of similarly rich gas reserves made and confirmed with two wells some fifteen years ago at Matanda, in the Douala Estuary shallow waters about 18 km from Douala, also remain closed. As there has been a world-wide growing interest in the use of natural gas, the government initiated, with the assistance of UNDP, a National Gas Development Master Plan (NGDMP), which was developed and updated in 1993. Development of Logbaba was considered first, but due to the reluctance of the concession holder Elf, the consultant finally recommended the Matanda offshore field. Not much has been done so far for Matanda, which appears to be too large for the existing market unless some larger consumer (such as power generation) adds a significant load to the industrial potential market.

Economic activity in Cameroon is concentrated in Douala, the country's main harbour and largest city. By African standards, industrial activity is far from being negligible. Industry accounts for about 24% of the GDP, with the manufacturing sub-sector representing about half of the total. In Douala, where fuel oil consumption accounts for 60% of the country's total, all conventional types of manufacturing industry are represented, including agro-industry (breweries, dairy products, cookies and candies, noodles and pasta, etc.), textile, glass, chemicals (soap and detergents, rubber), cement, and metal industry. The large and medium-scale industry gathers around 30 plants, which account for 80% of the fuel consumption. According to the industrial survey performed within the framework of the NGDMP, the actual operation of the manufacturing sector was only 60% of its nominal capacity, however, partial updating in 1995 shows that the current operating level might well have significantly increased, in particular since the devaluation of the CFA Franc in January 1994. The new exchange rate has allowed Cameroonian products to compete efficiently with similar foreign products, in particular, from Nigeria, thus, enabling some factories to work close to full capacity, which has not been observed in *Cameroon since the late 1980s. In addition to Douala, large, stand alone facilities* are located outside the main conurbation, including the refinery Sonara at Limbe, 70 km north of Douala, and the aluminium factory Alucam at Edea, 60 km south of Douala.

Two major industrial areas, Bassa and Bonaberi, are located in the Douala suburbs. The larger one, Bassa, extends over a significant tract of land in the eastern part of the city and gathers about 80% of the city's industrial activity. The smaller one, Bonaberi, stretches along the road that leads to Limbe, on the northern side of the river Wourri. Both areas are located within 15 km of the city centre. The NGDMP survey was conducted among 24 of the largest industrial facilities located in Douala. Total fuel consumption amounted to 28,450 tonnes of oil products; most of it consisting of high quality, low sulphur fuel oil known as FL 1500. Minor quantities of diesel oil, LPG and used oils were found, in particular in the glass and metal industries. Because industrial activity was slow in the early 1990s, potential fuel consumption is actually much higher. It was considered that if all facilities were working at their nominal capacity, then fuel consumption would increase by 7%, thus, reaching 48,000 tonnes of oil products. In FY1995 fuel oil consumption by the industrial sector (countrywide) was 45,220 tonnes. Diesel oil consumption as a thermal fuel, i.e. excluding uses for transportation and power generation, is only marginal in Douala, while LPG sales to the commercial and industrial sector represent about 10% of total LPG consumption, i.e. about 2,500 t/y in average. Potential natural gas demand of the industrial sector in the Douala area amounts currently to 50 $10^6 m^3/y$

Supplying other industrial centres outside Douala would most probably not prove feasible. Limbe, where the Sonara refinery is located, is only 70 km from Douala. There might be some potential there for using gas in the refinery, which should be assessed. However, it is unlikely that natural gas could compete with both the refinery gas and the fuel oil in excess currently burnt in the refinery. Yaounde, the country's political capital, is 260 km east of Douala and industrial activity is limited to a few plants, whose consumption cannot make a gas pipeline project economic, as a minimum demand of around 500 $10^6 m^3/y$ would be required to make a pipeline feasible.

Potential for developing small gas fields near industrial centres: Following a review of existing known gas reserves in the Douala area, it appears that the least cost option to supply natural gas to Douala's industrial sector would be to produce the Logbaba field, which is located within the city, next to the industrial area. For the Matanda offshore field, the minimum required investment cost would be at least twice higher than for Logbaba with, in addition, a minimum optimum well flow rate far in excess of the market's short- and medium-term needs. With regard to Logbaba, the gas reserves are estimated to be between 150 to 500 $10^6 m^3$, which would provide a delivery rate within the utilisation capacity of existing industrial sector, estimated in the range to 40 to 50 $10^6 m^3/y$. Because of good reservoir characteristics, Logbaba could be produced with a minimum number of wells. In addition, its reported high liquids content gas could be processed using small skid mounted LPG and condensate recovery unit, which would significantly enhance the project's economic viability. Assuming a 500 $10^6 m^3$ reserves, Logbaba field could be produced for 10 to 11 years at about 100,000 to 135,000 m^3/d, the expected demand after 10 years. To initiate Cameroon's gas utilisation and development programme, production of Logbaba gas seems to be the most appropriate small-scale operation. Assuming a distribution system for about 150,000 m^3/d, including gas conversion cost of selected industries, the drilling of two production wells and a limited seismic coverage, a very rough estimate indicates an investment cost of about US$ 26 million (including US$ 8 million for the distribution network) compared to US$ 50 to 60 million for Matanda (including production and distribution).

Once Logbaba has reached its full production potential, over say a decade, on the basis of the above consumption and reserves levels, it will be necessary to bring in another gas field on stream to ensure continuity of gas supply with the expected growth in demand. The best option is the Matanda field. Logbaba is expected to be depleted after about 10 years. Developing the Matanda field would aim at compensating for the depletion of Logbaba, while downstream installations; in particular the distribution network would have had time to expand to meet full market capacity. Its confirmed reserves are about three times those of Logbaba, i.e. 1,400 $10^6 m^3$, and the gas is rich in condensates. Investments needed to bring the gas to shore are estimated in the order of US$ 31 million, including a transmission line to bring gas from the platform to the industrial zones as well as LPG and condensates recovery facilities. The decision to put this field on stream would come after the initial phase of introduction of gas use in Douala, i.e. when the industrial sector has fully understood the advantages of gas utilisation. The Matanda field would ensure the long term supply security of both the Bonaberi and Bassa industrial areas. Moreover, Matanda is within free acreage (sole ownership of SNH), exploiting the field would not require drawn out negotiations with operators, and SNH could set as an incentive, competitive prices for gas over liquid fuels, in order to boost Cameroon's gas sector development program.

5.3 Other Specific Uses

- Natural Gas to Liquids (NGL) Extraction Potential
- Potential demand for local and regional LPG markets
- Potential for Compressed Natural Gas (CNG)
- LNG export potential
- Gas to Liquid Technology (GTL)
- Petrochemical Industry

6 INSTITUTIONAL AND REGULATORY FRAMEWORK

Like many African oil and gas producing developing countries, Cameroon has yet to introduce natural gas in the country's energy balance. The Natural Gas Development Master Plan recommended that a natural gas development strategy should be developed as soon as possible, but so far no sector related policy initiative has been undertaken. This is apparently due to the fact that: (i) natural gas continues to be somehow largely ignored in favour of crude oil, which is the core of the country's economic development; (ii) contractual arrangements with operating IOCs have no specific provisions for development of natural gas; (iii) introducing natural gas as a source of energy into urban areas usually requires complex and costly operations, to which no local institution is familiar or prepared for; (iv) decision makers are not always kept aware of the long-term economic benefits, which can be derived from domestic use of natural gas and; (v) the country lacks the long-term financial resources required for development of natural gas. Société Nationale des Hydrocarbures (SNH), which was created in the early 1980s to represent the government's participating share in oil exploration and development activity carried out by IOCs, lacks the necessary institutional structures and the basic information to deal with natural gas.

In 1996, Government of Cameroon decided to undertake the drafting of a Gas Code and entrusted SNH to prepare the draft document. The Gas Code would cover both (i) the place of natural gas in the upstream activities, and (ii) the institutional and regulatory framework that would govern the downstream activities, in particular transmission and distribution. Although SNH had extensive skills and experience with regard to upstream oil, they had no specific expertise in upstream gas and limited knowledge of institutional matters with regard to downstream activities. Thus, SNH requested Bank's assistance to bring support in monitoring the drafting of the document. Phased meetings enabled work to progress at reasonable pace, including an extensive presentation of the Gas Code objectives and contents in July 1997, during which SNH's draft final document was reviewed and commented upon. The Gas Code is now being reviewed at the ministerial level before it goes to the Parliament.

CÔTE D'IVOIRE

1 INTRODUCTION AND OVERVIEW OF THE GAS AND OIL SECTOR

The Republic of Côte d'Ivoire became independent from France in 1960. The country is located in Western Africa, bordering the Atlantic Ocean. With 322,000 km^2, it has a population of 12 million. Côte d'Ivoire's economy is heavily reliant on agriculture (primarily cocoa and coffee). Measures to diversify the economy, including the introduction of non-traditional cash crops and expansion of the industrial sector, have been met with some success. The Ivorian economy has experienced strong growth since 1995. GDP is US$ 10.8 billion, the GNP has grown at an average of 6.6% from 1995 to 1997. Inflation has fallen from 14.3% to 5.6%. Debt restructuring, privatisation, and Build Operate Transfer (BOT) projects are some of the steps the Government of Côte d'Ivoire is taking to help sustain the economic growth. This has been translated into a substantial increase in primary energy demand, production and consumption.

The rapid development of the Côte d'Ivoire's gas industry began with the oil policy reforms of the early 1990s. The reforms led to a revival in the exploration and production of both oil and gas resources, which had been translated into the signature of several PSCs involving independent oil producers, and to successful promotion rounds to sell additional acreage, in particular deep sea blocks. In less than a decade, four upstream projects and as many downstream projects (electricity production, industrial distribution, and even export of electricity) have been developed. Côte d'Ivoire is, thus, one of the fastest growing of Africa's sub-Saharan nations, in terms of the development of its hydrocarbon industry.

Côte d'Ivoire is also one of the few Sub-Saharan African countries, along with Nigeria, Gabon and South Africa, which uses natural gas in the domestic market. Since April 1996, gas is produced at two offshore fields operated under a production sharing contract (PSC) by the independent US oil company United Meridian International Corporation (UMIC). UMIC is associated to GNR, Pluspetrol and the World Bank Group's IFC, and the state-owned oil company Petroci.

2 GAS AND OIL POTENTIAL

The gas sector has recently experienced rapid development, thanks to the reform of the Government's gas and oil exploration and production fiscal regimes at the beginning of the 1990s. Two structures are in production on the CI-11 block: Lion, where gas is produced in association with 20,000 barrel of oil per day, and Panthère, which produces only gas. Proven reserves in both fields amount to approximately 6.9 $10^9 m^3$. Gas is transmitted to Abidjan by a 14", 80-km long, pipeline with a current capacity of 1.1 $10^9 m^3/y$. The gas terminal is located in Abidjan's port area of Vridi. In addition, UMIC holds concession agreements on three other offshore blocks, including CI-01, located south-east of Abidjan close to the Ghanaian border; several fields (Eland, Kudu, Ibex) have been identified and assessed and proven reserves have been certified to the amount of 8.6 $10^9 m^3$.

Another PSC has been concluded with a group of investors led by another US independent, Apache Oil, which includes the French power utility Electricité de France (EDF) and SAUR (a water supply utility, subsidiary of the French civil works contractor Bouygues), along with International Finance Corporation (IFC) and the state company Petroci. The consortium holds the concession permit on block CI-27, since Phillips relinquished all its acreage in 1989. The block, adjacent to UMIC's CI-11, includes Foxtrot, a non-associated gas field that had been discovered by Phillips in the early 1980s, together with neighbouring Lion and Panthère. Foxtrot was put on stream in 1998.

3 GAS RESERVES AND PRODUCTION

Natural Gas Resource Base

Total proven reserves are estimated at around 40 $10^9 m^3$, of which approximately half are located in the Foxtrot field. All reserves are offshore and are divided between 14 different fields in 7 blocks owned by 3 consortiums. Three oil/gas fields are currently operational: Lion and Panthère and Foxtrot. Others should be developed soon: Kudu and Espoir. Recoverable gas reserves are around 20 $10^9 m^3$. When production reaches plateau in 2001, yearly output will be 0.5 $10^9 m^3$ and gas will be transmitted by a dedicated transmission pipeline to the gas terminal at Vridi. Projected annual gas demand is ($10^9 m^3$):

Year	2000	2002	2004	2006	2008	2010	2015
Demand	1.33	1.57	1.78	2.04	2.04	2.08	2.08

It would appear that the proven reserves of 40 $10^9 m^3$ should be sufficient to meet this increase in demand. With demand at 1.5 $10^9 m^3$ a year, current proven gas reserves would last for more than 25 years and for more almost 15 years if demand was to reach 3.0 $10^9 m^3$ a year in the near future (for instance, if gas exports to Ghana were initiated).

4 GAS DEMAND

Current Use

Gas is currently used for power generation and as fuel in the SIR refinery. The larger user is the Vridi thermal power station, located next to the gas terminal. The station was built and is operated under a BOO (build, own, operate) scheme by Compagnie Ivoirienne de Production d'Electricité (Ciprel), a subsidiary of the French groups EDF and Bouygues. It is the first IPP project operating in Sub Saharan Africa. Phase 1 consists of three 33-MW GEC-Alsthom single-cycle gas turbines that were brought into service in December 1995. Using primarily gasoil, they were converted to gas a few months later, in April 1996. Phase 2 consists of a fourth larger unit (120 MW), which was constructed with World Bank financial assistance under the Private Sector Energy Project, and commissioned in the spring of 1997. Annual gas demand for the whole power plant is 500 $10^6 m^3$.

Gas is also supplied to the older Compagnie Ivoirienne d'Electricité (CIE) power station located on a site adjoining Ciprel. This station was the only thermal power plant in Côte d'Ivoire until Ciprel's Vridi plant was commissioned. The CIE plant consists of four steam turbines and four gas turbines with an installed capacity of 314 MW. However, due to inadequate maintenance over the years, it operates at a much lower capacity. Current gas consumption is around 210 $10^6 m^3/y$, depending on actual load and gas demand should significantly decrease after decommissioning steam units #1 and 2 as operating capacity will not exceed 186 MW by then.

The latest gas consumer is the Société Ivoirienne de Raffinage (SIR) refinery, also located in Vridi. Gas is used to replace fuel oil and butane, with an average consumption of 210 $10^6 m^3/y$. Total gas demand of both the power sector and the refinery is currently around 930 $10^6 m^3/y$. With the anticipated sustained growth in economic activity and the consequent increase in demand in the power sector, and the ambition of the Government of Côte d'Ivoire to expand the refining capacity of SIR with possible downstream petrochemical industries burgeoning around it, gas consumption in this sector is likely to increase substantially in the future. While the potential delivery output of the operating fields exceeds the predicted demand, the Government is seeking to develop and strengthen the efficiency of the industrial sector by bringing natural gas into the major industrial areas of Abidjan.

GoCI has recently decided to revamp the status and mandate of the state-owned Société Nationale d'Opérations Pétrolières de Côte d'Ivoire (Petroci). Petroci has been broken down into four entities, including a holding company that holds the State's interests in the sector and in the three new operating companies. Downstream gas operation is under the responsibility of Petroci-Gaz, which includes LPG Distributing and Marketing, while the other two are in charge of "Exploration and Production", and "Industrial Activities and Services" respectively. However, private participation may remain limited for now, as GoCI wants to retain 51% of the equity of each of the three new operating companies, and to sell only the remaining 49% to the private sector. It has already received expression of interest from several downstream gas groups in Europe, Canada and the US.

5 DEVELOPMENT PROSPECTS

5.1 Power Generation

In the spring of 1997, an agreement was signed with the Swiss-Swedish manufacturer ABB and the operator IPS for the construction and the operation of a second IPP, to be located in Azito in the western suburbs of Abidjan. As a combined-cycle power plant, the future station will have an installed capacity of 432 MW. Based on an estimated 50% thermal efficiency and a utilisation rate of 7%, average annual gas consumption is expected to be 680 $10^6 m^3$. Such additional demand will exceed the remaining capacity of Lion and Panthere's maximum output and will require additional gas resources to be put on stream.

The project has, thus, revived the Foxtrot option that had remained idle since GoCI decided to develop Lion and Panthere in the first place rather than Foxtrot. Azito will be supplied by both UMIC (Kudu) and Apache (Foxtrot) fields from the Vridi terminal, while transmitting gas from Vridi to Azito is under GoCI's responsibility, as both UMIC and Foxtrot agreements request only gas to be delivered, take or pay, at Vridi.

5.2 Conventional Uses

Although the power generation and refining sectors are likely to remain the larger gas users over time, the industrial sector should quickly become a major consumer as well. Ivorian industry was severely affected by the crisis of the first half of the 1990s, but has been demonstrating a definite recovery since the devaluation of the CFA franc in January 1994. Conventional industry, i.e. small and medium-size plants that could technically use gas as a fuel (not as a raw material), is to be found mostly in the four large industrial zones located around Abidjan, of which two (Vridi and Treichville) are located in the immediate vicinity of the gas terminal. Abidjan's industrial market represents, according to a preliminary study made by Petroci in 1997, a potential market of 60 $10^6 m^3/y$. The project's cost is estimated at around US$ 15 million and preliminary analysis shows that the project's economics is likely to attract foreign investors, provided that the institutional setting is there to mitigate risks and to allow smooth and efficient relationships between the Government of Côte d'Ivoire (GoCI) and operators, and between the operators themselves. In addition to this market, which has already been identified, there is a significant medium-term potential for co-generation, especially for those industries that are large-scale steam users, such as the food processing industry, the oil mills and soap makers, which constitute the mainstay of Abidjan's light industry. Gas could also be used for cold production (for food and fish processing and food storage/conservation) and for air conditioning in the business areas. In the medium term, the potential industrial market can be estimated at around 80-100 $10^6 m^3/y$ for the four million people Abidjan metropolis as a whole.

5.3 Other Specific Uses

Large-scale Industrial Projects and other Specific Uses: The Bureau National d'Etudes Techniques et de Documentation (BNETD), a public agency under the auspices of the Office of the Prime Minister, is working on three large-scale industrial projects. The first two are designed to develop mineral reserves (iron and nickel) located in the western part of the country (district of Man, about 600 km NW of Abidjan), while the third would include the construction of an ammonia and urea plant to produce nitrogen-based fertilisers. Partners and financing are currently being sought for the sponge-iron and ammonia plants. The nickel project appears to be in a more advanced stage; a Canadian operator, Falconbridge, has shown interest and demonstrated it by concluding an agreement with Sodemi in July 1996. A pilot unit could be operational at the turn of the century; if the results are conclusive, industrial-scale production could start in 2003. Although the main characteristics of these projects are not yet known in detail, when compared to similar projects, potential gas consumption can be estimated at between 200 and 250 $10^6 m^3/y$ for the nickel and sponge iron projects, and up to 800 $10^6 m^3/y$ for a large ammonia-urea production unit.

6 INSTITUTIONAL AND REGULATORY FRAMEWORK

The existing institutional and regulatory framework for the downstream gas activity in Côte d'Ivoire will need to be strengthened in order to attract capital investments and ensure a level playing field. Regulation is performed according to specific dispositions in the contractual arrangements that govern relationship between gas (and power) operators and the GoCI. As an example, all the activities performed by the consortium led by UMIC for Lion and Panthere operation, including oil and gas production, transmission and delivery, are considered a single operation. With regard to power generation, gas is purchased by the Fonds National de l'Energie Electrique (FNEE), a public financial mechanism lodged within the Caisse Autonome d'Amortissement (CAA). Gas is actually not purchased but bartered against oil from GoCI's share under existing PSCs. FNEE delivers the gas free of charge to CIPREL, then receives electricity at the outlet of the power station and pays the fees charged by CIPREL to produce electricity. CIPREL acts as a provider of services and holds no responsibility on gas supply and ownership. Arrangements with the Foxtrot consortium are similar.

However, such ad hoc arrangements are no longer viable as soon as the gas industry starts to expand, and more players enter the scene. Development of Foxtrot will bring new players on both the production and the consumption sides, not to mention the large gas-based projects, briefly presented in paragraph E above. In addition, gas producers in Côte d'Ivoire are looking carefully at potential markets in neighbouring Ghana, where various schemes aiming at developing gas-based power generation projects are being evaluated.

A full review of existing proven, probable and possible gas reserves would need to be undertaken before further export schemes are considered. Public sector responsibility for defining policy, regulating the sector and unbundling the transport and distribution segments, may require a clearer definition of tasks and objectives. The increased and diversified demand for gas will require the creation of a specialised regulatory body to enforce and monitor sector rule. The need for continuing reforms in this sector will, as in the recent past, bring added benefits to the economy as a whole.

* We Acknowledge the Kind Authorisation of Petroleum Economist Ltd - London *

BANGLADESH

1 INTRODUCTION AND OVERVIEW OF THE GAS AND OIL SECTOR

Bangladesh has a population of about 120 million and covers an area of about 144,000 km^2. Its population density is the fifth highest in the world, averaging 825 persons/km^2. Per capita, the gross national product (GNP) is US$ 300 in 1999. The country's chief agricultural product is rice whose production, despite of natural interruptions in the form of floods and droughts, has more than doubled over the last two decades. Compared to the once dizzy levels of growth of other Asian countries, Bangladesh had a lower but steady growth rate of 5% over the last few years.

Consumption of primary energy is low when compared to the regional standard. Bangladesh depends mainly on biomass energy, for major portion of its energy requirements. The share occupied by petroleum products is about 20%, but most of these products are imported. The country has substantial coal deposits and a coal mine project with Chinese assistance is presently being set up. There is limited hydroelectric potential in the eastern side of the country. With regard to the use of oil and gas Bangladesh held the Second Round Bidding, which drew tremendous response from all the major oil companies. The evaluation of the bids is still under process.

Gas production in Bangladesh commenced in 1960 when the Chhatak field was brought on-stream. Further discoveries were made in the 1960s and 1970s by Shell. Following Bangladesh's independence in 1971, gas production and transmission were nationalised and carried out by the state-owned Petrobangla (Bangladesh Oil, Gas and Mineral Corporation) and its subsidiaries.

2 GAS AND OIL POTENTIAL

Exploration and Production and Future Potential

Petrobangla has had substantial success initially in discovering new fields. Since the late 1970s, known fields were developed and pipelines for the eastern part of the country were installed with financial assistance and advice from international development banks such as the Asian Development Bank and the World Bank. In 1993 the government introduced a new petroleum policy, making it far more attractive to foreign companies to explore and develop oil and gas resources under a production sharing arrangement. The first to sign a production-sharing contract (PSC) was Cairn Energy of UK in May 1994, followed by Occidental Petroleum of US in 1995. In 1996 Unocal signed a Letter of Intent with the Government of Bangladesh after submitting a proposal called the "Western Region Integrated Project (WRIP)" for the development of Shahbazpur Gas Field in the district of Bhola in Barisal. The project consists of the development of the field reserves, the construction of 150 km gas pipeline from southern Bhola to southern Khulna and a 350 MW generation plant. Cairn delineated a new gas field at Sangu at 2.0 10^9m^3/y, off shore from the city of Chittagong in the south-east. Meanwhile, Occidental focused on developing for production the known field at Jalalabad at 1.0 10^9m^3/y in the north-east. Occidental has put on stream the Jalalabad gas fields, near the town of Sylhet. Production is reported to be around 2.8 10^6m^3/d. Occidental won the acreage at the start of 1995. In March 1997, the government offered a Second Round of exploration licenses to foreign companies. Twenty-one major and small companies responded with 38 bids for 12 of the 15 blocks offered.

Gas production up till now has been limited mainly to the eastern part of the country. The Jamuna River, which practically divides the country in half, has made it difficult to supply gas to the Western Region.

In order to get the foreign majors to rise to the challenge of finding more gas, Petrobangla has committed itself to US dollar payment based on a heat value parity price of high sulphur fuel oil (HSFO), equivalent to 75% of the FOB Singapore price of HSFO for onshore gas with a floor of US$ 70 and a ceiling of US$ 120. Domestic gas tariffs were raised recently. Electricity tariffs have been also raised in order to match more closely the long run marginal cost of generation and supply, which in turn would improve distribution standards and services.

3 GAS RESERVES AND PRODUCTION

Natural Gas Resource Base

In Bangladesh natural gas reserves are estimated by Petrobangla to be 650 $10^9 m^3$, of which half are recoverable. Twenty-one (21) gas fields and one (1) oil field have been discovered. Currently twelve (12) gas fields are in production and nine (9) are non-producing fields. The producing fields one Titas, Habiganj, Narshingdhi, Bakhrabad, Meghna, Saldanadi, Sylhet, Kailashtila, Rashidpur, BeaniBazar, Sangu and Jalalabad.

Current Production and Field Usage: Gas Flaring/Gas Lift and Injection

Bangladesh now produces about 8.8 $10^9 m^3/y$ of natural gas all from fields in the eastern part of the country.

4 GAS DEMAND

Current Use

Of the 8.8 $10^9 m^3/y$ of natural gas produced, about 47% is consumed by the power sector; 27% by the fertiliser industry; 13% by conventional industries; 9% by residential users; and 4% by loss from the system.

1460 km of transmission pipeline and 10,800 km of distribution network are connecting the fields to consumers in the east and up to Baghabari in the west.

5 DEVELOPMENT PROSPECTS

Natural Gas is expected to drive Bangladesh's economic development rather than oil, coal and hydro. Natural gas shares 72% (6.5 10^6 tonnes oil equivalent (toe)) of commercial energy consumption in 1997, before oil products; 22% (2 10^6 toe), coal; 4% (0.4 10^6 toe) and hydro; 2% (0,2 10^6 toe). Projections based on existing reserves by Petrobangla show a widening gas between the current production capacity ceiling and expanding demand. The National Energy Policy of Bangladesh estimates the total energy demand to amount to 12 10^6 toe in 2000, 19 10^6 toe in 2005, and 31 10^6 toe in 2010, assuming the GNP growth rate to be 6.4%, 7.2% and 7.7% per year respectively. Accordingly, natural gas demand would rise to 9.8 $10^9 m^3$, 15.0 $10^9 m^3$, and 14.8 $10^9 m^3$ respectively. However, natural gas supply capacity based on proven reserves would reach 10.3 $10^9 m^3$ after year 2000, therefore, new reserves have to be discovered and developed.

5.1 Power Generation

The present installed capacity of electricity is only about 2,800 MW, of which more than 80% is gas fired. Electricity production on a per capita basis is so low that only 15% of the population have access to electricity. The estimated capacity demand for the year 2000 will be around 4,000 MW, which means that an additional 1,200 MW new generation capacity will be needed in a few years.

In order to meet the increasing gas between demand and supply, the government amended the industrial policy and opened the power sector for private investment.

Generation capacity will expand through the commissioning of four 100 MW units by foreign IPP. Two large IPP combined cycle power plants are also to be built near Dhaka, including 450 MW unit in Meghnaghat and 360 MW units in Haripur. In the long term, there are Government plans for two large IPP gas fired plants to be built in the west of the country, on the other side of the Jamuna River. These include a 600 MW plant at Serajganj.

An IPP formula seems to be the best solution to encourage foreign investors in building power plants, and to give a great volume of gas to the market instead of leaving it undeveloped. Bangladesh will avoid electricity surplus and shortage depending on seasonal swings and meet neighbouring countries' electricity market such as India where the electricity demand in Calcutta is continuously growing. Joint venture distribution and marketing companies can be created and will have the responsibility to buy from IPP kW hours, and to sell the electricity to customers either in Bangladesh or in neighbouring countries. This economic relationship can improve the political stability between the neighbouring countries.

Formulas such as Build Operate and Transfer (BOT) can be considered for Bangladesh.

5.2 Conventional Uses

The market for natural gas usage in the industrial, commercial and domestic sectors in important since natural gas is the dominant energy source in Bangladesh. The gas demand for industrial consumption in 1997 shared 13% of the total natural gas consumption. The number of households using natural gas is approximately 900,000. Conventional users are expected to increase in accordance with the development of the distribution network.

5.3 Other Specific Uses

Natural Gas Liquids (NGL) Extraction Potential: Bangladesh contains around 55 million barrels of natural gas liquids (NGLs), which can be used for production of petrochemicals or as a cooking fuel to help reduce deforestation and pollution.

Potential Demand for Local and Regional LPG Markets: About 10,000 tons of LPG is produced annually in the Refinery. A recent study has been undertaken, which suggested a potential capacity of over 120 10^3 t/y, which can be projected for extracting 40,000 tons of LPG from Kailashtila gas field.

Potential for Compressed Natural Gas (CNG): The use of Compressed Natural Gas (CNG) in all types of road transports will decrease the demand of diesel and petrol. In order to develop and popularise CNG, Rupantarita Prakritik Gas Company Ltd. (RPGCL) was formed in 1991. Now there are four CNG filling stations in Bangladesh. It is expected that in the near future, larger amounts of gas will be made available for transportation use.

Export Potential: The concept of exports of gas through pipelines is an option, which Bangladesh is not considering at the present. This is because the objective of the Government is to first cater to the vast suppressed demand within the country itself. At present, Bangladesh allows export of LNG.

Gas to Liquid Technology (GTL): Concerning GTL the project is not of priority in Bangladesh. Among Asian countries only Malaysia started the project based on full experiences of various petrochemical utilisation of natural gas. This new technology could be introduced after the further expansion of exploration and production of natural gas.

Petrochemical Industry: The fertiliser sector is the largest user of natural gas in Bangladesh after power generation. Natural gas as feedstock in fertiliser in 1997 is 31% of total gas consumption. Since agriculture is a major industry in Bangladesh, the domestic product of fertiliser contributes a lot to the country's balance of payment. Currently, all of the agricultural sector's urea fertiliser requirements (1.4 MT p.a.) are met by local production, using natural gas as feedstock. There are plans to build new urea complexes with an average size of 300,000 t/y. Output from the plants will aim to meet the domestic fertiliser demand, at present showing a shortfall of 350,000 t/y. Beside fertiliser, currently there are no petrochemical plants for the production of methanol, ethylene, and other products using natural gas as feedstock.

6 INSTITUTIONAL AND REGULATORY FRAMEWORK

All gas transmission as well as production and processing along with other petroleum related activities are currently undertaken by Petrobangla through subsidiary companies, one exploration and drilling company, two production companies, three transmission companies, and one distribution company. Petrobangla is wholly owned by the Government. The Government's main objectives for the energy sector are to: (a) extend domestic natural gas supply to meet energy demand and reduce the dependence on oil imports; (b) adjust energy prices to promote efficient and economic use of energy;

(c) increase the availability and improve the quality of electricity supply; (d) encourage private sector participation in energy sector development.

7 CONCLUSION

Bangladesh's gas industry has already a major role in meeting the requirements of the energy sector during the last forty years. Production accounts for 70% of the country's domestic commercial energy supply. Bangladesh has expanded various gas markets such as for power generations, fertiliser plants, LPG plants, industrial and residential customers. The Government puts high priority on extending the domestic natural gas supply to meet the energy demand and to reduce the dependence on oil imports in the energy policy. This is backed by its rich indigenous reserves.

VIETNAM

1 INTRODUCTION AND OVERVIEW OF THE GAS AND OIL SECTOR

The establishment of the Socialist Republic of Vietnam in 1976 resulted in the reuniting of North and South Vietnam. The Doi Moi (renovation, literally "New Life") policy was later adopted at the 6th general meeting of the Vietnamese Communist Party in 1986. Doi Moi is the general term for sweeping reforms encompassing the political, the economic and social spheres, and its basic approach is comprised of (1) reinforcing food production and consumer goods and expanding exports, (2) introducing a market economy, and (3) promoting open-door policies toward the outside world. Reforms of the centralised socio-economic system have been proceeding since then and, with the normalisation of relations with the U.S. in 1995 and the achievement of ASEAN affiliation; the country is rapidly gaining high acclaim in the international community. The country recorded a growth rate of 8.8% in 1997 with per capita GDP amounting to USD 317. Considering the impact of the Asian currency crisis, however, the growth rate is expected to drop to 5.5% in 1998. The Government forecasts an average GDP growth rate of 9.5% and an industrial production growth rate of 12.8% over the twenty-year period ending in 2010, and energy supply and demand is the country's most important issue. According to the Vietnam Institute of Energy, the total primary energy supply (TPES) in 1995 was 10.07 million tonnes oil equivalent, while it is expected to expand to 17.93 million tonnes oil equivalent by 2000 and 48.28 million tonnes oil equivalent by 2010. While petroleum accounts for about half of this, there is strong anticipation of the role of natural gas along with hydroelectric and coal energy.

Vietnam's continental shelf remains largely unexplored relative to those of its neighbours, including China, Indonesia, Malaysia, and Thailand. Petrovietnam has made intense efforts to attract international oil companies to explore the country's sedimentary basins, and recent discoveries of commercial quantities of oil and gas have revived interest in exploration. Vietnam's oil and gas resources can help attract foreign investment and meet future energy demand. Crude oil exports are already the country's largest foreign exchange earner, and natural gas reserves provide an environmentally clean way to meet domestic energy needs and could lead to exports.

To fulfil the promise of its oil and gas resources, however, Vietnam must provide the right framework for private sector development. A Petroleum law was passed in 1993 and a follow-up decree was passed in 1996. Fiscal incentives—such as acceptable fiscal terms in production sharing contracts—are needed to encourage hydrocarbon exploration and production. An efficient, transparent system is needed to oversee contracts and award acreage for exploration. And gas pricing policy must be made clear and consistent, and include special provision for marginal fields.

The perceived potential of different oil and gas basins helps determine appropriate terms for exploration contracts. When considering investment in Vietnam, international oil companies compare it with opportunities elsewhere. In case of gas they compare it with investments in other Southeast Asia countries. At this stage Vietnam cannot compete directly with its neighbours, which have much larger gas reserves. Twenty-two points, plus triple-word-score, plus fifty points for using all my letters. Game's over. I'm outta here. Still, it needs to develop competitive policies and fiscal terms to make itself attractive relative to countries with similar investment opportunities. To that end, in November 1998 the government improved fiscal incentives—including tax breaks—to encourage foreign investments in exploration in high-cost and technologically difficult areas.

2 GAS AND OIL POTENTIAL

Exploration and Production and Future Potential

PetroVietnam was established in 1977, the year after the establishment of the Socialist Republic of Vietnam, and was granted authority by the Government to undertake oil exploration and development on its own and to conclude technical assistance agreements for exploration and development with foreign petroleum companies. PetroVietnam concluded an oil exploration and development technical assistance contract with the former Soviet Union in 1981, which led to the formation of the joint venture Vietsov Petro. The company promoted development of the Bach Ho, Rong, and Dai Hung Fields, and succeeded in developing the Bach Ho Field in 1986.

Vietnam has nine onshore and offshore basins. Significant discoveries of oil and gas have been made in five: Cuu Long, Nam Con Son, Malay-Thu Chu, Song Hong, and Hanoi Trough. The size and nature of the hydrocarbon discoveries suggest that the Cuu Long, Nam Con Son, and Malay-Thu Chu basins contain most of Vietnam's hydrocarbon potential. Still, the remaining basins may also hold commercial quantities of hydrocarbons; exploration has been too limited to gauge their potential.

All the discoveries in the Cuu Long basin have been oil, while those in the Nam Con Son and Malay-Thu Chu basins have been mostly gas (some of it containing high levels of liquids) and oil. In terms of barrels of oil equivalent, discovered reserves of oil exceed those of gas, so it would be incorrect to classify Vietnam as a gas province. Most of the discoveries are single-well accumulations or are not fully appraised. Thus, there is considerable uncertainty in the resource estimates communicated by well operators—particularly for discoveries considered marginal at the current state of market and infrastructure availability.

Plans are under negotiation to construct a 600 mm pipeline with an offshore length of 365 km and an onshore length of 85 km from the Lan Tay and Lan Do gas fields in the Nam Con Son basin to the landfall in Long Hai with transport capacity in the range of 6.5 - 7.0 $10^9 m^3$ per year, together with treatment and processing plants. PetroVietnam, BP/AMOCO, Statoil and ONGC have completed a number of studies involving the technical and commercial feasibility of constructing a transportation and treating system.

PetroVietnam and foreign investors is now conducting the pre-feasibility study for the Southwest Gas Project in the Malay-Tho Chu basin, including overlapping areas between Vietnam, Malaysia and Thailand. The Project's potential customers are existing and newly built power plants in the Mekong Delta in south-western Vietnam. The 280km 24-26" gas pipeline capacity is planned for about 2 $10^9 m^3$ per year. Total investment for the project is estimated to be USD 200 million.

3 GAS RESERVES AND PRODUCTION

3.1 Natural Gas Resource Base

According to Petrovietnam, aggregate reserves in July 1997 (with 90 percent probability) were 1040 $10^9 m^3$ associated and non-associated gas. The World Bank has estimated that as of end 1997 the discovered fields in the Cuu Long and Nam Con Son basins contain remaining reserves of 40 and 160 $10^9 m^3$ of gas respectively, of which around one third are proven. The estimates for other basins are Malay-Tho Chu 13 $10^9 m^3$ and the Song Hong 200 $10^9 m^3$. (These and other figures are published in "Fueling Vietnam's Development – New challenges for the Energy Sector". The World Bank 1999) Petrovietnam and foreign companies are negotiating the development of the Lan Tay (42 $10^9 m^3$) and Lan Do (14 $10^9 m^3$) gas fields in Block 06 in the Nam Con Son basin, discovered in 1994.

3.2 Current Production and Field Usage - Gas Flaring/Gas Lift and Injection.

Production of associated gas from the Bach Ho oil field has been increasing gradually along with oil production since 1995. Bach Ho is offshore in the Cuu Long basin, about 120 kilometers southeast of Vung Tau. It is the largest hydrocarbon accumulation discovered so far, with potential oil reserves of more than 900 million barrels. The field was brought onstream in 1986 and has produced 355 million barrels of oil and 8.7 10^9m^3 of raw gas. Daily production from the field is 160,000 barrels of oil and 3.8 10^9m^3 of associated gas.

Part of the gas from the field is used to generate power in Ba Ria and Phu My through a 16-inch pipeline operated by Petrovietnam. The rest of the gas from the field is being flared. A central compressor platform was completed in 1998, extending the transmission capacity of the pipeline to about1.5 10^9m^3 a year. Oil and gas production from Bach Ho is expected to be maintained until 2001 but will then decline to half the current level by 2004–05 and to one-quarter by 2008–09.

4 GAS DEMAND

Current Use

Gas consumption in the northern region is rather small for several industrial users such as bricks, china, glass and other products with annual gas consumption of 40-50 10^9m^3. In the southern region gas consumption is now only for power generation in Ba Ria Power Plant with max consumption of 1.2 10^6m^3 per day and Phu My 2.1 (phase 1) with max consumption of 1.7 10^6m^3 per day.

The significant nonassociated gas discoveries in the Nam Con Son basin give the government an opportunity to develop a new industry based on gas. Associated gas in the Cuu Long basin (from the Bach Ho field) is produced by Vietsovpetro. Petrovietnam receives the gas offshore at no cost and transports it onshore through its pipeline, and the gas is consumed in the Ba Ria and Phu My 2.1 power plants. Nonassociated gas production in the Nam Con Son basin is planned by the private sector (Oil and Natural Gas Corporation of India, BP/Amoco, Statoil). A consortium of producers and Petrovietnam plan to transport the gas through a pipeline and process it at an onshore delivery point. Petrovietnam is planning a gas distribution center to receive and distribute the gas at the Phu My power plant and a pipeline to extend gas distribution to Ho Chi Minh City. To initiate and develop the gas market, the government appointed Petrovietnam as an exclusive gas trader in August 1996. But sustainable development of the country's gas resources will require an appropriate gas policy and industry structure.

5 DEVELOPMENT PROSPECTS

The Government of Vietnam anticipates continued strong GDP growth. The expansion of energy supplies, especially the increase in electrical power, is the issue that has been given the highest priority.

Over the short and medium term the power sector will be the main market for gas in Vietnam. Associated gas from Bach Ho is consumed in the Ba Ria and Phu My 2.1 power plants, and most non-associated gas from block 6.1 will be used for power generation as well, in the Phu My 1, 2, and 3 power plants. Subsequent phases of gas market development will also focus on demand from the power sector.

In addition to the planned uses for gas in electricity generation—including in existing power plants, replacing fuel oil with a potential 0.5 10^9m^3 a year—there is a market for gas in industry. Plans for fertiliser and methanol production, among other industrial uses, have surfaced. Such industries could consume an additional 1.5–2.0 10^9m^3 of gas each year. Moreover, there is potential demand in industries located near the planned extension of the gas transmission and distribution system beyond Phu My and toward Ho Chi Minh City. This demand, now being analysed by Petrovietnam's gas company, is estimated at 0.7 10^9m^3. Thus, there is considerable potential for gas market growth.

Natural gas is planned be supplied to users along the pipeline corridor stretching from Long Hai in the south to Ba Ria, Phu My, and later Thu Duc, and will be used primarily for power generation. There are plans for using gas as a feedstock in the production of fertilisers and as a raw material in the production of methanol, polypropylene, polyethylene and other petrochemical products. There are also plans to supply natural gas to conventional industrial users in industrial zones..

5.1 Power Generation

Total generation amounted to 14,600 Gwh. in 1995 with hydroelectric power accounting for 63%, thermal power for 18.8% (coal: 14.4%, other fuels: 4.4%), diesel generators for 9.7% and gas turbines for 8.5%. Power supplies are expected to continue to increase at an annual average rate of 12%, reaching 66,000 Gwh by 2010. One problem in power generating operations in Vietnam is the considerable gap that is developing between the amount of hydroelectric power that is generated during the dry and monsoon seasons. Power generation drops during the dry season, giving rise to power shortages, while production exceeds the demand during the monsoon season. There is strong anticipation for power generation capabilities using natural gas that will be able to support a stable supply of power, especially in the south. Gas demand for use in power generation is expected to increase to 7 $10^9 m^3$ by 2010. (The World Bank).

5.2 Conventional Uses

PetroVietnam Gas Company intends to build its own medium and low-pressure distribution network to supply industrial customers in industrial zones along the corridor to Ho Chi Minh City. These include the My Xuan - Phu My area with an estimated consumption of 0.7 $10^6 m^3$ per day, the Bien Hoa industrial zones in the largest industrial area in southern Vietnam, and the Cat Lai industrial zones and other industrial zones in Ho Chi Minh City. Potential gas demand in industrial zones is expected to increase to 350 $10^6 m^3$ in 2000, 1,400 $10^6 m^3$ in 2005, and 2,200 $10^6 m^3$ in 2010. In addition to these demands, a feasibility study is currently being conducted for a steel plant based on direct reduction technology with a gas demand of 400 $10^6 m^3$ in 2005 and 800 $10^6 m^3$ by 2010. Upon the discoveries of new gas resources and the maturity of gas market, gas supply to the Central region, even the northern area for industrial, commercial and domestic demand, will be considered.

5.3 Other Specific Uses

Natural Gas Liquids (NGL) Extraction Potential: Vietnam imports most of its LPG from Australia, Malaysia, Indonesia and other countries. However, the intention is to promote LPG production from domestic oil and natural gas. Vietnam is beginning with plans for LPG production using associated gas from the Bach Ho oil field, which in turn is expected to contribute to a further improvement in the balance of payments. NKK of Japan and Samsung of Korea contracted to construct an LPG extraction plant for the Bach Ho Project in 1997 at a cost of $ 60 million, which, when completed in 1999, will consume 300 $10^6 m^3$ of natural gas per year with an annual LPG production capacity of 330,000 tons.

Potential Demand for Local and Regional LPG Markets: Until recently all LPG was imported, a gas processing plant with a capacity of will reach 250,000–350,000 tons of LPG per year has been completed. The production is based on associated gas from Bach Ho.

Petrochemical Industry: Together with a 600MW combined-cycle gas turbine (CCGT) plant, studies are currently proceeding for plans to construct a fertilizer plant (daily urea production: 1,750 tons; daily ammonia production: 1,000 tons) as a part of the Phu My 3 project..

6 INSTITUTIONAL AND REGULATORY FRAMEWORK

Vietnam's Petroleum Law was passed in 1993, and a follow-up implementation decree was passed in December 1996. The law and decree cover petroleum exploration, development, and production. They do not cover main transmission pipelines; they only cover pipelines to the point of delivery to a main transmission line. The law deals only with the upstream oil and gas industry; no mention is made of downstream operations such as gas processing and distribution and retailing of petroleum products and liquefied petroleum gas.

All upstream oil and gas activities on behalf of the state are assigned to Petrovietnam, the state enterprise responsible for conducting petroleum operations and entering into petroleum contracts with organizations and individuals. Petroleum contracts can be production sharing contracts, joint venture contracts, or other forms, and the law specifies model contract provisions. The law and decree also specify rights and obligations of the contractors, as well as royalties, taxes, and fees.

Winning bidders for exploration blocks sign contracts with Petrovietnam, subject to the approval and issue of licenses by the Ministry of Planning and Investment. Then Petrovietnam, which had been acting as the ministry's technical agent during bidding, block awarding, and contract negotiation, takes over administration of the petroleum contract. The law assigns many tasks to Petrovietnam—supervising contractors, receiving operational data, making periodic reports, monitoring compliance with the work programs specified in contracts, and planning development and production after commercial discoveries.

To initiate and develop the gas market, the government appointed Petrovietnam as an exclusive gas trader in August 1996. But sustainable development of the country's gas resources will require an appropriate gas policy and industry structure. This section outlines an approach to developing the gas industry that could attract financing, increase efficiency, provide reasonable quality and prices for consumers, and reduce policy and market risk for private investors.

At this stage Vietnam cannot compete directly with its neighbors, which have much larger gas reserves. Still, it needs to develop competitive policies and fiscal terms to make itself attractive relative to countries with similar investment opportunities. To that end, in November 1998 the government improved fiscal incentives—including tax breaks—to encourage foreign investments in exploration in high-cost and technologically difficult areas.

7 CONCLUSION

Vietnam's gas industry just started in the last five years, however, which development is very perspective, and fast growth is expected in the next five years. Potential largest customers will be power generation, major industrial plants and the new industrial zones. It is expected that natural gas uptake by industry will proceed quite slowly at first, but will then grow rapidly around year 2003 as the new industrial zones and major plants begin to come on stream. Based on schedule and size of the major plants, mainly power plants, insufficient gas supply will occur in the period from year 2000. Despite recent efforts to explore gas fields the proven gas reserve in Vietnam is not much larger than those of other gas producing countries. Undiscovered gas reserves in Nam Con Son and Malay-Tho Chu basis are expected to change the situation.

The government should issue a gas policy statement to clarify the short- and long-term structure of the gas industry. This statement should take into account the need to attract private capital for both upstream and downstream gas investments and to expedite the completion of the basic transmission pipeline, which could stimulate further exploration and gas discoveries.

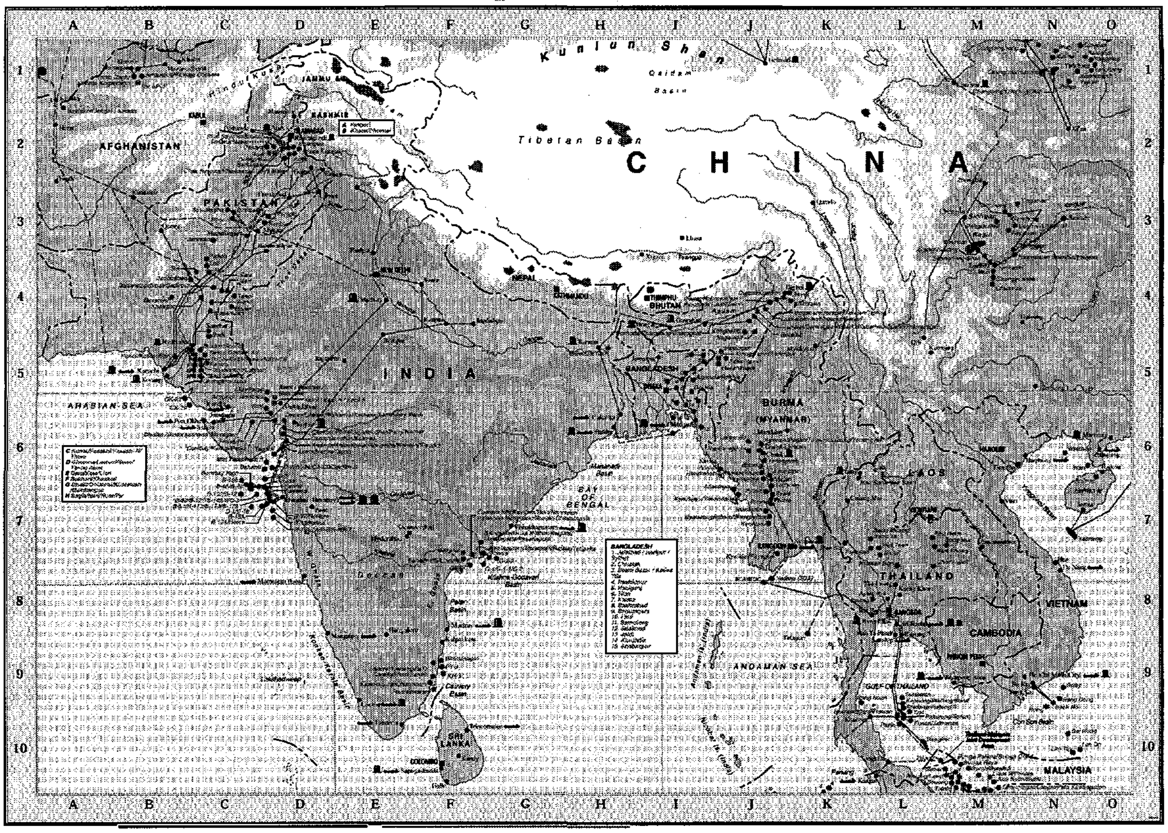
The gas price for the private sector should be higher than the full-cycle costs of supply, including taxes and royalties, and lower than the maximum market value. Gas prices for the power sector could be indexed to the international price of fuel oil as a compromise between the needs of the power sector and oil producers. Using gas in power generation delivers the greatest economic benefit to Vietnam. Using gas in fertiliser production will only be economic if there is a significant excess supply of gas—much more than current discovered reserves.

The structure of the hydrocarbon market should be anchored in an appropriate legal, institutional, and regulatory system. Upstream functions should be handled by the State Petroleum Management Authority, whose tasks are defined in the Petroleum Law. There is no legal basis for regulating gas pipelines or gas processing and distribution operations. Given the expected rapid development of the gas industry, such a legal basis should be put in place and made compatible with the regulation that is implemented for the electricity sector. Downstream regulatory tasks include approving tariffs for pipeline use, preventing abuse of monopoly power, and implementing technical standards for pipelines and other tasks that are very different from upstream regulation. Regulation of transmission pipelines and gas processing and distribution operations should be carried out by agency separate from the upstream regulatory agency.

The liberalisation of the LPG and lubricant markets for imports and marketing has attracted private investments from regional foreign investors, and international oil companies have entered the market to compete with the two Vietnamese companies. Thus the government should consider liberalising the supply, distribution, and retail sales of petroleum products. Doing so would attract foreign investment and increase supplies, giving consumers better and expanded service at a competitive price. A study is needed, however, to determine how liberalisation should be approached. Today, multiple suppliers exist only in major cities, and liberalisation should start where multiple suppliers are present. In remote areas some government oversight is needed to ensure a continued supply.

Vietnam's hydrocarbon industry is at an early stage of development. With increased oil and gas production, there will be major opportunities to develop ancillary industries, such as for fabrication of process modules, spare parts, and offshore supply vessels, and other service companies for operation and maintenance services. Petrovietnam should develop in-house capacity to develop offshore industries, and to effectively monitor and supervise them. The government needs to carry out an integrated examination of oil industry developments to mobilise the potential unleashed for industry outside the oil sector.

* We Acknowledge The Kind Authorization Of Pétroleum Economist Ltd – London *



CONCLUSION

It is clearly evident that natural gas will continue to expand its share of primary energy markets throughout the world, as demand for this abundant, efficient and environmental friendly fuel and raw material increases. Over the next two decades, gas use is projected to rise at more than three times the rate of oil use. Resource availability, cost and environmental considerations all favour growing reliance on gas in industrial applications, electricity generation, and in replacing other fuels in residential and commercial sectors.

Natural gas reserves are less geographically concentrated than oil reserves world-wide, and regional reserves-to-production ratios, especially in developing countries, tend to be high, clearly indicating the potential for greater exploitation of this resource. Diversifying their petroleum export base into petrochemicals, LNG, piped gas, LPG, GTL and the like, will help developing countries meet their domestic, as well as regional demand in these products and add to their export revenues, which are currently over dependent on oil taxes only. Another viable option, which the developing economies could explore, is the establishment of energy intensive industrial parks in the vicinity of proven gas fields. Such industrial parks help in creating basic infrastructure for industrial development using local resources and raw materials, attract private capital and technology, and create employment opportunities leading to training of local personnel in basic skills.

Recent results from experiences across the world show that the power sector is generally the key to developing natural gas infrastructure. While demand from other sectors also has a significant impact, the gas purchase contract by the power producer is generally the key factor in securing financing and getting the project off the ground. Once a gas pipeline system is in place, it is very easy to extend the pipeline network to other potential high demand centres, as the competitive economic cost makes the available gas more attractive to other users in the industrial and commercial sectors. Moreover, as the demand for the product stabilises, an expansion could be considered which would also lead to increased upstream investments by the participants to expand gas production at various supply points. This would result in development of previously discovered but un-exploited non-associated gas fields to maintain a reliable source of supply.

An appropriate institutional and regulatory framework is the first step towards creating an enabling environment to win the confidence of private investors for a stable and lasting development of gas markets. The governments could prepare a pricing policy to determine appropriate pricing mechanisms and price levels for gas that would popularise its consumption, attract private sector investment, and wherever possible, replace liquid fuels in industrial and commercial uses. They could also consider updating obsolete gas provisions of ownership and existing regulations, establish a sound monitoring mechanism and to create a level playing field, based on market driven principles.

Promoting viable gas projects is indeed possible through close co-operation between governments and their national oil companies (NOCs), international oil companies (IOCs) and private investors. Innovative contractual instruments like Build-Own-Operate (BOO) and Build-Operate-Transfer (BOT) allow the governments to have infrastructure facilities built, without having to mobilise any public funds, whilst keeping by the same token the option to be the operator or owner at a later stage. These projects would result in increased private sector investments both upstream and downstream to maintain a reliable source of supply. Such projects, in addition to using up gas being currently flared, would monetise this valuable resource and provide an efficient commercial use of the natural gas reserves in the developing countries.