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STAFF APPRAISAL REPORT

BURMA

GAS DEVELOPMENT AND UTILIZATION PROJECT

May 21, 1987

Energy Department
Petroleum Projects, Division I

CURRENCY EQUIVALENTS

Currency Unit	=	Kyat (K)
K1.00	=	100 Pyas
as of April 30, 1987:		
K8.6349	=	SDR 1.00
K6.6104	=	US$1.00

WEIGHTS AND MEASURES

1 barrel (bbl)	=	0.159 cubic meters (m^3)
1 British Thermal Unit (Btu)	=	0.252 kilocalories (kcal)
1 cubic foot (CF)	=	0.028 m^3
1 kilometer (km)	=	0.621 miles
1 metric ton (mt) of oil (0.85 sp.gr.)	-	7.5 bbl
BCF	=	billion cubic feet
bpd	=	barrels per day
kgoe	=	kilogram of oil equivalent in heating value
MCF	=	thousand standard cubic feet
MMbbl	=	million barrels
MMCFD	=	million standard cubic feet per day
MMtoe	=	million tons of oil equivalent
MW	=	megawatt (1,000 kilowatts)
TCF	=	trillion (1,000 billion) standard cubic feet
toe	=	tons of oil equivalent in heating value

ABBREVIATIONS AND ACRONYMS

CNG	Compressed Natural Gas
CPI	Council of People's Inspectorate
ECC	Economic Coordinating Committee
EPC	Electric Power Corporation
GOB	Government of Burma
GUS	Gas Utilization Study
IBRD	International Bank for Reconstruction and Development
IDA	International Development Association
IOC	International Oil Companies
IRR	Internal Rate of Return
LPG	Liquefied Petroleum Gas
LRMC	Long-run Marginal Cost
MOC	Myanma Oil Corporation
PGDP	Payagon Gas Development Program
PIC	Petrochemical Industries Corporation
PIU	Project Implementation Unit
PPSC	Petroleum Products Supply Corporation
SCADA	Supervisory Control and Data Acquisition
UNDP	United Nations Development Program

FISCAL YEAR

Except as otherwise specified, years in the report and annexes refer to the GOB/MOC fiscal year from April 1 - March 31 (as of 1974).

BURMA
GAS DEVELOPMENT AND UTILIZATION PROJECT
DEVELOPMENT CREDIT AND PROJECT SUMMARY

Borrower: Socialist Republic of the Union of Burma

Beneficiary: Myanma Oil Corporation (MOC)

Amount: SDR48.3 million (US$63.0 million equivalent)

Terms: Standard

Onlending Terms: The Government will onlend proceeds of the Credit to MOC at an interest rate of 7.9% per annum, with a repayment period of 20 years including 5 years of grace. The Borrower will bear the foreign exchange risk.

Project Description: This first IDA operation in the pétroleum sector would help alleviate the growing shortage of petroleum, which has hindered the growth of the Burmese economy, by supporting further development of the Payagon gas field to provide about 35 million cubic feet per day of additional gas to substitute for diesel and fuel oil in the Rangoon area. The project, which corresponds to Phase I of Burma's Payagon Gas Development Program (PGDP), would support: (a) the establishment of a sound gas pricing policy based on full cost recovery as a minimum; (b) drilling and completion of production wells, as well as installation of surface facilities, and gas transmission and distribution pipelines for Rangoon; (c) appraisal of additional reserves for Phase II of the PGDP; (d) gas subsector investment planning; (e) oil reservoir and production studies to evaluate options for increasing domestic oil production; and (f) introduction of modern petroleum engineering practices, technical assistance and training.

Justification and Risks: The economic rates of return are 59% for the Payagon Gas Development Program and 72% for Phase I of the PGDP (the proposed project). The project's high economic return is due to the low gas production costs, the high productivity of the Payagon gas field wells, and the proximity of assured markets for gas. The project would yield economy-wide benefits by substantially improving commercial energy availability. Technical risks related to gas reserves are low and would be further minimized by adequate seismic work before or in conjunction with drilling so as to minimize the number of dry delineation wells. The high importance attached to this project by GOB should reduce the risk of slow project implementation, especially as the project itself will help alleviate the severe energy shortage in the country.

Estimated Project Cost:

	Foreign	Local a/	Total
	------(US$ million)------		
Gas Field Development	20.5	13.0	33.5
Gas Transmission and Distribution	19.0	9.0	28.0
Technical Assistance	4.7	1.2	5.9
Appraisal Drilling for Phase II	5.0	3.0	8.0
LPG/CNG Pilot Scheme	1.5	0.5	2.0
Base Cost Estimate	50.7	26.7	77.4
Physical Contingencies	11.7	2.9	14.6
Price Contingencies	3.1	5.0	8.1
Total Project Cost	65.5	34.6	100.1

a/ Local costs include US$15.8 million of taxes and duties.

Financing Plan:

	Foreign	Local	Total
	------(US$ million)------		
Loans:			
GOB	-	34.6	34.6
IDA	63.0	-	63.0
UNDP	2.5	-	2.5
Total	65.5	34.6	100.1

Estimated Disbursements:

	US$ million						
IDA Fiscal Year	1988	1999	1990	1991	1992	1993	1994
Annual	13.9	21.6	15.8	9.4	1.9	0.3	0.1
Cumulative	13.9	35.5	51.3	60.7	62.6	62.9	63.0

Economic Rates of Return

The Payagon Gas Development Program	59%
The Project (Phase I of the Program)	72%

BURMA

GAS DISTRIBUTION AND UTILIZATION PROJECT

Table of Contents

This report is based on the findings of an IDA mission to Burma in December 1986 and was prepared by Messrs. A. S. El-Mekkawy, S. Khwaja, F. R. Manibog, M. Sergo and A. Smit of the Energy Department and Ms. M. Tumaliwan (Consultant).

ANNEXES

CHARTS

MAP

I. THE ENERGY SECTOR 1/

Introduction

1.01 Compared to most developing countries, Burma is fortunate to be endowed with abundant and varied indigenous sources of energy, including natural gas, crude oil, hydropower, forest resources, and coal. The country has substantial oil and gas reserves and the capacity to meet increasing domestic energy requirements at relatively low cost. Current energy supply, however, has been kept below realizable potential due to the scarcity of technical and financial resources needed to accelerate gas development and reverse the decline in oil production. The country has been experiencing serious energy shortages, which will become more acute in the absence of further energy sector investments. Burma has been successful in exploiting some of its gas resources on its own in recent years. As regards oil, however, production per well has been limited and further extraction from currently producing reservoirs has become increasingly difficult due to the natural productivity decline of the partially depleted oilfields and adverse conditions confronting oil production in Burma. An infusion of modern petroleum technology is required and could be expected to contribute to a significant improvement in oil recovery, as has been the case in China, where access to modern technology has been a key factor in achieving recent production gains.

1.02 The energy sector could be transformed into an important source of economic growth. Firstly, there is significant potential for increasing oil production. Secondly, the future role of Burma's sizeable but underdeveloped natural gas resources can be significantly enlarged and has become one of the key energy policy issues. The Government of Burma (GOB) has begun exploiting some onshore gas reserves through a series of natural gas-based industries and by encouraging the conversion to gas, wherever feasible, of power plants and industries using diesel and fuel oil. Since production costs for natural gas are very low and markets close to the gas fields, natural gas should remain a competitive energy source even at low oil international prices (para 5.08). The possibility of developing the Martaban offshore natural gas reserves to support major export-oriented, gas-based industries has also been considered by GOB but has been postponed due to large capital requirements and uncertainties in export markets for the industrial products. The more immediate supply option, therefore, is to accelerate the domestic production and utilization of lower-cost onshore gas reserves.

1.03 The proposed project would be a critical step in increasing rapidly the energy sector's contribution to economic growth by supporting the further appraisal and development of the Payagon gas field in southern Burma, as well as by expanding the gas transmission and distribution network to Rangoon. A

1/ A more detailed description and analysis of the energy sector is contained in the report entitled "Burma: Issues and Options in the Energy Sector" (June 1985, Report No. 5416-BA), which is part of a series of reports prepared under the Joint UNDP/World Bank Energy Sector Assessment Program.

gas utilization study would also be undertaken in order to outline a priority sequence of gas investments over the medium term, help design an efficient pipeline network to meet growing gas demand and, in conjunction with a major technical assistance package, promote better planning and strengthen institutions in the gas subsector. The project would also support transfer of much needed technology for petroleum reserve evaluation and reservoir management, heavy oil extraction and enhanced oil recovery.

Commercial Energy Supply/Demand Balance

1.04 Burma's main commercial energy resources are oil, natural gas and hydropower. The country also has some sub-bituminous coal deposits but their development for power generation appears less economic than that of gas or hydro resources in the foreseeable future. Burma's commercial energy consumption is among the lowest in the world at 33 kilograms of oil equivalent (kgoe) per capita, compared to 36 kgoe per capita in Bangladesh. It is estimated that as much as 86% of total energy requirements are met from traditional sources such as fuelwood, charcoal and biomass residues. Petroleum products dominate the commercial energy mix, accounting for 63% of total primary commercial energy supplies in 1985/86. The largest consumer of commercial energy was the transport sector (53%), followed by industry (42%) and households (5%). The minor share of the household sector reflects limited access to electricity and constrained supply of kerosene for use as cooking fuel.

1.05 Commercial energy is supplied almost entirely from domestic resources, with a very small contribution from imported coal. GOB's policy is not to trade in crude oil or petroleum products, relying entirely on local production and refining capacity. The result is a very high level of suppressed demand for petroleum products, which are now administratively allocated. Even under a conservative scenario of energy demand growth, the gap between supply and demand is estimated to be substantial, given falling domestic oil production and a level of commercial energy demand that is projected to at least double by the year 2000. 1/ This gap may be expected to widen unless immediate actions are taken to augment domestic commercial energy supplies.

Crude Oil

Reserves

1.06 Burma has a long history of oil exploration and production, dating back to 1887 when Burmah Oil Company made a first discovery at Yenangyaung. Twenty six fields have been discovered to date, mainly in Central Burma and some in the Upper Delta Basin, with potential in-place reserves including condensates estimated at 2 billion barrels (bbls); however, more than half of

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1/ More optimistic demand forecasts suggest a six-fold increase by the year 2000. Detailed demand forecasts for GOB's "Planned Growth" scenario and a lower "Economic Growth" scenario are provided in Chapter III and relevant annex tables of the June 1985 Energy Assessment Report.

these reserves are highly waxy with low recovery rates. Annex 1.01 provides more details on oil exploration, reserves and production.

Production

1.07 Oil production in Burma is characterized by a disparity between relatively large, proven reserves and continuously low and falling production. Modern engineering practices have not been applied to oil production, which, due to various technical difficulties, is at a very low 2.0% per year of proven recoverable reserves. Production levels have declined since FY81, also partly due to an excessive focus on exploration to the detriment of field development. Consequently, total available supply of petroleum products in FY84 was 0.86 million tons of oil equivalent (MMtoe), or around 19% less than the 1.06 MMtoe in FY80. Faced with such a decline, GOB decided to restrict kerosene supply for cooking purposes, making middle distillates available on a priority basis to industry.

1.08 Large infusions of modern petroleum technology are required in order to reverse the rapid decline in oil production. Furthermore, most oilfields have passed their peak production and further investments for oil extraction requires studies involving secondary and enhanced oil recovery techniques for optimal results. Oil production in Burma faces several technical constraints: (i) the high wax content and/or high viscosity of the crude oil in many reservoirs; (ii) the low formation pressures of many reservoirs; and (iii) low permeability of the reservoirs particularly due to the presence of clay particles that tend to swell in contact with fresh-water drilling mud. The project's technical assistance component provides an opportunity for Burma to expand and diversify its contacts with the international oil industry's expertise and leading service companies, which would help address some of these technical challenges. Many new wells will need to be drilled each year just to maintain production at the current level. As of December 1986, oil production averaged 21,500 barrels per day (bpd), down from 25,280 bpd in June 1986. This drop has been caused by a shortage of tubulars and other drilling consumables, which has severely restricted the level of development and infill drilling necessary to offset the natural decline of the oil fields. Continuing decline in development drilling, as reflected in the number of wells planned for FY87, will further result in reduced inventory of producing wells and steeper drops in oil production.

1.09 The offshore areas of Burma have always been open to international oil companies (IOCs) for petroleum exploration. However, the IOCs have not shown a strong interest in the offshore areas recently because these areas are considered gas-prone based on drilling results. Large reserves have been discovered offshore by the national oil company, the Myanma Oil Corporation (MOC) (see para 1.14), but cannot be developed economically on the basis of current international market and price conditions. Consequently, IOC interest in offshore exploration is expected to remain low. Since about 1963, GOB has not allowed any IOC to operate in the onshore areas as part of the Government's overall inward-looking economic policies. The onshore areas outside the currently producing provinces are underexplored. Although large areas of the country offer little petroleum potential as they are expected to consist mainly of metamorphosed rocks, the younger and less disturbed sediments in the western and northern parts of the country offer better possibilities. Any potential involvement by IOCs in these areas, however, would be further

complicated by local insurgency. The situation is similar to that of eastern Bangladesh, where Shell recently had to abandon its exploration venture in the Chittagong Hill Tracts due to continuing security problems.

1.10 While showing less interest in the southern, more gas-prone areas, there are indications that IOCs would be interested in exploration and production in the already established northern/central oil-producing basins. Their involvement could be beneficial to MOC through the transfer of advanced technology, particularly in the areas of drilling and reservoir engineering, including training of staff in reservoir management and production optimization. Although GOB has shown a willingness to discuss the interest of IOCs -- as evidenced by discussions in mid-1986 with the Japan National Oil Company, British Petroleum, Amoco and regular meetings with Shell -- some obstacles stand in the way of any imminent IOC involvement. For example, local insurgency problems exist in the areas of IOC interest. Furthermore, the Government may prefer IOCs to explore in the higher-risk, unexplored areas rather than the proven, producing basins that IOCs appear to prefer.

Petroleum Product Prices

1.11 All the domestic crude oil production is locally refined in three main and two small refineries operated by the Petrochemical Industries Corporation. Total petroleum products consumption is broken down as follows: diesel - 39%; gasoline - 29%; fuel oil - 21%; aviation fuel and lubricants - 9%; and kerosene - 2%. Petroleum product retail prices, which were fixed in the mid-1970s and have not been adjusted since, are almost 80% of equivalent border prices on a reconstituted barrel basis as shown below:

	Domestic Prices		CIF Prices a/	Domestic-to-Border
	K/IG	US$/mt	(US$/mt)	Price Ratio
Gasoline	3.60	162.	144.	1.13
Kerosene	2.60	105.	162.	0.65
Diesel	2.60	99.	167.	0.59
Fuel Oil	2.00	69.	110.	0.63

a/ Based on World Bank projections for international crude oil prices, adjusted for a set of projected refinery margins to arrive at expected ex-Singapore petroleum product prices; includes freight differentials. These international product price assumptions are explained in Chapter V ("Project Justification and Risks") and Annex 5.02.

The objective of pricing petroleum products to reflect fully their economic value should be attainable for GOB, considering that the weighted average domestic price is relatively near the equivalent border price. The pricing structure needs to be revised, focussing particularly on the low price of diesel, which has the highest share in total products consumption. Nonetheless, the petroleum products subsector is not a financial drain on the budget of GOB; to the contrary, it is a net contributor because the retail prices incorporate a high commodity tax of about 40%, representing revenues captured by GOB. On an annual basis, these tax revenues exceed GOB loans to cover the cash shortfalls of MOC and other state energy enterprises.

Natural Gas

Reserves and Production

1.12 Southern Burma is a major gas province. The predominance of gas over oil increases towards this area of the country. Based on the low level of the exploration effort for the different types of prospects (or "plays") in Burma's sedimentary basins, substantial possibilities remain for further non-associated gas discoveries, particularly in the lower delta area, onshore as well as offshore. Total established reserves of natural gas in Burma are estimated at 10 trillion standard cubic feet (TCF), of which MOC classifies 75% as proven and 25% as probable. Similar to the case of oil, the production rate of gas is very low at 0.5% of established reserves per year. This is due, however, to the fact that gas market development is still at its early stages and to financial constraints in expanding the gas infrastructure, and not to adverse reservoir conditions as in the case of oil production. Annex 1.01 provides more details on gas exploration, reserves and production.

1.13 Central Burma and the Upper Delta Basin contain nearly 2 TCF of gas in mainly oil-bearing reservoirs. In 1984/85, associated gas production from this region amounted to 65 MMCFD (23 BCF) of which about 25 MMCFD were used for power generation, fertilizer manufacturing, as a refinery fuel, and in cement/glass industries. 1/ With no other significant commercial users in the region, the rest of the gas (up to 40 MMCFD) is used in captive power plants and industries, reinjected or flared. 2/ Gas production in Burma to date has been mainly in the form of associated gas. Possibilities for increasing the production of this associated gas, which presently constitutes about 70% of overall gas production, is restricted by the rate at which oil production can be stepped up. Consequently, the bulk of the projected increase in demand for natural gas will have to be met from non-associated gas reserves.

1.14 During recent years, non-associated gas has been discovered in the Lower Delta Basin of Burma in two offshore structures and one onshore area. The offshore structures, which are estimated to contain 4 to 5 TCF, are located in the Gulf of Martaban. A preliminary study by Petro-Canada in 1985 of a commercial venture to recover 300 MMCFD of offshore gas for export-oriented petrochemical production indicated very high levels of investment required (about US$900 million in 1985 prices). The study also identified many significant commercial and technical risks associated with such a large project. GOB has reviewed the study with IDA and has agreed that, given the low international petroleum prices at present, it would postpone decision on the implementation of the Martaban offshore gas development project.

1/ Power generation (4.5 MMCFD); fertilizer manufacture (9.3 MMCFD); refinery fuel (3.5 MMCFD); cement/glass (8.0 MMCFD).

2/ Transportation by pipeline of this limited quantity of gas (up to 40 MMCFD) to the nearest concentration of medium-sized industrial demand over about 300 miles of rough and difficult terrain would be uneconomical.

Payagon Gas Field

1.15 The recent onshore non-associated gas discovery in the Lower Delta Basin is the Payagon field, located 64 miles from Rangoon. Details on the geology of Payagon are presented in Annex 1.01. Proven and probable reserves are presently estimated at about 0.8 TCF: proven reserves (i.e., gas reserves in the sands that are already producing) are calculated at 208 BCF, while probable reserves (i.e. gas reserves in sands found by exploratory drilling but from which production has not yet started) are calculated at 629 BCF. Several wells have been drilled and the field has been connected by a 10-inch diameter transmission pipeline to Rangoon. Production from three wells is around 30 MMCFD, which is the maximum capacity of the existing pipeline.

1.16 While MOC's exploration efforts have been sufficient to firm up gas reserves, ensuing appraisal and production efforts have been inadequate. Additional geophysical mapping of the producing horizons, drilling of appraisal and production wells, the construction of supplementary pipeline network (64 miles or 103 kilometers from Payagon to Rangoon and 152 miles or 245 kilometers from Rangoon to southern Burma) and an assessment of the potential for domestic uses of liquefied petroleum gas (LPG) and compressed natural gas (CNG) are required to achieve full utilization of the Payagon gas field. In view of the acute shortage of petroleum products, GOB has indicated strong interest in exploring the potential use of CNG and LPG in the transport sector. While a few gasoline- and diesel-fueled vehicles have been converted by MOC to use CNG and LPG on an experimental basis, it has not been possible in the absence of adequate equipment and knowhow to evaluate the performance of the converted vehicles and to prepare a full feasibility study.

Gas Utilization

1.17 Total domestic gas consumption has risen rapidly from 4.9 billion cubic feet (BCF) in FY75 to 8.8 BCF in FY79 and 16.8 BCF in FY84. This rapid growth has been due to increased gas use in three sectors: power generation, oil refining and industry. Current Payagon gas production of 30 MMCFD is being used in the Rangoon area for power generation (19 MMCFD), fuel for one refinery (7 MMCFD), and brick manufacture and a few, large industries (4 MMCFD).

1.18 Use of natural gas in Burma is projected to continue to rise substantially during the next two decades. Gas will substitute for current diesel and fuel oil consumption and stem further growth in diesel demand in the power, refinery and industry sectors. All the liquid fuels released can be readily absorbed within the domestic economy due to the high level of suppressed demand for petroleum products, especially middle distillates (see para 1.05). Projected Payagon gas sales up to FY96 for existing consumers, as well as step-wise and incremental demand growth, are discussed in Chapter V on "Project Justification and Risks".

1.19 In pursuing the full development of the Payagon gas field, it is essential that scarce financial resources be allocated to their best use, that is, in priority investments that deliver maximum benefits to the national economy at least cost. In practical terms, given the early stage of gas development in Burma, GOB requires an operational subsector policy and investment planning framework that is closely linked to the achievement of optimal

resource allocation and macroeconomic objectives. To meet this need, a Gas Utilization Study (GUS) will be undertaken as part of the project in order to firm up gas supply estimates, develop gas demand forecasting capabilities, estimate unconstrained gas demand, identify gas network and other field infrastructure requirements, and recommend optimal gas allocation among alternative uses and a sequence of priority investments, as well as concrete measures to accelerate penetration of the gas markets. Detailed terms of reference for the Study, which the United Nations Development Program has agreed to finance with IDA acting as executing agency, are provided in Annex 1.02. During negotiations, the final terms of reference for the Gas Utilization Study were agreed and assurances were obtained that GOB will review with IDA the progress and results of the Study.

Gas Pricing

1.20 Since the 1985 energy assessment, IDA has recommended to, and sought from, GOB the adoption of gas pricing principles based on full cost recovery, that is, a level that would at least cover the long-run marginal cost of Payagon gas development, transmission and distribution, and, at the same time, make the full development program for the Payagon field a financially viable operation for MOC. Application of these principles requires a substantial price increase from a level of about US$0.30 to US$1.00 (around K7.00) per thousand cubic feet (MCF). 1/ The existing low gas tariff was set originally to reflect only the incremental production costs of separating associated gas, which is a by-product in the production of crude oil. The Payagon field, however, contains "free" or non-associated gas, for which gas-dedicated wells need to be drilled, and a capital-intensive transmission and distribution system constructed, to deliver gas to consumers. The level of price increase required for Payagon gas was confirmed during the June 1986 IDA pre-appraisal mission, which has prepared jointly with MOC detailed pricing calculations following the above cost recovery criteria. This analysis subsequently formed the basis of further dialogue between IDA and GOB, and supported a position paper prepared by MOC seeking GOB approval to increase the Payagon gas price.

1.21 GOB has agreed to adopt Payagon gas pricing principles based on full cost recovery for MOC. In March 1987, GOB announced to IDA its decision that Payagon gas would be priced at K7.50/MCF (or US$ 1.13/MCF), to become effective on April 1, 1987. This price is well above long-run marginal cost and the level required for full cost recovery. During negotiations, GOB confirmed that the March 1987 announcement on Payagon gas price increase had been implemented. The further passing along of the increased gas price is not expected to require major adjustments under this project since the overall impact, even with the gas price increase, would be to lower the costs of the gas-using enterprises over time for the following reasons. Over 75% of full Payagon gas production will go to new gas users who would otherwise use more costly fuel oil and diesel whose prices are, respectively, around 46% (K11/MCF) and 113% (K16/MCF) higher than the increased Payagon gas prices in

1/ For Burma, which is a gas-surplus country, the depletion premium is estimated to be negligible. Under conservative reserve assumptions, this premium plus the US$1/MCF level that would achieve full cost recovery is well within the gas price levels decided by GOB. This analysis is presented in Chapter V on "Project Justification and Risks".

energy equivalent terms. For existing gas users, which will account for no more than 25% of Payagon gas production, cost savings due to the envisaged rapid rate of gas substitution for more expensive liquid fuels will quickly offset the cost increases resulting from the quadrupled gas price. For example, only about 5% of the Electric Power Corporation's installed generating capacity will be affected. In addition, at the time that Payagon gas was introduced at a low price, the new gas-using enterprises reaped a windfall as prices of their products based on costlier liquid fuels were not reduced despite the reduction in energy costs. Even at the higher gas price in effect as of April 1, 1987, these enterprises are in a more favorable position than prior to gas conversion due to the lower cost of gas (at the new price) as compared to the liquid fuels they were using. Nonetheless, the study on MOC's financial viability (see para 4.09 and Annex 4.03) will evaluate, among other financial measures, the effect of Payagon gas price increases on the financial viability of intermediate, gas-using enterprises, as well as the impact of passing along these gas price increases.

Hydropower

1.22 Burma has abundant hydropower resources in its river systems draining the Irrawadday, Chindwin, Salween and Sittang basins. The Electric Power Corporation estimates the whole country's hydropower potential to be more than 100,000 MW on an installed capacity basis, as compared to only around 650 MW of currently installed and planned capacity. Burma also has numerous sites that are suitable for mini-hydropower plants; seven stations with a total capacity of around 10.5 MW have been completed and 16 other sites with a total capacity of 14 MW are being investigated for possible development. GOB places high priority on hydropower development over the long term. Due to the high cost, environmental impact and long lead time of hydropower development, however, GOB has given equal and immediate importance to lower capital cost, gas-based power generation in order to meet the rapid growth in electricty demand.

1.23 Burma's sizeable natural gas potential has important implications for power generation. The bulk of projected gas substitution until the mid-1990s will occur in the power sector, specifically in the existing Kyaiklat, Ahlone and Ywama plants and the committed Thaketa plant. The Thaketa gas turbine alone would absorb over half of the additional Payagon gas production that would result from the project. Gas development, while stemming the demand growth for liquid fuels in power generation, is also the most economic means of meeting additional generating capacity requirements. According to the IDA/UNDP Energy Assessment Report, studies indicate that the cost of hydropower averages around 3.9 US cents/kWh, as compared to about 2.5 US cents/kWh for gas turbine generation at a gas price of US$1.0/MCF. The Energy Assessment Report also estimated that overall investment needs in the power sector would be US$500 million less if the gas option is pursued rather than the large hydro option. In addition, the large hydropower projects being considered in Burma cannot be justified on the basis of power benefits alone; irrigation and other benefits from proposed multipurpose hydro schemes still need to be confirmed. In this context, natural gas-based power generation may be expected to play an important role at least through the next decade. Beyond the mid-1990s, the relative share of gas and hydro resources in power generation will be determined largely by the relative economics of alternative hydropower schemes and results of the least-cost power sector expansion plan study being proposed to GOB for implementation, as well as the opportunity

cost of gas over time, which would be addressed by the Gas Utilization Study under the project.

Traditional Energy

1.24 While Burma remains fortunate to be covered by forests for around 70% of its land area, recent surveys indicate that this forest cover is declining at an accelerating rate due mainly to fuelwood extraction for energy use in rural areas. Indeed, fuelwood accounts for almost 90% of non-commercial energy use, the rest being shared by charcoal and other biomass residues. Rural households depend almost exclusively on fuelwood for cooking and heating; however, almost half of total fuelwood and charcoal consumption occurs in the main urban areas of Rangoon, Mandalay, Magwe and Pegu. At the current average growth rate in fuelwood consumption (2% per year), it is estimated that the level of sustainable yield would be exceeded shortly after the year 2000. Although it would not be possible to reduce dependence on fuelwood in the short term, concrete efforts are required to stabilize extraction rates, manage demand through conversion and end-use efficiency improvements, promote biomass research and utilization of wood wastes, and encourage fuelwood plantation schemes, particularly in areas where localized penuries are a near-term possibility. These measures need to be implemented soon in order to postpone if not avert irreversible loss of tropical forest cover, soil damage, and shortages of biomass energy on which the majority of the population depends.

Sector Institutions and Planning 1/

1.25 In establishing the Ministry of Energy (MOE) in April 1985, GOB has taken the initial step required for coordinating sector institutions and strengthening energy planning capabilities. In addition to four energy corporations -- namely the Myanma Oil Corporation, the Petrochemical Industries Corporation, the Petroleum Products Supply Corporation, and the Electric Power Corporation -- a new Energy Planning Department is also being established under MOE to: (i) continuously monitor developments in the petroleum and power subsectors; (ii) carry out energy supply and demand studies and provide recommendations on balancing and substitution possibilities; (iii) initiate or undertake energy research and development activities; (iv) monitor progress in the implementation of energy projects; and (v) assist MOE in coordinating the activities of the corporations under the Ministry. While the organizational set-up of MOE (see Chart 1) appears adequate, its effectiveness needs to be closely monitored in the coming years. In particular, the local capability to undertake detailed gas market surveys, analysis and demand projections that explicitly take into account macroeconomic, demographic and other parameters, needs to be strengthened. The Gas Utilization Study (para 1.19) aims to develop this capability within the Ministry of Energy and MOC. In addition, the Gas Utilization Study would serve as a vehicle for reorienting energy planning from an approach that is almost exclusively focussed on physical plant aspects towards a better recognition of the cost implications and economy-wide effects of alternative sector development strategies.

1/ The specific technical and other institutional strengthening requirements of MOC are discussed separately in Chapter III ("The Project").

IDA's Role and Lending Strategy

1.26 The 1985 IDA/UNDP Energy Assessment Report was the first comprehensive analysis of the major issues faced by the Burmese energy sector. In the petroleum subsector, these issues include the relative neglect of onshore gas potential, inadequate pricing of natural gas, undue emphasis on exploration instead of development, and insufficient technology for improving oil recovery. IDA's subsequent dialogue with GOB has revolved around the Report's conclusion that future production gains will depend largely on overcoming these constraints, and has resulted in positive shifts in GOB's petroleum policies. In the area of natural gas, costly development of offshore gas reserves, judged uneconomic at this stage, has been postponed. GOB is focusing instead on lower-cost Payagon onshore gas reserves, which can be developed economically at current prices and delivered via a compact distribution network to nearby demand centers to substitute for diesel and fuel oil. A major policy initiative in the gas subsector has been GOB's decision, supported by IDA, to increase the Payagon gas price to cover long-run marginal cost and ensure the financial viability of the Payagon Gas Development Program. GOB has also realized the importance of undertaking investment planning in the gas subsector and has agreed to review its gas investment program with IDA. For crude oil, more emphasis is now being given to development and improvement of production technology, as well as tapping of vast waxy crude deposits. Finally, GOB has recognized the need to gain access to foreign expertise in the international petroleum industry and included a substantial petroleum technical assistance package under this project. GOB has also shown preliminary interest in exploring gradually a possible private sector role in further development of the petroleum sector.

1.27 IDA's basic objective in the petroleum subsector is to help alleviate the shortage of petroleum products, which has constrained economic development. In addressing this fundamental goal, IDA is supporting several policy, technical assistance, and investment initiatives aimed at: (i) enlarging the role of natural gas by developing natural gas reserves and by substituting gas for diesel or fuel oil in power generation, industry and other major uses; (ii) offsetting the natural decline in oil production by introducing production improvement techniques, including those for tapping waxy crude deposits; (iii) encouraging gas pricing policy reform; and (vi) strengthening petroleum subsector development planning.

1.28 GOB has limited resources to meet the large financial requirements for developing the petroleum sector, making it essential for GOB to focus on priority investments. Therefore, adequate assistance in formulating sector development policy needs to be provided in conjunction with transfer of modern petroleum technology and financial resources. This type of assistance should enable Burma to rapidly put the Payagon gas field into full use and, with advanced production management, also double oil production to a level of around 50,000 bpd by the mid-1990s.

1.29 This petroleum project is the first IDA operation in a key sector of the economy. It provides a concrete opportunity --- at this crucial juncture when GOB is in the initial stages of formulating a long-term development policy for the petroleum sector --- to pursue IDA's sector policy recommendations and build further on the productive dialogue so far achieved. In addition to a revised gas pricing policy, IDA's involvement in the proposed project would facilitate a gradual introduction of modern petroleum technology

while encouraging the preliminary interest shown by GOB towards oil industry involvement in the sector. IDA's involvement would also promote investment planning through the implementation of a gas utilization study that would identify priority gas development objectives and map out an optimal sequence of investments. IDA's presence in the sector would have the longer term objective of making available to Burma the extensive institutional, technology transfer and policy experience which the World Bank group has gained in other countries, particularly in the area of natural gas, to support the rational development of Burma's hydrocarbon resources.

II. THE BENEFICIARY

Introduction

2.01 The oil industry was in private hands until 1963, when the assets of private oil companies operating in Burma, mainly Burmah Oil Company, were acquired by GOB and the People's Oil Industry was established to manage all aspects of the industry from exploration and production to marketing of products. The Myanma Oil Corporation (MOC) was established in 1963 under the supervision of the Ministry of Mines to take over the responsibilities for onshore and offshore exploration, development, production and marketing of oil and natural gas in Burma. In 1977, MOC was transferred to the Ministry of Industry No. 2 and in 1985 to the Ministry of Energy (MOE), which currently supervises its operations.

The Myanma Oil Corporation

Organization and Capabilities 1/

2.02 MOC's 1976 charter gives MOC adequate financial autonomy, authority to hire and dismiss employees and prescribe wage rates, and revise prices, after prior approval of the Economic Committee of the Council of Ministers. The charter also stipulates that MOC should be run along commercial lines. MOC prepares a capital budget, which has to be approved by the Ministry of Industry's Equipment Control Committee and the Ministry of Construction's Construction Control Committee; MOC's operating expenditures are included in the GOB-approved budget for MOE.

2.03 MOC is headed by a Board of Directors, which is chaired by MOC's Managing Director and includes five representatives from MOC's management and two from its staff. The Board is directly responsible to MOE. MOC is organized into eight departments, each headed by a Director, for planning, exploration, drilling, engineering, fields, administration, finance and offshore operations. MOC's present organizational set-up (see Chart 2) is adequate and in line with that of other national oil companies.

2.04 MOC has 17,500 employees, including 1,110 professional staff, and operates 15 geological field parties, three gravity survey parties, five seismic crews (including a marine survey vessel), a data center and 45

1/ See also paras 3.08 and 3.29 on MOC force account.

drilling rigs. MOC has about 35 years of experience as part of Burmah Oil Company and 25 years since nationalization in the fields of drilling and pipeline engineering. MOC's track record in drilling and pipeline construction is fairly impressive; its established practices and procedures are time-tested and well suited to local conditions. The MOC organization is staffed with a competent top management. Together with the middle management-level professionals, they are well-versed in the basic technology and practices of drilling and pipeline engineering. MOC's expertise for routine operations in seismic acquisition and drilling is at a level commensurate with the international oil industry; its exploration department is adequately staffed with the required expertise. A number of managers and senior executives have had the benefit of technical education in Europe, North America and Eastern block countries. Some on-the-job training for MOC on seismic acquisition and processing have also been conducted in the past using foreign expertise.

2.05 Due to its long isolation from the international oil and gas industry for the last 15 years, however, MOC is not fully apprised of the full range of modern advances in petroleum engineering standards, practices and technology, and state-of-the-art techniques have not been introduced. MOC's management is fully aware of this deficiency and would like to gain access to international oil industry technical expertise in order to bring MOC's operations up to date. The project is expected to help fill this gap, particularly at middle management levels, through a training program and exposure of MOC to consultants from the international oil and gas industry.

Accounts and Audit

2.06 MOC has maintained the commercial accounting practices adopted by the Burmah Oil Company with the following modifications: as from FY80, offshore exploration expenditures are capitalized; depreciation rates were revised in FY83; and as from FY84, all successful wells are capitalized. To provide its management with adequate information, MOC's accounting system now discriminates among development, exploration and offshore operations, and separate budgets are made for these areas. On the whole, MOC's accounting procedures are adequate and follow generally accepted commercial accounting principles. Training in cost accounting and pricing of oil and gas will be provided under the project in order to equip MOC with adequate expertise in cost recovery estimation and enable MOC to better assist GOB in formulating pricing policies for the sector.

2.07 MOC's external audit, including control of compliance with current rules and regulations, as well as financial performance, are under the supervision of the Council of People's Inspectorate (CPI), which has 19 auditors permanently assigned to the audit of MOC. CPI also has staff stationed all around Burma who assist in the audit of MOC operations outside Rangoon. Except for timeliness of audit reports, these audit arrangements are adequate and have been accepted by IDA and ADB under previous projects.

2.08 Due to recent changes in accounting practices (see para 2.06), the audit reports for MOC were delayed and the most recent report available is for FY83. This matter was discussed with MOC's financial management, which indicated that these delays will be reduced now that no further changes in accounting policies are contemplated. During negotiations, assurances were obtained that MOC will submit to IDA its unaudited accounts within nine

months, and the corresponding audit report, including a report on the Special Account, not later than twelve months, after the end of MOC's fiscal year. This would apply as from MOC's FY88, so that all audited accounts for FYs84-88 would be submitted to IDA not later than by March 31, 1989.

III. THE PROJECT

Project Objectives

3.01 The main objective of the proposed project is to help alleviate chronic shortages of petroleum, which has hindered growth of the Burmese economy. This is to be achieved by assisting in the further development of the onshore Payagon gas field as well as the introduction of modern petroleum technology and latest advances in international petroleum engineering and production practices. To achieve this overall objective, the project would support:

(i) a development and appraisal drilling component for the Payagon gas field;

(ii) a gas transmission and distribution component that would deliver Payagon gas to large consumers in Rangoon; and

(iii) technical assistance and training to assist in the implementation of the various project components, as well as studies to identify options for enhancing oil recovery and to strengthen investment planning capabilities in the gas subsector.

Project Rationale

3.02 The proposed project establishes the framework for pursuing IDA's dialogue with GOB on development policy and assistance requirements in the petroleum subsector. In order to identify the issues constraining further development of Burma's petroleum resources, GOB requested IDA to undertake an Energy Assessment, which was completed in June 1985. Among other findings, the Energy Assessment concluded that the development of onshore gas reserves should be given priority over the more costly offshore gas development, thus leading to the identification of the Payagon Gas Development Program (PGDP). The PGDP's fundamental objective is to transform Burma's natural gas wealth into a major force driving economic growth. It consists of two phases to produce an additional 35 MMCFD for the Rangoon area under Phase I (FYs88-91) and another 35 or more MMCFD to serve areas beyond Rangoon under Phase II (FYs91-94). Total peak production from the Payagon field by the late-1990s would reach around 120 MMCFD, serving Rangoon as well as Sittang, Thaton and Myaingale in southern Burma.

3.03 The proposed project corresponds to Phase I of the PGDP. The project will also serve as the vehicle for implementing GOB's decision to quadruple the Payagon gas price (see para 1.20) in order to cover PGDP's long-run marginal cost at the minimum and begin to move MOC towards becoming a financially viable entity. The underlying economic rationale behind the PGDP is that it would rapidly enable a country that is seriously short of commercial energy to develop and deliver domestic gas supplies to existing demand centers at an economic cost that is significantly lower than the

estimated border price values of alternative liquid fuels. As such, the PGDP would form part of any reasonable priority investment program that the Gas Utilization Study (para 1.19) may identify.

Project Description

Gas Field Development and Appraisal Drilling

3.04 To increase production from the Payagon gas field by about 35 MMCFD, the project includes goods and services for: (i) the drilling of 12 development wells; (ii) urgently needed imported drilling tools, consumables and necessary replacement parts for MOC's drilling rigs; and (iii) the upgrading of seismic field equipment. To establish sufficient reserves for meeting projected gas demand beyond Phase I, the project also includes goods and services for the drilling of 5 deep appraisal wells.

Gas Transmission and Distribution

3.05 The project will finance the following main elements of this component:

(a) construction of an 18-inch diameter natural gas transmission pipeline over a distance of 64 miles (103 kilometers) from the gathering station at Payagon to the city gate station at Ywama outside Rangoon; provision of cathodic protection, pigging and telemetering facilities to the expanded transmission system to maximize its life, security and throughput;

(b) expansion of the existing Rangoon city gate station at Ywama, presently only a pressure regulation station, commensurate with projected demand; provision of customer meter stations and conversion equipment; upgrading with modern gas filteration, odorization, pressure/flow monitoring and control facilities to enable it to function as the gas control and dispatch center from the Payagon field to Rangoon;

(c) design of a basic Rangoon distribution system, equipped with modern pressure and flow control and data acquisition equipment, and construction of the main elements of this basic design; and

(d) cathodic protection against corrosion for the existing 10-inch diameter Payagon to Rangoon gas transmission pipeline.

Technical Assistance, Studies and Training

3.06 The technical assistance included in the project in the form of consultancy services will be for the following: (a) seismic interpretation; (b) design and installation supervision of cathodic protection systems on the existing 10-inch and proposed 18-inch diameter pipelines; (c) quality control inspection of pipeline welding and coat wrapping operations; (d) design of a basic distribution system for Rangoon; and (e) design and installation supervision of the telecommunications, telemetery, as well as the supervisory control and data acquisition (SCADA) systems for the transmission pipelines and Rangoon basic distribution design. The project will also support consultancies for the implementation of two studies: (a) Enhanced Oil Recovery Studies to address production difficulties in two producing oil fields (Tetma and Chauk); and (b) a Gas Utilization Study to promote gas subsector planning

(see para 1.19). The project will support MOC's training needs in the design, installation and operations of modern gas transmission and distribution systems (see para 3.15).

LPG/CNG Pilot Activity

3.07 The project will finance consultancy services, conversion kits, service stations, and equipment for a small pilot operation to investigate the technical and economic feasibility of promoting the use of CNG/LPG as fuel in the transport sector.

Project Implementation

3.08 The Myanma Oil Corporation (MOC) would be the implementing agency for the project. The development and appraisal drilling, seismic activities, and pipeline construction work will be carried out under MOC force account (see para 3.29). MOC's past experience shows an excellent record with respect to economy of operations, cost-competitiveness relative to the international petroleum industry, and field safety. Costs of wells drilled and pipelines constructed by MOC are well below comparative international costs even in the present depressed market. Unit costs of pipe-laying are in the range of 60% of international levels; drilling costs are low even when compared to the soft international market particularly for wells of shallow and medium depth, which is the case in the Payagon field. Having operated with, and as successor of, the Burmah Oil Company over the past 35 years, MOC has had a long drilling and seismic work experience since its formation and has successfully concluded hundreds of wells and seismic lines. MOC's pipeline construction experience include about 300 miles of transmission pipelines in central and southern Burma, including several submerged crossings. Routine operations in drilling and pipeline construction are commensurate with international standards, while employing techniques best suited to local conditions. While the past record of MOC drilling operations is acceptable, however, time delays have been experienced in moving the rigs in swampy areas. Operations in the Payagon area are strongly controlled by seasonal conditions and rig movements during the May to November wet season are nearly impossible. The same weather constraints affect the seismic surveys. Under the project, where a low level of activity would be spread out intermittently over several years due to seasonal conditions, mobilization of foreign contractors would not be warranted due to high standby fees.

3.09 During appraisal, agreement has been reached with GOB and MOC for the creation of a special Project Implementation Unit (PIU) within MOC under the supervision of a Project Director. The PIU, which will be fully dedicated to the project, will facilitate implementation and coordination of the various components of this project. During negotiations, GOB confirmed that the PIU has been established and a Director appointed. The terms of reference and organization of the Unit were reviewed and agreed; GOB also confirmed that the Unit would be fully staffed, including support services, prior to Board presentation. The project implementation schedule, which has been agreed with MOC, is provided in Chart 3. Implementation of each of the project's components is elaborated below.

Development/Appraisal Drilling and Seismic Acquisition

3.10 The development and appraisal drilling and seismic activities will be carried out by MOC's own drilling rigs and seismic parties. MOC will deploy a total of 4 drilling rigs. Two rigs will be used for drilling appraisal wells, each of which is expected to take 4 to 5 months, including the rig moving time. Development wells, to be drilled by the other 2 rigs, are expected to take 3 months. Consequently, the proposed 12 development and 5 appraisal wells can be drilled in a total of about 18 months, spread out over 2 dry seasons. Development drilling will tap further already producing sands or initiate production from sands that are found productive by appraisal wells being currently drilled and self-financed by MOC. The search for additional reserves through appraisal drilling will be directed towards the yet untested structures in the Payagon area and the deeper reservoirs on structures where production has already been established. MOC also needs to continue seismic surveys in the Payagon area. Upgraded seismic equipment will be used to produce a larger quantity of higher-resolution seismic information in the marshy areas of Payagon; future drilling sites will be selected on the basis of this better information on the structural geology. During negotiations, assurances were obtained from MOC that, during supervision missions, MOC will furnish IDA for its review and comment MOC's proposals for the locations of future development and appraisal wells as well as seismic programs, and that at regular intervals, MOC will also review with IDA staff the seismic, well drilling and testing results and consequent updating of the reserve calculations. Assurances were also obtained that MOC will review with IDA the progress and results of the Enhanced Oil Recovery Studies.

Gas Transmission and Distribution

3.11 Pipeline construction work will also be carried out by MOC's pipeline crews. Construction management and field supervision will be provided by MOC's managers and engineers. The 18-inch diameter pipeline will be laid parallel to the existing 10-inch diameter pipeline along the same right-of-way. Due to extensive waterlogging in the monsoon season, almost all field work is planned to be done in the dry seasons (December-April) of FY88 through FY90. MOC plans to undertake inspection and rectification works for the existing pipeline simultaneously with the start-up of its cathodic protection works.

3.12 The present Rangoon distribution system, which consists largely of a few individual pipeline spurs operating at various pressures from the city gate station, is not equipped for optimal reticulation of gas supply at steady pressures. During appraisal, it was agreed with MOC that, based on the most recent experience in Europe, the distribution system will be designed on the modern concept of medium-pressure operation, under which all distribution networks would operate at a uniform pressure of 4 bars, thus resulting in simpler design, reduction in pipe size and significant cost savings of 20 to 30%. This system would also provide greater built-in storage capacity (system pack), greater operational flexibility and scope for future expansion at relatively low additional costs, while providing at least equivalent standards of safety.

3.13 MOC will also implement the LPG/CNG pilot operation. During negotiations, IDA discussed and agreed with MOC the objectives, criteria, monitoring system and evaluation methods for this component and obtained

assurances that MOC will prepare a detailed implementation plan for IDA review and comment not later than three months after Credit effectiveness.

Technical Assistance, Studies and Training

3.14 The seismic interpretation consultant will work with MOC's exploration staff on the interpretation of seismic and well data and assist in the selection of locations for the appraisal and development wells to be drilled under the project. Consultancy services for pipeline inspection, the design of the cathodic protection system, the telecommunication/telemetery system and the basic Rangoon distribution grid, would be obtained shortly after approval of the IDA credit. The Enhanced Oil Recovery Studies will analyze the available reservoir and production data and advise MOC on methodologies that could enhance the production rate and ultimate recovery from these fields. The Gas Utilization Study (para 1.19), which is expected to take 18 months to complete, will focus on preparing a gas subsector planning framework and a short-term priority investment program. Detailed terms of reference for the Enhanced Oil Recovery Studies is presented in Annex 3.01 and for the Gas Utilization Study in Annex 1.02. Final terms of reference for the consultancy services and studies were agreed with GOB during negotiations. To maximize the transfer of advanced petroleum engineering technology and modern industry practices, Burmese counterparts will be fully associated with all aspects of the technical assistance and studies, both during the field work in Burma as well as during any parts of the studies conducted in overseas offices of the consultants.

3.15 For training purposes, MOC has prepared and reviewed with IDA a program involving: (a) specialized education and operational exposure for a core group of about 22 engineers and 2 economists who will be sent to selected institutes and gas utilities abroad to attend formal courses in the various disciplines of gas engineering, gas economics, energy planning, and cost accounting; and (b) on-the-job training of about 150 engineers, supervisors and technicians who will be working with the consultants and inspectors, supplemented by invited lecturers on specialized topics, over a period of three to four years. The detailed components of a formal training program for MOC and the Energy Planning Department of the Ministry of Energy were agreed with GOB during negotiations.

3.16 On GOB's request, the United Nations Development Program (UNDP) has agreed to finance the Gas Utilization Study, the Enhanced Oil Recovery Studies and the training program, with IDA acting as the executing agency.

Status of Project Preparation

Seismic Acquisition

3.17 During appraisal, the mission, assisted by a Bank consultant specialized in seismic acquisition in swampy areas, discussed in detail with MOC the current status of its exploration technology and the need for further data collection and seismic acquisition equipment in the Payagon area. Various options for optimizing the productivity of MOC's field crews were evaluated, taking into account protected rice crop areas and current limitations on yearly recording to a short dry weather window of five months. The present recording method of using deep shotholes is heavily dependent on the mobility of truck-mounted drilling equipment and water supply

vehicles that are slow under Payagon conditions. Since the February 1986 IDA identification mission, MOC has conducted tests with shallow, multiple shotholes, which yielded good quality data and can be drilled by hand-carried equipment. Spare parts and additional recording equipment are required in order to enhance the quality of data and increase MOC's efficiency by allowing the simultaneous recording of more data points. A preliminary list of required seismic equipment has been agreed with MOC during negotiations.

Drilling

3.18 Severe shortages of equipment have interfered with MOC's operations, thus constraining MOC's efficient drilling of wells. The appraisal team reviewed in detail and agreed with MOC's staff on the requirements for drilling materials, consumables and services so as to ensure uninterrupted MOC operation, except for delays caused by necessary rig movements during the rainy season. The present drilling time needed for a 1,400-meter well is 8 weeks including testing, which is considered acceptable.

Transmission and Distribution

3.19 MOC's design for the 18-inch diameter Payagon to Rangoon transmission system, as well as related materials, equipment and their specifications, have been examined and agreed with MOC during project appraisal. The selection criteria for this pipeline is discussed in detail in Annex 3.02.

Project Cost Estimates

3.20 The project cost estimates for the whole Payagon Gas Development Program (PGDP) are presented in Annex 3.03. Interest during construction is expected to be expensed immediately against income in accordance with MOC's practices. The total financing requirements of the proposed project (Phase I of PGDP), including physical and price contingencies, are estimated at about US$100 million equivalent, of which about US$66 million are in foreign exchange, as shown in detail in Annex 3.03 and in summary form below:

Project Cost Estimate

	Foreign	Local[a/]	Total
	(US$ million)		
I. Gas Field Development			
(a) Seismic equipment and services	1.5	1.5	3.0
(b) Development drilling	7.0	5.0	12.0
(c) Production surface facilities	7.0	4.5	11.5
(d) Transport equipment and vessels	5.0	2.0	7.0
Sub-total	20.5	13.0	33.5
II. Gas Transmission and Distribution			
(a) 18" transmission pipeline	14.5	7.0	21.5
(b) Ywama city gate station, customer meter stations and conversion equipment	1.5	1.0	2.5
(c) Cathodic protection for 10" pipeline	1.5	0.5	2.0
(d) Basic distribution development (Rangoon)	1.5	0.5	2.0
Sub-total	19.0	9.0	28.0
III. Technical Assistance and Computer Software			
(a) Seismic interpretation	0.25	0.05	0.30
(b) Corrosion control	0.75	0.20	0.95
(c) Pipeline inspection	0.75	0.20	0.95
(d) Distribution system design	0.40	0.10	0.50
(e) Telecommunications/telemetering, SCADA and computer software	0.35	0.15	0.50
(f) Gas utilization study	0.75	0.15	0.90
(g) Enhanced oil recovery studies	1.00	0.20	1.20
(h) Training	0.45	0.15	0.60
Sub-total	4.70	1.20	5.90
IV. Appraisal Drilling for Phase II			
Sub-total	5.0	3.0	8.0
V. LPG/CNG Pilot Scheme			
Sub-total	1.5	0.5	2.0
Base Cost Estimate	50.7	26.7	77.4
Physical Contingencies	11.7	2.9	14.6
Price Contingencies	3.1	5.0	8.1
Total Project Cost	65.5	34.6	100.1

a/ Local costs include US$15.8 million of taxes and duties.

3.21 The base cost estimates are expressed in March 1987 prices and were derived jointly by MOC and IDA. Physical contingencies average around 19% of the base cost. This relatively high physical contingency factor results from the potential necessity of: (i) drilling wells deeper than anticipated due to unforeseen reservoir conditions; (ii) more frequent reconditioning of production equipment; and (iii) diverting pipeline routes due to waterlogging and river crossings despite efforts to lay the new 18-inch diameter pipeline parallel to the existing 10-inch diameter pipeline to minimize costs. Price contingencies average about 11% of the base cost and are based on projected international inflation and local price increases (essentially for MOC equipment and wages) as follows: 3% (FY88), 1% (FYs89-91) and 3.5% (FYs92-94) for foreign costs; and 4% (FY88), 7% (FYs89-90), 6% (FY91) and 5% (FYs92-94) for local costs. Consultant services to be financed by IDA are estimated to total 180 man-months at an average cost of US$14,000 per man-month and are broken down as follows (in man-months): seismic interpretation (18); corrosion control (54); pipeline inspection (54); distribution system design (30); and telecommunications/telemetry (24).

Financing Plan

3.22 The financing plan for the project is set out below:

	Foreign	Local	Total
	(US$ million)		
Project cost	65.5	34.6	100.1
To be financed by loans:			
Proposed IDA credit	63.0	-	63.0
UNDP	2.5	-	2.5
GOB	-	34.6	34.6
Total Financing	65.5	34.6	100.1

3.23 The proposed IDA Credit will be extended to GOB on standard IDA terms and relent to MOC at an interest rate of 7.9%, namely, the current IBRD lending rate, with GOB assuming the foreign exchange risk; MOC will repay the loan over 20 years, including five years of grace. The execution of a Subsidiary Loan Agreement between GOB and MOC, acceptable to IDA, is a condition of Credit effectiveness.

3.24 During negotiations, assurances were obtained from GOB that all necessary foreign and local currency funds to complete the project in a timely manner will be made available to MOC.

Procurement

3.25 The procurement arrangements are summarized in the table below:

Procurement Table
(in US$ million)

Project Elements	Procurement Method			Total Cost
	ICB	LCB	Other	
1. Gas development	18.6 (18.6)	3.4 (-)	21.5 (8.0)	43.5 (26.6)
2. Gas transmission and distribution	18.7 (18.7)	2.3 (-)	15.4 (6.0)	36.4 (24.7)
3. Technical assistance	- (-)	- (-)	6.6 (2.8)	6.6 (2.8)
4. Computer software	- (-)	- (-)	0.6 (0.4)	0.6 (0.4)
5. Appraisal Drilling for Phase II	4.5 (4.5)	0.8 (-)	5.1 (2.0)	10.4 (6.5)
6. LPG/CNG pilot scheme	2.0 (2.0)	- (-)	0.6 (-)	2.6 (2.0)
	43.8 (43.8)	6.5	49.8 (19.2)	100.1 (63.0)

Note: Figures in parentheses are the respective amounts proposed to be financed by IDA. Total costs include contingencies. The "Other" category includes taxes as well as packages to be procured using LIB, direct contracting, IDA Guidelines on the Use of Consultants and force account expenditures.

3.26 About US$44 million of materials, equipment and services would be procured in accordance with IDA's procedures for international competitive bidding (ICB), which would include IDA's standard domestic preference clauses. However, it is expected that local bidders would qualify for only a very small number, if any, of procurement packages earmarked for ICB. Limited international bidding (LIB) procedures on the basis of at least three qualified suppliers would also be utilized for: (a) procurement packages whose estimated value is less than US$300,000 (CIF basis); (b) time-critical items needed on an urgent basis; and (c) items with limited suppliers such as specialized seismic, logging and testing services. The aggregate amount of LIB procurement is not expected to exceed US$15 million. About US$2.0 million of items of a proprietary nature would be procured through direct contracting with the suppliers of such goods. These items, which need to be acquired from the original manufacturer, are mainly spare parts or specific hardware to be used as "add-ons" to already operational equipment. All items procured through ICB, LIB and direct contracting (with foreign suppliers only) will be financed from the proposed IDA Credit.

3.27 Technical assistance totalling US$6.6 million will be provided as follows: US$2.8 million to be financed by IDA and US$2.5 million to be financed by UNDP (with IDA as executing agency), for a total of US$5.3 million, for consulting services which would be obtained in accordance with IDA's Guidelines on the Use of Consultants; and US$1.3 million equivalent in local counterpart funds.

3.28 MOC will follow IDA's procedures for ICB or LIB by submitting to IDA draft bid documents, bid evaluation documents and negotiated contracts prior to release or award, in respect of procurement of all items estimated to exceed US$300,000. It is estimated that 90% of ICB and LIB procurement, in terms of value, will be subject to prior IDA review. For items valued at US$300,000 and less, IDA's Guidelines for Procurement will be followed but IDA review will be on a post-award basis.

3.29 Items with an estimated value of about US$6.5 million, which are not suitable for ICB procedures and are available locally, would be procured by MOC according to its own local competitive bidding (LCB) procedures. Appraisal and development drilling, seismic activities and pipeline construction will be done under MOC force account using MOC's drilling, seismic and pipeline crews (see para 3.08). IDA will not finance any LCB procurement or force account expenditures.

3.30 The project is not expected to involve advance contracting or retroactive financing.

Disbursements

3.31 IDA disbursement would be made against 100% of the foreign expenditures for materials and equipment, as well as for contractors and foreign consultant services, and 100% of ex-factory cost for contracts awarded to local bidders under ICB. The major components of the project are expected to be completed by mid-1990; some support works and technical assistance may continue until mid-1993. The disbursement closing date would be December 31, 1993. The estimated schedule of disbursements is presented in Annex 3.04. The disbursement profile essentially conforms with the historical profile as of October 1985 for Bank/IDA gas projects except for the more rapid rate of disbursements for the gas field development and the transmission/distribution components as a result of the lump-sum nature of the procurement for the main items involved. In order to expedite procurement and disbursements on items where fast delivery is required, a Special Account would be established with the Myanma Foreign Trade Bank with an authorized allocation of the equivalent of SDR3.7 million. This Special Account would be replenished against withdrawal applications to be submitted by the Borrower at agreed intervals. Disbursement on the basis of statement of expenditures is not contemplated under this project.

Monitoring and Reporting

3.32 During negotiations, assurances were obtained that MOC will submit to IDA quarterly project progress and procurement status reports, which will include project accounts and a Report on the Special Account, within 45 days of the end of each calendar quarter. For this purpose, MOC will collect relevant data from monthly reports submitted by its various departments and combine these with project data. These quarterly progress reports will be in a format agreed with IDA, showing cost estimates, expenditures, procurement status, disbursements and other necessary information. An outline of the contents of the quarterly progress reports is provided in Annex 3.05. In addition, MOC will submit to IDA, promptly upon their preparation, the plans, specifications, work schedules, and any other reports and contracts connected with the project, as well as any modifications on the agreed work programs, costs and expenditures. During negotiations, assurances were obtained from MOC that within six months after the closing date of the Credit or after the final disbursement, whichever occurs first, MOC will prepare and furnish to IDA a completion report on the project, dealing with its implementation, initial operations and the costs and benefits derived and expected to be derived therefrom.

Ecology and Safety

3.33 No significant environmental problems are expected to result from the implementation of the project. To the contrary, the project is likely to result in improved environmental conditions. Since the combustion products of natural gas are less polluting than those of liquid hydrocarbon fuels (fuel oil and diesel) to be replaced, the project will contribute to a reduction in urban pollution level. The pipelines will be buried and therefore pose no unusual environmental hazard. Appropriate standards and codes of practice will be followed in the detailed engineering and construction to ensure proper protection and minimize the likelihood of third party damage. In addition, this project will substantially reduce the environmental hazards from possible leakages of the insufficiently protected 10-inch diameter Payagon to Rangoon high-pressure gas pipeline, which will be provided with adequate cathodic protection against corrosion under the project. No forest clearance is involved in implementing the project.

Insurance

3.34 As MOC's assets are spread over a large area in central and southern Burma, any single loss would be relatively small in comparison with total assets in operation. MOC, therefore, does not carry a comprehensive insurance coverage except for motor vehicles and materials in transit. During project appraisal, the IDA mission stressed upon MOC the need to review its risk exposure in view of the planned expansion of its gas-related assets. During negotiations, IDA reviewed with MOC the adequacy of MOC's insurance coverage in light of its risk exposure and planned expansion program and obtained assurances from MOC to have all materials and equipment financed under the IDA credit fully insured while in transit and installation in accordance with IDA requirements.

IV. FINANCIAL ANALYSIS

Introduction

4.01 MOC operated up to 1980 as an autonomous public company with satisfactory financial performance and annual dividend payments to GOB for its equity contribution. After 1980, however, prices for MOC's products and services were increased at a much slower rate than the increase in MOC's costs, resulting in large financial losses as from 1981 and MOC's increasing dependence on loans from GOB to cover its operating losses. MOC, therefore, operates like a department under the GOB budgetary system, despite its nominal status as a financially autonomous commercial entity (see para 2.02). As a formally independent entity, MOC, in accordance with its commercial accounting practices (para 2.06), books all funds received from GOB as debt. Such debts now exceed the value of total assets, leaving MOC with a negative net value and technically bankrupt. Other public corporations in the petroleum sector, such as the Petrochemical Industries Corporation and the Petroleum Products Supply Corporation, also have operational losses, but not of the magnitude found in MOC.

4.02 MOC's financial deficiencies have been caused mainly by insufficient prices to cover MOC's costs since 1980; a number of measures over several years would be needed to remedy this situation. In the context of the proposed project, the increase in the price of Payagon gas (para 1.20) and planned reduction in offshore exploration expenditures will improve significantly MOC's financial position. Further capital restructuring and revenue-enhancing as well as cost-reducing measures, to be defined in the MOC Financial Viability Study under the project (para 4.09 and Annex 4.03), are expected to result in MOC breaking even on a cash basis by 1991 and lead to full financial viability by the end of the project period.

MOC's Past Financial Performance

4.03 Since FY81, MOC has operated at a net loss, currently amounting to about K250 million (US$37.8 million) a year. MOC's equity turned negative in FY83 and MOC has not paid a dividend to GOB since FY80. MOC's financial statements for FYs83-87 are in Annex 4.01; a summary for FYs80-87 is given below:

FY Ending 3/31	1980	1981	1982	1983	1984	1985	1986 a/	1987 b/
	In million kyats							
Sales	393.7	393.6	361.8	357.4	348.7	374.6	374.0	402.7
Operating Exp.	322.2	404.8	480.1	535.6 c/	408.8 c/	448.7	427.0	453.7
Operating Income (Loss)	71.5	(11.2)	(118.3)	(178.2)	(60.1)	(74.1)	(53.0)	(51.0)
Interest & Exch. Losses	48.3	48.0	95.2	116.8	133.6	136.9	157.3	210.0
Net Income (Loss)	23.2	(59.2)	(213.5)	(295.0)	(193.6)	(211.0)	(210.3)	(261.0)

a/ Provisional.
b/ Based on revised budget for FY87.
c/ Decrease due to changes in accounting procedures (see para 2.06).

4.04 In recent years, MOC has been able to contain the increase in operating costs to about 5% a year. The main reason for MOC's poor financial performance is the low prices for its products: about K43 (US$6.50) per barrel of oil and K2.10 (US$0.32) per thousand cubic feet of gas. Currently, MOC would need about K60 (US$9.08) per barrel of oil and about K7.0 (US$1.06) per thousand cubic feet of gas to fully cover its capital and operating costs. The situation is aggravated by the fact that oil production in Burma declined during 1986 by about 10% (from a level of about 7.8 million barrels a year to a level of about 7.0) due to shortages of drilling consumables, which prevented MOC from attaining the level of infill/development drilling necessary to offset the natural decline of the oil fields. The situation would have been worse, however, if old loans from GOB carried the current 8% interest rate (the rates for old loans are 1% to 6% depending on age and purpose of the loan) and if natural gas production and revenues had not increased substantially during recent years.

4.05 MOC's heavy losses and investment expenditures have been covered by loans from GOB. As of March 31, 1987, long-term debt is estimated to amount to about K832 million (US$126 million) and short-term debt to about K4,200 million (US$635 million) and without continued GOB support, MOC would be bankrupt. A summary of MOC's current financial position is given below:

	1987 a/	
	(K Million)	%
Net Fixed Assets	3,144.1	79
Union of Burma Consolidated Fund	292.1	7
Current Assets	553.9	14
Total Assets	3,990.1	100
Equity	(1,121.9)	(28)
Long-Term Debt	832.0	21
Short-Term Debt	4,200.4	105
Accounts Payable	79.6	2
Total Liabilities	3,990.1	100

a/ Based on revised budget for FY87.

4.06 According to MOC's accounting practices, only the actual costs of successful onshore wells are capitalized and depreciated over 10 years. Unsuccessful onshore wells are expensed during the year of drilling. This "successful efforts" method is an internationally accepted accounting practice. However, as from FY83, all offshore exploration and appraisal expenditures are capitalized and these expenditures will not be amortized and charged against income until commercial production starts. The carrying of both unsuccessful and successful exploration expenditures as unamortized assets for an indefinite period of time, until the related offshore gas discoveries of the successful exploration wells are proven to be commercial and starts production, is not a generally accepted accounting practice. Therefore, the value of these offshore expenditures related to unsuccessful

exploration being reported as unamortized assets is questionable and past losses may have been understated due to this accounting practice. Finally, the Union of Burma Consolidated Fund (UBCF) cannot be used by MOC without approval by GOB and has basically remained unchanged in the last decade; it is a dead asset for MOC.

Measures to Improve MOC's Financial Viability

4.07 The low gas and oil prices and the need to improve MOC's overall financial structure and performance were discussed with GOB and MOC. During project pre-appraisal, it was agreed with MOE that the price for Payagon gas should at least cover all MOC's costs to develop, produce and distribute that gas. An estimate of the Payagon gas price required for full cost recovery (including financial costs) is given in Annex 4.02. Subsequently, MOE made a proposal to GOB to raise the price of existing Payagon gas as from April 1, 1987, to K7.5 (US$1.13) per thousand cubic feet (MCF). This proposal was accepted by the Economic Committee of the Council of Ministers in March 1987. The new price of K7.5 per MCF for Payagon gas, as compared with the old price of K2.1 per MCF, will make the proposed project financially attractive (see para 4.16) and provide MOC with additional revenues of over K200 million (US$30.3 million) a year by the end of the project period.

4.08 The new price for Payagon gas is a significant step towards improving MOC's financial viability. However, further steps will be required to make MOC's operations break even. As deficits and debt have been accumulating since 1980, price increases alone, within politically feasible limits, would not be sufficient to make MOC financially viable. Interest expenses amounted to about K210 million in 1987 and higher amounts are projected for subsequent years. A restructuring of MOC's capital base, e.g., by converting debt to GOB equity, would, therefore, be required together with new revenue-enhancing measures to make MOC's operations break even. These aspects were discussed with MOE and MOC, who recommended a cautious approach for the following reasons: (i) changes in transfer prices would affect the finances of the Petroleum Industries Corporation, the Petroleum Products Supply Corporation, and the Electric Power Corporation [1/]; (ii) a capital restructuring of MOC would become a precedent for other public enterprises; and (iii) increases in oil and gas prices could have an adverse impact on the cost-of-living index. For these reasons, GOB is not prepared to commit itself at this time to a timetable for further steps to improve MOC's financial performance before the impact on the economy of proposed measures resulting from a financial viability study (discussed immediately below) have been evaluated.

4.09 During appraisal, it was agreed that a Financial Viability Study for MOC be carried out under the supervision of MOE to: (i) identify measures that would improve MOC's financial viability; (ii) evaluate the impact of these measures on MOC and on users of oil and gas; and (iii) propose a combination of measures that would ensure MOC's financial viability by the end of the project period. A preliminary report on the findings of this Study would be made available to IDA for comment within one and a half years after Credit effectiveness and the final report, including comments from IDA, would be completed within six months thereafter. The Study's terms of reference, which were agreed with GOB during negotiations, are provided in Annex 4.03.

1/ Both PIC and PPSC operated at a loss in FY86, but their financial positions are not as bad as that of MOC.

During negotiations, agreement was also obtained from GOB that: the working group to undertake this Study would be established not later than by Board presentation; the working group would provide their preliminary findings to GOB and IDA for their joint review not later than eighteen months after Credit effectiveness; the final report incorporating relevant IDA comments would be completed within two years of Credit effectiveness; and upon completion, the Study would be submitted to the Ministry of Energy for its review and development of a plan of implementation, as appropriate.

Financial Projections

4.10 MOC has accumulated heavy losses during the last eight years and there are no easy options to remedy this situation. Even if MOC's prices were set at levels which would allow full recovery of operating costs, the interest on debt to GOB, which in FY87 amounted to about 50% of MOC's total revenues, would require MOC to borrow new funds. To make MOC's cash flow break even (i.e., internal cash generation to cover debt service, with new borrowings to be used only for investment purposes), a combination of measures would be required as follows: (i) an investment policy emphasizing the development of known profitable resources; (ii) less funds spent on offshore operations and other expensive projects with uncertain returns; (iii) revenue-enhancing measures; and (iv) a capital restructuring of MOC.

4.11 In addition to the new price for Payagon gas, some important steps have already been taken to improve MOC's finances. MOC is now concentrating its resources on activities that would be profitable in the near term (e.g., development of existing prospects) and is planning to reduce its offshore exploration and appraisal expenditures from a level of over K150 million per year in FYs82-88 to about K30 million as from FY89. Without pre-empting the outcome of MOC's Financial Viability Study, the FYs88-94 financial projections are based on the assumption (see Annex 4.01) that this Study will identify a mix of further revenue-enhancing measures for implementation as from FY90. These measures would need to reach a target increase in MOC's revenues of K400 million per year for MOC to produce, combined with a restructuring of MOC's capital base, a positive net income (after interest) by FY94. However, MOC would break even on a cash flow basis in FY92 (see para 4.15). On the basis of this scenario, MOC would have the following financial results:

FY ending 3/31	1988	1989	1990	1991	1992	1993	1994
	in million kyats						
Revenues a/	461.4	520.6	570.6	670.2	773.0	901.8	1028.2
Operating Costs	586.2	608.8	666.1	686.3	680.5	703.7	729.7
Operating Income	(124.8)	(88.2)	(95.5)	(16.1)	92.5	198.1	298.5
Less: Interest	278.3	348.3	198.3	230.3	249.3	276.3	298.3
Net Income	(403.1)	(436.5)	(293.8)	(246.4)	(156.8)	(78.2)	0.2

a/ Of which revenue-enhancing measures to be identified: 50 in FY89, 100 in FY 90, 150 in FY91, 200 in FY92, 300 in FY93 and 400 in FY94 (see Annex 4.01)

4.12 MOC's planned capital investments in FYs88-92 of about K440 million per year, in addition to the proposed investments for the Payagon gas project, would bring MOC's total annual capital construction expenditures in FYs88-94 well above levels achieved in FYs86-87. This may be optimistic, since MOC, in the recent past, has had to cut its approved investment plans, mainly due to constraints on foreign exchange. If FYs88-94 capital expenditures are reduced by K150 million per year, MOC's interest charges would be reduced by about K90 million per year at the end of the project period.

4.13 MOC's FY94 equity would be about K764 million and its total debt about K4,925 million --- or a debt/equity ratio of 87/13 --- assuming that K3,500 million of MOC's short-term debt is converted to equity in FY90 and K292 million from the Union of Burma Consolidated Fund is used for debt repayment. For the calculation of this debt/equity ratio, no distinction has been made between short-term and long-term debt (see Annex 4.01, para 14).

MOC's Financing Plan

4.14 MOC's projected FYs88-94 funds flow statement is shown in Annex 4.01; a summary is given below:

FY ending March 31	FYs88-94 (K Million)	(%)
Requirements for Capital Construction	3,708.3	100
Net Income Before Interest	255.4	6.9
Depreciation	1,696.4	45.7
Use of Union of Burma Consolidated Fund	292.1	7.9
Total Internal Sources	2,243.9	60.5
Less: Increase in Working Capital	59.8 a/	1.6
Debt Service	6,278.7	169.3
Net Internal Sources	(4,094.6)	(110.4)
GOB Equity Contribution	3,500.0	94.3
New Loans: Long-Term	829.6	22.4
Short-Term	3,473.3 a/	93.7
TOTAL NET SOURCES	3,708.3	100

a/ Short-term debt has been included under "new loans" as a major source of financing rather than under "working capital."

4.15 In addition to MOC's internal cash generation for FYs88-94, new equity and new short-term loans would be required to service and repay part of MOC's excessive short-term debt. Assuming new equity is made available to MOC, MOC's annual internal cash generation from FY92 would exceed its debt servicing requirements. A reduction in MOC's investment program (para 4.12) would reduce or eliminate the need for new short-term borrowing at the end of the project period. New long-term loans, including the proposed US$63.0 million IDA Credit and US$2.5 million from UNDP, would be used exclusively for implementation of the Payagon Gas Development Program (Phases I and II).

Project Financial Internal Rate of Return (IRR)

4.16 The financial IRR of the project is estimated at 13% in real terms (see Annex 4.04). This estimate may understate the real project benefits, as the capital expenditures are based on a pipeline size capable of handling additional gas volumes under Phase II development and Phase II gas revenues have not been considered incremental to the project. In addition, the gas price of K7.5 per MCF has been assumed to remain constant in nominal terms until FY2001, which implies a fall in real terms of over 55%. Even so, the estimated IRR of 13% is satisfactory, considering that it relates to a basically low- risk investment as regards demand and price for gas. If the gas price is maintained at K7.5 per MCF in real terms during the life of the project, the IRR would be 25%.

4.17 A sensitivity analysis was carried out indicating that even under a combination of adverse circumstances (capital and operating expenditures up 10% and revenues down 10%), the project IRR in real terms would not be less than 9%; the rate of return would not be less than 20% if the gas price is maintained constant in real terms during the project's life.

V. PROJECT JUSTIFICATION AND RISKS

Introduction

5.01 The main justification for the proposed project is that it will result in improved local availability of commercial energy to spur economic development activity, which has been hindered by growing fuel shortages. Gas consumers would also benefit from gas as a lower-cost energy source compared to alternative liquid fuels. Additional benefits from the use of natural gas include the elimination of storage requirements and inventory costs, its greater combustion efficiency compared to liquid fuels, and its clean-burning properties. Benefits from the project also include the identification of options to enhance oil recovery and tap the vast waxy crude deposits, and the introduction of urgently needed modern petroleum engineering techniques to optimize petroleum extraction. From the sectoral point of view, equally important benefits include initiatives at gas pricing policy reform and financial restructuring of MOC, as well as the strengthening of local capabilities to plan investments and formulate a development policy for the gas subsector.

Economic Evaluation

5.02 The economic viability of the Payagon Gas Development Program (PGDP) and of the project (Phase I of PGDP) has been evaluated by comparing their costs and benefits valued from the perspective of the national economy. The PGDP's investment stream and incremental operating costs (see Annex 3.03) are the least-cost approach to raising Payagon production to meet demand forecasts at a required level of system reliability. The principal benefit stream is represented by the economic value of the gas produced under different sets of border price values over time for the alternative fuels to be substituted for by gas.

5.03 Project Benefits. The appraisal mission reviewed in detail MOC's gas demand forecast, as presented in Annex 5.01. Gas volumes up to FY96 were based on MOC's forecast of firm gas sales for existing and committed gas consumers. During the late 1990s, it is estimated that gas demand would grow at an average annual rate of around 8%, covering further increases in existing consumption, step-wise growth in the power sector, and new industrial and possibly commercial/residential uses. From the year 2001 onwards, the level of demand is projected to remain stable since all the major gas substitutions would have been already completed. The structure of power, industrial and refinery gas demand is such that Payagon gas will substitute for diesel and fuel oil in the following ratios (diesel:fuel oil): (i) for the PGDP as a whole, 60:40 for FY91; an increasing share of fuel oil starting in FY92 and reaching 40:60 by FY2000; and stable shares at 40:60 from FY2001 to FY2008; and (ii) 60:40 for the project taken in isolation, reflecting gas substitution for diesel as first priority.

5.04 In the absence of investments associated with the proposed project, the existing 10-inch diameter pipeline may be expected to be out of commission by the early 1990s due to the absence of cathodic protection against corrosion, as discussed in Annex 3.02. Until it is provided cathodic protection and rectified satisfactorily, this pipeline, though operative, will remain prone to major breakdowns. Therefore, since the new 18-inch diameter pipeline will guarantee security of supply, and since the 10-inch diameter pipeline upon completion of cathodic protection and rectification works will be operating reliably as an integral part of the transmission system, the full average-day Payagon gas offtake constitute incremental benefits to the PGDP as whole. Separate analysis on the proportion of this average-day offtake attributable to Phase I alone has also been conducted.

5.05 In switching to natural gas, additional benefits would accrue from reduced operating costs (maintenance, fuel handling and storage). For inefficient industries, and less so for power and cement plants with frequently maintained sophisticated burners, increased thermal efficiency due to gas use would result in around 5% increase in benefits. These, however, have not been factored into the economic rate of return calculations given the already high rates obtained.

5.06 Product Price Assumptions. On the basis of World Bank projections for international crude oil prices, border price values (CIF Rangoon, ex-Singapore) for the two liquid fuels to be substituted for by gas (diesel and fuel oil) were derived by adjusting these crude oil prices by fixed product-to-crude price margins. These margins are estimated to remain constant on the assumption that, on a worldwide basis, as the recent shut-down of uneconomic units are completed and a better balance between refining capacity and demand is achieved, the refining margins in terms of product-to-crude price ratios will be more stable. The ratios used in the economic analysis are conservatively lower than current refining margins. The projected product values were further adjusted for a freight differential. Annex 5.02 provides details on the assumptions used for crude oil prices and product values in the project economic evaluation.

5.07 Project Costs. The appraisal mission reviewed GOB's detailed investment plans for the gas subsector, with a view to agreeing with GOB on priority investment activities. The mission concluded that the full

development of Payagon is essentially the long-term gas subsector investment program due to the serious lack of financial and technical resources to undertake activities other than those planned under PGDP. The selection criteria for delivering Payagon gas at least cost are discussed in Annex 3.02. Cost estimates for PGDP and for its Phase I (the project) are in constant 1987 US dollars, net of taxes and duties and inclusive of an average 19% physical contingencies (para 3.20).

Economic Rate of Return (ERR)

5.08 As shown in Annex 5.02, ERRs for the PGDP as a whole and for its Phase I (the project) were calculated on the basis of 2 sets of price assumptions: (i) projected product values based on World Bank international crude oil price projections and fixed product-to-crude price margins, as discussed above; and (ii) diesel and fuel oil prices prevailing in early-December 1986, which were the lowest ever in the past 10 years, that is, fuel oil at US$50/metric ton (mt) or US$7.41/bbl, and diesel at US$100/mt or US$13.19/bbl, including the freight differentials. The resulting ERRs are as follows:

	Economic Rates of Return	
	At Projected Product Values	At Lowest Historical Prices a/
Payagon Gas Development Program	59%	33%
The Project (Phase I of PGDP)	72%	46%

a/ Conservatively assumed to increase at average annual real rates of 1.0% and 0.5% for diesel and fuel oil, respectively.

The project's high economic rates of return are due to the relatively low gas production costs, the proven productivity of the Payagon gas field, the high rate of well deliverability, the proximity of gas markets in Rangoon and southern Burma, and the assured domestic markets for gas.

Sensitivity Analyses

5.09 Given the high project ERRs, even at the lowest historical prices of substitute liquid fuels, no further sensitivity analysis on prices of liquid fuels was carried out. Sensitivity to cost overruns were also not considered due to the adequate level of physical contingencies incorporated in the project cost estimates (para 3.20) as well as the depressed state of the international petroleum service industry, which is expected to remain for the duration of the project implementation period. There appears to be no rationale for testing the project's economic viability against projected gas demand not materializing, since the level of suppressed commercial energy demand is very high in Burma.

Long-run Marginal Cost (LRMC)

5.10 One of the project's main objectives is to ensure that the price charged for Payagon gas is sufficient to cover, at the minimum, the long-run marginal cost of the Payagon Gas Development Program (PGDP). Depending on the discount rate used, the LRMC for the PGDP (see Annex 5.03) ranges from US$0.62 to US$0.79 per MCF, delivered to the consumer. These figures represent the minimum boundary to price levels if the marginal economic cost of supplying Payagon gas is to be fully covered. The gas price level of K7.50 (US$1.13) per MCF decided upon by GOB more than guarantees this coverage and at the same time achieves the objective of making PGDP a financially viable operation for MOC. As provided for under the Gas Utilization Study, gas prices will be reviewed in light of new estimates of unconstrained gas demand and incremental costs for necessary field development and further expansion of the gas transmission and distribution network. The Study will also review the marginal cost of Payagon gas to major consumer categories, with a view to assessing in the Burmese context the relative merits of a uniform versus differential gas pricing structure as well as the need for future adjustments in the gas price level.

5.11 Being a gas-surplus country, with sufficient reserves to last around 150 years on the basis of current demand projections and onshore/offshore gas reserves of 4.8 TCF in the south, a depletion premium is either insignificant or inappropriate in the case of Burma. Even under a conservative assumption based on onshore Payagon reserves alone, the depletion premium would be around US$0.12/MCF (K0.79/MCF), which, when added to the US$1/MCF minimum required to achieve full cost recovery (see para 1.20), is well within the gas price level decided by GOB. This assumption, however, would not hold since the appraisal drilling component of the project is expected to firm up more Payagon reserves.

Project Risks

5.12 As illustrated above, the economic risks are limited. The geological risks of the project are small since the presence and deliverability of gas have already been established from earlier production in the Payagon area. Technical risks related to reserves appraisal are low and would be further minimized by doing seismic work before or in conjunction with drilling in order to limit the number of dry delineation wells. GOB has consistently attached high importance to the project since it will help alleviate within a relatively short period of time one of the economy's primary shortages, thus minimizing the risk of slow project implementation.

VI. AGREEMENTS REACHED AND RECOMMENDATIONS

6.01 During negotiations, the following agreements and assurances were obtained:

From the Government (GOB) that

(a) it will review with IDA the progress and results of the Gas Utilization Study (para 1.19);

(b) the execution of a Subsidiary Loan Agreement between GOB and MOC, satisfactory to IDA, will be a condition of Credit effectiveness (para 3.23)

(c) all necessary foreign and local currency funds to complete the project in a timely manner will be made available to MOC (para 3.24);

(d) the establishment of a working group to undertake the MOC financial viability study will be a condition of Board presentation; the working group will provide its preliminary findings to GOB and IDA for their joint review not later than eighteen months after Credit effectiveness; the final report incorporating relevant IDA comments will be completed within two years after Credit effectiveness; and the completed study will be submitted to the Ministry of Energy for its review and development of a plan of implementation, as appropriate (para 4.09);

From the Myanma Oil Corporation (MOC) that

(e) it will submit to IDA its unaudited accounts within nine months, and the corresponding audit report, including a report on the Special Account, not later than twelve months, of the end of MOC's fiscal year (para 2.08);

(f) during supervision missions, MOC will furnish to IDA for its review and comment MOC's proposals for the locations of future development and appraisal wells as well as seismic programs, and that at regular intervals, MOC will also review with IDA staff the seismic, well drilling and testing results and consequent updating of the reserve calculations; MOC will review with IDA the progress and results of the Enhanced Oil Recovery Studies (para 3.10);

(g) it will prepare a detailed plan for implementing the LPG/CNG pilot operation for IDA review and comment not later than three months after Credit effectiveness (para 3.13);

(h) it will submit to IDA quarterly project progress and procurement status reports, as well as project accounts and a report on the Special Account, within 45 days of the end of each quarter(para 3.32);

(i) it will prepare and furnish to IDA a completion report on the project, within six months after the closing date of the Credit or after the final disbursement, whichever occurs first (para 3.32); and

(j) it will have all materials and equipment financed under the Credit fully insured while in transit and installation (para 3.34).

6.02 During negotiations, IDA also obtained GOB confirmation of the Payagon gas price increase (para 1.21), as well as GOB agreement on: (i) the final terms of reference for the Gas Utilization Study (para 1.19), the Enhanced Oil Recovery Studies (para 3.14), and the MOC Financial Viability Study (para 4.09); and (ii) the detailed components of a formal training program for MOC and the Energy Planning Department of the Ministry of Energy (para 3.15).

BURMA GAS DEVELOPMENT AND UTILIZATION PROJECT

Background Information on the Oil and Gas Sector

1. Oil was first recovered in Burma at least one thousand years ago, when collection started from wells dug by hand near surface seepages. Drilling started in the 1880s, and Burmah Oil Company (BOC) made a first discovery in 1887 at Yenangyaung. Further drilling on the same trend discovered more structures, the last one being Minbu in 1916. During the 1920s and 1930s, exploration was severely curtailed due to low prices and restricted demand; production of the discovered fields reached a pre-World War II level of around 20,000 barrels per day. During the war, the BOC fields were badly damaged and had to be redrilled during the 1950s to restore production.

2. Exploration. In 1963, BOC was nationalized and its assets taken over by the Myanma Oil Corporation (MOC). MOC resumed exploration surveys and drilling mainly in Central Burma and the Upper Delta Basin. Initially, only small-size oil and gas fields were discovered but in 1970, a sizeable extension to Minbu, the large Mann field, was found. This discovery added substantially to MOC's reserves and prompted an intensification of the exploration effort, which was also extended to the Hkaung Valley and Chindwin basins north of the known productive areas. Major finds in the following years were Htaukshabin in 1978 and the Pagan, Tuyingtaing, Tetma and Payagon Group (PTTP) in 1981; both are situated in the Central Burma basin. Exploration towards the north failed to yield substantial reserves; towards the south, however, in the Martaban offshore area, MOC using its own drilling barge discovered the large "D" gas field in 1983. Simultaneous exploration in the onshore area resulted in locating a group of medium-size, gas-bearing structures in the Payagon area. Based on the low maturity of the exploration effort for the different plays in Burma's sedimentary basins, substantial possibilities for further discoveries remain. There is potential especially for further non-associated gas finds in the Lower Delta area and in the onshore/offshore area between Payagon and Structure "D".

3. MOC's exploration is carried out by their own seismic crews. The four crews work only during the five to six dry months of the year and average a total of some 450 km per year. The corresponding 20 km per crew month is very low by world standards, even considering the difficult terrain conditions facing the two MOC crews working in the lower delta area.

4. MOC has 45 drilling rigs in operation, which in 1983 drilled about 270 wells. Of these, 30 were exploratory wells and the remaining 240 were development wells. For the fiscal year 1987, the number of wells planned has plummeted alarmingly. The total number planned is 104 wells, of which 10 are exploratory wells. The main reason for this decrease, according to MOC, is the lack of foreign exchange for tubulars and other drilling consumables. In fact, some drilling rigs are busy recuperating casing from abandoned wells to be used at new locations.

5. Geology of Payagon. Geologically, the Payagon area is characterized by draping of younger formations over old basement highs, which are situated at a depth of over 15,000 feet. The younger formations are mainly alternating sand and shale deposits of Tertiary (Miocene) age. The main structural

elements can be conveniently mapped by seismic exploration; however, individual sand reservoirs, which are sometimes discontinuous because of their deltaic sedimentation, are yet inadequately delineated by this method. In the general Payagon area, five individual highs have been recognized, of which two have been found to have commercially exploitable gas reservoirs. Gas reservoir sands are situated at various depths from 4,600 to 9,000 feet with thicknesses ranging from 20 to 100 feet. Porosities decrease from 25% for the shallow sands to 15% for the deeper sands. The two sands which are currently producing are the 4,600-feet sand at the D structure and the 7,700-feet sand on the A structure. The discovery well flowed at a rate of 6.5 million cubic feet per day (MMCFD) and 200 barrels (bbl) of 60°API gravity condensate.

6. Oil and Gas Reserves. Currently, the oil reserves of Burma are estimated at over 2 billion barrels, including condensates. A major part of these reserves, or around 800 million barrels (MMbbl), are located in the newly-discovered PTTP group of fields in the Central Burma Basin. The older fields in this basin still contain 637 MMbbl of the original 1,070 MMbbl. The remainder of the reserves are in the Chindwin basin (120 MMbbl) and in the Upper Delta Basin (100 MMbbl). Total gas reserves in Burma are currently evaluated at some 10 trillion cubic feet (TCF). The predominance of gas over oil increases towards the south. The major gas reserves are located in the offshore "D" structure (4 TCF) and the Payagon area (0.8 TCF). These structures contain essentially non-associated gas while structures in Central Burma and the Upper Delta Basin contain nearly 2 TCF of gas in mainly oil-bearing reservoirs (associated gas).

7. Production. Oil production in Burma is characterized by the disparity between the rather large reserves and the continuously low and falling oil production. The current oil production of 25,300 barrels per day (bpd) in June 1986 has declined from the 26,850 bpd level in 1983, notwithstanding the large reserves, of which some 25% has been developed for production. This means that each year, only 2% of the developed reserves are produced. For gas, this percentage is equally low; however, gas production has increased significantly over recent years. The low and declining ratio of oil production versus reserves suggests that, while MOC's exploration efforts are sufficient to firm up reserves in the ground, the ensuing appraisal and production efforts are insufficient to allow removal of these reserves to the surface on a commensurate scale.

8. The above-mentioned decrease in drilling activity will further compound other production constraints that Burma is confronted with, namely: (a) the high wax content and/or high viscosity of the crude oil in many reservoirs, which severely impedes the flow of oil towards and into the bore hole; (b) the shallow position of many reservoirs with correspondingly low formation pressures; and (c) the presence of clay particles in the reservoir sands that tend to swell in contact with fresh water drilling mud, thus reducing the permeability of the reservoir. As a consequence, the production decline of the wells will be steep and many new wells will have to be drilled each year just to maintain production at the current level. To offset the decrease in the drilling of production wells, MOC intends to put more emphasis on workover operations of old wells, and where possible, by bringing shallower sands in production. However, the decline in drilling will ultimately reduce MOC's inventory of producing wells, leading to an unavoidable, steeper cut in oil production.

9. Gas production, which is less hampered by the above-mentioned adverse reservoir conditions, has shown a healthy increase over recent years. Production in FY84 was averaging 49.8 MMCFD, while during FY86 a level of 117 MMCFD was reached. This production increase comes mainly from the fields in the Upper and Lower Delta Basins, including production from the Payagon field. The increased gas production has resulted in growth of total hydrocarbon energy production in Burma from 36,150 to 44,785 barrels of oil equivalent per day between FY84 and FY86.

10. Operational Strategy. MOC has achieved very good results in the exploration and initial production phases, especially when considering the limited resources available. There is no doubt about the general level of technical competence of its management and staff. However, apart from assistance by Schlumberger in well services and occasional studies financed by bilateral aid from Germany and Norway, all these activities are carried out internally. By and large, these are done adequately, but there are areas where improvements are necessary if Burma wants to use its vast potential for increased oil production. Particular areas of improvement include drilling and reservoir engineering, including training of staff in reservoir management and production optimization. Experienced foreign consultants should first evaluate the present situation and advise MOC on where and how its drilling and production technologies can be improved. Recommendations should be tested in field pilot applications.

11. If these studies and tests show that improvements are possible, their full-scale application may place too much strain on Burma's capital and manpower resources. At that point, very serious consideration should be given to entering into service contracts with foreign oil companies. With proper technological and financial assistance, Burma should be able to bring more reserves into production and, with advanced production management, raise the oil production level from the current 25,000 bpd to 50,000 bpd by the mid-1990s. In view of the large oil and gas reserves, of which only a minor part has been developed, exploration drilling can be decreased for some years to allow the concentration of available drilling resources on the appraisal and development of oil fields.

BURMA - GAS DEVELOPMENT AND UTILIZATION PROJECT

NATURAL GAS UTILIZATION STUDY

Terms of Reference

Objectives

1. Burma's sizeable natural gas resources can play a major role in promoting growth and development of the Burmese economy. Despite the capacity to meet increasing domestic energy requirements at relatively low cost, current energy consumption levels are low in relation to available potential and the development of the natural gas delivery system is at its early stages. While there is a clear need to transform the natural gas subsector into a major driving force behind economic growth, it is essential that scarce financial resources be allocated to their best use, that is, in priority investments that yield maximum benefits to the national economy. Optimal resource allocation requires a dynamic policy and planning decision framework for the gas subsector that is closely linked to the achievement of macroeconomic objectives. This framework, in turn, needs to be firmly supported by quantitative analytical tools for formulating gas subsector investment strategies. The Government of Burma (GOB), therefore, has decided to conduct a Gas Utilization Study with the following main objectives:

(a) provide firm estimates of natural gas supplies, both associated and non-associated, and assess production potential over time;

(b) develop a quantitative model for continuous assessment and forecasting of natural gas demand; identify gas network requirements to meet demand by region and by consuming sector, as well as any supply/demand imbalances;

(c) evaluate the technical feasibility and the economic value of gas among alternative uses; recommend an optimal allocation among these uses in a manner that maximizes cost efficiency and national benefits; and on this basis, recommend a sequence of priority investments; and

(d) in conjunction with the above, prepare a quantitative gas planning and policy analysis framework that permits updating and revision as parameters affecting investment decisions change; and train GOB counterparts in the model's full operation.

This study will be financed by the United Nations Development Program under the Gas Development and Utilization Project between the Government of Burma and the International Development Association (IDA) of the World Bank Group, with the latter acting as executing agency.

Scope of the Study

2. To meet the objectives of this Study, the consultant is expected to carry out the following specific tasks:

Supply Assessment

(a) (i) evaluate available data on gas reserves, both associated and non-associated, offshore and onshore, and provide a firm set of reserve estimates, focusing on the following four onshore regions (and/or by other appropriate geographic classification as required):

Region I -
North Ayadaw/Chauk/Yenangyaung/Mann/Htaukshabin/Peppi
Region II - Myayde/Pyalo/Prome
Region III - Htantabin/Kyangin/Myanaung/Shwepyitha
Region IV - Payagon/Rangoon/Hmawbi/Syriam

(ii) review crude oil reserve data and gas/oil ratios to evaluate associated gas supplies;

(iii) estimate the potential role of discovered but undeveloped gas fields, as well as potential and possible reserves; and

(iv) assess the production capacity and deliverability of potential sources of supply, including LPG and flared gas;

Demand Projections

(b) (i) prepare forecasts for unconstrained gas demand over the short (up to 5 years), medium (between 6 to 10 years) and long term (beyond 10 years) in accordance with GOB Economic Plan periods, covering the same regional classifications as in 2(a)(i) above and all major uses, both existing and potential, either as incremental demand or as substitute for liquid fuels, including power, fertilizer, refining, cement, industry (disaggregated), as well as new uses in transport (LPG/CNG), agriculture, commercial/residential;

(ii) delineate key macroeconomic, demographic and other historical determinants of demand growth in each use, taking into full account the existing large unsatisfied energy demand;

(iii) update the results of the export marketing study that was part of the 1984 Martaban Offshore Gas Pre-Investment Study, with a view to assessing, in the Burmese context where proven gas resources are in excess of long-term domestic demand requirements, the economic potential for export-oriented gas uses such as petrochemicals;

(iv) prepare an explicit methodology and a quantitative model for monitoring changes in demand patterns and revising demand projections on a periodic basis; and

(v) undertake survey/s as required to fill in any gaps in available data;

(c) (i) project gas supply/demand balances by region and consuming sector;

(ii) project requirements for gas-based export industries, if warranted from the updating of the export marketing study in 2(b)(iii) above; and

(iii) take into full account technical parameters in the operations of the major end-users, such as the technical feasibility of converting existing users of liquid fuels to natural gas, average and peak production capacity, and field infrastructure requirements particularly where supply/demand imbalances are identified;

Gas Allocation

(d) based on 2(c) above,

(i) analyze the technical feasibility as well as the financial and economic costs and benefits of alternative gas development and utilization scenarios; and

(ii) provide estimates of the investments required to increase supplies from existing gas fields and/or develop new fields as may be required to satisfy projected average and peak demand, and for corresponding gas delivery network requirements;

(e) (i) determine the most likely value of gas in each alternative use and its sensitivity to the assumptions made;

(ii) take explicit account of the level and structure of retail petroleum product prices vis-a-vis comparative border prices over time, and the effect of these on gas substitution, as well as make suggestions on economic pricing of petroleum products; and

(iii) determine the optimum gas allocation, as well as the economic price path of gas, among existing uses and alternative future projects or project packages so as to maximize national benefits, based on the gas reserves scenario determined above, and possibly based on other supply scenarios to be agreed with GOB prior to the commencement of the Study (for example, relative emphasis between onshore versus offshore gas development);

Gas Utilization Plan

(f) based on the results of 2(d) and 2(e) above:

(i) rank projects or project packages;

(ii) recommend an optimal sequence of investments;

(iii) review the institutional and training requirements to implement these investments and to effectively manage over the long term a rapidly growing gas subsector;

(iv) recommend internationally accepted gas industry codes as well as standards for safety, supply, transport, accounting, evaluation and validation, etc; and

(v) review and comment on any potential constraints to implementing the recommended gas allocation posed by existing regulatory measures and procedures;

(g) (i) conduct sensitivity tests on supply, demand, international petroleum prices, energy demand management, and other parameters;

(h) (i) compare explicity the economic price path of gas under the optimum allocation scenario with existing gas prices, with a view to maintaining the full cost recovery principle being applied by the Myanma Oil Corporation (MOC); and

(ii) review the long-run marginal cost of Payagon gas development and the relevance, if any, of applying a depletion premium, calculate marginal cost to major consumer categories, and assess the relative merits in the Burmese context of a uniform versus differential gas tariff structure.

Major Output Expected

3. Since GOB's fundamental aim is to map out and implement a short- to medium-term gas supply allocation and investment strategy, the concrete output of this Gas Utilization Study should highlight: (a) gas supply/demand balances over time by region and consuming sector; (b) a ranking, based on optimal resource allocation criteria, of alternative investment programs for gas appraisal, development, production, delivery systems and market development; (c) gas network analysis for gas transport systems and a map of the required infrastructure for the recommended investment strategy; (d) codes and standards for the Burmese gas industry; (e) an empirically based, quantitative gas supply/demand forecasting, economic allocation and investment planning model that permits easy update and revision as determinants change over time; and (f) an action plan for implementing the optimal investment plan, including gas market development, the establishment of an organizational structure suitable for effective management of Burma's gas subsector, and training programs, where required. A high priority will be placed on the development of a replicable planning framework for future operational use by GOB, making

it essential that the consultants organize the analysis around either a micro-computer- or mainframe-based model to be left with the Ministry of Energy (MOE) and the MOC upon completion of the Study.

Methodology

4. In the proposal, the consultant should delineate clearly the methodology to be adopted in carrying out the Study. Special attention should be given to: (i) agreeing with GOB and IDA before commencement of the Study the international crude oil and petroleum product price assumptions over time to be used in the Study; (ii) marginal and total costs at each stage of exploration, development, transmission, distribution, conversion to gas, and end-use (i.e., from field to burner tip); (iii) distinguishing between the relative cost of additional gas produced for average and peak demand; (iv) the substitutability of gas use over time; (v) complementarities in gas investment, making inappropriate the comparison of alternative projects as if they were mutually exclusive; (vi) the trade-offs between alternative time profiles for a given project package; (vii) the ranking criteria used (e.g., netbacks or project package(s) net present values); and (viii) the basic methodological problem that the economic price path of gas, which is necessary for ranking, is in itself dependent on the set of projects selected. The proposal should indicate the degree of user disaggregation proposed (e.g., industry subdivisions, commercial activities, residential locations, etc.). The analysis should also take explicit account of the cost of gas substitutes, location-specific costs of delivering alternative inputs/outputs, conversion costs for existing plants and seasonality of demand (load factors). For each of the supply scenarios, the marginal supply cost and time profile of capacity availability will be agreed with GOB. The consultant, where necessary, will be required to estimate marginal investment costs to a 20% level of accuracy, taking into account local conditions.

Organizational Support and Data Availability

5. GOB will assist the consultant in obtaining the necessary data. A small, high-level Task Force comprised of officials from the Ministry of Energy, the Ministry of Planning and Finance, the Myanma Oil Corporation, the Electric Power Corporation, the Petrochemical Industries Corporation, the Petroleum Products Supply Corporation, and possibly others, will be established with the main objective of facilitating data procurement from the various energy entities and other sources as required, as well as surveys that may be necessary to fill in data gaps. In order to avoid duplicating work already done, the consultants should make full use of available information (updating where necessary) including MOC's gas reserve and other technical data, the Joint UNDP/World Bank Energy Assessment Report, the Martaban Off-shore Gas Pre-Investment Study, and others. At the same time, a core Working Group comprised of MOE and MOC staff will be established to work closely with the consultants during the course of the Study with the main purpose of learning the assumptions, construction and full operations of the gas supply/demand balances, allocation and investment planning model. MOC will be providing the consultants access to its computing facilities for this purpose. Importance will be given to close interaction among MOE/MOC staff, the Task Force and Working Group for the Study, other local counterparts and the consultants, during the course of implementing the Study, so that future users are fully familiar with the work in progress and the model's assumptions, features and operations.

Timetable and Reporting Requirements

6. The Myanma Oil Corporation will be in charge of supervising the Study in the field. It is estimated that the Study would require about 60 staff-months and 18 months to complete. The consultant selected for the Study will supply GOB with a detailed schedule of work and information requirements at commencement. Immediately thereafter, the consultants and GOB shall agree on the work program, elaborate on the proposed methodology, agree on specific outputs from the Study and establish the nature and timing of assistance to be provided by GOB as well as timing of proposed additional formal consultations.

7. An interim report shall be submitted 6 months and a draft final report 12 months after commencement to GOB and IDA for review. It is expected that a final report would be ready by the end of 18 months after commencement for review and discussion with IDA and GOB. All information generated by the Study is to be treated as strictly confidential with IDA and GOB.

Staffing

8. It is expected that this Study will require high-level staff with extensive field experience of at least 15 years in the following areas of expertise: (i) gas economics, demand analysis, valuation and allocation methodology, and policy; (ii) geology, reservoir engineering and supply projections; (iii) natural gas engineering, system planning and economics; and (iv) gas utility operations. The Gas Economist would lead the Project Team and would be primarily responsible for the preparation of a computer-based gas planning framework.

BURMA GAS DEVELOPMENT AND UTILIZATION PROJECT

ENHANCED OIL RECOVERY STUDIES (CHAUK AND TETMA FIELDS)

Terms of Reference 1/

TERMS OF REFERENCE FOR ENHANCED OIL RECOVERY APPLICATIONS IN CHAUK FIELD, BURMA

I. INTRODUCTION

1. The Myanma Oil Corporation (MOC) is interested in acquiring the services of consultants of repute to perform a Feasibility Study on the application of Enhanced Oil Recovery (EOR) processes for improving oil recovery from the Chauk Field.

2. Location. Chauk Oil Field is located at approximately Latitude 20° 54' N and Longitude 94° 49' E in Central Burma.

3. Background. The Chauk Field was discovered in 1902. It is situated in the Central Burma basin and covers approximately 10.2 square miles. The field has an estimated original oil-in-place of about 400 million barrels (MMbbl). It has produced 145.3 MMbbl from 1,568 wells. The reservoir studies were performed in 1960. The initial average production was 4.09 MMbbl/year in the early 1940s but has declined to 0.33 MMbbl/year by 1985.

4. Geology. Chauk Oil Field is a thrusted asymmetrical anticline. The structure was dissected by many cross faults. Oil accumulation is found in suprathrust Oligocene formation. Commercial gas accumulation has been discovered in subthrust Oligocene.

5. Quality of Oil. The oil contained in Oligocene reservoir in Chauk Field has a specific gravity of 39.8° API, wax content of 7.2%, pour point of 80°F, and nil sulphur content. Surface viscosity of crude is 1.51 centipoise at 100°F. The reservoirs have been penetrated by 1,568 wells through 1,640 feet (500 meters) of productive formations. The depth of the reservoirs is between 1,500 feet (457 meters) and 4,000 feet (1,200 meters).

6. Based on the studies undertaken by MOC, the original oil-in-place is estimated at 400 MMbbl. The production potential by primary recovery is expected at 151.5 MMbbl. It is expected that Enhanced Oil Recovery processes are likely to improve ultimate recovery from these reservoirs.

II. SCOPE OF THE STUDY

7. The prime objective of the Study is to determine for each reservoir the most suitable engineering and economic proposition, which would merit a pilot test and ultimately lead to full-scale field application.

1/ Excluding annexures.

8. The consultant will review the data supplied by MOC; study the geology, petrophysics, reservoir engineering, phase behavior, thermodynamics, etc.; and develop various physical and mathematical models to evaluate the results of various EOR methods.

9. The consultant will develop and define a comprehensive methodology, including engineering study, of an EOR system in the Chauk Field.

10. The consultant will provide practical training to MOC personnel throughout the various phases of the Study, at the field in Chauk, as well as at the consultant's home office facilities.

11. The consultant will provide financial and economic analysis, testing the rate of return for various processes and their application against incremental production.

III. DETAILED ASSIGNMENT

12. General. To ensure the achievement of the Study's objectives, the consultant will provide the services of highly qualified and experienced personnel to carry out various aspects of this Study. The consultant will carry out the assignment using modern techniques, latest technology and industry standards. The consultant will work in close cooperation with MOC personnel assigned to this project, and will keep the MOC management fully informed of the progress of the Study. The consultant will review the reservoir studies performed to date by MOC and, if necessary, recommend to make reservoir studies if a reservoir study update is necessary prior to a thermal recovery process study.

13. Data Gathering. The consultant will gather the available data from MOC, and arrange and supervise the collection of additional data as required. The consultant will discuss and agree with MOC as to the procedure for the collection/transmittal of existing data and the acquisition and transmittal of any additional data. The consultant will inventory all data. All data including microfilms, tapes, etc., shall be returned to MOC after the completion of the Study.

14. The consultants will review the data available, and may recommend collection of additional data, including additional logging and coring; subsurface reservoir and well data; and further laboratory analysis. The consultant will spell out the additional information required at an early stage, including cost and timing, and will present these requirements to MOC for agreement.

15. Approach. The Chauk Oil Field has reached maturity in its production life, the water cut is increasing and the overall production level is declining. The consultant will, therefore, evaluate the relevance and applicability of various EOR methods. However, application of these methods involves substantial capital outlay and carries considerable technical risk, particularly in view of the characteristics and uncertainties of many EOR processes. Therefore, before considering any field application, it would be necessary to undertake a staged Feasibility Study, which should follow the classical approach of: (a) screening the various EOR methods; (b) conducting a Feasibility Study; (c) laboratory experiments; (d) application of one or

more processes on a pilot scale; and (e) field application of the most suitable EOR process or processes. The data contained and the conclusion arrived at in an updated reservoir study could also be an important input for EOR pilot project design.

IV. STAGES OF STUDY

16. The Study will be carried out in three stages. The scope of these stages will be as defined below:

STAGE I

17. Pre-Feasibility Study. The consultant will review the data, screen the various EOR methods, conduct the laboratory experiments and, based thereon, develop three scenarios for at least two accredited EOR methods considered suitable for various types of oil reservoirs of the Chauk Field. The consultant will further study the technical feasibility and economic viability of the selected EOR methods in order to determine the most viable enhanced recovery process, while also ensuring the training of MOC personnel in these processes during the course of the Study.

18. The consultant will prepare a draft pre-feasibility report, discussing the analysis of various options, results and recommendations, including economic analysis. The consultant will spell out the recommendations for the selection of one or more EOR processes for pilot tests.

19. The consultant will make a presentation at a meeting with MOC discussing the review, analysis and recommendations contained in the draft pre-feasibility report. The final selection of EOR process/processes shall also be made at this meeting.

STAGE II

20. Pilot Test(s). After the final selection of the optimum EOR method, a pilot test or tests shall be conducted for a physical demonstration of the selected process. The consultant will prepare an engineering study that will cover process definition, engineering designs, equipment and material specifications, and implementation schedule for a pilot project (including data collection and interpretation, as well as capital and operating cost estimates, separately indicating local and foreign currency components).

21. The consultant will assist MOC in the selection of a pilot test site, procurement of equipment, materials, services, installation, commissioning, operation, data collection and monitoring of the pilot project.

22. Training. The consultant will assess the training requirements of MOC staff within and outside Burma and develop a comprehensive training program, including components, cost and timing. The training program will also include visits by MOC technical staff to oil fields in foreign countries experiencing problems similar to the Chauk Field and where application of recommended EOR processes have been successful.

STAGE III: Final Study

23. Data Integration. The consultant will integrate the data acquired from the pilot test, and will carry out the final evaluation for an EOR program for field-wide applications.

24. Models and Recommendations. The consultant will develop various models, defining in detail the available alternatives, and spell out the recommendations for the most effective EOR process to maximize recovery, including time spans, recovery rates and economic benefits.

25. Process Definition. The consultant will design and define, in detail, the recommended EOR process or processes, including but not limited to flow diagrams, estimated recovery rates, reservoir management and monitoring techniques and all other parameters.

26. Engineering Design. The consultant will carry out the detailed engineering design of equipment and facilities required for EOR programs, including but not limited to optimum sizing of equipment and ancillary facilities, metering system, equipment and material specifications, bid documents suitable for international bidding, and capital and operating cost estimates for individual components and the entire project (indicating the foreign exchange and local currency cost components).

27. Technical Assistance and Training. The consultant will provide the complete technical assistance during the implementation stage of the project, and such assistance will include the consultant's work at the field and home office support services. The consultant will also review and update the training programs including components, cost, timing, etc.

28. Project Schedule. The consultant will prepare the project implementation schedule, fully considering weather conditions, delivery of material and equipment and all other relevant factors.

29. Economic Analysis. The economic analysis should follow discounted cash flow techniques. The streams of total costs, in economic terms, should be developed. The consultant will calculate the internal economic rate of return of the project based on the economic cost and benefit streams.

V. TIMETABLE AND REPORTING REQUIREMENTS

30. Review Meetings. The number of review meetings will depend on the results of the feasibility study. Meetings considered necessary by the consultant or MOC will be discussed and agreed to by both parties. In principle, the timing of these planned meetings shall be as follows:

(a) Stage I: The first review meeting shall be held at the consultant's home office, at the end of the pre-feasibility study.

(b) Stage II: The second review meeting will be held after completion of the preliminary pilot design, at a venue to be designated by MOC.

A review meting will be held prior to the start of the pilot operation and further meetings will be planned as necessary to monitor its operations at a venue to be designated by MOC.

31. It is estimated that the feasibility study would require 60 staff-months and about 12 months to complete. The consultant selected for the study will supply the Government of Burma (GOB) with a detailed schedule of work and information requirements at commencement. Immediately thereafter, the consultants and GOB shall agree on the work program, elaborate on the proposed methodology, agree on specific outputs from the study and establish the nature and timing of assistance to be provided by GOB as well as timing of proposed additional formal consultations.

32. An interim report shall be submitted six months and a draft final report nine months after commencement to GOB and the International Development Association (IDA) for review. It is expected that a final report on the feasibility study would be ready by the end of 12 months after commencement of the study for review and discussions with GOB and IDA. The consultant will submit ten (10) copies of the final report to MOC and two (2) copies to IDA. The consultant will also forward to MOC all computer output and return all the data received from MOC.

33. All information generated by the study is to be treated as strictly confidential with IDA and MOC.

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TERMS OF REFERENCE FOR THERMAL RECOVERY PROCESSES FOR IMPROVING OIL RECOVERY IN TETMA OIL FIELD

I. INTRODUCTION

1. The Myanma Oil Corporation is interested in acquiring the services of consultants of repute to perform a Feasibility Study on the application of thermal recovery processes for improving oil recovery from the Tetma Field.

2. Location. Tetma Field is located at approximately Latitude 20° 58' N and Longitude 95° 00' E in Central Burma.

3. Background. The Tetma Field was discovered in 1982. It is situated in the Central Burma Basin and covers approximately 0.30 square miles. The field has an estimated original oil-in-place of about 185.6 million barrels (MMbbl). It has produced 0.138 MMbbl from five wells. The initial production by pumping from discovery well no. 2 was 92 barrels of oil per day (bopd) and 14 barrels of water per day (bwpd), which has declined to 40 bopd and 90 bwpd in 1986. Altogether there are about 13 proved sands with a total net pay thickness of about 595 feet (181 meters).

4. Geology. Tetma Oil Field is situated on the Tuyintaung-Pagan Hill-Natpalin-Tetma-Gwegyo-Payagyigon-Ngashandaung-Nyaunggon geological anticline. It is the second line of structure east of the well known proved oil province of Yenangyat-Lanywa-Chauk-Yenangyaung-Mann-Htaukshabin structural trend.

5. Quality of Oil. The oil contained in Oligocene reservoir in the Tetma Field has a specific gravity of 34° API, pour point of 100°F, and nil sulphur content. Surface viscosity of crude is 2.18 centipoise at 210°F. The reservoirs have been penetrated by five wells through 595 feet (181 meters) of productive formations. The depth of the reservoir is between 1,000 feet (305 meters) and 3,450 feet (1,052 meters).

6. Based on the studies undertaken by MOC, the original oil-in-place is estimated at 185.6 MMbbl. The production potential by primary recovery is expected at 9.28 MMbbl. It is expected that thermal recovery processes are likely to improve ultimate recovery from these reservoirs.

II. SCOPE OF THE STUDY

7. The prime objective of the Study is to determine for each reservoir the most suitable engineering and economic proposition, which would merit a pilot test and ultimately lead to full-scale field application.

8. The consultant will conduct a thorough review of the data available with MOC. The consultant will identify the missing data and make recommendations for obtaining it.

9. The consultant will use the data in a petrophysical computer model to assist in the interpretation of reservoir description and its petrophysical characteristics using all available data and petrophysical analyses.

10. The consultant will make geological evaluation and draw structure contour and other maps.

11. The consultant will estimate oil-in-place and ultimate recoverable reserves.

12. The consultant will provide the estimated optimal recovery from the reservoir using numerical simulation models and compare and evaluate recoveries using various thermal recovery processes.

13. Based on the results of the reservoir study, the consultant will prepare a Feasibility Study of the pilot project in Tetma reservoir, taking into consideration: (i) state-of-the-art thermal recovery process technology; (ii) technological aspects; (iii) flexibility of the operations taking into consideration the local conditions; (iv) availability of injection fluids; (v) quality of produced fluid and its handling; and (vi) economic viability.

III. DETAILED ASSIGNMENT

14. General. To ensure the achievement of the Study's objectives, the consultant will provide the services of highly qualified and experienced personnel to carry out various aspects of this Study. The consultant will carry out the assignment using modern techniques, latest technology and industry standards. The consultant will work in close cooperation with MOC personnel assigned to this project, and will keep MOC management fully informed of the progress of the Study. The consultant will review the reservoir studies performed to date by MOC and, if necessary, recommend to make reservoir studies if a reservoir study update is necessary prior to a thermal recovery process study.

15. Data Gathering. The selected consultant will gather the available data from MOC, as well as arrange and supervise the collection of additional data as required. The consultant will discuss and agree with MOC as to the procedure for the collection/transmittal of existing data and the acquisition and transmittal of any additional data. The consultant will inventory all data. All data, including microfilms, tapes, etc., shall be returned to MOC after the completion of the Study.

16. The consultant will review the data available, and may recommend collection of additional data, including additional logging and coring; subsurface reservoir and well data; and further laboratory analysis. The consultants will spell out the additional information required at an early stage, including cost and timing, and present these requirements to MOC for agreement.

17. Approach. The consultants will evaluate the relevance and applicability of various thermal recovery processes, i.e.: (i) cyclic steam stimulation; (ii) stream drive; (iii) initial cyclic stimulation converted to steam drive; (iv) in situ combustion; and (v) any other method, or combination of methods.

IV. STAGES OF THE STUDY

18. The study will be carried out in three stages. The scope of these stages will be defined as below:

STAGE I

19. Pre-Feasibility Study. The consultant will review the data, screen the various thermal recovery methods, conduct the laboratory experiments and, based thereon, choose the thermal recovery process considered suitable for the Tetma Field. The consultant will further study the technical feasibility and economic viability of the selected methods, and also ensure training of MOC personnel during the course of implementing this study.

20. The consultant will prepare a draft pre-feasibility report, discussing the analysis of various alternatives and options, results and recommendations, including economic analysis. These results will be discussed in a review meeting.

STAGE II

21. The consultant will spell out the recommendations for the selection of one or more thermal recovery processes for pilot tests if these are evaluated to be economically viable. The preliminary selection of process/processes shall be made at a second review meeting. The final report on the feasibility study will be available at that time.

22. After the final selection of the thermal recovery method, the consultant will prepare an engineering study and such study will cover process definition, engineering design, equipment and material specifications, and implementation schedule for a pilot project (including data collection and interpretation, as well as capital and operating cost estimates, separately indicating local and foreign currency components).

23. The consultant will assist MOC in the selection of a pilot test site, procurement of equipment, materials and services, installation, commissioning, operation, data collection and monitoring of the pilot project.

24. Training. The consultant will assess the training requirements of MOC staff within and outside Burma and develop a comprehensive training program, including components, cost and timing. The training program will also include visits by MOC technical staff to oil fields in foreign countries experiencing problems similar to the Tetma Field and where application of recommended thermal recovery processes have been successful.

STAGE III: Implementation of the Pilot Test

25. Data Integration. The consultant will monitor the running of the pilot test and integrate the data acquired from the pilot test, and will carry out the final evaluation for a thermal recovery program for field wide-applications.

26. Models and Recommendations. The consultant will develop various models, define in detail the available alternatives, and spell out the recommendations for the most effective thermal recovery process to maximize recovery, including time spans, recovery rates and economic benefits.

27. Process Definition. If economic benefits can reasonably be expected, the consultant will design and define, in detail, the recommended process or processes, including but not limited to, flow diagrams, estimated recovery rates, reservoir management and monitoring techniques, and all other parameters.

28. Engineering Design. The consultant will carry out the detailed engineering design of equipment and facilities required for a thermal recovery program, including but not limited to optimum sizing of equipment and ancillary facilities, metering system, equipment and material specifications, bid documents suitable for international bidding, and capital and operating cost estimates for individual components and the entire project (indicating the foreign exchange and local currency cost components).

29. Technical Assistance and Training. The consultant will provide the complete technical assistance during the implementation stage of the project, and such assistance will include the consultant's work at the field and home office support services. The consultant will also review and update the training programs including components, cost, timing, etc.

30. Project Schedule. The consultant will prepare the project implementation schedule, fully considering weather conditions, delivery of material and equipment, and all other relevant factors.

31. Economic Analysis. The economic analysis should follow discounted cash flow techniques. The streams of total costs, in economic terms, should be developed. The consultant will calculate the internal economic rate of return of the project based on the economic cost and benefit streams.

32. Review Meetings. The consultant will plan three initial meetings. Any additional meetings considered necessary by the consultant or MOC will be discussed and agreed to by both parties. The timing of these planned meetings shall be as follows:

(a) The first review meeting shall be held at the end of the pre-feasibility study.

(b) The second review meeting will be held after completion of the preliminary design of the pilot test.

(c) A third review meeting shall be held after construction, but before the start of operations of the field pilot. Additional meetings during the pilot application will be scheduled as necessary.

V. TIMETABLE AND REPORTING REQUIREMENTS

33. It is estimated that the Study would require 60 staff-months and 12 months to complete. The consultant selected for the Study will supply the Government of Burma (GOB) with a detailed schedule of work and information requirements at commencement. Immediately thereafter, the consultants and GOB shall agree on the work program, elaborate on the proposed methodology, agree on specific outputs from the Study and establish the nature and timing of assistance to be provided by GOB, as well as timing of proposed additional formal consultations.

34. An interim report shall be submitted six months and a draft final report nine months after commencement to GOB and the International Development Association (IDA) for review. It is expected that a final report would be ready by the end of 12 months after commencement for review and discussion with GOB and IDA. The consultant will submit ten (10) copies of the final report to MOC and two (2) copies to IDA. The consultant will also forward to MOC all computer output and return all the data received from MOC.

35. All information generated by the Study is to be treated as strictly confidential with IDA and MOC.

BURMA GAS DEVELOPMENT AND UTILIZATION PROJECT

Selection Criteria for 18-inch Diameter Payagon to Rangoon Transmission Pipeline

1. The appraisal mission evaluated total transmission and distribution requirements to deliver gas from the Payagon field on the basis of the Payagon Gas Development Program (PGDP) and projected gas demand over a 20-year horizon for Rangoon and southern Burma. Gas demand is projected to grow to 65 MMCFD by 1990, and reach 90 MMCFD by the mid-1990s, and taper off at 120 MMCFD from 2001 onwards.

2. The existing 10-inch diameter pipeline, which was not equipped with cathodic protection against corrosion when it was built due to lack of foreign currency, is already operating at full capacity (30 MMCFD). While the appraisal mission's inspection of its above ground installations and construction records, prima facie, indicated overall satisfactory condition, underground corrosion is a likely eventuality. Cathodic protection under the project to arrest further deterioration as well as further inspection and rectification works to be done by MOC is essential to enable this pipeline to function reliably as part of the entire gas transmission system and thereby to meet the full projected demand by the year 2000 of 120 peak MMCFD for Rangoon and southern Burma.

3. The option of revalidating the existing 10-inch diameter pipeline (30 MMCFD capacity) and selecting smaller additional pipeline sizes was not considered feasible since this would involve exposing the entire pipeline length over the short dry weather windows available each year; serious load-shedding for the Rangoon area over prolonged periods would result. Safe and steady operation of this pipeline with minimized risk of service interruptions cannot be assured until cathodic protection and rectification works are completed. Gas demand by 1990 is projected at 65 MMCFD, reaching around 90 MMCFD by the mid-1990s. In evaluating the additional 90 MMCFD of peak capacity required, various pipeline sizes operating under free flow or with compression were considered and evaluated in detail with MOC. A 14-inch diameter pipeline was not recommended since its capacity of 45 MMCFD under free flow would not be sufficient to meet demand of 65 MMCFD by 1990; an excessively high compression ratio would otherwise be required. A 16-inch diameter pipeline, under a free flow of 65 MMCFD, would be insufficient to meet gas demand approaching 90 MMCFD towards 1995. While compression would enable this 16-inch diameter pipeline to deliver 90 MMCFD, the cost of compression and back-up facilities is nearly equal to the additional cost of selecting an 18-inch diameter pipeline instead. Operating cost of the 16-inch diameter pipeline with compression, however, would be significantly higher than the operation of an 18-inch diameter pipeline under free flow. For these technical, as well as economic reasons, an 18-inch diameter pipeline was selected as the least-cost option since it will be able to meet demand with an assured level of system reliability up to the mid-1990s. Upon completion of cathodic protection and rectification works on the existing pipeline, it will function as an integral part of the transmission system, which will deliver 120 MMCFD towards the year 2000 (i.e., 30 MMCFD and 90 MMCFD of peak capacities for the existing and 18-inch diameter pipelines, respectively).

PAYAGON GAS DEVELOPMENT PROGRAM (PGDP): PHASES I AND II

COMPONENTS OF BASE COSTS (in 1986 US$ million)

FIELD COSTS

FY ending March 31	1988		1989		1990		1991		1992		1993		1994		TOTALS	
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.
1. Gas Field Development																
a. Seismic	0.6	0.4	0.5	0.4	0.2	0.1	0.6	1.5	0.3	1.3	0.0	0.0	0.0	0.0	2.2	3.7
of which: Phase I	0.6	0.4	0.5	0.4	0.2	0.1	0.2	0.2							1.5	1.1
Phase II							0.4	1.3	0.3	1.3					0.7	2.6
b. Development drilling/ Reserve Appraisal	2.0	1.2	4.9	3.4	3.1	2.0	4.8	5.7	3.2	4.6	1.6	2.3	0.0	0.0	19.6	19.2
of which: Phase I	2.0	1.2	4.9	3.4	3.1	2.0	1.8	1.2	0.2	0.1					12.0	7.9
Phase II							3.0	4.5	3.0	4.5	1.6	2.3			7.6	11.3
c. Production Facilities	0.0	0.0	1.3	0.6	2.7	1.9	3.8	2.4	3.2	1.2	2.5	1.1	2.0	0.9	15.5	8.1
of which: Phase I			1.3	0.6	2.7	1.9	2.8	1.8	0.2	0.1					7.0	4.4
Phase II							1.0	0.6	3.0	1.1	2.5	1.1	2.0	0.9	8.5	3.7
d. Transport	0.5	0.3	1.0	0.5	1.3	0.5	3.2	1.3	3.0	1.2	2.0	0.6	0.0	0.0	11.0	4.4
of which: Phase I	0.5	0.3	1.0	0.5	1.3	0.5	1.2	0.7	1.0	0.6	0.0				5.0	2.6
Phase II							2.0	0.6	2.0	0.6	2.0	0.6			6.0	1.8
3. LPG/CNG Pilot Scheme	0.2		0.4	0.1	0.3	0.1	0.2	0.1	0.2	0.1	0.2	0.1			1.5	0.5
of which: Phase I	0.2		0.4	0.1	0.3	0.1	0.2	0.1	0.2	0.1	0.2	0.1			1.5	0.5
Phase II															0.0	0.0
PHASE I TOTALS:	3.3	1.9	8.1	5.0	7.6	4.6	6.2	4.0	1.6	0.9	0.2	0.1	0.0	0.0	27.0	16.5
PHASE II TOTALS:	0.0	0.0	0.0	0.0	0.0	0.0	6.4	7.0	8.3	7.5	6.1	4.0	2.0	0.9	22.8	19.4
PGDP TOTALS:	3.3	1.9	8.1	5.0	7.6	4.6	12.6	11.0	9.9	8.4	6.3	4.1	2.0	0.9	49.8	35.9

TRANSMISSION AND DISTRIBUTION COSTS

FY ending March 31	1988		1989		1990		1991		1992		1993		1994		1995		1996		1997		TOTALS	
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.
Phase I:																						
18" Yuama-Rangoon	1.8	0.7	6.8	3.1	3.3	1.9	2.0	0.8	0.6	0.5											14.5	7.0
Yuama City Gate Station			1.4	0.7	0.1	0.3															1.5	1.0
Cathodic Protection for 10"	0.4	0.2	0.4	0.1	0.7	0.2															1.5	0.5
Distribution Development	0.1	0.1	0.4	0.1	0.8	0.1	0.2	0.2													1.5	0.5
Phase II:																						
12" Yuama-Sittang							4.5	2.3	4.0	5.0											8.5	7.3
10" Sittang-Thaton									2.5	1.5	2.5	2.5									5.0	4.0
8" Thaton-Hvaingale											1.5	1.0		1.0							1.5	2.0
Other							2.0	1.5	0.8	0.4	0.8	0.4	0.8	0.4	0.7	0.3	0.5	0.1	0.5	0.1	6.1	3.2
PHASE I TOTALS:	2.3	1.0	9.0	4.0	4.9	2.5	2.2	1.0	0.6	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.0	9.0
PHASE II TOTALS:	0.0	0.0	0.0	0.0	0.0	0.0	6.5	3.8	7.3	6.9	4.8	3.9	0.8	1.4	0.7	0.3	0.5	0.1	0.5	0.1	21.1	16.5
PGDP TOTALS:	2.3	1.0	9.0	4.0	4.9	2.5	8.7	4.8	7.9	7.4	4.8	3.9	0.8	1.4	0.7	0.3	0.5	0.1	0.5	0.1	40.1	25.5

TECHNICAL ASSISTANCE/TRAINING/STUDIES/SOFTWARE

FY ending March 31	1988		1989		1990		1991		1992		1993		1994		TOTALS	
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.
Oil & Gas a/	0.7	0.2	1.2	0.4	1.1	0.2	0.8	0.2	0.5	0.1	0.3	0.1	0.1		4.7	1.2
Gas b/	0.4	0.2	0.8	0.3	0.8	0.1	0.5	0.2	0.5	0.1	0.3	0.1	0.1		3.4	1.0

Notes:

a/ Corresponds to the full technical assistance package under Phase I.
b/ Excludes oil-related studies.

GRAND TOTALS FOR PHASES I AND II BASE COSTS

FY ending March 31	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Capital Costs (PGDP) a/	9.1	27.2	20.5	37.8	34.2	19.5	5.2	1.0	0.6	0.6 (end)
Phase I	9.1	27.2	20.5	14.1	4.2	0.7	0.1	0.0	0.0	0.0
Phase II	0.0	0.0	0.0	23.7	30.0	18.8	5.1	1.0	0.6	0.6
Total OC (PGDP) b/	0.0	0.0	0.0	1.9	2.2	2.2	3.2	3.2	3.2	3.2 (until FY2008)
Phase I	0.0	0.0	0.0	1.9	2.2	2.2	2.2	2.2	2.2	2.2
Phase II	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0
Grand Totals (PGDP)	9.1	27.2	20.5	39.7	36.4	21.7	8.4	4.2	3.8	3.8
Phase I	9.1	27.2	20.5	16.0	6.4	2.9	2.3	2.2	2.2	2.2
Phase II	0.0	0.0	0.0	23.7	30.0	18.8	6.1	2.0	1.6	1.6

Notes:

a/ Annual totals comprise both foreign and local currency components, including taxes and duties, before any physical or price contingencies are applied.
b/ Source: MOC

PAYAGON GAS DEVELOPMENT PROGRAM: PHASE I

SUMMARY OF PROJECT COSTS (US$ million)

FY ending March 31	1988		1989		1990		1991		1992		1993		1994		FY88-94 TOTALS	
	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC
1. Field Costs	3.3	1.9	8.1	5.0	7.6	4.6	6.2	4.0	1.6	0.9	0.2	0.1			27.0	16.5
2. Gas Transmission and Distribution	2.3	1.0	9.0	4.0	4.9	2.5	2.2	1.0	0.6	0.5					19.0	9.0
3. Technical Assistance a/	0.7	0.2	1.2	0.4	1.1	0.2	0.8	0.2	0.5	0.1	0.3	0.1	0.1		4.7	1.2
Total Base Cost	6.3	3.1	18.3	9.4	13.6	7.3	9.2	5.2	2.7	1.5	0.5	0.2	0.1	0.0	50.7	26.7
Plus: Physical Contingencies b/	1.3	0.3	4.6	1.1	3.4	0.8	1.8	0.5	0.5	0.2	0.1				11.7	2.9
Subtotal	7.6	3.4	22.9	10.5	17.0	8.1	11.0	5.7	3.2	1.7	0.6	0.2	0.1	0.0	62.4	29.6
Plus: Price Contingencies b/	0.2	0.1	0.9	1.2	0.9	1.5	0.7	1.5	0.3	0.6	0.1	0.1			3.1	5.0
TOTAL PROJECT COST	7.8	3.5	23.8	11.7	17.9	9.6	11.7	7.2	3.5	2.3	0.7	0.3	0.1	0.0	65.5	34.6

Notes:

a/ The project includes oil-related technical assistance and studies. A total of US$ 2.5 million will be financed by the United Nations Development Program.
b/ The levels of physical and price contingencies applied are explained in Chapter III.

BURMA - GAS DEVELOPMENT AND UTILIZATION PROJECT

Estimated Schedule of Disbursements 1/

(US$ million)

IDA Fiscal Year and Semester		Amount Disbursed	Cumulative Amount	Cumulative %
1988	II	13.9	13.9	22.1
1989	I	11.6	25.5	40.5
	II	10.0	35.5	56.3
1990	I	8.6	44.1	70.0
	II	7.2	51.3	81.3
1991	I	5.7	56.9	90.3
	II	3.9	60.8	96.4
1992	I	1.6	62.4	98.9
	II	0.3	62.7	99.4
1993	I	0.2	62.8	99.7
	II	0.1	62.9	99.8
1994	I	0.1	63.0	100.0

BURMA - GAS DEVELOPMENT AND UTILIZATION PROJECT

DISBURSEMENT PROFILE WORKSHEET (in 1986 US$ million)

(years from Board approval date)	YEAR 1		YEAR 2		YEAR 3		YEAR 4		YEAR 5		YEAR 6		YEAR 7		TOTALS
	S1	S2	S1	S2	S1	S2	S1	S2	S1	S2	S1	S2	S1	S2	
ALL REGIONS "ENERGY-GAS" PROFILE: (%)															
Per semester	0.0	12.0	14.0	11.0	12.0	11.0	9.0	9.0	7.0	5.0	5.0	3.0	2.0		100.0
Cumulative - semestral	0.0	12.0	26.0	37.0	49.0	60.0	69.0	78.0	85.0	90.0	95.0	98.0	100.0		100.0
- annual		12.0		25.0		23.0		18.0		12.0		8.0		2.0	100.0
PROJECT PROFILE: (%)															
Per semester	0.0	22.1	18.4	15.9	13.6	11.3	9.0	6.1	2.5	0.5	0.2	0.2	0.2		100.0
Cumulative - semestral	0.0	22.1	40.5	56.3	70.0	81.3	90.3	96.4	98.9	99.4	99.7	99.8	100.0		100.0
- annual		22.1		34.3		25.0		15.1		3.1		0.4		0.2	100.0

PROJECT COSTS (in 1986 US$ million)

GOB FY ending March 31	1988		1989		1990		1991		1992		1993		1994		FY88-94 TOTALS		
Semesters	S1	S2	S1	S2	S1	S2	S1	S2	S1	S2	S1	S2	S1	S2	S1	S2	PROJECT COMPONENT
1. Gas Field Development																	
Profile	0.0	2.5	2.9	2.9	2.9	2.9	2.5	2.5	1.4	0.0	0.0	0.0	0.0	0.0	9.7	10.8	20.5
Cumulative	0.0	2.5	5.4	8.3	11.2	14.1	16.6	19.1	20.5	20.5	20.5	20.5	20.5	20.5			
2. Gas Transmission and Distribution																	
Profile	0.0	2.3	5.0	6.0	2.7	2.2	1.6	0.6	0.4	0.2	0.0	0.0	0.0	0.0	9.7	9.3	19.0
Cumulative	0.0	2.3	7.3	11.3	14.0	16.2	17.8	18.4	18.8	19.0	19.0	19.0	19.0	19.0			
3. Technical Assistance a/																	
Profile	0.0	0.6	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.0	1.2	1.6	2.8
Cumulative	0.0	0.6	1.0	1.3	1.6	1.9	2.1	2.3	2.5	2.6	2.7	2.7	2.8	2.8			
4. Appraisal Drilling																	
Profile	0.0	0.6	1.0	0.9	0.9	0.6	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	2.4	2.6	5.0
Cumulative	0.0	0.6	1.6	2.5	3.4	4.0	4.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0			
5. LPG/CNG Pilot Scheme																	
Profile	0.0	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.7	0.8	1.5
Cumulative	0.0	0.2	0.4	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.5			
TOTAL BASE COSTS	0.0	6.2	9.5	8.3	7.0	6.1	4.9	3.9	2.1	0.4	0.2	0.2	0.1	0.0	23.7	25.1	48.8
Plus: Physical Contingencies b/	0.0	1.2	2.4	2.1	1.8	1.5	1.0	0.8	0.4	0.1					5.6	5.7	11.3
SUBTOTAL	0.0	7.4	11.9	10.4	8.8	7.6	5.9	4.7	2.5	0.5	0.2	0.2	0.1	0.0	29.3	30.8	60.1
Plus: Price Contingencies b/	0.0	0.3	0.5	0.4	0.4	0.4	0.4	0.3	0.2						1.5	1.4	2.9
TOTAL PROJECT COSTS	0.0	7.7	12.4	10.8	9.2	8.0	6.3	5.0	2.7	0.5	0.2	0.2	0.1	0.0	30.8	32.2	63.0
IN IDA FY TERMS c/	0.0	13.9	11.6	10.0	8.6	7.2	5.7	3.9	1.6	0.3	0.2	0.1	0.1	0.0	27.7	35.4	63.0
Cumulative - semestral	0.0	13.9	25.5	35.5	44.1	51.3	56.9	60.8	62.4	62.7	62.8	62.9	63.0	63.0			63.0
- annual		13.9		21.6		15.8		9.5		1.9		0.3		0.0			63.0

Notes:

a/ Amounts exclude US$2.5 million to be financed by the United Nations Development Program.

b/ The levels of physical and price contingencies applied are explained in Chapter III.

c/ To translate into IDA fiscal years: using the figures based on the GOB fiscal year, one-half of the immediately following semester is added to the current semester, which in turn is half of its original value since half has been added to the immediately preceding semester.

BURMA

GAS DEVELOPMENT AND UTILIZATION PROJECT

Progress Reporting Requirements

1. The following information is required to be reported periodically to the International Development Association (IDA) in relation to the progress of work on the project and the operations of the Myanma Oil Corporation (MOC).

2. During the implementation of the project, quarterly reports should be submitted to IDA within 45 days of the end of each calendar quarter covering: (a) technical progress; (b) cost estimates, expenditures and disbursements; (c) project accounts; and (d) management and operations.

3. MOC is also required to send, within six months after the closing date of the Credit or the final disbursement, whichever occurs first, a Completion Report on the project summarizing the initial operations and implementation experience with the project, as well as costs/benefits derived therefrom.

I. Quarterly Technical Progress Reports

4. This report should cover the following:

(i) work accomplished during the reporting period;

(ii) a comparison between the planned and actual progress;

(iii) changes, events or conditions which would materially delay the construction of the project or increase its cost and the Borrower's proposed remedies, if any;

(iv) changes in key personnel; and

(v) expected completion date.

5. Such quarterly technical progress report shall concentrate on the main components of the project, broken down as follows:

Gas Field Development

(a) Seismic equipment and services
(b) Development drilling progress and results
(c) Production surface facilities
(d) Transport equipment and vessels

Gas Transmission and Distribution

(a) 18-inch diameter transmission pipeline
(b) Ywama city gate station, customer meter stations and conversion equipment

(c) Cathodic protection for the 10-inch diameter pipeline
(d) Basic distribution development for Rangoon

Technical Assistance, Studies and Training

(a) Seismic interpretation
(b) Corrosion control
(c) Pipeline inspection
(d) Distribution system design
(e) Telecommunications/telemetering, SCADA and computer software
(f) Gas Utilization Study
(g) Enhanced Oil Recovery Studies
(h) Training

Appraisal Drilling for Phase II

LPG/CNG Pilot Scheme

Progress of construction should be covered in the text of the report and shown graphically in charts.

II. Implementation Schedule

6. A chart showing planned and actual progress on each of the principal components referred to above shall be presented. Simplified CPM or PERT diagrams can be presented with the chart to give a comprehensive picture of the schedule.

III. Schedule of Orders and Deliveries

7. A schedule of orders and deliveries for majors items of equipment shall be presented in the following form:

- Description of the item/s
- Date of bid invitation
- Date of order
- Name and address of supplier
- Contract amount
- Delivery dates (original/revised/actual)

The schedule shall list major items for which orders have been placed or bid invitations issued, and those for which bid invitations are scheduled to be issued in the next quarter. The amount in the currency of the contract shall be shown as well as its equivalent in US dollars, to be rounded to the nearest equivalent thousand US dollars.

IV. Quarterly Report on Cost Estimates, Expenditures and Commitments Statement

8. This report consists of one table to be submitted with, and cover the same period as, the technical progress report. The figures of original estimated costs should be those used in the corresponding tables submitted to IDA.

9. The table should show any substantial changes in the cost estimates that have become necessary since the previous report. The reasons for such changes should be explained in the text of the report. Estimates should be reviewed and, if necessary, revised periodically. Such revisions may be necessary after important contracts have been awarded.

10. The table shall include the following:

A) Foreign Costs

- Original Estimate	(1)
- Revised estimate	(2)
- Disbursements	
Previous quarter	(3)
This quarter	(4)
Total	(5) = (3 + 4)
- Balance of outstanding commitments	(6)
- Total	(7) = (5 + 6)
- Remaining costs to complete project	(8) = (2 - 7)

B) Local Costs

Same as in (A) above.

V. Quarterly Report on Management and Operations

11. This should be a narrative report, supplemented by graphs or schedules, if necessary. The subjects to be covered are:

(i) changes in key personnel;
(ii) changes in the organization of MOC;
(iii) arrangements for financing the project including overruns;
(iv) development of the training program for MOC staff and its implications;
(v) any significant problems or developments in MOC's general operations.

VI. Project Completion Report

12. The project completion report is a comprehensive review of the extent to which objectives and expectations at the time the Credit was made have been, or show promise of being, achieved. For each major project component, the original cost estimate and construction time should be compared with the actual result, with comments on the reasons for any major deviations. Non-physical objectives, (e.g. training, studies, installation of new accounting systems) should also be reviewed and the degree of accomplishment described, with an analysis of the reasons for any delays or lack of success.

13. The report should also cover whenever appropriate:

(a) the major problems (e.g. physical, financial, management) which have arisen, why they arose, and what was done to solve them or minimize their effects;
(b) the performance of consultants and contractors;

(c) any unusual features of procurement or disbursement;
(d) any specific procedures of IDA which gave rise to problems;
(e) staffing and training aspects of the project;
(f) any deviation from the original financing plan and reasons;
(g) any problems or changes of an environmental or sociological nature;
(h) the financial results of operations during the project execution (e.g. sales, operating expenses, operating income) and the actual financial position and prospects of MOC; and
(i) any actions that need to be taken in order to maximize the benefits from the project (e.g. complementary investments, further technical training or advisory services).

In brief, the report should review the appraisal of the project in light of events to date in order to determine if the original basic assumptions and judgments have turned out to be substantially correct.

VII. Financial Reporting

14. Project accounts specifying the foreign and local costs for each project component, and a report on the Special Account, will be prepared and submitted together with the quarterly progress reports. MOC's unaudited accounts (income statement, balance sheet and funds flow statement in the format indicated in Annex 4.01), will be submitted to IDA within nine months of the end of MOC's fiscal year; these accounts, including the Special Account, will be audited annually and submitted to IDA not later than three months thereafter.

BURMA - GAS DEVELOPMENT AND UTILIZATION PROJECT

MYANMA OIL CORPORATION (MOC)

Notes to Financial Statements and Assumptions for Projections

1. Until FY86, financial results were based on MOC's financial statements; FY87 is based on a revised budget and FY88 on MOC's budget for that year. Projections for FYs 89-92 are based on MOC's capital budget up to FY90, project cost estimates (see Annex 3.03) and gas production forecasts (see Annex 5.01). Specific comments on each item are given below.

Income Statement

2. Crude Oil sales reflect a price of K43/bbl up to FY84 and as from FY85 a price of K78/bbl for Payagon condensates (a minor part of MOC's production) and K43/bbl for other products. Projections are based on current MOC prices and an oil production stabilizing at seven million barrels per year.

3. Gas sales up to FY87 reflect a gas price of K2.05 per MCF for Payagon gas and K1.80 per MCF for other gas. Projections are based on a price of K7.5 as from FY88 for Payagon gas and an unchanged price for other gas. The volumes and price of gas sold are assumed to remain stable until the completion of the project.

4. Revenue-Enhancing Measures as from FY89 are expected to result from the study on MOC's financial viability (see para 4.09). Among possible measures, a unification of the gas price at K7.5/MCF would produce an additional revenue of about K220 million per year and each one K1.0 increase per barrel of oil would produce an additional revenue of about K7.0 million per year.

5. Operating Costs and wages in general are expected to increase by 5% per year, which is in line with past experience. Costs for materials and "Schlumberger", mainly for drilling, are expected to peak in FYs 88-89, partly due to project activities, and then decline to more normal levels. As in the past, depreciation is expected to average about 4.4% of gross fixed assets, except for offshore assets, which are not depreciated (see para 4.06). It should be noted that a 10% depreciation on capitalized deferred expenditures (mainly successful wells) has been deducted from the deferred expenditures for the year, causing differences between depreciation as given in the income statement and depreciation in the balance sheet.

6. Interest charges vary from 1% to 8%, depending on the purpose and the age of the loan, and average 4.1% on outstanding debt at the end of FY87. For projection purposes, all new debt (including recent IDA funds) are expected to carry an interest charge of 7.9% per year.

7. No exchange losses are projected as from FY87; the exchange rate is assumed to remain stable at around K7.0/US$.

Balance Sheet

8. The projected increase in fixed assets is based on MOC's capital budget up to FY90, an assumption that MOC's investments outside the project will remain at about FYs 88-90 levels also in FYs 91-94 and that the cost of project components will be capitalized when completed (see implementation schedule in Chart 3). It has happened in the past that, due to foreign exchange constraints, MOC has not received the necessary funds from GOB to carry out approved capital investment plans. If this happens in the future, MOC's investments in fixed assets would be lower and new borrowing from GOB would be reduced accordingly.

9. Offshore expenditures are expected to be capitalized as in the past, but as from FY89, these expenditures are expected to be reduced to about K30 million per year.

10. The Union of Burma Consolidated Fund (UBCF) is expected to remain at the same level as in the past up to FY89. In FY90, it is assumed that GOB will allow MOC to use its UBCF funds to repay loans from Government as part of a capital restructuring of MOC.

11. Stores and spares are expected to increase during the early part of project execution and then fall back to previous levels.

12. Accounts receivable are assumed to equal about 15% of billing (about 1.8 months of outstanding bills), which is in line with past experience.

13. GOB Capital is assumed to be increased by K3,500 million in FY90 as part of the capital restructuring of MOC.

14. Long-term debt is basically all debt with a repayment schedule and short-term debt is basically all other debt. As MOC has been a net borrower since FY80 and the short-term debt has been rolled over from one year to the other, the distinction between long-term and short-term debt has become less meaningful. It is, therefore, doubtful if MOC's short-term debt should be classified as current liability, and a major objective of a capital restructuring would be to reduce MOC's short-term debt.

Funds Flow Statement

15. Others and adjustments contains the difference between depreciation as shown in the income statement and depreciation as shown in the balance sheet (see para 5 above). Further, due to recent changes in accounting principles (see para 2.06), some adjustments of asset values have been done. The use of the UBCF funds in FY90 has also been shown under this heading.

16. Debt service assumes repayment of short-term debt, by the use of UBCF and GOB equity (para 13 above), totalling K3,792 million.

BURMA - GAS DEVELOPMENT & UTILIZATION PROJECT

MYANMA OIL CORPORATION (MOC)

INCOME STATEMENTS 1983-1994

(Millions of Kyats)

FY Ending March 31	ACTUAL 1983	1984	1985	1986	1987	FORECAST 1988	1989	1990	1991	1992	1993	1994
Crude Oil	336.1	320.6	333.9	299.8	323.5	293.9	298.9	298.9	298.9	298.9	298.9	298.9
Natural Gas	15.0	17.6	29.5	59.4	73.9	162.2	166.4	166.4	216.0	268.8	297.6	324.0
Revenue Enhancing Measures	-	-	-	-	-	-	50.0	100.0	150.0	200.0	300.0	400.0
Others	6.3	10.5	11.2	14.8	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
TOTAL REVENUES	357.4	348.7	374.6	374.0	402.7	461.4	520.6	570.6	670.2	773.0	901.8	1,028.2
Salaries and Wages	74.7	78.3	81.9	84.2	91.7	96.7	101.5	106.4	111.2	116.0	121.8	128.0
Materials	237.5	229.0	142.0	130.1	106.0	238.7	209.7	205.1	195.2	150.0	150.0	150.0
Schlumberger	69.2	70.3	84.0	72.1	66.6	121.3	106.8	104.4	99.5	76.9	70.0	65.0
Maintenance	8.9	11.1	10.3	17.0	19.9	20.7	21.7	22.7	23.8	24.8	26.0	27.3
Petrol, Oil, Lubric	19.1	19.0	17.0	17.2	18.0	19.0	19.9	20.9	21.8	22.8	23.9	25.1
Depreciation	85.9	120.4	128.8	134.1	151.0	172.2	203.7	226.9	246.3	264.4	282.4	300.5
Royalties and Taxes	6.9	6.5	6.8	6.1	6.9	7.2	6.1	6.1	6.1	6.1	6.1	6.1
Administration	11.7	11.1	18.3	17.5	17.8	18.5	19.5	20.4	21.3	22.2	23.3	24.5
Others	45.7	55.9	38.6	37.6	45.8	47.7	50.1	52.5	54.9	57.3	60.2	63.2
OPERATING COST	559.6	601.6	527.7	515.9	523.7	742.0	739.0	765.4	780.1	740.5	763.7	789.7
Less: Deferred Expenses, net	23.8	192.8	79.0	88.9	70.0	155.8	130.2	99.3	93.8	60.0	60.0	60.0
NET OPERATING COST	535.8	408.8	448.7	427.0	453.7	586.2	608.8	666.1	686.3	680.5	703.7	729.7
OPERATING INCOME (LOSS)	(178.4)	(60.1)	(74.1)	(53.0)	(51.0)	(124.8)	(88.2)	(95.5)	(16.1)	92.5	198.1	298.5
Less: Interest	96.5	121.9	135.1	153.2	208.4	277.0	347.0	197.0	229.0	268.0	275.0	297.0
Exchange Losses	18.2	10.9	1.7	3.5	-	-	-	-	-	-	-	-
Other Non-Operating	2.1	0.7	0.1	0.5	1.7	1.3	1.3	1.3	1.3	1.3	1.3	1.3
NET PROFIT (LOSS)	(295.2)	(193.6)	(211.0)	(210.2)	(261.1)	(403.1)	(436.5)	(293.8)	(246.4)	(156.8)	(78.2)	0.2

BURMA - GAS DEVELOPMENT & UTILIZATION PROJECT

MYANMA OIL CORPORATION (MOC)

BALANCE SHEETS 1983-1994

(Millions of Kyats)

	ACTUAL					FORECAST						
FY Ending March 31	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
ASSETS												
Fixed Assets at Cost in Op	2,522.4	2,819.6	3,147.8	3,377.8	3,437.2	3,913.9	4,628.9	5,157.7	5,598.5	6,008.5	6418.5	6828.5
Less: Accu Depreciation	706.3	833.4	985.3	1,188.2	1,296.2	1,468.4	1,672.1	1,899.0	2,145.3	2,409.7	2692.1	2992.6
Net Fixed Assets in Op	1,816.1	1,986.2	2,162.5	2,189.6	2,141.0	2,445.5	2,956.8	3,258.7	3,453.2	3,598.8	3,726.4	3,835.9
Capitalized Offshore Exp	193.3	426.9	671.1	857.3	1,003.0	1,141.8	1,171.8	1,201.8	1,230.0	1,260.0	1290.0	1320.0
Union of Burma Cons Fund	292.1	292.1	292.1	292.1	292.1	292.1	292.1	-	-	-	-	-
Cash and Banks	14.0	23.6	19.1	21.6	21.0	21.0	22.0	23.0	24.0	25.0	25.0	25.0
Stocks of Crude & Products	12.7	12.6	11.7	10.5	10.5	10.5	11.0	11.0	12.0	12.0	13.0	13.0
Stores & Spares	623.8	542.0	507.7	447.5	457.9	476.8	500.0	500.0	480.0	460.0	460.0	460.0
Accounts Receivable	66.8	44.2	42.0	41.2	64.6	73.2	78.0	85.0	100.0	115.0	127.8	136.2
Total Current Assets	717.3	622.4	580.5	520.8	554.0	581.5	611.0	619.0	616.0	612.0	625.8	634.2
TOTAL ASSETS	3,018.8	3,327.6	3,706.2	3,859.8	3,990.1	4,460.9	5,031.7	5,079.5	5,299.2	5,470.8	5,642.2	5,790.1
EQUITY AND LIABILITIES												
Government Capital	218.5	218.5	218.5	218.5	218.5	218.5	218.5	3,718.5	3,718.5	3,718.5	3,718.5	3,718.5
Reserves	65.9	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Retained Earnings	(543.5)	(736.6)	(942.0)	(1,153.1)	(1,410.3)	(1,813.4)	(2,249.9)	(2,543.7)	(2,790.1)	(2,946.9)	(3,025.1)	(3,024.9)
Total Equity	(259.1)	(448.1)	(653.5)	(864.6)	(1,121.8)	(1,524.9)	(1,961.4)	1,244.8	998.4	841.6	763.4	763.6
Long-Term Debt	959.1	998.5	947.3	907.3	852.0	906.6	1,031.2	1,065.8	1,140.4	1,185.4	1115.0	1045.0
Short-Term Debt	2,218.9	2,664.3	3,174.9	3,601.9	4,200.3	5,004.1	5,861.9	2,668.9	3,060.4	3,343.8	3663.8	3881.5
Accounts Payable	99.9	112.9	237.5	215.2	79.6	75.1	100.0	100.0	100.0	100.0	100.0	100.0
Total Current Liabilities	2,318.8	2,777.2	3,412.4	3,817.1	4,279.9	5,079.2	5,961.9	2,768.9	3,160.4	3,443.8	3,763.8	3,981.5
Total Liabilities	3,277.9	3,775.7	4,359.7	4,724.4	5,111.9	5,985.8	6,993.1	3,834.7	4,300.8	4,629.2	4,878.8	5,026.5
TOTAL EQUITY AND LIABILITIES	3,018.8	3,327.6	3,706.2	3,859.8	3,990.1	4,460.9	5,031.7	5,079.5	5,299.2	5,470.8	5,642.2	5,790.1

BURMA - GAS DEVELOPMENT & UTILIZATION PROJECT

MYANMA OIL CORPORATION (MOC)

FUNDS FLOW STATEMENTS 1983-1994

(Millions of Kyats)

	ACTUAL					FORECAST						
FY Ending March 31	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
SOURCES												
Net Income Before Interest	(198.7)	(71.7)	(75.9)	(57.0)	(52.7)	(126.1)	(89.5)	(96.8)	(17.4)	91.2	196.8	297.2
Add: Depreciation	85.9	120.4	128.8	134.1	151.0	172.2	203.7	226.9	246.3	264.4	282.4	300.5
Others & Adjustments	(4.8)	11.3	28.8	67.7	(39.1)	-	-	292.1	-	-	-	-
Total Internal Funds	(117.6)	60.0	81.7	144.8	59.2	46.1	114.2	422.2	228.9	355.6	479.2	597.7
GOB Equity Contribution	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,500.0	0.0	0.0	0.0	0.0
New Loans: Long-term	500.7	89.4	-	-	-	150.0	200.0	110.0	150.0	150.0	34.6	35.0
"Short-term"	619.7	445.4	510.6	427.1	598.4	803.8	857.8	599.1	391.5	283.4	320.0	217.7
TOTAL SOURCES	1,002.8	594.8	592.3	571.9	657.6	999.9	1,172.0	4,631.3	770.4	789.0	833.8	850.4
REQUIREMENTS												
Capital Construction	709.3	530.8	572.4	416.2	205.1	615.5	745.0	558.8	469.0	440.0	440.0	440.0
Interest	96.5	121.9	135.1	153.2	208.4	277.0	347.0	197.0	229.0	248.0	275.0	297.0
Amortization	50.0	50.0	51.2	40.0	75.3	75.4	75.4	3,867.5	75.4	105.0	105.0	105.0
Debt Service	146.5	171.9	186.3	193.2	283.7	352.4	422.4	4,064.5	304.4	353.0	380.0	402.0
Change in "Working Capital"	147.0	(107.9)	(166.4)	(37.5)	168.8	32.0	4.6	8.0	(3.0)	(4.0)	13.8	8.4
TOTAL REQUIREMENTS	1,002.8	594.8	592.3	571.9	657.6	999.9	1,172.0	4,631.3	770.4	789.0	833.8	850.4

COST RECOVERY CALCULATION FOR THE PAYAGON GAS FIELD

(EXPENDITURES AND REVENUES IN KYATS MILLION AND ANNUAL GAS VOLUMES IN BILLION CUBIC FEET)

FY ENDING MARCH 31	EXPENDITURES Capital	EXPENDITURES Operating	REVENUES	NET BENEFIT	DISCOUNT FACTORS (8 %)	PRESENT VALUE	GAS VOLUME 87-08	DISCOUNTED VOLUMES
	(1)	(2)	(3)	(4)=1+2-3	(5)	(6)=4x5	(7)	(8)=5x7
1960	6.6			(6.6)	7.988	(52.7)		
1975	2.7			(2.7)	2.518	(6.8)		
1979	3.0			(3.0)	1.851	(5.6)		
1980	1.3			(1.3)	1.714	(2.2)		
1981	1.1			(1.1)	1.587	(1.7)		
1982	1.3			(1.3)	1.469	(1.9)		
1983	6.0			(6.0)	1.360	(8.2)		
1984	12.4			(12.4)	1.260	(15.6)		
1985	93.3	2.3	4.3	(91.3)	1.166	(106.5)		
1986	100.7	2.4	8.1	(95.0)	1.080	(102.6)		
1987	120.0	10.0	2.5	(127.5)*	1.000	(127.5)	7.6	7.6
1988	143.6	10.5	4.5	(149.6)	0.926	(138.5)	8.4	7.8
1989	223.1	11.0	5.4	(228.7)	0.857	(196.1)	9.9	8.5
1990	270.0	11.6	6.4	(275.2)	0.794	(218.5)	9.9	7.9
1991	150.0	18.1	7.4	(160.7)	0.735	(118.1)	16.1	11.8
1992	100.0	19.0	9.5	(109.5)	0.681	(74.5)	18.6	12.7
1993	75.4	20.0	9.7	(85.7)	0.630	(54.0)	22.2	14.0
1994	20.2	30.4	9.9	(40.7)	0.583	(23.7)	23.0	13.4
1995	9.2	31.9	10.1	(31.0)	0.540	(16.7)	24.1	13.0
1996	6.4	33.5	10.4	(29.5)	0.500	(14.8)	25.9	13.0
1997	6.4	35.2	10.4	(31.2)	0.463	(14.5)	27.4	12.7
1998		36.9	10.4	(26.5)	0.429	(11.4)	29.2	12.5
1999		38.8	10.4	(28.4)	0.397	(11.3)	30.7	12.2
2000		40.7	10.4	(30.3)	0.368	(11.1)	31.8	11.7
2001		42.8	10.4	(32.4)	0.340	(11.0)	32.9	11.2
2002		44.9	10.4	(34.5)	0.315	(10.9)	32.9	10.4
2003		47.1	10.4	(36.7)	0.292	(10.7)	32.9	9.6
2004		49.5	10.4	(39.1)	0.270	(10.6)	32.9	8.9
2005		52.0	10.4	(41.6)	0.250	(10.4)	32.9	8.2
2006		54.6	10.4	(44.2)	0.232	(10.2)	32.9	7.6
2007		57.3	10.4	(46.9)	0.215	(10.1)	32.9	7.1
2008		60.1	10.4	(49.7)	0.199	(9.9)	32.9	6.5
						(1,418.3)		228.2

KS/MCF =	(6.21)	(7.19)	(8.39)
Discount Rate =	0.08	0.10	0.12

*As from 1987, condensate sales are estimated to equal 5 bbl per 1 MCF, equivalent to about K 385 per MMCF.

BURMA - GAS DEVELOPMENT AND UTILIZATION PROJECT

STUDY OF MYANMA OIL CORPORATION'S FINANCIAL VIABILITY

Terms of Reference

A. Background

1. During the last couple of years, the Myanma Oil Corporation (MOC) has been operating at a loss of between K200 million and K300 million a year. These losses have forced MOC to borrow heavily and, as of March 31, 1986, its long-term debt amounted to about K910 million and short-term debt amounted to about K3,600 million. In the year ending March 1986, interest only on these loans amounted to about K153 million, equity was a negative K865 million and MOC's current ratio was 0.14. MOC has not been able to make a contribution to Government for its equity investment since FY80 and without continued Government support, MOC would be bankrupt.

2. According to generally accepted principles, a revenue-earning entity should generate sufficient funds to cover its operating expenses, debt service, a reasonable return on equity, as well as contribute a portion of funds needed for investment purposes. To achieve the above for MOC, a change in MOC's capital structure and revenue-enhancing/cost-reducing measures would be required. The basic objective of this Study would be to identify such measures.

3. A change in MOC's capital structure could be made by Government without major consequences for the rest of the economy. However, changes in transfer prices of crude oil and gas produced by MOC could affect the finances of the Petrochemical Industries Corporation (PIC), the Petroleum Products Supply Corporation (PPSC), the Electric Power Corporation (EPC) and others. It would, therefore, be necessary to study the impact of revenue-enhancing measures for MOC on intermediate energy users, as well as on final consumers, before deciding on which measures to implement. To minimize the near-term impact on the economy, the first step would be to revise MOC's capital structure. The next step would be to identify revenue-enhancing measures that would ensure MOC's operations at least to break even before the end of the project period even if at that time, MOC revenues are insufficient to provide for an adequate return on the equity of the Government of the Socialist Republic of the Union of Burma. In the longer run, however, MOC should also be able to generate enough funds to provide the Government of the Socialist Republic of the Union of Burma an adequate return on its equity investment and contribute a reasonable portion of funds needed for investment purposes.

B. Scope of Study

(a) To identify measures that would improve MOC's financial viability, e.g., capital restructuring, higher transfer prices for crude oil and gas, and cost-reducing/efficiency-improving measures;

b) to evaluate the impact of these measures on MOC's financial viability and on the financial viability of intermediate energy enterprises (e.g., PPSC, PIC, EPC, and other industries);

(c) to evaluate the impact of these measures on the end-users of energy, i.e., consumers of petroleum products, electricity and certain industrial products; and

(d) to propose a combination of measures, and an implementation plan, that would lead to a strengthening of MOC's capital structure by the end of 1989 and ensure its financial viability not later than by the end of the project period. For this purpose, MOC would be considered financially viable as long as it has a positive equity base and its operations are breaking even after adequate allowances for depreciation and interest, i.e., MOC's income statement should show a positive net income.

C. Executing Agency

4. A working group would be established, under the supervision of the Ministry of Energy, to carry out the tasks under the proposed Study. Representatives from the Ministry of Planning and Finance and the Peoples' Inspectorate should be invited to join the working group. It is important that the supervisor of the working group be given adequate authority to contact and request cooperation from entities that may be affected by the Study. The working group will discuss choice of methodology and interim results with IDA, as necessary, during the execution of the Study.

D. Time Schedule

1. These terms of Reference were agreed between the Government of the Socialist Republic of the Union of Burma and IDA at Credit negotiations

2. The working group will be established not later than by Credit Board presentation

3. A preliminary report on the findings would be made available to the Government of the Socialist Republic of the Union of Burma and IDA for their joint review not later than one and a half years after Credit effectiveness

4. The final report, incorporating relevant comments from IDA, would be completed within two years of Credit effectiveness

5. The Study, upon completion, would be submitted to the Ministry of Energy, and the Government of Socialist Republic of the Union of Burma for review and development of a plan of implementation, as appropriate

BURMA

GAS DEVELOPMENT AND UTILIZATION PROJECT

Internal Financial Rate of Return (IFRR) Calculations

1. The IFRR calculations are based on the following assumptions:

(a) Capital costs for the Payagon Gas Development Program's Phase I (the project) and Phase II are the same as in Annex 3.03, including contingencies, taxes and duties, but excluding seismic interpretation and oil studies, as these items do not belong to the gas development;

(b) the average gas offtake is shown in Annex 5.01. As the existing 10-inch diameter Payagon to Rangoon pipeline would be expected to end its useful life in FY95 without the project, all Payagon gas, as well as operating costs, are regarded as incremental to the project as from that year;

(c) the useful life of the Payagon gas investments is estimated to average 20 years; no scrap value has been considered at the end of the useful life as the net present value would be insignificant;

(d) all expenditure and revenue streams have been discounted by 10% p.a. in FYs 88-90, 9% in FY91, 8% in FY92, 7% in FY93, 6% in FY94, and 5% until FY2000, to bring them to FY88 real price levels. As from FY2001, operating costs and revenues are expected to remain stable in real terms.

2. With the above assumptions, incremental expenditure and revenue streams in K million of FY88 purchasing power would be:

		Capital Exp.		Operating Exp.		Revenues		Net Revenues	
FY	Deflator	Phase 1	Phase 1/11	Phase 1	Phase 1&11	Phase 1	Phase 1&11	Phase 1	Phase 1&11
1988	1.00	84.7	143.6	-	-	-	-	(84.7)	(143.6)
1989	.91	154.2	203.0	-	-	-	-	(154.2)	(203.0)
1990	.83	129.6	224.1	-	-	-	-	(129.6)	(224.1)
1991	.76	92.0	114.0	13.8	13.8	97.5	97.5	(8.3)	(30.3)
1992	.70	59.3	70.0	13.3	13.3	103.8	103.8	31.2	20.5
1993	.66	37.0	50.0	13.2	13.2	116.7	116.7	66.5	53.5
1994	.62	8.2	12.4	13.0	18.8	111.2	113.7	90.0	82.5
1995	.59	1.8	5.6	13.0	18.8	105.8	113.1	91.0	88.7
1996	.56	1.1	3.6	13.0	18.8	100.4	115.5	86.3	93.1
1997	.53	1.0	3.4	13.0	18.8	95.0	115.7	81.0	93.5
1998	.51			13.0	18.8	91.4	118.6	78.4	99.8
1999	.48			13.0	18.8	86.1	117.4	73.1	98.6
2000	.46			13.0	18.8	82.5	116.5	69.5	97.7
2001-08	.44			13.0	18.8	78.9	115.3	65.9	96.5

3. The resulting IFRR, in FY88 real terms, for Phase I (the project) is 13.0% and the IFRR for Phases I and II (the whole Payagon Gas Development Program) is 9.0%. The two phases are interdependent and Phase II would bring no benefits without the completion of Phase I. The IFRR for Phase I may understate the real return of the project, as its capital expenditures are based on a pipeline size capable of handling the additional gas volumes for Phase II. Corresponding gas revenues, however, have been regarded as incremental to Phase II only. Furthermore, the gas price of K7.5 per MCF has been assumed constant in nominal terms until FY2001, which implies a fall in real terms of about 55%. 1/ Even so, the estimated 13.0% IFRR in real terms for the project is satisfactory.

4. A sensitivity analysis was carried out with the following results:

	Resulting IFRR %	
	Phase I	Phase I&II
Capital expenditures + 10%	11.3	7.7
Operating expenditures + 10%	12.7	8.7
Revenues - 10%	10.8	7.2
Combination of all above	8.9	5.7

1/ If gas prices are maintained at K7.5 in real terms over the useful life of the Payagon gas investments, the IFRR for Phase I would be 25.0% and for Phases I & II, 19.5%.

BURMA - GAS DEVELOPMENT AND UTILIZATION PROJECT

DEMAND FORECAST FOR PAYAGON GAS a/

(in million cubic feet)

FY ending March 31	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001-2008
POWER	4380	5256	7519	7519	12082	11753	13286	13286	13286	13286	13286	13286	13286	13286	13286
REFINERY	2044	2044			2044	2044	2044	2044	2044	2044	2044	2044	2044	2044	2044
INDUSTRIES															
Cement							1533	1533	1533	1533	1533	1533	1533	1533	1533
Paper						1660	1660	1660	1660	1660	1660	1660	1660	1660	1660
General Industries	1241	1241	1241	1241	2956	3102	3723	4343	5584	7446	7446	7446	7446	7446	7446
DEMAND GROWTH b/											1406	3049	4691	5786	6881
ANNUAL TOTALS	7665	8541	8760	8760	17082	18559	22246	22866	24107	25969	27375	29018	30660	31755	32850
Maximum Day Offtake c/	26.0	29.0	30.0	30.0	65.0	70.0	84.0	86.0	90.0	96.0	100.0	106.0	112.0	116.0	120.0
Average Day Offtake	21.0	23.0	24.0	24.0	46.8	51.0	61.0	63.0	66.0	71.0	75.0	79.5	84.0	87.0	90.0
of which:															
Phase I					46.8	51.0	61.0	61.6	61.6	61.7	61.6	61.1	61.5	61.5	61.5
Phase II								1.4	4.4	9.3	13.4	18.4	22.5	25.5	28.5
Incremental Gas: d/ (in billion cubic feet/year)					17.1	18.6	22.3	23.0	24.1	25.9	27.4	29.0	30.7	31.8	32.9
of which:															
Phase I					17.1	18.6	22.3	22.5	22.5	22.5	22.5	22.3	22.4	22.4	22.4
Phase II								0.5	1.6	3.4	4.9	6.7	8.2	9.3	10.4

Source: mission estimates and Myanma Oil Corporation

Notes:

a/ For power, refinery and industries, the figures refer to sales forecasts based on identified consumers that are existing or soon to come on stream.
b/ Gas volumes under this row would cover additional gas market development (mainly in power and industry) that would be identified under the Gas Utilization Study's task of estimating unconstrained gas demand.
c/ System capability is 33 MMCFD up to FY90 and 120 MMCFD from FY91 onwards.
d/ Based on average day offtake and assuming a target level of system reliability.

BURMA GAS DEVELOPMENT AND UTILIZATION PROJECT

Assumptions for Economic Analysis

The values of diesel and fuel oil (CIF Rangoon), for which Payagon gas will substitute, were derived by adjusting projected international prices for crude oil by assumed fixed product-to-crude margins and international transport costs using the Singapore market. Product-to-crude ratios are estimated to be 1.30 for diesel and 0.80 for fuel oil. Transport costs are around US$10/metric ton (mt) for both products. The conservative assumption is made that crude oil prices will remain constant in real terms beyond the year 2000. Under these assumptions, and based on World Bank international crude oil price projections, the border price values of diesel and fuel oil used in the economic analysis are as follows (in constant 1986 US$):

Year	Project Crude Oil Price		Expected Product Value (CIF Rangoon)			
			HSD		FUEL OIL	
	US$/bbl a/	US$/mt	US$/mt	US$/MCF b/	US$/mt	US$/MCF b/
1987/88	15.50	111.60	155.10	3.69	99.30	2.40
1988/89	17.20	123.80	170.90	4.07	109.00	2.63
1989/90	17.10	123.10	170.00	4.05	108.50	2.62
1990/91	16.90	121.70	168.21	4.01	107.40	2.59
1991/92	17.60	126.72	174.70	4.16	111.40	2.70
1992/93	18.30	131.80	181.30	4.32	115.50	2.80
1993/94	19.00	136.80	187.80	4.47	119.50	2.90
1994/95	19.70	141.80	194.30	4.63	123.50	3.00
1995/96	20.90	150.50	205.60	4.90	130.40	3.15
1996/97	22.10	159.00	216.80	5.20	137.30	3.30
1997/98	23.50	169.00	230.00	5.50	145.00	3.50
1998/99	24.90	179.00	243.00	5.80	153.00	3.70
99/2000	26.60	191.00	259.00	6.20	163.00	3.90

a/ Prices from 1991/92 to 1993/94 and from 1995/96 to 1998/99 were calculated based on the average annual growth rate implicit in the price data available for 1994/95 and 1999/2000.

b/ In heat equivalent terms, at around 42.0 MCF/mt of diesel and 41.4 MCF/mt of fuel oil.

BURMA - PAYAGON GAS DEVELOPMENT PROGRAM (PHASES I AND II)

ECONOMIC RATE OF RETURN CALCULATIONS

(Costs and Benefits in 1986 US$ million; Gas volumes in MMCFD and BCF)

Product Price Assumptions:
World Bank international crude oil price projections,
adjusted for fixed product-to-crude margins
and freight differentials.

FY ending March 31	EXPENDITURES CAPITAL	EXPENDITURES OPERATING	GROSS COST	CONDEN-SATE REVENUES	GAS VOLUMES F.O. SUBSTITUTE (MMCFD)	F.O. SUBSTITUTE (BCF)	DIESEL SUBSTITUTE (MMCFD)	DIESEL SUBSTITUTE (BCF)	TOTAL (MMCFD)	TOTAL (BCF)	EQUIV PRODUCT PRICES (CONSTANT 86 $/MCF) FO	DO	GAS VALUATION FO SUBS	DO SUBS	TOTAL	GROSS BENEFITS	CASH FLOW
1988	8.7		8.7								2.40	3.69	0.0	0.0	0.0	0.0	(8.7)
1989	24.8		24.8								2.63	4.07	0.0	0.0	0.0	0.0	(24.8)
1990	19.2		19.2								2.62	4.05	0.0	0.0	0.0	0.0	(19.2)
1991	36.4	1.9	38.3	0.6	18.0	6.6	29.0	10.6	47.0	17.2	2.59	4.01	17.0	42.4	59.5	60.1	21.8
1992	33.6	2.2	35.8	0.8	23.0	8.4	28.0	10.2	51.0	18.6	2.70	4.16	22.7	42.5	65.2	66.0	30.2
1993	18.7	2.2	20.9	0.9	30.0	11.0	31.0	11.3	61.0	22.3	2.80	4.32	30.7	48.9	79.5	80.4	59.5
1994	4.9	3.2	8.1	1.1	31.0	11.3	32.0	11.7	63.0	23.0	2.90	4.47	32.8	52.2	85.0	86.1	78.0
1995	0.8	3.2	4.0	1.4	33.0	12.0	33.0	12.0	66.0	24.1	3.00	4.63	36.1	55.8	91.9	93.3	89.3
1996	0.6	3.2	3.8	1.4	43.0	15.7	28.0	10.2	71.0	25.9	3.15	4.90	49.4	50.1	99.5	100.9	97.1
1997	0.6	3.2	3.8	1.4	45.0	16.4	30.0	11.0	75.0	27.4	3.30	5.20	54.2	56.9	111.1	112.5	108.7
1998		3.2	3.2	1.4	48.0	17.5	32.0	11.7	80.0	29.2	3.50	5.50	61.3	64.2	125.6	127.0	123.8
1999		3.2	3.2	1.5	50.0	18.3	34.0	12.4	84.0	30.7	3.70	5.80	67.5	72.0	139.5	141.0	137.8
2000		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	3.90	6.20	76.9	81.5	158.3	159.8	156.6
2001		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	3.90	6.20	76.9	81.5	158.3	159.8	156.6
2002		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	3.90	6.20	76.9	81.5	158.3	159.8	156.6
2003		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	3.90	6.20	76.9	81.5	158.3	159.8	156.6
2004		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	3.90	6.20	76.9	81.5	158.3	159.8	156.6
2005		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	3.90	6.20	76.9	81.5	158.3	159.8	156.6
2006		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	3.90	6.20	76.9	81.5	158.3	159.8	156.6
2007		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	3.90	6.20	76.9	81.5	158.3	159.8	156.6
2008		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	3.90	6.20	76.9	81.5	158.3	159.8	156.6

Internal Economic Rate of Return 59.09%
NPV @ DR = 12% (US$ million) 446.48

BURMA - PAYAGON GAS DEVELOPMENT PROGRAM (PHASES I AND II)

ECONOMIC RATE OF RETURN CALCULATIONS

(Costs and Benefits in 1986 US$ million; Gas volumes in MMCFD and BCF)

Product Price Assumptions:
Fuel Oil US$50/ton (US$7.41/bbl)
Diesel Oil US$100/ton (US$13.19/bbl)
These early-December 1986 prices have been the lowest in the past 10 years.

FY ending March 31	EXPENDITURES		GROSS COST	CONDEN-SATE REVENUES	GAS VOLUMES						EQUIV PRODUCT PRICES (CONSTANT 86 $/MCF)		GAS VALUATION			GROSS BENEFITS	CASH FLOW
					F.O. SUBSTITUTE		DIESEL SUBSTITUTE		T O T A L								
	CAPITAL	OPERATING			(MMCFD)	(BCF)	(MMCFD)	(BCF)	(MMCFD)	(BCF)	FO	DO	FO SUBS	DO SUBS	TOTAL		
1988	8.7		8.7								1.22	2.39	0.0	0.0	0.0	0.0	(8.7)
1989	24.8		24.8								1.22	2.40	0.0	0.0	0.0	0.0	(24.8)
1990	19.2		19.2								1.23	2.42	0.0	0.0	0.0	0.0	(19.2)
1991	36.4	1.9	38.3	0.6	18.0	6.6	29.0	10.6	47.0	17.2	1.23	2.42	8.1	25.6	33.6	34.2	(4.1)
1992	33.6	2.2	35.8	0.8	23.0	8.4	28.0	10.2	51.0	18.6	1.25	2.45	10.5	25.1	35.5	36.3	0.5
1993	18.7	2.2	20.9	0.9	30.0	11.0	31.0	11.3	61.0	22.3	1.27	2.49	13.9	28.2	42.0	42.9	22.0
1994	4.9	3.2	8.1	1.1	31.0	11.3	32.0	11.7	63.0	23.0	1.28	2.53	14.5	29.5	44.0	45.1	37.0
1995	0.8	3.2	4.0	1.4	33.0	12.0	33.0	12.0	66.0	24.1	1.30	2.56	15.7	30.9	46.6	48.0	44.0
1996	0.6	3.2	3.8	1.4	43.0	15.7	28.0	10.2	71.0	25.9	1.32	2.60	20.8	26.6	47.4	48.8	45.0
1997	0.6	3.2	3.8	1.4	45.0	16.4	30.0	11.0	75.0	27.4	1.34	2.64	22.1	28.9	51.0	52.4	48.6
1998		3.2	3.2	1.4	48.0	17.5	32.0	11.7	80.0	29.2	1.36	2.68	23.9	31.3	55.2	56.6	53.4
1999		3.2	3.2	1.5	50.0	18.3	34.0	12.4	84.0	30.7	1.38	2.72	25.2	33.8	59.0	60.5	57.3
2000		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	1.40	2.76	27.7	36.3	64.0	65.5	62.3
2001		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	1.43	2.80	28.1	36.8	64.9	66.4	63.2
2002		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	1.45	2.85	28.5	37.4	65.9	67.4	64.2
2003		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	1.47	2.89	28.9	38.0	66.9	68.4	65.2
2004		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	1.49	2.93	29.4	38.5	67.9	69.4	66.2
2005		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	1.51	2.98	29.8	39.1	68.9	70.4	67.2
2006		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	1.54	3.02	30.3	39.7	69.9	71.4	68.2
2007		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	1.56	3.07	30.7	40.3	71.0	72.5	69.3
2008		3.2	3.2	1.5	54.0	19.7	36.0	13.1	90.0	32.9	1.58	3.11	31.2	40.9	72.1	73.6	70.4

Internal Economic Rate of Return 32.97%
NPV @ DR = 12% (US$ million) 153.68

BURMA - YAGAON GAS DEVELOPMENT PROGRAM (PHASE I)

ECONOMIC RATE OF RETURN CALCULATIONS

(Costs and Benefits in 1986 US$ million; Gas volumes in MMCFD and BCF)

Product Price Assumptions:
World Bank international crude oil price projections,
adjusted for fixed product-to-crude margins
and freight differentials.

FY ending March 31	EXPENDITURES CAPITAL	EXPENDITURES OPERATING	GROSS COST	CONDENSATE REVENUES	GAS VOLUMES F.O. SUBSTITUTE (MMCFD)	GAS VOLUMES F.O. SUBSTITUTE (BCF)	GAS VOLUMES DIESEL SUBSTITUTE (MMCFD)	GAS VOLUMES DIESEL SUBSTITUTE (BCF)	GAS VOLUMES TOTAL (MMCFD)	GAS VOLUMES TOTAL (BCF)	EQUIV PRODUCT PRICES (CONSTANT 86 $/MCF) FO	EQUIV PRODUCT PRICES (CONSTANT 86 $/MCF) DO	GAS VALUATION FO SUBS	GAS VALUATION DO SUBS	GAS VALUATION TOTAL	GROSS BENEFITS	CASH FLOW
1988	8.7		8.7								2.40	3.69	0.0	0.0	0.0	0.0	(8.7)
1989	24.8		24.8								2.63	4.07	0.0	0.0	0.0	0.0	(24.8)
1990	19.2		19.2								2.62	4.05	0.0	0.0	0.0	0.0	(19.2)
1991	13.2	1.9	15.1	0.6	18.0	6.6	29.0	10.6	47.0	17.2	2.59	4.01	17.0	42.4	59.5	60.1	45.0
1992	4.4	2.2	6.6	0.8	20.0	7.3	31.0	11.3	51.0	18.6	2.70	4.16	19.7	47.1	66.8	67.6	61.0
1993	0.8	2.2	3.0	0.9	24.0	8.8	37.0	13.5	61.0	22.3	2.80	4.32	24.5	58.3	82.9	83.8	80.8
1994	0.1	2.2	2.3	1.1	25.0	9.1	37.0	13.5	62.0	22.6	2.90	4.47	26.5	60.4	86.8	87.9	85.6
1995		2.2	2.2	1.4	25.0	9.1	37.0	13.5	62.0	22.6	3.00	4.63	27.4	62.5	89.9	91.3	89.1
1996		2.2	2.2	1.4	25.0	9.1	37.0	13.5	62.0	22.6	3.15	4.90	28.7	66.2	94.9	96.3	94.1
1997		2.2	2.2	1.4	25.0	9.1	37.0	13.5	62.0	22.6	3.30	5.20	30.1	70.2	100.3	101.7	99.5
1998		2.2	2.2	1.4	25.0	9.1	37.0	13.5	62.0	22.6	3.50	5.50	31.9	74.3	106.2	107.6	105.4
1999		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.70	5.80	33.8	78.3	112.1	113.6	111.4
2000		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.90	6.20	35.6	83.7	119.3	120.8	118.6
2001		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.90	6.20	35.6	83.7	119.3	120.8	118.6
2002		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.90	6.20	35.6	83.7	119.3	120.8	118.6
2003		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.90	6.20	35.6	83.7	119.3	120.8	118.6
2004		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.90	6.20	35.6	83.7	119.3	120.8	118.6
2005		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.90	6.20	35.6	83.7	119.3	120.8	118.6
2006		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.90	6.20	35.6	83.7	119.3	120.8	118.6
2007		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.90	6.20	35.6	83.7	119.3	120.8	118.6
2008		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	3.90	6.20	35.6	83.7	119.3	120.8	118.6

Internal Economic Rate of Return 72.03%
NPV @ DR = 12% (US$ million) 424.72

BURMA - PAYAGON GAS DEVELOPMENT PROGRAM (PHASE I)

ECONOMIC RATE OF RETURN CALCULATIONS

(Costs and Benefits in US$ million; Gas volumes in MMCFD and BCF)

Product Price Assumptions:
Fuel Oil US$50/ton (US$7.41/bbl)
Diesel Oil US$100/ton (US$13.19/bbl)
These early-December 1986 prices have been the lowest in the past 10 years.

FY ending March 31	EXPENDITURES CAPITAL	EXPENDITURES OPERATING	GROSS COST	CONDEN REVENUES	GAS VOLUMES FUEL OIL SUBSTITE (MMCFD)	GAS VOLUMES FUEL OIL SUBSTITE (BCF)	GAS VOLUMES DIESEL SUBSTITUTE (MMCFD)	GAS VOLUMES DIESEL SUBSTITUTE (BCF)	GAS VOLUMES TOTAL (MMCFD)	GAS VOLUMES TOTAL (BCF)	EQUIV PRODUCT PRICES (CONSTANT 86 $/MCF) FO	EQUIV PRODUCT PRICES (CONSTANT 86 $/MCF) DO	GAS VALUATION FO SUBS	GAS VALUATION DO SUBS	GAS VALUATION TOTAL	GROSS BENEFITS	CASH FLOW
1988	8.6		8.6								1.22	2.39	0.0	0.0	0.0	0.0	(8.6)
1989	24.6		24.6								1.22	2.40	0.0	0.0	0.0	0.0	(24.6)
1990	18.9		18.9								1.23	2.42	0.0	0.0	0.0	0.0	(18.9)
1991	13.2	1.9	15.1	0.6	18.0	6.6	29.0	10.6	47.0	17.2	1.23	2.42	8.1	25.6	33.6	34.2	19.1
1992	4.4	2.2	6.6	0.8	20.0	7.3	31.0	11.3	51.0	18.6	1.25	2.45	9.1	27.7	36.8	37.6	31.0
1993	0.8	2.2	3.0	0.9	24.0	8.8	37.0	13.5	61.0	22.3	1.27	2.49	11.1	33.6	44.7	45.6	42.6
1994	0.1	2.2	2.3	1.1	25.0	9.1	37.0	13.5	62.0	22.6	1.28	2.53	11.7	34.1	45.8	46.9	44.6
1995		2.2	2.2	1.4	25.0	9.1	37.0	13.5	62.0	22.6	1.30	2.56	11.9	34.6	46.5	47.9	45.7
1996		2.2	2.2	1.4	25.0	9.1	37.0	13.5	62.0	22.6	1.32	2.60	12.1	35.1	47.2	48.6	46.4
1997		2.2	2.2	1.4	25.0	9.1	37.0	13.5	62.0	22.6	1.34	2.64	12.3	35.7	47.9	49.3	47.1
1998		2.2	2.2	1.4	25.0	9.1	37.0	13.5	62.0	22.6	1.36	2.68	12.4	36.2	48.6	50.0	47.8
1999		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.38	2.72	12.6	36.8	49.4	50.9	48.7
2000		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.40	2.76	12.8	37.3	50.1	51.6	49.4
2001		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.43	2.80	13.0	37.9	50.9	52.4	50.2
2002		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.45	2.85	13.2	38.4	51.6	53.1	50.9
2003		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.47	2.89	13.4	39.0	52.4	53.9	51.7
2004		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.49	2.93	13.6	39.6	53.2	54.7	52.5
2005		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.51	2.98	13.8	40.2	54.0	55.5	53.3
2006		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.54	3.02	14.0	40.8	54.8	56.3	54.1
2007		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.56	3.07	14.2	41.4	55.6	57.1	54.9
2008		2.2	2.2	1.5	25.0	9.1	37.0	13.5	62.0	22.6	1.58	3.11	14.4	42.0	56.5	58.0	55.8

Internal Economic Rate of Return 46.22%
NPV @ DR = 10% (US$ million) 223.89

BURMA-GAS DEVELOPMENT AND UTILIZATION PROJECT
LONG-RUN MARGINAL COST WORKSHEET

COSTS OF PAYAGON GAS DEVELOPMENT PROGRAM (PHASES I & II)

(in 1986 US$ million)

FY ending March 31	1988		1989		1990		1991		1992		1993		1994		1995		1996		1997		TOTALS	
	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC
1. Gas Field Development and Appraisal Drilling	3.1	1.9	7.7	4.9	7.3	4.5	12.4	10.9	9.7	8.3	6.1	4.0	2.0	0.9							48.3	35.4
2. Gas Transmission and Distribution	2.3	1.0	9.0	4.0	4.9	2.5	8.7	4.8	7.9	7.4	4.8	3.9	0.8	1.4	0.7	0.3	0.5	0.1	0.5	0.1	40.1	25.5
3. Technical Assistance a/	0.4	0.2	0.8	0.3	0.8	0.1	0.5	0.2	0.5	0.1	0.3	0.1	0.1								3.4	1.0
4. LPG/CNG Pilot Scheme	0.2	0.0	0.4	0.1	0.3	0.1	0.2	0.1	0.2	0.1	0.2	0.1									1.5	0.5
TOTAL	6.0	3.1	17.9	9.3	13.3	7.2	21.8	16.0	18.3	15.9	11.4	8.1	2.9	2.3	0.7	0.3	0.5	0.1	0.5	0.1	93.3	62.4
TOTAL (net of taxes/duties) b/	6.0	1.3	17.9	2.9	13.3	2.8	21.8	8.8	18.3	9.9	11.4	4.4	2.9	1.2	0.7	0.0	0.5	0.0	0.5	0.0	93.3	31.3
With Physical Contingencies = 0.190	7.1	1.5	21.3	3.5	15.8	3.3	25.9	10.5	21.8	11.8	13.6	5.2	3.5	1.4	0.8	0.0	0.6	0.0	0.6	0.0	111.0	37.2
Plus: Total Operating Costs c/								1.9		2.2		2.2		3.2		3.2		3.2		3.2		
GRAND TOTALS	7.1	1.5	21.3	3.5	15.8	3.3	25.9	12.4	21.8	14.0	13.6	7.4	3.5	4.6	0.8	3.2	0.6	3.2	0.6	3.2	111.0	56.3

PAYAGON GAS DEVELOPMENT PROGRAM (PHASES I & II)

INCREMENTAL GAS PRODUCTION d/

FY ending March 31	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001-2008
Average Day Offtake (MMCFD)	44	51	61	63	66	71	75	80	84	87	90
Annual Totals (BCF)	16	19	22	23	24	26	27	29	31	32	33

Notes:

a/ Excluding oil-related technical assistance for seismic interpretation and oil recovery.
b/ According to MOC, taxes and duties are 50% of FOB prices of imported items. The foreign exchange figures in the table are in CIF prices, which MOC calculates to be a factor of 1.2 above FOB prices. Only development drilling, reserve appraisal, field production facilities, and transmission and distribution facilities were adjusted for taxes and duties.
c/ Source: MOC. Operating costs continue until FY2008.
d/ Assuming a target level of system reliability.

PAYAGON GAS DEVELOPMENT PROGRAM (PHASES I & II)

LONG RUN MARGINAL COST CALCULATION

FY year ending March 31	Total Costs (MMUS$)	Less:Condensate (MM kvats)	Revenues (MM US$)	Net Cost Stream (MM US$)	Gas Production (BCF)
1988	8.7			8.7	
1989	24.8			24.8	
1990	19.2			19.2	
1991	38.3	4.5	0.7	37.7	16.1
1992	35.8	5.4	0.8	35.0	18.6
1993	21.0	6.4	0.9	20.1	22.3
1994	8.1	7.4	1.1	7.0	23.0
1995	4.0	9.5	1.4	2.6	24.1
1996	3.8	9.7	1.4	2.4	25.9
1997	3.8	9.9	1.5	2.3	27.4
1998	3.2	10.1	1.5	1.7	29.2
1999	3.2	10.4	1.5	1.7	30.7
2000	3.2	10.4	1.5	1.7	31.8
2001	3.2	10.4	1.5	1.7	32.9
2002	3.2	10.4	1.5	1.7	32.9
2003	3.2	10.4	1.5	1.7	32.9
2004	3.2	10.4	1.5	1.7	32.9
2005	3.2	10.4	1.5	1.7	32.9
2006	3.2	10.4	1.5	1.7	32.9
2007	3.2	10.4	1.5	1.7	32.9
2008	3.2	10.4	1.5	1.7	32.9

Discount Rate (%) =	12.00	10.0	8.0
PV Costs =	104.1	112.4	121.9
PV Gas Volumes =	131.3	159.6	196.4
LRMC (US $/MCF) =	0.793	0.704	0.621
(Kvats/MCF) =	5.39	4.79	4.22

Exchange Rate (Ks/US$) = 6.8

BURMA GAS DEVELOPMENT AND UTILIZATION PROJECT

Documents in the Project File

1. Ministry of Energy:

   (a) Utilization of Natural Gas in Burma. June 1986.
   (b) Natural Gas Project. December 1986.

2. Myanma Oil Corporation:

   (a) Data Given to World Bank Mission (bound). June 1986.
   (b) Cost Calculations for Payagon Gas.
   (c) Organization, including Notifications No. 26/76, 10/77 and 41/85.
   (d) Accounting Policies. February 1986.
   (e) Financial Data. February 1986.
   (f) Investment Plans, 1987-90.
   (g) Budget, 1987-92.
   (h) Gas and Light Crude Reserves: Payagon Area. February 10, 1985.
   (i) Reservoir Data of Payagon Field. January 1986.
   (j) Drilling Program for Payagon and Hteinkyun. December 1985.

3. Terms of Reference (May 1987):

   (a) Project Implementation Unit.
   (b) Consultants for:

      - Seismic Reservoir Interpretation
      - Corrosion Control
      - Pipeline Inspection
      - Distribution System Design
      - Telecommunications/Telemetering, SCADA and Computer Software

4. Financial and Economic Rate of Return Calculations. May 1987.

5. Cowiconsult. Seismic Auxillary Terrain Vehicle Survey Report. April 1987.

6. Minutes of Technical Discussions Held During Credit Negotiations, May 4-8, 1987.

7. Aide-Memoire on the Formation of a Task Force for the Myanma Oil Corporation Financial Viability Study.

CHART 1

BURMA
GAS DEVELOPMENT AND UTILIZATION PROJECT
Energy Sector Organization

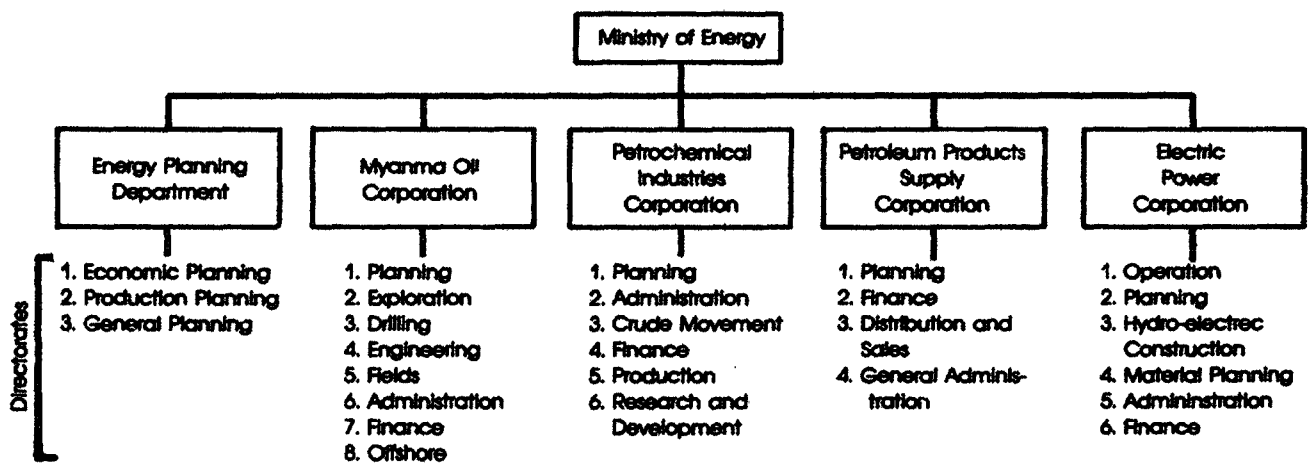

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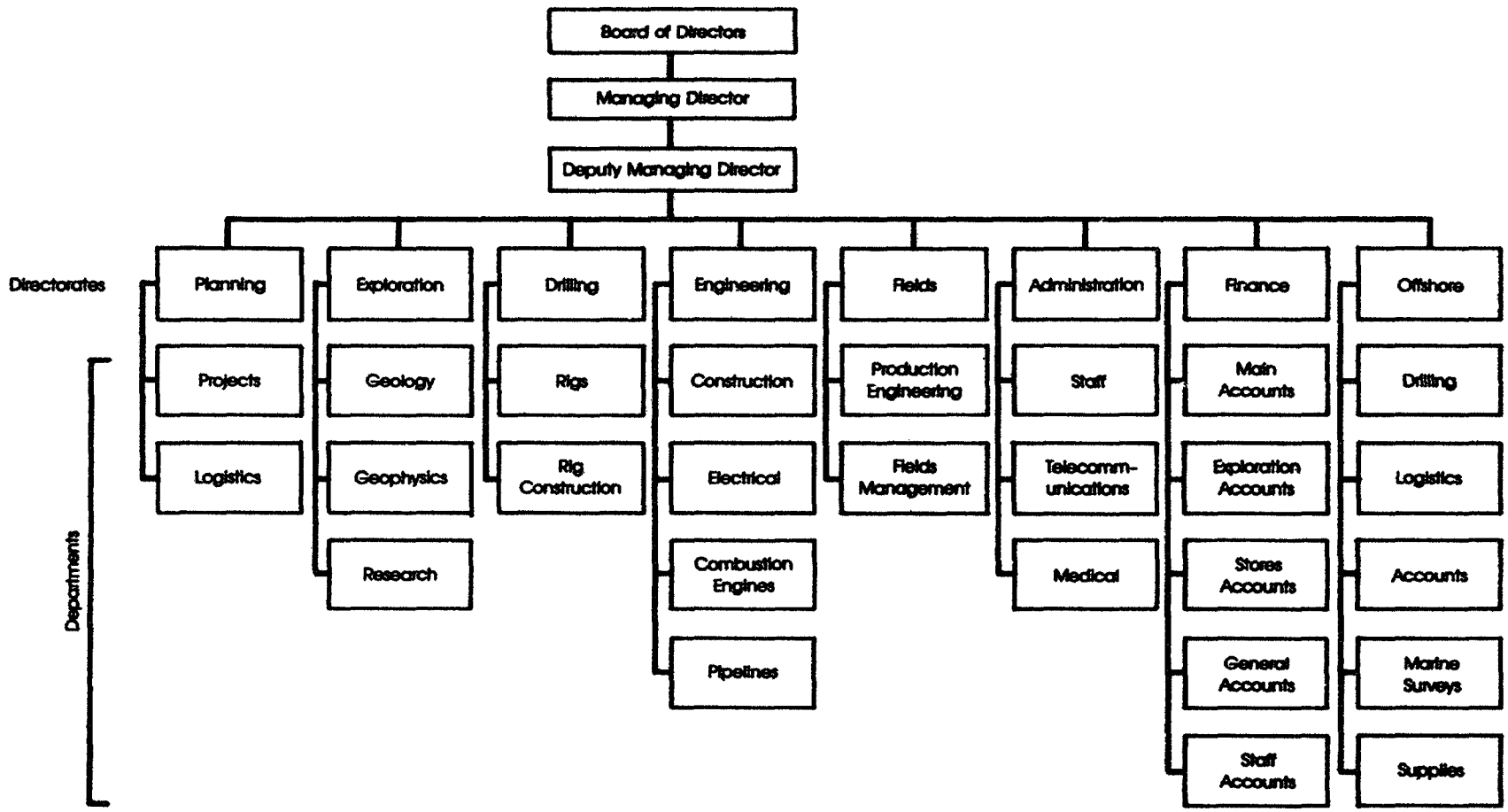
CHART 2

BURMA
GAS DEVELOPMENT AND UTILIZATION PROJECT
Organization Chart for Myanma Oil Corporation (MOC)



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BURMA GAS DEVELOPMENT AND UTILIZATION PROJECT

Implementation Schedule

GOB FY ending March 31

Project Component

I. Gas Field Development

- A. Seismic Development
- B. Development Drilling/Reserve Appraisal
- C. Production and Transport

II. Gas Transmission and Distribution

- A. 18" diameter pipeline
- B. Upgrading of Ywama city gas station, including telecommunications/telemetering
- C. Cathodic protection for 10-inch pipeline
- D. Basic distribution development (Rangoon)

III. Technical Assistance, Studies and Training

- A. Specialized consultancies
- B. Studies:
  - Enhanced Oil Recovery Studies
  - Gas Utilization Study
- C. Training

IV. LPG/CNG Pilot Scheme

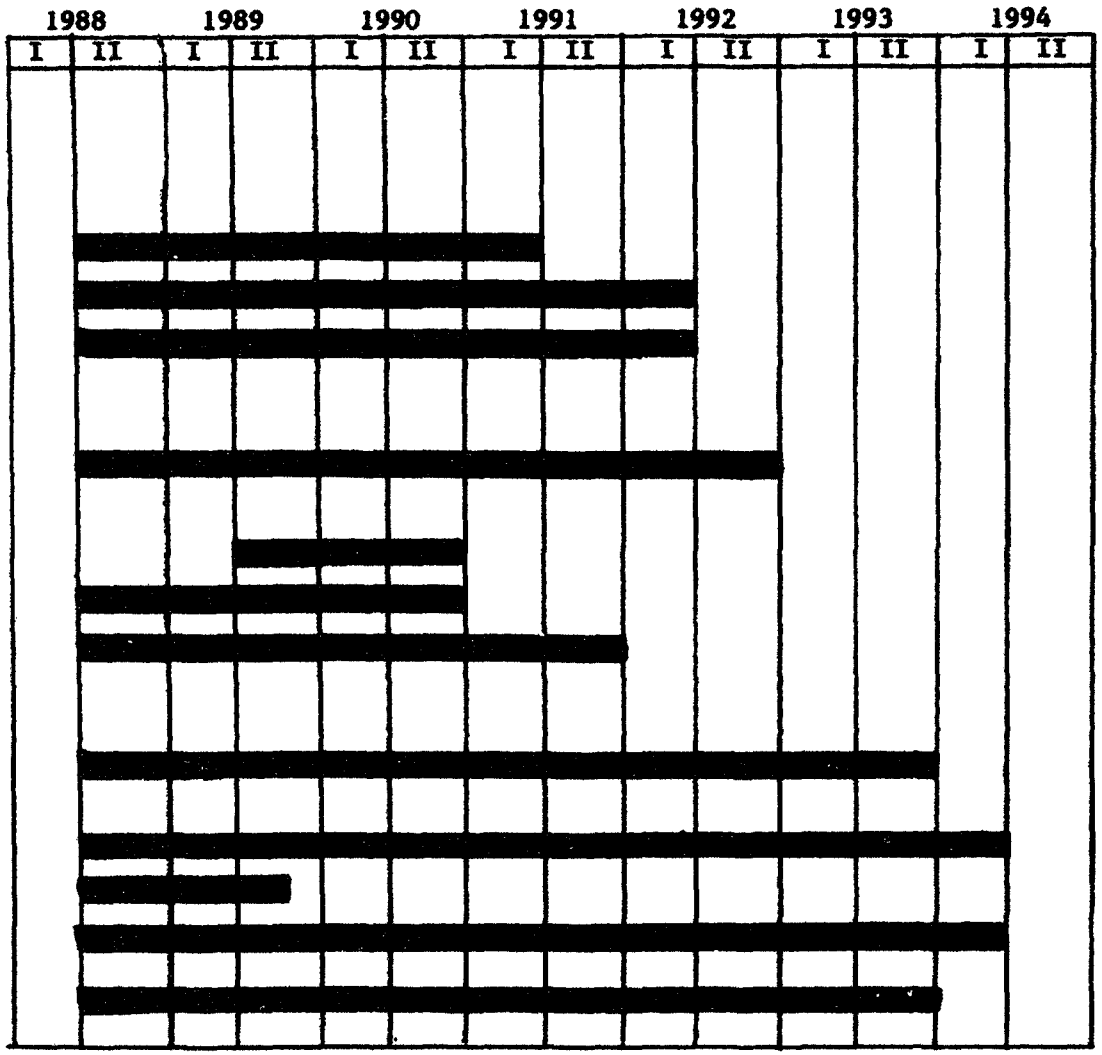

CHART 3

MAP SECTION