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STAFF APPRAISAL REPORT

INDIA

WESTERN GAS DEVELOPMENT PROJECT

January 11, 1988

Asia - Country Department IV (India)
Transport and Energy Operations Division

CURRENCY EQUIVALENTS

Currency Unit	=	Rupee (Rs)
Rs 1	=	100 Paise
US$ 1	=	Rs 13.0
Rs 1	=	US$0.0769
Rs 1 million	=	US$76,923

The US$/Rs exchange rate is subject to change. Conversions in this report have been made at US$1 to Rs 13.0, which represents the projected exchange rate over the disbursement period.

FISCAL YEAR

April 1 - March 31

MEASURES AND EQUIVALENTS

1 Metric Ton (mt)	=	1,000 kilograms (kg)
1 Metric Ton (mt)	=	2,204 Pounds (lb)
1 Meter	=	3.28 Feet
1 Kilometer (km)	=	0.62 Miles
1 Cubic Meter (m^3)	=	35.3 Cubic Feet (cft)
1 Barrel (Bbl)	=	0.159 Cubic Meter, 42 gallons
1 Metric Ton of Oil (33^o API)	=	7.3 Barrels
1 Normal Cubic Meter (Nm3) of Natural Gas	=	37.32 Standard Cubic Feet (SCF)
1 Kilocalorie (kcal)	=	3.97 British Thermal Units (Btu)
1 MW	=	1,000 kilowatts
1 kWh	=	kilowatt-hour
1 GWh	=	1 Million kWh
1 Bbl/d	=	1 Barrel per day

PRINCIPAL ABBREVIATIONS AND ACRONYMS USED

Bbl/d	=	Barrels per day
BMC (BCF)	=	Billion cubic meters (feet)
DEA	=	Department of Economic Affairs, Government of India
EIL	=	Engineers India Limited
ERR	=	Economic rate of return
GAIL	=	Gas Authority of India Limited
GOI	=	Government of India
GOR	=	Gas-oil ratio
HBJ	=	Hazira-Bijaipur-Jagdishpur Gas Pipeline
LPG	=	Liquefied petroleum gas
MCM	=	Million cubic meters
MCMD (MCFD)	=	Million cubic meters (feet per day)
MMCMD (MMCFD)	=	Million cubic meters (feet) per day
MMtoe	=	Million tons of oil equivalent
mtpy	=	Millions of tons per year
NGL	=	Natural gas liquids
NPV	=	Net present value
OIL	=	Oil India Limited
ONGC	=	Oil and Natural Gas Commission
toe	=	(Metric) ton of oil equivalent
tpd	=	(Metric) ton per day
tpy	=	(Metric) ton per year
TCF	=	Trillion cubic feet

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INDIA

WESTERN GAS DEVELOPMENT PROJECT

Loan and Project Summary

Borrower: Government of India (GOI)

Beneficiary: Oil and Natural Gas Commission (ONGC)

Amount: US$295.0 million equivalent

Lending Terms: Repayment over 20 years, including five years grace, at the standard variable interest rate. Funds will be onlent to ONGC at a rate of at least 15% per annum; repayment over 15 years, including five years' grace. GOI would bear the foreign exchange and interest rate risks.

Project Description: The objectives of the Western Gas Development Project are to accelerate the production and utilization of natural gas in India as a replacement for imported petroleum products, thus saving substantial foreign exchange, and helping to overcome energy shortages which constrain economic growth. In particular, the project will:

- expand production of the offshore South Bassein gas field from 10 to 20 MMCMD;
- support initial development of the Gandhar gas field, which will produce up to 3.5 MMCMD of gas;
- eliminate flaring of about 1 MMCMD of associated gas at the offshore Heera oilfield, by linking it by pipeline to Bombay;
- appraise the potential of the outlying Tapti and Hazira fields by seismic surveys for possible future additions to India's gas supply.

In addition, the project will encourage optimal planning of gas production and utilization in India, through support for studies of the least-cost investments for field development and transmission infrastructure for the western region, and the uses of gas which yield the greatest economic benefit.

Project Benefits: The project investments are expected to result in additional production of 11-12 MMCMD of natural gas, equivalent to about 3.2 million tons of crude oil annually, plus an additional 0.7 million tons per annum of liquid petroleum products (LPG and NGL). This is roughly equivalent to one-third of India's current annual petroleum imports. The net economic benefit to the country is estimated at US$550 million annually from 1991/2 onwards. The total net present value of the investment is approximately US$2.5 billion.

Project Risks: All petroleum investments have certain risks inherent in the process of drilling and producing oil and gas. Even though the major project components comprise development (rather than exploration/appraisal) of new fields, technical risks associated with eventual reservoir performance do exist and are comparable to any other new field development. Furthermore, poor planning and coordination of the gas market with gas supply would result in underutilization of the infrastructure proposed. While sensitivity analyses indicate that the project remains sound even with delayed gas offtake, substantial benefits may be lost without proper planning. Provision for comprehensive planning studies is thus included in the project. Oil price fluctuations will influence project economics; however, the economic return on the investment will still be over 10% for oil prices as low as US$12 per barrel.

Estimated Costs:

	In US$ Millions		
	Local a/	Foreign	Total
South Bassein Field Phase II - Offshore	78.5	178.4	256.9
- Onshore	74.6	55.3	129.9
Heera-Uran Gas Pipeline	5.5	104.6	110.1
Gandhar Field - Drilling	203.6	247.0	450.6
- Facilities	53.8	8.0	61.8
North Tapti and Hazira Fields - Drilling	29.7	47.0	76.7
- Seismic	1.0	7.0	8.0
Studies, Consulting	0.3	1.0	1.3
Base Cost	447.0	648.3	1,095.3
Physical Contingencies	44.7	64.9	109.5
Price Contingencies	91.9	57.1	149.1
Total Project Cost	583.6	770.3	1,353.9

a/ Including duties and taxes of US$192.1 million.

Financing Plan:

	In US$ Millions		
	Local	Foreign	Total
IBRD		295.0	295.0
Commercial Borrowings		305.2	305.2
Export and Suppliers Credits		170.1	170.1
ONGC (Equity)	583.6	-	583.6
Total Financing Required	583.6	770.3	1,353.9

Estimated Disbursements:

IBRD Fiscal Year	FY88	FY89	FY90	FY91	FY92	FY93
	In US$ Millions					
Annual	10	90	95	60	35	5
Cumulative	10	100	195	255	290	295

Economic Rate of Return: 28%

INDIA

WESTERN GAS DEVELOPMENT PROJECT

STAFF APPRAISAL REPORT

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ANNEXES

MAPS

I. THE ENERGY SECTOR

A. Overview

1.01 The energy scarcity remains a key constraint to accelerating the rate of India's economic growth. Fuel and power shortages continue to hamper the full utilization of industrial and agricultural production capacities, and oil imports, while significantly reduced, continue to absorb approximately one-third of India's export earnings.

1.02 The growth of the energy sector has been constrained by the slow pace at which energy resources have been developed, due to limited availability of funds for investment and the efficiency with which these are used. The level of efficiency in the major subsectors such as the industrial sector, which provides much of the equipment for energy production, and the transport sector, which provides the vital link between the coal industry -- India's major commercial energy supplier -- and its users, also needs to be improved for the country to achieve significant growth in the energy sector. Large investments are required, in addition to greater efficiency in the use of both new and existing investments in the energy sector in order to accelerate the pace of development of energy resources.

1.03 Because of the difficulties of rapidly mobilizing substantial investment resources for the energy sector -- as well as the long gestation period required for implementing energy projects, particularly hydro projects -- it is important that the management of energy demand be improved, correct energy substitution choices on the part of users be encouraged, and institutional capabilities and linkages in the energy sector be strengthened. Improvements in these areas could contribute significantly to reductions in production costs and consumption of energy per unit of production by principal energy users.

1.04 Although the Government of India (GOI) has accorded high priority to development of energy resources, past efforts to reduce the rate of growth of energy consumption have had only a marginal impact. During 1979/80-1986/87, the growth of consumption of all commercial forms of energy averaged about 6% annually, compared to an average GDP growth rate of 5% per year during the same period. The elasticity of energy consumption with respect to income still remains, at 1.2, relatively high for a resource-scarce country such as India.

B. Primary Energy Production

1.05 In India, commercial primary energy, which consists of coal, hydro and nuclear power, and petroleum, accounts for slightly less than one-half of total primary energy supply. The balance comes from non-commercial sources, mostly firewood, agricultural and animal wastes. The supply of commercial energy has been growing faster than that of non-commercial energy. By 1985/86 production of primary commercial energy had reached about 120 million tons of oil equivalent per year.

1.06 Coal is, and will continue to be, India's most abundant commercial energy resource. It meets about 50% of the country's commercial energy requirements. Total resources are estimated at over 112 billion tons, approximately half of which is economically recoverable under present conditions. At current rates of consumption this is equivalent to about 250 years total primary commercial energy. Most of India's coal is of low to medium quality, and there are substantial bottlenecks in coal transportation, with the result that in many areas of the country coal is a relatively expensive energy resource.

1.07 Power. As of 1985 total installed power generating capacity was approximately 42,000 MW, of which 65% was conventional thermal, 33% hydro, and 2% nuclear. India has extensive hydro potential. The GOI accords high priority to the development of hydropower, but because hydroelectric projects require long lead times and large capital commitments for their implementation, only a small share of India's hydro potential has been developed now. Consequently most recent additions to power generating capacity have been from thermal power plants. The share of thermal has increased steadily over the last twenty years. At present, it accounts for approximately two-thirds of generating capacity.

1.08 India's economic growth is highly dependent upon the performance of the power sector. At India's stage of growth, large gains in productivity can result from increased use of power. Present per-capita production of electricity is about 200 kilowatt hours which compares, for example, with about 400 kilowatt hours per capita in the Philippines, where GNP per capita is about three times that of India. Conversely, power shortages have a serious adverse impact throughout the economy. During the 1950's and 1960's power generation has kept pace with demand. Since 1970, however, supply has fallen short of demand. This has resulted from delays in the commissioning of new projects, operating and maintenance problems, and budget constraints which have limited investment in the sector. These problems have been aggravated by inefficient operations and distribution, unreliable coal supplies due to transport problems, and the declining quality of coal. Recognizing these problems, the GOI has undertaken a program of remedial measures. Although power plant utilization rates increased significantly recently, the supply of power is still expected to remain inadequate, especially in areas where coal is not readily available.

1.09 Petroleum. In the 1970's India discovered the giant Bombay High offshore oil field. As a result, the country is presently able to produce about 75% of its petroleum requirements. The results of stepped up exploration efforts and recent discoveries point to existence of considerable pltroleum resources. Nevertheless, India is not self-sufficient, and the shortfall in the country's commercial energy requirements are met primarily through imports of crude and petroleum products.

1.10 It is estimated that only one-fourth of India's likely commercially recoverable petroleum reserves have been proven, with undiscovered potential heavily weighted towards gas. Systematic petroleum exploration has only been undertaken recently, and large parts of India's potentially hydrocarbon-bearing basins have yet to be explored. It is expected that reserves yet unproved will likely be in the more difficult geological areas, and more likely will consist of gas than oil. Present recoverable reserves of oil are approximately 500 million metric tons - enough to last 15 years at current rates of production. Output from the Bombay High oil field, which accounts for 70% of domestic oil production, is reaching a plateau, and unless new resources are identified, developed, and brought onstream, domestic oil production will decline as Bombay High production declines over the next decade.

C. Energy Consumption

1.11 In India the household sector accounts for a relatively small share of commercial energy consumption (7% of coal, 19% of petroleum and 10% of electricity). However, consumption of non-commercial energy in this sector is high, particularly in the rural areas where the use of electricity and kerosene is still limited mostly to lighting. Although the substitution of commercial energy for non-commercial energy will continue, non-commercial energy will likely remain the most important energy resource for many rural households.

1.12 In agriculture, energy needs are met mostly by animal power or by the use of liquid fuels, mainly diesel oil. Commercial energy consumption in agriculture accounts for only about 6% of total commercial energy use, but it has grown rapidly during the past two decades, reflecting the efforts to modernize this sector.

1.13 The industrial sector consumes about 35% of total commercial energy resources and almost 60% of all energy (including non-commercial fuels). It is by far the largest user of coal and electricity. In 1982/83, Indian industry accounted for slightly more than 80% of coal consumption, 22% of oil consumption, 47% of natural gas consumption and 62% of electricity consumption. Over the past twenty years the energy intensity (energy cost per unit of value added) of industry has increased significantly. However, the growth of energy intensity in industry is expected to slow down as a result of the introduction of more energy-efficient technologies, the more efficient use of existing capacities, and improvements in the design of plants and machinery.

1.14 The transport sector is the largest user of petroleum products and the second largest user of coal. Over the past twenty years the structure of energy demand by this sector has changed considerably as a result of the rapid growth of road transport and the substitution of diesel electric for steam locomotives. Current energy demand projections for the transport sector point to a continuing decline in coal consumption as road transport increases and railways continue to shift to more efficient diesel electric locomotives, thereby contributing to a growing demand for petroleum products.

D. Energy Policy and the Role of Petroleum

1.15 Significant increases in energy demand in India are forecast over the next twenty years as population grows and as the economy becomes more industrialized. Demand is expected to grow most rapidly in the household and industrial sectors, and the demand for electricity and petroleum is expected to grow more quickly than demand for coal. The country's energy requirements will far outstrip domestic supply for the foreseeable future, although this overall shortfall can be reduced by increases in domestic energy production and to a lesser extent by improvements in conservation and energy efficiency. GOI's strategy in dealing with this situation is:

(a) To increase power generating capacity as rapidly as possible, especially hydro and nuclear;

(b) To encourage the use of coal and accelerate the development of gas resources;

(c) To reduce dependence on liquid petroleum products through substitution; and

(d) To encourage conservation, energy efficiency and fuel substitution through pricing, allocation, and conservation programs.

1.16 This strategy is reasonable, given: (i) the persistent shortfall in energy supply - especially power and coal supplies - which continues to hamper economic growth and more rapid industrial development; (ii) the small likelihood of any major reduction in the growth of energy demand in the near future; (iii) fiscal constraints which limit GOI's capability to undertake all of the investments required in the energy sector; and (iv) recent changes in petroleum prices and its impact on the oil industry. Even if these constraints can be overcome, a substantial shortfall in energy supply is still expected for the foreseeable future, most of which will have to be met from imports of crude oil and petroleum products. The petroleum subsector will, therefore, continue to play a crucial role in India's energy strategy for the remainder of the century.

1.17 India's effort to adjust to the shocks of the two major oil price increases of the 1970's has been largely successful; however, there is a need to prepare for potentially serious shortfalls again in the 1990's. In order to avoid a recurrence of the situation in which petroleum shortages could constrain economic growth and/or put an unacceptable burden on the balance of payments, the GOI has:

(a) Almost doubled its investment program in oil and gas exploration and development;

(b) Expanded the role of natural gas as a replacement for liquid hydrocarbons; and

(c) Encouraged the involvement of private contracting and service firms in the petroleum sector, and solicited the interest of international oil companies in the exploration process.

E. Petroleum Reserves and Production

1.18 India contains some 1.7 million sq km of sedimentary basins containing projected reserves of about 15 billion metric tons of oil and oil equivalent of gas in place. This corresponds to some 4-5 billion metric tons or tons equivalent (30-35 billion barrels) of commercially recoverable reserves. About 70% of the recoverable reserves are expected to be gas. Up to now, only about 700 million metric tons (mt) of oil and 650 million mt oil equivalent of gas reserves (800 billion cubic meters of gas) have been proven - or slightly more than one-quarter of the likely commercially recoverable reserves.

1.19 Oil production has increased dramatically over the last ten years, principally as a result of development of the Bombay High field. Production from this field contributes over 70% of domestic production, the balance being produced in about equal proportions from onshore areas in Gujarat and Assam (Table 1.1).

Table 1.1

Crude Oil Production and Reserves by Area
(million mt)

	Production				Estimated Remaining Recoverable Reserves (1987)	1985/86 Reserve/ Production Ratio (Years)
	1970/71	1975/76	1980/81	1986/87		
Bombay High	-	-	5.0	20.6	330	16
Assam	3.4	4.3	1.7	5.2	40	8
Gujarat	3.5	4.1	3.8	4.6	211	45
Total	6.9	8.4	10.5	30.4	581	19

Source: GOI, ONGC, Bank staff estimates.

1.20 Oil production from Bombay High has now reached a plateau and is expected to start to decline after 1992. Production from the other regions is being sustained by improved recovery levels and augmented by marginal discoveries of new reserves.

F. Petroleum Product Demand

1.21 Domestic production of petroleum has never been sufficient to meet demand in India. However, due to the low level of petroleum intensity in the economy, this shortfall did not become a major problem until the 1960's. At that time increasing industrialization and population growth resulted in increasingly large oil imports. By 1980/81 over 16 million tonnes (65% of requirements) were imported. These relationships for selected years are summarized in Table 1.2 below (Annex 1.1).

Table 1.2

Production, Consumption and Import of Oil
(Million metric tons per annum)

	1970/71	1975/76	1980/81	1986/87
Petroleum Product Consumption	17.9	22.5	30.9	43.4
Domestic Crude Oil Production	(6.8)	(8.5)	(10.5)	(30.4)
Net Crude plus Products Imports a/	12.5	15.7	23.6	16.1
Import Dependency (%)	69	71	77	37

a/ Figures do not add because of process losses, changes in stocks, and re-exports.
Source: GOI

1.22 In the 1970's India met almost all of its requirements for petroleum products by refining imported crude. Since then demand for refined products has grown 5-6% per year. This additional demand has been met by refining increased amounts of domestic crude (principally from Bombay High) and from imports. Total refinery capacity has kept approximate pace with demand of about 40 million tons per year (mtpy). However, the composition of refinery output does not match the composition of demand. As a result, there is a shortage of middle distillates, particularly kerosene and diesel, which is met through imports.

G. Projected Supply/Demand Balances

1.23 Petroleum products demand in India will continue to grow, both because current consumption is low, and because urban and industrial growth results in increased intensity of petroleum use. Even with improvements in demand management and increased energy efficiency, consumption is expected to grow at over 5% p.a. for the rest of the century, resulting in demand doubling (to about 80 mtpy) by the year 2000. It is estimated that the production of petroleum may increase to about 40 mtpy of crude by then (Annex 1.2). This estimate is based on the assumption that production from the Bombay High oilfield plateaus and then declines through the 1990's, and that new production will, in general, be from smaller, more marginal new fields, and from higher recovery rates of established fields.

1.24 Current plans of ONGC and GOI aim for an increase of production from existing fields to 35 mtpy by 1990 (Annex 1.2). They are based on the assumption that the pattern of small to medium discoveries continues at the same rate as during the Sixth Plan, thus adding some 150 million tonnes of commercially recoverable reserves in each five-year period. This would then allow increases in production at the same rate as in the last two plan periods (about 5 mtpy every five years) up until 1995, at which point the decline from existing fields (especially the Bombay High oilfield) starts to take effect, and production declines to the 35 mtpy level, having peaked at 40 mtpy in the 1990's.

1.25 Thus the petroleum supply constraint will likely continue through the remainder of the century, and India will need to increase its imports of petroleum. The Government is according high priority to identifying new petroleum resources for the 1990's and beyond. One potentially significant option is the substitution of natural gas for liquid petroleum products, and although there are technical and economic limits to substitution possibilities, the utilization of gas in appropriate markets offers the prospect of substantially reducing India's prospective shortfall in petroleum resources. The GOI, as a matter of policy, is supporting the substitution of gas for petroleum to the greatest extent feasible. The current project is designed to support these initiatives.

H. Petroleum Sector Policy

1.26 Exploration and Production. There is substantial scope for increasing the domestic production of oil and gas in India, both by discovering new resources and by increasing recovery from existing oil fields by the use of enhanced production techniques. Many areas with petroleum potential are still under-explored and only a fraction of the country's projected reserves have been found. Bank staff estimates that perhaps some 50% of expected oil and 75-80% of expected gas remains to be found. The pace and scope of exploration activity have been uneven, and there have been limited important finds since the discovery of the Bombay High oilfield in 1974. The GOI has recently attached high priority to an expanded exploration effort by the two national oil companies, ONGC and OIL. Almost US$3 billion equivalent has been allocated for exploration purposes alone over the current Five-Year Plan period.

1.27 The finding of new hydrocarbon resources is of utmost importance to India, and the overall prospectivity of the country justifies a continuing and substantive exploration effort. The GOI's exploration strategy involves a two-pronged approach: first, a continuing exploration effort by the two national oil companies, ONGC and OIL; second, involving the international oil industry in the more difficult, high risk offshore areas to complement this national exploration effort. In regard to the exploration investment strategy undertaken by the national oil companies, GOI recognizes that the investment strategy has to be as cost effective as possible and thus should be made on the basis of detailed geological information from seismic surveys, in order to avoid premature drilling and needless dry holes. Specific Bank involvement in making these programs increasingly cost-effective is being carried out in the context of the Krishna-Godavari project and in the recently approved Oil India project. In parallel, international oil companies were invited in May 1986 to participate in a Third Round of exploration acreage offerings in which GOI offered 27 exploration blocks on a sole risk basis. The response to this offering in a difficult external climate, was encouraging. Twelve offers by seven different companies or consortia covering both the western and eastern offshore areas have been received. Four initial contracts were signed at the end of 1987, with exploration activity expected to start soon thereafter.

1.28 The Role of Gas. India has substantial untapped reserves of natural gas. It is estimated that by the end of the century gas could replace up to 17 mtpy of petroleum products (about one-half of current consumption). To date, however, there have been substantial delays in developing the gas market and coordinating it with field and infrastructure development. As a result gas remains underutilized. This situation is now changing as GOI establishes a more concrete gas strategy. However, there are still problems of planning and coordination, which this project seeks in part to overcome. The role of gas and associated policy issues are described in more detail in Chapter II.

1.29 Public and Private Investment. As the petroleum sector has grown over the last decade, commitments of budgetary resources have increased commensurately. Initially, most of these resources have been made available to ONGC as budgetary transfers from the Government. During the past seven years, ONGC has relied on internally generated funds supplemented by direct borrowings. Under the recently completed Sixth Plan, the petroleum sector was originally allocated an equivalent of approximately US$5 billion of resources. This was increased to US$11 billion at a mid-Plan review, as it became clear that accelerated expansion of the Bombay High oilfield would yield high returns. Actual expenditure is estimated at US$9 billion equivalent, as a result of some delays in a number of large projects. Despite the large investments, the sector remained a net contributor to public finances, paying approximately US$15 billion equivalent in taxes and duties over the Sixth Plan period according to preliminary estimates.

1.30 Under the Seventh Plan (1984/85-1990/91), about Rs 127 billion (approximately US$9.7 billion equivalent, out of total public investment of about US$140 billion), has been allocated to the petroleum sector, as summarized in Table 1.3, below.

Table 1.3

Seventh Plan Budgetary Allocation

Activity	Agency	Rs Million	US$ billion
Exploration and Production	ONGC	87,530	6.7
	OIL	9,500	0.8
Gas Infrastructure	GAIL	9,500	0.7
Refining & Marketing	GOI & EIL	5,210	0.4
	Oil refining and marketing companies	14,540	1.1
Total		126,280	9.7

Source: GOI

1.31 By far the highest priority has been accorded to exploration and production. All firm oil and gas development programs have been financed, with the understanding that additional funds will be made available as necessary for any new fields which can be developed during the Plan period. In the natural gas sector most funds are allocated for the large on-going infrastructure projects to exploit the western offshore gas fields.

1.32 The allocation of US$9.7 billion should be viewed against the background of a request for almost US$22 billion equivalent from the implementing agencies (mostly ONGC). The Government cut these requests back substantially because there is a growing perception that many of the tasks which ONGC has undertaken itself could be performed in a more cost-effective manner by sub-contractors and/or suppliers, and that there should be an increased role for private sector firms in the development of India's energy sector.

1.33 Role of the Private Sector. Over the past few years, privately owned companies have become increasingly involved in providing goods and services to this industry and in entering into joint ventures (between Indian private companies and foreign companies) to supply technical oil field services and equipment. A large portion of the offshore equipment and services are provided directly by foreign private companies on the basis of international competitive bidding. During the last two years there has been a marked shift in emphasis away from the financing of capital investments in the petroleum sector by the public sector. This can be seen most notably in the Seventh Plan, under which the GOI has instructed ONGC to cut its drilling rig acquisition program by about 50% and instead to lease rigs from the private sector. In addition, a decision was made not to commit public funds for the full financing of proposed new refineries, but rather to seek joint venture private partners to develop these projects.

1.34 Under the recent Third Round exploration offering, international oil companies have been invited to bid on offshore acreage to explore on a sole risk basis. Under this arrangement oil companies commit themselves to a certain program of exploration work at their own cost in exchange for a share of subsequent production if hydrocarbons are found. Previous offerings to the international industry by India have met with limited success because the terms were not perceived as competitive, and the acreage offered was relatively high risk. Under the current Third Round offering, a wider variety of acreage is being offered, and the terms and conditions proposed are competitive with those offered by countries of similar prospectivity. Bidding under this offering is currently going on and is expected to be completed during the early part of 1988.

I. Petroleum Pricing

1.35 Producer Prices. ONGC and OIL are paid a fixed producer price of about Rs 1,800/mt (US$18.70/Bbl equivalent) for crude oil production. From this amount, the Government deducts royalties, a federal tax ("cess"), and a sales tax, resulting in a net producer price of about Rs. 1,020/mt (approximately US$10.60/Bbl). This is in line with the average producer prices realized elsewhere in the world, the cost of imported crude and estimated production costs.

1.36 Consumer Prices. Petroleum product prices are set by the Government. These prices are based on the international prices of products which are imported (generally CIF with an adjustment for domestic transport). Exceptions are made in the cases of kerosene, which is subsidized for social reasons, and for fuel oil and gasoline, which are sold at a premium above import prices as a means of discouraging excessive consumption. Typical consumer prices during the 1984-85 period in India (prior to the 1986 drop in international crude and petroleum product prices) are summarized below (Table 1.4).

Table 1.4

Consumer Prices of Petroleum Products
(December 1987 Prices)

Fuel	Domestic Price Rs/kl	Domestic Price US$/gal	Estimated Border Price (US$/gal)	Domestic as % of Border (%)
Naphtha	2,189	0.64	0.47	136
(for Fertilizer)	1,351	0.39	0.47	83
Gasoline	6,694	1.95	0.56	348
Kerosene	1,957	0.57	0.54	106
Diesel	3,096	0.90	0.54	167
Fuel Oil	2,903	0.85	0.37	230

Source: Petroleum Economist, and Bank staff estimates. Average spot prices CIF Northwest Europe. Transport charges from Persian Gulf to Europe are assumed equal to transport charges from Persian Gulf to India.

1.37 Following the recent drop in world oil prices, domestic prices are high relative to the border prices of imports. The GOI has decided not to realign domestic prices immediately on the grounds that: (a) the fall in international prices may be short-lived; (b) conservation efforts should be encouraged; (c) investment in petroleum intensive technologies which may be expensive to supply in the longer run should continue to be discouraged; and (d) the resource mobilization opportunity presented by the temporary gap between low international prices and domestic prices should be utilized. India's present pricing regime is reasonable in light of these legitimate concerns; however, if low international prices persist, the GOI may review its domestic price structure accordingly.

II. THE GAS SUBSECTOR

A. Introduction

2.01 Geological conditions indicate that India probably has more undiscovered gas reserves than oil reserves. Since recovery rates of gas tend to be higher than for oil, natural gas can be expected to play a potentially important role among India's future energy sources. To date, gas production in India has consisted almost exclusively of gas produced in association with oil. Large proportions of this gas have been flared for lack of infrastructure or market. Recently infrastructure has been established to deliver associated gas from Bombay High to users in Bombay. Initial development of the giant South Bassein offshore free gas field is now also under way, and financing for the second phase development is included in the proposed project. Plans are for South Bassein to ultimately produce 20 MMCMD of gas, equivalent to about 6.4 million metric tons of oil annually, or 16% of India's total current consumption of petroleum.

2.02 Utilization of India's gas resources has been constrained by the absence of distribution and transmission infrastructure, and the need to develop markets for gas use. This situation is changing as the Government recognizes the importance of gas as an energy source, and as the magnitude of India's total gas reserves becomes better established. In 1984 the Government established the Gas Authority of India Ltd (GAIL), with responsibilities which include gas planning, marketing, and distribution. GAIL will also operate the HBJ gas pipeline, a 1,700-km trunk line to take South Bassein gas to fertilizer and power plants in the interior of the country. Commissioning of the pipeline is planned for 1988.

2.03 Original plans for the development and use of South Bassein gas restricted use to the fertilizer and petrochemical industries, on the assumption that gas availability was limited. This policy has now been relaxed, and the GOI is allocating gas to combined-cycle power plants along the HBJ gas pipeline, as well as opening up the market to medium-scale industrial users.

B. Gas Reserves and Production

2.04 Small amounts of associated gas have been produced in the Gujarat and Assam regions for over 20 years. Since 1981 more significant quantities of associated gas have been produced from Bombay High. Still, by 1985/86 natural gas accounted for less than 2% of India's commercial energy consumption. The large reserves of non-associated gas which have been discovered in the South Bassein field are expected to enter into production by the early part of 1988. Table 2.1 shows the historical production of gas by region in India (Annex 1.3).

Table 2.1

Natural Gas Production by Region
(Million Cubic Meters per Day)

Region	1970/71	1980/81	1987/88 a/
Assam	2.7	2.3	3.0
Gujarat	1.3	2.3	1.3
Western Offshore	--	1.8	10.6
Total	4.0	6.4	14.9

a/ April-September 1987
Source: GOI, ONGC.

2.05 India's proven and probable gas reserves are estimated by Bank staff at about 680 billion cubic meters (BCM), equivalent to about 550 million tons of oil. Approximately 80% of these reserves are located in the western offshore region (550 BCM), 10% in the mountainous region of Assam (70 BCM), and the other 10% in the Cambay Basin in Gujarat (60 BCM). These estimates probably understate the potential for total gas discoveries, since gas-prone areas have generally received less attention for lack of an immediate market. Additional commercial reserves are expected to be found in the eastern coastal area (including Krishna-Godavari) as a result of current exploration efforts, and in the extreme northeast (Tripura-Nagaland).

2.06 The reserves and potential production from the three established gas-producing areas, together with estimated reserve/production ratios, are shown in Table 2.2. Total production of natural gas could rise over the next decade from about 22 MMCMD in 1985/86 to 45-60 MMCMD, equivalent to 13-17.5 MMtoe per year, or one-half of India's present production of crude. The bulk of this additional production is expected to come from the western offshore area.

Table 2.2

Gas Reserves and Potential Production by Region

	Estimated Recoverable Reserves (BCM)	Actual 1986/87 Production (MMCMD)	Planned 1993/94 Production (MMCMD)	Reserve/ Production Ratio 2/ (Years)
Western Offshore	550	18.4	40	37.7
Gujarat	60	2.5	8	20.7
Assam	70	6.0	6	31.8
Total	680	26.9	54	34.5 (Average)

1/ Proved and probable recoverable remaining reserves. Proved reserves are ONGC estimates. Probable reserves are Bank staff estimates.
2/ Based on planned 1993/94 production.
Source: ONGC, Bank staff estimates.

2.07 The principal constraints to bringing discovered reserves into production are the absence of production and transmission infrastructure and the relative under-development of the gas market. The major tasks facing the Government are thus the coordination of supply facilities, construction of infrastructure, and development of the market.

C. Gas Utilization

2.08 Gas markets in India are essentially regional markets, and are currently limited to a small number of users of associated gas. In Assam these include a fertilizer plant, the tea industry and the Assam State Electricity Board. In Gujarat gas consumers include a few industries in Baroda, the Jayat paper mill, a fertilizer plant and a power plant. Gas from the Bombay High oilfield is utilized by a few fertilizer plants in Bombay, by the Tata Electric Company, by the Maharashtra State Electricity Board (MSEB), and for the extraction of liquefied petroleum gas (LPG).

2.09 Up to the early 1980's, as much as 50 percent of associated gas has been flared due to the isolated locations of many fields, the absence of distribution infrastructure, and the lack of a developed market. Associated gas from Bombay High has also been flared, but this has been substantially reduced recently with the installation of sufficient compression capacity to pump all gas to market in Bombay and in Gujarat (through the South Bassein pipeline). Estimated gas use by sector in 1985/86 is shown in Table 2.3.

Table 2.3

Estimated Gas Use by Sector

Sector	Quantity 1985/86 (MMCM)	(MMCMD)	%
Power Generation	1,562	4.3	35
Industrial Fuel	181	0.5	4
Fertilizer Feedstock	1,676	4.6	37
Captive Power Generation	670	1.8	15
Tea Plantations, Domestic Use, Other	200	0.5	4
LPG Production	209	0.6	5
Petrochemical Feedstock	20	0.1	-
Total	4,518	12.4	100

Source: Ministry of Petroleum and Natural Gas

A further 606 MMCM (1.7 MMCMD) of gas was used for re-injection and in field use, and the balance of 3,118 MMCM (8.5 MMCMD, or 38% of total production) was flared.

D. Potential Total Demand

2.10 Gas reserve estimates are still being reviewed as evaluation and development of fields proceed. A long-range, country-wide demand forecasting exercise for gas has not yet been completed, as the Gas Authority of India Ltd (GAIL) is currently undertaking a series of market assessments on a region-by-region basis. In the absence of detailed demand information, indicative estimates of the potential penetration of gas in India's energy sector can be made on the basis of the experience of comparable developing countries with more mature gas markets.

2.11 In general, the most economically attractive uses for gas are as replacement for petroleum products, either as feedstock or as fuel. In many countries, fuel oil replacement in power generation or industry represents the dominant gas use in the early years of market development. However, in India gas consumption will be concentrated, at least initially, in feedstock uses. India has large domestic fertilizer requirements and consumption of fuel oil, which gas would otherwise replace, is relatively limited as a result of the extensive use of domestic coal resources in industry and power generation. Fuel oil consumption in India is limited to about 20% of total petroleum product consumption, compared to 40-60% in most middle-income developing countries.

2.12 Estimates of potential gas demand in India for liquid fuel and feedstock replacement are shown in Table 2.4.

Table 2.4

Potential Oil Replacement Market for Gas

Product	Petroleum Product Consumption (MMtoe)	Potential Gas Penetration (%)	Theoretical Replacement (MMtoe)
LPG	1.29	10	0.13
Naphtha	3.19	50	1.60
Gasoline	2.31	-	-
Kerosene	6.22	10	0.62
Jet Fuel	1.46	-	-
High-Sulfur Diese	14.64	15	2.20
Light Diesel	1.08	15	0.16
Fuel Oil	7.36	60	4.42
Others	2.51	-	-
Tota	40.06		9.13

Source: Bank staff estimates.

These figures are based on India's estimated 1985/86 petroleum product demand, and product-specific penetration rates derived from experience in other countries. These estimates do not take into account infrastructure constraints or the lead times needed to develop new gas markets. However, they do allow for diminishing returns as gas infrastructure is extended into areas of lower industrial concentration and population density. The estimates shown in Table 2.4 do not include any allowance for additional induced demand which may take place.

2.13 Based on these assumptions, it is estimated that gas could substitute in the long term for about one-fourth of total petroleum product consumption in India (8% of total commercial energy). This level of replacement would represent about 30 MMCMD of gas, or 9 million toe. At a 6% annual growth rate in consumption, this would imply a potential demand for gas at a fuel oil equivalent price of over 55 MMCMD by 1996/97. This is in the same range as planned production from known reserves (para. 2.06).

2.14 It would be highly speculative to estimate the potential market for gas as a replacement for coal, given the current levels of possible supply. In view of the long distances and high ash content, the long-run marginal cost of domestic coal delivered to the western region of India is estimated at about US$2.50/MMBtu. Comparable costs of offshore non-associated natural gas is estimated to be about US$2.00/MMBtu. The potential market for western gas as a coal substitute is thus probably substantial.

E. Supply and Demand in the Western Region

2.15 Reserves and Production. Estimated gas reserves and projected production profiles of the various gas producing fields in the western region are shown in Table 2.5. The Bombay High and South Bassein fields are the most important fields by far. Production of associated gas from Bombay High is expected to continue at 15 MMCMD through the late 1980s and to gradually decline thereafter (Annex 2.1). The South Bassein field is expected to produce 20 MMCMD of (non-associated) gas by 1991/92 (Annex 2.2). Onshore gas production in Gujarat is expected to increase to about 4 MMCMD by 1988/89 (Annex 2.3). Significant production from the other western gas fields is not expected until the mid-1990s.

Table 2.5
Projected Gas Availability in the Western Region

Field	Estimated Recoverable Reserves (BCM)	PRODUCTION Actual 1986/87	Projected 1987/88	Projected 1990/91	Projected 1994/95
		MMCMD ex-Platform			
Bombay High	250 a/	18.4	14.3	11.2	9.2
South Bassein	205	---	5.0	20.0	20.0
Panna	25	---	---	1.0	2.4
South, Mid & North Tapti	20 b/	---	---	3.2	3.2
Heera	20	---	---	1.4	0.5
B-55	15 b/	---	---	0.7	1.4
Ratna and B-57	15 c/	---	---	0.3	1.1
Gujarat Onshore	60	2.5	3.7	5.0	6.4
Total	610	20.9	23.0	42.8	44.2

a/ Includes about 110 BCM of gas-cap and free gas not counted in official reserves.
b/ Bank staff estimate. Not included in official reserve data because of insufficient appraisal to date.
c/ Associated gas, not included in official reserves.
Source: ONGC and Bank staff estimates.

2.16 The planned production level of 44 MMCMD in 1994/95 may be conservative relative to the level of gas production possible over the next decade. Depending on the level of associated gas production at Bombay High, the rate at which new satellite fields around Bombay High and South Bassein are brought into production, and the rate at which South Bassein resources are exploited, a range of production profiles could result. A lower bound is probably about 28 MMCMD by 1994/95.

2.17 More likely, production will be higher than planned. The gas-oil ratio (GOR) at Bombay High may increase more than expected, with associated gas production remaining over the 12 MMCMD level well into the 1990s.[1/] The South Bassein field could be exploited more quickly than presently planned, at

1/ A technical note on the production of associated gas from Bombay High is attached as Annex 3.7.

a production rate of 25-30 MMCMD (depleting the reservoir, based on present data, over about 20 years). This option would be of particular interest if significant additional reserves are identified in new fields. An upper bound on production based on these considerations is about 55 MMCMD.

2.18 Existing and Planned Infrastructure. While offshore gas supply could be as high as 55 MMCMD, the capacity of the offshore pipeline system, based on present planned investments, will only be about 30 MMCMD. The existing Bombay High-Uran line has a capacity 9.5 MMCMD (currently being increased to 11 MMCMD), and the South Bassein-Hazira line has a capacity of 20 MMCMD (which can be increased to 30 MMCMD with the addition of compression). There is a link between these two lines, so that some excess Bombay High production can be sent to Hazira and inland through the HBJ pipeline.

2.19 Under the proposed project an additional line of approximately 7 MMCMD capacity will be constructed from Heera to Uran, which will provide further capacity to deliver gas from Bombay High satellite fields to the Bombay market. ONGC has preliminary longer-term plans for a network of field and pipeline development to deliver western region gas to Bombay and to the Hazira/HBJ pipeline system. An investment study to identify least-cost longer term development plans is included in the project (para. 2.49).

2.20 Most gas is presently consumed near landfall or near the onshore fields. Onshore infrastructure is minimal. The HBJ pipeline is a major first step in expanding the gas market from a local to a regional level. There are also plans to extend an existing local gas grid in the Baroda/Ahmedabad area in increments and link it to the HBJ pipeline to provide an integrated transmission network to take gas from both South Bassein and onshore Gujarat fields to consumers either in Gujarat or along the HBJ pipeline system.

2.21 Potential Markets. A preliminary planning exercise to assess the future market and to set priorities for gas use was carried out in 1979 by a Working Group established by the Ministry of Petroleum. It limited its analysis to the use of 21-27 MMCMD of offshore gas that was then expected to constitute the future gas supply. The Working Group recommended use of western gas principally as a fertilizer feedstock. This led to the decision to build a group of ten gas-based fertilizer plants to supply the domestic market and to construct the HBJ pipeline to supply the six inland plants (see IBRD Map 19878). As more gas has been confirmed and as delays are now expected in construction of the last three fertilizer plants, the Government has expanded the market for western gas to include some power plants and existing industrial plants. GAIL has also decided to extend the HBJ line to Delhi to increase the potential for additional gas utilization; it is currently carrying out market surveys to quantify this market potential for gas.

2.22 The quantity of associated gas which can be transmitted to Uran for consumption in the Bombay area is currently limited by the capacity of the Uran terminal facilities, which can handle only 8.0 MMCMD of rich natural gas (to be increased to 10.5 MMCMD). Any gas in excess of this amount must currently be transmitted to Hazira for consumption there or input into the HBJ pipeline. Gas users in Bombay comprise three fertilizer plants, several medium-sized industrial users, two power plants (MSEB and Tata Electric, totalling 3.8-6.6 MMCMD, depending on demand), and a gas cracker to be commissioned in three years. The total of these users amounts to between 6 and 13 MMCMD, with actual consumption varying considerably with seasonal demand and industrial operations. In addition to these users, ONGC has identified small industrial users within the current gas grid as well as additional potential commercial and domestic demand. Details are given in Annex 2.4.

2.23 The offtake from the Gujarat gas grid consists of about 3 MMCMD by committed consumers, including two fertilizer plants, two power plants, and a number of industrial and commercial users. In addition, another 1.2 MMCMD could be taken by existing fertilizer plants and 3 MMCMD by power plants on an interruptible basis. ONGC and GAIL have identified a further potential demand of 2.5 MMCMD from industrial, commercial, and domestic consumers. Total potential consumption in this market is in the range of 11 MMCMD, and no difficulty is anticipated in finding a market for gas from the Gandhar field (see Annex 2.5 for details).

2.24 Near Hazira and along the HBJ pipeline route, up to 16 MMCMD will be used by fertilizer plants and up to 6 MMCMD by new combined-cycle power plants. Existing plants for immediate conversion to gas could consume about 5 MMCMD of gas. The demand of other industrial and power users is estimated to total approximately 7 MMCMD. Total potential demand for this area is thus about 35 MMCMD, of which about 20 MMCMD is expected to come from fertilizer and power plants. More detailed breakdown of total annual demand by potential users is provided in Annex 2.6 and summarized in Table 2.8.

2.25 In summary, the market for western gas amounts to some 26 MMCMD from committed consumers, a further 21 MMCMD from interruptible consumers and 16 MMCMD from additional potential users. This breakdown is summarized below in Table 2.6.

Table 2.6

The Western Gas Market: Potential Lean Gas Demand by 1993/94
(MMCMD)

	Bombay	Gujarat	Hazira	HBJ	Total
Committed					
Fertilizer	4.8	2.0	3.5	8.9[a/]	20.2
Power	-	0.4	-	3.7	4.1
Industry	0.7	0.6	0.2	-	1.5
Subtotal	5.5	3.0	3.7	12.6	25.8
Interruptible					
Power	6.6	3.0	-	6.6	16.2
Industry/Captive Power	1.9	-	0.6	2.0	4.5
Subtotal	8.5	3.0	0.6	8.6	20.7
Potential Additional					
Fertilizer	-	1.2	-	2.5	3.7
Power	-	-	-	2.3	2.3
Industry	1.8	2.8	-	3.3	7.9
Distribution/Domestic	0.5	0.5	-	0.8	1.8
Subtotal	2.3	4.5	-	8.9	15.7
Total	16.3	10.5	4.3	30.1	61.2

a/ Based on current GOI plans; up to 5 MMCMD currently allocated to fertilizer production may be replaced by demand from industrial power plants.

Source: GOI, ONGC, GAIL and Bank staff estimates.

These figures represent a preliminary estimate of the market for western gas, however more work is required to identify the details of possible gas consumption, the technical requirements and costs of conversion, and to prepare users in time to take gas as it becomes available. GAIL has already taken the first steps in this direction, with technical assistance from the Bank, during project preparation.

2.26 The original decision to allocate the bulk of western gas supplies to the fertilizer sector was made as a result of the recommendation of the 1979 Working Group. Based on a review of the demand/supply balance in India's fertilizer sector, the Working Group proposed the establishment of ten new 1,350 tons-per-day ammonia units, six along the HBJ pipeline, and four on the western coast.

2.27 The four plants along the coast have already been constructed. They consist of two pairs of ammonia and urea plants, one at Thal, south of Bombay, and owned by RCFL [1/]; and one set at Hazira, owned by KRIBHCO.[2/] All of these facilities are presently operational. The six plants along the HBJ pipeline are scheduled to be constructed over the next three years (Table 2.7). They will each consume about 1.65 MMCMD of gas as feedstock and for power generation. Construction is being undertaken by a combination of the Ministry of Fertilizers and private sector interests, which will own and operate several of the plants. The completion schedule for the six inland plants is as follows:

Table 2.7

HBJ Fertilizer Plants

Location	Sponsor	Sector	Scheduled Completion
Bijaipur, Madhya Pradesh	National Fertilizers Ltd. a/	Public	Commissioned August 1987
Jagdishpur, Uttar Pradesh	PICCUP	Joint	July 1988
Aonla, Uttar Pradesh	IFFCO a/	Cooperative	March 1988
Sawaimadhopur, Rajasthan	Zuari Agro	Private	1991/92
Babrala, Uttar Pradesh	Tata	Private	1991/92
Shajahanpur, Uttar Pradesh	Shriram	Private	1991/92

a/ Being implemented with Bank assistance.

2.28 The plants at Bijaipur, Jagdishpur, and Aonla are under construction, and are expected to be completed on schedule in 1988. However, construction has not yet started on the three private sector plants, and it is anticipated that these will be significantly delayed from their original start-up dates in 1989.

1/ Rashtriya Chemical Fertilizer Ltd.
2/ Krishak Bharati Cooperative Company.

2.29 As additional gas has become available, GOI has expanded the gas market beyond fertilizer, initially by approving the construction of three gas-based combined-cycle power plants along the HBJ pipeline. These will consume up to 6.0 MMCMD of gas. These plants (financing for which has also been supported by the Bank)[1] will augment generating capacity in the power-short western region, in areas where there are severe transport constraints on the delivery of domestic coal. In addition, GOI and GAIL are now starting to plan for additional offtake of gas by industrial users. The Bank has played a substantial role in encouraging the government to expand the gas market. With Bank assistance, GAIL has undertaken preliminary surveys for existing plants which could be converted to natural gas, and the HBJ pipeline is now being extended to Delhi, to capture the potential market there. Existing petrochemical, power, fertilizer, and other industrial plants have been identified which could take up the slack in the market left by the delay in completing the construction of the three fertilizer plants.

2.30 Given the critical importance of developing the gas market so that there are enough users ready to justify the major investment in field and pipeline infrastructure, the <u>GOI has confirmed the schedule for commissioning of the fertilizer plants, and agreed to keep the Bank informed on a regular basis (annually) of the plans for utilizing gas produced under the project, and on progress of implementation of the fertilizer plants and conversion of other users (see para. 2.54). Furthermore, GOI has agreed to take appropriate measures to ensure the full utilization of gas in a timely manner</u>.

2.31 Based on the potential production of gas in the western region of India and identified consumers, the likely supply/demand balance for HBJ gas for selected years is summarized below in Table 2.7 (see also Annex 2.7).

1/ IBRD Loan 2674-IN for US$485 million, approved March 10, 1986.

Table 2.8

Western Region Gas Supply and Demand for Selected Years
(Millions of Cubic Meters per Day)

	1986/87	1988/89	1990/91	1994/95
Gas Availability				
Bombay High Fxcess a/	4.4	0.6	0	0
South Bassein a/	-	9.1	17.8	23.0
Total	4.4	9.7	17.8	23.0
less: Hazira Demand b/	(3.2)	(4.3)	(4.7)	(4.7)
Rich Gas to HBJ	1.2	5.4	13.1	18.3
less: Compressor & LPG Plant Use	(0.1)	(0.5)	(1.2)	(1.6)
Lean Gas Available Ex-HBJ	1.1	4.9	11.9	16.7
Gas Utilization				
Three Fertilizer Plants c/	-	(3.3)	(4.5)	(5.0)
Combined-Cycle Plants (2) d/	-	(1.1)	(3.7)	(3.7)
Total Committed Users	-	(4.4)	(8.2)	(8.7)
Conversion of Existing Plants e/	-	(0.5)	(2.8)	(2.8)
Balance Lean Gas Available	1.1	0	0.9	5.2
Uses of Gas Balance				
Interruptible Power Stations f/	2.0	4.3	4.3	4.3
Additional Potential Users	3.0	4.2	6.9	7.4

a/ After condensate fractionation, sweetening, and dew point depression, production could be increased if demand warranted.
b/ Rich gas, includes KRIBHCO, Heavy Water, LPG extraction.
c/ First three plants: Aonla, Bijaipur, and Jagdishpur.
d/ Gas supply committed to Anta and Auraiya plants.
e/ Includes GSFC and IEL (Fertilizers) and IPCL (Petrochemicals) plants, possibly to be replaced by offtake to second three (private sector) fertilizer plants from 1991/92 if constructed and gas in short supply.
f/ Kawas, DESU (Delhi), and GEB (Dhuvaran).
Source: Bank staff estimates.

2.32 From Table 2.7 it can be seen that sufficient potential demand exists to fully utilize the net volumes of gas expected to be available in the western region. At the same time, gas may be available in surplus if potential users are not developed and connected, especially in the event that the three private sector fertilizer plants are delayed. It is this concern which has led GOI and GAIL, with the Bank's encouragement, to initiate steps to expand the gas market beyond the fertilizer sector, and to undertake recent efforts to identify specific consumers for rapid conversion to gas.

F. Institutional Arrangements

2.33 The Ministry of Petroleum has overall responsibility for matters of gas development, utilization and pricing policies. The Planning Commission is responsible for screening investment plans, and the Finance Ministry, in consultation with other concerned Ministries, is responsible for matters of financing and taxation. To date the task of gas policy and planning has been undertaken by a number of ad-hoc committes, the most recent being the Gas Task Force (GTF). The Gas Planning group in the recently established Gas Authority of India Limited (GAIL) is now taking responsibility for forecasting gas demand, surveying markets, assessing the economics of gas use, and planning regional infrastructure development. This group also acts as Secretariat to a new technical Gas Coordination Committee involving ONGC, OIL, and GAIL, which brings together producers and market information to coordinate gas development on a regional basis. At the policy level, GOI is considering establishing a similar group under the auspices of the Planning Commission to coordinate utilization planning and market development with gas availability.

2.34 The Oil and Natural Gas Commission currently produces, transports, and sells most of the natural gas in India, with the exception of the Assam region where gas production is split between ONGC and Oil India Limited (OIL). GAIL is to assume the gas transmission and marketing role currently performed by both ONGC and OIL, although GAIL will initially concentrate on HBJ pipeline operations. In addition to these agencies, gas consumers and the producers of alternate fuels are also involved in the debate over sub-sector development policies and plans. These include the government departments and companies concerned with coal, power, fertilizer, and petrochemicals.

G. Gas Sector Development Planning

2.35 The GOI's approach to the development of initial markets for natural gas parallels the strategies adopted by the developed countries in the 1950's and 1960's when gas first emerged as a major energy source in Europe and North America. Major users are identified to ensure the proper location of transmission facilities. Such major users typically account for 50-60 per cent of pipeline capacity. Then, additional large-volume users (generally power utilities) are identified and developed to ensure that the line is utilized as close to capacity as possible. Once a more diversified gas market has developed, with significant cumulative demand from high-value users, gas-based power generation is usually scaled back for use during peak demand periods only. Base-load power generation is then usually based on other fuels with a lower economic cost.

2.36 Planning for gas utilization in India has proceeded during a period of rapid change in the underlying assumptions about gas availability. Upward revisions of gas production forecasts have overtaken the policy guidelines of several years ago. There is a need to carefully integrate the planning of gas field development and pipeline investments with development of the gas market. Substantial progress has been made towards this objective with the establishment of a gas planning capability within GAIL. However, additional steps are required to ensure that optimal gas sector development takes place. In particular there is a need to re-examine (i) the most economic uses for gas in India; (ii) the best manner and timing of developing the western gas fields; and (iii) the specific marketing plans for South Bassein and

Bombay High gas over the next few years. Substantial additional amounts of gas may become available in the western region over the next 5-10 years beyond those already committed to fertilizer and combined-cycle power plants. In view of the lead times required to develop gas customers and plan and implement distribution infrastructure, there is a need to plan now to utilize these potential resources.

2.37 To date gas development has been planned on the basis of large "once-only" investments. This approach was appropriate for the initial large discrete investments in development, such as Bombay High, South Bassein, and the HBJ pipeline. However now that the development of a number of smaller fields and pipeline linkages is involved, ONGC and GAIL are faced with a larger number of project investment choices, among which the interlinkages and tradeoffs are more complex. The aggregate investment involved is potentially very large (about US$2 billion) and it is important that the costs and benefits of the various options be carefully quantified.

2.38 A short-term market planning exercise of the Bombay and HBJ market areas is also needed to ensure fullest use of available production. About 2-3 MMCMD of Bombay High gas is presently being diverted to Hazira and another 2-4 MMCMD is flared because of transmission constraints to Bombay. In addition, given the delays in construction of the last three fertilizer plants, there will be underutilization of western gas in the early 1990's if users are not identified now. Although GAIL has undertaken some preliminary analysis, there is still a need for much detailed work on the conversion and preparation of users. An annual market plan to address these problems is also incorporated in the proposed project (para. 2.51).

H. Gas Pricing

2.39 Gas prices should promote economic efficiency by encouraging the optimal level of gas use and investments in potential gas-using industries, and by giving the correct incentives to producers to find and develop gas resources. In regions with constrained supplies of gas for the foreseeable future, marginal replacement fuel equivalence is the correct pricing basis to achieve these objectives. In the case of western gas, the Government's present pricing principles are in accordance with these principles.

2.40 All gas in India has historically been produced along with crude oil. Since most such gas, which would otherwise be flared, is sold to consumers on a cost-plus basis, there has been no pressing need for a comprehensive gas pricing policy. With the advent of larger volumes of offshore associated gas from Bombay High, ONGC and the GOI have been moving more towards replacement pricing over the last few years. As a result, a number of different pricing levels have evolved based on contractual arrangements negotiated at different times in different regions of the country. For example, onshore associated gas from Gujarat has been priced as low as Rs 355/MCM (US$0.79/MCF). This reflects the very low contractual prices negotiated as a result of lack of alternative markets for gas at the time of field development. Offshore associated gas has been priced between Rs 555 and Rs 2,780/MCM (US$1.24-6.20/MCF), depending on end-use. The lower price is for interruptible supplies to power plants, and the higher price for guaranteed supplies to fertilizer and industry. On average ONGC has received Rs 1,428/MCM (US$3.19/MCF), just below the average fuel oil equivalent level, over the last few years.

2.41 With large quantities of non-associated gas to be produced for the first time (primarily from South Bassein), it has been recognized that there is a need for a more comprehensive pricing policy in the western region. The GOI has examined various policy options over the last two years, and the Bank has maintained working discussions with the Government as the principles of this policy have been formulated. The following set of principles with respect to HBJ pipeline gas was developed: (a) the base price of natural gas would be linked to the price of the fuel or feedstock replaced; (b) the price structure should be simple to administer and to understand, and with prices to users to be uniform along the pipeline; and (c) the pipeline operator, GAIL, should earn a fair return on costs. Any surplus would accrue at the producer end, where the resource rent would be taxed by the Government. These policy principles have now been formalized into the following set of gas prices, announced in mid 1987: (i) Rs 1400/MCM for gas at landfall points and for onshore gas; (ii) Rs 2250/MCM for gas supplied along the HBJ pipeline; and (iii) Rs 500 to Rs 1000/MCM in Assam, where associated gas exists in surplus. Allowances are also made for discounts in the cases of interruptible users, and to encourage market build-up during the initial years of new field development. These prices are above the current import parity price of fuel oil, but somewhat lower than the administered domestic fuel oil price, as shown in Table 2.9.

Table 2.9

Fuel Oil and Natural Gas Prices

			Corresponding Gas Price	
			Rs/MCM	$/mcf
C.I.F. Fuel Oil Price (Sept. 1987)		$105/mT	1310	2.90
Natural Gas Price -	Landed		1400	3.10
	Ex-Pipeline		2250	4.95
Domestic Fuel Oil Price		Rs 3160/mT	2780	6.15

Source: Ministsry of Petroleum and Natural Gas

2.42 The approach adopted by the GOI in formulating gas pricing policy is an acceptable one. The GOI has confirmed the gas pricing principles outlined above.

2.43 Gas pricing policy in India is important to the fertilizer sector, which is already a major consumer of gas, and for which the largest single share of gas from the western region is planned. The present structure of fertilizer prices in India, based on a retention price formula to producers and centrally fixed prices to users, is highly distorted. The Bank is encouraging a program of price liberalization in this sector. In the Cooperative Fertilizer Industry Project (US$302 million, approved June 28, 1986), the GOI agreed to implement a program of "Initiatives in the Fertlizer Sector." These initiatives include the modification and rationalization of the fertilizer pricing system based on internal GOI reviews which are currently ongoing in consultation with the Bank. Further reform of fertilizer pricing is being addressed by the Bank as part of the policy discussion associated with a forthcoming fertilizer distribution project.

I. The Role of the Bank in the Gas Sector

2.44 GOI has increasingly recognized the importance of gas as an energy source. It is expanding the role of gas by accelerating the development of known gas fields and expanding the use of gas not only for production of fertilizer, petrochemicals and LPG, but also for use in power generation and as an industrial fuel. The Bank has played an instrumental role in supporting these initiatives by (i) encouraging rapid development of gas fields (especially South Bassein) to replace imported petroleum products; (ii) encouraging and assisting in the establishment of GAIL to undertake gas planning, transmission, and marketing; (c) encouraging first the use of gas in power generation, and then encouraging for its expansion into industrial use; (d) encouraging the establishment of a uniform gas pricing policy on the basis of economic principles; and (e) advising on contractual arrangements for gas. The Bank has recently provided experts to help identify plants for immediate conversion to gas, and to review the terms of gas sales contracts.

2.45 The Bank has materially assisted these efforts with a series of projects including initial development of the South Bassein gas field, review of the HBJ pipeline, and more recently, financing two of the fertilizer plants to be constructed along the HBJ pipeline route and a combined-cycle power project also utilizing western gas resources. Experience with the South Bassein and HBJ projects has shown, however, a critical need to ensure that markets and supply sources are developed in parallel, in order to maximize the overall returns from development of the gas sector. In the past, growth of the gas industry has been hampered by inadequate coordination between the development of gas resources, investments in infrastructure facilities, and development of the gas market. To ensure the efficient use of gas, these issues need to be resolved as supplies from further development efforts come onstream.

2.46 The proposed Western Gas Development project represents a follow-on to the first South Bassein project in terms of expanding gas production from the South Bassein free gas field. In addition, it would finance substantial appraisal and development work of potentially significant gas resources from other fields in the western area. The project would allow the Bank to continue its ongoing dialogue with the GOI on natural gas sector issues.

2.47 Specifically, the Bank's dialogue under this project will focus on:

(a) Encouraging ONGC to plan investments in further field and infrastructure development in the most cost-effective manner;

(b) Longer-term analysis of gas markets and utilization to ensure that India derives the maximum potential benefit from the use of gas resources;

(c) Short-term planning for utilization of quantities of gas expected to come onstream in the near future;

(d) Coordinating production planning and utilization efforts; and

(c) Supporting the establishment of adequate pricing and contractual arrangements to encourage proper use of gas.

The project will incorporate specific measures to address each of these issues, as described below.

2.48 Production Planning. There exist a number of alternative possibilities for developing the various western gas fields and linking them to market. A comprehensive study needs to be undertaken to determine the most cost-effective means of developing western offshore and onshore gas resources in an integrated manner. The proposed planning exercise would involve:

(a) Reviewing the reserves and potential production profiles for each of the western region gas sources;

(b) Identifying the various development options, including the order in which fields are developed, alternative pipeline sizes and configurations; and field production technologies;

(c) Identifying the development and operating costs associated with each option; and

(d) Selecting, on the basis of the demand pattern identified under the gas utilization study, the least-cost program for developing western gas resources over the next twenty years.

Much of the study could be undertaken by ONGC; some specialized technical inputs for the more complex or marginal fields from domestic and/or foreign specialized firms may be appropriate. The results of this work could then serve as a basis for the long-term investment program in the western region of the country.

2.49 Gas Utilization. Given the longer-run availability of larger quantities of western gas than originally planned, and the changes in world prices for petroleum products and fertilizers, the longer run strategy for gas utilization in India needs to be reexamined with particular emphasis on the uses for additional gas available in the western region. Such a planning exercise would involve:

(a) Projecting high, low and medium gas supply scenarios;

(b) Identifying in more detail potential gas users in the Bombay, Gujarat areas, and along the HBJ pipeline, the volumes of gas they could consume, the approximate prices at which conversions to gas would be made, and the costs of conversion, including the infrastructure costs of serving each customer or market area;

(c) Estimating the economic value of gas in each use, taking account of the fuel replaced and differential capital and operating costs resulting from gas use;

(d) Ranking potential gas uses with respect to economic value;

(e) Determining the allocation of gas to users which results in the greatest net economic value to the country under each gas availability scenario; and

(f) Identifying the actions and investments required to bring new users onstream.

2.50 The GOI confirmed that it is carrying out studies on the areas listed above, and that the results of such studies would be reviewed with the Bank by June 30, 1989.

2.51 Market Planning. There is a need to continually update detailed market plans for the marketing of western gas for the immediate future. Such a plan would concentrate on identifying specific additional users and preparing plans for their connection and conversion. The GOI has agreed to submit to the Bank an annual report on gas marketing in the western region which will address steps necessary to ensure the connection of sufficient users to achieve and sustain a high capacity utilization rate as quickly as possible for western region gas, covering both associated gas from Bombay High, gas from the Gandhar field, and gas to be supplied to the HBJ pipeline. Such a plan would address the expected offtake by customer by year for the coming three years, the steps and costs required to convert and connect each customer, and the progress of market development during the current year. This report would be prepared by GAIL and ONGC and submitted to the Bank no later than March 31 of each year during the project implementation period.

2.52 Coordination. It is likely and appropriate that the bulk of planning work with respect to gas production would be undertaken by ONGC, and with respect to gas utilization by GAIL. It is important that the preparation, conclusions and implementation of these studies be closely coordinated. This coordination may be achieved through the Gas Coordinating Committee or by other appropriate institutional means. The GOI confirmed that arrangements for such coordination had been made.

2.53 Contractual Arrangements. In order to assure proper pricing policy between ONGC as producer of gas and GAIL as distributor, the GOI agreed to provide to the Bank the contractual basis upon which gas will be provided by ONGC to GAIL. The Bank will wish to review these terms to be assured that pricing terms provide ONGC adequate remuneration to permit it to meet its financial covenants to the Bank and to assure the financial autonomy and viability of GAIL.

2.55 The Bank's dialogue with the GOI in the gas sector, now extending over almost ten years, may serve as the basis for future gas development in other regions of India, notably in the eastern region, and for development of resources identified by the Krishna-Godavari Exploration project. The Bank would also broaden its dialogue with GOI on gas pricing and address issues across the energy and industrial sectors, including the fertilizer industry.

III. THE PROJECT

A. Background and Project Objectives

3.01 Large scale production of natural gas in India first started with the development of the Bombay High project in the mid 1970's, which is producing substantial amounts of associated gas for the Bombay market. The free gas field at South Bassein, just south of Bombay High off the west coast, was discovered in 1976, and the first phase of field development is just being completed with Bank assistance. India is now embarking on a second phase of development to increase gas production and treatment capacity up to its design level of 20 MMCMD. At the same time, a number of smaller satellite oil and gas fields have been identified offshore, including the Heera, Tapti and Hazira structures, and onshore exploration has resulted in the discovery of an additional gas and condensate fields at Gandhar in Gujarat on the west coast.

3.02 The principal objectives of the Western Gas Development project are:

(a) to support rapid development of proven gas reserves, and at the same time to help identify further reserves for the future;

(b) to encourage simultaneous expansion of the gas market to effectively utilize the gas produced; and

(c) to support longer-run planning for least-cost development of gas supply, and utilization planning to ensure gas is used in sectors which yield the greatest economic benefit.

In particular, the project will increase production from South Bassein from 10 MMCMD to 20 MMCMD, an increase equivalent to 65,000 Bbl/d of petroleum. Construction of a pipeline to shore from the Heera field will also permit use of over 1 MMCMD of associated gas from this field which is presently flared (equivalent to 6,500 Bbl/d of petroleum). Funds are provided for appraisal and initial development of the Gandhar field in Gujarat state, to produce, on average, 2 MMCMD of gas and 0.4 mtpy of condensate. Seismic studies will provide information on the reserves for future gas production from the Hazira and North Tapti fields.1/ Studies are also included to plan integrated development of the western gas fields, and to assess the economics of gas utilization in India.

B. Project Description

3.03 The specific project components are:

(a) Phase II development, both offshore and onshore, of the South Bassein gas field;

(b) Laying of the Heera-Uran gas pipeline;

(c) Phase I development of the Gandhar gas/condensate field;

1/ See Annex 3.7 for more detailed discussion of these fields.

(d) Seismic surveys of the Hazira and North Tapti fields; and

(e) Studies for longer run optimization of gas production and utilization.

These components are discussed in further detail below.

3.04 South Bassein Phase II. The South Bassein field, located approximately 65 km west of Bombay in the Arabian Sea, in water depth of 57 meters, is presently estimated to have reserves of approximately 8 trillion cubic feet (TCF), of which 6 TCF (equivalent to over 2 billion barrels of oil) are recoverable (Annexes 3.1 and 3.2). The field is being developed in two phases. Phase I, presently being implemented, will provide production of 10 MMCMD.

3.05 Phase II development would double gas production to 20 MMCMD (Annex 3.3). This requires installation of: (a) a second gas processing platform with gas and condensate treatment facilities for the additional production capacity, together with power generation facilities, workshops and a control center; (b) a nine-slot wellhead platform; (c) a living quarters platform for 124 men; (d) a flare structure; (e) tie lines to Phase I facilities; (f) the drilling of 27 development wells; and (g) the construction of onshore gas processing facilities and an onshore terminal at Hazira.

3.06 Gas and condensate produced from the South Bassein field is dehydrated and transmitted to shore through a 36" gas line, already constructed under Phase I, the capacity of which is sufficient to handle the full 20 MMCMD production foreseen from Phases I and II. The landfall point of the line is Hazira. At Hazira the gas is treated by passing it through "sweetening" (desulfurization) and other facilities to prepare the gas for transmission through the HBJ line. Condensate is separated out and split into LPG and other products. A conceptual diagram of the Hazira plant is attached as Annex 3.4. A map of the Western Gas Development Area (IBRD Map No. 19877) can be found at the end of this report. Onshore Hazira facilities also include a storage facility, a single-buoy mooring system with a 16" loading line to allow shipment of natural gas liquids by tanker, and a waste water treatment plant for treatment of process water.

3.07 Heera-Uran Gas Pipeline. The Heera oilfield, located 80 km southeast of Bombay High and about 55 km south of South Bassein, was discovered in 1977 and covers an area of about 10 by 18 kms. Heera is being developed in three phases. Phase I, recently completed, included installation of initial production facilities, resulting in crude production of 45,000 Bbl and 1.2 MMCMD of associated gas. The gas is presently being flared since there is no pipeline linking the production complex to shore.

3.08 Phase II, currently being undertaken by ONGC, will include water injection facilities to maintain oil production, and construction of crude and gas pipelines to allow direct transfer of crude and gas to shore. The Western Gas Development project incorporates laying of a 24", 100 km submarine gas pipeline to take the associated gas to the Uran terminal which serves the Bombay market. This will eliminate the flaring of about 1.2 MMCMD (Annex 3.5) of natural gas (equivalent to about 390,000 tpy of fuel oil) at an estimated annual saving of $46 million.

3.09 Gandhar. The recently discovered Gandhar field, located on the shores of the Gulf of Cambay, Gujarat state, will be appraised and developed. The drilling program for Gandhar consists of 40 appraisal and 75 development wells (Annex 3.6). The Gandhar appraisal plan is quite well advanced; twenty wells are already committed and ten well locations already identified. Technical notes on the drilling program for these fields are included in Annex 3.7. In addition, the project includes surface facilities for treatment of the gas and condensate, and transmission to market.

3.10 North Tapti and Hazira. Hazira is an offshore gas field, discovered in 1969 in the shallow waters of the Gulf of Bombay, west of the town of Surat. Only two wells have been drilled in Hazira. The discovery well produced gas at a fairly good rate. A second well, drilled on the onshore part, was water-bearing. North Tapti is also an offshore gas field, discovered in 1983 in the Gulf of Cambay, southwest of Hazira field. Since the discovery well, which produced gas at a good rate, no further drilling has been carried out.

3.11 As part of its long-term program of developing the Bombay offshore satellite fields, ONGC will evaluate the hydrocarbon potential of the Hazira and North Tapti fields. The evaluation program includes seismic surveys, seismic data interpretation and some appraisal drilling. Both fields require the application of modern geophysical methods such as high resolution and/or 3-D seismic surveys which would help resolve the size and prospectiveness of the structure and determine the appraisal drilling program. Both fields require about 500 line-kms of seismic data acquisition. This seismic program is expected to be very effective since, to date, the highly prospective areas in the Gulf of Cambay have not been surveyed with specialized geophysical techniques.

3.12 Studies. Funds have been included for long-term development plans for both optimum production and utilization of western gas resources. A shorter-term marketing plan would also be undertaken on an annual basis, to identify users for gas. This plan would identify prospective consumers of gas within the HBJ corridor area and the other areas contiguous to that where gas from Bombay High and Heera is landed. The production and utilization studies, to be undertaken separately, will each require an estimated 20 man-months of work plus approximately 5 man-months to coordinate results, at an estimated US$10,000 per man-month. Preliminary descriptions of studies are given in paras. 2.49-2.52.

C. Project Implementation

3.13 The organizational arrangement adopted by ONGC is to create project teams under a manager for each project area, which report to one of ONGC's Senior Group General Managers in Bombay, depending on the dominant activity in that area. These teams are backed up during all phases of project design and implementation by the lead consultant, Engineering India Limited (EIL). EIL is the largest and most experienced project engineering firm in the oil and gas production and processing field in India. EIL, in turn, has collaboration and back-up arrangements with experienced foreign engineering firms.

3.14 Maximum use of turnkey contracting allows ONGC to supervise a large number of projects with limited staff resources. A typical project team is shown in Annex 4.1. In addition to technical staff, project teams are also assigned both an experienced financial supervisor and a materials procurement and planning coordinator.

3.15 Implementation of the South Bassein and Heera components of the project will be the responsibility of ONGC's Regional Office in Bombay. This office, which was initially set up to implement the Bombay Offshore Project, and then continued to implement Phase I of the South Bassein development, has demonstrated its ability to manage large-scale offshore projects and oil and gas operations effectively. Its management team has received exposure to all phases of offshore development. As a result of this experience, it has built up a well-structured organization with sufficient trained staff to handle the work program represented by the proposed project.

3.16 Implementation of the Gandhar component is the responsibility of ONGC's field office in Baroda, which is in charge of implementation of all onshore activities in the western region. Senior management of these projects will, however, be based in New Delhi; careful coordination between ONGC's Bombay and Baroda offices needs to be assured. <u>ONGC has confirmed the establishment of Project Implementation Units in Bombay (for the Heera and South Bassein components) and in Baroda (for the Gandhar component); in addition ONGC has agreed to identify a coordinator for the purposes of the Bank project to provide liaison and coordination with both the Bombay and Baroda units</u>.

3.17 The Baroda office of ONGC has a relative shortage of experienced middle management in technical areas of drilling, and lacks adequate equipment for onshore drilling owing to the higher priority given by ONGC to offshore development activities. Most of the development drilling for Gandhar will therefore be undertaken bv drilling contractors. The project includes measures to strengthen ONGC's onshore drilling capabilities by financing most of the oil services contracts required from specialized service companies, and technical assistance from consulting firms specialized in oil and gas field operations.

3.18 In order to allow the Bank to monitor project activities (Annexes 4.2 and 4.3), <u>assurances will be obtained from ONGC at negotiations that regular progress reports will be provided on a basis to be agreed upon, the scope of which will include procurement, construction, gas production and sales, and performance of contractors as well as consultants</u>. Particular emphasis will be placed on reporting of drilling activities in Gandhar. <u>In addition, ONGC will prepare a Project Completion Report within six months of project completion</u>.

D. <u>Project Cost</u>

3.19 Total cost of the project is estimated at approximately US$1,354 million including physical and price contingencies, and including taxes and custom duties, estimated at approximately US$192 million, on imported materials and equipment. The proposed Bank loan of US$295 million represents 25.4% of total project cost, and 38.3% of estimated total foreign exchange expenditures.

3.20 Estimated project costs are summarized in Table 3.1. An estimated cost breakdown of project expenditures by year appears in Annex 4.4. Costs are based on actual recent contract prices in the area, which are in line with worldwide price trends.

Table 3.1

Project Cost Summary
(for fiscal years ending March 31)

	Local	Foreign	Total	Local	Foreign	Total
	------Rupees Million-----			-------US$ Million------		
South Bassein Field -Phase II						
Offshore Facilities:						
Engineering, Management	20.8	135.2	156.0	1.6	10.4	12.0
BPB Platforms and Pipeline	208.0	1339.0	1547.0	16.0	103.0	119.0
Drilling (27 wells)	791.7	845.0	1636.7	60.9	65.0	125.9
Onshore Facilites (Hazira):						
Gas Processing Facilities	522.6	377.0	899.6	40.2	29.0	69.2
Infrastructure	158.6	55.9	214.5	12.2	4.3	16.5
Engineering	104.0	0.0	104.0	8.0	0.0	8.0
NGL Terminal	119.6	286.6	404.6	9.2	22.0	31.2
Other	65.0	0.0	65.0	5.0	0.0	5.0
Heera-Uran Pipeline						
Engineering	71.5	72.8	144.3	5.5	5.6	11.1
Pipeline	0.0	1287.0	1287.0	0.0	99.0	99.0
Gandhar Field						
Development and Appraisal Wells (about 90)	2646.8	3211.0	5857.8	203.6	247.0	450.6
Surface Facilities	608.4	65.0	673.4	46.8	5.0	51.8
Engineering	91.0	39.0	130.0	7.0	3.0	10.0
Hazira and North Tapti Fields						
Appraisal Drilling (about 15 wells)	386.1	611.0	997.1	29.7	47.0	76.7
Seismic - Regular	6.5	32.5	39.0	0.5	2.5	3.0
Seismic - 3-D	6.5	58.5	65.0	0.5	4.5	5.0
Consulting Studies	3.9	13.0	16.9	0.3	1.0	1.3
Base Cost (1987 Prices)	5811.0	8427.9	14238.9	447.0	648.3	1095.3
Physical Contingencies	581.1	843.7	1424.8	44.7	64.9	109.5
Price Contingencies	1194.7	742.3	1937.0	91.9	57.1	149.1
Total Project Costs	7586.8	10013.9	17600.7	583.6	770.3	1353.9

3.21 The cost estimates are based on mid-1987 price levels. Physical contingencies are 10% of base costs. Price contingencies are based on the following expected price increases: 7% in 1988, 4% in 1989, and 3% for the period 1990-93 for imported goods and services; 8% in 1987 and 1988, 7% in 1989, and 6% per annum for the period 1990-93 for domestic goods and services. Taxes and customs duties on imported goods and services have been estimated based on estimated average rates. Interest during construction has not been included in project costs; ONGC is expected to charge such interest expense against income as incurred.

E. Financing Plan and Items for Bank Financing

3.22 In the past it has been possible for ONGC to meet most of the local cost component of its investment needs from internally generated funds and this situation is expected to continue. ONGC does not, however, earn foreign exchange resources directly. These are raised through suppliers' credits, allocations of foreign exchange resources from the central government, and overseas loans, including loans from the World Bank. More recently, the strategy of the GOI has been to diversify the sources of financing to ONGC. As ONGC has become a prime borrower of its own in recent years, GOI has authorized ONGC to borrow directly from foreign sources.

3.23 On major procurement items ONGC requests financing proposals as bid documents are tendered. In the case of the proposed Western Gas Development Project, the Government has worked closely with Bank staff to identify those project components most suitable for Bank financing and to separate out components for which other financing is considered more appropriate. It was in this manner, for example, that a bid and financing package offered by the Government of Italy and Snam Progetti for the BPB platform complex (part of the South Bassein offshore facilities and originally considered for Bank financing) was secured.

3.24 Important components of the proposed project, including notably the offshore platforms, are of interest to export credit agencies for financing. Many other components, however, such as pipe-laying and drilling contracts, are not normally financed from such sources. In the case of pipe-laying, pipelaying barges are usually not registered under the flag of the contractor's nationality, preventing eligibility for export credit financing. These factors have been taken into account in selecting the specific items proposed for Bank financing. In addition, the Bank has sought out items for which the Bank's supervisory role may be of particular value in terms of technical assistance (such as drilling contracts, engineering, and management contracts), and where disbursement may be particularly rapid (such as pipelaying and gas processing facilities). A Bank loan in the amount of US$295 million to the Government of India is proposed, for 20 years including 5 years of grace, to be onlent to ONGC at a rate of at least 15% per annum. The Government would bear both the foreign exchange and interest rate risks.

3.25 Based on estimates of likely financing sources, including borrowings by ONGC in the international capital market, the following financing plan has been prepared:

Table 3.2

Project Financing Plan

	Local	Foreign	Total Amount	Total Percent
	--------US$ Million--------			
Export Credits (BPB platform)		120.0	120.0	8.9
Other Export/Suppliers' Credit		50.1	50.1	3.7
Proposed IBRD Loan		295.0	295.0	21.8
Other ONGC Borrowings		305.2	305.2	22.5
ONGC Internally Generated Funds	583.6	-	583.6	43.1
Total	583.6	770.3	1,353.9	100.0

3.26 Because the proposed project comprises part of ONGC's ongoing investment program, commercial financing for the project will be arranged by ONGC as part of its ongoing company-wide financing arrangements. Export credit arrangements for financing of the South Bassein Phase II "BPB" platform awarded to Snam Progetti have been arranged, but other export and suppliers' credits are estimates only. The Bank has been assisting both export credit agencies and commercial banks interested in cofinancing the Western Gas Project. The estimates shown are based on Bank staff review of goods and equipment for which cofinancing is considered likely.

3.27 Items which would be financed by the Bank fall broadly into the following categories:

(a) Facilities at the Hazira onshore processing plant;

(b) The Heera-Uran gas pipeline;

(c) Drilling materials, equipment, and well services (for development drilling in the South Bassein field and appraisal drilling in the Hazira and Gandhar fields);

(d) Surface facilities, including gathering lines, at Gandhar;

(e) Seismic surveys (at Hazira and North Tapti); and

(f) Engineering and other consultancy services.

3.28 For the onshore Hazira processing plant, items include two condensate fractionation units, two gas sweetening (desulphurization) plants, two dewpoint depression units, two sulphur recovery units, a digital distribution control center, and an NGL terminal.

3.29 Drilling materials and equipment include casing and tubing, drilling and coring units, mud chemicals, oil well cement and additives, drilling and production wellheads, casing accessories, stimulation chemicals and materials, and downhole drilling and completion equipment. Drilling services include drilling rig hire charges and specialized services such as drilling mud; cementing, drill stem, and production testing; electric logging; mud logging; directional drilling; well stimulation; and completion and offshore logistical support services (including diving).

3.30 Surface facilities at Gandhar include field stations, gathering and transmission lines. Engineering and consultancies will include project management and design assistance as well as the gas production and utilization studies described elsewhere in this report.

F. Procurement

3.31 Procurement arrangements are summarized in Table 3.3 below:

Table 3.3

Summary of Procurement Arrangements
(US$ Million)

Project Element	Procurement Method: ICB	LCB	Other a/	N.A. b/	Total
Process Facilities					
BPB Platform and South Bassein Tie Lines	144.5	-	-	-	144.5
	(-)	(-)	(-)	(-)	(-)
Hazira Facilities	85.3	30.0 c/	-	-	115.3
	(70.0)	(-)	(-)	(-)	(70.0)
Gandhar Surface Facilities	15.0	55.4 c/	-	-	70.4
	(6.0)	(-)	(-)	(-)	(6.0)
Pipeline					
Heera-Uran Gas Pipeline	106.4	17.0	-	7.6	131.0
	(60.0)	(-)	(-)	(-)	(60.0)
Drilling d/					
Materials and Equipment	257.6	51.6	9.7	89.9	408.8
	(55.5)	(-)	(5.0)	(-)	(60.5)
Services	183.1	119.5	27.2	94.6	424.4
	(70.0)	(-)	(14.0)	(-)	(84.0)
Seismic Surveys	8.5	-	1.0	-	9.5
	(8.5)	(-)	(1.0)	(-)	(9.5)
Engineering, Management and Studies	-	-	50.0	-	50.0
	(-)	(-)	(5.0)	(-)	(5.0)
Total	800.4	273.5	87.9	192.1	1,353.9
	(270.0)	(-)	(25.0)	(-)	(295.0)

Note: Figures in parentheses are the respective amounts financed by the Bank.
a/ Limited international bidding, direct contracting and force account.
b/ Taxes and duties.
c/ All local expenditure; includes local civil works.
d/ Includes South Bassein and Gandhar.

3.32 About US$800 million worth of goods and services for the project will be procured in accordance with international competitive bidding (ICB) procedures, of which US$270 million will be Bank-financed. About US$274 million will be procured under local competitive bidding (LCB) procedures. Other procedures (e.g. limited international bidding and direct contracting) will apply to approximately US$88 million, of which US$25 million would be Bank-financed. Because there are only a limited number of qualified contractors and suppliers, ONGC will be permitted to procure by LIB all well-related services and equipment required for special operations relating to wireline and well logging, mud logging, well cementing and stimulation, well testing, directional drilling, coring, fishing, drilling and blow-out control regardless of the value of each package. All qualified bidders will be invited to bid on these packages. In addition, any package valued at one million or below that ONGC considers to be time critical may be procured by LIB. Direct contracting will also be permitted for equipment and spare parts that are proprietary or to ensure standardization and compatibility with existing equipment and facilities. The aggregate of all LIB and direct contracting packages to be financed by the Bank under the project shall not exceed US$25 million. Consulting services will be obtained in accordance with the Bank's Guidelines for the Use of Consultants.

3.33 It is estimated that Bank financing will cover approximately thirty tender packages. Prior Bank review of all essential procurement documentation will be required for packages estimated to cost more than one million. Packages estimated at one million or less will be subject to the Bank's review after contract award.

3.34 For items to be financed by the Bank, the Bank's standard domestic preference provisions will, at ONGC's option, be accepted for the evaluation and comparison of bids submitted for the project. The total value of contracts procured under LIB and direct contracting is not expected to exceed about US$25 million. Consultancy services will be procured in accordance with Bank's Guidelines for the Use of Consultants. ONGC agreed to make every effort to provide to the Bank the documents requiring prior Bank review at least one month before the date they are scheduled to be released.

3.35 Although ONGC has carried out much of its drilling operations and technical well services using its own equipment and personnel, it has agreed with the Bank's recommendation to utilize the services of specialized firms for most of the proposed project. ONGC has, however, proposed using force account for about 40 appraisal wells in the Gandhar field. This has been agreed to for the following reasons: (a) ONGC can undertake the appraisal drilling operations, based on review of the drilling load on ONGC and the need for timely project implementation, provided auxiliary drilling services are made available through specialized firms; (b) ONGC would use the same established field management teams and crews to continue similar operations after completion of the project; (c) transfer of technology and skills in oil field activities such as drilling is better accomplished if ONGC works side by side with foreign contractors which will be mobilized for the development drilling phase; and (d) the alternative of contracting appraisal drilling would likely be substantially costlier. ONGC has been drilling and producing in the basin for over twenty years, during which it has drilled more than 1,400 wells. It has the experience and management capability that are needed to undertake a drilling program of the scope proposed.

3.36 Given the advanced stage of project preparation, ONGC has already started the procurement process for the gas processing facilities at Hazira. As a result, and depending on the pace with which final contracts can be concluded, up to US$25 million of retroactive financing by the Bank may be required. At ONGC's request, the Bank has reviewed all the packages for which advance contracting might apply and has found them in accordance with Bank Guidelines.

G. Disbursements

3.37 Phasing of the estimated disbursements of the proposed Bank loan is shown in detail in Annex 4.5 and summarized in Table 3.4 below:

Table 3.4

Projected Phasing of Expenditures

	Year 1 FY88	Year 2 FY89	Year 3 FY90	Year 4 FY91	Year 5 FY92	Year 6 FY93
Annual	$10	$ 90	$ 95	$ 60	$ 35	$ 5
Cumulative	$10	$100	$195	$255	$290	$295

Disbursement of the proposed Bank loan has been estimated on the basis of the loan becoming effective by the end of FY88. Projected disbursement extend over five years. Bank disbursement experience with all energy projects is that 99% is disbursed in six years; for the smaller number of oil projects, 100% has been disbursed within five and one-half years. In view of the advanced level of preparation of this project, inclusion of advance procurement for contracts already signed, the "second phase" character of two of the major project components, and the provision for standardization of procurement tender documents for Bank-financed components, the projected disbursement period is considered realistic. Based on the estimated schedule of expenditures, allowance for disbursement lag and contingencies, a closing date for the loan of June 30, 1994 has been agreed.

3.44 Disbursement of the proposed Bank loan of US$295 million would be made as summarized in Table 3.5 below:

Table 3.5

Allocation of Proposed Bank Loan

Category	Amount (US$ Million)	% of Expenditures Financed
Process Facilities a/	$76.0	100% of foreign expenditure and 90% of local expenditures
Pipeline System including installation	$60.0	100% of foreign expenditures and 90% of local expenditure
Drilling Materials and Equipment b/	$61.0	100% of foreign expenditures and 100% of local expenditures (ex-factory)
Drilling Services	$70.0	90% of expenditures. c/
Seismic Surveys	$8.0	90% of expenditures.
Engineering and Studies	$5.0	100% of expenditures.
Unallocated	15.0	
	$295.0	

a/ Includes about $6 million for Gandhar surface facilities.

b/ Of which it is estimated that South Bassein would account for about $10 million of the equipment and about $20 million of the services.

c/ Contracts are net of customs duties, and the proposed proportion for percent of expenditures financed includes allowance for direct and indirect foreign exchange costs.

H. Ecological Aspects and Safety

3.38 Process equipment in fields which will be subjected to water injection, such as Heera, are designed for "sour" (high sulfur content) service to allow for the possibility that anaerobic bacteria, present in seawater, may result in higher sulfur content when interacting with oil. Rules regarding return of effluent water into the sea and gases into the atmosphere are governed by Indian MINAS regulations (Minimum National Standards) which are as strict or stricter than those of the North Sea countries.

3.39 Water injected into oil fields, like Bombay High, is treated with biocides. So far no biocides have been detected in formation water produced with the oil, but this may vary from field to field. ONGC is alert to the possibility that eventually biocides may appear in the formation water of Heera and monitors its quality regularly, so that appropriate measures can be taken if necessary.

3.40 The gas treatment facilities at the Hazira gas terminal will be provided with a waste water treatment plant which will treat process water from the sweetening (desulfurization) facilities. Discharge of sulphuric gases into the atmosphere will be minimal, since hydrogen sulfide will be converted to sulphur in a sulphur recovery plant.

3.41 The design of wells to be drilled conforms to the recommended practices of the American Petroleum Institute (API) as well as to accepted oil field norms and standards. ONGC has acquired throughout the past several years a satisfactory record in this area. Onshore well locations are selected to avoid close proximity to habitation and water wells, if and when they are present. Subsurface formation water and surface source water will be protected following oil industry drilling standards.

3.42 Well effluents (oil, gas, and produced formation water), chemicals used in production operations (methyl, alcohol, surfactants and ammonia) and drilling fluids, constitute a possible source of pollution while drilling. These are treated offshore in closed systems to minimize losses by leakage, and onshore by containment in specially constructed pits. All residual waste chemicals and well effluents will be burned or injected into water disposal wells to prevent pollution of fresh water sources. ONGC will ascertain that contractors mobilized in connection with the proposed project will contain and clean up any drilling fluid or chemicals and reclaim any portion of land which is not required for production operation such as access roads and locations of abandoned wells.

3.43 ONGC follows the recommendations of Lloyds of London as primary insurer of the Commission regarding structural integrity of equipment, hazard control and personnel safety. In addition, ONGC follows applicable Indian regulations and codes, which in general conform with other internationally applied codes. These regulations are reflected in the design and construction specifications issued in all turnkey bid documents.

3.44 ONGC observes all of the safety standards of the American Bureau of Shipping (ABS), Britain's Lloyds Shipping and Norway's Det Norske Veritas (DNV) with regard to offshore drilling and production platforms. Each platform is equipped with sufficient survival craft to accommodate all of the men at work at any given time. In addition, India is a signatory to the Safety of Life at Sea (Solas) convention; the coast guard fleet is responsible for meeting Solas norms.

IV. THE BORROWER: ONGC

A. Organization and Management: Introduction

4.01 The Oil and Natural Gas Commission was established by the Government of India in 1959 to explore and develop petroleum resources in India outside the areas already being prospected in the eastern part of the country. The determination to explore these areas was based upon the conclusions of Indian geologists and confirmed by a panel of international experts. ONGC is a government-owned corporation established by the Oil & Natural Gas Commission Act of 1959 to plan, promote, organize and implement programs for the development of oil and natural gas resources and the production and sale of oil and natural gas products.

4.02 ONGC has grown to become the principal entity which explores for and develops oil and natural gas resources in India. Its activities are mainly the exploration and production of oil and natural gas. ONGC does not participate in downstream activities such as petroleum refining or distribution and retailing of refined products.1/ ONGC's revenues are derived from the sale of its production of oil, natural gas, liquified petroleum gas and natural gas liquids. The major part of ONGC's expenditures, other than for normal operating costs, is for exploration and development.

4.03 For the fiscal year ended March 31, 1987, ONGC's gross crude oil production amounted to 27.9 million tons. This represented about 90% of India's total domestic production of crude oil for the same period. The balance was produced by OIL, a government-owned company which operates mainly in the state of Assam, in the eastern part of the country.

B. Organization

4.04 The 1959 ONGC Act provides that the Commission shall consist of a Chairman and not less than two, but not more than eight, Members appointed by the Government for a term not exceeding five years at a time (Annex 5.1). Members are eligible for reappointment. All decisions of the Commission must be approved by a majority of Members. The Commission sets policies, manages the activities, and develops the plans and budgets of ONGC.

4.05 At present, the Commission consists of six Members from within ONGC and two additional Members representing the Ministry of Finance and the Ministry of Petroleum and Natural Gas. Until recently, the six internal Members were designated, respectively, Operations, Exploration, Drilling, Technical, Finance, and Personnel. In view of the rapid increase in importance of gas production and gas operations, the Member Operations has recently been changed to Member Natural Gas, responsible for formulation and promulgation of policies and strategies regarding development of natural gas in addition to oil production. The former Chairman of GAIL has been appointed to this position. The presence of this new Member in ONGC should help to assure better coordination of planning in the gas sector between ONGC as the producing entity, GAIL as the primary gas transportation entity, and gas users. An outline of the structure and responsibilities of the Members of ONGC is attached as Annex 5.1.

4.06 The Chief Operating Executive of ONGC is Colonel S.P. Wahi, who assumed the position of Chairman in October, 1981. The Chairman is appointed for a five-year term. The Government has announced that Col. Wahi will serve for an additional one-year period pending designation of a new Chairman for this office.

C. Institutional Aspects

4.07 The Bank has been closely involved in the petroleum and gas sector in India with ONGC. The commission has been the beneficiary of five Bank loans totalling US$1,180 million since 1979. This period has been one of rapid growth and one during which major adjustments have been necessary in organizational structure and management approach.

1/ The principal distributor of oil products is the Indian Oil Corporation; the principal distributor of natural gas will be the Gas Authority of India Limited.

4.08 Certain organizational strains and inefficiencies have inevitably resulted from ONGC'S rapid growth. Recently, a reorganization was implemented based on a functional structure for the Commission and a regional or "common basin" approach for the operating organization. In this approach all operations in a given basin are integrated; formerly, offshore and onshore operations in the same basin had been handled under separate organizations. The Bank has also encouraged ONGC's increasing use of private sector contractors and consultants in order to focus managerial and technical manpower on essential functions and to reduce capital expenditure requirements, as well as to accelerate the transfer of technology.

4.09 This approach has been adopted both by the Government and ONGC as a matter of policy. Thus in July of this year ONGC announced that it wished to sell over 30 offshore supply vessels, as well as support and standby vessels, worth an estimated Rs 1,800 million (approximately US$140 million). After the Bank approved the first loan to ONGC in 1977, ONGC began borrowing directly from the international financial markets (Annex 5.2) and has raised about US$1.5 billion from these sources. The Commission is also considering schemes to attract private sector involvement, including financing, in the future appraisal and development of certain offshore fields. ONGC is also working closely with the Government of India to implement the GOI's policy of offering increased acreage to international companies to expedite the country's total exploration effort (para. 1.27).

4.10 During the period of the Bank's involvement with ONGC, management systems have also been improved. Considerable investment has been made in recent years in strengthening the managerial information system and improving communications among the several regional production centers. Comprehensive reports are provided monthly to management. Important portions of the Commission's accounting systems have been computerized. The Commission has submitted timely and complete progress and financial reports to the Bank in compliance with loan agreements.

4.11 ONGC has grown rapidly and has been successful at implementing complex and difficult new technologies in offshore drilling in India. There has been an extensive dialogue on technical issues between the Bank and ONGC staff. Bank staff recommendations have, in specific situations, been followed. The financing of portions of the estimated foreign exchange cost of many of the drilling operations included in the Western Gas Development Project will provide a basis for continuing this important dialogue.

D. Financial Aspects: Past Results

4.12 ONGC's operations over the past five years have expanded very rapidly, reflecting the brisk build-up of its offshore operations, notably Bombay High. A summary of the Commission's recent operating results (Annexes 5.3 to 5.5) is shown in Table 4.1.

Table 4.1
ONGC: Summary of Recent Results
(Fiscal year ending March 31, in Rs million)

	Actual				(Provisional)
	1983	1984	1985	1986	1987
Revenues	24,016	34,728	40,350	43,879	49,206
Operating Expenses:					
Gross Taxes and Royalties to Govt...	4,379	9,049	9,762	12,781	14,878
Operating Costs	1,970	2,606	4,193	4,175	4,806
Subtotal, Expenses	6,349	11,655	13,955	16,956	19,684
Depreciation, Depletion & Amort	4,965	6,112	8,783	6,361	8,925
Subtotal, Operating Expenses	11,314	17,767	22,738	23,317	28,608
Operating Income (Revenues - Expenses) ..	12,702	16,961	17,612	20,562	20,598
less: Interest	873	884	1,338	1,580	2,511
Net Income before Corporate Tax	11,829	16,077	16,274	18,982	18,087
less: Corporate Taxes	4,900	8,020	7,450	5,960	7,235
Net Income after Corporate Tax	6,929	8,057	8,824	13,022	10,852
less: Dividends	274	309	326	343	343
Net Income Retained	6,655	7,748	8,498	12,679	10,509
Total Government Tax/Revenue	39.8%	50.0%	43.5%	43.5%	45.6%
Operating Cost/Revenue	8.2%	7.5%	10.4%	9.5%	9.8%
Cash Flow (Net Income Retained plus Depreciation)	11,620	13,860	17,281	19,040	19,434
Cash Flow (US$ million equivalent)	1,107	1,113	1,420	1,465	1,495

Source: ONGC

4.13 ONGC's revenues have increased almost ten-fold over the past ten years. Despite significant contributions by ONGC to the public sector (gross taxes and royalties to the government, plus income taxes and dividends) which have represented as much as 50% of earnings, the Commission has still generated substantial cash flow (net income retained plus depreciation). This has increased to about Rs 19 billion (US$1.5 billion) in 1987. ONGC is presently the largest public sector company in India in terms of capital employed and net profits, and together with the Indian Oil Corporation, among the largest Indian companies in terms of sales.

4.14 ONGC's sound financial performance has been the result both of pricing and taxing policy by the Government of India and relatively low-cost operations by the company. Domestic crude prices, on which ONGC revenues are based, have been maintained to provide adequate returns to investment and sufficient internal cash generation to meet a substantial portion of future investments; ONGC presently receives US$18.70/Bbl of crude produced before royalties (para 1.35). The company has been able to utilize net cash flows as a significant source of investment funds. At the same time, operating costs have been kept around 10% of net revenues.

4.15 Summary statistics regarding ONGC's production (Annex 5.4) and investment (Annex 5.6) are shown in Tables 4.2 and 4.3 below:

Table 4.2

ONGC: Summary of Production
(Fiscal year ending March 31)

Production a/	Actual 1983	1984	1985	1986	(Provisional) 1987
Crude oil, offshore (MMmt)	12.30	16.89	19.56	20.90	20.59
Crude oil, onshore (MMmt)	5.37	5.78	6.14	6.79	7.27
Total crude oil (MMmt)	17.67	22.67	25.70	27.69	27.86
Natural gas offshore (MMCM)	1,105	1,485	2,050	2,855	4,171
Natural gas onshore (MMCM)	751	738	740	790	871
Total natural gas (MMCM)	1,856	2,223	2,790	3,645	5,042
LPG (thousand mt)	161	196	242	321	452
NGL (thousand mt)	25	38	58	68	0

a/ Crude oil figures are gross production; natural gas figures are net of volumes flared or consumed in production.
Source: ONGC

Table 4.3

ONGC: Summary of Investment Program
(Fiscal year ending March 31)

	Actual 1983	1984	1985	1986	(Provisional) 1987
Investment (Rs billion)					
Fixed Assets	9,169	9,461	11,251	11,555	12,339
Exploration a/	2,621	2,728	3,360	3,052	6,455
Development	1,799	2,796	2,106	2,033	2,471
Total	13,589	14,985	16,717	17,363	21,265

a/ Includes geophysical expenditures
Source: ONGC

E. Operating Performance

4.16 It is difficult to make comparisons between oil companies which reveal in a meaningful way the relative success of any individual company in undertaking its operations. This is particuarly true in the case of ONGC, a relatively new company which has grown rapidly, and which has adapted well to new and difficult offshore technologies on a large scale. Furthermore, the local costs of a company like ONGC operating in India may vary markedly from those of international oil companies operating in other parts of the world.

4.17 ONGC operates quite profitably, with relatively low operating costs. The company produces approximately 570,000 Bbl/d of petroleum (13 Bbl/d per employee). Total annual investments have averaged approximately US$1.5 billion equivalent. One common basis for comparison of the cost of producing petroleum is investment cost per daily barrel produced. This measure reflects total investment and costs after exploration (and before transport) per additional daily barrel of oil production. Development investment in high-cost offshore sources, among which the North Sea is typical, often average US$15,000-20,000 per daily barrel. More typical offshore costs are in the US$10,000 range. ONGC's total development investment costs (of which offshore development comprises by far the largest component) are in the range of US$12,000-15,000 per daily barrel. This average combines relatively low development costs for Bombay High (estimated to be below US$10,000 per daily barrel) with higher average costs elsewhere.

4.18 Using this same parameter for the major project components, estimated development costs range from US$6,250 for South Bassein Phase II development (in terms of oil equivalent of gas) and US$25,000 for the Gandhar field. The low cost of incremental production from South Bassein does not, of course, include the (relatively expensive) cost of transporting gas by pipeline. The relatively high development costs of the Gandhar field reflect the fact that only the initial phases of production are being taken into account.

4.19 While offshore costs are generally greater than onshore costs, the Arabian sea offshore Bombay is neither deep (averaging 60 meters) nor turbulent. As a result, production costs from these fields have been relatively low. ONGC's total operating expenses, including overhead and depreciation, are approximately US$1 billion equivalent for production of about 200 million barrels annually; this represents average total operating costs per barrel of approximately US$5. Direct cash costs (i.e. excluding depreciation but including overhead) have run between one-quarter and one-third of this.[1/] These figures are based only on oil production; gas sales, in any event, have not yet been significant. These costs are in line with international industry costs and reflect both the economies deriving from peak production from the Bombay High oilfield and low manpower costs in India.

F. Financial Projections

4.20 The Bank has built a financial model based on past and projected operations, announced government policy with respect to selling prices, the Commission's present financial structure, and projected investment outlays -- including implementation of the proposed Western Gas Development Project. Details of this financial model, including assumptions, are attached as Annexes 5.3 to 5.11.

1/ Depreciation tends to be an overstated cost because of the lag effect of new production coming onstream in the company with growing investment as well as production.

4.21 A summary of the Commission's projected income statement (Annex 5.3) and balance sheet (Annex 5.7) is shown in Table 4.4.

Table 4.4

ONGC: Summary of Projected Operations

	Projected				
	1988	1989	1990	1991	1992
NET VOLUMES SOLD					
Crude oil, offshore (MMmt)	21.11	21.64	22.18	22.73	23.30
Crude oil, onshore (MMmt)	7.77	8.32	8.90	9.52	10.19
Natural gas, offshore (MMmt) ...	4,980	7,532	9,130	9,130	9,960
Natural gas, onshore (MMmt)	961	1,065	1,181	1,313	1,457
LPG (MMmt)	511	627	824	924	1,150
NGL (MMmt)	0	0	200	500	700
REVENUES (Million Rs)	60,701	66,477	71,566	74,547	78,829
EXPENSES (Million Rs)					
Taxes and Royalties	24,270	25,719	26,995	27,952	28,956
Operating costs	5,100	5,706	6,240	6,523	6,982
Depreciation, Depletion + Amort.	10,415	12,773	14,907	16,951	16,185
Operating Income	20,916	22,279	23,425	23,121	26,706
Interest	2,872	3,033	3,358	3,678	4,205
Taxes	7,218	7,698	8,027	7,757	9,001
Dividends	343	343	343	343	343
Net Income Retained	10,484	11,204	11,697	11,293	13,158
BALANCE SHEET (Million Rs)					
Current Assets	52,712	50,914	51,757	53,606	54,256
Fixed Assets	73,775	90,236	104,169	115,121	125,131
Other	7,200	7,200	7,200	7,200	7,200
Total Assets	133,687	148,350	163,126	175,927	186,587
Current Liabilities	37,420	39,417	38,720	38,649	41,121
Long-term Debt (excluding current portion) ..	30,231	31,693	35,469	37,048	35,437
Shareholders' Equity	66,036	77,240	88,937	100,230	110,029
Total Liabilities	133,687	148,350	163,126	175,927	186,587

4.22 On the basis of these projections ONGC will continue to be financially sound. This is reflected in the financial ratios and summary projected sources and uses of funds statements (Annex 5.8) shown in Table 4.5.

Table 4.5

Summary Ratios, Sources and Uses of Funds

	Projected				
	1988	1989	1990	1991	1992
Selected Financial Ratios					
Current Ratio	1.4	1.3	1.3	1.4	1.3
Debt-Equity Ratio a/	0.5	0.4	0.4	0.4	0.3
Debt Service Ratio	4.2	4.6	4.7	4.3	3.6
EBIT % of Average Fixed Assets b/	30.3%	27.2%	24.0%	20.8%	22.2%
Sources (MMRs)					
Internal Cash Generation	24,114	27,353	30,305	32,315	33,890
Loan Drawdown	3,831	4,592	7,495	6,825	3,510
Total Sources	27,945	31,945	37,800	39,140	37,400
Uses (MMRs)					
Capital Expenditure	10,696	15,896	15,777	15,777	15,777
Exploration and Development	9,061	13,549	13,652	13,652	13,652
Debt Service	5,676	5,953	6,488	7,448	9,451
Other	2,512	(3,453)	1,883	2,263	(1,480)
Total Uses	27,945	31,945	37,800	39,140	37,400

a/ L-T debt excluding current portion.
b/ Earnings before interest and income taxes.
Source: Bank staff estimates.

G. ONGC's Investment Program

4.23 Implementation of the Western Gas Development Project will take place largely within the Seventh Five Year Plan (1985-1990). During the Seventh Plan Period, ONGC's overall investment program (Annex 5.9) has been set at Rs 121 billion (approximately US$9.8 billion), or an average of about Rs 24 billion (US$2 billion) annually. Total cost of the proposed project, excluding interest during construction, is about US$1.35 billion and represents about 14% of total Seventh Plan outlays projected for ONGC.

4.24 From the sources and uses of funds projections shown in Table 4.5 it can be seen that ONGC will be able to rely largely on internally generated funds for its investment outlays for both capital equipment and exploration and development. The projections do not, however, include investments greater than those officially anticipated by ONGC, which would require additional resources. In the past, investments by ONGC have been undertaken at a rate significantly higher than originally planned as a result of further appraisal of fields. An important need which remains is meeting the foreign exchange component of ONGC's investment program. In the case of offshore work such as the proposed project, the foreign exchange requirements comprise a significant portion (more than half) of total outlays. ONGC will continue to seek, at regular intervals during the project implementation period, foreign currency loans, untied to procurement packages, to help finance its overall investment program. The timing of such corporate borrowings will depend on the financial market conditions as well as on the foreign exchange needs of the company. Parts of these international borrowings are expected to be used towards the financing of the proposed project to the extent needed to cover the direct foreign exchange cost not financed by Exim Bank, export/suppliers' credits and the proposed Bank loan. In the first quarter of 1987, ONGC borrowed from the international capital markets a total of about US$260 million comprising DM 150 million and two Yen loans of about Y 25 billion.

H. Financial Analysis of the Project

4.25 Calculations of the financial rates of return for the three major project components (South Bassein, Heera, and Gandhar) are shown in Annexes 5.10 and 5.11. These calculations are made based on ONGC selling prices and the capital and operating cost estimates shown in the project cost table (including physical contingencies and local taxes). The calculations are in constant 1987 terms. They are also made before and after income taxes and assume that the project components pay the full tax liabilities computed using the project's own interest costs and depreciation charges.

4.26 The results show a financial rate of return before income taxes for the South Bassein Phase II component of 66% and an after tax return of 44%. The high return is primarily due to the incremental nature of the Phase II development which takes advantage of the existing infrastructure (i.e. offshore gas pipeline) already provided for under Phase I. To a lesser extent, the relatively high financial return is also due to ONGC gas sales prices being slightly above international equivalents (US$2.83/MCF); the energy-equivalent price of gas corresponding to US$15/Bbl crude is approximately US$2.50/MCF.

4.27 The financial return from the Heera investment is about 26% before and 13% after taxes. The financial return on the Gandhar project component is 17% before and 10% after taxes. The financial return exceeds ONGC's cost of capital in real terms. Financial return on the total of the major project components is a satisfactory 47% before income taxes and 29% after taxes.

I. Financial Covenants

4.28 The following agreements have been reached:

(a) With the Government that it will:

carry out, from time to time, a review of the prices of crude oil and natural gas paid to ONGC, and shall set such prices at a level needed to enable ONGC, under conditions of efficient operation, to meet its debt service requirements, maintain adequate working capital and finance a substantial portion of its proposed capital investments;

(b) With the ONGC that it will:

(i) submit annually to the GOI an analysis of its financial situation as a basis for setting ONGC's selling prices, and in addition submit to the GOI analysis of any major investment project indicating the level of prices required for ONGC to earn a satisfactory return on such major investment and on any related subsequent major developments;

(ii) maintain its current ratio at 1.2 times or higher, its debt-service coverage ratio at 1.5 times or higher, and its debt to equity ratio at not more than 60:40; and

(iii) have its financial accounts audited by an independent auditor acceptable to the Bank, and will submit its audited accounts to the Bank within nine months of the end of each fiscal year, as well as quarterly unaudited financial reports in such a scope and format satisfactory to the Bank.

Similar provisions were agreed to by GOI and ONGC under earlier petroleum projects. These covenants have been complied with under past loans and have in part provided a basis for past revisions to petroleum prices implemented by the GOI.

V. ECONOMIC JUSTIFICATION

A. Project Benefits

5.01 The proposed project will result in the production of substantial quantities of natural gas, which will substitute for liquid petroleum products, thus reducing India's petroleum import requirements and the consequent drain on foreign exchange; and this is its principal justification. It is estimated that over the life of the project 63 billion cubic meters of natural gas will be produced, plus 4 million tons of condensate and 11 million tons of petroleum products extracted from gas. This is equivalent in total to approximately 66 million tons of oil, with an estimated net value to the country of US$2.5 billion.

5.02 The contributions of the various project components are summarized in the following table:

Table 5.1

Economic Value of Project Components

	Total Volume of Production Under Project: Gas (MCM)	Total Volume of Production Under Project: Petroleum Liquids (Mtpy)	Net Present Value (US$ million)	Average Economic Cost of Production (US$)
South Bassein (Phase II)	54.3	11.0 a/	2,240	0.70 d/
Heera	2.5	-	52	1.62 d/
Gandhar	6.2	4.1 b/	237	10.20/Bbl c/
Total:	63.0	15.1	2,529	

a/ Extracted LPG and NGL only
b/ Condensate
c/ Oil and oil equivalent of gas
d/ Price per million cubic feet
Source: Bank staff estimates

At peak production, the project components yield a total output of over 4.3 mtpy of crude oil equivalent, corresponding to about one-third of current petroleum imports. In addition, the planning studies associated with the project should lead to a substantially more rapid and cost-effective exploitation of India's gas resources in uses which yield the country greatest benefit.

5.03 Natural gas has been valued on the basis of the fuel which it replaces, delivered at the point of use. For the purposes of project evaluation, it has been conservatively assumed that all gas replaces fuel oil, the lowest-valued replacement. International prices of fuel oil were forecast based on a range of possible crude oil prices, and adjusted for international transport to arrive at a CIF value Bombay. Gas used at the coast is valued at the thermal equivalence value of fuel oil CIF Bombay; gas used inland is valued at the thermal equivalence of fuel oil CIF Bombay plus transport inland.

5.04 On the basis of gas demand and utilization plans, actual gas use is expected to be about 50% as fuel oil replacement in boilers and power generation, and 50% as feedstock for fertilizer production. Although in the latter use gas would replace naphtha, the economic viability of naphtha-based fertilizer plants is uncertain in the present international economic environment, based on the projected relative international prices of naphtha and fertilizer. Accordingly it has been assumed that in the absence of natural gas, the fertilizer plants would not operate rather than utilize naphtha. Thus for the purpose of project evaluation, the net benefit to the country of gas consumed is calculated based on the corresponding value of fuel oil imports only and not on the value of naphtha exports foregone.

5.05 Crude oil prices are taken at $18/Bbl (in constant terms), the current price of which is not expected to change for some time, and at $12/Bbl and $25 Bbl, which are considered reasonable low and high price scenarios. As a worst-case, given inherent uncertainties in world oil prices, the project was also evaluated at a constant price of US$10/Bbl. For the purposes of calculating international product prices, it has been assumed that constant refinery margins are maintained over the forecasting period. This methodology results in economic values for natural gas ranging from US$54/MCM (US$1.53/mcf) to US$164/MCM (US$4.68/mcf), as summarized in Table 5.2 below.

Table 5.2

Economic Valuation of Natural Gas

Crude Price (US$ Bbl)	Corresponding Price of Fuel Oil (US$/mt CIF Bombay)	Corresponding Value of Natural Gas At Coast (US$/MCM)	Corresponding Value of Natural Gas Inland (US$/MCM)
$10	60	54.00	67.40
$12	75	66.90	80.30
$18	118	105.50	118.80
$25	168	150.00	163.80

Source: Bank staff estimates

Given the expected geographic mix of gase use, this results in a weighted-average value of gas as a fuel oil replacement of about US$3.25/mcf at a crude price of $18/Bbl. (The value of natural gas as a naphtha replacement would be substantially higher, at about $4.00/mcf at crude prices of US$18/Bbl). The detailed assumptions underlying valuation of gas and products are given in Annex 6.1.

5.06 When converting to natural gas there are additional economic benefits in the form of reduced storage and handling costs, reduced maintenance costs as well as lower pollution. Further benefits result from the increased thermal efficiency of natural gas relative to liquid fuels, which typically results in a 5%-10% increase in benefits depending on use and type of burner. Although the magnitude of these savings varies from industry to industry, their total impact can be substantial. The net effect of these considerations is that project benefits as currently measured, using direct thermal equivalence of gas for fuel oil, tend to be conservative.

5.07 The South Bassein component of the project will also produce substantial quantities of LPG and natural gas liquids (NGL, also known as natural gasoline), both of which are imported in India. Both of these commodities have been valued at their estimated CIF prices as shown in Table 5.3 below.

Table 5.3

Assumed Value of Products

Crude Oil Price (US$/Bbl)	Value CIF Bombay LPG (US$/mt)	NGL (US$/mt)
$12.00	$132	$136
$18.00	$176	$180
$25.00	$226	$230

Source: Annex 6.1

5.08 The Gandhar project component will also result in the production of condensate which is equivalent to very light crude oil. Condensate production is valued on the basis of the assumed crude prices FOB Singapore, adjusted for quality as well as international transport to Bombay. These components are also evaluated at a constant oil price of US$10/Bbl.

B. Project Costs

5.09 Project cost estimates are in constant 1987 dollars, net of taxes and duties, but inclusive of 10% physical contingencies. Operating costs are estimated at 5% per annum of capital costs. This is a common estimate in the offshore oil industry in general, and on the high side for onshore production, especially in India because of low prevailing wage levels. Sensitivity analysis has been performed assuming all costs up to 50% higher.

C. Economic Analysis

5.10 South Bassein. The outputs of the South Bassein (Phase II) component of the project consist of rich natural gas, and LPG and NGL at the outlet point of the Hazira treatment facilities. Plateau production (reached by 1992) will be about 9 MMCMD of rich gas, 500 tons per day (tpd) of LPG, and 1,400 tpd of NGL. This is equivalent to about 3.5 million tons of petroleum products annually (9% of current consumption), and the net benefits to the country are in the order of US$450 million per year (Annex 6.2). Rich gas has been valued on the basis of its replacement value ex-Hazira, net of any downstream shrinkage and ignoring inland transport benefits and costs, which would, it is estimated, increase the value of benefits by about 5%.

5.11 The economic internal rate of return on this component is about 82%, with a net present value of US$2.3 billion. The incremental investment in Phase II of South Bassein yields such high returns principally as a result of the large sunk costs in pipeline infrastructure under the first South Bassein project. The rate of return is still 53% under the worst-case scenario of oil prices at US$10/Bbl. The average (discounted) cost of gas produced under this component is estimated at about US$0.52/mcf, equivalent on an energy basis to an oil price of US$3.16/Bbl; oil prices would thus have to fall to approximately this level before the project ceased to be viable.

5.12 To assess the full costs and benefits of the entire South Bassein gas development program, economic analysis was also undertaken for the integrated package of South Bassein and HBJ pipeline investments (Annex 6.3). This shows that the whole program yields an economic rate of return of 28%. The cost of gas is US$0.81/mcf ex-Hazira, and US$1.79/mcf ex-HBJ (attributing all costs to gas, and excluding the additional benefits of NGL and LPG). The difference in ex-Hazira and ex-HBJ costs is attributable to the cost of the HBJ pipeline. At an oil price of US$10/Bbl, the integrated South Bassein-HBJ project still yields a net present value of US$0.5 billion, and a 17% economic rate of return.

5.13 A scenario more likely than that of a sustained low price of oil at US$10/Bbl is a delay in the construction of the last three fertilizer plants planned along the HBJ pipeline. While other gas users are being sought to substitute offtake (Table 5.4), gas utilization could be substantially reduced for several years in the event that an alternative market is not developed sufficiently rapidly. In order to test the economic implications of such underutilization with respect to the proposed South Bassein project component, calculations were made based on a two-year delay in gas offtake. The result is a decrease in the net present value of the South Bassein phase II investments to US$1.4 billion; a net cost to the country of US$0.9 billion in benefits foregone.

Table 5.4

Impact of a Delay in Gas Offtake

		South Bassein Phase II	South Bassein Phase I and Phase II (inc HBJ)
Base Case:	ERR:	82%	28%
	NPV:	$2.3 billion	$2.4 billion
Two-Year Delay in Gas Offtake: a/	ERR:	36%	23%
	NPV:	$1.4 billion	$1.6 billion

a/ Gas allocated to last three fertilizer plants
Source: Bank staff estimates

5.13 Heera. The benefits of the Heera component will be about 1 MMCMD of associated natural gas delivered onshore Bombay which would otherwise be flared. The value of the gas saved will cover the costs of the pipeline within two years. The total net present value of the benefits is estimated at US$72 million, yielding an economic return of 36% (Annex 6.4). If oil prices are assumed to remain at US$10/Bbl, the rate of return from Heera becomes negative. However, the investment in bringing associated gas to shore remains viable down to US$12/Bbl oil prices, since the average incremental cost of production and delivery is only US$2.00/MCF. These estimates tend to understate the benefits of the Heera-Uran pipeline, since it has been over-sized to carry gas from other satellite fields to market as they are developed over the next ten years.

5.14 Gandhar. Analysis based on preliminary estimates of the production levels from the Gandhar field show an average net benefit to the country of about $70 million per year by the early 1990's (about half of which is gas replacement of petroleum products, and half condensate). This yields an economic rate of return of about 66% (Annex 6.5). This falls to 7% under the US$10/Bbl crude price scenario. The estimated average cost of production of oil and oil equivalent gas is US$10.20/Bbl. However, these results are based only on projected production from the initial stages of field development. Substantially more wells are planned to determine the full extent of reserves, and if additional reserves are confirmed, average production costs from the field would drop accordingly. In addition, the appraisal drilling included under the project will yield valuable information essential to planning optimal field development in the longer run, and no value has been attached to this.

5.15 The economic rate of return for the aggregate of subprojects (South Bassein Phase II, Heera and Gandhar) is about 72%.

D. Project Risks

5.16 Potential risks to the proposed project fall into three categories: (i) technical, (ii) market; and (iii) oil price uncertainty. Regarding technical risk, any petroleum project has certain risks inherent to the process of drilling and producing oil and gas. Exploration risk is essentially not present since all major project components consist of developing established fields. Technical risks are greater for offshore than for onshore projects. However, ONGC has accumulated considerable expertise and established a good track record in both onshore and offshore production. The project has provided for expert assistance in drilling, where necessary, and a number of technical studies have been undertaken to confirm the extent of reserves. The major technical risk arises from the uncertainty about reservoir performance given that the fields being developed are new and have no production history. Conservative well productivity assumptions have been used.

5.17 Poor planning and coordination of market development with installation of the project facilities would result in underutilization of capacity. Some underutilization is unavoidable as new capacity is first brought outstream; in addition, potential users tend to require that supply capacity be ready before committing to purchase agreements. Most important, however, is that planning for major users such as fertilizer and power be carefully coordinated with increased supply capacity. Sensitivity analysis indicates that although project economics remain sound under delayed offtake scenario, losses of potential benefits from delayed offtake would be substantial. Project conditionality has been drawn up minimize such losses.

5.18 Declines in the international price of petroleum and petroleum products (and hence in the substitution value of natural gas) remain an unavoidable risk. However, sensitivity analyses indicate that only one project component, Heera, becomes economically unviable under "worst case" conditions defined as crude oil declining to US$10/Bbl and remaining there in constant terms. This situation is highly regarded as unlikely, and the main South Bassein component remains viable at oil prices as low as $4/Bbl. The returns on other project components remain satisfactory under all other foreseeable conditions (Annex 6.6).

VI. AGREEMENTS

6.01 The following agreements have been reached:

(a) With the Government that it will:

(i) will use its best efforts to ensure the connection of the fertilizer plants and sufficient other users as may be necessary to ensure full utilization of gas produced under the project (para 2.30), and will provide the Bank annually during project implementation with a report on plans for gas use for the coming three years, as well as progress to date in market development (para 2.52);

(ii) review natural gas prices with the Bank on a regular basis (para 2.43);

(iii) ensure the continuing financial viability of ONGC through reviews, from time to time, of the prices of crude oil and natural gas paid to ONGC and set such prices at a level needed to enable ONGC, under conditions of efficient operation, to meet its operating expenses and earn a sufficient return after taxes on assets employed in operation, meet its debt-service requirements, maintain adequate working capital and finance a substantial portion of its proposed capital investments (para 4.29);

(iv) ensure that a production planning study to identify the least-cost means of developing and delivering gas to market in the western region (para 2.49);

(v) ensure that a gas utilization study to assess the optimal economic uses for gas in India will be completed by June 30, 1989 (para 2.50); and

(iv) that the progress and results of the above studies will be reviewed with the Bank; and that, in addition, satisfactory coordination arrangements will be made at the government level to coordinate the studies and to bring the results together for policy formulation (para 2.51).

(b) With the Oil and Natural Gas Commission that it will:

(i) establish Project Implementation Units for each of the major project components, and identify an overall coordinator for purposes of the Bank project (para 3.16);

(ii) provide the Bank with regular progress reports detailing implementation, cost, procurement, disbursement, and production activities associated with the project, in an agreed format, and will prepare a Project Completion Report within six months of project completion (para 3.18);

(iii) maintain its current ratio at 1.2 times or higher, its debt-service coverage ratio at 1.5 times or higher, and its debt to equity ratio at not more than 60:40 (para 4.29(c)); and

(iv) have its financial accounts audited by an independent auditor accpetable to the Bank, and will submit its audited accounts to the Bank within nine months of the end of each fiscal year, as well as quarterly unaudited financial reports in such a scope and format satisfactor to the Bank (para 4.29(d)).

6.02 Execution of a subsidiary loan agreement between GOI and ONGC on terms and conditions satisfactory to the Bank will be a condition of loan effectiveness (para 3.24).

6.03 On the basis of the project justification and the agreements to be sought during negotiations, it is recommended that the Bank support the proposed project with a loan of US$295 million to GOI for a period of twenty years, including 5 years of grace, at the standard interest rate.

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Crude Oil and Petroleum Product Balances

(Million metric tons)

	1970-71	1975-76	1980-81	1984-85	1989-90 (Projected)	1994-95 (Projected)
Petroleum Product Demand	17.9	22.5	30.9	38.5	54.0	70.3
less: Refinery Output	(17.1)	(20.8)	(24.1)	(33.2)	(48.0)	(58.0)
Petroleum Product Imports (net)	0.8	2.1	7.3	5.1	6.0	12.3
Petroleum Product Demand	17.9	22.5	30.9	38.5	54.0	70.3
less: Domestic Crude Production	(6.8)	(8.5)	(10.5)	(29.0)	(34.0)	n/a
Crude Imports	11.7	13.6	16.3	7.2	14.0	n/a

Totals do not add due to process losses, changes in stocks, and re-exports.

Volume and Costs of Imports

	1970-71	1975-76	1980-81	1982-83	1983-84	1984-85
Crude Oil Consumption (MMmt)	18.4	22.3	25.8	33.2	35.3	35.6
Crude Oil Production (MMmt)	(6.8)	(8.5)	(10.5)	(21.1)	(26.0)	(29.0)
Net Crude Imports (MMmt)	11.7	13.6	16.3	12.4	10.4	7.2
Value of Crude Imports (US$ Bln)	0.1	1.1	3.3	3.0	2.1	1.6
Net Product Imports (MMmt)	0.8	2.1	7.3	4.2	2.9	5.1
Value of Product Imports (US$ Bln)	-	0.2	1.9	1.4	0.8	1.4
Total Cost of Imports (US$ Bln)	0.1	1.3	5.2	4.4	2.9	3.0

INDIA

Petroleum Sector Data

Crude Oil Production by Area

(Million metric tons)

	1970-71	1975-76	1980-81	1982-83	1984-85	(Projected) 1989-90
Assam - OIL	3.2	3.2	1.3	2.8	2.7	3.5
ONGC	0.2	1.1	0.4	2.2	2.2	4.1
Gujerat (ONGC)	3.5	4.1	3.8	3.2	3.9	6.0
Bombay High (ONGC)	-	-	5.0	12.9	20.1	20.8
Krishna-Godavari	-	-	-	-	-	0.6
Subtotal (Existing Fields)	6.8	8.4	10.5	21.1	29.0	35.0
Possible New Fields	-	-	-	-	-	5.6
TOTAL	6.8	8.4	10.5	21.1	29.0	40.6

INDIA

Petroleum Sector Data

Natural Gas Production & Use by Region

(MMCMD)

	1970-71	1975-76	1980-81	1982-83	1984-85	(Projected) 1989-90
Gas Produced						
Assam	2.7	4.4	2.3	5.0	5.6	5.7
Gujerat	1.3	2.1	2.3	2.1	2.5	3.0
Bombay High	-	-	1.8	6.5	14.2	11.1
South Bassein	-	-	-	-	-	20.0
TOTAL	4.0	6.5	6.4	13.6	22.3	39.8
Gas Consumed						
Assam	1.0	1.8	1.6	2.7	3.2	n/a
Gujerat	0.9	1.7	1.9	1.8	2.2	n/a
Bombay High	-	-	0.8	3.0	8.4	n/a
TOTAL	1.9	3.5	4.3	7.5	13.8	n/a
Balance Flared						
Assam	1.7	2.6	0.7	2.3	2.4	n/a
Gujerat	0.4	0.4	0.4	0.3	0.3	n/a
Bombay High	-	-	1.0	3.5	5.8	n/a
TOTAL	2.1	3.0	2.1	6.1	8.5	n/a

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Western Gas Development Project

Gas Supply - Bombay High & Satelite Fields

(MMCMD)

Year Ended March	Bombay High Associated Gas: Total Production	Bombay High Associated Gas: Platform Use	Bombay High Associated Gas: Ex-Platform	Bombay High Satellite Fields: Total Production - Ex-wellhead (a): B-55	Neera	Ratna (c)	S-1	Total Net of Platform Use (b)	Gas to Uran	Balance to Hazira
1986	14.0	1.2	12.0					0.0	9.0	
1987	17.5	1.2	16.3					0.0	9.0	7.3
1988	16.2	1.2	15.0					0.0	10.5	4.5
1989	15.5	1.2	14.3					0.0	10.5	3.8
1990	14.8	1.4	13.4		1.0			0.9	11.0	3.3
1991	13.0	1.7	11.3		1.2			1.1	12.0	0.4
1992	12.9	1.7	11.2	0.7	1.5	0.3		2.3	12.0	1.5
1993	12.7	1.7	11.0	0.7	1.1	1.1		2.7	12.0	1.7
1994	12.0	1.7	10.3	1.5	0.7	1.2		3.2	12.0	1.5
1995	11.0	1.8	9.2	1.5	0.5	1.2	3.3	6.0	12.0	3.2
1996	10.0	1.9	8.1	1.5	0.4	1.2	3.3	6.0	12.0	2.1
1997	9.0	1.9	7.1	1.5	0.3	1.1	2.9	5.4	12.0	0.5
1998	7.8	2.0	5.8	1.5	0.3	1.1	2.8	5.3	10.5	0.6
1999	6.7	2.0	4.7	1.5	0.2	1.1	2.6	5.0	9.7	0.0
2000	6.3	2.0	4.3	1.5	0.2	1.1	2.5	4.9	9.2	0.0
2001	5.0	2.0	3.0	1.5	0.2	1.1	2.5	4.9	7.9	0.0
2002	5.0	2.0	3.0	1.5	0.2	1.1	2.5	4.9	7.9	0.0
2003	5.0	2.0	3.0	1.5	0.2	1.1	2.5	4.9	7.9	0.0
2004	5.0	2.0	3.0	1.5	0.2	1.1	2.5	4.9	7.9	0.0
2005	5.0	2.0	3.0	1.5	0.2	1.1	2.5	4.9	7.9	0.0
2006	5.0	2.0	3.0	1.5	0.2	1.1	2.5	4.9	7.9	0.0

Notes: (a) Production profiles for B-55, S-1, and Ratna are Bank staff estimates only.
(b) Assumes average of 7% for platform use and pipeline shrinkage.
(c) Includes expected development of satellite fields R-7, R-9, B-57, B-58, B-131, B-178 and B-174.

INDIA

Western Gas Development Project

Gas Supply - South Bassein & Satellite Fields

(MMCMD)

Year Ended March	South Bassein: Total Production	South Bassein: Platform Use	South Bassein: After Shrinkage (a)	Satellite Fields: Total Production: Panna (b)	Satellite Fields: Total Production: Mid & South Tapti	Satellite Fields: After Platform Use and Shrinkage (c)	Total Gas Available at Hazira	Corresponding Lean Gas Ex-Sweetening and LPG Plants (d)
1986			0.0			0.0	0.0	0.0
1987			0.0			0.0	0.0	0.0
1988	2.5	0.1	2.4			0.0	2.4	2.0
1989	10.0	0.2	9.7			0.0	9.7	8.3
1990	15.0	0.5	14.3			0.0	14.3	12.2
1991	20.0	0.7	19.1			0.0	19.1	16.3
1992	21.0	0.7	20.0	1.0	3.2	3.9	24.0	20.5
1993	21.0	0.9	19.8	1.5	3.2	4.3	24.1	20.6
1994	21.0	0.9	19.8	2.0	3.2	4.8	24.6	21.1
1995	21.0	1.3	19.4	2.4	3.2	5.2	24.6	21.0
1996	22.0	1.8	19.9	2.9	3.2	5.6	25.5	21.8
1997	22.0	1.8	19.9	3.3	3.2	6.0	25.9	22.1
1998	22.0	1.8	19.9	3.6	3.2	6.2	26.1	22.3
1999	22.0	1.8	19.9	3.0	3.2	5.7	25.6	21.9
2000	22.0	1.6	20.1	2.0	3.2	4.7	24.8	21.2
2001	21.0	1.5	19.2	1.2	3.1	3.9	23.1	19.8
2002	21.0	1.4	19.3	0.8	2.6	3.1	22.4	19.2
2003	21.0	1.3	19.4		2.2	2.0	21.4	18.3
2004	21.0	1.0	19.7		1.8	1.7	21.4	18.3
2005	21.0	1.0	19.7		1.1	1.0	20.7	17.7
2006	21.0	1.0	19.7		0.7	0.7	20.4	17.4

Notes:
(a) Assumes average of 1.5% for pipeline shrinkage.
(b) Production profile for Panna cannot be determined until fields delineated.
(c) Assumes average of 8.5% (7% platform use plus 1.5% pipeline shrinkage).
(d) Assumes average of 8% sweetening plant shrinkage and 6.5% LPG plant shrinkage and use.

INDIA

Western Gas Development Project

Gas Supply - Onshore Gujarat

(MMCMD)

Year Ended March 31	Associated Gas Existing Fields	--------New Production--- (a) Ghandar	Dahej	Hazira	Total Gross	Net after Field Use & Shrinkage (b)
1986	2.5				2.5	2.3
1987	2.5				2.5	2.3
1988	3.0	0.3			3.3	3.0
1989	3.0	1.1			4.1	3.7
1990	3.0	1.2	0.1		4.3	3.9
1991	3.0	1.4	0.2	0.3	4.9	4.4
1992	3.0	2.0	0.3	0.3	5.6	5.0
1993	3.0	2.5	0.3	0.3	6.1	5.5
1994	3.0	3.5	0.3	0.3	7.1	6.4
1995	3.0	3.5	0.3	0.3	7.1	6.4
1996	3.0	3.5	0.3	0.3	7.1	6.4
1997	3.0	3.5	0.3	0.3	7.1	6.4
1998	3.0	3.5	0.2	0.3	7.0	6.3
1999	3.0	3.5	0.2	0.3	7.0	6.3
2000	2.5	3.5	0.2	0.3	6.5	5.9
2001	2.5	3.5	0.1	0.3	6.4	5.8
2002	2.0	2.5	0.1	0.3	4.9	4.4
2003	2.0	2.5	0.1	0.3	4.9	4.4
2004	1.5	2.0	0.1	0.3	3.9	3.5
2005	1.0	2.0	0.1	0.3	3.4	3.1
2006	1.0	2.0	0.1	0.3	3.4	3.1

Notes: (a) Estimates prior to field appraisal.
(b) Assumes average of 10% for field use and shrinkage.

INDIA

Western Gas Development Project

The Gas Market

Identified Gas Demand - Bombay Area

(MMCMD)

I. COMMITTED USERS	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1994/95
Fertilizer - RCF Trombay	1.80	1.80	1.80	1.80	1.80	1.80	1.80
- RCF Thal	3.00	3.00	3.00	3.00	3.00	3.00	3.00
- DFPCL Taloja	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Industry - NWP Thal			0.15	0.15	0.15	0.15	0.15
- BEL Taloja			0.06	0.06	0.06	0.06	0.06
- HOC				0.15	0.15	0.15	0.15
Sub-Total - Base Demand	5.10	5.10	5.31	5.46	5.46	5.46	5.46
II. INTERUPTIBLE USERS							
Power - MSEB	1.80	1.80	3.60	3.60	3.60	3.60	3.60
- TEC	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Industry - HPCL Bombay	0.10	0.10	0.10	0.10	0.10	0.10	0.10
- BPCL Bombay	0.10	0.10	0.10	0.10	0.10	0.10	0.10
- RCF Thal	1.06	1.06	1.06	1.06	1.06	1.06	1.06
- MGCC			0.60	0.60	0.60	0.60	0.60
Sub-Total - Interuptible Demand	6.06	6.06	8.46	8.46	8.46	8.46	8.46
III. POTENTIAL ADDITIONAL USERS							
Medium-Sized Industries					0.80	1.80	1.80
Maharastra Town Distribution					0.25	0.50	0.50
TOTAL Identified Potential Demand	11.16	11.16	13.77	13.92	14.97	16.22	16.22

INDIA

Western Gas Development Project

The Gas Market

Identified Gas Demand - Onshore Gujarat

(MMCMD)

I. Committed Users	1986/87	87/88	88/89	89/90	90/91	91/92	94/95
Fertilizer - GNFC Baroach (Exist)	0.65	0.65	0.65	0.65	1.20	1.20	1.20
- IFFCO Ahmedabad	0.84	0.84	0.84	0.84	0.84	0.84	0.84
Industry - Baroda Grid	0.23	0.23	0.23	0.23	0.23	0.23	0.23
- Heavy Water Project	0.14	0.14	0.14	0.14	0.14	0.14	0.14
- Kaloi Industries	0.21	0.21	0.21	0.21	0.21	0.21	0.21
- Dairy Industry	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Power - GEB Uttran	0.25	0.25	0.25	0.25	0.25	0.25	0.25
- GEB Cambay	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Sub-Total - Base Demand	2.47	2.47	2.47	2.47	3.02	3.02	3.02
II. Interuptible Users (Potential)							
Power - GEB Dhuvaran	1.00	1.00	1.00	1.00	1.00	1.00	1.00
- GEB Qnkbei	1.00	1.00	1.00	1.00	1.00	1.00	1.00
- GEB Ukai	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Sub-Total - Interuptible Demand	3.00	3.00	3.00	3.00	3.00	3.00	3.00
III. Potential Additional Users							
- Replacement			1.20	1.20	1.20	1.20	1.20
Medium-Sized Industries					0.80	1.80	1.80
Gujarat Town Distribution					0.25	0.50	0.50
Sponge Iron Plant					0.50	1.00	1.00
TOTAL Identified Potential Demand	5.47	5.47	6.67	6.67	8.77	10.52	10.52

INDIA

Western Gas Development Project

Identified Gas Demand - Hazira and HBJ

(MMCMD of Lean Gas)

	1985/86	86/87	87/88	88/89	89/90	90/91	91/92	92/93	93/94
A. HAZIRA I. COMMITTED USERS									
Fertilizer - KRIBHCO Phase I	1.04	1.31	1.57	1.74	1.74	1.74	1.74	1.74	1.74
- Phase 2		1.04	1.31	1.57	1.74	1.74	1.74	1.74	1.74
Heavy Water Plant			0.00	0.00	0.00	0.25	0.25	0.25	0.25
Sub-Total - Base Demand	1.04	2.35	2.88	3.31	3.48	3.73	3.73	3.73	3.73
II. INTERUPTIBLE USERS									
KRIBHCO Fertilizers - Phase 1 & 2	0.32	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
TOTAL Identified Potential Demand	1.36	2.99	3.52	3.95	4.12	4.37	4.37	4.37	4.37
B. HBJ I. COMMITTED USERS									
Fertilizer : Guna			0.52	1.18	1.43	1.56	1.65	1.65	1.65
Jagdishpur				1.05	1.31	1.56	1.65	1.65	1.65
Aonla				1.05	1.31	1.56	1.65	1.65	1.65
Sawaimadhopur							0.52	1.43	1.56
Babrala								1.31	1.56
Shahjahanpur								1.18	1.43
Power : Sawaimadhopur					1.12	1.69	1.69	1.69	1.69
Auraiya					1.12	2.00	2.00	2.00	2.00
Sub-Total - Base Demand	0	0	0.52	3.28	6.29	8.37	9.16	12.56	13.19
II. INTERUPTIBLE USERS									
Power : Kawas					2.25	2.25	2.25	2.25	2.25
GEB, Dhuvaran			1.05	1.05	1.05	1.05	1.05	1.05	1.05
DESU, Delhi				1.00	3.30	3.30	3.30	3.30	3.30
Fertilizer : GSFC, Baroda			0.45	0.75	0.75	0.75	0.75	0.75	0.75
Industry : IPCL, Baroda			1.20	1.20	1.20	1.20	1.20	1.20	1.20
Sub-Total - Interuptible Demand	0	0	2.10	4.00	8.55	8.55	8.55	8.55	8.55
III. POTENTIAL ADDITIONAL USERS									
Fertilizer : IEL Kanpur				0.32	0.75	0.75	0.75	0.75	0.75
FCI (Gorokhpur)								1.19	1.19
Kota				0.57	0.57	0.57	0.57	0.57	0.57
NTPC, Dadri					0.56	2.25	2.25	2.25	2.25
Gazibad/Faridabad (Small Industry)				0.50	1.00	1.00	1.00	1.00	1.00
Karnal Refinery (Power Plant)						0.50	0.50	0.50	0.50
Saleempur Aromatics (Power Plant)						0.50	0.50	0.50	0.50
Koyali Refinery (LHSH Replacement)	0.50	0.5	0.50	0.50	0.50	0.50	0.50	0.50	0.50
AEC (Ahmebad)			0.83	0.83	0.83	0.83	0.83	0.83	0.83
Sura City Gas Supply		0.57	0.57	0.57	0.78	0.78	0.78	0.78	0.78
TOTAL Identified Potential Demand	0.50	1.07	4.52	10.57	19.83	24.60	25.39	29.98	30.61

INDIA

Western Gas Development Project

Western Region Gas Supply/Demand Balances

(MMCMD)

	1986/87	87/88	88/89	89/90	90/91	91/92	94/95	Notes
Bombay High Ex-Platform	16.3	15.0	14.3	13.4	11.3	11.2	9.2	
Plus: Satellite Production	0.0	0.0	0.0	0.9	1.1	2.3	6.0	(ex-Platform)
Less: Shrinkage & Terminal Use	1.1	1.1	1.1	1.1	1.1	1.1	1.1	
Gas Available Bombay	15.2	13.9	13.2	13.2	11.3	12.4	14.1	
Less: Base Load Bombay Demand	5.1	5.1	5.3	5.5	5.5	5.5	5.5	
Bombay Surplus/Shortage (Lean Gas)	10.1	8.8	7.9	7.8	5.9	7.0	8.7	(Maximum to Hazira)
Interuptible Demand	6.1	6.1	8.5	8.5	8.5	8.5	8.5	
Balance to Hazira: Minimum	4.7	3.4	0.7	0.0	0.0	0.0	0.0	
Gujarat Onshore - Existing Fields	2.5	3.0	3.0	3.0	3.0	3.0	3.0	
Plus: New Fields	0.0	0.3	1.1	1.3	1.9	2.6	4.1	
Less: Field Use & Shrinkage	0.3	0.3	0.4	0.4	0.5	0.6	0.7	(Assumes 10%)
Gas Available Gujarat	2.3	3.0	3.7	3.9	4.4	5.0	6.4	
Less: Base Load Gujarat Demand	2.5	2.5	2.5	2.5	3.0	3.0	3.0	
Gujarat Surplus/Shortage (Lean Gas)	(0.2)	0.5	1.2	1.4	1.4	2.0	3.4	(Maximum to Hazira)
Interuptible Demand	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
Balance to Hazira: Minimum	0.0	0.0	0.0	0.0	0.0	0.0	0.4	
South Bassein Ex-Platform	0.0	2.4	9.7	14.3	19.1	20.0	19.4	
Plus: Excess Bombay High Gas	4.7	3.4	0.7	0.7	0.0	0.0	0.0	
Plus: Satellite Production	0.0	0.0	0.0	0.0	0.0	3.9	5.2	
Adjusted Rich Gas at Hazira	4.4	5.4	9.7	14.0	17.8	22.4	23.0	(After 6.5% sweetening plant shrinkage)
Less: Rich Gas to KRIBBCO and Hazira LPG	3.2	3.8	4.3	4.4	4.7	4.7	4.7	
Rich Gas to HBJ	1.2	1.6	5.4	9.6	13.1	17.7	18.3	
Less: Compressor Use	0.0	0.0	0.2	0.3	0.4	0.4	0.4	
Equivalent Lean Gas Ex-HBJ	1.4	1.7	4.9	8.7	11.9	16.2	16.7	(After LPG extraction)
HBJ Lean Gas Demand	0.0	0.5	3.3	6.3	8.4	9.2	13.2	
Balance	1.4	1.2	1.6	2.4	3.5	7.0	3.5	
HBJ Interuptible Demand	0.0	2.1	4.0	8.6	8.6	8.6	8.6	

Annex 3.1

INDIA

WESTERN GAS DEVELOPMENT PROJECT

ESTIMATED OIL AND GAS RESERVES AND PRODUCTION PROFILES - SELECTED FIELDS

Estimates of Oil and Natural Gas reserves in the South Bassein, Heera and Tapti fields, located offshore, and the Dahej and Gandhar fields, located onshore, India, are summarized as follows:

OIL RESERVES

	Oil-in-Place (MMmt)	Oil-in-Place (MMBbl)	Recoverable Oil (MMmt)	Recoverable Oil (MMBbl)
Offshore:				
Heera (South Block B Zone)..........	125	923	26.3	194
Onshore:				
Gandhar............................	9	64	2.0	11

GAS RESERVES

	Gas-In-Place (BCM)	Gas-In-Place (BCF)	Recoverable Raw Gas (BCM)	Recoverable Raw Gas (BCF)
Offshore				
South Bassein (B Zone)...........	224.6	7,970.0	168.5	5,980.0
South Tapti.......................	12.6	447.6	8.9	315.5
Mid Tapti.........................	9.3	329.0	6.5	230.3
North Tapti.......................	1.0	36.2	0.7	25.3
Onshore:				
Dahej.............................	2.1	75.9	1.2	42.7
Gandhar...........................	9.5	337.8	3.0	107.0

Source: ONGC estimates as reviewed by Sproule Associates, Ltd. (Calgary)

INDIA
Western Gas Development Project

Gas Production & Shrinkage
South Bassein/HBJ Program

Yr No	Year Ended March 31	Production Ex-Wellhead (MMCMD) Gas	Liquids	Platform Use (Gas)	Arriving Hazira Gas	Liquids (mT/day)	Output After Condensate Fractionation Sweetening, and Dew Point Depression: LPG (mt/day)	NGL (mt/day)	Rich Gas (MMCMD)
1	1984	0	0	0	0	0	0	0	0
2	1985	0	0	0	0	0	0	0	0
3	1986	0	0	0	0	0	0	0	0
4	1987	0	0	0	0	0	0	0	0
5	1988	2.5	0.1	0.2	2.2	458	99	296	0.0
6	1989	10.0	0.3	0.2	9.2	1877	441	1270	4.4
7	1990	15.0	0.4	0.5	13.6	2800	676	1923	8.7
8	1991	20.0	0.6	0.7	18.1	3731	912	2583	13.1
9	1992	20.0	0.6	0.7	18.1	3731	912	2583	13.1
10	1993	21.0	0.6	0.7	19.0	3920	961	2717	14.0
11	1994	21.0	0.6	0.9	18.9	3906	956	2706	13.8
12	1995	21.0	0.6	0.9	18.9	3906	956	2706	13.8
13	1996	21.0	0.6	1.3	18.5	3877	947	2682	13.4
14	1997	22.0	0.6	1.8	18.9	4030	984	2787	13.9
15	1998	22.0	0.6	1.8	18.9	4030	984	2787	13.9
16	1999	22.0	0.6	1.8	18.9	4030	984	2787	13.9
17	2000	22.0	0.6	1.8	18.9	4030	984	2787	13.9
18	2001	22.0	0.6	1.6	19.1	4044	988	2799	14.1
19	2002	21.0	0.6	1.5	18.3	3862	942	2670	13.3
20	2003	21.0	0.6	1.4	18.4	3870	945	2676	13.3
21	2004	21.0	0.6	1.3	18.5	3877	947	2682	13.4
22	2005	21.0	0.6	1.0	18.8	3899	954	2700	13.7
23	2006	21.0	0.6	1.0	18.8	3899	954	2700	13.7
	Totals:	366.5	10.4	21.1	324.1	67775	16524	46841	231.4

Yr No	Year Ended March 31	HAZIRA: Rich Gas To Hazira LPG Plant (MMCMD)	Output: LPG (mt/day)	NGL (mt/day)	Lean Gas (MMCMD)	HBJ PIPELINE: Rich Gas to HBJ Pipeline (MMCMD)	Compressor Use (MMCMD)	Rich gas into LPG plants	Output: LPG (tons/day)	NGL (tons/day)	Lean Gas (MMCMD)
1	1984	0	0	0.0	0	0	0	0.0	0	0	0.0
2	1985	0	0	0.0	0	0	0	0.0	0	0	0.0
3	1986	0	0	0.0	0	0	0	0.0	0	0	0.0
4	1987	0	0	0.0	0	0	0	0.0	0	0	0.0
5	1988	2.1	190	61	1.9	0.0	0.0	0.0	0	0	0.0
6	1989	4.6	412	132	4.3	4.4	0.2	4.2	344	65	3.1
7	1990	4.6	412	132	4.3	8.7	0.3	8.4	692	130	7.2
8	1991	4.6	412	132	4.3	13.1	0.4	12.7	1040	195	11.2
9	1992	4.6	412	132	4.3	13.1	0.4	12.7	1040	195	11.2
10	1993	4.6	412	132	4.3	14.0	0.4	13.6	1115	209	12.1
11	1994	4.6	412	132	4.3	13.8	0.4	13.4	1100	207	11.9
12	1995	4.6	412	132	4.3	13.8	0.4	13.4	1100	207	11.9
13	1996	4.6	412	132	4.3	13.4	0.4	13.0	1071	201	11.6
14	1997	4.6	412	132	4.3	13.9	0.4	13.5	1110	208	12.1
15	1998	4.6	412	132	4.3	13.9	0.4	13.5	1110	208	12.1
16	1999	4.6	412	132	4.3	13.9	0.4	13.5	1110	208	12.1
17	2000	4.6	412	132	4.3	13.9	0.4	13.5	1110	208	12.1
18	2001	4.6	412	132	4.3	14.1	0.4	13.7	1124	211	12.2
19	2002	4.6	412	132	4.3	13.3	0.4	12.9	1057	198	11.4
20	2003	4.6	412	132	4.3	13.3	0.4	12.9	1064	200	11.5
21	2004	4.6	412	132	4.3	13.4	0.4	13.0	1071	201	11.6
22	2005	4.6	412	132	4.3	13.7	0.4	13.0	1093	205	11.9
23	2006	4.6	412	132	4.3	13.7	0.4	13.0	1093	205	11.9
	Totals:	84.9	7604	2445	79.3	231.4	6.9	223.9	18443	3463	199.1

Assumptions: Condensate ex-wellhead @ 2.8% of gas produced by volume. Pipeline condensate @ 6.19% of gas ex-platform.

Proportions extracted or used:

	Condensate Fractionation	Gas Sweetening	Dew Point Depression	LPG Plants	Conversion Factors (tons/MMCM)
LPG	21.5%	-	0.4%	4.0%	2238.64
NGL	64.5%	-	0.4%	0.5%	3428.18
Gas	13.9%	6.5%	0.2%	2.0%	562.00

	(tons/MMCM)
Condensate X-Wellhead:	4143.33
Condensate X-Pipeline:	1171.21
Gas X-Condensate fractionation:	562.00

INDIA

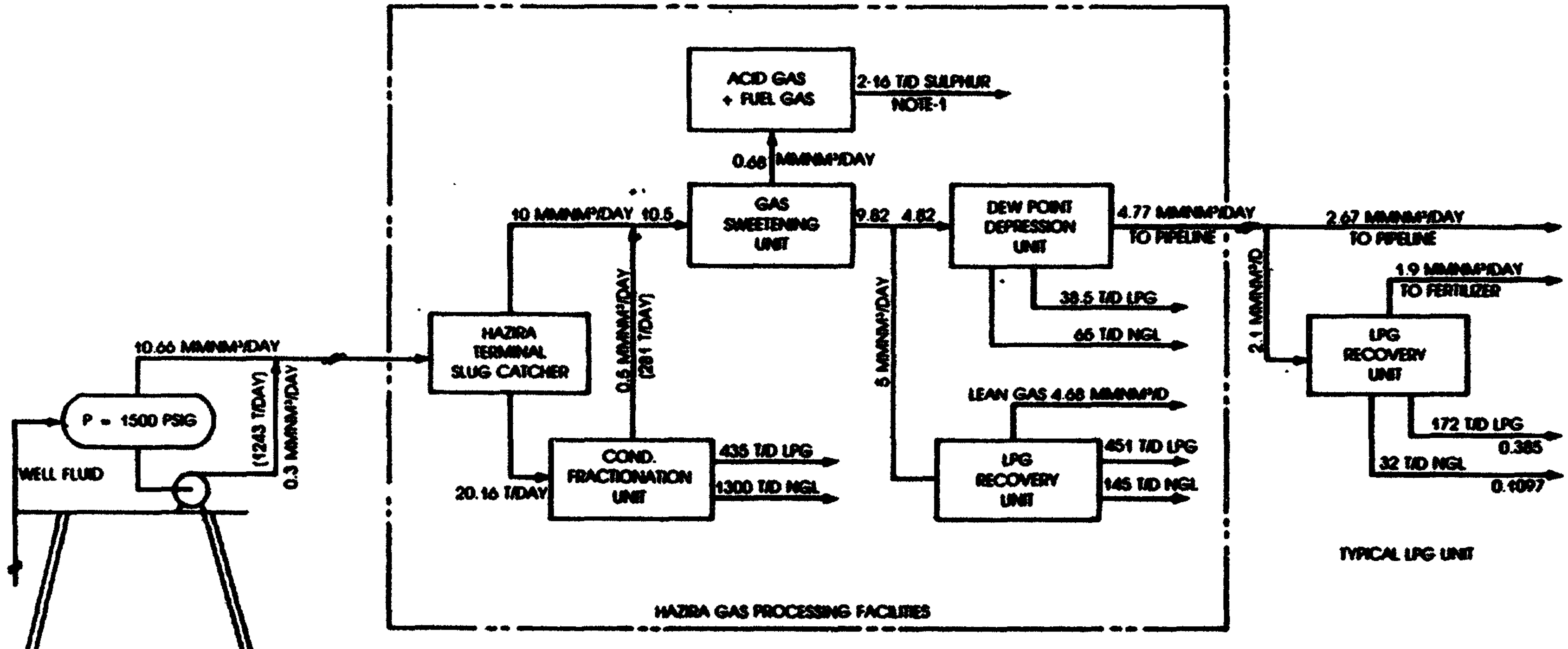
Western Gas Development Project

Gas Production & Shrinkage

South Bassein Phase II

Year Ended March 31	Production Ex-Wellhead Gas (MMCMD)	Production Ex-Wellhead Liquid (MMCMD)	Platform Use (Gas)	Arriving Hazira Gas (MMCMD)	Arriving Hazira Liquids (tons/day)	Output After Condensate Fractionation Sweetening, and Dew Point Depression LPG (tons/day)	NGL (tons/day)	Rich Gas (MMCMD)
1987	0.0	0.0	0.0	0.0	0	0	0	0.0
1988	0.0	0.0	0.0	0.0	0	0	0	0.0
1989	0.0	0.0	0.0	0.0	0	0	0	0.0
1990	5.0	0.1	0.2	4.5	931	237	660	4.4
1991	10.0	0.3	0.4	9.1	1866	475	1322	8.8
1992	10.3	0.3	0.4	9.3	1913	487	1356	9.0
1993	10.5	0.3	0.4	9.5	1960	499	1389	9.3
1994	10.5	0.3	0.5	9.4	1953	497	1384	9.2
1995	10.5	0.3	0.5	9.4	1953	497	1384	9.2
1996	10.5	0.3	0.7	9.2	1938	492	1372	9.0
1997	11.0	0.3	0.9	9.5	2015	510	1424	9.2
1998	11.0	0.3	0.9	9.5	2015	510	1424	9.2
1999	11.0	0.3	0.9	9.5	2015	510	1424	9.2
2000	11.0	0.3	0.9	9.5	2015	510	1424	9.2
2001	10.5	0.3	0.8	9.1	1928	489	1363	8.9
2002	10.5	0.3	0.8	9.1	1931	490	1366	8.9
2003	10.5	0.3	0.7	9.2	1935	491	1369	9.0
2004	10.5	0.3	0.7	9.2	1938	492	1372	9.0
2005	10.5	0.3	0.5	9.4	1949	495	1381	9.1
2006	10.5	0.3	0.5	9.4	1949	495	1381	9.1

INDIA
WESTERN GAS DEVELOPMENT
GAS TREATMENT COMPLEX AT HAZIRA
Mass Balance Diagram



NOTES:

1. DEPENDING ON 150 TO 1200 PPM(V) OF H_2S IN SOUR GAS.
2. ADDITIONAL 40 T/DAY OF LPG & 67.5 T/DAY OF NGL WILL BE PRODUCED FROM DEW POINT DEPRESSION CONDENSATE EQUIVALENT TO 5 MMNM³/DAY FEED GAS TO D.P.D. UNIT.
3. FUTURE LPG PLANT (DOWN STREAM OF THE DPD UNIT) WILL PRODUCE 411 T/DAY OF LPG & 77.5 OF NGL FROM 5 MMNM³/DAY FEED GAS.
4. EXCEPT FOR LPG UNITS, WHICH IS 330 DAYS OPERATION, ALL UNITS ARE FOR 365 DAYS OPERATION PER YEAR.

World Bank—40395:1

Annex 3.5

INDIA

Western Gas Development Project

Production Profiles

Heera

(MMCMD)

Year Ended March 31	Production Ex-Wellhead	Field Use Offshore	Gas Delivered to Market
1987	0.91	0	0.91
1988	1.01	0	1.01
1989	1.05	0	1.05
1990	1.47	0.3	1.17
1991	1.83	0.3	1.53
1992	1.37	0.3	1.07
1993	1.03	0.3	0.73
1994	0.83	0.3	0.53
1995	0.71	0.3	0.41
1996	0.63	0.3	0.33
1997	0.58	0.3	0.28
1998	0.54	0.3	0.24
1999	0.50	0.3	0.20
2000	0.50	0.3	0.20
2001	0.50	0.3	0.20
2002	0.50	0.3	0.20
2003	0.50	0.3	0.20
2004	0.50	0.3	0.20
2005	0.50	0.3	0.20
2006	0.50	0.3	0.20

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Western Gas Development Project

Production Profiles

Gandhar

Year Ended March 31	Condensate (MMmt)	Gas (MMCMD)
1987	0.0	0.0
1988	0.0	0.0
1989	0.4	0.3
1990	0.4	1.1
1991	0.5	1.2
1992	0.5	1.4
1993	0.4	1.5
1994	0.3	1.4
1995	0.3	1.4
1996	0.2	1.4
1997	0.2	1.3
1998	0.1	1.3
1999	0.1	1.2
2000	0.1	1.1
2001	0.1	1.1
2002	0.1	1.0
2003	0.1	1.0
2004	0.1	1.0
2005	0.1	1.0
2006	0.1	1.0

Source: Bank staff estimates.

INDIA

WESTERN GAS DEVELOPMENT PROJECT

TECHNICAL NOTES ON CHARACTERISTICS OF WESTERN REGION FIELDS AND ONGC DEVELOPMENT PLANS

Bombay High Oil Field and Associated Gas Production

1. The Bombay High oil field is also a substantial source of associated gas, which plays an important role in the long-term planning of gas supplies in the Western Region. At present, some 15 MMCMD is produced, of which 5 MMCMD a day is flared. This volume of flared gas represents almost US$500,000 a day of crude equivalent at today's prices (US$15/Bbl). Flaring is planned to be eliminated as new industrial complexes and power generation facilities come onstream in the Bombay area and additional users are converted from alternative fuels.

2. The Gas-Oil Ratio, or GOR, is 324 CM/CM for Bombay High North and 192 CM/CM for Bombay High South. Though the latter is acceptable and in line with predicted solution ratios, the former is too high and indicates that gas-cap gas is being produced, which could impair maximum oil recovery from this part of the field. ONGC has been aware of the need to correct this situation and installed water injection facilities in the north of the field, which have been operational since March 1984. Water injection in the south has been delayed, but is expected to be operational early 1987. The results of water injection in the north have been encouraging: reservoir pressure has risen 6-8 bars and the GOR's are stabilizing. Only four wells showed water breakthrough and three had to be shut in because of high GOR's.

3. If GOR continue to stabilize, then Bank estimates are that gas should be produced at a plateau rate of approximately 14.5 MMCMD gross for the next five years or 12.5 MMCMD net (after meeting gas demand for field production requirements). ONGC's predictions are substantially above earlier forecasts of 10 MMCMD. In order to transfer the additional gas production to shore, ONGC is restaging the compressors on the BHN platform to produce a higher discharge pressure. ONGC's assumption for planning purposes is that any extra gas would find a ready market in the Bombay industrial area and that, accordingly, demand for gas from the South Bassein field would not likely be affected by higher production from Bombay High.

South Bassein Field

4. The South Bassein field is an offshore natural gas reservoir located approximately 65 km west of Bombay. The gas reservoir is a structurally high area situated on the continental shelf between the Bombay High oil field to the west and the city of Bombay to the east.

5. Exploratory drilling has defined the area as a symetrical anticlinal feature having two well defined gas reservoirs overlying each other, both trending in a north-northwest, south-southeastern direction. The reservoir is of the Lower Oligocene and Upper Eocene age. The upper gas zone is at approximately 1,650 meters subsea and the lower zone at approximately 1,700 meters subsea. The water depth in the area is about 30 meters. The total area of the reservoir is approximately 210 sq. km. with an average gas pay thickness of 41 meters.

6. As of July 1986, seven exploratory wells have been drilled, of which six encountered commercial gas from the Bassein limestone. Five of these wells were exploration wells and have since been plugged and abandoned. The entire South Bassein structure is underlain by a thin oil column and water. This oil column is very thin and would be extremely difficult to produce.

7. ONGC has one platform in place with nine wells drilled to a depth of 1,450 meters. Only one well, BA-1, on this platform has been tested at a gas rate of 9 MMCFD from the lower zone. The other wells require additional drilling and completion before production tests can be performed. ONGC plans to develop the area with four platforms (nine wells each) for a total of 36 wells. Due to the possibility of water coning, 20 wells will be drilled in the central area of thick gas column (70 to 100 meters) and will be restricted to 700 MCMD (25 MMCFD), and 400 MCMD (14 MMCFD). Water production is forecast to commence in ten years, and this production would increase to a rate of 4,050 CMD (2,500 Bbl/d) after 20 years.

8. The major concern associated with this reservoir is the potential of water coning. ONGC has had a coning model study prepared for the South Bassein field and has followed the recommendations of well locations and production restrictions as suggested in the study. ONGC has also prepared in-house studies using a coning model and is using the results of these studies to optimize production from the field.

Heera Oil Field

9. The Heera oil field, located about 60 km southeast of the South Bassein gas field, was discovered in 1977. Its major structure, Heera South, is wedge-shaped, with the thin edge of the wedge slanted up-dip t the east. Oil is found in three horizons. The major accumulation is in the Bassein limestone (Oilgocene-Middle-Eocene) at 1,650 meters depth. The structure has an average porosity of 15% and average water saturation of 35%.

10. Oil reserves in place have been estimated at 125 MMmt of a high quality 38° API sweet crude. These reserves have been calculated for the Bassein limestone on a volumetric basis, based on an isopach map of net pay. The net pay thicknesses were selected using an 8% porosity cut-off and a 70% water saturation cut-off. This approach is realistic.

11. Since oil produced from Heera is undersaturated, the field appears to have no gas cap. The oil-water contact has not been clearly established. With no gas cap and no apparent waterdrive, pressure maintenance is required in order to reach reasonable rates of recovery. A study by the French petroleum company, Compagnie Francaise du Petrole (CFP) suggested the need for water injection to enhance recovery from the field. ONGC undertook a 15-year performance simulation using a 3-D model. These studies confirm that water injection would have to be started after recovering approximately 3% of oil in place, that is, after approximately two years of production at 24,000 Bbl/d. The ONGC study indicates that the optimum method of field development is pressure maintenance by pattern injection in the central zone, and a row of injectors on the periphery on the down-dip side.

12. The objective of phase II is (i) to implement this water injection scheme; (ii) to provide a crude pipeline to Uran so that the present practice of crude oil evacuation by tanker can be eliminated; and (iii) to provide gas treatment and compression facilities and to lay a gas pipeline to Uran, so that flaring of associated gas can be stopped; gas facilities will be located on a separate platform.

13. Gas processing will consist of dehydration and dew point depression facilities to meet specifications required for safe pipeline transport to shore. The gas will be compressed to 900 psi pipeline-inlet pressure in a first stage. Part of the gas will subsequently be raised to a pressure of 1,900 psi and distributed through a pipeline network to all oil wells. By leading the high pressure gas to the bottom of the well, the upward movement of the resulting gas bubbles effectively reduces downhole pressure and improves well performance. The gas used for gas lift purposes returns with the oil via production facilities to the gas processing plant where it is jointly treated with the associated gas produced, and recirculated after recompression. Gas lift will be essential to maintain plateau oil production, as the presence of water in the oil increases as a result of water injection. The resultant higher specific gravity of the oil-water mix would increase the back pressure in the well, reducing flow further without the gas lift.

14. ONGC has designed all production and gas processing facilities to be capable of handling hydrogen sulfide, if necessary. This is a precaution against the potential formation of hydrogen sulfide and hydrogen sulfide compounds in the oil-bearing structure, which often occurs when anaerobic bacteria in sea water come in contact with oil, an environment in which they can proliferate. Although sea water is treated with biocides before injection in an effort to prevent growth of such bacteria, this method is not infallible and, accordingly, process design to allow for the possibility of higher sulfur content at slightly higher cost is appropriate and justified.

15. The proposed 24" gas line, to follow the same course as the oil line, will eliminate flaring of associated gas at the present rate of 1.2 MMCMD and at a future plateau rate of 0.8 MMCMD. For these amounts of gas, the proposed gas line, with a capacity of over 5 MMCMD (with compression), would be

considerably oversized. However, the pipeline can be completed about one-year earlier than gas compression on the gas processing platform can be installed and made operational, and this will allow flaring of gas from Heera to be stopped one-year earlier, saving some 400 MMCM of associated gas. During this first year, the gas line will be operated at low pressure. The value of gas saved, almost US$40 million (based on oil equivalent value, with crude at US$15/Bbl), more than exceeds the cost of doubling the diameter of the pipeline (from 12" to 24"). The Heera gasoline will also be a component of ONGC's strategic Western Offshore Integration Project, which is funded by GOI with the objective of safeguarding the uninterrupted supply of India's major hydrocarbon resources from the offshore fields.

The Gandhar Field

16. In April 1984, a discovery was made at Gandhar, onshore in Gujarat state adjacent to the eastern shore of the Gulf of Cambay, about 85 km SW of Baroda and 75 km from the Ankleshwar field, the principal producing area in the southern portion of the Cambay Basin. A large part of the Gandhar field is in tidal-swept mud flats and in a contiguous shoal area. Its extension may well continue offshore beneath the shallow waters of the Gulf, requiring mat-type shallow water jack-up rigs for development. Since discovery, five appraisal wells (all productive) have been drilled and data from these wells, in addition to the original well, is available.

17. The Gandhar wells have established eight reservoir sands which yield volatile oil with high gas saturation (that is, Gandhar is similar for all practical purposes to a gas/condensate field). Free gas caps on these reservoirs are highly probable, but gas-oil contacts have not yet been established. Down-dip oil-water contacts have been established in several of the sands and thus each is expected to have individual gas-oil and oil-water contacts, and be entirely separate one from the other. Thus far, a productive zone has been established between 2,800-3,100 m depth in an area representing 140 m of structural relief. No limits to up-dip or down-dip production have yet been established, although recent offshore seismic results in the Gulf of Cambay indicate an up-dip limit of the overall productive interval. This strongly suggests that there exists a favorable band of production where the up-dip pinchout of reservoir sands relative to structural position is optimal. Up-dip from this optimum area, the productive reservoirs will be thinner and mostly gas productive, while down-dip from the area most reservoirs will be thicker and predominantly water-bearing. Drilling to date is not sufficient to determine the width of the optimum area or its trend.

18. The volatile oil in the reservoirs is 45-50° API (specific gravity is 0.80) and is gas-saturated at approximately 350 CM/CM (1,950 CF/Bbl) at a reservoir pressure of 4,300 psi, normal for production from this depth. The reservoir intervals suspected of being gas-bearing yield associated liquids of 52-55° API (specific gravity 0.77) with gas-liquid ratios of 2,500 CM/CM (14,000 CF/Bbl, equal to 70 Bbl condensate/MMCF). With proper completion, the oil reservoirs would be capable of producing 500 Bbl/d or more on a sustained basis. Oil completions with significant formation damage will perform as gas wells.

19. Data available to date suggests wells in the oil production area will develop recoverable reserves of the order of 1.6MM Bbl oil and 5.5 BCF gas per km^2, while wells in the up-dip gas-prone area will develop reserves of the order of 9 BCF gas and 0.35MM Bbl condensate per km^2. Wells down-dip of the oil productive area may yield 0.8MM Bbl and 2.2 BCF gas per km^2. Ultimate reserves associated with the pinchout trend are impossible to estimate at this time, but could be very large. In fact, it may be that more prior discoveries indip of the oil productive area may yield 0.8MM Bbl and 2.2 BCF gas per km^2. Ultimate reserves associated with the pinchout trend are impossible to estimate at this time, but could be very large. In fact, it may be that more prior discoveries in the South Cambay Basin are associated with the trends identified with the Gandhar discovery, including the Ankleshwar field itself (with estimated recoverable reserves in the range of 600MM Bbl).

20. The Gandhar field is at its initial appraisal stage. Currently, four ONGC-owned and operated drilling rigs are drilling delineation wells. Four rigs are in Gandhar where six wells have been completed as gas, volatile oil producers and condensate producers.

21. In light of the appraisal well testing results and the geological survey studies, the Gandhar field may be India's largest discovery after Bombay High. ONGC is setting up a task force to prepare detailed plans for development of both fields.

Main Characteristics of the Gandhar Field

	Gandhar
Size (km^2)	50
Average depth of producing zones (m)	3,000
Age of producing zones	Middle Eocene
Porosity (%)	18
Permeability (millidarcy)	100
Salinity of formation water (grams/lit)	6-14
Gas-oil ratio (CM/CM)	200-2,300
Oil gravity (API)	45-55

22. The Gandhar field is not yet delineated. The geological knowledge of its configuration is still quite limited. The field is at the start-up phase of appraisal and it is very difficult to evaluate the size and the extent of the resources associated with their discovery.

23. ONGC's estimates for proved initial petroleum reserves in place, recoverable and production rate are currently as follows:

Estimated Reserves and Production: Gandhar Field

	Gandhar
Oil in Place	8.6 MMmt (10.2 MMCM)
Oil Recoverable	1.5 MMmt (1.8 MMCM)
Condensate in Place	2.8 MMmt (2.6 MMCM)
Condensate Recoverable	0.8 MMmt
Gas in Place	11.6 (BCM)
Gas Recoverable	4.2 (BCM)
Tons of Oil Equivalent in Place	17.0 MMtoe
Tons of Oil Equivalent Recoverable	4.5 MMtoe
Additional Probable Recoverable Reserve	
Oil	12.5 MMmt
Condensate	1.9 MMmt
Gas	9.6 BCM
Average Production Forecast per Well	
Liquid (Bbl/d)	350 for 10 yrs
Associated Gas (CMD)	54 MCM for 10 yrs
Non-Associated Gas (CMD)	24 MCM for 10 yrs

24. ONGC's proved reserves and production rate estimates are conservative. Proved plus probable estimates are Bank staff estimates based on the proposed program. Final proved plus probable reserves may be considerably larger. Wells drilled to date have been evaluated through drill stem and short-term production testing using a 5-1/2" casing size and 2-7/8" tubing size, both of which are restrictive. With appropriate well design and completion practices, in Gandhar a daily sustained production rate averaging 500 Bbl/d of liquid and 50,000 CMD of gas may likely be obtained for the first four years or so.

25. Given the substantial amount of liquid to be produced, ONGC has decided to convert the testing phase into an early production system during which gas would be flared and liquids trucked to the nearest refinery. This early production program will allow better understanding of reservoir performance and adequate well completion design.

26. Four drilling rigs are currently assigned to the delineation program. The same rig fleet would be maintained throughout the appraisal phase, which may last until 1988. In general, the strategy of the appraisal program is designed to fully assess the hydrocarbon potential of the Middle Eocene formation and to provide better understanding of the structural trend of the fields and their relationship with existing fields in the Cambay Basin in order to establish a sound basis for estimating the production potential, the recoverable reserves and, finally, the size of the production facilities.

27. Concurrently, ONGC is actively preparing a development program for this field. A first development phase, consisting of about 50 wells, of which 35 would be production wells and 15 water injection wells, is planned to begin in 1988 in Gandhar. The first development wells would be located where the reservoir is most liquid-productive in the previously appraised area. The program is being designed to ascertain optimum liquid production and is flexible enough to allow for shifting the emphasis from liquid to gas production when changes occur within the program, as might be required by well results. It is also conceived as a minimum program for a field where there is some evidence of large gas, condensate and volatile oil reserves. All of the wells will be drilled with the Middle Eocene as the objective, to about 3,000 meters. To implement this program, ONGC is preparing, with the consent of GOI, to mobilize specialized drilling contractors with five rigs.

Hazira and North Tapti Fields

28. Hazira is an offshore gas field, discovered in 1969 in the shallow waters of the Gulf of Cambay. A small portion of the field continues north, under the shoal areas and farther onshore near Hazira town. Only two wells have been drilled in Hazira. The discovery well produced gas at a fairly good rate. A second well, drilled on the onshore part, was water-bearing. North Tapti is also an offshore gas field, discovered in 1983 in the Gulf of Cambay, southwest of Hazira field. Since the discovery well, which produced gas at a good rate, no further drilling has been carried out.

29. Both fields produce from an early to a middle Miocene sandstone formation, in both cases, on a structural anticline. The producing sandstone was encountered in the discovery wells at about 1,160 m depth in Hazira and 560 m depth in North Tapti with several hydrocarbon-bearing layers within an average gross thickness of 60 m and 130 m, respectively. On the basis of existing data, the size of Hazira would be about 20 sq km and North Tapti about 37 sq km. On the basis of existing geophysical, geological and discovery well data studies, ONGC's forecast is to produce up to 0.6 MMCMD of gas from Hazira and 0.4 MMCMD of gas from North Tapti, with seven wells in each field.

30. Based on the limited geological and geophysical data available, the following main characteristics of Hazira and North Tapti have been tentatively established:

Main Characteristics of Hazira and North Tapti

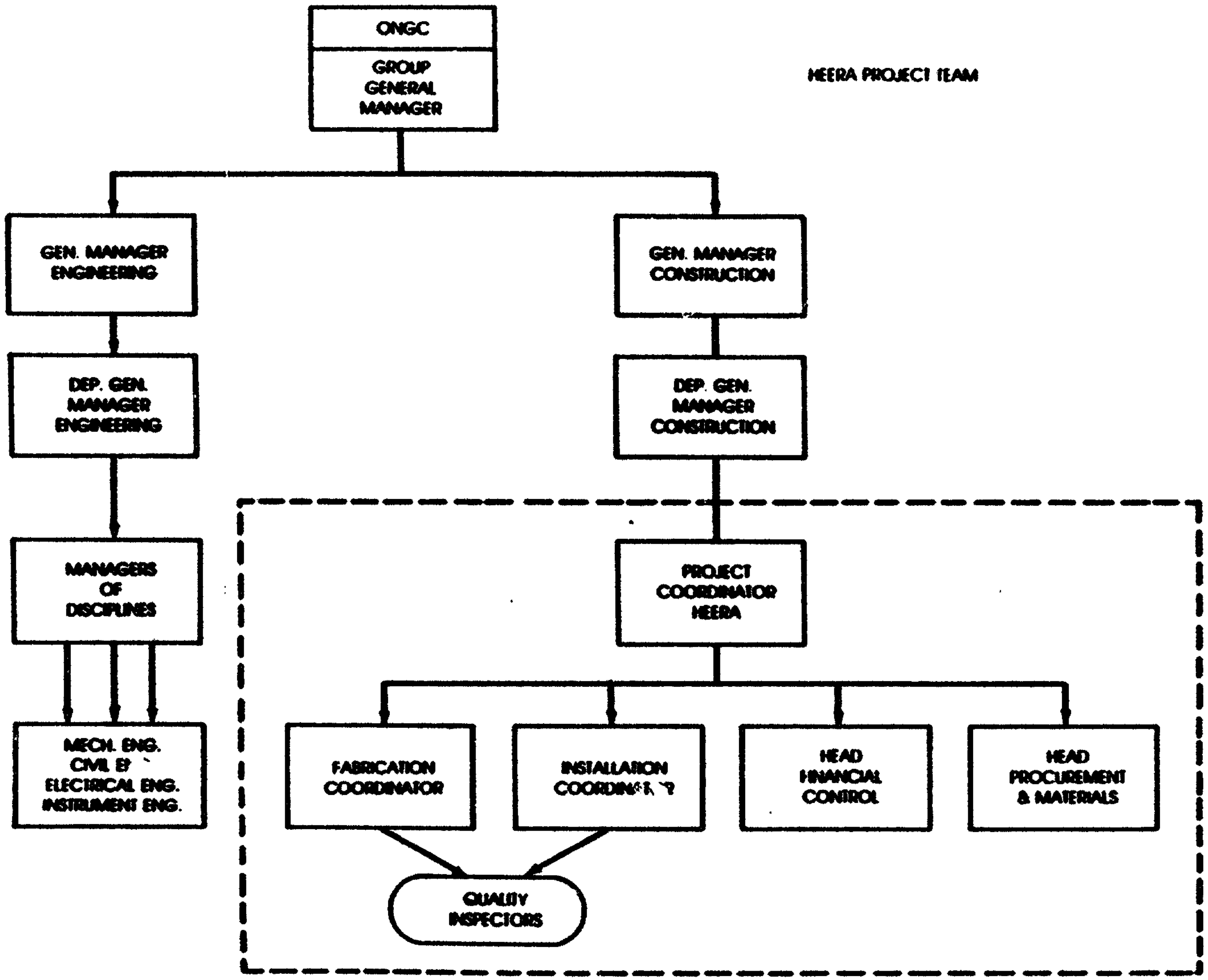
	Hazira	North Tapti
Gas in Place	7 BCM	1 BCM
Gas Recoverable	4 BCM	0.7 BCM
Reservoir Pressure	110 bars	60 bars
Average Depth (subsea)	1,150 m	550 m
Water Depth	5-20 m	30 m
Maximum Areal Closure	30 km^2	60 km^2
Maximum Vertical Closure	70 m	200 m

31. There is no seismic control data for the offshore part of Hazira, which is presumed to close seaward. The existing seismic data is old and in addition it was surveyed from varying distances and alignments because of the difficult environment - shallow water with sand bars and tidal mud flats with strong sea currents - it is of poor quality. ONGC's forecasts are based primarily on flow data from the discovery wells. Hazira produced about 236,000 CMD of gas and a 1/2" choke at a flowing pressure of about 83 bars (1,170 psi) and North Tapti produced about 130,000 CMD of gas on a 1/2" choke at a flowing pressure of about 40 bars (600 psi).

32. As part of its long term program of developing the Bombay offshore satellite fields, ONGC will evaluate the hydrocarbon potential of the Hazira and North Tapti fields. The evaluation program includes seismic surveys, seismic data interpretation and some appraisal drilling. Both fields require the application of modern geophysical methods such as high resolution and/or 3-D seismic surveys which would help resolve the size and prospectiveness of the structure and determine the appraisal drilling program. High resolution seismic would help identify the Miocene formation limit, delineate more precisely the main faults and fault controlled traps, and outline the onshore extent of the Hazira structure. The main objective of the 3-D seismic would be to identify and help map the various prospective sand layers of the Miocene. Given the difficult environment, a large part of the seismic data acquisition would be by streamer and teleseis, particularly over the tidal and shoal areas. Both fields require about 500 line-kms of seismic data acquisition. This seismic program is expected to be very effective since, to date, the highly prospective areas in the Gulf of Cambay have not been surveyed with specialized geophysical techniques.

33. With regard to appraisal drilling, ONGC intends to drill three appraisal wells on each structure on the basis of the seismic data interpretation. While the final well locations will be determined by the seismic results, ONGC is already proposing to drill one well on the southeastern flank of each structure. ONGC's geophysical program is appropriate but appraisal drilling would better be postponed until a thorough review of the results of the seismic program. While Hazira may be highly prospective, the North Tapti field, as a result of the shallow depth and low pressure, could deplete quite rapidly. A positive aspect of North Tapti is that the structure could be very large and contain a correspondingly large volume of gas.

INDIA
WESTERN GAS DEVELOPMENT
Typical Project Organization



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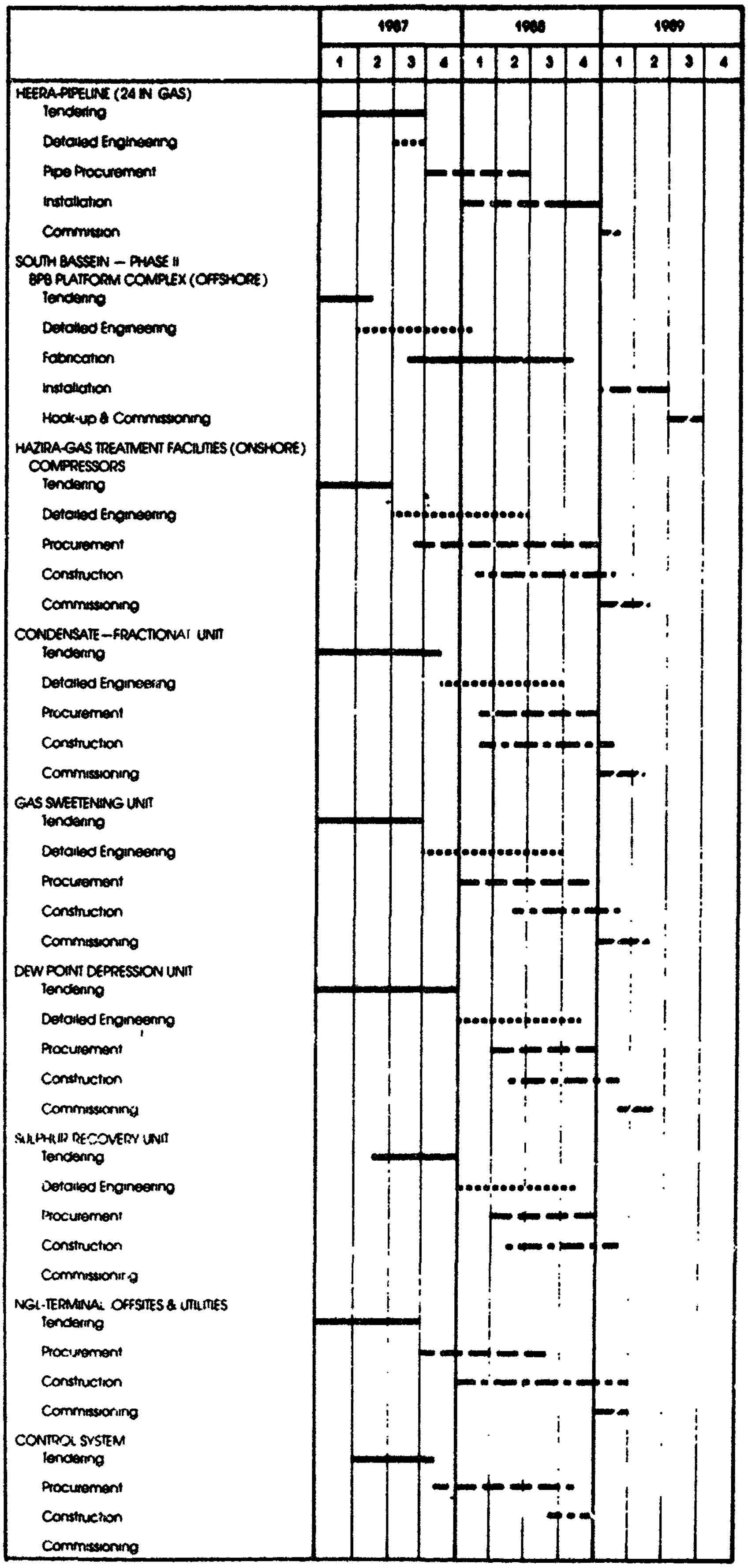
ANNEX 4.2

INDIA
WESTERN GAS DEVELOPMENT PROJECT
Implementation Schedule



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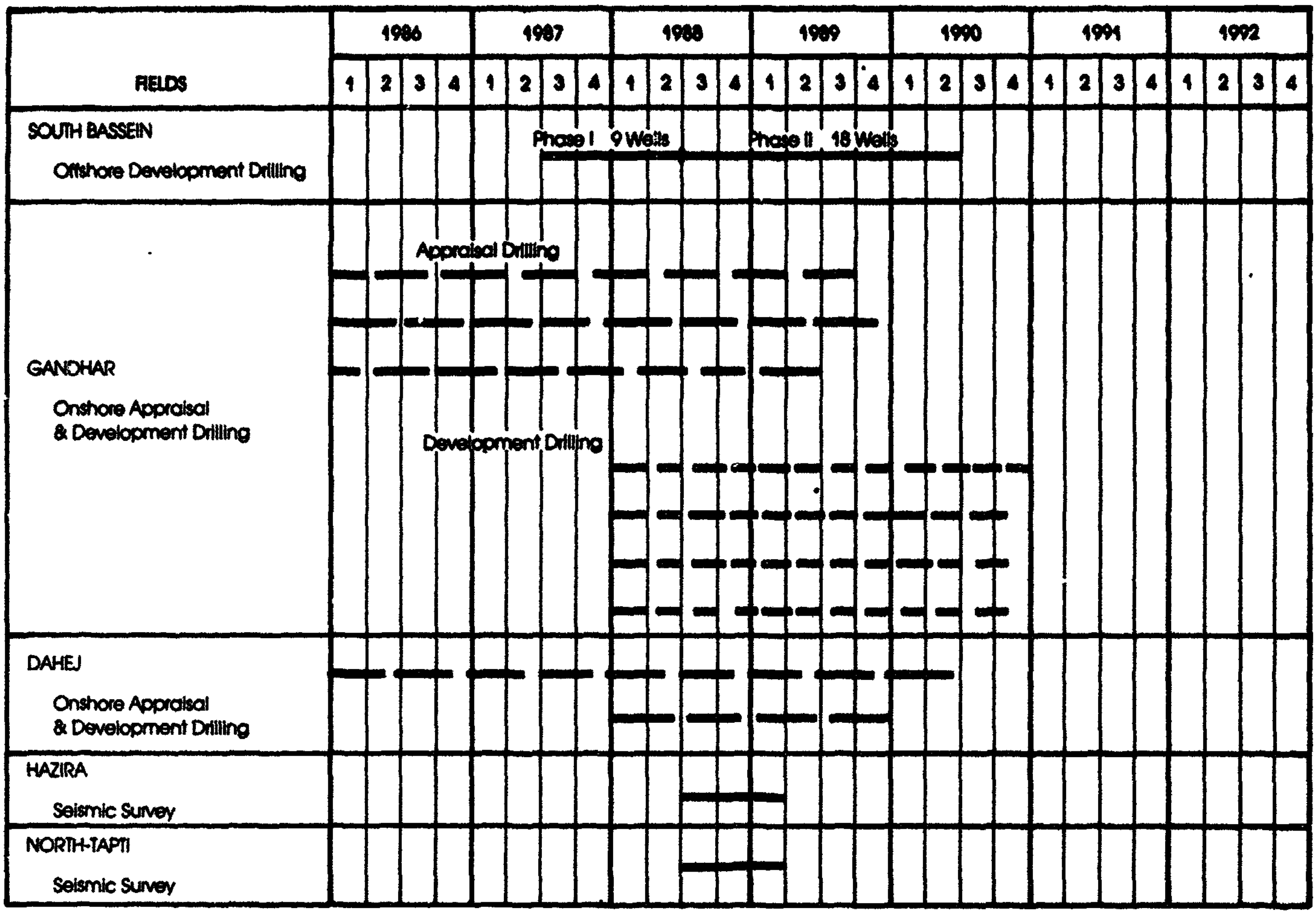
ANNEX 4.3

INDIA
WESTERN GAS DEVELOPMENT PROJECT
Implementation Schedule of the Drilling & Seismic Components



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INDIA

Western Gas Development Project

OIL AND NATURAL GAS COMMISSION
DETAILED PROJECT COST TABLE
(FY ending March 31)

(US$ Millions)

	FY 87			FY 88			FY 89		
	Loc	For	Tot	Loc	For	Tot	Loc	For	Tot
South Bassein field Phase II:									
Offshore Facilities									
Engineering, Management	0.4	2.5	2.9	0.4	2.5	2.9	0.4	2.5	2.9
BPB Platforms and Pipeline .	0.0	10.3	10.3	0.0	51.5	51.5	1.6	30.9	32.5
Drilling (27 wells)				1.4	1.7	3.1	11.4	13.3	24.7
Onshore Facilities (Hazira)									
Gas Processing Facilities ..	1.0	0.0	1.0	10.8	8.0	18.8	21.6	16.0	37.6
Infrastructure	2.0	0.0	2.0	6.7	2.0	8.7	2.0	1.5	3.5
Engineering	3.0	0.0	3.0	2.0	0.0	2.0	1.5	0.0	1.5
NGL Terminal				2.1	3.0	5.1	4.6	12.0	16.6
Other	1.0	0.0	1.0	2.0	0.0	2.0	2.0	0.0	2.0
Heera field:									
Pipeline				0.0	12.0	12.0	0.0	42.0	42.0
Engineering................	1.0	2.0	3.0	1.0	1.0	2.0	2.0	1.0	3.0
Gander/Dahej field:									
Engineering................				1.5	0.5	2.0	2.0	1.0	3.0
Surface Facilities				0.0	0.0	0.0	18.1	3.0	21.1
Drilling (90 wells)				8.5	10.0	18.5	61.3	90.0	151.3
North Tapti and Hazira fields:									
Appraisal Drilling (15 wells).				4.7	10.0	14.7	6.9	14.0	20.9
Seismic - Regular							0.5	2.5	3.0
Seismic - 3-D							0.5	4.5	5.0
Studies, Consulting							0.1	0.5	0.6
Base Cost (1987 prices)	8.4	14.8	23.2	41.1	102.2	143.3	136.5	234.7	371.2
Physical Contingencies	0.8	1.5	2.3	4.1	10.2	14.3	13.6	23.5	37.1
Price Contingencies	0.0	0.0	0.0	2.9	6.8	9.7	20.3	24.9	45.2
Total Project Cost	9.2	16.3	25.5	48.1	119.2	167.3	170.4	283.1	453.5

	FY 90			FY 91			FY 92			Total : FY 87-92		
	Loc	For	Tot	Loc	For	Tot	Loc	For	Tot	Loc	For	Tot
South Bassein field Phase II:												
Offshore Facilities												
Engineering, Management	0.4	1.5	1.9	0.0	1.4	1.4				1.6	10.6	12.0
BPB Platforms and Pipeline .	12.9	10.3	23.2	1.5	0.0	1.5				16.0	103.0	119.0
Drilling (27 wells)	28.4	33.3	61.7	19.7	16.7	36.4				60.9	65.0	125.9
Onshore Facilities (Hazira)												
Gas Processing Facilities ..	6.8	5.0	11.8							40.2	29.0	69.2
Infrastructure	1.5	0.8	2.3							12.2	4.3	16.5
Engineering	1.5	0.0	1.5							8.0	0.0	8.0
NGL Terminal	2.5	7.0	9.5							9.2	22.0	31.2
Other	0.0	0.0	0.0							5.0	0.0	5.0
Heera field:												
Pipeline	0.0	45.0	45.0							0.0	99.0	99.0
Engineering................	1.5	1.6	3.1							5.5	5.6	11.1
Gander/Dahej field:												
Engineering................	2.0	1.0	3.0	1.5	0.5	2.0				7.0	3.0	10.0
Surface Facilities	13.7	2.0	15.7	10.0	0.0	10.0	5.0	0.0	5.0	46.8	5.0	51.8
Drilling (90 wells)	53.0	77.0	130.0	45.3	40.0	85.3	35.5	30.0	65.5	203.6	247.0	450.6
North Tapti and Hazira fields:												
Appraisal Drilling (15 wells).	18.1	23.0	41.1							29.7	47.0	76.7
Seismic - Regular										0.5	2.5	3.0
Seismic - 3-D										0.5	4.5	5.0
Studies, Consulting	0.2	0.5	0.7							0.3	1.0	1.3
Base Cost (1987 prices)	142.5	208.0	350.5	78.0	58.6	136.6	40.5	30.0	70.5	447.0	648.3	1095.3
Physical Contingencies	14.3	20.8	35.0	7.8	5.9	13.7	4.1	3.0	7.1	44.7	64.9	109.5
Price Contingencies	30.7	15.5	46.3	22.8	5.9	28.7	15.2	4.0	19.2	91.9	57.1	149.1
Total Project Cost	187.5	244.3	431.8	108.6	70.4	179.0	59.8	37.0	96.8	583.6	770.3	1353.9

Note: Of total Local Costs indicated above, US$192.1 million comprise local taxes and custom duties.

Annex 4.5

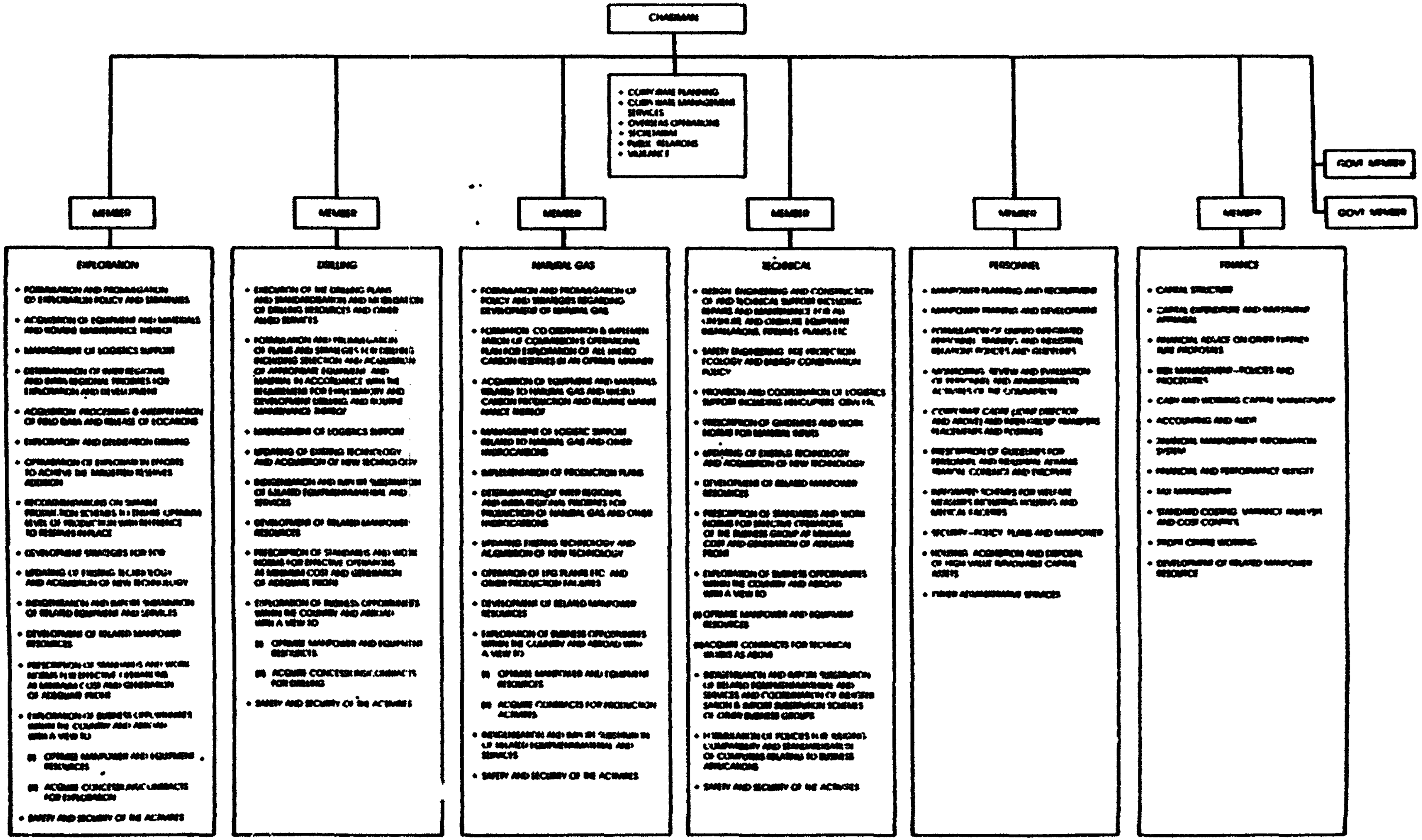
INDIA

WESTERN GAS DEVELOPMENT PROJECT

Estimated Schedule of Disbursement
(US$ Million)

IBRD Fiscal Year	Quarters	Amount Disbursed	Cumulative Amount	%
1988	I			
	II			
	III			
	IV	10	10	3
1989	I	15	25	8
	II	25	50	17
	III	25	75	25
	IV	25	100	34
1990	I	25	125	42
	II	25	150	51
	III	25	175	59
	IV	20	195	66
1991	I	15	210	71
	II	15	225	76
	III	15	240	81
	IV	15	255	86
1992	I	10	265	90
	II	10	275	93
	III	10	285	97
	IV	5	290	98
1993	I	5	295	100

INDIA
WESTERN GAS DEVELOPMENT
Management of Oil and Natural Gas Commission



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INDIA: WESTERN GAS DEVELOPMENT PROJECT
ONGC: SCHEDULE OF LONG-TERM LOANS OUTSTANDING
(As of March 31, 1986)

	Date of Loan	Original Amt (MM)	Balance 3.31.86	Maturity Years	Grace Period	Principal Repayments	Final Payment	Interest Rate (%)
1) Local Loans								
Government of India		19.3	9	5 yrs			9.75	
Oil Industry Development Board (3 loans)		1,260.4	15 & 9	2 yrs			4.5, 9.75, 10.25	
Hydrocarbons India Limited		478.1	9	5 yrs			9.75	
Subtotal		1,757.8						
2) Official Development Aid								
IBRD Loan 1473 - Bombay High I		$ 150.00	823.9	20	3 yrs			10.25
IBRD Loan 1925 - Bombay High II		$ 400.00	3,801.6	20	5 yrs			10.75
IBRD Loan 2205 - K-G Project		$ 165.50	929.3	30 semi-annual installments beg'g 1.2.88				12.25
IBRD Loan 2241 - South Bassein Proj		$ 139.30	153.1	20 semi-annual installments beg'g 1.7.88				12.25
IBRD Loan 2403 - Cambay Basin Proj		$ 242.50	212.7	15	5 yrs			12.75
Kuwait Fund		KD 14.60	579.7	20	3 yrs			10.25
OPEC I		$ 14.00	82.9	20	5 yrs			10.25
OPEC II		$ 30.00	229.3	20	5 yrs			10.25
Subtotal		6,812.3						
3) Exim Financing								
Exim Bank of USA							10.75	
Exim Korea Loan	8.29.83	$ 77.93	764.7	10	1 yr	10.1.84	9.30.93	9.50
Exim Korea Banker Trust	1.25.83	$ 19.84	164.4	8	1 yr	2.6.84	2.4.91	9.50
KFW Loan	1.22.82	DM 50.00	253.4	15	3-1/2 yrs	11.4.85	5.3.97	5.375
Subtotal		1,182.6						
4) Commercial Loans								
Japan Consortium		100.61	5	6 mos	various	various	7.50	
ENI - Credit Italy	3.14.84	$ 6.30	55.93	7	6 mos	9.28.84	3.30.91	9.50
EKS - Norway	5.14.82	NOK 180.48	194.23	9	1 yr	5.12.83	5.12.91	8.50

ONGC: SCHEDULE OF LONG-TERM LOANS OUTSTANDING
(As of March 31, 1986)

	Date of Loan	Original Amt (MM)	Balance 3.31.86	Maturity Years	Grace Period	Principal Repayments	Final Payment	Interest Rate (%)
Hitachi Zosen Japan	8.51.81	Y 9,469.00	422.76	10	2 yrs	8.16.83	8.16.91	8.00
BNP France	4.15.83	$ 9.925	79.31	7	6 mos	11.09.83	5.04.90	10.00
BNP France R-12)	5.12.82	FF 98.70	109.21	7	6 mos	12.27.82	7.01.90	8.25
BFCE)		FF 14.10		8	7-1/2 yrs	1.01.90	7.01.90	8.25
HHI NQO Exim)	12.16.83	$ 59.51	665.74	11	1-1/2 yrs	6.26.85	12.26.94	9.60
Chase)				6	1-1/2 yrs	6.26.85	12.26.89	
HHI SHP Exim)	5.29.84	$ 51.60	577.31	11	1-1/2 yrs	8.28.85	2.25.95	9.00
Chase)				6	1-1/2 yrs	8.28.85	2.25.90	
Hitachi Zosen Japan	1.21.85	Y 10,489.00	638.58	8-1/2	6 mos	8.05.85	8.05.93	8.75
BNP KVX)	11.09.82	FF 163.40	208.8	8	1-1/2 yrs	5.31.84	11.30.90	10.60
BFCE)				9	8-1/2 yrs	5.31.91	11.30.91	
BNP Loan Foramer	7.26.83	$ 3.23	22.4	5-1/2		11.01.83	5.01.89	10.00
BNP-CFP-BH	12.30.82	FF 282.30	378.4	7		4.13.83	9.06.90	8.00
		FF 45.90						8.26
BNP - Sedco	11.30.82	FF 35.89	26.6	5-1/2	6 mos	7.25.83	7.25.88	10.60
USSR			4.7	10	1 yr	4.01.86	4.01.96	
Yen Bond 'A'	11.25.85	Y 10,000.00	690.0	7	4 yrs	11.00.89	11.00.92	7.00
Yen Bond 'B'	2.00.86	Y 10,000.00	690.0	7	4 yrs			6.60
			5,965.4					
5) Euro Loans and Bond Issues								
Euro Dollar Loan 1	11.04.81	$ 30.00	223.7	7	2-1/2 yrs	5.04.84	11.04.88	3/8 of 1% abv LIBOR
Euro Dollar Loan 2	3.06.81	$ 200.00	994.4	7	2-1/2 yrs	9.06.83	3.06.88	1/2 of 1% abv LIBOR
Euro Dollar Loan 3	4.15.83	$ 400.00	4,972.0	8	4 yrs	4.15.87	4.15.91	Tranche A: $260m 1/2 of 1% abv LIBOR Tranche B: $140m 3/20 of 1% abv APR
Yen Loan KVX Project	11.09.82	Y 8,250.00	569.3	10	5 yrs	11.09.87	11.09.92	3/8 of 1% abv LIBOR
Yen Loan R-12	5.05.82	Y 5,400.00	372.6	10	5 yrs	5.07.87	5.07.92	3/8 of 1% abv LIBOR upto 5.05.89; 1/2 of 1% abv LIBOR thereafter
FRN Issue	2.05.86	$ 150.00	1,864.4					
FRN Issue	3.00.86	$ 125.00	1,553.8					
Subtotal			10,550.2					
Revaluations			978.0					
TOTAL BALANCE OUTSTANDING AS OF MARCH 31,1986			26,145.0					

INDIA

Western Gas Development Project

OIL AND NATURAL GAS COMMISSION
INCOME STATEMENTS
(FY ending March 31, in Rs. Million)

STATEMENT OF INCOME AND EXPENSES	Actual 1983	1984	1985	1986	(Prov) 1987	Projected 1988	1989	1990	1991	1992
Gross Revenues	24,016	34,728	40,350	43,879	49,206	60,701	66,477	71,566	74,547	78,829
Operating Expenses:										
Gross Taxes and Royalties to Govt	4,379	9,049	9,762	12,781	14,878	24,270	25,719	26,995	27,952	28,956
Operating Costs	1,970	2,606	4,193	4,175	4,806	5,100	5,706	6,240	6,523	6,982
Subtotal, Costs	6,349	11,655	13,955	16,956	19,684	29,370	31,426	33,235	34,475	35,939
Depreciation, Depletion & Amort	4,965	6,112	8,783	6,361	8,925	10,415	12,773	14,907	16,951	16,185
Subtotal, Operating Expenses	11,314	17,767	22,738	23,317	28,608	39,785	44,198	48,141	51,426	52,123
Operating Income	12,702	16,961	17,612	20,562	20,598	20,916	22,279	23,425	23,121	26,706
less: Interest	873	884	1,338	1,580	2,511	2,872	3,033	3,358	3,728	4,205
Income before Corporate Tax	11,829	16,077	16,274	18,982	18,087	18,045	19,246	20,067	19,393	22,501
less: Corporate Taxes (a)	4,900	8,020	7,450	5,960	7,235	7,218	7,698	8,027	7,757	9,001
Net Income after Corporate Tax	6,929	8,057	8,824	13,022	10,852	10,827	11,547	12,040	11,636	13,501
less: Dividends	274	309	326	343	343	343	343	343	343	343
Net Income Retained	6,655	7,748	8,498	12,679	10,509	10,484	11,204	11,697	11,293	13,158
Memo Items:										
Operating Costs Excl Depreciation Per Bbl Oil & Oil Equiv. Sold (US$/Bbl)	$1.45	$1.26	$1.84	$1.66	$1.81	$1.86	$2.00	$2.11	$2.12	$2.19
Operating Costs Incl Depreciation Per Bbl Oil & Oil Equiv. Sold (US$/Bbl)	$5.12	$4.23	$5.68	$4.20	$5.18	$5.65	$6.48	$7.15	$7.64	$7.26
Operating Costs as Percent of Gross Revenues	8.2%	7.5%	10.4%	9.5%	9.8%	8.4%	8.6%	8.7%	8.8%	8.9%
Operating Ratio (Operating Expenses as % of Gross Revenues)	47.1%	51.2%	56.4%	53.1%	58.1%	65.5%	66.5%	67.3%	69.0%	66.1%
Operating Income (EBIT) as % of Average Fixed Assets	63.4%	59.0%	47.4%	44.2%	35.4%	30.3%	27.2%	24.0%	20.8%	22.2%

Note: (a) Assumed Tax Rate is 40%, for projected FY88 - FY92.

Source: ONGC, Mission estimates, FY87 data is provisional

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Western Gas Development Project

OIL AND NATURAL GAS COMMISSION
PRODUCTION PROJECTIONS

	(Units)	Actual 1983	1984	1985	1986	(Prov) 1987	Projected 1988	1989	1990	1991	1992
Crude Oil:											
Offshore	(MM mt)	12.88	17.39	20.14	21.54	21.23	21.76	22.30	22.86	23.43	24.02
less: losses:	(MM mt)	(0.57)	(0.50)	(0.58)	(0.64)	(0.64)	(0.65)	(0.67)	(0.69)	(0.70)	(0.72)
Net Offshore Production	(MM mt)	12.30	16.89	19.56	20.90	20.59	21.11	21.64	22.18	22.73	23.30
Onshore, Western [Gujarat] .	(MM mt)	3.19	3.59	3.91	4.45	4.76	5.09	5.45	5.83	6.24	6.68
Onshore, Eastern [Assam] ...	(MM mt)	2.19	2.19	2.23	2.34	2.50	2.68	2.87	3.07	3.28	3.51
Subtotal, Crude Oil	(MM mt)	17.67	22.67	25.70	27.69	27.86	28.88	29.95	31.08	32.25	33.49
Natural Gas:											
Offshore, Gross	(MMCM)					5,025	6,000	9,075	11,000	11,000	12,000
less: Consumed, Flared ...	(MMCM)					(854)	(1,020)	(1,543)	(1,870)	(1,870)	(2,040)
Offshore, Net	(MMCM)	1,105	1,485	2,050	2,518	4,171	4,980	7,532	9,130	9,130	9,960
Onshore, Western [Gujarat] .	(MMCM)				709	782	863	952	1,051	1,159	1,280
less: Consumed, Flared ...	(MMCM)				(4)	(4)	(5)	(5)	(6)	(6)	(7)
Onshore, Western, Net	(MMCM)				705	778	858	947	1,044	1,154	1,272
Onshore, Eastern [Assam] ...	(MMCM)				85	94	103	119	138	160	186
less: Consumed, Flared ...	(MMCM)				0	(1)	(1)	(1)	(1)	(1)	(1)
Onshore, Eastern, Net	(MMCM)				85	93	102	118	137	159	185
Onshore, Subtotal, Net......	(MMCM)	751	738	740	790	871	961	1,065	1,181	1,313	1,457
Subtotal, Natural Gas, Gross .	(MMCM)					5,901	6,966	10,146	12,188	12,320	13,465
Subtotal, Consumed, Flared ...	(MMCM)					(859)	(1,025)	(1,549)	(1,877)	(1,877)	(2,048)
Subtotal, Natural Gas, Net ...	(MMCM)	1,856	2,223	2,790	3,645	5,042	5,941	8,597	10,311	10,443	11,417
LPG Production [= Net Sales]:											
Offshore	(Mmtons)	161	196	242	320	409	471	542	724	824	1,023
Onshore, Western [Gujarat] .	(Mmtons)	0	0	0	1	43	40	43	43	43	55
Onshore, Eastern [Assam] ...	(Mmtons)	0	0	0	0	0	0	42	57	57	72
Subtotal, LPG	(Mmtons)	161	196	242	321	452	511	627	824	924	1,150
NGL Production [= Net Sales]:											
Offshore	(Mmtons)	25	38	52	68	0	0	0	200	500	700
Onshore, Western [Gujarat] .	(Mmtons)	0	0	0	0	0	0	0	0	0	0
Onshore, Eastern [Assam] ...	(Mmtons)	0	0	0	0	0	0	0	0	0	0
Subtotal, NGL	(Mmtons)	25	38	52	68	0	0	0	200	500	700

Source: ONGC, Mission estimates, FY87 data is provisional

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Western Gas Development Project

OIL AND NATURAL GAS COMMISSION
REVENUE PROJECTIONS

	(Units)	Actual 1983	1984	1985	1986	(Prov) 1987	Projected 1988	1989	1990	1991	1992
SUMMARY of NET VOLUMES SOLD:											
Crude oil, offshore	(MM mt)	12.30	16.89	19.56	20.90	20.59	21.11	21.64	22.18	22.73	23.30
Crude oil, onshore	(MM mt)	5.37	5.78	6.14	6.79	7.27	7.77	8.32	8.90	9.52	10.19
Natural gas, offshore	(MMCM)	1,105	1,485	2,050	2,855	4,171	4,980	7,532	9,130	9,130	9,960
Natural gas, onshore	(MMCM)	751	738	740	790	871	961	1,065	1,181	1,313	1,457
LPG	(Mmtons)	161	196	242	321	452	511	627	824	924	1,150
NGL	(Mmtons)	25	38	52	68	0	0	0	200	500	700
SALES PRICES [Past - Averages; Projections - Seventh Plan]											
Crude oil, offshore	(Rs/mt)	1,225	1,388	1,388	1,382	1,513	1,813	1,813	1,813	1,813	1,813
Crude oil, onshore	(Rs/mt)	1,188	1,355	1,341	1,382	1,513	1,813	1,813	1,813	1,813	1,813
Natural gas, offshore	(Rs/MCM)				1,307	1,400	1,400	1,400	1,400	1,400	1,400
Natural gas, onshore	(Rs/MCM)				449	449	449	449	449	449	449
LPG	(Rs/mt)	1,830	1,879	1,830	1,829	1,830	1,830	1,830	1,830	1,830	1,830
NGL	(Rs/mt)	2,595	2,588	1,783	2,015	2,015	2,015	2,015	2,015	2,015	2,015
REVENUES [Based on Above Factors]:											
Crude oil, offshore	(MMRs)	15,076	23,446	27,145	28,882	31,157	38,269	39,225	40,206	41,211	42,241
Crude oil, onshore	(MMRs)	6,377	7,823	8,230	9,382	10,992	14,094	15,081	16,136	17,266	18,474
Natural gas, offshore	(MMRs)				3,732	5,839	6,972	10,545	12,782	12,782	13,944
Natural gas, onshore	(MMRs)				355	391	432	479	[illegible]	590	655
LPG	(MMRs)	295	367	442	587	826	935	1,147	1,508	1,691	2,105
NGL	(MMRs)	64	98	92	137	0	0	0	403	1,007	1,410
Other Receipts..............					804						
Total Revenues, Past and Projected:		24,016	34,728	40,350	43,879	49,206	60,701	66,477	71,566	74,547	78,829

Source: ONGC, Mission estimates, FY87 data is provisional

INDIA

Western Gas Development Project

OIL AND NATURAL GAS COMMISSION
INVESTMENT PROGRAM
(FY ending March 31, Rs. Million)

DETAILS OF INVESTMENT PROGRAM:	Actual 1983	Actual 1984	Actual 1985	Actual 1986	(prov) 1987	Projected 1988	Projected 1989	Projected 1990	Projected 1991	Projected 1992
Acquisition of Capital Assets..........	9,169	9,461	11,251	11,555	12,339	10,696	15,896	15,777	15,777	15,777
Exploration Drilling....................	2,283	2,212	2,775	3,052	5,651	4,897	8,623	9,231	9,231	9,231
Development Drilling....................	1,799	2,796	2,106	2,033	2,471	3,170	4,352	3,832	3,832	3,832
Surveys.................................	338	516	585	723	804	994	574	589	589	589
Subtotal Exploration & Development	4,420	5,524	5,466	5,808	8,926	9,061	13,549	13,652	13,652	13,652
	13,589	14,985	16,717	17,363	21,265	19,757	29,445	29,429	29,429	29,429
Research and Development	39	75	91	171	338	500	716	732	732	732
Carried Forward from VI Plan				739	500					
Total Investment Program (a)...........	13,628	15,060	16,808	18,273	22,103	20,257	30,161	30,161	30,161	30,161

Source: ONGC, Mission Estimates, FY87 data is provisional

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Western Gas Development Project

OIL AND NATURAL GAS COMMISSION
BALANCE SHEET
(As of FY ending March 31, Rs. Million)

ASSETS	Actual 1983	1984	1985	1986	(Prov) 1987	Projected 1988	1989	1990	1991	1992
Current Assets:										
Cash	168	92	96	337	355	300	200	200	200	200
Accounts Receivable	3,216	2,506	4,046	3,979	6,889	8,698	8,714	9,057	9,000	9,000
Deposits & Advances & Others	1,545	2,085	3,598	7,278	8,383	8,500	7,000	7,500	8,906	9,056
Inventories	4,005	4,666	5,910	8,870	9,300	10,214	10,000	10,000	10,500	11,000
Prepaid Income Taxes	8,050	15,907	23,607	22,051	25,000	25,000	25,000	25,000	25,000	25,000
Subtotal, Current Assets:	16,984	25,256	37,257	42,515	49,927	52,712	50,914	51,757	53,606	54,256
Fixed Assets:										
Property, Plant and Equipment	15,221	20,775	26,131	30,774	40,096	45,773	54,436	64,412	71,823	78,234
Work in Progress & Others	5,197	7,623	9,464	11,384	14,157	16,212	20,700	22,975	24,820	26,000
Producing Prop & Developmt Drilling	3,866	4,813	5,532	9,850	10,296	11,790	15,100	16,782	18,478	20,897
Subtotal	24,284	33,211	41,127	52,008	64,549	73,775	90,236	104,169	115,121	125,131
Long-Term Investments	4,145	5,148	5,276	5,574	5,800	5,800	5,800	5,800	5,800	5,800
Other Assets	509	440	1,323	1,328	1,400	1,400	1,400	1,400	1,400	1,400
TOTAL ASSETS	45,922	64,055	84,983	101,425	121,676	133,687	148,350	163,126	175,927	186,587
LIABILITIES & SHAREHOLDERS' EQUITY										
Current Liabilities:										
Current Portion of Long-Term Debt	1,274	1,996	2,149	3,005	2,804	2,920	3,130	3,720	5,266	5,121
Provision for Tax	6,946	14,966	22,430	21,383	25,000	25,000	25,000	25,000	25,000	25,000
Other Current Liabilities	6,463	6,158	6,276	8,854	9,000	9,500	11,287	10,000	8,403	11,000
Subtotal, Current Liabilities	14,683	23,120	30,855	33,242	36,804	37,420	39,417	38,720	38,649	41,1[illegible]1
Long-Term Debt (excl Current Portion)	15,134	17,082	21,767	23,140	29,320	30,231	31,693	35,469	37,048	35,437
Shareholders' Equity:										
Capital	3,429	3,429	3,429	3,428	3,428	3,428	3,428	3,428	3,428	3,428
Reserves	12,676	20,424	28,932	41,615	52,124	62,608	73,812	85,509	96,802	106,601
Subtotal, Shareholders' Equity	16,105	23,853	32,361	45,043	55,552	66,036	77,240	88,937	100,230	110,029
TOTAL LIABILITIES & EQUITY	45,922	64,055	84,983	101,425	121,676	133,687	148,350	163,126	175,927	186,587
Current Ratio	1.2	1.1	1.2	1.3	1.4	1.4	1.3	1.3	1.4	1.3
Debt-Equity Ratio	0.9	0.7	0.7	0.5	0.5	0.5	0.4	0.4	0.4	0.3

Source: ONGC, Mission estimates, FY87 data is provisional

ANNEX 5.7

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Western Gas Development Project

OIL AND NATURAL GAS COMMISSION
SOURCES AND USES OF FUNDS
(FY ending March 31, Rs. Million)

	Actual				(Prov)	Projected				
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
SOURCES										
After Tax Income	6,929	8,057	8,824	13,022	10,852	10,827	11,547	12,040	11,636	13,501
Additions (Deductions):										
Interest	873	884	1,338	1,580	2,511	2,872	3,033	3,358	3,728	4,205
Depreciation	4,965	6,112	8,783	6,361	8,925	10,415	12,773	14,907	16,951	16,185
Other Non-Cash Expenses	260	829	1,195	1,021						
Internal Cash Generation	13,027	15,882	20,140	21,984	22,288	24,114	27,353	30,305	32,315	33,890
Loan Drawings	7,500	3,196	4,754	3,898	8,984	3,831	4,592	7,495	6,825	3,510
TOTAL SOURCES	20,527	19,078	24,894	25,882	31,272	27,945	31,945	37,800	39,140	37,400
USES										
Acquisition of Capital Assets	9,169	9,461	11,251	11,555	12,339	10,696	15,896	15,777	15,777	15,777
Exploration & Development Expenditure	4,420	5,524	5,466	5,808	8,926	9,061	13,549	13,652	13,652	13,652
Long-Term Investment	3,895	1,003	128	298	226	0	0	0	0	0
Debt Service										
Principal repayments	1,112	1,269	1,894	2,496	3,005	2,804	2,920	3,130	3,720	5,246
Interest	873	884	1,338	1,580	2,511	2,872	3,033	3,358	3,728	4,205
Subtotal, Debt Service	1,985	2,153	3,232	4,076	5,516	5,676	5,953	6,488	7,448	9,451
Dividends	274	309	326	343	343	343	343	343	343	343
Increase (Decrease) in Working Capital	752	617	4,457	3,757	3,850	2,169	(3,795)	1,540	1,920	(1,822)
Increase (Decrease) in Other Assets	32	11	34	45	72	0	0	0	0	0
TOTAL USES	20,527	19,078	24,894	25,882	31,272	27,945	31,945	37,800	39,140	37,400
Debt Service Coverage	6.6	7.4	6.2	5.4	4.0	4.2	4.6	4.7	4.3	3.6
Working Capital	2,301	2,136	6,402	9,273	13,123	15,292	11,497	13,037	14,957	13,135

Source: ONGC, Mission estimates, FY87 data is provisional

Annex 5.9

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Western Gas Development Project

OIL AND NATURAL GAS COMMISSION

Financial Analysis Assumptions.

DISCOUNT RATE: 10% assumed throughout.

COSTS: Capital costs are obtained from project cost estimates and include local taxes and duties as well as 10% physical contingencies. Annual operating costs for South Bassein II and Neera are calculated as 5% of total capital costs. Total operating costs for Gandhar was calculated on the basis of US$1.5 per barrel of oil equivalent, and then the annual amounts were obtained. Operating costs remain constant in real terms.

BENEFITS: ONGC's future price estimates for the various outputs have been used. Details of these prices are contained in the revenue projections (Annex 5.5) For the after tax returns, these prices were taken net of production taxes before being deflated to constant 1987 values.

DEBT: Interest expense generated by the project:

World Bank loan: US$295 million, maturing in 15 years including 5 years of grace, disbursed according to the disbursement schedule, with interest at 15% per annum.

Other borrowings: US$475.3 million, maturing in 10 years, including 2 years of grace, fully disbursed in year 1, with semi-annual interest payments at 10%.

Debt service charges are allocated to each project component on a pro-rated basis determined by its portion of the total capital costs. Interest charges were deflated using the inflation factors below.

DEPRECIATION: Capital investments, including physical contingencies: straight line method assuming a 15-year-life and zero salvage value.

PRICES:

Year	Condensat US$/MT	Offshore Gas US$/MCM	LPG US$/MT	NGL US$/MT	INFLATION Annual Rate	Comp'ded Rate	Cumulative Rate
1987	155.00	90.23	140.77	155.00	0.00%	1.000	1.000
1988	143.52	83.55	130.34	143.52	8.00%	1.080	1.080
1989	134.13	78.08	121.81	134.13	7.00%	1.070	1.156
1990	126.54	73.66	114.92	126.54	6.00%	1.060	1.225
1991	119.37	69.49	108.41	119.37	6.00%	1.060	1.298
1992 (a)	121.76	70.88	110.58	121.76	6.00%	1.060	1.376
1993	124.650	72.560	113.210	124.650	6.00%	1.060	1.400

Note (a):Prices increase in real terms after 1991 by 2% per year. Inflation remains at 6% per annum

OTHERS: Exchange Rate : Rs./US $ 13.000 /1.00

1mmmt LPG = 1250mmcm Gas Equiv.
1mmmt NGL = 1170mmcm Gas Equiv
1mt Condensate = 1.12 TOE
1 metric Ton Oil(33 API) = 7.3 Bbls

1200mmcm Gas = 1mmTOE
1mt LPG = 1.12 TOE
1mt NGL = 1.12 TOE

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Western Gas Development Project

OIL AND NATURAL GAS COMMISSION

Financial Returns of Project Components (Before Income Taxes)

(Million US$)

Year Ended March 31	South Bassein II			Heera			Gandhar			Total		
	Costs	Benefits	Net Benefits	Costs	Benefits	Net Benefits	Costs	Benefits	Net Benefits	Costs	Benefits	Net Benefits
1987	22	0	(22)	3	0	(3)	0	0	0	26	0	(26)
1988	99	0	(99)	15	0	(15)	24	0	(24)	138	0	(138)
1989	122	0	(122)	45	0	(45)	172	19	(153)	339	19	(320)
1990	111	184	73	46	34	(12)	142	65	(76)	298	283	(15)
1991	47	344	297	5	36	31	93	66	(27)	145	446	301
1992	17	359	342	5	47	43	70	79	9	91	486	396
1993	17	378	361	5	34	29	13	86	73	35	498	463
1994	17	382	365	5	32	28	13	88	75	35	502	467
1995	17	389	373	5	33	28	13	90	76	35	512	477
1996	17	390	373	5	22	17	13	92	78	35	504	469
1997	17	408	391	5	19	14	13	93	80	35	520	485
1998	17	416	399	5	17	12	13	95	82	35	528	493
1999	17	424	408	5	14	10	13	91	77	35	529	494
2000	17	433	416	5	15	10	13	93	79	35	540	505
2001	17	426	409	5	15	10	13	94	81	35	535	500
2002	17	435	418	5	15	10	13	96	83	35	546	511
2003	17	447	431	5	15	11	13	91	78	35	554	519
2004	17	457	440	5	8	3	13	93	80	35	558	523
2005	17	470	454	5	8	3	13	88	74	35	566	531
2006	17	480	463	5	0	(5)	13	74	61	35	554	519
NPV @ 10%			1879.99			53.68			121.90			2055.58
Financial Rate of Return			66.2%			26.0%			16.5%			46.6%
Average Financial Cost of (a) Gas + Gas Equiv of Liquids			$9.56 /MCM			$46.40 /MCM						
Average Financial Cost of (a) Oil + Oil Equiv of Gas			$11.19 /TOE $1.53 /Bbl			$55.67 /TOE $7.63 /Bbl			$32.49 /TOE $4.45 /Bbl			

Note (a): Using undiscounted cash flows.

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Western Gas Development Project

OIL AND NATURAL GAS COMMISSION

Financial Returns of Project Components (After Income Taxes)

(Million US$)

Year Ended March 31	South Bassein II			Heera			Gandhar			Total		
	Costs	Benefits	Net Benefits	Costs	Benefits	Net Benefits	Costs	Benefits	Net Benefits	Costs	Benefits	Net Benefits
1987	22	0	(22)	3	0	(3)	0	0	0	26	0	(26)
1988	99	0	(99)	15	0	(15)	24	0	(24)	138	0	(138)
1989	122	0	(122)	45	0	(45)	172	16	(156)	339	16	(323)
1990	153	161	7	51	29	(23)	142	55	(87)	346	244	(102)
1991	143	301	158	9	30	21	93	56	(38)	245	386	141
1992	117	314	196	14	40	26	70	66	(4)	201	420	219
1993	125	330	205	9	22	19	16	72	57	150	431	281
1994	128	334	206	9	27	18	16	74	58	153	435	282
1995	132	340	209	10	28	18	18	75	57	160	443	283
1996	133	341	208	7	19	12	20	77	57	160	436	276
1997	141	357	216	6	16	10	22	78	56	169	451	282
1998	144	364	220	5	14	9	24	80	56	173	458	285
1999	148	371	224	5	12	7	25	76	51	177	459	282
2000	151	379	228	5	12	7	26	78	52	181	468	287
2001	149	373	224	5	12	8	27	79	52	181	464	283
2002	153	380	227	5	13	7	28	81	53	186	474	288
2003	160	391	231	5	13	8	27	76	49	192	481	288
2004	166	399	233	5	7	2	32	78	46	203	484	281
2005	174	411	238	5	7	2	34	73	40	213	491	279
2006	178	420	242	5	0	(5)	32	62	31	214	482	268
NPV @ 10%			925.65			8.66			-0.34			933.98
Financial Rate of Return			43.5%			12.7%			10.0%			29.1%
Average Financial Cost of (a) Gas + Gas Equiv of Liquids			$40.20 /MCM			$55.73 /MCM						
Average Financial Cost of (a) Oil + Oil Equiv of Gas			$47.05 /TOE $6.45 /Bbl			$64.25 /TOE $8.80 /Bbl			$39.85 /mt $5.46 /Bbl			

Note (a): Using undiscounted cash flows

ANNEX 6.1

INDIA

Western Gas Development Project

Assumptions Underlying Economic Analysis

1. Discount Rate : 10% is assumed throughout.

2. Costs :
   Capital Costs : Project cost estimates, net of taxes and duties, but including 10% physical contingencies.
   Operating Costs: Estimated on the basis of 5% per annum of total capital costs.

3. Benefits :
   The project was evaluated using constant oil prices of US$10, $12, $18 (Base Case) and $25/bbl.

   Crude Oil : Valued on the basis of crude delivered CIF at Bombay.
   Products (NGL and LPG) at the coast: Valued on the basis of CIF Bombay, assuming constant margins relative to crude prices as shown below.
   Natural Gas : Valued at the thermal equivalence of the delivered value of the fuel replaced (assumed to be fuel oil), using CIF values, adjusted for internal transport if used inland.

Oil Price Projections (Constant US$/Bbl)	Corresponding Landed Value of Products: Fuel Oil (US$/mt)	Gasoline (NGL) (US$/mt)	LPG (US$/mt)	Landfall Value of Natural Gas Replacing: Fuel Oil (US$/MCM)	Naphtha (US$/MCM)	Corresponding Inland Value of Natural Gas Replacing: Fuel Oil (US$/MCM)	Naphtha (US$/MCM)
$10.00	60.50	122.00	118.00	54.02	82.59	67.41	91.52
$12.00	74.90	136.40	132.40	66.88	95.45	80.27	104.38
$18.00	118.10	179.60	175.60	105.45	134.02	118.84	142.95
$25.00	168.50	230.00	226.00	105.45	179.02	163.84	187.95

Conversion Factors

	MCM Gas per mt	Margin Over Crude (US$/mt)	Adjustments for Transport: International (US$/mt)	Internal (if used inland) (US$/mt)
LPG	1.216	$36.00	$10.00	$15.00
Naphtha	1.182	$30.50	($10.00)	$10.00
Gasoline	1.182	$40.00	$10.00	$15.00
Fuel Oil	1.120	($21.50)	$10.00	$15.00

INDIA

Western Gas Development Project

Project Economic Analysis

South Bassein II - Incremental

(US$ millions)

Year Ended March 31	South Bassein Phase II: Capital Costs	Operating Costs @ 5% p.a.	Total	Volume of Output: Rich Gas (MMCMD)	LPG (mt/day)	NGL (mt/day)	Value of Output (Annual): Rich Gas	LPG	NGL	Net Benefits
1987	22.2	0.0	22.2	0.0	0	0	0.0	0.0	0.0	(22.2)
1988	97.8	1.1	98.9	0.0	0	0	0.0	0.0	0.0	(98.9)
1989	116.9	6.0	122.9	0.0	0	0	0.0	0.0	0.0	(122.9)
1990	72.2	11.8	84.0	4.4	237	660	168.6	15.2	43.2	143.0
1991	13.9	15.5	29.4	8.8	475	1,322	338.9	30.4	86.7	426.6
1992		16.1	16.1	9.0	487	1,356	347.7	31.2	88.9	451.7
1993		16.1	16.1	9.3	499	1,389	356.4	32.0	91.1	463.4
1994		16.1	16.1	9.2	497	1,384	353.0	31.8	90.7	459.4
1995		16.1	16.1	9.2	497	1,384	353.0	31.8	90.7	459.4
1996		16.1	16.1	9.0	492	1,372	346.2	31.5	89.9	451.5
1997		16.1	16.1	9.2	510	1,424	355.2	32.7	93.4	465.2
1998		16.1	16.1	9.2	510	1,424	355.2	32.7	93.4	465.2
1999		16.1	16.1	9.2	510	1,424	355.2	32.7	93.4	465.2
2000		16.1	16.1	9.2	510	1,424	355.2	32.7	93.4	465.2
2001		16.1	16.1	8.9	489	1,363	341.1	31.3	89.4	445.7
2002		16.1	16.1	8.9	490	1,366	342.8	31.4	89.5	447.6
2003		16.1	16.1	9.0	491	1,369	344.5	31.5	89.7	449.6
2004		16.1	16.1	9.0	492	1,372	346.2	31.5	89.9	451.5
2005		16.1	16.1	9.1	495	1,381	351.3	31.8	90.5	457.5
2006		16.1	16.1	9.1	495	1,381	351.3	31.8	90.5	457.5
NPV @ 10%										2329.9

Notes:
1) Output is ex-Hazira treatment facilities, and consists of LPG, NGL, and rich gas.
2) 1 MCM of rich gas ex-Hazira is equivalent to the following delivered ex-HBJ:
   0.92 MCM feedstock or fuel + .081 mt LPG + .015 mt NGL
3) Corresponding value net of transport costs is at least 5% higher than lean gas.

NPV - Net Benefits = $2,330 millions
IRR - Net Benefits = 81.9%

Average Cost of Production (Rich Gas)

at Hazira

$18.41 /MCM
$0.52 /MCF
$3.16 /Bbl (Approx. equivalent oil price)

INDIA

Western Gas Development Project

Project Economic Analysis

South Bassein / HBJ Program

(US$ millions)

Year Ended March 31	Capital Costs: South Bassein SBI	Capital Costs: South Bassein SBII	Capital Costs: HBJ	Operating Costs @ 5% p.a.	Grand Total	Volume of Output: Rich Gas (MMCMD)	Volume of Output: LPG (mt/day)	Volume of Output: NGL (mt/day)	Value of Output (Annual): Rich Gas	Value of Output (Annual): LPG	Value of Output (Annual): NGL	Net Benefits
1984	143.0				143.0	0	0	0	0.0	0.0	0.0	(143.0)
1985	143.0			7.2	150.2	0	0	0	0.0	0.0	0.0	(150.2)
1986	170.0			14.3	184.3	0	0	0	0.0	0.0	0.0	(184.3)
1987	172.0	22.2	130.0	22.8	347.0	0	0	0	0.0	0.0	0.0	(347.0)
1988		97.8	530.0	39.0	666.8	2.1	99	296	81.7	6.3	19.4	(559.4)
1989		116.9	330.0	86.6	533.5	8.8	441	1,270	358.6	28.3	83.2	(63.4)
1990		72.2		140.3	212.5	13.0	676	1,923	542.6	43.3	126.1	499.5
1991		13.9		166.3	180.2	17.3	912	2,583	726.1	58.5	169.3	773.7
1992				167.0	167.0	17.3	912	2,583	726.1	58.5	169.3	786.9
1993				167.0	167.0	18.2	961	2,717	765.6	61.6	178.1	838.3
1994				167.0	167.0	18.0	956	2,706	758.0	61.3	177.4	829.7
1995				167.0	167.0	18.0	956	2,706	758.0	61.3	177.4	829.7
1996				167.0	167.0	17.6	947	2,682	742.6	60.7	175.8	812.1
1997				167.0	167.0	18.1	984	2,787	762.9	63.0	182.7	841.6
1998				167.0	167.0	18.1	984	2,787	762.9	63.0	182.7	841.6
1999				167.0	167.0	18.1	984	2,787	762.9	63.0	182.7	841.6
2000				167.0	167.0	18.1	984	2,787	762.9	63.0	182.7	841.6
2001				167.0	167.0	18.3	988	2,799	770.6	63.3	183.5	850.4
2002				167.0	167.0	17.5	942	2,670	734.9	60.4	175.1	803.4
2003				167.0	167.0	17.5	945	2,676	738.8	60.5	175.4	807.7
2004				167.0	167.0	17.6	947	2,682	742.6	60.7	175.8	812.1
2005				167.0	167.0	17.9	954	2,700	754.1	61.1	177.0	825.2
NPV @ 10%												2440.1

Notes: 1) Rich gas is total of gas supplied to Hazira and HBJ LPG plants (after shrinkage and compressor use, but before LPG extraction). Products are ex-Hazira treatment facilities.

NPV - Net Benefits = 2,440 millions
IRR - Net Benefits = 27.8%

Average Cost of Production (Rich Gas)

at Hazira	ex-HBJ	
$28.58 /MCM	$62.88 /MCM	
$0.81 /MCF	$1.79 /MCF	
$4.90 /Bbl	$10.79 /Bbl	(Approx. equivalent oil price)

INDIA

Western Gas Development Project

Project Economic Analysis

Heera

(US$ millions)

Year Ended March 31	Capital Costs	Operating Costs @ 5% p.a.	Total Cost	Volume of Gas Produ (MMCMD)	Value of Gas	Net Benefits
1987	19.6	0.0	19.6	0.00	0.0	(19.6)
1988	48.7	1.0	49.7	0.00	0.0	(49.7)
1989	20.5	3.4	23.9	1.05	40.4	16.5
1990		4.4	4.4	1.17	45.0	40.6
1991		4.4	4.4	1.53	58.9	54.4
1992		4.4	4.4	1.07	41.2	36.7
1993		4.4	4.4	0.73	28.1	23.7
1994		4.4	4.4	0.53	20.4	16.0
1995		4.4	4.4	0.41	15.8	11.3
1996		4.4	4.4	0.33	12.7	8.3
1997		4.4	4.4	0.28	10.8	6.3
1998		4.4	4.4	0.24	9.2	4.8
1999		4.4	4.4	0.20	7.7	3.3
2000		4.4	4.4	0.20	7.7	3.3
2001		4.4	4.4	0.20	7.7	3.3
2002		4.4	4.4	0.20	7.7	3.3
2003		4.4	4.4	0.20	7.7	3.3
2004		4.4	4.4	0.20	7.7	3.3
2005		4.4	4.4	0.20	7.7	3.3
NPV @ 10%						72.2

Notes: 1) Gas is assumed to be used exclusively for fuel oil replacement.
2) Costs include a proportion of platform and treatment costs (8%)

NPV - Net Benefits = $72 millions
IRR - Net Benefits = 36.4%

Estimated Cost of Production
$62.41 /MCM
$1.77 /MCF
$10.71 /Bbl
(Approximate equivalent oil price)

INDIA

Western Gas Development Project

Project Economic Analysis

Gandhar

(US$ millions)

Year Ended March 31	Capital Costs	Operating Costs @ 5% p.a.	Total Costs	Volume of Output: Condensate (MMmt)	Volume of Output: Gas (MMCMD)	Value of: Condensate	Value of: Gas	Net Benefits
1987	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1988	18.7	0.0	18.7	0.0	0.0	0.0	0.0	(18.7)
1989	96.4	0.9	97.3	0.4	0.3	54.6	11.5	(31.2)
1990	82.3	5.8	88.1	0.4	1.1	54.6	42.3	8.8
1991	53.4	9.9	63.3	0.5	1.2	68.3	46.2	51.2
1992	56.1	12.5	68.6	0.5	1.4	68.3	53.9	53.6
1993		15.3	15.3	0.4	1.5	54.6	57.7	97.0
1994		15.3	15.3	0.3	1.4	41.0	53.9	79.6
1995		15.3	15.3	0.3	1.4	41.0	53.9	79.6
1996		15.3	15.3	0.2	1.4	27.3	53.9	65.9
1997		15.3	15.3	0.2	1.3	27.3	50.0	62.0
1998		15.3	15.3	0.1	1.3	13.7	50.0	48.4
1999		15.3	15.3	0.1	1.2	13.7	46.2	44.6
2000		15.3	15.3	0.1	1.1	13.7	42.3	40.7
2001		15.3	15.3	0.1	1.1	13.7	42.3	40.7
2002		15.3	15.3	0.1	1.0	13.7	38.5	36.9
2003		15.3	15.3	0.1	1.0	13.7	38.5	36.9
2004		15.3	15.3	0.1	1.0	13.7	38.5	36.9
2005		15.3	15.3	0.1	1.0	13.7	38.5	36.9
2006		15.3	15.3	0.1	1.0	13.7	38.5	36.9
NPV @ 10%								273.8

Notes:
1) Gas is assumed to be used exclusively for fuel oil replacement.
2) Condensate conservatively valued at cif crude oil price.

		Total Project
NPV - Net Benefits	=	$279 millions
IRR - Net Benefits	=	66.3%

Estimated Cost of Production Total (Oil & Oil Equivalent Gas)
$67.91 /mt
$9.43 /bbl

INDIA

Western Gas Development Project

Project Economic Analysis

Sensitivity Analysis

Project Components		Base Case	Capital and Operating Costs Up 50%	Oil Prices $10/Bbl	Oil Prices $25/bbl	Gas Offtake Delayed Two Years	Approximate Breakeven Prices (@ 10% Discount) Gas ($/MCF)	Approximate Breakeven Prices (@ 10% Discount) Oil or Oil Equiv. ($/Bbl)
1. South Bassein and HBJ Integrated	(IRR)	27.8 %	20.4 %	16.9 %	42.1 %	22.5 %	$1.79	$10.79
	(NPV)	$2440 m.	$1384 m.	$540 m.	$4103 m.	$1605 m.		
2. South Bassein Phase II Incremental	(IRR)	81.9 %	60.7 %	52.5 %	102.5 %	36.1 %	$0.52	$3.16
	(NPV)	$2330 m.	$2157 m.	$1139 m.	$3372 m.	$1411 m.		
3. Heera - Gas Only	(IRR)	36.4 %	16.0 %	3.5 %	58.2 %		$1.77	$10.71
	(NPV)	$72 m.	$21 m.	($13 m.)	$146 m.			
4. Gandhar	(IRR)	66.3 %	25.0 %	7.0 %	139.2			$9.43
	(NPV)	$279 m.	$134 m.	$19 m.	$507 m.			

INDIA

Western Gas Development Project

Related Documents in the Project File

1. Review of the Petroleum and Natural Gas Reserves and Production Forecasts for the South Bassein, Heera, Tapti, Dahej and Gandhar Fields in India (as of July 1, 1986), prepared for the World Bank, August 1986; Sproule Associates Limited, Calgary, Canada.

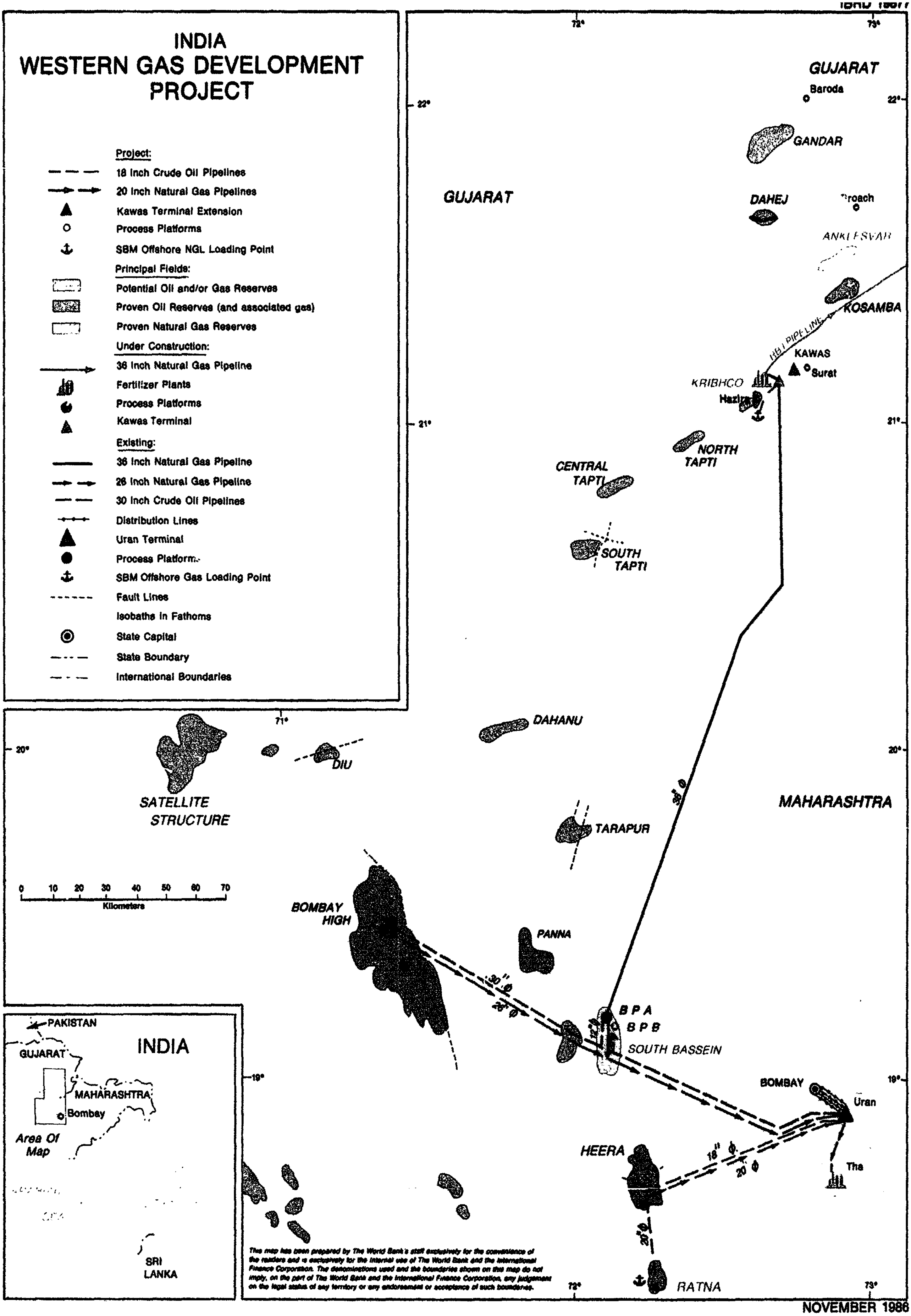
2. Report of the Sub-group on Demand Projections and Refining Capacity, Working Group on Petroleum for the Seventh Plan, July 1984.

3. Seventh Five-Year Plan (1985-86 to 1980-90); Report of the Sub-group on Exploration, Development and Production of Oil and Gas (including Gas Utilization), July 1984.

4. ONGC Annual Report, 1984-85, 1983-84.

5. Oil India Limited Annual Report, 1984-85.

MAP SECTION



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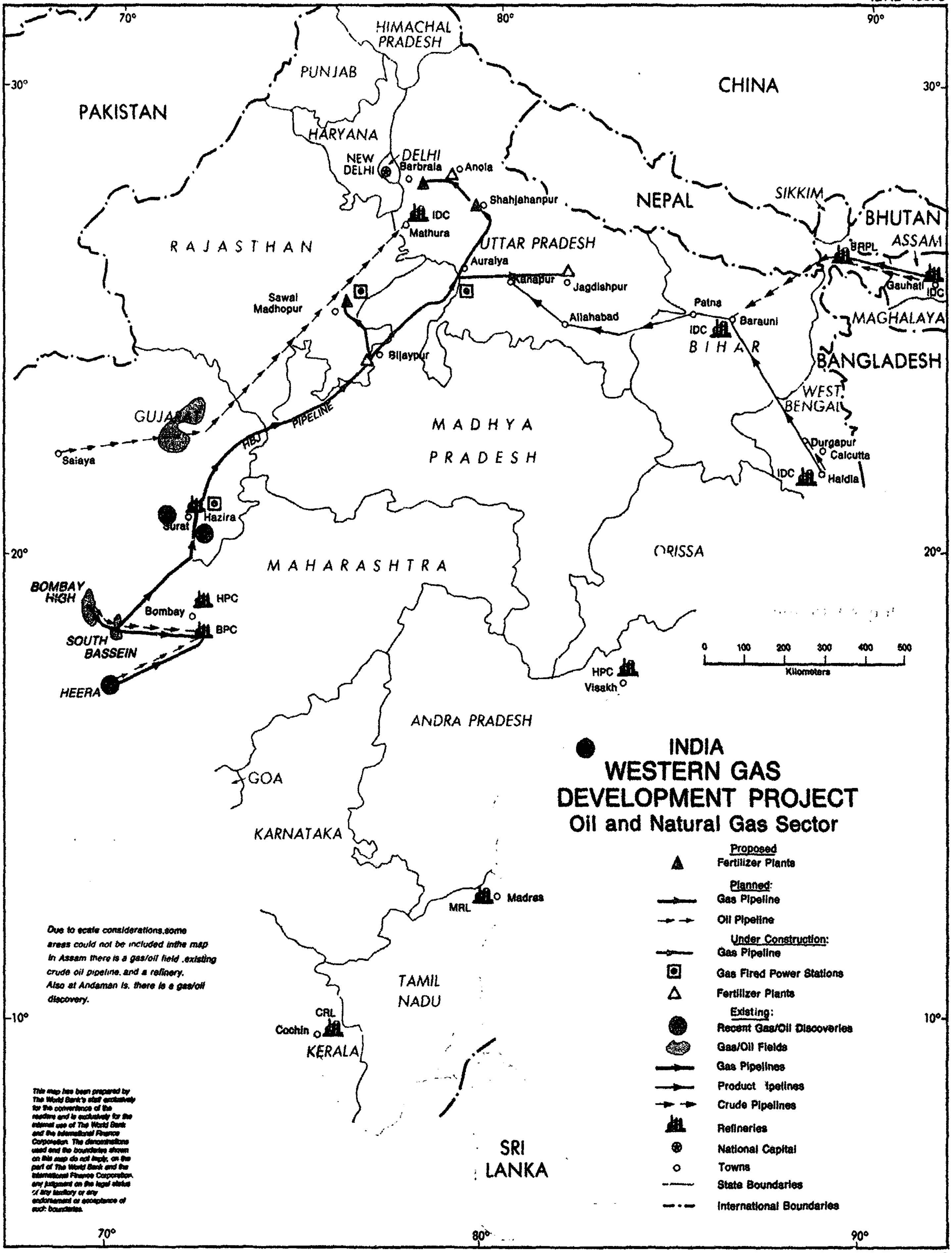

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