Africa Gas Initiative

Cameroon

Volume III

ESM240
Vol 3

Energy

Sector

Management

Assistance

Programme

ESMAP

Report 240/01

February 2001

JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run as part of the World Bank's Energy, Mining and Telecommunications Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and bilateral official donors in 1983, it focuses on the role of energy in the development process with the objective of contributing to poverty alleviation, improving living conditions and preserving the environment in developing countries and transition economies. ESMAP centers its interventions on three priority areas: sector reform and restructuring; access to modern energy for the poorest; and promotion of sustainable energy practices.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG) composed of representatives of the UNDP and World Bank, other donors, and development experts from regions benefiting from ESMAP's assistance. The ESMAP CG is chaired by a World Bank Vice President, and advised by a Technical Advisory Group (TAG) of four independent energy experts that reviews the Programme's strategic agenda, its work plan, and its achievements. ESMAP relies on a cadre of engineers, energy planners, and economists from the World Bank to conduct its activities under the guidance of the Manager of ESMAP, responsible for administering the Programme.

FUNDING

ESMAP is a cooperative effort supported over the years by the World Bank, the UNDP and other United Nations agencies, the European Union, the Organization of American States (OAS), the Latin American Energy Organization (OLADE), and public and private donors from countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States of America.

FURTHER INFORMATION

An up-to-date listing of completed ESMAP projects is appended to this report. For further information, a copy of the ESMAP Annual Report, or copies of project reports, contact:

ESMAP
c/o Energy and Water
The World Bank
1818 H Street, NW
Washington, DC 20433
U.S.A.

Africa Gas Initiative

Cameroon

Volume III

February 2001

Joint UNDP/World Bank Energy Sector Management Assistance Programme
(ESMAP)

First printing February 2001

ESMAP Reports are published to communicate the results of the ESMAP's work to the development community with the least possible delay. The typescript of the paper therefore has not been prepared in accordance with the procedures appropriate to formal documents. Some sources cited in this paper may be informal documents that are not readily available.

Contents

List of Tables

List of Figures

Foreword

The Africa Gas Initiative (AGI) Study is aimed at identifying countries where gas flaring could be reduced, for better utilization in the industrial and commercial sectors of their economies. This study was conducted by Mourad Belguedj, Senior Energy Specialist and Team Leader at the Oil and Gas Division of the World Bank and Henri Beaussant, Gas Economist and consultant.

The focus of the study, aimed initially at select countries on the West Coast of Africa, is of direct relevance to ESMAP's mandate and might be useful to Policy makers, Industry and practitioners in the target countries. The Study is published as part of the ESMAP series of reports and may usefully contribute to Project Identification and to addressing key Policy Issues in these countries, as well as enriching the debate on Energy Sector Reform. The authors wish to express their gratitude to all the colleagues who contributed directly or indirectly, to the review and completion of this work.

Abbreviations and Acronyms

AIC	Average Incremental Cost
CCGT	Combined-Cycle Gas Turbine
CFA	Communauté Financière Africaine
CIF	Cost, Insurance, Freight
ESMAP	Joint World Bank/UNDP Energy Sector Assistance Management Program
FCFA	Franc - Communauté Financière Africaine
FL 1500	Fuel Lourd 1500 (heavy fuel oil)
FOB	Free On Board
GDP	Gross Domestic Product
GNP	Gross National Product
GoC	Government of Cameroon
GPP	Groupement Professionnel du Pétrole
GT	Gas Turbine
HHV	Higher Heating Value
HV	High Voltage
IDC	Interest during Construction
IMF	International Monetary Fund
IOC	International Oil Company
ISO	International Standards Organization
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gases
NGDMP	Natural Gas Development Master Plan
PSA	Production Sharing Agreement
RTP	Reserves to Production ratio
SCTM	Société Camerounaise de Construction Métallurgiques
SNH	Société Nationale des Hydrocarbures
SONARA	Société Nationale de Raffinage
SONEL	Société Nationale d'Electricité
SSA	Sub Saharan Africa
UNDP	United Nations Development Program
UNIDO	United Nations Industrial Development Organization
USD	US Dollar

Units of Measure

bcf	billion cubic feet
bcm	billion cubic meters
bcmy	billion cubic meters per year
bl, bbl	barrel, barrels
bpd	barrel per day
cf	cubic foot (feet)
cfd	cubic feet per day
GJ	gigajoule
cm	cubic meter
GWh	gigawatthour
kcal	kilocalorie
km2	square kilometer
kW	kilowatt
kWh	kilowatthour
Mcal	megacalorie
mbpd	thousand barrels per day
mcf	thousand cubic feet
mcfd	thousand cubic feet per day
mcm	thousand cubic meters
mcmd	thousand cubic meters per day
mcmy	thousand cubic meters per year
mmb	million barrels
mmbtu	million BTU (British Thermal Units)
mmcfd	million cubic feet per day
mmcm	million cubic meters
mmcmy	million cubic meters per year
mmt	million tons
mt	thousand tons
mtoe	thousand tons oil equivalent
mty	thousand tons per year
MW	megawatt
MWh	Megawatthour
t	ton
tcf	trillion cubic feet
tcm	trillion cubic meters
toe	ton oil equivalent
tpy	ton per year
TWh	terawatthour

Conversion Factors

Volume

1 barrel	=	159 liters
1 cm	=	6.29 barrels
1 cm	=	35.315 cf
1,000 cf	=	28.3 cm

Energy

1 mmbtu	=	252 Mcal = 293 kWh
1 mmbtu	~	1 mcf
1 GJ	=	0.95 mmbtu
1 kWh	=	0.86 Mcal = 3,412 btu

Oil products

crude oil	7.30 bbl/ton
diesel/gas oil	7.46 bbl/ton
fuel oil	6.66 bbl/ton
jet fuel	7.93 bbl/ton
kerosene	7.74 bbl/ton
naphtha	8.80 bbl/ton

Rules of Thumb

1 bpd	~	50 tpy
1 mmbtu	~	1 mcf ~ 1 GJ
1 mmcfd	~	10 mmcmy
1 USD/mmbtu	~	40 USD/mcm
1 tcf	~	30 bcm

1

Oil and Gas Resources

Sub-Sector Overview

1.1 The Republic of Cameroon is situated on the Gulf of Guinea and forms part of West Central African. The major cities are Douala – the economic metropolis; Yaoundé – the political capital; Nkongsamba; and the port of Limbé where the refinery is located. In 1998, the estimated population is 14.7 millions for an area of 475,000 km^2. GNP is slightly above SSA average, at USD 620 per capita in 1997.

1.2 Cameroon is one of Africa's oil producing countries, contributing about 100,000 bpd (5 mmty), about 3 percent of the region's oil production. Oil reserves at the beginning of 1999 were estimated at 400 mmb, i.e. 1.2 percent of the region's reserves, dominated by Nigeria. The reserves-to-production ratio (RTP) reaches a low 11 years, the lowest of the region's mid-size oil producers. The country also has gas reserves estimated at 3.9 tcf, which are still largely unexploited. The upstream oil industry is, thus, the key to the economy.

1.3 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 hydrocarbons resources and management of the state's interests in any discoveries of oil and gas resources.

1.4 Petroleum has greatly contributed to the economic and social development of the country from 1978 to 1985, a period during which Cameroon enjoyed a high development rate, thanks to oil export revenues that provided the necessary financing to sustain economic growth. In 1985-1986, when oil production peaked (9.5 million tons), oil exports revenues contributed to 18 percent of GDP and nearly 53 percent of the value of all goods and services produced. Following the 1986 drop in oil prices, from USD 24 to 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 percent in real terms, dropped by -4% in 1987, and -6% in 1988. The drop in oil prices is compounded by a substantial decrease in production, which was almost cut in half since the 1986 heyday. The subsequent spectacular regression in economic activity led the authorities to initialize and introduce reform in the economy.

1.5 Since late 1970s, 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 known natural gas reserves, which are estimated to be far in excess of the local market's needs, but not sufficient to support an export scheme in the form of liquefied natural gas (LNG), have not yet been delineated. As a result, the assessment of the gas resource base is less mature than that of oil, and gas reserves could be much larger than current estimate. Proposals have been made over the recent years to recover liquid petroleum gases (LPG) from associated gas being flared offshore, and to develop medium-size gas fields located in the Douala estuary or south of the city, to develop power generation and local industrial uses. These proposals, which would have initiated development of natural gas, have not materialized yet.

Oil and Gas Potential

Exploration and Production

1.6 Petroleum exploration in Cameroon began in the late 1940s. Exploratory drilling started in 1954 near Douala, where a number of surface oil seeps had been found. The drilling resulted in the discovery of natural gas in 1955 at an average depth of 2,500 m, in an onshore gas field 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 have been discovered since the early 1970s, within water depths of less than 70 m. Nearly all producing fields are about 50 km from the coast.

1.7 The first significant oil discovery was made in 1972 with the d'Ekoundou field developed by Elf. Since then, an intensive activity led to more discoveries of larger fields, such as Kole (1974), Kombo and Bravo Marine (1976) by Elf, Lokele (1977) by Shell-Pecten, and Moudi (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 mmt and, then, declined to level off an average 8.5 mmty from 1987 to 1990. In 1990, it started declining again at an increasing rate, reaching about –10 percent in 1993 with 6.2 mmt, and –14 percent in 1994 with about 5.5 mmty. Production has slightly recovered in 1997, reaching 6.2 mmt. Recent developments include agreements with Trophy Petroleum, Perenco and CMS-Nomeco. France's Elf (now part of the TotalFina group) has been the historical anchor of oil production and is still by far the largest producer, contributing approximately 75 percent of the country's yearly production. It is followed by Shell-Pecten with 22% and Perenco, which, as Kelt, acquired Total's assets in 1994, with the remaining 3 percent. Natural gas production has so far been limited to associated gas at an average rate of about 2.5

mmcmd, decreasing to 2 mmcmd in 1998 due to declining oil production. Almost one-third is being used within the fields for power generation and in oil production, the remaining being flared. Most of the gas being flared comes from the western fields of the basin. No gas is sold in either the domestic or the international markets.

Table 1.1 – Evolution of Crude Oil Production

Year	Crude Oil Production (mbpd)	Oil Reserves (billion bbl)
1985	185	
1990	161	
1995	111	
1996	108	
1997	124	0.4 (1/1998)

Source: USD DoE

1.8 The Sonara refinery, located in the port city of Limbe, 70 km north of Douala, is the source for the country's petroleum products, in addition to substantial smuggling from Nigerian refineries. With a capacity of 45,000 bpd (2.2 mmty), Sonara is owned by GoC (66 percent) along with Elf, Mobil, Shell, Texaco and Total. In addition to supplying the domestic market (around 0.8 mmty), the refinery utilizes spare capacity to refine products for export.

Gas Flaring

1.9 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 LPG recovery and commercialization of gas were reportedly discussed between government officials, operating companies, and, to some extent, international development agencies, but never pursued. While it is still unknown whether a recovery scheme for Rio del Rey's 2 mmcmd of associated gas (10,000 bpd of oil equivalent) is economically viable, it suggests that a gas utilization study for such a rich gas, which has been flared for more than 17 years, would not only have addressed the Government's concerns, but facilitated the start-up of the country's natural gas development program. As more gas will be required for oil production (gas lift), the overall gas flaring is expected to continue to decline, reaching about 1 to 1.5 mmcmd in the coming years. Such a study, which is still feasible, would have proved highly beneficial if it were 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, utilization 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.

Future Potential

1.10 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 there were 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, a gas prone area with a fairly good potential. Reserves, however, are regarded too low 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 Douala basin. The other parts of the country, where some speculative potential exists, would be in the onshore Logone, Birni and Garoua basins, which seem to be an extension into northern Cameroon of the rift basins from Chad (Bornu basin), where promising prospects have been identified. However, no petroleum exploration has been carried out in Cameroon's Birni and Garoua basins for which IOCs seem to express little or no interest, except for two contract areas held undrilled since 1980 by Elf and Pecten.

1.11 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 bcm (20 tcf) of gas. More than half of these projected discoveries would be made in the Rio del Rey basin in the River 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 percent 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 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.

Gas Reserves And Production

1.12 Based on currently available data, Cameroon's total (initial in place) natural gas reserves can reasonably be estimated, as of 1994, at 260 bcm (9.2 tcf)[1], of which: (i) 200 bcm would be in the Rio del Rey offshore basin, consisting of up to 165 bcm of non-associated gas and up to 35 bcm of associated gas; and, (ii) 60 bcm in the Douala offshore basin, all of which as non-associated gas. Of the Rio del Rey's initial gas in place, about 130 bcm can be considered as proved reserves, consisting of approximately 72 bcm of non-associated gas, 22 bcm of gas-cap gas, and 35 bcm of associated gas. Of the latter, about

[1] Other evaluations are more conservative: the US DoE's EIA estimates gas reservesat 3.9 tcf, as of 1/1999.

half (17 bcm) has already been produced. Rio del Rey's remaining 70 bcm can be considered as probable and possible reserves consisting of about 65 bcm of non-associated gas and about 5 bcm of gas-cap gas. In the Douala basin, about two-thirds (40 bcm) can reasonably be estimated as proved reserves, and the balance 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 bcm) of the known reserves can be considered as associated gas.

1.13 Except for remaining associated gas (18 bcm) and gas-cap gas (22 bcm), 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 bcm in the Rio del Rey offshore basin, and about 10 fields of small to medium size, with total proven reserves of about 40 bcm, 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 River Estuary some 20 km from the 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 in the 1950s. 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 bcm of proven reserves consisting of about 73 bcm in the Rio del Rey offshore basin and about 37 bcm in the Douala coastal offshore basin; and (ii) 80 bcm of probable and possible reserves, of which 64 bcm in the Rio del Rey offshore basin and 16 bcm in the Douala offshore basin.

2

Potential Gas Projects

Overview

2.1 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 should be given now to making economic use of existing natural gas resources with the objective of maximizing effective substitution of oil products in the domestic market. Although gas utilization 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 small gas fields located near Douala, the economic capital, together with the production of LPG, using gas being flared in offshore fields and extracted from the gas stream of non-associated gas, represent an economically attractive start-up of Cameroon's gas sector development program, for which participation of IOCs could facilitate project financing and minimize the risk of implementation delays.

2.2 The AGI has identified three major areas of gas development, which are presented and discussed in this chapter. First, the use of gas as a fuel in the conventional industry, to save oil for exports while improving the performance of the Cameroonese industrial sector. Then, the introduction of gas for power generation, which should be considered in the longer term as an alternative to costly hydro schemes. Last, the much needed development of LPG for the residential and commercial sectors, blocked by institutional obstacles in spite of high demand. In addition, a fourth area has been only lately considered following the recent surge in oil price, and should be thoroughly assessed in the near future: developing GTL projects to meet the country's increasing demand in middle distillates. Finally, the AGI has worked with Cameroonese authorities on the institutional and regulatory framework for the downstream gas activities. Except the GTL area, which is discussed in the main report, the other projects are discussed in this section.

Table 2.1 – Energy Supply and Demand

	Crude Oil (mt)	Oil Products (mt)	Electricity (GWh)	Biomass (mtoe)
Production	**6,269**	873	**3,128**	**4,630**
Imports		14		
Exports	(5,361)	(17)		
Bunkers		(53)		
Domestic Supply	908	**817**	**3,128**	**4,630**
Losses[2]	(35)	(10)	(612)	210
Final Consumption		**807**	**2,516**	**4,420**
Industry		49	1,428	760
Transport		606		
Residential & Commercial		121	1,088	3,660
Non energy		31		

Source: IEA: Energy Statistics and Balances of non-OECD Countries, 1997 (Edition 1999)

Industry

2.3 For many industrial activities in Cameroon, natural gas is clearly the best alternative to the various fuels currently used, in particular, given the country's declining oil production. Cameroonese industry continues to rely on liquid fuels, in particular heavy fuel oil, while natural gas is within reach. The main potential natural gas consumption center is Douala, the harbor metropolis where most of the country's industrial activity is located. Residential and commercial market does not appear to be prospective for now, although a demand may develop, to a limited extent, once the distribution system for the industrial sector becomes operational

2.4 Some 150 to 500 mmcm of rich natural gas reserves were discovered in the mid-1950s and confirmed with four wells at Logbaba, near Douala. They remain untapped. Another 1.4 bcm of similarly rich gas reserves discovered and confirmed with two wells some fifteen years ago at Matanda, in the shallow waters of the Douala River estuary, about 18 km from the city, also remain undeveloped. As there has been a worldwide growing interest in the use of natural gas, the Government initiated in 1986, with the assistance of UNDP, the study of the National Gas Development Master Plan (NGDMP). The NGDMP, which was developed and updated in 1993 with World Bank funding, recommended the development and production of fields within the Douala area. Development of Logbaba was considered first because of its location close to the city's largest industrial area. Due to the reluctance of the concession holder Elf, the consultant finally recommended to develop the Matanda offshore field. However, not much has been done so far on either Logbaba or Matanda, and the Master Plan's recommendations still need to be implemented.

2 Including transformation, own use and statistical differences.

2.5 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 in order to minimize the cost of transporting gas to the market. For the Matanda offshore field, the minimum required investment cost would be at least twice as high as for Logbaba with, in addition, a minimum optimum well flow rate actually in excess of the market's short- and medium-term needs. With regard to Logbaba, gas reserves are estimated to be between 150 to 500 mmcm, which would provide a delivery rate within the utilization capacity of existing industrial sector, estimated in the range to 40 to 50 mmcmy. Because of good reservoir characteristics, Logbaba could be produced with a minimum number of wells. In addition, the reported high liquids content of the gas stream could be processed using a small skid-mounted LPG and condensate recovery unit, which would significantly enhance the project's economic viability. To initiate Cameroon's gas utilization and development program, production of Logbaba gas seems to be the most appropriate small scale operation. Assuming 500 mmcm reserves, Logbaba field could be produced for 10 to 11 years at about 100,000 to 135,000 cmd, i.e. the level of the estimated demand. Assuming a distribution system designed for about 150,000 cmd, 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 USD 26 million (including USD 8 million for the distribution network) compared to USD 50 to 60 million for Matanda (including production and distribution facilities).

2.6 Once Logbaba has reached 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 then the Matanda field. Logbaba is expected to be depleted after about 10 years. Developing the Matanda field would aim at compensating the depletion of Logbaba, while downstream installations, in particular, the distribution network, would have had time to expand to meet full market capacity. Matanda's confirmed reserves are about three times those of Logbaba, i.e. 1,400 mmcm, and the gas is rich in condensate. Investment required to bring the gas to shore are estimated in the order of USD 31 million, including a transmission line to bring gas from the platform to the industrial zones, as well as LPG and condensate 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 utilization. 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, to boost Cameroon's gas sector development program.

2.7 ***Project Scope***. Economic activity in Cameroon is concentrated in Douala, the country's main harbor and largest city. By African standards, industrial activity is far from being negligible. Industry accounts for about 24 percent of the country's GDP, with the manufacturing sub-sector representing about half of the industrial sector. In Douala, where fuel oil consumption accounts for 60 percent of the country's total demand, all conventional types of manufacturing industry are represented, including agri-industry (breweries, dairy products, cookies and candies, noodles and pasta, etc.), textile, glass, chemicals (soap and detergents, rubber), construction materials, and metal industry. The large and medium-scale industry gathers around 30 plants, that account for 80 percent of fuel consumption. According to the industrial survey performed for the update of the NGDMP, actual operation rate of the manufacturing sector was only 60 percent of its nominal capacity in the early 1990s. A partial updating, performed a few years later with the assistance of the AGI, showed that current operating level might well have substantially increased, in particular since the devaluation of the CFA Franc in January 1994. The new exchange rate has allowed Cameroonese products to efficiently compete with similar foreign products, in particular, from Nigeria, thus enabling some factories to work close to full capacity, which had not been observed in Cameroon since the late eighties. In addition to Douala, large, stand alone facilities are located outside the main conurbation, including the Sonara refinery at Limbe, 70 km north of Douala, and the aluminum factory Alucam at Edea, 60 km south of Douala.

2.8 Two major industrial areas, Bassa and Bonaberi, are located in Douala suburbs. The larger one, Bassa, extends over a significant tract of land in the eastern part of the city and gathers about 80 percent 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 center. Bassa industrial area lies close to the yet undeveloped gas field of Logbaba, located at the eastern edge of the industrial area, only 18 km east of Douala's city center. The industrial market is considered to have reached the critical mass above which a Logbaba gas-based project would be feasible. The pair Logbaba gas field / Douala industrial market is actually the prototype of what a successful "small use of gas" scheme can be. Logbaba gathers several characteristics that suit perfectly the potential market: (i) it is the neighbor next door; (ii) its small size fits the currently limited absorptive capacity of the local market; (iii) the risks associated with the new project should remain limited because the project's development and operating cost would be kept low; and (iv) once Logbaba is depleted, the Matanda gas field, located offshore 25 km west of Douala in the estuary of the river Wourri, could take over at a reasonable cost. In addition, Logbaba gas is rich in condensate; LPG and natural gasoline contents are estimated at 3 percent and 6 percent, respectively, which would significantly enhance the global attractiveness of the project.

2.9 The NGDMP survey was conducted among 24 of the largest facilities located in both industrial areas. Total fuel consumption amounted to 28,450 tons of oil products, most of it consisting of high quality, low sulfur fuel-oil known as FL 1500[3]. 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 nineties, potential fuel consumption is currently considered quite higher. It was considered that if all facilities were working at nominal capacity, then fuel consumption would increase by 70 percent, thus reaching 48,000 tons of oil products (in 1997 fuel oil consumption by the industrial

[3] FL 1500 is a blend of heavy fuel oil and a limited quantity of diesel oil (up to 10 percent), which enables the product to be transported and used without re-heating it. Cost and value of FL 1500 are above standard HFO.

sector [countrywide] was 49,000 tons). Diesel oil consumption as an industrial fuel, i.e., excluding uses for transportation and power generation, is only marginal in Douala, while LPG sales to the commercial and industrial sector represents about 10 percent of total LPG consumption, i.e., about 2,500 tons per year in average. Potential natural gas demand of the industrial sector in the Douala area amounts currently to 50 mmcmy[4].

2.10 Supplying other industrial centers outside Douala could prove feasible and should be assessed. For instance, Limbe, where the Sonara refinery is located, is only 70 km from Douala, and might retain some potential for using gas in the refinery. While natural gas would not compete with refinery gas, it might compete with the fuel oil in excess currently burnt in the refinery, considering the high value in the international market of such high quality, low-sulfur fuel oil. This option was implemented recently at the Abidjan SIR refinery, where 200 mmcmy of natural gas substitutes for fuel oil. Conversely, Yaounde, the country's political capital, located some 260 km east of Douala, does not gather a sufficient market to make a dedicated gas pipeline profitable. Industrial activity is limited to a few plants whose substitutable fuel consumption cannot make a gas pipeline project economic, which would require a minimum demand of around 500 mmcm per year.

2.11 ***Project Economics.*** Based on the forecasted consumption of Douala's industrial market, and on updated investment and operating costs for Logbaba (years 1 to 10 of operation) and Matanda (from year 11 on), the delivery cost of gas (based on AIC) at the user's burnertip (i.e., including the cost of gas production and distribution as well as the cost of converting thermal equipment to gas) over a 20 year period is USD 2.87/mmbtu, when additional income from condensate recovery is not considered. Competing fuels consist of FL1500, diesel oil and LPG, where the former represents about 90 percent of the fuel mix. Since fuel oil and most oil products (albeit to a lesser extent) that are produced by the refinery are in excess of domestic needs and exported, the opportunity cost of gas is considered close to the export price of FL1500 (it is actually slightly higher, considering that diesel oil and LPG represent about 10 percent of fuel consumption in the industrial sector). Based on oil at USD 20/bl, ex-Limbe export price of FL1500 is USD 98/ton according to figures from the Sonara refinery. Inland transportation, storage and final delivery to the customer add a USD 36 mark up to the ex-refinery price. At the user's gate, the economic cost of FL1500 is thus USD 134/ton, i.e., USD 3.39/mmbtu. Natural gas would thus be able to compete easily with FL1500, even when LPG and condensate recovery is not considered. The rate of return of the "basic" project, i.e., without condensate recovery, is 14 percent.

2.12 Condensate recovery, including LPG and natural gasoline, would significantly improve the feasibility of the project. Recovery would consist of extracting the condensate at the wellhead and shipping it by truck to the refinery for separation. While additional investment cost for condensate recovery would remain marginal, its valorization would bring incremental income equivalent to more than 20 percent of the total project cost (in present value), thus decreasing significantly the production cost of

4 Based on the current distribution into HFO, diesel oil and LPG, and considering that natural gas cannot compete with self-produced used oils.

gas. At USD 2.43/mmbtu, natural gas would compete even more easily with FL 1500. Economic rate of return comes to 17 percent. In addition, natural gas should benefit to some extent from its own operating qualities and from improved efficiency vs. fuel oil, which would give gas a 2 to 5 percent premium depending on the type of thermal equipment, thus increasing its opportunity cost to the range of around USD 3.45 to 3.55/mmbtu; the economic rent would reach USD 1/mmbtu.

2.13 Exploitation of the Logbaba and Matanda gas fields would thus enable Cameroon to expand current exports of high quality, low sulfur fuel oil that valorizes well on the regional and international markets. Exporting fuel oil and, to a limited extent, diesel oil is expected to bring Cameroon USD 122 million in hard currency (@USD20/bl of crude) over the 20-year economic life of the project. This compares very favorably with capital expenditure estimated at USD 57 million. Project benefits are likely to be higher if, in the meantime, Cameroon has become a net importer of energy. Valorizing the condensate included in the gas would bring additional benefits estimated at USD 25 million.

2.14 ***Project schedule and program***. As discussed above, developing the use of natural gas will inevitably be limited to the Douala area. New, stand alone projects, the feasibility of which would have to be assessed, could become part of the project. A project geared at developing the use of natural gas in the industrial sector will consist of the following components, in addition to production facilities :

- construction of the industrial distribution network;
- conversion of thermal appliances (boilers, furnaces, etc.);
- set up of arrangements to handle financing of plant conversion;
- technical and commercial training for operational staff.

2.15 The Bank has not been successful in trying to convince Elf, who shares with SNH the concession of Logbaba, to open up the field for production, either using existing wells after work-over or drilling new wells. After Elf confirmed to SNH that they were not interested in developing Logbaba, SNH has approached several potential investors, in particular, independant US companies, including Grynberg, Walter Oil & Gas, Moreno, Opeco, Vermilion and Tradewinds. In addition, they have been contacted by several other companies, including Ocelot of Canada that has already acquired experience in other projects in Africa. In a first step, follow-up assistance by the AGI to help promotion, would include :

- review of the interpretation of the latest (1984) seismic survey. Based on this review, a follow-up action would be decided, such as a re-interpretation of relevant sections of existing seismic coverage and/or the need of a limited new 3-D seismic survey on the basis of which drilling location of a first production well location will be decided, with the objectives of minimizing field development and production cost;

- drafting of the terms of reference for the update of the market survey and the design of basic engineering, with implementation schedule and cost estimate for a least cost production facility, including options for LPG and condensate recovery.

Power Generation

2.16 The AGI has commissioned a pre-feasibility study of the use of gas for power generation, bearing in mind that a driving force – a sizable gas-consuming project -- is usually required to launch grass-root gas operation. Because Cameroon is one of the best-endowed SSA countries with regard to hydro potential, the possibility to use gas for power generation does not show before the medium term, when gas could reasonably compete with high-cost, to-be-built hydro schemes. While the detailed approach and conclusions of the gas to power study are shown in Chapter 3, this section presents the summary of the current situation and the main conclusions of the study.

2.17 Cameroon has a very large hydro-electrical potential. An extensive inventory made in 1979 estimated the economically-attractive potential at 105 TWh at least. Moreover, annual and seasonal variations of river flows are relatively limited, thus reducing the need for thermal backup units. The state-owned utility SONEL (Société Nationale d'Electricité du Cameroun) has been in charge of electricity production, transmission and distribution in Cameroon since 1974. There is no legal monopoly in any of these activities. The Cameroon power system consists in two main independent subsystems. The southern network actually covers the southwest region (Yaounde, Douala, Bafoussam, Bamenda), while the northern system supplies Garoua, Guider and Maroua. The southern system accounts for than 94 percent of the total energy produced, against 5 percent for the northern system and 1 percent for the isolated centers. There is presently no project of interconnecting the two systems.

2.18 With 490 MW of available firm capacity in the dry season vs. 400 MW of peak demand, the southern interconnected system (where Douala is located) is characterized by an important generation over-capacity. Considering the limited future demand growth prospects, this seems to leave no place for any new power plant before the year 2004. The only significant investment in the coming years should concern the transmission network, in order to improve the security of supply to Yaounde, and delivery stability in the western part of the network. The present share of thermal power in the interconnected system is almost negligible. Whatever investment program, this share will remain very low (below 5 percent) 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.

2.19 When additional capacity is required (2004) there is a clear interest in diversifying the system by introducing gas turbines. What the system requires at that time is a mean to supply peak power, especially during the dry season, without having to bear high investment cost. Consequently, no hydroelectric scheme appears competitive compared to light thermal units. Although the Lom Pangar regulation dam, which is relatively cheap (no power house), correctly addresses the problem of hydro power availability during the dry season, it still shows high investment cost, which does not make the project 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.

2.20 If no cheap natural gas is available, the least-cost scenario is to base incremental production on gas oil-fired gas turbines of the 100 MW size category. Three of them have to be added to the system between 2004 and 2014. The option based on 50 MW gas turbines is slightly more expensive, mainly because of counter-economies of scale. However, the difference is not very high between these two options, and might be offset when considering explicitly the transmission aspects (smaller units may be better adapted to the geographical load structure, thus reducing transmission losses and network investments). Tentatively, an intermediate solution with two 50 MW turbines in 2004 (one in Douala and one in Yaounde, followed by two 100 MW units in 2011 and 2014, would be the most attractive option.

2.21 Assuming that natural gas could be made available in the Douala region at a reasonably low cost, the scenario with 100 MW natural gas-fired gas turbines appears as the least-cost option. Under present assumptions (i.e., with economic cost of gas of 1.50 USD/GJ), the discounted benefit is USD 4.6 million, compared to the next-best option (gas oil-based). The first set would be required in 2004, with an option to install it at an earlier stage (2000) to avoid re-inforcing the Songloulou-Douala HV transmission line that would prove more expensive. Other sets would be required from 2010 onwards. A major economic issue is that the 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 cost of gas production and transportation infrastructure (which would have to be sized for high peak demand), gas turbines should be constructed as close as possible to the gas source. However, while gas-fired power plants look more cost-effective than hydro, gas demand for power generation cannot be considered a potential driving force for gas development, which will have to driven by smaller gas uses.

2.22 Natural gas-fired combined cycle units are often a very interesting option for bulk power generation. However, in the present case, the annual expected working load is too low to take advantage of the remarkable thermal efficiency of such equipment. Due to higher investment costs, they lead to a total discounted cost which is significantly higher than for the option based on regular, open-cycle gas turbines.

LPG Recovery and Development

Recovery Scheme

2.23 Cameroon's oil (and associated gas) producing fields have been fully developed and are now undergoing a natural production decline. The production of associated gas is nearly 2 mmcmd, of which almost two-thirds is flared. The gas is rich enough to be considered for liquids recovery. Moreover, it could be transported to the shore where it could supplement, if required, the non-associated gas fields that are proposed to be developed, e.g. as a fuel for the refinery as well as for other industries. For this purpose, the AGI recommended that the Government consider undertaking a study to develop an LPG recovery scheme. To minimize the investment cost and maximize the return on capital investment, the proposed scheme would be developed offshore, within the Rio del Rey's oil producing fields. The gas would be collected from selected existing production platforms and processed in a new specially conceived platform. The platform could be a converted jack-up drilling rig, located on the western sector, which produces about 70% of associated gas being flared. The processed LPG would be barged to onshore LPG bottling facilities, as currently being done by the refinery. The recovered LPG would consist of propane and butane, in a mix suitable for direct sale to distributors and end-users. Since Rio del Rey's associated natural gas is rich in heavier hydrocarbons, recovered condensate can either be sold separately or mixed with the crude oil. Because of declining associated gas production and the need for progressively using non-associated gas over time, the capital investment would be optimized through maximum liquids recovery. The liquids intended to be recovered would be C3, C4 and C5+ for about 0.20 to 0.25 mmty of LPG and 0.10 to 0.15 mmty of condensate. The proposed scheme may seem complex, but in reality the technology is quite simple and successfully used in many countries.

Market Development

2.24 Current LPG market seems to be poorly defined due to the lack of accurate surveys. The present gap between production and demand may look relatively small, which is actually due to the fact that the economy is now depressed, and, to some extent, to the lack of bottles (bottled LPG represents almost 90% of the LPG's market). LPG consumption in Cameroon is expected to increase rapidly over the next few years, provided that technical and institutional barriers are overcome. In any case, LPG will always remain the fuel of convenience for a large part of the population, since it would be used as an alternative source of supply to firewood, a well known and important cause of deforestation. In this regard, the country's firewood consumption is estimated at 6-7 million tons per year. In addition, the proposed LPG recovery scheme would allow Cameroon to resume exports to neighboring countries, particularly to Chad and the Central African Republic, which are well known LPG supply-constrained countries.

2.25 Cameroon has a fairly well developed LPG industry. Consumption is concentrated in the larger cities, including Douala and Yaounde, which together account for above 80 percent of total sales. Current market is supplied by the sole Sonara refinery (no imports), while limited output in excess is sold in the neighboring central and west African markets. Reliable, regular supply is hampered by the volatility of the refinery output that can show significant variations within a short period of time. For instance, in 1995, total production amounted to 34,940 tons (i.e., 2.4 percent of the refinery output), of which 21,100 tons (60 percent) were sold in the domestic market. In that year, the global activity of the refinery soared by over 30 percent, from 1.12 to 1.48 million tons output, which enabled Sonara to export 13,960 tons of LPG, ten times more than in the previous year (1,460 tons). In the following two years, output decreased sharply to 18,000 and 24,000 tons in 1996 and 1997, respectively, and no exports were reported.

2.26 As in most African countries, actual demand is far from being met by current supply, and a strong upside potential exists. Potential supply is not the main cause, but additional resources need to be tapped: close-by sources are abundant, which should keep freight charges at a reasonable level. Developing the Logbaba gas field and extracting LPG from the gas flared in the Rio del Rey area would produce significant additional quantities of LPG, well above the demand of the local market. In addition, Equatorial Guinea produces marginal quantities of LPG from the operation of its Alba field, while stripping LPG from the Nkossa field in offshore Congo generates as much as 250,000 tpy at full capacity, well beyond the total consumption of Western Africa.

2.27 Potential market still needs to be clearly assessed, although a self-financed, project-oriented study prepared by Canada's Liquigaz was performed in a recent past. Comparison with other Sub-Saharan countries where LPG is fairly developed, such as Senegal and Gabon, shows that there is a strong upside potential and that demand is far from being met. As an example, LPG sales in Senegal in the 70's and 80's have increased at an average rate of 14 percent p.a., and the market is still developing; it is considered that well over fifty percent of urban households in Senegal use LPG on a regular basis. A preliminary estimate shows that LPG consumption in Douala and Yaounde only could more than double to reach 50,000 tons by the turn of the century, if supply is made available. Among those key measures that are likely to be instrumental in developing the market are (i) increasing the use of small-size cylinders (6 kg), (ii) implementing financial instruments to facilitate the access of newcomers from medium- and lower-income to cylinder+appliance packages, and (iii) developing local supply through the expansion of next-door retailers.

Environmental Benefits

2.28 Increasing the use of LPG in the household and commercial sector would help mitigating the consequences of deforestation, in particular, in Central and Northern Cameroon. Though the impact of the project on the environment needs to be fully assessed, substituting 1 kg of LPG for wood and charcoal is expected to save over 11 kg of wood, or 4 kg of charcoal. At plateau, the project would save 675,000 t of wood or 245,000 t of charcoal every year. In addition, developing the LPG industry would have a multiplier effect by contributing to create or expand industry-related activities, in particular, in the small-scale industrial sector (e.g., cooking appliances and cylinders manufacturing) as well as services (transportation, maintenance of equipment, etc.).

Project Scope

2.29 In order to promote the use of LPG, the AGI has devised the scope of a project that includes two main components. Component 1 includes LPG and condensate recovery from flared gas. Since Rio del Rey associated gas is rich in heavy hydrocarbons, recovered condensate could either be sold separately or mixed with the crude oil stream. The proposed scheme would be designed for an initial gas processing capacity of about 2 mmcmd to produce about 200,000 to 250,000 t of LPG and 100,000 to 150,000 t of condensate on a yearly basis. Because of the decline in associated gas production, the scheme would be conceived for both associated and non-associated gas, with the possibility of expansion as demand for LPG and natural gas develops. Assuming a converted jack-up using a turbo-expander process unit, the proposed scheme cost has been roughly estimated at USD 60-70 million. Based on a yearly average of 225,000 tons of LPG and 125,000 tons of condensate recovered from the Rio del Rey fields, exports of both products would yield around USD 50 million p.a. when valorized simply at crude oil equivalent.

2.30 A production profile for associated gas should be developed jointly by SNH and all field operators, modeled on the format which was discussed between AGI and SNH, i.e., showing the actual production for the last 10 years and projected production for the next 15 years. Having access to this profile, by sector, will greatly help evaluate an LPG recovery scheme involving construction of gathering lines and a process platform.

2.31 Component 2 looks at downstream operation, i.e. the development of the LPG market for households and commercial activities. Developing Logbaba and Rio del Rey would generate substantial additional volumes of LPG in the near future, that would be available to meet both local as well as regional demand. Though the refinery's output may exceed, from time to time, the absorptive capacity of the market, the actual potential market for LPG is considered well above the current sales that remain severely restricted by technical as well as institutional issues. The component's objective is to make butane accessible to 60 percent of the urban population (80 percent in the larger cities). It would include: (i) the extension of the present facilities; (ii) the production and tagging off additional cylinders, including cylinder+burner packages; (iii) the development of retail outlets; and (iv) the establishment of credit arrangements to facilitate the purchase of packages. As a preliminary estimate, the cost of the component, for the cities of Douala and Yaounde only, is around USD 38 million. This would raise LPG consumption to around 80,000 t per year in the medium term (5 years), of which 50,000 t for the two main cities where over 410,000 households would use LPG from an estimated 240,000 in 1995. The component for the cities of Douala and Yaounde would include (in addition to the production installations memntioned above) the following tasks and items:

- extension of the present storage, filling, bulk and retail transportation facilities to meet increasing demand;
- production and tagging of enough 12.5-kg cylinders to eliminate the present shortage and interruptions of the distribution cycle (as an example, the number of additional cylinders for Douala and Yaounde is estimated at 310,000 units);
- development of the 6-kg cylinder so as to make butane more accessible to lower income households, and of cylinder+burner packages (respectively: 207,000 cylinders and 226,000 packages for Douala and Yaounde);
- development of retail outlets;
- establishment of credit arrangements for the purchase of cylinder-and-stove packages by households still without this equipment;

- campaigns to make households aware of the advantages of butane and necessary safety measures.

Institutional Issues

2.32 LPG distribution is handled by two private groups: SCTM and GPP (Groupement Professionnel du Pétrole). The latter federates the local distributors of three international oil companies (Total, Mobil, and Agip), and the marketer Camgaz. Their market share has abruptly decreased in the recent years to a mere 40 percent in the mid-1990s due of the introduction of a newcomer, SCTM, that entered the market in the late 1980s. SCTM (Société Camerounaise de Transformations Métallurgiques), a local manufacturer of domestic appliances, began to produce LPG cylinders to develop its activities in the metal industry, and developed later on LPG distribution to market the cylinders. It controls 60 percent of the market countrywide, and an even higher share in Douala (70 percent), although total sales have remain unchanged. While the arrival of a new player can be considered beneficial for both the customers and the LPG industry, in particular, because the market is far from maturity, it is understood that the introduction of the new company has not followed the basic principles and the widely admitted rules of sound competition and free access to market. Such a situation has deterred the other distributors from expanding their activity and has actually led them to putting the activity on the back-burner.

2.33 *Next Steps. Component 1.* For preparation of the proposed recivery scheme, the AGI has proposed to assist SNH in implementing the following tasks :

- production profile for associated gas following a format already discussed with SNH, showing the actual production for the last 10 years and projected production for the next 15 years.

- terms of reference for a detailed feasibility study on the technical aspects (turbo-expanders) and financial implications of recovering the associated liquids, particularly LPG, from both associated gas currently flared and non-associated gas, which is now undeveloped. The process could include liquids extraction and fractionation on the platform and an option for a fractionation at the refinery. Under the proposed scheme, it is assumed that remaining dry gas would be flared due to the lack of market. However, the possibilty of piping the gas to Limbe could also be evaluated;

- terms of reference for a third party reserve assessment for oil, associated and non associated gas of relevant gas fields;

2.34 *Component 2.*

- review current status of market inaccessibility due to institutional gridlock,

- LPG demand estimate showing separately Douala, Yaounde, other major cities and possibility of exports to neighboring countries.

Institutional Aspects: Downstream Gas Code

2.35 Like many African oil and gas producing countries Cameroon has yet to introduce natural gas in the country's energy balance. The Natural Gas Development Master Plan (NGDMP) prepared by GoC in 1993, recommended that a natural gas development strategy 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 favor 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, for which no local institution is familiar with 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. The SNH, which was created in the early eighties 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.

2.36 In 1996, GoC decided to undertake the drafting of a Gas Code and entrusted SNH to prepare the draft document. The Gas Code is intended to 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. Institutional aspects of LPG activities were not included in the scope. 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. SNH thus requested AGI assistance to bring support in monitoring the drafting of the document. The AGI has provided assistance through transfer of in-house expertise and review by international consultants of interim drafts prepared by SNH. Phased meetings enabled work to progress at reasonable pace, including an extensive presentation of the Gas Code objectives and contents, during which the SNH's draft final document was reviewed and commented upon.

3

Gas for Power Generation

Methodology and Assumptions

3.1 In many cases, the power sector appears as the only one capable of absorbing sufficient quantities of gas to make an initial gas infrastructure profitable. This may then serve as a backbone for further gas transmission and distribution projects aimed at supplying other types of consumers such as industrial zones or densely populated residential areas. Accordingly, the objective of the power study is to analyze technical and economic conditions for introducing natural gas within the power system, either in existing or in future generating units.

3.2 The question of natural gas availability (reserves estimates, production profiles and costs) is not dealt with in this part of the study. The potential market of natural gas is calculated without consideration to supply limitations, i.e. under the assumption that enough cheap gas can be made available to power plants in the area considered. For simulation purposes (generating units ranking by merit order), the economic cost of gas at the plant gate is taken as 1.5 USD/GJ[5] in all cases. However, the actual value of gas is calculated in all cases independently of that assumption. Gas value and foreseen gas consumption profile will constitute the basis for the final appraisal of the economics of gas use in the power sector.

3.3 A set of possible development scenarios have been established regarding the power generation system. They have been optimized using a computerized linear programming model developed by the Consultant. The model has been designed for optimizing the development of a generation and transmission system, taking account of investment and operating costs. It is generally applied to problems where geographical aspects are to be considered (plant site comparison, generation or transmission investment balancing, etc) and then features a geographical description of the network topology. In the present case, these network aspects have not been included in the modeling exercise, though they are important and should be covered in a later stage. The model has been used to optimize the choice of generating units and their commissioning years, and the whole system operation (unit commitment) on a yearly and seasonal basis. Finally, the model

[5] 1 GJ = 0.95 mmbtu. 1.5 USD/GJ = 1.58 USD/mmbtu

results are synthesized in economic calculation sheets that will be used to compare the total discounted economic costs and the value of gas for all considered scenarios.

3.4 All calculations are made on an economic basis, i.e. aiming at optimizing decisions from the point of view of the national economy. No national taxes, duties or subsidies are therefore included the cost of any commodity. All costs (both investment and operation) incurred to supply electricity over the study period (20 years) are discounted at a uniform rate of 10 %.

3.5 Cameroon owns significant hydroelectric resources, which constitute the basis of its power generation system. Thermal units are generally limited to peak load generation, emergency backup and supply to remote areas. Present thermal units are either diesel engines or gas turbines. The future development of thermal generation in these countries will probably face the same limitations, and it is very unlikely that heavy base-load thermal units such as steam generators would be appropriate in this kind of small-scale systems. Therefore, only two types of thermal units have been considered among the options for developing the generation systems: single-cycle gas turbines (GT) and combined-cycle gas turbines (CCGT). The main standard characteristics for these units have been determined on the basis of a market review, as explained below.

3.6 Fig. 1.1 shows the observed relationship between nominal power and unit price (USD/kW), for 76 best-selling gas turbines[6]. The figure also shows a regression curve calculated to best fit the observations. Based on this curve, one may estimate an average equipment cost for different typical sizes of gas turbines. Two typical sizes have been considered here:

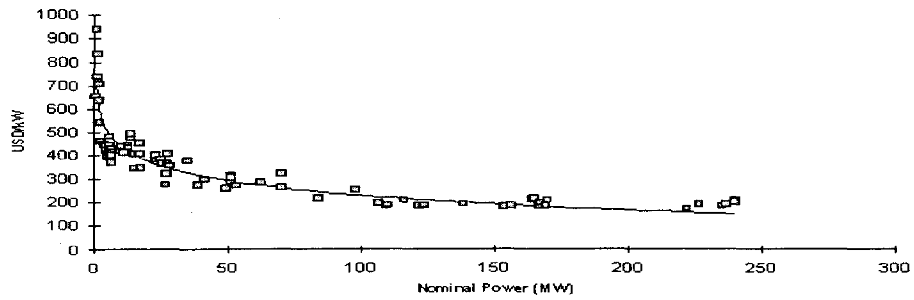
- 50 MW: In order to have a real available ("derated") power of 50 MW in running conditions in African countries, one will have to install a unit of 55 MW nominal power. Using the regression curve, the typical cost will be 282 USD/kW, or 310 USD per derated kW. This covers only the equipment itself, FOB factory; it does not include items such as step-up transformers, switchgear, fuel treatment and compression equipments, foundations, freight and insurance, real estate, contingencies, etc. In order to estimate the total turnkey installed plant price, one typically may add between 50 and 100 percent to the equipment cost. Assuming 75 % in the present case, this leads to a total installed cost, excluding taxes and duties as well as financial and debt service charges, of 543 USD/derated kW.

- 100 MW: Similarly, a real 100 MW available power will correspond to some 110 MW installed capacity. The regression curve gives a typical cost of 219 USD/kW, or 241 USD/derated kW. Assuming 75 % non-equipment costs, it gives a total 421 USD/derated kW.

- The investment cost is assumed to be 5 % higher for dual-fired turbines, designed to operate either on a natural gas or on a gas oil basis.

[6] Source: average price data published in the *Gas Turbine World Handbook*.

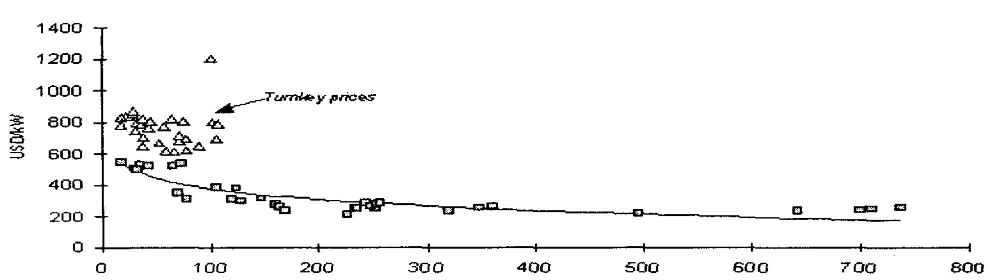
Figure 3.1: Turbogenerator Price Levels



Note: Prices are for equipment only, FOB factory.
Add between 75 and 100% for turnkey prices

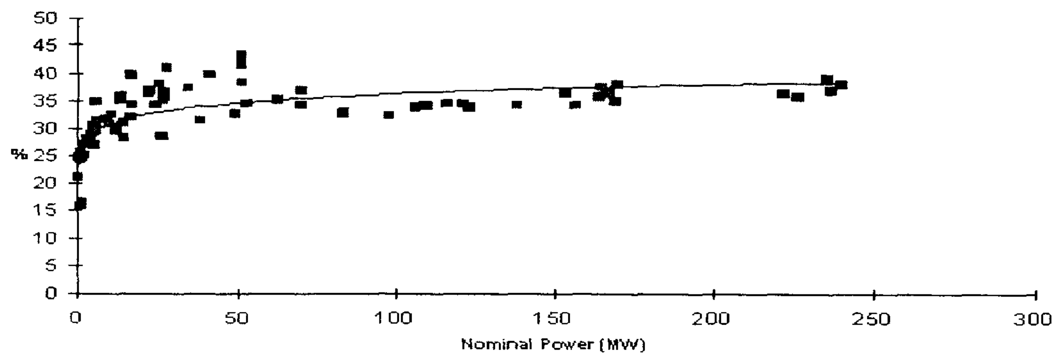
3.7 Fig. 3.2 shows the observed relationship between nominal power and unit price (USD/kW), for 31 commonly marketed combined-cycle packages (same data source as for gas turbines). The regression curve, calculated to best fit the observations, allows to estimate the equipment cost for typical sizes of combined-cycle plants. Taking account of the relatively small size of the power system, units of no more than 150 MW have been taken as standard options for the present study. As for open-cycle gas turbines, nominal power has been taken as 10 % higher than derated power. The equipment cost, estimated for a 165 MW (nominal) unit, is 323 USD/kW, i.e. 356 USD per derated kW. Considering the higher degree of uncertainty on the investment cost of combined-cycle plants (due to the greater impact of site requirements, of competitive market conditions), the non-equipment share of the total cost has been taken as 100 % of the equipment cost. Thus, the turnkey investment cost that has been used for calculation purposes is 711 USD per derated kW.

Figure 3.2: Combined Cycle Price Levels



3.8 Fig.1`.3 shows the ISO thermal efficiencies (LHV basis) for the same set of 76 single-cycle gas turbines as considered above. Though data dispersion is greater, a similar regression calculation has been performed. For a 50 MW (55 MW nominal) unit, it gives a 34.8 % net efficiency under ISO conditions (15°C, sea level and 60 % relative humidity). Assuming a 10 % degradation under real African climatic and operating conditions, that leads to a 31.3 % net efficiency. For a 100 MW gas turbine, the same calculation results in a 36.3 % ISO efficiency and 32.7 % under actual conditions.

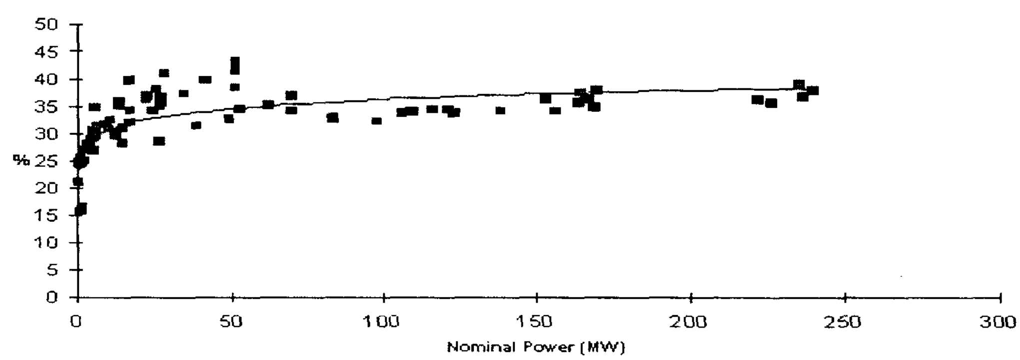
Figure 3.3: Typical Turbogenerator efficiency



Note: Net efficiencies under ISO conditions (15^{0}Celsius, sea level and 60% relative humidity.

3.9 On the basis of a similar regression analysis (fig.3.4.), the ISO thermal efficiency for a 150 MW combined-cycle package (165 MW nominal) is estimated at 51.7 %; under operating conditions, the actual efficiency is assumed to be 10 % lower, i.e. 46.5 %.

Figure 3.4: Typical Combined Cycle Efficiency



3.10 Assumptions have been made on the cost of competing fuels. As a matter of fact, gas oil is the best alternative to gas for feeding future thermal units (either gas turbines or combined-cycle units) and is used as the reference energy carrier. The price ratio of gas oil over crude oil is based on actual observations of the spot price of gas oil in the NWE market (Rotterdam) vs. the OPEC basket. Over the observation period the index shows at 128. That ratio has thus been adopted for the present study. The future evolution of crude oil price is assumed to be flat, at 21 USD per barrel, FOB loading port. The corresponding gas oil price is 26.88 USD/bl, or 194 USD/ton, FOB Rotterdam.

3.11 For calculation purposes, natural gas is assumed to have a lower calorific value of 37 MJ/cm after treatment (LPG extraction). It is assumed to be supplied at a minimum pressure of 25 bar, which is sufficient for most gas turbines and combined-cycle units.

Infrastructure

3.12 The state-owned utility SONEL (Société Nationale d'Electricité du Cameroun) has been in charge of electricity production, transmission and distribution in Cameroon since 1974. There is no legal monopoly in any of these activities.

3.13 Cameroon has a very large hydroelectric potential. An extensive inventory made in 1979 estimated the economically-attractive potential to 105 TWh at least. Moreover, annual and seasonal variations of river flows are relatively limited, thus reducing the need for thermal backup units.

3.14 The power system consists in two main independent subsystems: the southern network actually covers the southwest region (Yaounde, Douala, Bafoussam, Bamenda), while the northern system supplies Garoua, Guider and Maroua. The southern system typically accounts for more than 94 % of the total energy produced, against 5 % for the northern system and 1 % for the isolated centres. There is presently no project of interconnecting the two systems. Therefore, only the southern system will be studied here and no interconnection is considered over the study period, until 2015.

3.15 The southern system is mainly supplied by two large hydroelectric plants, Edea (263.2 MW installed capacity) and Song-Loulou (387.6 MW). Both are run-of-river plants, located on the Sanaga river, 60 and 90 km east of Douala, respectively. Song-Loulou has a daily regulation capacity, for itself and for the downstream Edea plant. Table 3.1 summarizes the main characteristics of these units. All units are reported to be in good condition.

3.16 The southern interconnected system also comprises three backup diesel plants: Bassa (Douala), 6 units totalling 15 MVA; Mefou (Yaounde), 6 units totalling 13 MVA (these units are the oldest ones in the system and have the poorest thermal efficiency); and Bafoussam, 2 units totalling 12 MVA. Their main technical characteristics are shown on Table 3.2. All these units presently use diesel oil, and no conversion to natural gas may be envisaged. These diesel units only operate a few hours per year (average utilization is typically 110 hours). As a consequence, their remaining lifetime is expected to be quite long; for planning purposes, Mefou is assumed to be operational until 2000, and Bassa and Bafoussam until 2010.

3.17 Self-generation is very common in remote areas, for forestry or agriculture. The total installed capacity is estimated at 50 MW over the whole country. However, most of it lies in zones that are not covered by the interconnected grids. Only two significant self-producers exist in the southern system area: the glass factory Socaver and the Sonara refinery. Both of them operate gas oil-fired diesel units, that are unsuitable for conversion to natural gas.

3.18 Song-Loulou and Edea are inter-connected by two 225 kV transmission lines. Two other 225 kV lines run from Edea to Douala (61 km) and to Yaounde (168 km). Another one goes directly from Song-Loulou to Douala (93 km). A line at the same voltage level connects Douala to Bekoko (41 km). That network, completed by additional

90 kV lines, e.g. from Edea to Douala and Yaounde, seems sufficient to ensure a good security of supply to Douala and, to a lesser extent, to Yaounde.

Table 3.1: Existing Hydroelectric Plants (Southern System)

	Edea I	Edea II	Edea III	**Total Edea**	Song-Loulou I	Song-Loulou II	**Total Song-Loulou**
Commissioning Year	1953	1958	1971/75		1981	1988	
Decommissioning Year	*not planned*	*not planned*	*not planned*		*not planned*	*not planned*	
Type	Run - of - river				Daily regulation		
Number of Units	3	6	5	14	4	4	8
Installed Power (MW)	34	125	104	263	192	192	384
Guaranteed flow in dry season (m3/s)				850			850
Power coefficient (MW/m3/s)				0.206			0.370
Firm Power in dry season (MW)				175			315
Minimum flow in extra-dry season * (m3/s)				700			700
Power coefficient (MW/m3/s)				0.206			0.370
Min. Power in extra-dry season (MW)				144			259
Availability (%)				80			87
Average Energy (GWh)				1740			2355
Firm Energy (GWh)				1050			1680

(extra-dry season = minimal flow statistically observed every 20 years)*

System Operation

3.19 In a typical year, total southern system energy sales amount to 2340 GWh, including 1335 GWh for the large aluminium factory Alucam, situated next to the Edea power plant. The energy generated was 2623 GWh, among which only 3.5 GWh from thermal units, 1341 GWh from Edea and 1279 GWh from Song-Loulou. The total loss factor appears rather low at the first glance (12 %); however, taking into account that more than half of the energy is supplied directly to Alucam at the Edea generator's end, the remaining public sector entails a much higher loss rate, above 25 %.

3.20 Peak load reach 242 MW for the public sector and 166 MW for Alucam. These peaks are not synchronous, which explains that the total system peak load was only 395 MW. The annual peak generally appears at the beginning of the dry season (here defined as from January to June).

Table 3.2: Technical data and assumption on existing and (considered) future thermal plants

Unit	Fuel type	Commis-sioning Year	Assumed Decommiss. Year (or expected lifetime)	Installed Power (MW)	Net Efficiency (%)	Specific Consump-tion (kg/kWh)	Lubricant Consump-tion (kg/kWh)	Equiv. Energy Consumption (MJ/kWh)	Variable Maintenance Cost (USD/MWh)	Total Vari-able Cost (USD/MWh)	Avail-ability (%)
. Existing:											
Pointe-Noire AGO	Diesel Oil	1979	2010	6.4	28.2%	0.3	0.01	15.15	10.00	117.47	70
Pointe-Noire 12PC	Diesel Oil	n.a.	2000	8.5	28.2%	0.3	0.01	15.15	10.00	117.47	75
Pointe-Noire Sulzer	Diesel Oil	n.a.	2010	4.2	30.3%	0.28	0.005	13.10	10.00	102.94	75
2. Future single-cycle gas turbines:											
TGGO50	Diesel Oil		20	50	31.3%	0.27	0.002	11.98	8.00	93.01	82
TGGN50	Natural Gas		20	50	31.3%		0.002	11.98	8.00	25.97	82
TGGO100	Diesel Oil		20	100	32.7%	0.26	0.002	11.49	8.00	89.52	82
TGGN100	Natural Gas		20	100	32.7%		0.002	11.49	8.00	25.23	82
3. Future combined-cycle units:											
CCGN	Natural Gas		20	150	46.5%		0.002	8.22	8.00	20.33	82

3.21 Three separate load duration curves have been considered for modeling purposes. Two for the utility, corresponding to wet and dry seasons, and one for Alucam over the whole year. As expected, the latter is almost flat, with an average utilization of 8040 hours/year. Seasonal curves for the utility have been calculated on the basis of available hourly peak records. The resulting average annual utilization is 5365 hours for the utility, and 6691 hours for the whole southern system. Figures 3.7 and 3.8 show the utility's seasonal load duration curves and its step approximation as introduced into the model. Shapes of all load curves have been assumed constant over the study period.

3.22 Considering the geographical breakdown of electricity consumption, it appears that the Douala region accounts for 50 % of energy sales at the MV level, against 31 % for Yaounde, 15 % for the western zone (Limbe, Bafoussam, etc) and 3 % for the Edea area (Alucam excluded).

3.23 No reliable data series have been found regarding historical energy consumption for the southern system as a whole. However, on the basis of production figures at the national level, a very contrasted evolution may be observed over the past three decades. During the post-independence period, between 1964 and 1974, the electricity production remained almost stagnant (+ 0.7 % on an annual basis), in spite of a steady growth of the national economy. This may be explained by the overwhelming importance of the quasi-constant Alucam demand, which accounted in 1964 for some 90 % of the total. A much more impressive growth was recorded during the 1974-1984 decade (+ 6.6 % p.a.), and more especially in the golden early 1980's. From 1984 to 1994, the worsening general economic context has induced a dramatic slowdown in the power sector, leading to an average annual growth rate of 2.2 % only.

Figure 3.5: Dry Season Load Curve (Jan-Jun)

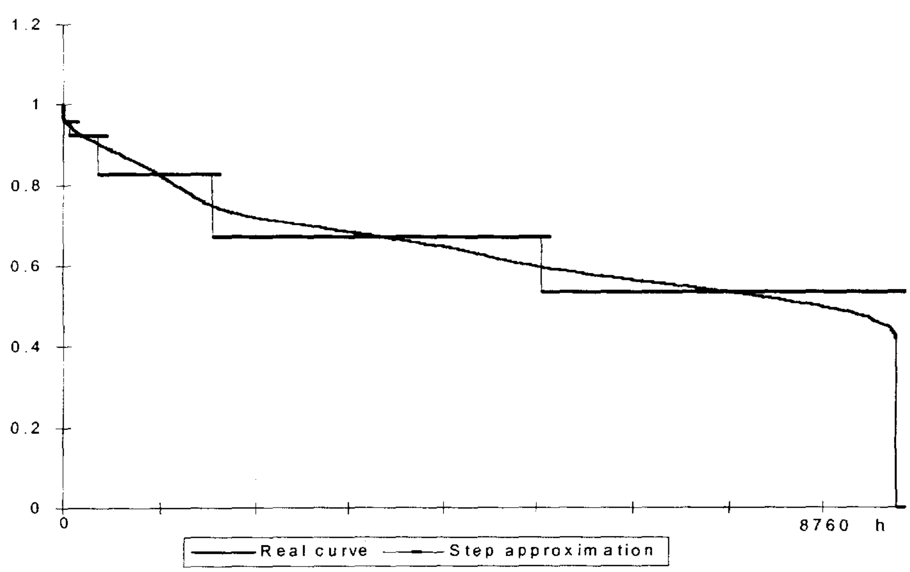
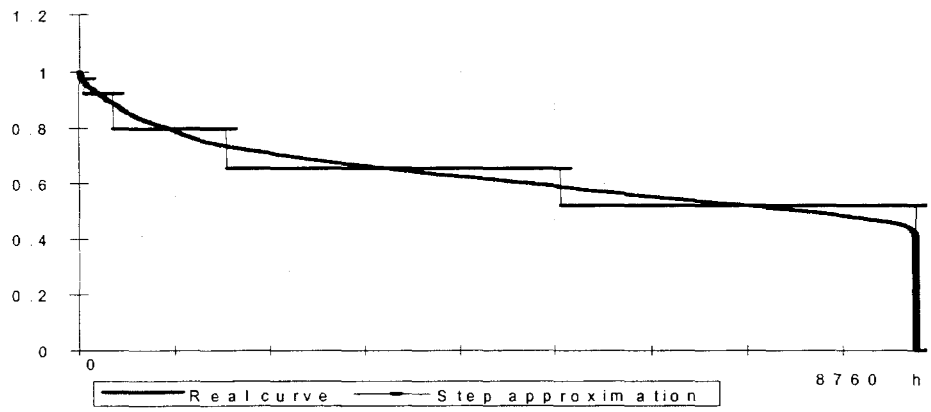


Figure 3.6: Wet Season Load Curve (Jul-Dec)



Note: For modelling reasons, both curves are presented here under an annual basis (8760 h) and in proportion of the seasons. The seasonal peak in the wet season is approximately 92.5% of the dry season peak.

Demand Forecast

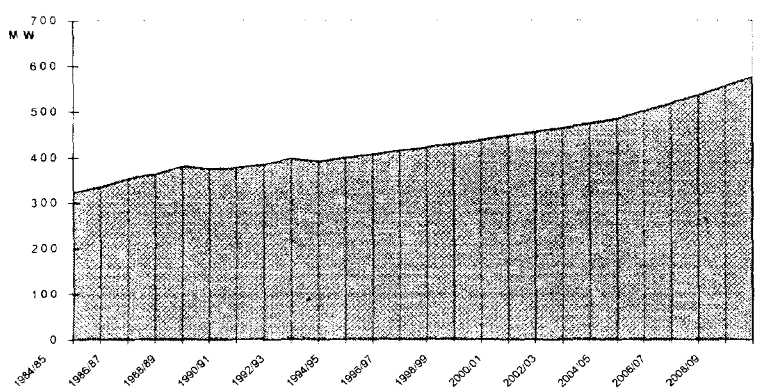
3.24 The importance of Alucam in the total electricity consumption, together with its very particular features (constant level of activity, extremely flat load curve) make it necessary to clearly separate it from the utility's demand in the elaboration of demand forecasts. The energy and power requirements of the Alucam factory, where no expansion is planned, are very likely to remain at the same level in the future. Average values of 1335 GWh and 166 MW have thus been adopted over the whole study period. It should be mentioned that projects have been evoked about the erection, in the long-term, of a second Alucam production site; would that be the case, a dedicated hydro plant (isolated from the national grid) would most probably be part of the project.

3.25 After a very fast growth period (+13.1 % per year) between FY1980/81 and 1986/87, the utility's (excluding Alucam) energy consumption has entered into a long stagnation period (+ 0.4 % per year from FY1987/88 on). The prime causes of that phenomenon are the general depression of the national economy and the dramatic reduction of the average purchase power resulting from devaluation and tax increases. There are no clear indices that a steady growth could resume in the short- to medium-term. In accordance with the views of Sonel planning executives, it appears reasonably optimistic to assume a 3 % average growth rate, for planning purposes, until the mid-2000s. However, a higher growth rate of 5 % will be adopted from FY2004/05 to the end of the planning horizon. Under these assumptions, the whole southern system would have to generate 3056 GWh in the year 2004/2005 (peak power 485 MW) and 4037 GWh in the year 2014/15 (peak power 696 MW). As a result from the decreasing relative share of Alucam, the overall system load factor will also progressively decrease, from the present 76 % (6691 hours) to 66 % (5800 hours) in 2014/15. Details on these energy demand forecasts are given in Table 3.9 and Figure 3.7.

Table 3.3: Power and Energy Demand Forecasts

	Alucam Energy Demand (GWh)	Public Sector Energy Demand (GWh)	Total Energy Demand (GWh)	Energy to be Produced (GWh)	Alucam Peak (MW)	Alucam Synchronous Peak (MW)	Public Sector Peak (MW)	Total Peak (MW)
1993/94	1335	1005	2340	2623	166	150	242	392
1994/95	1335	1035	2370	2657	166	150	249	399
1995/96	1335	1066	2401	2692	166	150	257	407
1996/97	1335	1098	2433	2727	166	150	264	414
1997/98	1335	1131	2466	2764	166	150	272	422
1998/99	1335	1165	2500	2802	166	150	281	431
1999/00	1335	1200	2535	2842	166	150	289	439
2000/01	1335	1236	2571	2882	166	150	298	448
2001/02	1335	1273	2608	2924	166	150	307	457
2002/03	1335	1311	2646	2966	166	150	316	466
2003/04	1335	1351	2686	3010	166	150	325	475
2004/05	1335	1391	2726	3056	166	150	335	485
2005/06	1335	1461	2796	3134	166	150	352	502
2006/07	1335	1534	2869	3216	166	150	369	519
2007/08	1335	1610	2945	3302	166	150	388	538
2008/09	1335	1691	3026	3392	166	150	407	557
2009/10	1335	1776	3111	3487	166	150	428	578
2010/11	1335	1864	3199	3586	166	150	449	599
2011/12	1335	1957	3292	3691	166	150	471	621
2012/13	1335	2055	3390	3800	166	150	495	645
2013/14	1335	2158	3493	3916	166	150	520	670
2014/15	1335	2266	3601	4037	166	150	546	696

Figure 3.7: Past and Forecasted Evolution of the Total Southern System Peak Load



Options for Power Generation

3.26 Comparing the present generation system and the projected demand evolution, it is quite clear that the present over-capacity situation will continue well into the next decade. The total hydroelectric capacity is 651 MW, and the firm hydro power in dry season amounts to 490 MW (total for Edea and Song-Loulou). They are supplemented by some 38 MW of thermal units in Bassa, Bafoussam and Mefou. Even if the latter presumably has a short remaining lifetime, that is probably enough to cover power (and energy) demand until the mid-2000s at least. Therefore, the set of development projects that had been identified and studied during the fast-growth period of the eighties has remained almost unchanged, and Sonel feels no real urgency in updating and refining these studies. The main projects are detailed hereunder.

3.27 The Lom and Pangar hydro storage dam is designed to regulate the Sanaga river in order to increase the regulated flow at Song-Loulou, from the present 850 cubic meters per second (cms) in dry season to 1040 cms; the total firm power of Edea and Song-Loulou would then reach 595 MW (i.e. a 105 MW increase). The budget for that project was estimated at 30 billion FCFA before devaluation. Assuming a 80 % increase due to devaluation and 2% annual escalation, the cost would now be in the order of 115 million USD, or 1095 USD/kW, excluding interests during construction (IDC). The construction time would be between 2 and 3 years. That project should certainly be considered among the first candidates when additional hydro power is required.

3.28 The Nachtigal run-of-river hydroelectric project is located on the Sanaga river, upstream of Song-Loulou and closer to Yaounde (70 km). It would add 266 MW to the generation system, with an average energy output of 1060 GWh per year. The investment cost has not been reevaluated since the 1988 estimate of 77 billion FCFA. Assuming a 2 % annual price escalation and a 80 % increase for devaluation, the total cost might now reach some 318 million USD, or 1195 USD/kW, plus IDC. According to the Sonel planning department, Nachtigal should be the first hydroelectric project to be realized (albeit after the Lom-Pangar regulation dam).

3.29 Njock is a reservoir dam on the Njong river, situated between Douala and Yaounde. The project consists in a 150 MW installation, with an average annual energy of 950 GWh. The investment cost, without IDC, is estimated at 371 million USD, or 2476 USD/kW. This project, as well as other hydro projects such as Memvé Elé, seems not to be given a very high degree of priority and clearly requires, anyway, thorough updating of technical and economical studies already done. Table 3.4 summarizes the main technical and economic characteristics of Nachtigal and Njock.

3.30 Concurrently to the hydroelectric projects, and taking account of the system size, 50 or 100 MW conventional gas turbines, either gas oil- or natural gas-fired, and 150 MW combined-cycle units have been considered among the possible generation options in some of the studied scenarios. Gas-fired units are assumed to be located in the Douala region. As mentioned previously, the *a priori* economic cost of natural gas has been taken as 1.50 USD/GJ. Economic opportunity cost of gas oil has been estimated considering that the alternative use is a local exportation to neighboring Central African countries. The calculation detailed on Table 3.5 shows that gas oil should be exported at 209 USD/t (FOB Limbe) to compete in the African markets with imports from Europe. Adding internal transport and distribution costs (or margins), it gives an economic cost of 266 USD/t CIF in Douala, or 6.26 USD/GJ.

Table 3.4. Cameroon: Possible Hydroelectric Projects Main Data and Assumptions

	Nachtigal	**Njock**
Type	Run-of-river	Reservoir
River	Sanaga	Njong
Installed Power (MW)	160	150
Firm Power in dry season (MW)	106	135
Min. Power in extra-dry season (MW)	94	105
Availability (%)	82	82
Average Energy (GWh)	1060	950
Estimated Investment_Cost (million USD)	318	371
Cost per kW (USD)	1990	2476

Note: Investment costs are given without interests during construction.

Table 3.5: Cameroon : Fuel Cost Assumptions (Taxes and Duties Excluded)

		USD/bbl	USD/ton	FCFA/l	USD/GJ
Gasoil Density	0.86				
Gasoil L.H.V. (MJ/kg)	42.5				
Crude OPEC Basket FOB		**21**			
Gasoil FOB Rotterdam		26.88	194		
Europe-Africa Freight Cost			30		
Selling Price on the African Market			224		
Regional Freight Cost			15		
Gasoil FOB Export Limbe			209	89.7	
Barge Transport to Douala				3.0	
Int. Margins Gasoil				21.6	
Gasoil CIF Douala			266	**114.3**	**6.26**
Natural Gas (a priori assumption)					**1.50**
Lubricants			**1700**		

3.31 Several projects exist regarding the reinforcement of the 225 kV transmission network. Two of them aim at improving the security and quality of supply in given cities of the existing network: the doubling of the Edea-Yaounde line, on the one hand, and a new line from Song-Loulou to Bafoussam (200 km), on the other hand. Both projects seem to have sound technical justifications, and studies should be launched by the utility in order to appraise their economical feasibility, which is not the objective of the present study. However, when comparing scenarios with thermal production sites in Douala, close to the load, to hydro solutions with new production capacity in Edea, Song-Loulou or upstream, the question arises whether more transmission infrastructure would be required in the latter case. Only a more detailed, network-based modeling exercise could answer that question properly. Yet a rapid analysis of the present HV transmission system shows that the maximum active power flow from the Sanaga plants to Douala is limited to some 151 MW in 225 kV plus 45 MW in 90 kV. Since two-thirds of the utility's power has to transit in that direction, it means that an additional line is required as soon as the public sector demand exceeds 294 MW, i.e. in the year 2000. Therefore, the investment cost for an additional line from Song-Loulou to Douala will be taken into account for all scenarios except those with a sufficient thermal capacity in Douala. That investment is roughly estimated at 150 USD/meter, which gives 14 million USD for 93 km.

Scenarios with no Natural Gas: Definition and Discussion

3.32 On the basis of the few basic investment options presented above, many development scenarios may be envisaged, and a large number of them have been tested with the model. Seven of them are presented in this section, chosen for being the most representative and/or economically attractive ones. They may be ranked in four categories; pure hydro, mixed hydro/thermal (gas oil-fired), pure thermal (gas oil-fired) and pure thermal (natural gas-fired). They are presented hereunder.

3.33 Among the possible development plans that rely only on hydro plants, the most attractive one (**Scenario 1**) features the Lom Pangar regulation dam, appearing in 2004, followed by the Nachtigal 266 MW hydropower scheme in 2011. No other investment is required over the study period, except an additional transmission line from Song-Loulou to Douala which becomes necessary in the year 2000. Table 3.2 details the economic calculations made on the basis of the annual investment and operating costs. The total investment costs were split over a 3 or 4 years lead time, according to standard assumptions for gas turbines on the one hand, and for hydro plants on the other hand; residual values are estimated assuming a 20 years lifetime for gas turbines, 25 years for transmission lines and 35 years for hydro plants. Operating costs have been calculated by the model and thus result of systematic unit commitment calculations for each year, each season and each step of the load curve. In the present hydro scenario, operating costs are of course almost negligible but the investment amounts are quite high. The total discounted cost, calculated with a 10 % discount rate, is 88.8 million USD for this scenario. Other hydro scenarios, including Njock or anticipating Nachtigal and postponing Lom Pangar, all lead to significantly higher discounted costs. In fact, the problem of having a full-hydro production system is that, in spite of large power reserve ratios during the wet season, power is constrained during dry season peak hours, and especially during extra-dry years. Therefore, the Lom Pangar regulation dam appears as a good solution since it increases the firm power of Edea and Song-Loulou during the dry season. It is also the lowest-investment hydro project among those considered, as both Nachtigal and Njock entail initial costs of more than 300 million USD.

3.34 The next two scenarios are both constituted of gas oil-fired gas turbines exclusively; **Scenario 2** supposes that all future investments are 50 MW gas turbine sets; according to the load evolution, five such units must be commissioned over the study period, in the years 2000, 2004, 2010, 2011 and 2014. Actually, the first one could be delayed until 2004 but then again a new transmission line would be required from Song-Loulou to Douala and the resulting cost would be higher. In the present case (see Table 3.7), the total discounted cost amounts to 42.6 million USD, which is significantly lower than the pure hydro option. It must be stressed that the need for investment is always a need for peak power only; consequently, the new gas turbines are expected to operate only a few hours per year, during the dry season peaks only. As shown on the figure, the thermal share in total generation remains very small over the whole period and is still below 5%, with an average utilization of 732 hours only, in the final year of the study. It should be noted here that in this kind of computations, the optimization principle generally tends to underestimate the actual working time of peak units; in addition, random supply shortages due to the transmission network have not been taken into consideration in the present study. Nevertheless, it remains clear that the role of thermal power in the system will remain drastically limited to peak and backup for the next 15 to 20 years at least.

3.35 **Scenario 3** is very similar to the previous one, except that it is based on larger-size gas turbines (100 MW). This allows to reap benefit from lower investment costs (per kW) and higher thermal efficiencies, but gives less flexibility for progressive capacity buildup. Table 3.8 shows how these advantages and disadvantages balance each other, leaving a small additional benefit compared to scenario 2, with a total discounted cost of 39.2 million USD.

3.36 Besides the previous three scenarios which were either full-hydro or full-thermal, it is evident that a large place remains for "hybrid" scenarios mixing hydro plants and gas turbines. Many combinations have been investigated, including either Lom Pangar or Nachtigal before or after one or several gas oil-fired gas turbines. The one presented here as **scenario 4** leads to the lowest discounted cost. It supposes the Lom Pangar regulation dam as the first investment, in 2004, followed by two 100 MW gas turbines in 2011 and 2014 (Table 3.3). This solution is by far less expensive than the pure hydro scenarios, but still results in a total cost of USD 58.2 million, which is 19 million above scenario 3. As a consequence, the cost of scenario 3 will be retained as reference cost for the economic appraisal of scenarios with natural gas, namely to calculate the discounted benefit for determining the netback value of natural gas in each of these scenarios.

Scenarios with Natural Gas: Definition and Discussion

3.37 As already mentioned, the introduction of natural gas in the power generation system is envisaged through three types or sizes of units: 50 or 100 MW gas turbines or 150 MW combined cycle packages. Each of the three "gas" scenarios will thus explore one of these options. **Scenario 5** (see Table 3.10) is the gas option equivalent to scenario 2, with five GT units commissioned over the study period. Though the investment cost, assumed to be 5 % higher for dual-fuel turbines, increases the discounted cost by 1.6 million USD, this is more than offset by much lower operating costs over the period (-6.1 million USD in discounted value). As a result, the total discounted cost for this scenario is 38.1 million USD, i.e. 4.5 million USD lower than for scenario 2, and still 1.1 million USD lower than the reference cost of scenario 3. In spite of their lower operating cost, the number of working hours of thermal units is the same as in scenario 2 and, consequently, natural gas demand remains low, reaching a maximum of 57 mmcm in the period's last year.

3.38 The value of gas, or average incremental benefit, is defined as the total discounted benefit resulting from the use of gas (assuming a nil cost for gas), divided by the discounted quantity of gas consumed over the period. In the present case, a constant *a priori* cost of 1.5 USD/GJ had been assumed for natural gas in all scenarios; therefore, this 1.5 USD has to be summed up with the result of the above calculation. The resulting value of gas in the present scenario is 2.4 USD/GJ.

3.39 Similar to scenario 3, **scenario 6** is based on 100 MW gas turbines, using of course natural gas instead of gas oil. Here again, in spite of a slight increase in investment costs, the total discounted cost is significantly lowered by the use of natural gas: 34.6 million USD, or 4.6 million USD less than the reference cost of scenario 3 (see Table 3.4). The netback value of natural gas in this scenario reaches the respectable value of 5.5 USD/GJ. However, the quantities of gas used remain in the same - very low - order as in scenario 5.

3.40 In spite of its lower total cost, it must be noted that scenario 6 offers less flexibility than scenario 5 regarding both time and place of future generation investments. In particular, considering that natural gas could only be made available in Douala, it may be advisable to base the future investment program on natural gas-fired gas turbines for the Douala region, and on gas oil-fired units to supply the Yaounde region. That split is more easily done with smaller-size units, as shown in **scenario 7** (Table 3.5) where 50 MW natural gas and gas oil units are commissioned in sequence. The total discounted cost is almost equal to that of scenario 5, as well as natural gas consumption, while gas oil units only operate at the very peak of the load curve, i.e. only a few hours a year. Trying the same exercise on the basis of 100 MW units would have led to a significant cost increase due to an imperfect adaptation of the supply system to the geographic load breakdown. However, entering deeper into this kind of geographic considerations could only be done on the basis of more detailed, network-oriented computations which are beyond the limits of the present study.

3.41 The last option (**scenario 8**) that will be presented here consists in the progressive buildup of a 150 MW natural gas-fired combined cycle unit. The package is composed of two 50 MW gas turbines complemented by a 50 MW heat recovery steam turbine. These components are not necessarily to be installed the same year, which allows to better distribute the investment charge over time. In the present case, a first 50 MW gas turbine is put in operation in the year 2000, the second one in 2004 and the steam unit in 2010. In possible preparation to a second combined cycle, two more gas turbines are installed in 2011 and 2014. The economic calculations detailed in Table 3.6 show that the efficiency gain due to the combined cycle structure is not very significant (and, in addition, it is only observed from 2010 on) while the investment cost increase is substantial. As a result, the total discounted cost amounts 42.3 million USD. This is 7.7 million above the cost of scenario 6 (which definitely appears as the least-cost option), but it is also 3.1 million more expensive than scenario 3, our "no gas" reference. This explains that the calculated netback value of gas is negative for this scenario (-2 USD/GJ). These results are, in fact, not surprising since the efficiency gain of combined cycle units may only be rewarding if the system composition allows them to operate with a rather high load factor, at least half-base. In the present case, where thermal power is only assigned to peaking and backup, less capitalistic options such as single-cycle gas turbines logically retain the advantage.

Table 3.6: Economic Calculation Sheet - Scenario 1

Monetary Unit: MUSD
Discount Rate: 10%
Gasoil Cost: 6.26 USD/GJ
Natural Gas Cost: 1.50 USD/GJ
GT Inv.cost: USD/kW
CC Inv.cost: USD/kW

Country: Cameroon

Scenario: Lom Pangar (regulation) in 2004 Nachtigal in 2011

	Generation Investments		Transmission Investments	Operating	Total	Natural Gas	G.T.	TG50	TG100	CC	Tot.gaz	Hydro	Diesel
	Lom Pangar	Nachtigal	Second Line Song Loulou - Douala	Cost		Consumption (Mm3/y)	Aver. Oper. Time (h)	GWH	GWH	GWH			
Inv. Cost	*115*	*318*											
1995/96					**0.0**								
1996/97				0.0	**0.0**	0	0					2714	
1997/98				0.0	**0.0**	0	0					2751	
1998/99				0.0	**0.0**	0	0					2795	
1999/00				0.0	**0.0**	0	0					2843	
2000/01			14	0.0	**14.0**	0	0					2886	
2001/02	17.3			0.2	**17.4**	0	0					2934	
2002/03	28.8			0.3	**29.1**	0	0					2981	
2003/04	57.5			0.5	**58.0**	0	0					3029	2
2004/05	**11.5**			0.0	**11.5**	0	0					3079	
2005/06				0.0	**0.0**	0	0					3129	
2006/07				0.0	**0.0**	0	0					3224	
2007/08				0.0	**0.0**	0	0					3315	0
2008/09		47.7		0.1	**47.8**	0	0					3417	0
2009/10		79.5		0.3	**79.8**	0	0					3518	2
2010/11		159.0		0.8	**159.8**	0	0					3630	2
2011/12		**31.8**		0.0	**31.8**	0	0					3745	
2012/13				0.0	**0.0**	0	0					3868	
2013/14				0.0	**0.0**	0	0					3991	
2014/15				0.0	**0.0**	0	0					4125	
2015/16				0.2	**0.2**	0	0					4264	
Res.Value	-76	-273	-6		***-354***								

TOTAL DISCOUNTED COST: **88.8** MUSD
AVERAGE NETBACK VALUE OF GAS: *#DIV/0!* USD/GJ

Table 3.7: Economic Calculation Sheet - Scenario 2

Country: Cameroon

Scenario: 5 x 50 MW Gasoil GT

Monetary Unit:	MUSD	
Discount Rate	10%	
Gasoil Cost:	6.26	USD/GJ
Natural Gas Cost :	1.50	USD/GJ
GT Inv.cost:	543	USD/kW
CC Inv.cost:		USD/kW

	Generation Investments					Operating	Total	Natural Gas	G.T.	Natural Gas	TG50	TG100	CC	Tot. gaz	Hydro I
	50 MW GT	50 MW GT	50 MW GT	50 MW GT	50 MW GT	Cost		Consumption (Mm3/y)	Aver. Oper. Time (h)	Consumption (Million GJ/y)	GWH	GWH	GWH		
Invest. Cost	*27.2*	*27.2*	*27.2*	*27.2*	*27.2*										
1995/96						0.0	**0.0**								
1996/97						0.0	**0.0**	0							2714
1997/98						0.0	**0.0**	0							2751
1998/99	4.1					0.0	**4.1**	0							2795
1999/00	13.6					0.0	**13.6**	0							2843
2000/01	**9.5**					0.0	**9.5**	0							2886
2001/02						0.0	**0.0**	0	0		0			0	2934
2002/03		4.1				0.1	**4.2**	0	20		1			1	2982
2003/04		13.6				0.1	**13.7**	0	20		1			1	3029
2004/05		**9.5**				0.2	**9.7**	0	20		2			2	3076
2005/06						0.3	**0.3**	0	20		2			2	3130
2006/07						0.4	**0.4**	0	30		3			3	3219
2007/08						0.6	**0.6**	0	50		5			5	3308
2008/09			4.1			1.1	**5.1**	0	90		9			9	3405
2009/10			13.6	4.1		2.1	**19.7**	0	140		14			14	3497
2010/11			**9.5**	13.6		3.2	**26.3**	0	200		30		0	30	3593
2011/12				**9.5**		4.6	**14.1**	0	275		55		0	55	3689
2012/13					4.1	6.3	**10.3**	0	365		73		0	73	3795
2013/14					13.6	8.2	**21.8**	0	460		92		0	92	3899
2014/15					**9.5**	11.2	**20.7**	0	528		132		0	132	3993
2015/16						15.8	**15.8**	0	732		183		0	183	4071
Res.Value	*-16*	*-11*	*-19*	*-20*	*-24*		***-91***								

TOTAL DISCOUNTED COST:	**42.6**	MUSD
AVERAGE NETBACK VALUE OF GAS:	*#DIV/0!*	USD/GJ

Table 3.8: Economic Calculation Sheet - Scenario 3

Country: Cameroon

Scenario: 3 x 100 MW Gasoil GT

Monetary Unit:	MUSD	
Discount Rate:	10%	
Gasoil Cost:	6.26	USD/GJ
Natural Gas Cost:	1.50	USD/GJ
GT Inv.cost:	421	USD/kW
CC Inv.cost:		USD/kW

	Generation Investments			Transmission Investments	Operating	Total	Natural Gas	G.T.	Natural Gas	TG50	TG100	CC	Tot	Hydro	Diesel
	100 MW GT	100 MW GT	100 MW GT	Second Line Song Loulou - Douala	Cost		Consumption (Mm3/y)	Aver. Oper. Time (h)	Consumption (Million GJ/y)	GWH	GWH	GWH	gaz		
Inv. Cost	*0*	*0*	*0*												
1995/96						**0.0**									
1996/97					0.0	**0.0**	0							2714	
1997/98					0.0	**0.0**	0							2751	
1998/99					0.0	**0.0**	0							2795	
1999/00					0.0	**0.0**	0							2843	
2000/01				14	0.0	**14.0**	0							2886	
2001/02					0.2	**0.2**	0							2934	
2002/03	0.0				0.3	**0.3**	0							2981	
2003/04	0.0				0.5	**0.5**	0							3029	2
2004/05	**0.0**				0.2	**0.2**	0	20			2		2	3076	
2005/06					0.2	**0.2**	0	30			3		3	3129	
2006/07					0.4	**0.4**	0	40			4		4	3219	
2007/08					0.6	**0.6**	0	70			7		7	3309	0
2008/09					1.0	**1.0**	0	120			12		12	3405	0
2009/10		0.0			2.0	**2.0**	0	210			21		21	3498	0
2010/11		0.0			3.7	**3.7**	0	360			36		36	3593	2
2011/12		**0.0**			4.4	**4.4**	0	275			55		55	3690	
2012/13			0.0		6.0	**6.0**	0	365			73		73	3795	
2013/14			0.0		7.9	**7.9**	0	460			92		92	3898	
2014/15			**0.0**		10.6	**10.6**	0	440			132		132	3993	
2015/16					14.8	**14.8**	0	613			184		184	4081	
Res.Value	*0*	*0*	*0*	*-6*		**-6**									

TOTAL DISCOUNTED COST: **16.5** MUSD
AVERAGE NETBACK VALUE OF GAS: *#DIV/0!* USD/GJ

Table 3.9: Economic Calculation Sheet - Scenario 4

Monetary Unit:	MUSD	
Discount Rate:	10%	
Gasoil Cost:	6.26	USD/GJ
Natural Gas Cost:	1.50	USD/GJ
GT Inv.cost:	421	USD/kW
CC Inv.cost:		USD/kW

Country: Cameroon

Scenario: Lom Pangar (regulation) in 2004
2 x 100 MW Gasoil GT

	Generation Investments			Transmission Investments	Operating	Total	Natural Gas	G.T.	Natural Gas	TG50	TG100	CC	Tot.gaz	Hydro	Diese
	Lom Pangar	100 MW GT	100 MW GT	Second Line Song Loulou - Douala	Cost		Consumption (Mm3/y)	Aver. Oper. Time (h)	Consumption (Million GJ/y)	GWH	GWH	GWH			
Invest. Cost	*115*	*42.1*	*42.1*												
1995/96						**0.0**									
1996/97					0.0	**0.0**	0							2714	
1997/98					0.0	**0.0**	0							2751	
1998/99					0.0	**0.0**	0							2795	
1999/00					0.0	**0.0**	0							2843	
2000/01				14	0.0	**14.0**	0							2886	
2001/02	17.3				0.2	**17.4**	0							2934	
2002/03	28.8				0.3	**29.1**	0							2981	
2003/04	57.5				0.5	**58.0**	0							3029	2
2004/05	**11.5**				0.0	**11.5**	0							3079	
2005/06					0.0	**0.0**	0							3129	
2006/07					0.0	**0.0**	0							3224	
2007/08					0.0	**0.0**	0							3315	0
2008/09					0.1	**0.1**	0							3417	0
2009/10		6.3			0.3	**6.7**	0							3518	2
2010/11		21.1			0.8	**21.8**	0							3630	2
2011/12		**14.7**			0.3	**15.1**	0	40			4		4	3740	
2012/13			6.3		0.7	**7.0**	0	70			7		7	3861	
2013/14			21.1		1.4	**22.5**	0	110			11		11	3979	
2014/15			**14.7**		1.8	**16.6**	0	115			23		23	4102	
2015/16					3.6	**3.6**	0	220			44		44	4220	
Res.Value	*-76*	*-32*	*-38*	*-6*		***-151***									

TOTAL DISCOUNTED COST: 58.2 MUSD
AVERAGE NETBACK VALUE OF GAS: USD/GJ

Table 3.10: Economic Calculation Sheet - Scenario 5

Country: Cameroon

Scenario: 5 x 50 MW Nat.Gas GT

Monetary Unit:	MUSD	
Discount Rate:	10%	
Gasoil Cost:	6.26	USD/GJ
Natural Gas Cost:	1.50	USD/GJ
GT Inv.cost:	570	USD/kW
CC Inv.cost:		USD/kW

	Generation Investments					Operating	Total	Natural Gas	G.T.	Natural Gas	TG50	TG100	CC	Tot.gaz	Hydro	Diesel
	50 MW GT	50 MW GT	50 MW GT	50 MW GT	50 MW GT	Cost		Consumption (Mm3/y)	Aver. Oper. Time (h)	Consumption (Million GJ/y)	GWH	GWH	GWH			
Invest. Cost	*28.5*	*28.5*	*28.5*	*28.5*	*28.5*											
1995/96						0.0	**0.0**			0.0						
1996/97						0.0	**0.0**	0		0.0					2714	
1997/98						0.0	**0.0**	0		0.0					2751	
1998/99	4.3					0.0	**4.3**	0		0.0					2795	
1999/00	14.3					0.0	**14.3**	0		0.0					2843	
2000/01	**10.0**					0.0	**10.0**	0		0.0					2886	
2001/02						0.0	**0.0**	0	20	0.0	1			1	2933	
2002/03		4.3				0.0	**4.3**	0	20	0.0	1			1	2981	0
2003/04		14.3				0.1	**14.3**	1	40	0.0	2			2	3029	0
2004/05		**10.0**				0.1	**10.0**	1	20	0.0	2			2	3077	0
2005/06						0.1	**0.1**	1	30	0.0	3			3	3129	0
2006/07						0.1	**0.1**	1	40	0.0	4			4	3220	0
2007/08						0.2	**0.2**	2	70	0.1	7			7	3308	0
2008/09			4.3			0.4	**4.7**	4	120	0.1	12			12	3405	0
2009/10			14.3	4.3		0.9	**19.4**	7	210	0.2	21			21	3498	0
2010/11			**10.0**	14.3		1.0	**25.3**	12	253	0.4	38			38	3594	0
2011/12				**10.0**		1.5	**11.4**	17	275	0.6	55			55	3689	
2012/13					4.3	2.1	**6.4**	23	365	0.8	73			73	3795	
2013/14					14.3	2.9	**17.2**	29	460	1.1	92			92	3899	
2014/15					**10.0**	3.6	**13.6**	41	528	1.5	132			132	3993	
2015/16						5.3	**5.3**	57	732	2.1	183			183	4071	
Res.Value	*-17*	*-11*	*-20*	*-21*	*-26*		**-95**									

TOTAL DISCOUNTED COST: **38.1** MUSD

AVERAGE NETBACK VALUE OF GAS: *2.4* USD/GJ

Table 3.11: Economic Calculation Sheet - Scenario 6

Country: Cameroon

Scenario: 3 x 100 MW Natural Gas GT

Monetary Unit:	MUSD	
Discount Rate:	10%	
Gasoil Cost:	6.26	USD/GJ
Natural Gas Cost:	1.50	USD/GJ
GT Inv.cost:	442	USD/kW
CC Inv.cost:		USD/kW

	Generation Investments			Transmission Investments	Operating	Total	Natural Gas	G.T.	Natural Gas	TG50	TG100	CC	Tot.gaz	Hydro	Diesel
	100 MW GT	100 MW GT	100 MW GT	Second Line Song Lou-lou - Douala	Cost		Consumption (Mm3/y)	Aver. Oper. Time (h)	Consumption (Million GJ/y)	GWH	GWH	GWH			
Inv. Cost	*44.2*	*44.2*	*44.2*												
1995/96						**0.0**			0.0						
1996/97					0.0	**0.0**	0		0.0					2714	
1997/98					0.0	**0.0**	0		0.0					2751	
1998/99					0.0	**0.0**	0		0.0					2795	
1999/00					0.0	**0.0**	0		0.0					2843	
2000/01				14	0.0	**14.0**	0		0.0					2886	
2001/02					0.2	**0.2**	0		0.0					2934	
2002/03	6.6				0.3	**7.0**	0		0.0					2981	
2003/04	22.1				0.5	**22.6**	0		0.0					3029	2
2004/05	**15.5**				0.1	**15.5**	1	20	0.0		2		2	3076	
2005/06					0.1	**0.1**	1	30	0.0		3		3	3129	
2006/07					0.1	**0.1**	1	40	0.0		4		4	3219	
2007/08					0.2	**0.2**	2	70	0.1		7		7	3309	0
2008/09					0.4	**0.4**	4	120	0.1		12		12	3405	0
2009/10		6.6			0.9	**7.5**	6	210	0.2		21		21	3498	0
2010/11		22.1			1.7	**23.8**	11	360	0.4		36		36	3593	2
2011/12		**15.5**			1.4	**16.9**	16	275	0.6		55		55	3690	
2012/13			6.6		2.0	**8.7**	22	365	0.8		73		73	3795	
2013/14			22.1		2.9	**25.0**	27	460	1.0		92		92	3898	
2014/15			**15.5**		3.3	**18.8**	39	440	1.5		132		132	3993	
2015/16					4.7	**4.7**	55	613	2.0		184		184	4081	
Res.Value	*-18*	*-33*	*-40*	*-6*		***-96***									

TOTAL DISCOUNTED COST: **34.6** MUSD

AVERAGE NETBACK VALUE OF GAS: **5.5** USD/GJ

Table 3.12: Economic Calculation Sheet - Scenario 7

Country: Cameroon

Scenario: 3 x 50 MW Nat.Gas GT
2 x 50 MW Gasoil GT

Monetary Unit:	MUSD	
Discount Rate:	10%	
Gasoil Cost:	6.26	USD/GJ
Natural Gas Cost:	1.50	USD/GJ
NG GT Inv.cost:	570	USD/kW
GO GT Inv.cost:	543	USD/kW

	Generation Investments					Operating	Total	Natural Gas	Natural Gas	TG50 NG	TG50 GO	CC	Tot.gaz	Hydro	Diesel
	50 MW NG GT	50 MW GO GT	50 MW NG GT	50 MW GO GT	50 MW NG GT	Cost		Consumption (Mm3/y)	Consumption (Million GJ/y)	GWH	GWH	GWH			
Invest. Cost	*28.5*	*27.2*	*28.5*	*27.2*	*28.5*										
1995/96						0.0	**0.0**		0.0						
1996/97						0.0	**0.0**	0	0.0					2714	
1997/98						0.0	**0.0**	0	0.0					2751	
1998/99	4.3					0.0	**4.3**	0	0.0					2795	
1999/00	14.3					0.0	**14.3**	0	0.0					2843	
2000/01	**10.0**					0.0	**10.0**	0	0.0					2886	
2001/02						0.0	**0.0**	0	0.0	1				2933	
2002/03		4.1				0.0	**4.1**	0	0.0	1				2981	0
2003/04		13.6				0.1	**13.6**	1	0.0	2				3029	0
2004/05		**9.5**				0.1	**9.6**	1	0.0	2	0			3077	0
2005/06						0.1	**0.1**	1	0.0	3	0			3129	0
2006/07						0.2	**0.2**	1	0.0	4	0			3220	0
2007/08						0.3	**0.3**	2	0.1	5	1			3308	1
2008/09			4.3			0.5	**4.8**	3	0.1	9	2			3405	1
2009/10			14.3	4.1		1.1	**19.4**	5	0.2	17	3			3498	1
2010/11			**10.0**	13.6		1.2	**24.7**	11	0.4	36	1			3594	1
2011/12				**9.5**		1.7	**11.2**	16	0.6	51	4			3689	
2012/13					4.3	2.5	**6.8**	20	0.7	65	7			3795	
2013/14					14.3	3.6	**17.9**	25	0.9	80	12			3899	
2014/15					**10.0**	4.0	**14.0**	39	1.4	125	7			3993	
2015/16						6.0	**6.0**	53	2.0	171	12			4071	
Res.Value	*-17*	*-11*	*-20*	*-20*	*-26*		***-94***								

TOTAL DISCOUNTED COST: **38.0** MUSD

AVERAGE NETBACK VALUE OF GAS: *2.6* USD/GJ

Table 3.13: Economic Calculation Sheet - Scenario 8

Country: Cameroon

Scenario: 3 x 50 MW NG.(GT-CC) in 2000-2010
2 x 50 MW NG.GT in 2011 and 2014

Monetary Unit:	MUSD	
Discount Rate:	10%	
Gasoil Cost:	6.26	USD/GJ
Natural Gas Cost:	1.50	USD/GJ
GT Inv.cost:	570	USD/kW
CC Inv.cost:	711	USD/kW

	Generation Investments				Transmission	Operating	Total	Natural Gas	G.T.	Natural Gas	TG50	TG100	CC	Tot.gaz	Hydro	Diesel
	2 x 50 MW GT	50 MW ST	50 MW GT	50 MW GT	Second Line Song Loulou - Douala	Cost		Consumption (Mm3/y)	Aver. Oper. Time (h)	Consumption (Million GJ/y)	GWH	GWH	GWH			
Invest. Cost	*28.5*	*49.65*	*28.5*	*28.5*												
1995/96							**0.0**			0.0						
1996/97						0.0	**0.0**	0		0.0					2714	
1997/98						0.0	**0.0**	0		0.0					2751	
1998/99	4.3					0.0	**4.3**	0		0.0					2795	
1999/00	14.3					0.0	**14.3**	0		0.0					2843	
2000/01	**10.0**					0.0	**10.0**	0	0	0.0					2886	
2001/02						0.0	**0.0**	0	20	0.0	1			1	2934	
2002/03	4.3					0.0	**4.3**	0	20	0.0	1			1	2981	
2003/04	14.3					0.1	**14.3**	1	40	0.0	2			2	3029	
2004/05	**10.0**					0.1	**10.0**	1	20	0.0	2			2	3077	
2005/06						0.1	**0.1**	1	30	0.0	3			3	3130	
2006/07						0.1	**0.1**	1	40	0.0	4			4	3219	
2007/08						0.2	**0.2**	2	70	0.1	7			7	3308	
2008/09		7.4				0.4	**7.8**	4	120	0.1	12			12	3405	
2009/10		24.8	4.3			0.9	**30.0**	7	210	0.2	21			21	3497	
2010/11		**17.4**	14.3			0.9	**32.5**	8	253	0.3			38	38	3593	
2011/12			**10.0**			1.3	**11.2**	12	275	0.4	1		54	55	3689	
2012/13				4.3		1.8	**6.1**	15	360	0.6	1		71	72	3795	
2013/14				14.3		2.6	**16.9**	20	460	0.7	3		89	92	3899	
2014/15				**10.0**		3.2	**13.1**	28	528	1.0	7		125	132	3993	
2015/16						4.7	**4.7**	40	732	1.5	12		171	183	4071	
Res.Value	*-17*	*-35*	*-21*	*-26*	*0*		***-99***									

TOTAL DISCOUNTED COST:	**42.3**	MUSD
AVERAGE NETBACK VALUE OF GAS:	*-2.0*	USD/GJ

Joint UNDP/World Bank
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	--
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa (English)	06/96	182/96
	Commercialization of Marginal Gas Fields (English)	12/97	201/97
	Commercilizing Natural Gas: Lessons from the Seminar in Nairobi for Sub-Saharan Africa and Beyond	01/00	225/00
	Africa Gas Initiative – Main Report: Volume I	02/01	240/01
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
	Africa Gas Initiative – Angola: Volume II	02/01	240/01
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cameroon	Africa Gas Initiative – Cameroon: Volume III	02/01	240/01
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
	In Search of Better Ways to Develop Solar Markets: The Case of Comoros	05/00	230/00
Congo	Energy Assessment (English)	01/88	6420-COB

Region/Country	*Activity/Report Title*	*Date*	*Number*
Congo	Power Development Plan (English and French)	03/90	106/90
	Africa Gas Initiative – Congo: Volume IV	02/01	240/01
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
	Project of Energy Efficiency in Buildings (English)	09/95	175/95
	Africa Gas Initiative – Côte d'Ivoire: Volume V	02/01	240/01
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
	Africa Gas Initiative – Gabon: Volume VI	02/01	240/01
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
	Implementation Manual: Financing Mechanisms for Solar Electric Equipment	07/00	231/00
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83

Region/Country	*Activity/Report Title*	*Date*	*Number*
Malawi	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87
	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
	Sample Survey of Low Voltage Electricity Customers	06/97	195/97
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Energy Assessment (English and French)	07/91	8017-RW
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vols. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
Republic of South Africa	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84

Region/Country	*Activity/Report Title*	*Date*	*Number*
Sudan	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
	Household Energy Strategy Study	10/97	198/97
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90
	Power Loss Reduction Volume 1: Transmission and Distribution SystemTechnical Loss Reduction and Network Development (English)	06/98	204A/98
	Power Loss Reduction Volume 2: Reduction of Non-Technical Losses (English)	06/98	204B/98
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
	Energy Assessment (English)	12/96	193/96
	Rural Electrification Strategy Study	09/99	221/99
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Power Sector Management Institution Building (English)	09/89	--
	Petroleum Management Assistance (English)	12/89	109/89
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP) (English)	12/94	--
	Rural Electrification Study	03/00	228/00

Region/Country	*Activity/Report Title*	*Date*	*Number*
	EAST ASIA AND PACIFIC (EAP)		
Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
	Improving the Technical Efficiency of Decentralized Power Companies	09/99	222/999
Fiji	Energy Assessment (English)	06/83	4462-FIJ
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
	Institutional Development for Off-Grid Electrification	06/99	215/99
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979-SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94

Region/Country	*Activity/Report Title*	*Date*	*Number*
Vietnam	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
	Petroleum Fiscal Issues and Policies for Fluctuating Oil Prices In Vietnam	02/01	236/01
Western Samoa	Energy Assessment (English)	06/85	5497-WSO
	SOUTH ASIA (SAS)		
Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
	Environmental Issues in the Power Sector (English)	06/98	205/98
	Environmental Issues in the Power Sector: Manual for Environmental Decision Making (English)	06/99	213/99
	Household Energy Strategies for Urban India: The Case of Hyderabad	06/99	214/99
	Greenhouse Gas Mitigation In the Power Sector: Case Studies From India	02/01	237/01
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Formulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86
	EUROPE AND CENTRAL ASIA (ECA)		
Bulgaria	Natural Gas Policies and Issues (English)	10/96	188/96
Central and Eastern Europe	Power Sector Reform in Selected Countries	07/97	196/97

Region/Country	*Activity/Report Title*	*Date*	*Number*
Central and Eastern Europe	Increasing the Efficiency of Heating Systems in Central and Eastern Europe and the Former Soviet Union	08/00	234/00
	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Kazakhstan	Natural Gas Investment Study, Volumes 1, 2 & 3	12/97	199/97
Kazakhstan & Kyrgyzstan	Opportunities for Renewable Energy Development	11/97	16855-KAZ
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
	Natural Gas Upstream Policy (English and Polish)	08/98	206/98
	Energy Sector Restructuring Program: Establishing the Energy Regulation Authority	10/98	208/98
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Slovenia	Workshop on Private Participation in the Power Sector (English)	02/99	211/99
Turkey	Energy Assessment (English)	03/83	3877-TU
	Energy and the Environment: Issues and Options Paper	04/00	229/00

MIDDLE EAST AND NORTH AFRICA (MNA)

Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
Morocco	Energy Sector Institutional Development Study (English and French)	07/95	173/95
	Natural Gas Pricing Study (French)	10/98	209/98
	Gas Development Plan Phase II (French)	02/99	210/99
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector (English)	06/90	115/90
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
	Renewable Energy Strategy Study, Volume I (French)	11/96	190A/96
	Renewable Energy Strategy Study, Volume II (French)	11/96	190B/96
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91

LATIN AMERICA AND THE CARIBBEAN (LAC)

LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
	Elimination of Lead in Gasoline in Latin America and the Caribbean (English and Spanish)	04/97	194/97
	Elimination of Lead in Gasoline in Latin America and the Caribbean - Status Report (English and Spanish)	12/97	200/97

Region/Country	*Activity/Report Title*	*Date*	*Number*
LAC Regional	Harmonization of Fuels Specifications in Latin America and the Caribbean (English and Spanish)	06/98	203/98
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	National Energy Plan (Spanish)	08/91	131/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
	Introducing Competition into the Electricity Supply Industry in Developing Countries: Lessons from Bolivia	08/00	233/00
	Final Report on Operational Activities Rural Energy and Energy Efficiency	08/00	235/00
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
	Hydro and Thermal Power Sector Study	09/97	197/97
	Rural Electrification with Renewable Energy Systems in the Northeast: A Preinvestment Study	07/00	232/00
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--
	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88

Region/Country	***Activity/Report Title***	***Date***	***Number***
Jamaica	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
	Reform and Privatization in the Hydrocarbon Sector (English and Spanish)	07/99	216/99
	Rural Electrification	02/01	238/01
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Sub Andean	Environmental and Social Regulation of Oil and Gas Operations in Sensitive Areas of the Sub-Andean Basin (English and Spanish)	07/99	217/99
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR

GLOBAL

	Energy End Use Efficiency: Research and Strategy (English)	11/89	--
	Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
	Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
	Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--
	Long-Term Gas Contracts Principles and Applications (English)	02/93	152/93
	Comparative Behavior of Firms Under Public and Private Ownership (English)	05/93	155/93
	Development of Regional Electric Power Networks (English)	10/94	--
	Roundtable on Energy Efficiency (English)	02/95	171/95
	Assessing Pollution Abatement Policies with a Case Study of Ankara (English)	11/95	177/95
	A Synopsis of the Third Annual Roundtable on Independent Power Projects: Rhetoric and Reality (English)	08/96	187/96
	Rural Energy and Development Roundtable (English)	05/98	202/98
	A Synopsis of the Second Roundtable on Energy Efficiency: Institutional and Financial Delivery Mechanisms (English)	09/98	207/98
	The Effect of a Shadow Price on Carbon Emission in the Energy Portfolio of the World Bank: A Carbon		

Region/Country	***Activity/Report Title***	***Date***	***Number***
Global	Backcasting Exercise (English)	02/99	212/99
	Increasing the Efficiency of Gas Distribution Phase 1: Case Studies and Thematic Data Sheets	07/99	218/99
	Global Energy Sector Reform in Developing Countries: A Scorecard	07/99	219/99
	Global Lighting Services for the Poor Phase II: Text Marketing of Small "Solar" Batteries for Rural Electrification Purposes	08/99	220/99
	A Review of the Renewable Energy Activities of the UNDP/ World Bank Energy Sector Management Assistance Programme 1993 to 1998	11/99	223/99
	Energy, Transportation and Environment: Policy Options for Environmental Improvement	12/99	224/99
	Privatization, Competition and Regulation in the British Electricity Industry, With Implications for Developing Countries	02/00	226/00
	Reducing the Cost of Grid Extension for Rural Electrification	02/00	227/00
	Undeveloped Oil and Gas Fields in the Industrializing World	02/01	239/01

2/13/01

ESMAP

The World Bank

1818 H Street, NW

Washington, DC 20433 USA

Tel.: 1.202.458.2321 Fax.: 1.202.522.3018

Internet: www.esmap.org

Email: esmap@worldbank.org

A joint UNDP/World Bank Programme