METHODS FOR THE ECONOMIC EVALUATION OF PETROLEUM EXPLORATION AND SYNTHETIC FUELS PRODUCTION: AN APPLICATION TO BRAZIL - VOL. 1

by

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ABSTRACT

A Bayesian probabilistic oil exploration model was developed, using geologic and economic parameters, to estimate the size of undiscovered oil resources, the probability of future oil discovery and the net present value of future oil exploration programs. This model was applied to Brazil and the results compared to evaluations of shale oil and alcohol production options. A framework for the public evaluation of energy projects was developed which accounts for the benefits such projects have to the economy and to the external debt position of the country.

After application of the evaluation framework to account for the benefits of domestically produced fuels, the results indicate that the current Brazilian 5-year investment plans in oil exploration, alcohol, and shale oil are likely to be socially profitable only if real oil prices increase 3% to 5% annually.

The results of the probabilistic model indicate that the expected amount of undiscovered oil in Brazil is small, about 500 to 700 million barrels. These results compare well (within several percent) to industry based estimates. Two thirds of the undiscovered oil is expected to be found offshore. There are diminishing expected returns to exploration offshore and very low probabilities of large undiscovered oil deposits onshore or in the Amazon delta. The model results indicate that the optimal (most profitable) offshore exploration program for the state oil company (PETROBRAS) requires less investment than current PETROBRAS plans. If all offshore exploration were allocated to foreign oil companies, under current contract terms, the expected outcome is of lower benefit to Brazil than the optimal plan, but possibly of greater benefit than the current PETROBRAS exploration plan.

Both the probabilistic exploration model and the framework for energy program evaluation are applicable to a variety of other regions or to other countries.

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Introduction

Many oil importing developing countries have experienced major problems due to dependence on imported oil. The rapid rise in oil prices and disruption of imported supplies have had a negative impact on their economies and contributed to increased foreign indebtedness. Energy planners in these countries face numerous uncertainties in their efforts to increase domestic petroleum supplies and produce synthetic fuels. The outcome and risks of oil exploration programs are particularly large, mainly due to geologic uncertainties. Planners must also choose the extent and terms of foreign participation in oil exploration. Uncertainties in the production of synfuels are also large, mainly due to uncertainties in technical production cost.

One oil importing developing country where both the magnitude of the oil related problems and the uncertainties related to domestic liquid fuel production are particularly large, is Brazil. Brazil imports 80 percent of the oil it consumes. The cost of oil imports increased from only $375 million in 1972 to $11 billion in 1980 (current dollars). The cost of oil imports was 55% of total export earnings in 1980. Foreign debt has grown to $57 billion in 1980, caused in large part by heavy borrowing to finance oil imports in the mid-1970's.

In response to these pressures the Brazilian government has launched a massive domestic energy investment program, with plans to invest a total of $60 billion (constant $1979) over the next 5 year period, from 1981 through 1985. Sixty percent of this investment is to be electricity, and a third is earmarked for the liquid fuels sector. The long term prospects for liquid fuel production depend on the success of planned investments in oil exploration, shale oil and alcohol production. Investment plans for these sub-sectors over the five year period from 1981 through 1985 are ambitious. They include planned expenditure of \$3.7 billion (constant \$1979) in oil and gas exploration, \$3.6 billion in alcohol production (95% from sugarcane feedstock), and \$1.1 billion for a 25,000 bbl/day shale plant which will later be expanded to 50,000 bbl/day.

The topic of this study is to develop new methods to evaluate liquid fuel investment programs and then apply these methods to evaluate current Brazilian investment plans in petroleum, shale oil and alcohol production. The goals of this study can be broken down into three parts:

1) The development of a framework to evaluate public energy programs which accounts for the primary and secondary objectives of the program. The primary objective is the provision of domestic liquid fuel supplies cheaper than oil. The secondary objectives are the reduced vulnerability to oil import disruptions, and the reduced negative impact of oil price shocks on the economy and on the country's foreign debt position.

2) The development of a Bayesian probabilistic oil exploration model using geologic and economic parameters, that estimates the probability of future oil discovery and the net present value of various investment programs in oil exploration. This exploration model allows oil exploration programs to be compared directly to other, more traditional projects, evaluations that were used for shale oil and by the World Bank for the alcohol

program.

3) The application of the above methods to compare Brazilian investment plans in petroleum exploration, shale oil and alcohol production. The results are used to analyze the economic and financial aspects of various energy investment strategies and policies toward foreign investment.

1-1. Current Energy and Economic Situation

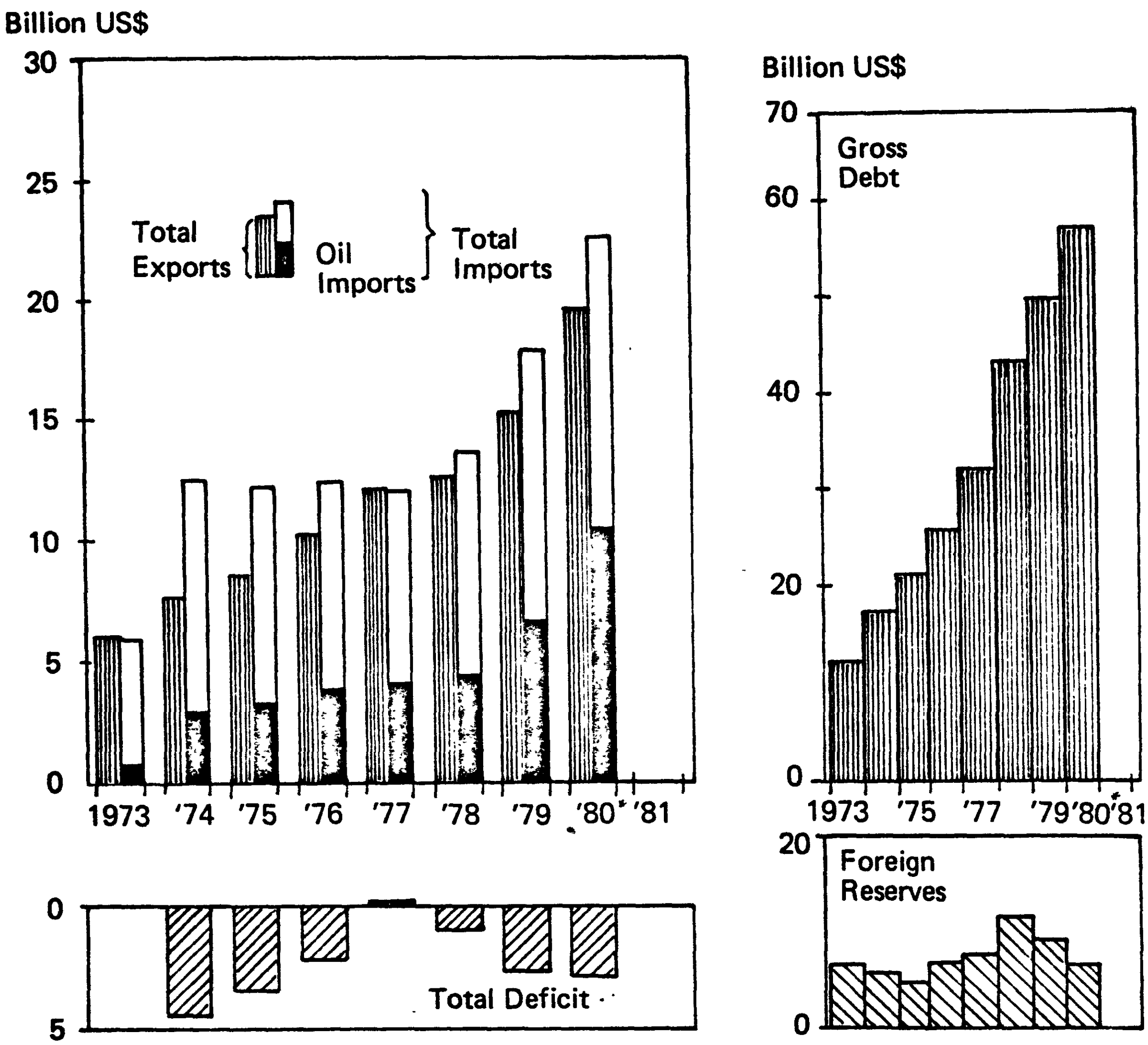
Recent economic history in Brazil can be divided into two periods. During the period of rapid economic growth in Brazil between 1967 and 1972 (the so-called "Brazilian miracle"), real GDP increased at 11% per year. The country's development strategy was based on export-lead growth with heavy reliance on cheap imported oil and foreign borrowing. Primary energy consumption (excluding firewood) grew by 10.3% per yar over this same period, and the share of petroleum in total primary energy consumption increased to 41%, with imports accounting for 80% of the oil consumed.

Since the oil price rise in 1973, the rate of growth of GDP has declined to 7% per year, while primary energy consumption has grown by 8% per year. Oil imports, which amounted to 460,000 bbl/d in 1972, grew to 900,000 bbl/d in 1980. The cost of the oil imports (in current dollars) increased from only $375 million in 1972 to $11 billion, or 55% of total export earnings, in 1980 (see Table 1-1). While policies since 1973 have maintained a high growth rate by world standards and have resulted in heavy investment in domestic energy production, they have also caused foreign debt to soar to $57 billion in 1980 from only 8 billion in 1972. Furthermore, the inflation rate of the general price index in 1980 reached 109%.

One of the major porbems in the energy sector is the poor fit between the energy resource base and the energy consumption pattern. On the supply side (Tables 1-2 and 1-3), Brazil is well-endowed with hydroelectric power (second largest resources in the world), shale oil

Table 1-1

Brazilian Balance of Payments Deficit
Oil Import Bill and Gross Debt



*Financial Times Estimate.
Source: Financial Times, Nov. 14, 1980.

Table 2

Non-Renewable Energy Reserves and Resources in Brazil

Fossil Fuels

Petroleum (June 1979)	Cumulative Production	1051 mmb
	Proved Reserves	1226 mmb
	Estimated Total Ultimate Discoverable (Com. Prod. Proved Probable and Possible)	3300 mmb[1/] 4546 mmb[2/] 3200-3600 mmb[3/]
Shale Oil (1979)	Proved Reserves	1260 mmb
	Total Resources	842,000 mmb
Natural Gas (Dec. 1978)	Proved Reserves	44 billion cubic m^3
	Cumulative Production	22 billion cubic m^3
	Estimated Additional[2/]	71 billion cubic m^3
Coal (1977)	Measured Reserves	1.4
	Indicated Resources	2.5
	Inferred Resources	15.7
	Total	19.7 billion tons

Electric Power

Hydropower (1978)	Developed	23,000
	Surveyed	33,853
	Estimated	47,597
	Total	104,450
	(Planned Developed by 1990)	(33,000)
Uranium (1979)	Proved Reserves	126,000 U_3O_8

1/ From Adelman and Paddock 1979

2/ World Energy Conference estimates, 1980

3/ Estimates by Gray 1980

Remaining data from the Brazilian Energy Model

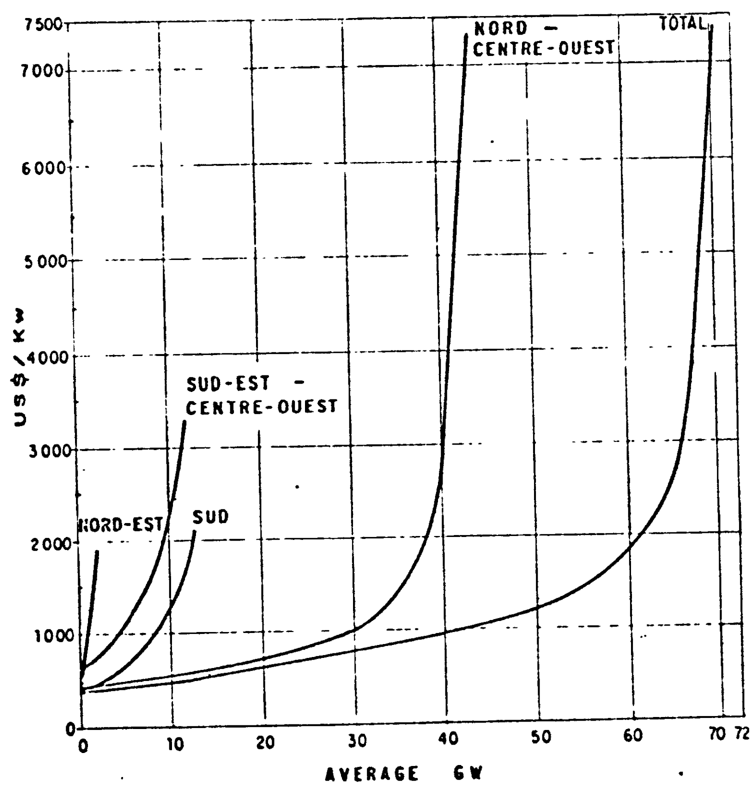
Table I-3

Brazil: Hydroelectric Potential
(Firm Megawatts)

Basin	Developed	Surveyed	Estimated	Total
	Hydro Generating Capacity			
Amazon Tributaries	10	2633	32461	35104
North Atlantic	10	--	475	485
N. E. Atlantic	127	67	61	255
Tocantius	2103	8665	1892	12660
Sao Francisco	3397	4249	1391	9037
E. Atlantic	2024	4285	5274	11583
Parana	15157	7834	4930	27921
Uruguay	172	6120	1113	7405
Total (1978)	23000	33853	47597	104450
Estimated(1990)	33000			

Source: Brazilian Energy Model, Ministry of Mines and Energy 1979. Est. Developed by 1990 from World Energy Conf. vol. 1A, 1980

UNIT COST OF THE BRAZILIAN HYDROELECTRIC POTENTIAL AVAILABLE AFTER 1990



Source: World Energy Conference Proceedings, 1980 deposits (second largest in the world) and biomass energy resources, but poorly endowed with conventional oil and gas resources. Proven oil reserves were only 1226 million barrels in 1979, or less than 4% of recoverable oil reserves in the U.S. On the demand side (Table 1-4), total primary energy consumption more than doubled from 1967 to 1977. The share of petroleum in total consumption increased from 33 to 42%, while the share of hydropower increased from 16 to 26%. These increases were offset by a decline in the share of firewood from 38% to 20%.

The potential for hydroelectric power in Brazil is enormous. Hydroelectric capacity was 23,000 MW of energy. The Brazilians are planning to increase this figure to 33,000 MW by 1990 (Brazil Energy Model, 1979). After 1990, surveys indicate that 60,000 MW of additional capacity can be developed before substantial rises in costs (i.e., costs greater than $1800/KW ($1979)) will occur (Table 1-3). Much of the underdeveloped hydropower potential is located in the north, far from industrial centers. Due to the shortage of hydropower near industrial centers in the south, the Brazilians initiated a vigorous program of nuclear power production in the early 1970's. Original plans called for eight 1,300 MW reactors, a uranium enrichment plan and reprocessing plant, all to be built by 1990. Reactors were to be purchased from West Germany for a total of $8 billion, and Brazil was to furnish Germany with uranium. Proven reserves of uranium are fifth largest in the world (126,000 tons U_3O_8 in 1979).

The Brazilian nuclear power program has been scaled back from these

Table 1-4

Primary energy consumption in tons of petroleum equivalent

YEARS	PETROLEUM		NATURAL GAS		ALCOHOL		SHALE OIL		SUBTOTAL		WATER POWER		COAL		FIREWOOD		BAGASSE		CHARCOAL		URANIUM		TOTAL	
	1,000 tons	%	1,000 tons	%	1,000 tons	%	1,000 tons	%	1,000 tons	%	1,000 tons	%	1,000 tons	%	1,000 tons	%	1,000 tons	%	1,000 tons	%	1,000 tons	%	1,000 tons	%
1967....	17,371	33.8	105	0.2	367	0.7	—	—	17,843	34.7	8,465	16.5	2,048	4.0	19,291	37.4	2,825	5.5	1,003	1.9	—	—	51,475	100.0
1968....	20,279	37.9	93	0.2	160	0 3	—	—	20,532	38.4	8,860	16.6	2,317	4.3	18,048	33.8	2,564	4.8	1,094	2.1	—	—	53,415	100.0
1969....	21,993	38.7	96	0.2	27	0.0	—	—	22,116	38.9	9,481	16.7	2,342	4.0	18,999	33.4	2,762	4.9	1,191	2.1	—	—	56,891	100.0
1970...	23,311	38.1	104	0.2	155	0.2	—	—	23,570	38.5	11,560	18.9	2,391	3.9	18,809	30.8	3,356	5.5	1,484	2.4	—	—	61,170	100.0
1971....	26,186	39.9	140	0.2	213	0.3	—	—	26,539	40 4	12,549	19.1	2,431	3.8	18,862	28 8	3,559	5.4	1,655	2.5	—	—	65,595	100.0
1972 ...	28,740	41.0	166	0.2	328	0.4	—	—	29,234	41.6	14,918	21 3	2,491	3.6	17,661	25.2	3,990	5.7	1,822	2.6	—	—	70,116	100.0
1973....	34,240	43 9	178	0.2	260	0.3	—	—	34,678	44.4	17,055	21.9	2,493	3 2	17,429	22.4	4,459	5.7	1,897	2.4	—	—	78,011	100.0
1974...	36,947	43.8	339	0.4	160	0.2	—	—	37,446	44.4	19,011	22.5	2,469	2.9	18,541	22 0	4,361	5.2	2,536	3 0	—	—	84,364	100 0
1975....	39,300	43.5	369	0 4	136	0.1	—	—	39,805	44.0	21,412	23 7	2,850	3.2	19,328	21.4	4,032	4 5	2,897	3 2	—	—	90,324	100.0
1976 ...	42,894	43.3	367	0.4	144	0.1	—	—	43,405	43.8	23,626	23 8	3,435	3 5	21,294	21.5	4,166	4.2	3,154	3.2	—	—	99,080	100.0
1977....	43,063	41.7	505	0.5	537	0 5	—	—	44,105	42.7	26,953	26.1	4,106	4.0	20,885	20.2	4,714	4.6	2,489	2.4	—	—	103,252	100.0

Source: Brazilian National Energy Balance, 1978 initial goals, however, due to cost overruns and delays. Completion date for the reactors has been moved back to the year 2000, and current cost estimates of the program are $30 billion (NYT, 5/18/81). These large cost overruns and long delays have forced the Brazilians to emphasize the development of hydroelectric power in the north to be transmitted to the south.

While domestic electricity demand can be satisfied by domestic hydropower and some nuclear power for many years to come, the acute problem in Brazil today is the low level of domestic oil production relative to the high demand for petroleum. Oil production has been declining at 4% per year for the last 6 years, and oil imports have risen to 85% of oil consumption. Oil for onshore fields discovered in the 1950's is rapidly being depleted. A large fraction fo the primary oil reserves of these fields has been produced, and most are undergoing secondary recovery operations at the present time. It is hard to believe that a country as large as Brazil has so little oil. The onshore cratonic basins have very poor source rocks and few structures, and this type of onshore basin contains only 1% of the known oil reserves worldwide.

The Brazilians launched an accelerated program of oil exploration, concentrated in the offshore basins, in the 1970's. By 1979, 411 offshore wells were drilled, and in 1975 a significant discovery of 8 fields was made in the Campos basin. Eight offshore production platforms are now being installed at a total cost of $4.7 billion, $1980 Offshore, 9/80). Peak production is expected to be around 110 million barrels per year in the late 1980's. Although the capital coefficient is $14,000 per daily barrel (among the world's highest), the production cost is around $10/bbl as compared to over $30/bbl for oil imports. As a result of these discoveries, Brazil's proven oil reserves now stand at 1226 million bbls. The combined production from the known onshore and offshore reserves is expected to increase from 60 million bbl/yr in 1978 to 117 million bbl/yr in 1985. This should increase to 146 million bbl/yr in the late 1980's and then decline rather quicky if additional resources are not discovered.

While Brazil is deficient in conventional oil deposits, shale oil resources are substantial (842 billion bbls). Current measured shale oil reserves at three mining sites in southern Brazil are 1.26 billion barrels. Average oil content is only 7.4% (23 gallons/ton or 0.55 bbls/ton), which is less than the oil content of U.S. shale (30-35 gallons/ton). Most of this shale has overburden less than 30 meters and can thus be strip mined. Petrobras, the state-owned oil company, has been operating a pilot plant that has been producing 1000 bbls/day for the last 8 years. Current plans call for the construction of the first industrial scale plant, designed to produce 23,000 bbl/d, in the late 1980's. Investment cost estimates, however, are very high, in the range of $45,000 to 50,000 per daily barrel.

In addition to hydropower, oil and shale oil resources, Brazil has natural gas and coal deposits. Natural gas resources are small. In 1987 they totaled 44 billion cubic meters (280 million bbls of oil equivalent), equal to one fourth of oil reserves. Although coal reserves are moderate (19.7 billion tons of total resources), they are of poor quality and far from major demand centers. Coal production in 1980 was 12 million tons or 4% of total primary energy.

1-2. Brazilian Energy Policies

The primary goal of Brazilian policies today is to reduce Brazil's overwhelming dependence on foreign oil imports. The current strategy is two-pronged, combining an effort to increase oil production with incentives to substitute available domestic energy rosources for petroleum products. The main objectives of the Brazilian energy plan are to:

- Increase oil production through development of recently discovered offshore fields to bring total oil production up from 60 million bbls in 1978 to 181 million bbls in 1985. Continue a high level of exploration by Petrobras, particularly offshore where 800 wells costing $2.4 billion are planned between 1980 and 1985.

- Substitute fuel oil in industrial use with coal, firewood and charcoal. Double coal production from 1980 to 1985, substituting approximately 60 milion bbls of fuel oil with coal and substituting 30 million bbls of fuel oil with other sources (mainly wood and charcoal).

- Substitute alcohol, produced primarily from sugarcane, for gasoline in automobiles. Produce 10.7 billion liters of alcohol by 1985 to replace 63 million bbls of gasoline. Manufacture 350,000 all-alcohol cars by 1982.

- Institute measures to conserve petroleum products and electricity using regulation and licensing schemes desiged to save up to 41 million bbls of petroleum by 1985.

Four major topics raised by the Brazilian energy plan will be discussed in this introductory chapter:

- The structure of petroleum product demand

- Energy pricing policies
- Petroleum exploration
- Shale oil
- The Brazilian alcohol program

1-3. The Structure of Petroleum Product Demand

In order to appreciate the difficulty of substituting domestic energy resources for oil, it is important to understand the structure of Brazil's liquid fuel demand. Petroleum product consumption is composed of roughly equal parts of gasoline, diesel and fuel oil. All of the gasoline consumed and three-fourths of the diesel consumed is in the transportation sector. Fuel oil is demanded primarily by industrial users concentrated in the southeast of Brazil. Oil consumption in residential enery use is minor, since 70% of residential energy needs are met with firewood. Petroleum product demand is therefore concentrated in the transportation sector, which accounts for 50% of oil consumption.

The main emphasis of the Brazilian energy plan is to reduce the share of gasoline and fuel oil in the total consumption of petroleum products. The share of diesel oil (used primarily in bus and truck transport), however, may thus increase to half of petroleum product demand, causing an imbalance in the refining sector. Since the Brazilian energy plan was announced in 1979, a patchwork approach to the diesel problem, characterized by investments in the refining sector and research on vegetable oil and alcohol substitute for diesel, has been developed. Brazil's liquid fuel problems in the future are likely to be centered primarily on controlling the consumption of diesel fuel.

1-4. Energy Pricing Policies

The most important and effective method to manage the adjustment to the higher cost of oil imports is to set domestic energy prices that properly reflect the marginal cost of the energy source. Setting proper energy prices will reduce consumption and achieve substitution objectives more efficiently than reliance on regulatory measures to encourage conservation and substitution. Several points are relevent to the setting of prices that reflect marginal costs to society:

i) Non-traded domestic energy resources should be priced at the long-run marginal cost of production. In Brazil the most important energy source of this type is electricity.

ii) The domestic prices of tradeable energy resources, such as petroleum, should reflect their true opportunity costs to society and be set equal to international oil prices.

iii) The price of imported oil should reflect the fact that supply is subject to short-term disruptions. Uncertainties in the short-run supply are best handled with a strategic petroleum reserve as insurance against short-term disruption. The long-run price of oil is also subject to considerable uncertainty. This may be handled through a mix (or portfolio) of domestic energy investments that minimizes the risks associated with the international oil price. Both the added costs of maintaining a stockpile and the costs of additional investments to encourage substitution are real costs and should be paid for by the consumers of petroleum through a premium or tax on petroleum products.

Brazilian energy policies rely heavily both on regulatory measures for conservation and substitution and on investment plans for state-owned enterprises. Serious distortions that discourage substitution and promote wastage of energy are caused by current energy prices.

An annual price series for petroluem products from 1970 to 1980 is shown in Table 1-5. These prices were translated into constant terms using the general price index for Brazil calculated by the World Bank, with results shown in Table 1-6. As can be seen gasoline prices were constant in real terms until they doubled in 1976 and then doubled again by 1980. Kerosene, diesel, and fuel oil prices remained basically constant in real terms until they doubled in the 1979-1980 period.

Real prices of electricity have declined fom 1975 to 1979 and are considerably below long-run marginal costs. Fuel oil prices in 1980 were about one-fourth of international prices, and coal prices were also heavily subsidized, costing only a small fraction of domestic fuel oil prices (on a BTU basis). These subsidies have created serious financing problems in the coal and electricity sectors. Diesel oil prices were raised in 1979 to about four-fifths of the international level, however and gasoline prices are at international parity.

Raising diesel and fuel oil prices would encourage substitution with cheaper domestic substitutes. It would eliminate the need to subsidize coal prices. Without correcting these distortions, the current goals for substitution and conservation are unlikely to be achieved. Current trends indicate that the goal of substituting coal for fuel oil is likely to fall far short of current plans by 1985.

TABLE 1-5

RETAIL PRICES OF PETROLEUM PRODUCTS

IN BRAZIL 1970 - 1980

		Regular Gasoline "A" Cr$/L	Premium Gasoline "B" Cr$/L	Kerosene Cr$/L	Diesel Cr$/L	Fuel Oil (low boiling point -low sulfur) Cr$/KG	LPG Cr$/KG
1970	January	0.42	0.55	0.37	0.35	0.08	0.64
1971	May	0.56	0.71	0.50	0.47	0.11	0.85
1972	May	0.69	0.87	0.66	0.59	0.14	1.10
1973	April	0.79	1.01	0.73	0.66	0.16 - 0.18	1.24
1974	January	1.03	1.39	0.87	0.73	0.18 - 0.22	1.48
1975	January	2.02	2.67	1.31	1.13	0.27 - 0.33	2.40
1976	January	3.63	4.53	1.84	1.73	0.44 - 0.52	3.25
1977	February	5.10	6.30	2.42	2.70	0.61 - 0.72	4.10
1978	February	7.30	8.90	4.10	4.00	0.94 - 1.1	6.30
1979	February	9.60	12.50	5.90	5.40	1.40 - 1.60	8.40
	October	14.30	21.50	9.45	8.70	2.4 - 3.0	9.30
1980	March	26.00	38.00	16.40	12.00	3.6 - 4.5	10.70

Source: National Petroleum Council (CNP).

TABLE 1-6

RETAIL PRICES OF PETROLEUM PRODUCTS IN BRAZIL IN CONSTANT 1970 Cr$, 1970-1980

		Regular Gasoline "A" Cr$/L	Premium Gasoline "B" Cr$/L	Kerosene Cr$/L	Diesel Cr$/L	Fuel Oil (low boiling point -low sulfur) Cr$/KG	LPG Cr$/KG	Index
1970	January	0.42	0.55	0.37	0.35	0.08	0.64	100
1971	May	0.47	0.59	0.42	0.39	0.11	0.71	120
1972	May	0.50	0.63	0.48	0.43	0.10	0.80	138
1973	April	0.49	0.63	0.46	0.41	0.10-0.11	0.78	160
1974	January	0.48	0.65	0.40	0.34	0.08-0.10	0.69	215
1975	January	0.73	0.96	0.47	0.41	0.10-0.12	0.86	278
1976	January	0.89	1.11	0.45	0.43	0.11-0.13	0.80	407
1977	February	0.90	1.12	0.43	0.48	0.11-0.13	0.73	565
1978	February	0.92	1.12	0.52	0.50	0.12-0.14	0.79	796
1979	February	1.12	1.45	0.69	0.63	0.16-0.19	0.98	857
	October	1.15	1.73	0.76	0.70	0.19-0.24	0.75	1246
1980	March	1.73 p	2.52 p	1.09 p	0.80 p	0.24-0.30 p	0.71 p	1507 p

1/ General Price Index (Domestic Availability).

p - preliminary, 5%/month increase in price index assumed for January - March 1980.

Source: Retail Prices of Petroleum Products in Brazil 1970-1978 from CNP data.

1-5. Exploration for Domestic Petroleum

The national energy plan has a stated goal of increasing oil production from 60 million bbls in 1978 to 181 million bbls by 1985. This short-term production can only come from recently discovered offshore fields, not from expected future discoveries. Current scheduling of production from the Campos fields indicate that total onshore and offshore production in 1985 is likely to be around 117 million bbls, increasing to 150 million bbls in the late 1980's. This production is expected to decline quickly if additional discoveries are not made.

Petrobras (the state-owned oil company) maintained a strict monopoly on exploration until 1975, when risk contracts for small blocks were offered to foreign oil companies. By mid-1979, 411 wildcat exploration wells had been drilled offshore. A total of 26 wells were drilled by foreign oil companies, and all were dry. The number of wildcat wells drilled in the interior basins totaled 177, and 1400 were drilled in the coastal oil provinces. The best oil potential is still considered offshore, and according to the Oil and Gas Journal (2/6/81), Petrobras plans to spend $3.6 billion the next 4 years ($2.8 for 800 offshore wells, $0.8 for 975 onshore wells). Exploration contract terms have been somewhat relaxed, but the share of exploration completed through risk contracts is still very small.

A major portion of this thesis is devoted to the estimation of the amount of oil expected to be discovered both in undiscovered fields in known plays (cluster of fields) and in undiscovered plays in Brazil.

Data from exploration will be used to update initial prior estimates of the resource base for groups of geologically similar basins. Estimates will then be made of the expected economic return and its variance for blocks of future exploration wells. Preliminary results indicate that the best prospects lie offhshore and that by and large exploration has been relatively efficient, with low probabilities that sizeable fields have remained undiscovered.

The results of the model indicate that economic returns from future exploration are positive even with low probabilities of occurrence since if oil is found oil production costs are likely to be low compared to the international oil price. However, the wide range of possible outcomes of exploration does present risks to Petrobras. This is particulary important to recognize, since Petrobras plans to spend $3.6 billion over the next 4 years on exploration. Petrobras could maintain flexibility in its investment planning by subcontracting seismic exploration and drilling to privte Brazialian firms, rather than continuing to build up its own in-house capability. Also, by increasing the share of investment in exploration contributed by foreign companies and other sources, the risk of exploration by Petrobras could be reduced. A major issue to be looked at is the profitability of oil exploration from the viewpoint of the foreign oil companies as opposed to the profitability of exploration from the viewpoint of Petrobras.

1-6. Shale Oil

As briefly described earlier, Brazil has the world's second largest shale oil resources. There is a great deal of uncertainty in the technical cost of production and the initial investment costs are a large lump-sum investment. Petrobras (which currently has control over shale oil operations) has, up to this point, decided not to move strongly into shale oil production. A major issue to be looked into is whether or not it is economic from a social viewpoint to invest in shale oil.

1-7. The Brazilian Alcohol Program

Brazil has launched the largest program to produce alcohol from biomass in the world. There are numerous advantages and disadvantages to the proposed program, and there is much debate about the program's impact on other agricultural production. In this thesis the economic analysis of the alcohol program in Brazil will be taken from the intensive study of the situation by the World Bank. The current technological and economic aspects of the program will be highlighted so that the alcohol production option can be compared to the oil exploration and shale oil options.

A major advantage of alcohol is that it can be used directly in automobile engines. If anhydrous alcohol is mixed with gasoline in proportions up to 20%, the economic value of the alcohol is the same as gasoline. When 100% anhydrous alcohol is used in specially designed engines, the economic value of alcohol is 85% that of gasoline, since pure alcohol is less efficient than gasoline or gasohol.

A second major advantage of alcohol is that it can be produced economically from surgarcane with current oil prices, according to a recently published World Bank study. A typical alcohol plant based on sugarcane produces 120,000 liters/day for 180 days/yr (136,000 bbls alcohol/yr) and has a capital cost of $7.6 million. The World Bank report has calculated economic rates of return for alcohol plants assuming various selling prices of gasoline and alternative sugarcane production costs. Brazil is considered a low cost country, with oil imports priced at about $31/bbl and sugarcane production costing about $10/ton. Since sugarcane stalks (bagasse) can be used as an energy source in the distillation of alcohol from fermented sugar, the process is calculated to have a positive energy balance.

The fact that sugar producers form a strong concentrated interest group and that sugar prices were depressed (8¢/lb) between 1976 and 1979 is a major driving force behind the program to convert sugarcane to alcohol, since the alcohol program provides a de facto price support. Sugar prices have since increased, but Brazilian energy planners have emphasized that while short-run losses of diverting sugar to alcohol production may occur, they are outweighed by long-run benefits of substituting for oil imports. Furthermore, the market price for sugar should not be directly translated into an alcohol production cost, since Brazil is not a price taker in the sugar market.

Alcohol production in Brazil was 4 billion liters in 1980. The state goals of the Brazilian government is to produce 10.7 billion liters by 1985, 3.5 for alcohol gasoline mixture, 5.7 for straight alcohol engines and 1.5 for chemical feedstocks. This 1985 goal relies almost completely on sugarcane and will require approximately 2.7 to 3.1 million ha of land (depending on whether yields are 3500 l/ha or 3000 l/ha) in addition to the 1.6 million ha under sugarcane cultivation in 1979. Production of 1 liter of alcohol produces a byproduct of 12 liters of liquid stillage waste, currently being expelled into rivers (For. Agr., 1981). By 1985, 128 billion liters of stillage waste must be processed (possibly as fertilizer) if production goals are met, adding additional costs to alcohol production.

The major problem with the alcohol program based on sugarcane is the significant rise in land costs and thus food costs that may occur as land is diverted from food production. Concern has been expressed that the incomes of food consumers, particularly low income consumers, might be reduced to the benefit of both sugarcane land owers and automobile owners. Export earnings from cash crops may decline as well, as prime land is diverted to alcohol production. Although it is uncertain how much land costs could rise, it is not inconceivable that the opportunity cost of land (currently about a fifth of sugarcane production costs) could double. Along with increased cost of stillage processing, this cost increase might make alcohol production from sugarcane uneconomic by the late 1980's. This is particulary likely to occur as alcohol production increases toward the 1987 stated target of 14 billion liters.

Sugarcane crops require the highest quality land. Due to this potential conflict betwen using the best land for food and using it for alcohol crops, there has been a move toward utilizing cassava and timber for ethanol alcohol production, since they can be grown on marginal land. The capital costs of alcohol plants based on cassava or timber are higher (30% higher for cassava) and crop yields per ha are lower, but these plants have longer operating seasons than plants based on sugarcane. The economics of large-scale production of ethanol from these sources is critically dependent on the magnitude of the costs of clearing and irrigating marginal lands, the opportunity cost of pasture lands and the additional costs of processing stillage. Results from current research may help lower production costs and improve crop yields for these alternative raw materials. Large-scale alcohol production from these sources may eventually be feasible, but progress will probably be slow.

Current technology does not permit the use of alcohol in diesel engines. Even if technology permitted, ethanol currently cannot be economically substituted for diesel oil, since test results indicate specific ethanol consumption is 1.7 times (by volume) that of diesel. Recent trends in Brazil are to use vegetable oils mixed with diesel oil in a 30:70 ratio. However, vegetable oils are expensive and utilize prime agricultural land. If the vegetable oil program is expanded substantially, a choice will have to be made between using prime lands for vegetable oil production or for alcohol from sugarcane.

1-8. Short Term Prospects in the Energy Sector

Brazil is in the midst of a difficult adjustment to higher oil prices. It is being forced to deal with the problems of producing synthetic fuels from biomass and shale earlier than most other countries. It is further along than any other country in the research and development of automobiles and trucks to run on alcohol fuels. In the not too distant future it might be the first country to depend on electricity and synfuels from shale and biomass) for the major portion of its energy supplies. The costs of this transition are enormous and are becoming apparent only now. The marginal cost of most liquid fuel sources is between $30 and $40/bbl, whether derived fom biomass, shale oil, or imported oil. Brazilian energy plans call for a massive investment of $60 billion from 1980 to 1985.

In the short-run it is particularly important to construct current plans in light of the sequential nature of both oil exploration and synfuel research and development. Future plans can be adjusted or revised as new information about the resource base or technical production costs becomes available. Short-run policies could concentrate on more efficient energy pricing policies and on investments in the coal and refinery sectors to achieve energy substitution objectives.

The Brazilian energy plan projects oil consumption in 1985 to increase only 4% over the 1978 level. The author estimates that oil consumption is more likely to be 20% greater in 1985 than in 1978, as shown in Table 1-7. These estimates are based on estimated income and

Table I-7

Brazilian Petroleum Balance

(1978 and 1985 estimates
in millions of barrels)

	1978 (actual)	1985 Goals of Brazilian Energy Plan[1/]	1985 (estimates)[2/]
Substitution of fuel oil with coal and with other sources		92	70
Substitution of gasoline with alcohol		63	57
Energy conservation		41	
Petroleum product consumption (energy uses, with conservation and substitution)	345	321	383
Non-energy petroleum consumption	31	69	69
Total consumption	376	390	452
Domestic production	59	181	117
Imports	317	250	335

[1/] Assumes real GDP/capita up 3.5%/yr, population up 2.5%/yr. Source: Brazilian Ministry of Mines presentation to the Financial Times of Brazil in October 1979.

[2/] Authors estimates. Assumes: real GDP/capita rises at 3%/yr; population rises 2.5%/yr; 80% of fuel and substition target met; alcohol production of 9.2 billion liters with hydrous alcohol use 85% as efficient as gasoline. "Conservation" as such is accounted for through income and price elasticities. Diesel consumption and joint gasoline plus alcohol consumption are calculated using elasticities from a cross-section time-series of 10 LDC's. Long-run price and income elasticities are -0.4 and 1.3 respectively. Short-run elasticities are one tenth of long-run elasticities. Gasoline prices are assumed to be maintained at import parity. Diesel prices assumed to be raised from 80% of international parity in 1978 to international parity in 1980 and maintained. Joint consumption of fuel oil and fuel oil substitutes projected to increase 4%/yr, without significant correction in the underpricing of fuel oil.

International oil price assumed to increase at 3%/yr in real terms from a base of $30/bbl in 1980.

price elasticities from a cross section study of ten LDC's. Since GDP in Brazil is expected to rise about 45% over this period from 1978 to 1985, oil consumption growth is still a substantial achievement, resulting in large part from lagged adjustment to higher oil prices. The Brazilian enery plan projects oil imports by 1985 to decline 21% from the 1978 level. A more realistic figure is a slight increase of 6% over the same period.

1-9. Major Issues of Investment in the Liquid Fuels Sector Focused on in this Thesis

Numerous issues have been discussed in this chapter but this thesis will concentrate only on the major liquid fuel supply options and their assoiciated risks, summarized as follows:

1. Imported Oil - There is a chance of a short-term cutoff of oil imports primarily caused by political events. This short term risk is best dealt with through an adequate oil stockpile. The cost of maintaining the stockpile should be passed on to the consumers of oil. The longer term risks associated with imported oil are caused by the wide range of possible oil import prices which are dependent on actions of the OPEC cartel.

2. Exploration and Production of Domestic Oil - The major risk associated with supplies of domestic oil is the geological risk assoicated with the existence of the oil, and the uncertainty of finding the oil given it exists. A probabilistic oil exploration model is developed in this thesis that explicitly calculates the probabilities of the existence of various amounts of oil and the probabilities of oil discovery for various levels of exploration. Using some reasonable guesses as to the cost of oil, if it is discovered, the rate of return (or net present value) of oil exploration can be calculated. Thus the analysis explicitly takes account of the impact of geologic risk, exploratory risk and risks associated with the price of oil. This approach also facilitates analysis of the potential to share risks between the Petrobras and multinational oil companies.

3. <u>Shale Oil Production</u> - The major risks associated with shale oil production are the large uncertainties in the technical cost of production and the risks associated wth the oil price. The large investment level required to build an initial shale plant may make shale too risky from the firm point of view but not from a social point of view.

4. <u>Alcohol Production</u> - The rate of return on alcohol from biomass is extremely sensitive to assumptions about the price of oil and the raw material impact. The raw material cost is in turn very sensitive to agricultural yield and the cost of land (or the opportunity cost of land for other food crops). The risks of alcohol fuel supply come primarily from the oil price and from technical-agricultural factors.

A major objective of this thesis is the economic comparison of the various liquid fuel options from the viewpoint of Brazilian society. Investments in the various options over the next 5 years will be evaluated on a common basis with the same assumptions about the price of oil, shadow price of foreign exchange, etc. Estimates of the socially optimal investment plan will take into account the social cost of capital and the risk characteristics of the various options. It may also be useful to analyze how investment undertaken by Petrobras or foreign oil companies may differ from the socially optimal investment plan. For example, Petrobras or a foreign company may perceive the risk of a specific project, the work of groups of projects, or the required rate of return on investment differently than Brazilian society and this would lead to less than optimal investment. While there are numerous examples of private versus social benefits to examine, this thesis will concentrate on only a few of the more important examples.

CHAPTER 2

METHODOLOGY FOR THE EVALUATION OF LIQUID FUEL OPTIONS IN BRAZIL

2-1. Financial Methods of Project Evaluation: NPV vs. IRR

In order to compare the option to explore for oil to other liquid fuel production options (shale oil and alcohol), all projects need to have a common basis for comparison. Two of the most common evaluation methods to compare projects are the Net Present Value method (NPV) and the Internal Rate of Return (IRR) method. The goal of this chapter is both to establish a method to calculate the NPV, variance of NPV, rate of return, and variance of the rate of return for liquid fuel production programs from the viewpoint of Brazilian society and to clarify points where public and private evaluation may differ.

The IRR method and the NPV method both assume that cash outflows (costs) are subtracted from the cash inflows (benefits). The NPV method uses the appropriate discount rate, reflecting the time value of money, to discount the annual cash flows.

$$\mathrm{NPV} = \sum_{i=0}^{n} \frac{(\mathrm{Benefits})_i - (\mathrm{Costs})_i}{(1 + r)^i}, \quad r = \text{discount rate} \qquad \text{(eq. 2-1)}$$

Project NPVs can then be directly compared. The IRR method uses the same principle, except the IRR is the rate of return, r, which brings the NPV to zero. NPV is the preferred evaluation method, since in certain special instances IRR may give different results in project ranking as compared to NPV. Situations where this may occur are shown below:

- If negative cash flows follow positive cash flows, NPV may rise with the discount rate. Thus, projects should be accepted if their IRR is <u>less</u> than the cost of capital. The IRR rule would lead incorrectly to rejection of the project.
- If there are changes in the signs of the cash flows over time, multiple internal rates of return may occur, giving biased and indeterminate results.
- The IRR rule may give incorrect ranking of mutually exclusive projects which differ in scale or life of the project.
- IRR assumes that cash flows generated can be reinvested at the same level as the IRR over the life of the project. NPV assumes that cash flows can be reinvested at the cost of capital. Variations in the cost of capital over time may cause differences in the ranking of projects, depending on whether IRR or NPV is used.

While NPV is the preferred method, IRR can be useful if special attention is paid to the conditions above. IRR and the variance of IRR can be used more easily than NPV when consideration is given to portfolio analysis of investment options. In this study investments will be compared primarily using NPV.

2-2. Private vs. Public Project Evaluation

As our goal is to calculate the NPV of a specific liquid fuel production program by discounting cash inflows and cash outflows, the next relevant question to ask is what the correct prices and costs to use in the evaluation are. The correct prices and costs are those that reflect the opportunity cost of a resource in its next best use. If we think of planning in an economy as a linear programming problem with the objective function being intertemporal maximization of society's income given constraints on the available resources (labor, foreign exchange, materials, etc.), the programming solution gives the shadow price for each resource. These shadow prices indicate the value of the marginal product that could be obtained if one more unit of scarce resource were available. This increase in income that would result if one more unit of resource were added is the relevant measure of the opportunity cost of the resource in its next best use.

Only under very rare circumstances would the true social opportunity costs (or shadow prices) equal the observed market prices in a real world economy. Market prices will equal social opportunity costs under conditions of perfect information, numerous consumers and producers, mobile factors of production, no externalities, no barriers to entry and no restrictions on price movements. These conditions do not hold in any real world economy, and certainly not in Brazil. A project can be evaluated with shadow prices (i.e., an economic evaluation) or market prices (a financial evaluation). If the economic evaluation produces a positive NPV and the financial evaluation produces a negative NPV, a case can be made that the public sector should take measures to insure that this socially beneficial project is undertaken since the private sector is reluctant to do so. It is not the purpose of this study to calculate the shadow price of each input in exhaustive detail. In many instances market prices are a good approximation to shadow prices, but it is necessary to take notice of the most important areas in which market prices may diverge from social prices. For the type of projects in Brazil this study is concerned with, the most important areas where distortions may occur are the price of oil, the cost of capital and, to a lesser extent, the price of foreign exchange (and its impact on the cost of imported capital items), the cost of labor and measurement of externalities caused by pollution. The price of oil and the cost of capital have an important effect on the outcome of the NPV calculations and will be discussed in detail in sections 2-4 and 2-5. Evaluations using the shadow price of foreign exchange show that it has a moderate effect on the NPV calculations, as discussed in section C. The other shadow prices have a small effect as discussed below.

The labor component of the oil production process (oil exploration and production) and the shale oil production process is small. Even if the shadow price of labor differs from the market price, the effect of NPV is expected to be extremely small. The process of producing alcohol from biomass does have a significant labor component. The economic analysis of the alcohol program used for this report is taken from an intensive study of the situation by the World Bank. For their evaluation the market price of labor was set equal to the social opportunity cost of labor in south and southeast Brazil. However, in the northeast, labor was shadow priced at 0.7 of the market rate due to a surplus of labor and minimum wage regulations. For the purposes of this study the price of labor will be set at the market rate for the oil and shale oil production processes for two reasons. First, the labor component is very small, and second, according to the World Bank labor prices equal the market rate in southern Brazil, where these oil production activities are taking place.

There are potential externalities (extra costs to society) caused by pollution from shale oil and stillage from alcohol production. These costs are not reflected in the market prices used to evaluate the production processes. If possible, these costs will be accounted for by adding the estimated cost of pollution equipment to the project costs. If these costs cannot be identified quantitatively they will at least be identified qualitatively.

2-3. Calculation and Use of the Shadow Price of Foreign Exchange

The projects under consideration involve investments in capital goods that are partly produced at home (in Brazil) and partly imported. For project evaluation, all costs and benefits need to be translated into a base currency. For simplicity, the U.S. dollar will be the base currency (since costs measured in U.S. $ are subject to more predictable inflation indexing than the Cr in Brazil, where several different cost indexes prevail and inflation was 109 percent in 1980). All costs and benefits will be translated into constant US $ 1979. The domestic component of the costs must be converted into US $ at the official exchange rate. The exchange rate in Brazil is a "crawling peg" where mini-devaluations that reflect (in principle) the high level of domestic inflation are made approximately every two weeks. However, the official exchange rate does not accurately measure the true opportunity cost of foreign exchange (or shadow exchange rate) if there are significant trade barriers. Various trade policies such as export subsidies, import tariffs, etc., are in some sense a substitute for devaluation and make the official rate overvalued relative to the shadow exchange rate. An economic interpretation of the shadow exchange rate (or free trade exchange rate) is the exchange rate which would prevail if all trade distorting tariffs, subsidies, import deposits, export taxes, and quantitative restrictions were eliminated. There exists a broad body of literature on the theory and calculation of the shadow exchange rate (Bacha and Taylor 1971, Balassa 1974, Roemer and Stern 1975, D. Lal 1974). Some methods may be theoretically superior but difficult if not impossible to apply in practice. A method that is widely used and relatively easy to apply in practice has been derived in Bacha and Taylor (1971) and Balassa (1974). The methodology expresses the ratio of the shadow exchange rate to the official exchange rate as a weighted average of the rates of protection of imports and exports. The weights are the relevant foreign trade elasticities, as shown below:

$$\frac{R'}{R} = \frac{\sum_i e_i^r X_i/(1+S_i) + \sum_i e_i^m M_i/(1+T_i)}{\sum_i e_i^f X_i + \sum_i e_i^m M_i} \qquad \text{(eq. 2-2)}$$

R = the official exchange rate

R' = the shadow exchange rate

e_i^f = the price elasticity of foreign exchange for product i

$$= \frac{e_i^{sx}(e_i^{dx} - 1)}{e_i^{sx} + e_i^{dx}}$$

e_i^{sx} = the price elasticity of export supply for product i

e_i^{dx} = the effective price elasticity of export demand facing product i, defined as a positive number

= the inverse of the country's share of world exports times the aggregate world price elasticity of demand

e_i^m = the price elasticity of demand for imports of product i

X_i = exports of product i

M_i = imports of product i

S_i = the subsidy on exports of product is as a ratio of the export price (an export tax is considered a negative subsidy)

T_i = the total protection on imports, including the effects of tariffs, advance import deposits, and quantitative restrictions.

This approach assumes that only goods currently traded would be traded under the free trade situation. This "free trade" exchange rate gives us a way to translate the costs of domestic products (which consist of traded and non-traded goods) into a dollar equivalent that is free of distortions caused by trade policies. This "free trade" exchange rate is called the first best shadow exchange rate, as it assumes free trade policies are desirable and the policies in the country are moving toward free trade. Balassa (1974) derives a more complicated "second best" shadow exchange rate that assumes that trade distortions will remain permanently. This shadow exchange rate will produce slightly different results by translating the costs of non-traded goods at a different rate than the "free trade" rate. The opportunity cost of traded goods is the price (in US $) they would bring if sold internationally. This traded good price is given by the "free trade" rate. The "free trade" shadow exchange rate will be used for all items since: a) the investment items for the projects under consideration consist largely of tradeable capital goods, b) the "free trade" rate is much easier to calculate than the complex second-best rate, and c) it is unknown what trade policies will prevail in the future, but assumed that policies will move toward the free trade policies.

The necessary import and price elasticities were obtained from the World Bank Brazil group. Using these elasticities in the above formula, calculations by both the author and World Bank staff show that the Brazilian Cr $ (in 1977-78) was overvalued 20 percent to 40 percent, with the best estimate being 30 percent overvaluation.[1] We will use a shadow exchange rate equal to 1.3 times the official rate

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[1]As of late 1977, there was a large maxi-devaluation accompanied by some change in tariffs and subsidies. The maxi-devaluation was about 10 percent greater than expected cumulative mini-devaluations and a rough calculation of the new shadow exchange rate was about 20 percent. Thus, as expected, using mid-1979 prices and a shadow rate of 1.3 times the mid-1979 official exchange rate produces the same result as early-1980 prices and a shadow rate of 1.2 times the early 1980 official rate (which is 10 percent higher in real terms than the mid-1979 rate).

(Cr \$ per US \$).

In order to apply the shadow price of foreign exchange in project appraisal, we need to know the foreign exchange component of the investment costs (i.e. the fraction of the investment cost which consists of imported materials). With a relatively thorough search of the relevant literature and personal communications with Petrobras and Brazilian officials, the author was able to compile the foreign exchange components of the various liquid fuel production processes (shown in Table 2-1). In addition to the direct foreign exchange component one must take account of the indirect component, which is a percentage of the domestic expenditure that eventually results in purchases of foreign goods. This indirect component is estimated to be 20 percent of domestic expenditure according to members of the World Bank Brazil Group (see Table 2-1). We now have all the necessary factors to calculate the cost adjustment factor. Examples are shown in Table 2-2. The first example is for development cost. The direct foreign exchange component is .45, the indirect component is .11 (= (1-.45)(.2)). Thus, .56 of development costs are spent in US \$, but 1-.56 is spent domestically and should be converted at 1.3 times the official rate. This gives an adjustment factor of .9. This means that for a social cost benefit calculation development costs reported in Cr \$ converted to U.S. \$ (at the official rate) should be multiplied by .9 and then discounted as in any other project appraisal. Exploration cost adjustment factors are given in Table 2-2, shale oil factors in chapter 5, and alcohol factors in Chapter 6.

Table 2-1

Foreign Exchange Components of Various Liquid Fuel Production Processes in Brazil

Petroleum Production:	Percent of Capital Investment in Foreign Exchange Directly
Offshore-Campos Basin (>50m)[1]	45 (Foreign labor 35)
Offshore-shallow water (<50m)[1]	10
Overall Production[2]	25
Exploration:	
Overall exploration by Petrobras[2]	30
Refining[2]	12
Overall Petrobras[2]	20
Shale Oil	
Mining	66
Solid Preparation	30
Retorting	25
Average (weighted)[3]	34
Petrobras estimate[4]	20-25
Alcohol (from sugar cane or cassava)	
Overall[5]	0

Indirect foreign exchange component is taken to be 20 percent of domestic expenditure, which is induced expenditure in foreign exchange due to increased domestic construction. Figure is from personal communication with World Bank Brazil group.

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[1] Offshore, Oct. 5, 1979

[2] Petrobras, personal communication

[3] Cameron Engineers.

[4] "Utilizacao do Xisto," Petrobras 1978.

[5] From data in "Alcohol Production from Biomass in the Developing Countries," World Bank, Sept. 1980.

Table 2-2

Adjustment Factors for Oil Exploration and Production due to Shadow Price of Foreign Exchange

Adjustment to Investment Cost due to Foreign Exchange Component:

Shadow price of foreign exchange = 1.3
Direct foreign exchange component = .45
Indirect foreign exchange component = (1 - .45)(.2) = .11

Development cost adjustment $= \left(\frac{1 - .11 - .45}{1.3} + .11 + .45\right) = .9$

Adjustment to Exploration Investment due to Foreign Exchange Component:

Direct component = .3

Indirect component = (1 - .3)(.2) = .14

Exploration cost adjustment $= \left(\frac{1 - .14 - .3}{1.3} + .3 + .14\right) = .87$

2-4. The Cost of Imported Oil

Oil or liquid fuels are tradeable items so the value for project appraisal is the international market price for that barrel. Supplies of imported oil are subject to interruption due to cutoffs created by an embargo or disruptions in the Middle East. Also, the long-term price of oil is subject to a wide range of uncertainty depending on the behavior of the OPEC cartel. It is important for energy policy makers to clearly understand the difference between a potential short-term disruption and a long-term trend in oil prices. Our example of this confusion was published in Brazil Energy (Oct. 10, 1980):

> "The Iran/Iraq war and the temporary loss of 400,000 bopd underlines Brazil's precarious dependence on foreign oil imports and has added a new impetus to the alcohol fuel substitution program."

The alcohol program is incapable of providing a large amount of fuel in a short period of time to replace disrupted supplies. A much more effective method is to have an adequate stockpile as insurance against disruptions and undertake long-term investments in supply only if they are economically justified.

Brazil lost 45 percent of its oil imports when Iraqi supplies were curtailed in mid-1980. By late 1980 much of the loss was made up with Saudi Arabia supplying 31 percent of imports. Stocks at that time were reported to be 120 mbbls (110 to 120 days consumption according to Brazil Energy, Oct. 10, 1980). The question is how much of that stock was in the refinery pipeline and how much was stored as a crude oil stockpile. According to Brazil Energy (10/10/80):

> "As it is government policy to keep the oil stocks as secret as possible, it is not known for certain how much stocked crude is actually available. Normally a good proportion of the stock is either in transit or being refined and estimates on this undisposed stock go as high as 70 percent."

This implies that the size of the crude stockpile was 80 to 90 days consumption. The optimal size of a stockpile depends on one's perception of the probability, duration, and damage caused by a cutoff. A detailed analysis of the optimal stockpile size is beyond the scope of this paper, but the IEA recommends minimum size stockpiles of 90 days consumption. Using this as a guide, Table 2-3 shows how the cost of holding insurance (in the form of a 90-day stockpile) can be calculated. The cost of holding inventories is $.50 to $.70 ($1981) per month according to PIW (9/28/81, p. 3). The cost of holding a 90-day stock is roughly $450 million to $675 million dollars per year (translated into $1979). The cost of this "stockpile premium" is $1.50 to 2.25 per barrel of imported oil (as shown in Table 2-3). Adding this stockpile premium to the current average oil import price (measured in constant $1979), we get approximately $30/bbl ($1979) as the social cost of a barrel of imported oil. For the purposes of our social project appraisals we will take the value of produced oil to be $30/bbl ($1979) with sensitivity analyses for oil prices increasing 0 percent, 3 percent, and 5 percent per year.

2-5. Private vs. Social Cost of Capital: The State of the Art

In order to compare investment options on a common basis, a cost of capital (or discount rate) is needed to discount cash flows for the NPV

Table 2-3 The Price of Imported Oil

		Average oil import price for Brazil (current US $/bbl)		Mid-year price (const. 1979 US $/bbl)[5]
1978	Dec.[1]	12.38		
1979	Jan.[2]	13.30	1979	20.00
	June[2]	20.00		
1980	Jan.[2]	27.96	1980	27.30
	June[3]	29.91		
	Sept.[3]	30.00		
1981	Feb.[4]	34.50	1981	28.40
	Sept.[4]	34.10		

Approximate Cost of Maintaining a 90-Day Stockpile in Brazil

1. Cost of carrying inventory $0.50 to 0.70 ($1981)/bbl per month (source: PIW Sept. 28, 1981, p. 3).

2. This cost equal to $0.40 to 0.60 ($1979)/bbl month.

3. For 90 days of Brazilian consumption (1.05 mill bbl/day) then cost per year is:
   (0.4 to 0.6)(12 months)(1.05 mb/d)(90 d) = $453 to 675 million/yr.

4. For imports of about 300 mill. bbl/yr this equals:
   $1.51 to $2.25/imported bbl.

5. Cost of imported oil plus insurance from stockpile = $30/bbl.
   (28.40 + 1.60, 1979 US$).

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[1]Petrobras Annual Report, 1979

[2]Majority of supplies until Aug. 1980 from Iraq, Basrah Light - 35 contract price used (PIW Jan. 1980).

[3]Actual weighted average import price (Brazil Energy, Sept. 24, 1980).

[4]Estimated average import price (using import sources shown in Brazil Energy February 24, 1981).

[5]Inflation assumed to be 10 percent/yr from 1979 to 1980.

evaluation or to provide comparison to the calculated IRR from a project. Many of the projects and programs considered in this thesis have rather low rates of return. Thus the choice of discount rate may well decide the acceptance or rejection of the project or program. This cost of capital should reflect the riskiness of the project under consideration as well as the opportunity cost of capital (which may be different for private investors as compared to the viewpoint of society). Traditional approaches to the cost of capital calculation have concentrated on the rate of return on capital foregone by the use of funds by a project (Squire 1975). This traditional literature has typically characterized the cost of capital as one rate for all projects when the project is undertaken by the public sector and another social discount rate for all projects undertaken by the private sector. Modern finance theory, however, contends that the return in the private sector is dependent on the risk of the activity being financed. This is one principle of the Capital Asset Pricing Model (CAPM).[1] There are compelling reasons to believe that this principle holds for the public sector as well (as argued by Bailey and Jensen in their article on "Risk and the Discount Rate for Public Investment," 1972, and by Hirshleifer and Shapiro in their "Treatment of Risk and Uncertainty," (1970)). Our goal here is to estimate social costs of capital that reflect the public risk associated with each of the various liquid fuel options under consideration (oil exploration, shale

[1]For a discussion of CAPM see Jensen, 1972.

oil and alcohol) in Brazil. Estimates of how the private sector rates (both the foreign private sector and the Brazilian private sector) may differ from the social rate for each project will also be made. We will begin by discussing the current CAPM approach for private sector evaluation and will then discuss the elegant integration as discussed by Bailey and Jensen, of the treatment of risk and Harberger's solution (1968) to the income tax distortion problem. An application of this approach will be made for the relevant projects in Brazil.

The CAPM approach is a mean-variance model of asset prices under uncertainty. It contends that the appropriate risk premium for an asset is linear in the marginal contribution of the asset to the portfolio that includes it. The portfolio is considered to be the current existing combination of all assets, whether for a firm (the market portfolio) or for other society (in which case the portfolio is national wealth). In particular, the present value of an additional unit of the Kth asset included in the portfolio P is given by:

$$PV_K = \frac{E(\tilde{V}_{Ki}) - \left[\frac{E(\tilde{V}_{pi}) - V_p(1 + R_F)}{\sigma(V_{pi})}\right] \frac{\text{cov}(\tilde{V}_{Ki}, \tilde{V}_{Pi})}{\sigma(\tilde{V}_{Pi})}}{1 + R_F} \qquad \text{(eq. 2-3)}$$

where, R_F is the riskless rate of interest, V_{pi} is the current value of portfolio P, $\tilde{V}_{Pi}$ is the random total value of portfolio P one period hence and the payoff of adding one more unit of Kth asset is $\tilde{V}_{Ki}$. This gives the equilibrium market price of a unit of the Kth asset assuming homogeneous investor expectations regarding the means, variance and covariance of asset outcomes.

If the above equation is rewritten as expected return on asset (or investment) K in the private market, where R_K $E[\tilde{R}_K] = E[\tilde{V}_{K1}]/PV_K$, then

$$R_K = R_F + [R_M - R_F]\beta \qquad \text{(eq. 2-4)}$$

where, $R_M = E[\tilde{R}_M]$ = expected return on the market portfolio, where

$$\beta = \frac{COV(R_K, R_M)}{Var(R_M)} \qquad \text{(eq. 2-5)}$$

is the coefficient of nondiversifiable or systematic risk for investment K. This formula gives the cost of capital as the riskless rate of interest, plus the risk premium on the market $(R_M - R_F)$ times the covariance of the returns on the project with returns on the market portfolio divided by the variance of the market portfolio. If we assume that the riskiness of the project under consideration is the same as the average risk of projects undertaken by a firm, then a measure of the firm's earnings can be used with returns on the market to calculate a firm β or systematic risk. This firm β is routinely calculated by financial firms such as Merrill Lynch. However, this firm β contains the financial risk of the firm as well as project business risk. Since we are interested only in a project β (to calculate a project cost of capital) we need to "unlever" the firm β for debt to get an all equity β.

$$\beta = \frac{\beta_{Firm}}{1 + (1 - T)D/E} \qquad \text{(eq. 2-6)}$$

where T is the corporate income tax rate, β_{Firm} is the observed stock beta, D is the market value of the firm's debt, E is the market value of the firm's equity, and β is the all equity beta which represents average business risk of the firm's projects. If the project under consideration has the same risk as the firm's average project risk, then β can be used to calculate the risk adjusted cost of capital for the project from the firm's viewpoint.

When a risk adjusted discount rate is calculated in the above manner and used to discount cash flows, it is implicitly assumed that risk increases as a constant rate as one looks out into the future. This assumption is usually reasonable. However, there are cash flow components of a project in which risk may not increase into the future. An example is R and D expenditures or exploration expenditures, since these expenditures resolve uncertainty at the beginning of a project. The solution is to discount these initial cash flows at the riskless rate and other development cash flows at the risk adjusted rate. In practice this adjustment for oil projects makes little difference, as exploration expenditure is a small part of the total project and comes early in the project.

The above formulation of the CAPM assumes that perfect risk markets exist, but Bailey and Jensen point out that in the case of imperfect risk markets the same formulation can be used if the portfolio P is interprested as the portfolio of the project's beneficiaries. Based on these results, Bailey and Jensen came to the following conclusions:

1. If private risk markets are <u>perfect</u> and the distribution of risk through the public sector is <u>perfect</u>, then the risk allowance on any given project should be identical for both the private and public sectors and equal to zero only for a

project whose covariance with national income is equal to zero. The risk allowance should be less than zero for a project with a negative covariance and greater than zero for a project with a positive covariance.

2. If private risk markets are imperfect and the distribution of risk through the public sector is perfect (a situation we believe is nonexistent), then the risk allowance for a public project should be less than that for a similar private project but must nevertheless still depend on the covariance of the project's returns with national income. The allowance should be negative, zero, or positive as the project's covariance is negative, zero, or positive.
3. If private risk markets are imperfect and if the distribution of risk through the public sector is also imperfect, then there must still be an allowance for risk in the public sector. The risk of the project in this situation must be measured by its covariance with the portfolio returns of the project's beneficiaries and can be either positive, negative, or zero, independently of its covariance with national income.
4. Finally, for completeness, although we believe the situation highly unrealistic, if private risk markets were perfect (including the ability to market all claims on the public sector) and the distribution of risk through the public sector were imperfect, then public projects should still bear the same risk allowance as that for private projects. The reason,

> of course, is that the imperfect risk distribution of the public sector is easily corrected in the private markets.

Their summary points out that in no case should the risk allowance on all public projects be zero. These conclusions run counter to the arguments, such as those by Arrow (1966), that a riskless or universally low discount rate be used for all public sector projects. To hold such a viewpoint (Arrow's viewpoint) implies that the public sector can diversify risks completely. For the variance of the portfolio of national wealth to be reduced to zero through diversification, it must be assumed there is zero covariance among a large number of assets in the national wealth portfolio or large negative covariance among some of the assets. Empirical evidence supports the view that assets in all sectors are positively correlated and that on the average, covariance is positive representing non-diversifiable (or systematic) risk.

Based on evidence that equity markets are fairly efficient at distributing risks, Bailey and Jensen argue that the government is likely to be a poorer distributor of risks than the private sector. They agree with Hirshleifer and Shapiro's conclusion that a public project should be discounted at a rate at least as high as the private sector rate for a project of comparable risk, with proper allowances taken for distortions.

Harberger (1968) shows that the presence of taxes creates distortions which lead to a divergence between the private cost of capital and the social opportunity cost of capital. He advocates the use of a weighted average social cost of capital. The capital displaced by a government project comes partly from the capital diverted from other investments which would have earned a before tax rate $R_F/(1 - T)$ (T is corporate tax rate) and partly by offering an additional inducement to savers to give up after tax savings which would have earned $R_F (1 - t)$ where t is the tax rate on savers. Each of these sources is weighted by the responsiveness of investors or savers to changes in the interest rate. The weighted average cost of capital is:

$$R_{SF} = R_F((1 - t)\frac{\partial S}{\partial B} - \frac{1}{1 - T}\frac{\partial I}{\partial B}) \qquad \text{(eq. 2-7)}$$

where $\frac{\partial S}{\partial B} > 0$ and $\frac{\partial I}{\partial B} < 0$ are the net impact of government borrowing on saving (S) and on investment (I).[1]

In order to integrate Harberger's solution to the tax distortion problem and the use of risk adjusted discount rate, Bailey and Jensen derive the following expression for the social cost of capital (R_{SK}) for project K.

$$R_{SK} = R_{SF} + \beta_K[(R_M - R_F)((1 - t)\frac{\partial S}{\partial B} - (\frac{1}{1-T})\frac{\partial I}{\partial B})] \qquad \text{(eq. 2-8)}$$

Social cost of capital for project K	Riskless public interest	Systematic risk of project K	Social risk premium

[1] If capital markets are in equilibrium $\frac{\partial S}{\partial B} - \frac{\partial I}{\partial B} = 1$. An equivalent expression according to Harberger is

$$R_{SF} = [(1 - t)R_F Se_S - (1/(1 - T))R_F Ie_i]/(Se_S - Ie_i]$$

where e_S is the elasticity of private-sector savings and e_i is the elasticity of private-sector investment with respect to change in the rate of interest.

The next section will use this formulation to estimate the cost of capital for the various liquid fuel projects in Brazil.

2-6. Estimates of the Private and Social Cost of Capital

In the Brazilian economy it is reasonable to assume that the distribution of risks by the private markets and by the public sector are both imperfect. If this is the case, Bailey and Jensen argue (as presented earlier) that the risk of a particular project must be measured by its covariance with the portfolio of returns of the project's beneficiaries. As the income of most all citizens in Brazil is affected by liquid fuel prices, one can argue that the beneficiaries of an energy project are a wide segment of the Brazilian population. One can further argue that the portfolio of returns of the Brazilian public is national income, which is highly correlated with the Brazilian capital market. Thus, whether a liquid fuel project is undertaken by the Brazilian private sector or the public sector, the risk premium should be the same (with proper allowance for distortions caused by taxes). However, the risk premium for the project from the viewpoint of a private foreign (U.S.) firm, may be different since the risk depends on the correlation of returns with the U.S. market.

The national income of Brazil is expected to be less diversified than the national income of the U.S., since Brazil is smaller and its economy more concentrated on a few types of argiculture and light manufacturing industries. This is another way of saying that the risk premium on the capital markets in Brazil is higher than in the U.S. In addition to this difference between Brazil and the U.S., the covariance of returns of a liquid fuel project with the national income of Brazil is likely to be different than the analogous U.S. correlation. In other words, the beta of a liquid fuel project is probably different and likely to be lower in Brazil than in the U.S. The share of oil projects in Brazilian national income is lower than in the U.S., and returns on projects composing Brazilian national income are probably reduced more when oil prices increase (i.e., when returns on liquid fuel projects increase) than in the U.S. The following paragraphs will outline a method of calculating the cost of capital for a liquid fuel project carried out by a U.S. private firm, a Brazilian private firm and the Brazilian government.

The real riskless rate of interest can be approximated by the real U.S. rate (1-2 percent) which is close to the real international riskless rate. In addition to the riskless rate, however, there may be additional risk premiums, for political risks from the viewpoint of the multinational firm and risks associated with international borrowing for Brazil. This will be discussed in detail later.

Social Risk Premium

In addition to estimating the return on a riskless asset in Brazil we need a measure of the return on the Brazilian capital market. The cost of capital for a project undertaken by a firm in the U.S. which has an all equity beta of 1 can be calculated from equation 2-4 using the riskless rate of interest R_F and the risk premium on the market $(R_M - R_F)$. A study of interest rates in the U.S. economy from 1926 to 1975 by Ibbotson and Sinquefield estimates the real after-tax rate on long-term U.S. government bonds to be 1.3 percent. What is needed for the CAPM approach is an estimate of the future riskless rate over the life of the project. Very recent real riskless rates have been 3-4 percent, but we will use a rate of 1-2 percent based on Ibbotson and Sinquefield's study. The real risk premium (R_M - R_F) on the U.S. market (after tax) has been calculated by Lessard (1976) to be 8.2 to 8.8 percent. The cost of capital for a project beta of 1 in the U.S. is thus estimated to be 10.2 percent.

The risk premium for the markets of 8 countries has been studied (Lessard 1976) through empirical estimation of the correlation of an average stock with the domestic market and with a world market portfolio. The results are presented in Table 2-4. The differences in the risk premiums between countries are substantial and the differences in risk premiums from the domestic and international perspective are even larger. The domestic risk premium for Brazil is estimated to be 10.4 percent (higher than the U.S.). Although this figure represents only a rough estimate and the functioning of the Brazilian market is less efficient than the U.S. market, it does represent a rough measure of how much less diversified the Brazilian economy is relative to the U.S. economy. Assuming a riskless real rate of interest in Brazil of 2 percent and a risk premium on the Brazilian market of 10.4 percent, the real cost of capital is 14 percent for a Brazilian investor for a project with a beta of 1 (measured relative to the Brazilian market).

In order to estimate the real social cost of capital, we need to

Table 2-4

Effect of international diversification on required rate of return

	Brazil	*France*	*Germany*	*Italy*	*Japan*	*Spain*	*Sweden*	*U.K.*	*U.S.*
Average Correlation with Domestic Market Portfolio[a]	.69	.68	.67	.66	.52	.63	.65	.61	.55
Risk Premium from Domestic Perspective (%)	10.4	10.2	10.1	9.9	7.8	9.5	9.8	9.2	8.2
Average Correlation with World Market Portfolio[b]	.14	.21	.31	.16	.15	.04	.19	.25	.44
Risk Premium from World Perspective (%)	2.1	3.2	3.7	2.5	2.2	0.6	2.8	3.8	6.6

a) Figures for Brazil from Lessard (1973), others from Lessard (1976).

b) Correlations with world obtained by multiplying the correlation with domestic market portfolio by the correlation of domestic market with the world market portfolio. This rests on the implicit assumption that the only relationship between individual securities and the world market is through their relationships with the domestic market portfolio. Figures for Brazil are based on subjective estimates of the correlation of the local market portfolio with the world market portfolio of .20.

Source: Multinational Business Finance, 1979 , p. 376, Appdx. A,Ch 10, Diversification and Required rates of Return by D. Lessard.

adjust the distortions caused by taxes, according to the method developed by Bailey and Jensen. The corporate income tax rates in Brazil are comparable to the U.S. rates (35 percent) but in practice the large number of tax deductions and loopholes greatly reduces the effective tax rate. According to discussions with members of the World Bank Brazil group, 1) the effective corporate income tax rate is approximately 15 percent, 2) the effective marginal tax rate on income from savings is zero (i.e. untaxed, to encourage savings) and the estimated net impact of an increment of government borrowing on savings is .3 and on investment -.7. These last two figures can be thought of as the share of savings and share of investment that would have gone to a hypothetical marginal project displaced by the government project.

A summary of the parameters for the social cost of capital calculation in Brazil are given below (all rates are real rates, net of inflation):

Riskless Interest Rate	R_F = 1.3 percent
Risk Premium on Market	$R_M - R_F$ = 10.4 percent
Marginal Tax Rate on Corporate Income	T = 15 percent
Marginal Tax Rate on Income from Savings	t = 0 percent
Net Impact of Government Borrowing	
on Savings	0.3
on Investment	-0.7

Using these estimates we can use equations (2-7) and (2-8) to get:

Riskless Public Interest Rate R_{SF}	2 percent

Social Risk Premium	12.0 percent
Social Cost of Capital (for a project with a beta of one)	14.0 percent

Betas

The additional parameters needed in the calculation of the cost of capital are estimates of the betas for the three types of projects under consideration (oil exploration, development and production; and alcohol development and production). The betas of firms measured relative to the U.S. market are available from financial publications (such as Value Line). If projects considered here have the same risk characteristics as the average project undertaken by a multinational firm (i.e., oil firm), then the observed betas can be used for the cost of capital for a project undertaken by a foreign firm in Brazil.

All equity betas for oil companies from the Value Line Investment Survey are given below:

Name	β_e
Ashland	0.8
Arco	0.9
Exxon	0.95
Getty	0.9
Gulf	0.9
Husky	1.0
Marathon	0.85
Occidental	1.2
Shell	1.0
Socal	1.05
Texaco	0.9
	0.95 = Average

If one believes that oil exploration and shale oil production projects have risks that are similar to the average risk of projects undertaken by these firms, then the cost of capital for these projects is estimated to be 10 percent.

Empirical estimates of betas in Brazil have not been made. To estimate the covariance of project returns with the national income and therefore the project beta, one option is to use beta estimates for similar projects in developed countries and then make some estimate of how the return on markets in developed countries correlates with the national income of Brazil. The beta of a project is composed of a weighted sum of betas of cash flows which make up the project (exploration, development, production). Estimates were made of asset betas by Paddock (1980), for firms involved only in development and production of oil in the North Sea. These can be thought of as pure betas for the activity of oil development (Bdev = to .7) and oil production (βprod = .7). The beta for oil exploration is almost completely non-systematic since the discovery of oil is dependent on technical and geological factors which are independent of economic activity. Thus, the exploration beta can be expected to be near zero (βexpl = 0 to .1). Betas are weighted by the investment share in a typical oil project. Development expenditures are the largest, being 5 to 10 times exploration expenditures. A rough breakdown of investment share by activity in an oil project is 0.1 for exploration, 0.7 for development and 0.2 for production. Using these weights and the betas estimated by Paddock the beta for a North Sea oil project is about 0.70. These betas were calculated relative to the British economy. Although the British economy has a larger share of domestic energy production than the Brazilian economy, the correlation of Brazilian real GDP with British real GDP has been +0.95 over the last 10 years. Based on this similarity, the North Sea beta of 0.70 will also be used for an oil project in the Brazilian economy. The correlation of the return on an oil project with the return on a portfolio of assets in the Brazilian economy would not be expected to be near one due to the low share of oil in the Brazilian economy. This beta would not be expected to be negative or near zero either, since changes in costs are partially correlated with economic activity. Also, variation in revenue streams of an oil project is composed of variations in price and quantity. As developed country GNP rises, so does Brazilian GDP and increased oil consumption leads to real oil price rises. Thus, Brazilian GDP would be expected to be at least somewhat positively correlated with the oil price. This was confirmed by the author, the contemporaneous correlation of the real price of oil and real GDP in Brazil was calculated to be 0.25. These rather loose arguments about the likely range of the oil project beta agree with the estimated beta of 0.70. We will use this as the beta for an oil project in Brazil. We will also use this as an estimate of the beta of an oil shale project as well. There are many similarities beteen the type of revenue and cost streams in a shale oil project and those in an oil project. The R and D expenditures in the shale project are largely unsystematic and similar to exploration expenditures. A beta of 0.70 for an oil shale will be used.

The beta for an alcohol project is quite different. The revenue streams of the alcohol project are composed of the alcohol price, which is linked to the oil price and to agricultural yields. Good sugar yields are most likely correlated with good agricultural yields elsewhere in the economy which are in turn correlated with increased national income. The beta of an alcohol project is most likely closer to one than the oil project for these reasons. The beta for agricultural and food production programs in the U.S. is estimated to be 0.84 (Baldwin 1981). This seems to be a reasonable estimate for an alcohol project, since the alcohol project has many similarities to typical agricultural projects.

Risk Premiums for Borrowing on International Markets

Private investors in Brazil, the Brazilian state owned enterprises, and the Brazilian government have borrowed heavily from foreign sources over the last 15 years. While this borrowing has been too small to affect the international LIBOR rate (London Interbank Offer Rate), risk of default perceived by foreign lenders is likely to result in an upward sloping supply curve for funds supplied from international banks. The default risk of all borrowers in Brazil (public or private) are perceived to be highly correlated. The country risk premium (interest charged over the LIBOR rate) is thus largely a function of total debt outstanding. The premium over LIBOR for loans to Brazil has been constant at 2.25 percent over the last several years. In a recent analysis of country risk Harberger (1976) argues that a "risk premium" reflecting the probability of default that is charged on loans should not be considered as a cost of borrowing if the probability of default is accurately perceived by both borrowers and lenders. However, if the lender is very cautious and requires the borrower to pay a higher premium than the premium that borrower believes reflects the true probability default, then the difference in the premia is a true cost of borrowing. Harberger shows that the country risk premium on loans from international banks to country borrowers such as Brazil reflect a true cost borrowing in addition to the riskless international rate (LIBOR rate). This country risk premium can be though of as an extra cost to all international borrowers that reflects the dead weight losses associated with default of a few of the borrowers. It results from the lack of ability of international banks to enforce international contracts (somewhat analogous to the costs of bankruptcy within a country).

As the country risk premium increases, the interest rate on foreign loans to Brazil rises. This has the effect of driving up the equilibrium interest rate in Brazil. The argument has been made (Baldwin, Lessard and Mason 1981) that this additional cost of borrowing created by the country risk premium has the effect of shifting the risk-return market line upward in those countries relying heavily on foreign loans. In a study of the cost of capital in Canada, the same authors discuss how real government borrowing rates in Canada are generally thought to be one percent higher than the U.S. due to a country risk premium of one-half to one percent. They argue that this effect is carried over to other more risky transactions and this results in an upward shift of the risk-return market line. As the country risk premium increases, the interest rate on foreign loans rises, which in turn drives up the equilibrium interest rate. The marginal rate increases even faster than the average rate as borrowing by one institution drives up the cost of borrowing to other institutions. This marginal country risk premium (estimated to be 4 percent in Brazil) is accounted for through an upward adjustment to the discount rate for all public projects.

If this approach is followed, the social cost of capital is the riskless rate (1 to 2 percent), plus a country risk premium (estimated to be 4 percent in Brazil), plus the project beta times the social risk premium. The discount rate is adjusted to account for the country risk premium, not by adjusting the cash flows, as the uncertainty surrounding the country risk premium is perceived to increase in the future.

Considering this precarious debt position in which Brazil is caught, an additional benefit of domestic liquid fuel investments may be to reduce the negative impact of future oil price increases on the foreign borrowing position of the country. In a country which is heavily in debt, a rapid rise in oil prices will not only have a negative impact on the economy, but also may well increase the size of the foreign debt and sharply increase the costs of further borrowing. Thus a liquid fuel project that reduces the level of oil imports will also reduce the oil import bill in the long-run. This may have the effect of reducing the risk which bankers perceive when lending to Brazil and lead to reduced real costs of borrowing. However, borrowing costs in the short-run are likley to increase as Brazilian institutions borrow to finance energy projects. The tradeoff to be analyzed is the additional costs of borrowing today to finance energy projects, which may lead to reduced costs of borrowing in the future if their energy investments are successful, as opposed to reduced costs of borrowing today and higher oil import bills in the future.

The country risk premium added to the discount rate is a rough measure of the effect of increased borrowing costs to finance new energy investments, as discussed earlier. The measurement of the benefit of an energy project on future reduced borrowing costs is much more difficult, whether accounted for through adjustments to the cash flows or through adjustments to the discount rate. The magnitude of this benefit is determined by the effect of sharply higher oil prices on the behavior of the euromarket LIBOR interest rate and the risk of default perceived by bankers (i.e. their reaction by increasing the country risk premium or outright credit rationing). Uncertainty about these events makes the calculation of this benefit very hard to make. A thorough analysis of this issue is beyond the scope of this study, but preliminary analysis indicate that overall macroeconomic policies have a much more important effect on country risk than specific energy investment policies. As a first approximation, to adjust for this effect we will assume that externalities associated with additional liquid fuel investments (i.e. increased costs to other Brazilian borrowers) are offset by longer-run reduced costs of borrowing due to effect of energy projects on reduction of the oil import bill. This implies that the discount rate should be adjusted upward by the average country risk premium (2 percent), not the estimated marginal premium (4 percent).

Political Risk Premium

The cost of capital calculation for the multinational oil firms also has an additional risk premium. The cost of capital could be raised for political risk (expropriation, war, etc.). Alternatively it could be argued that political risks to the project are not systematic and should be accounted for by adjusting the cash flows (not adjusting the discount rate). For example, a foreign company could postulate that if a large oil field is discovered in Brazil the original contract terms would be changed unilaterally by the Brazilians. But if a small oil field is found, the original contract terms would hold. This allows the potential political risks to be clearly put into the cash flows, not just an ad hoc adjustment to the rate. Both methods will be explored.

Cost of Capital Calculations

The cost of capital calculations can be summarized as follows:

	Project	Social Cost of Capital Risk	Risk Free Rate	Other Risk Premiums	Beta	Social Risk Premium
A.	Oil	10.5	2	0	.7	12
	Shale	10.5	2	0	.7	12
	Alcohol	12.0	2	0	.84	12
B.	Oil	12.0	2	2	.7	12
	Shale	12.0	2	2	.7	12
	Alcohol	14.0	2	2	.84	12

	Project	Multinational Firm Cost of Capital	Risk Free Rate	Political Risk Premium	Beta	Risk Premium on Market
A.	Oil	10.0	1.3	0	.95	8.8
B.	Oil	12-14	1.3	2-4	.95	8.8

Note: A - gives results when cash flows (not discount rate) are adjusted for risks associated with borrowing abroad and political risks

B - gives results when discount rate (not cash flows) are adjusted for borrowing and political risks.

These calculations should be viewed as rough estimates. The specific parameters used and possibly even the underlying assumptions are subject to revision. This method, however, does attempt to bring in important factors (such as the effect of high international borrowing costs, project risk and the low level of diversification of the Brazilian economy) into the calculation of the cost of capital for specific projects. The author feels that although the estimates are rough, and by no means unassailable, they are preferable to more simplistic cost of capital calculations which ignore these important factors.

This chapter has outlined the principles of financial and economic (social) project appraisal. Private (or financial) evaluations use market prices of oil, market exchange rates and firm cost of capital for the project in question. An economic (or social) evaluation uses the social cost of oil (which includes disruption insurance), the shadow price of foreign exchange and the social cost of capital for the project.

3-1. Reserves and Production

Petroleum production in Brazil declined 8.5% from the 1975 level of 64.7 m bbls to 59.25 m bbls in 1978. Production in 1979 was 59.26 m bbls, almost the same as in 1978. Reserves of petroleum increased 46% from their level in 1975 of 782 m bbls to 1144 m bbls in 1978.

The definitions of proved, probable and possible reserves conform to API guidelines (according to PETROBRAS). The National petroleum Council in the U.S. estimates that published petroleum proved-reserve estimates in Latin America are overestimated by only 1 to 3% as compared with true API standards. "Reserves" herein refers to remaining recoverable proved reserves.

Onshore petroleum reserves have been declining by 4%/year since 1969. Onshore petroleum production has been declining by 5 to 8% over the last four years. Offshore oil reserves jumped from 74 m bbls in 1975 to 513 m bbls in 1978 and were 637 m bbls in June 1979. This increase is due to discovery of the offshore Campos oil basin. A short summary of reserves and production for 1975 and 1978 is given below: A time series of reserves, production and gross reserve additions is given in Table 3-2.

3-2. Declining Onshore Oil Production

Three-fourths of both onshore oil reserves and onshore oil production are from the Reconcavo basin. Exploration in the Reconcavo basin began in the 1940s. Deposit size (recoverable reserves) vary

Table 3-1: Oil and Gas Reserves and Production in 1975 and 1978

		1975		1978	
		Reserves	Production	Reserves	Production
OIL (m bbls)					
Onshore		708	65	631	46
Offshore		74	-	513	13
	Total	782	65	1,144	59
GAS (m m^3)					
Onshore		19,564	1,627	25,997	1,422
Offshore		6,372	387	18,392	673
	Total	25,936	2,014	44,389	2,095

SOURCE: PETROBRAS

NOTE: For conversion there are 6.28 bbl/^{m} and 35.3 ft^3/m^3
bbls = barrels, b/d = barrels per day, m = million,
m^3 = cubic meters, f^3 = cubic feet

Table 3-2

BRAZIL: TOTAL OIL AND GAS PROVED RESERVES AND PRODUCTION 1965-79 (JUNE)

(million cubic meters) (Multiply by 6.3 to get barrels)

Year	Petroleum (mil. cubic meters)			Gas (mil. cubic meters)		
	Reserves	Production	Gross Reserve Additions	Reserves	Production	Gross Reserve Additions
1965	106.76			19,037.00	685.40	
1966	110.78	6.88	+ 10.90	24,973.76	790.24	6,727.00
1967	126.51	8.63	+ 24.36	24,476.48	887.08	389.80
1968	130.67	9.51	+ 13.67	26,804.02	983.31	3,310.85
1969	135.47	10.17	+ 14.97	25,573.88	1,247.86	17.72
1970	136.28	9.69	+ 10.50	26,612.13	1,263.00	2,301.85
1971	138.08	10.10	+ 9.90	26,210.64	1,176.79	775.30
1972	126.82	9.96	+ 0.70	26,116.63	1,241.56	1,147.55
1973	123.06	10.10	+ 6.34	25,862.95	1,179.91	926.23
1974	123.84	10.57	+ 11.35	26,260.63	1,487.83	1,885.51
1975	124.46	10.29	+ 10.91	25,936.14	2,014.88	1,690.39
1976	139.36	9.72	+ 24.61	33,983.31	1,597.22	9.644.39
1977	177.10	9.18	+ 46.94	39,454.62	1,800.90	7,272.21
1978	181.80	9.42	+ 14.19	44,389.50	2,094.55	7,029.43
1979 (June)	(197.93)	(4.42)	(+ 20.47)	(44,553.46)	(757.46)	(921.42)

from 260 million barrels to .05 million barrels. Over 50 deposits have been located. Exploration and production are in the mature stage of development. Over 700 exploratory wells and over 2,200 development wells have been drilled.

The remaining one-fourth of both onshore reserves and onshore production are from the onshore section of the Sergipe-Alagoas basin. This basin is also in a mature stage of development. The main producing reservoir, as well as the seven major Reconcavo reservoirs, are all under secondary recovery operations. The recovery factors and proved reserve estimates reflect the fact that these reservoirs are all undergoing secondary recovery. Since all major onshore reservoirs are in a similar stage of declining production, future production can be approximated with an exponential decline. An equation was fit using recent onshore production data.

$$\underset{\text{million bbls/year}}{\text{production (t)}} = 56.51\ e^{-0.07t} \qquad R^2 = 0.97,\quad t_{1976} = 1$$

This shows a 7% per year production delcine. The equation can be used to project continuing production decline:

Year	1980	39.80 million bbls/yr
	1986	28.06
	1990	19.77
	1995	13.94
	2000	9.82
	2010	4.88
	2020	2.42

The cumulative production from 1980 onward is equal to 595 million barrels as calculated by integrating the production decline equation. This compares well with the proved reserves reported in June 1979 of 590 million barrels.

3-3. Enhanced Recovery of Onshore Oil

The previous section described the estimation of a production decline curve for onshore production. This decline reflects primary and secondary recovery. The primary recovery factor is about 10% and current secondary recovery factors average 32% for the Reconcavo basin and 15% for the Sergipe-Alagoas onshore basin. These recovery factors vary by field as can be seen in Tables 3-3 and 3-4 which describe the basic field statistics for onshore fields.

While primary recovery oil flows with few additional wells the secondary recovery oil requires the investment of more wells, pumps etc. to get the oil out. One can think of additional annual units of enhanced recovery production added on to the primary recovery production decline. The sum of these additional units reduce the rate of primary production decline, as pictured in Figure 3-1. If possible it would be helpful to know how the cost of oil from each additional unit to determine the rate of cost increase. We will use the cost of a barrel produced in a year from one of these units to estimate the marginal cost of production. The cost per barrel from an additional unit can be thought of the same way as the cost of production from a large field derived by Adelman (1972). Adapting this formulation we have:

Table 33: Reconcavo Onshore Basin--Basic Field Data

OIL (Million barrels)							GAS (million cubic meters)			
Field Name[a]	Initial in Place	Ultimate Recovery	Primary Recovery Factor	Ultimate Recovery Factor[b]	Cumulative Production (6/1979)	Remaining Recoverable Reserves (6/1979)	Initial in Place	Volume Recoverable	Recovery Factor	Remaining Recoverable Reserves
Candeias	400	100	10%	25%	73	27	4,760	2,245	47%	1,200
Dom Joao	831	207	12%	25%	78	129	2,880	1,260	43%	1,125
Agua Grande	558	260	n.a.	45%	249	11	12,500	8,622	80%	3,130
Buracica	480	202	6.6%	42%	107	95	480	180	38%	51
Taquipe	215	75	n.a.	35%	69	6	2,260	1,130	50%	520
Aracas	366	126	n.a.	34%	80	46	4,840	2,060	90%	1,500
Miranga	590	180	n.a.	30.5%	140	40	12,160	7,080	58%	4,180
Others	626	150		24% (ave)	74	91	18,920	11,823	62% (ave)	9,424
Total Basin	4066	1300		32% (ave)	870	445	58,800	34,400	58% (ave)	21,130 = 133 million barrels oil equivalent

[a]Seven largest fields account for 88% of ultimate reserves (average recovery factor is 33.4%), 91% of cumulative production and 66% of gas reserves.

[b]As of 1979 ultimate recovery factor equals secondary recovery for all 7 major fields.

[c]Remaining recoverable gas includes 6,700 mm^3 of reinjected gas.

SOURCE: IIASA World Oil Database.

Table 3-4: Sergipe-Alagoas Basin Oil Discoveries
Onshore (7,300 km^2)

Field Name	Discovery Date	Initial In place reserves (million bbls)	Ultimate Recoverable Reserves (million bbls)	Primary Recovery Factor	Ultimate Recovery Factor	Cumulative Production (6/1979)	Remaining Recoverable Reserves (6/1979)
Riachuelo	9/1961	152	19	10%	13%	8	11
Carmopolis	8/1963	1,300	185	14%	14%	91	94
Siririzinho	8/1967	240	50	11%	20%	20	30
Furado	8/1969	53	12	n.a.	20%	6	6
Others		27	4	n.a.	15%	3	0
Total onshore		1,800	270	11%	15%	129	141

$$\text{Marginal cost} = MC(\$bbl) = \frac{N\ C}{q_o} \int_o^T e^{-(r+a)^t}\ dt \qquad \text{(eq. 3-1)}$$

a = decline rate for unit of E.R.

N = number of E.R. wells

C = cost of an E.R. well

r = discount rate

q_o = peak production

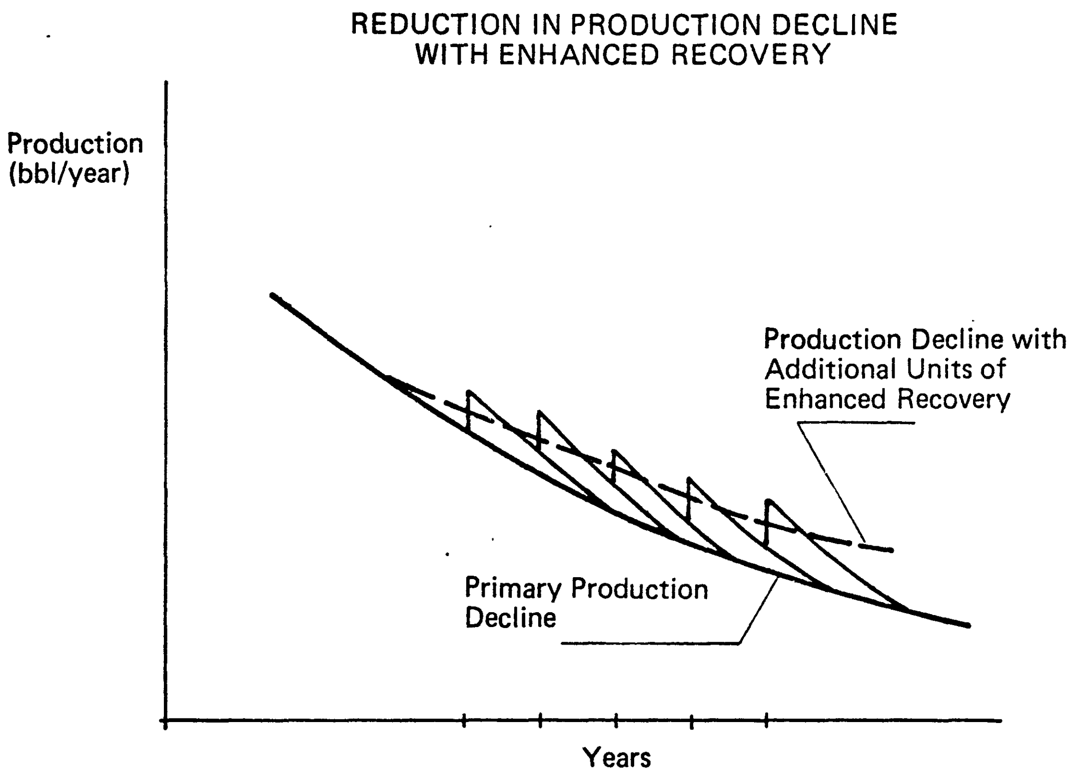
Since we know the rate of decline before E.R., primary recovery factor, secondary recovery factor and reserves in place we can calculate the rate of E.R. oil production cost increase as a function of C (cost per E.R. well). The AAPG bull. gives the number of E.R. wells drilled each year.

The sum of the oil produced for each unit of E.R. production must equal the difference in primary and secondary production. This holds when a decline rate of a = .13 for each unit is used. Production by annual E.R. unit is shown below:

Year	'74	'75	'76	'77	'78
New ER wells	45	48	57	51	77
Production by annual unit (mmb/yr)	2.7	1.8	1.4	1.1	0.9
		2.4	1.6	1.5	1.3
			2.1	1.9	1.7
				1.7	1.5
					2.3

Using the peak production per year and wells drilled per year in eq. 3-1 gives the rate of cost increase.

Figure 3-1



This diagram shows how enhanced recovery can be modelled as primary recovery plus additional annual units of enhanced recovery

	MC ($/bbl)	
1974	5.2 (C)	C is cost per E.R. wells in millions dollars
1975	5 (C)	
1976	6.8 (C)	
1977	7.5 (C)	
1978	8.1 (C)	

If E.R. well costs have remained constant this implies the marginal cost of oil production has doubled from 1974 to 1978. Although detailed well costs are not available some average onshore well costs (from Annexes in Chapter 5) are .3 to .5 million which give a cost per barrel of E.R. oil of 3 to 4 $/bbl due to well costs alone.

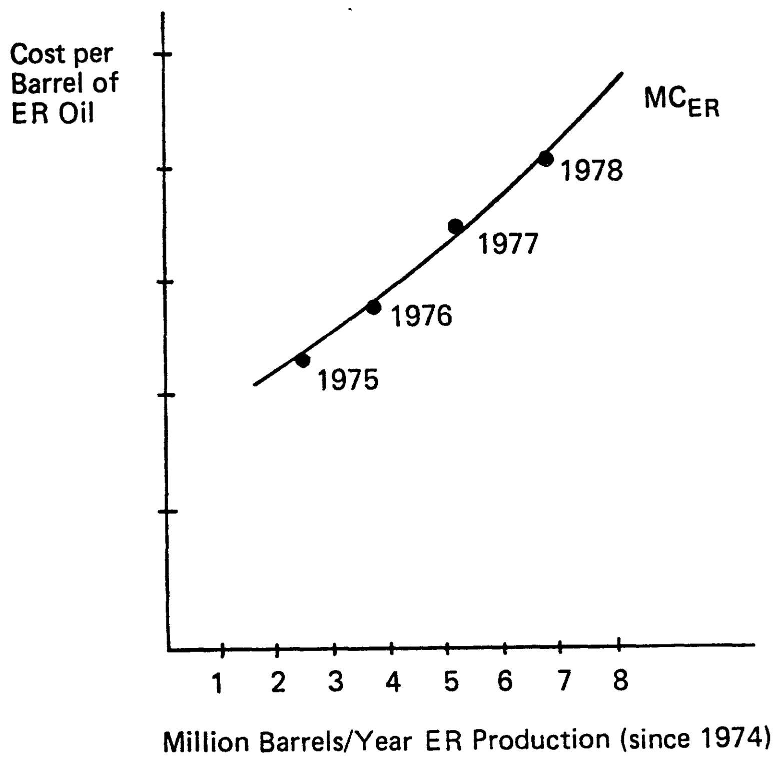
3-4. Production and Production Costs of Oil from Recently Discovered Petroleum Reservoirs

The major recent discoveries of oil in Brazil have been the offshore Campos basin in 1975. Approximately 90% of oil production increases in Brazil over the 1980-1990 period will come from the Campos Basin. Thus, the acceleration of production from those fields is of top priority to PETROBRAS and the government. In order to get the oil out quickly, PETROBRAS has installed two early production systems. The Enchova early production system came on stream in 1977 with 10,000 b/d which has declined to 8,177 b/d in 1979. The second early production system has been plagued by delays and cost overruns.

The Campos permanent production system will come on line in stages from 1983-1989. When complete it will have 8 offshore production platforms, 79 production wells, 55 injection wells, 2 subsea oil

Figure 3-2

INCREASE IN MARGINAL PRODUCTION COST
OF ENHANCED RECOVERY OIL (ER OIL)



By estimating the cost of production for each of the additional annual units of enhanced recovery, the marginal cost of enhanced recovery oil can be plotted against quantity produced per unit time.

pipelines and 2 subsea gas pipelines. The platforms will be in 95 to 170 meters of water and approximately 85 km from shore. Depth to the oil zone is 2000 to 3000 meters. The development has had several setbacks, the major setback being when the first permanent production platform sank in the North Sea on its way from Scotland in January 1979. The original estimate of 350,000 bbl/d in 1985 has been revised downward to between 150,000 and 200,000 bbl/d, The Garoupa platform is planned to come on line in 1983 (60,000 bbl/d), with the Namorado, Enchova and Badejo fields adding 146,000 bbl/day by 1984. The Cherne, Pampo Bagre fields will come on line in 1987 or 1988 adding about 200,000 bbl/d. Thus, Campos producion is expected to be 275 to 325,000 bbl/day in the time period 1987 to 1990. Details are given in Table 4.

The investment cost, platform cost and the water depth of the Campos basin production system are given in Table 5. All water depths are between 300 and 500 feet. The original total investment cost estimate was 2,675 million U.S. dollars in 1978. PETROBRAS officials revised this estimate considerably upward in 1980 to 4,700 million U.S. dollars. Using this later investment figure and a peak produciton estimate of 300,000 bbl/day, the capital coefficient in $15,600 per daily barrel. Capital coefficients for small fields in the Northeast and Sergipe-Alagoas basins are $4,000 to $6,000/daily barrel.

In order to calcuate the cost per barrel the following formula is used (as discussed earlier):

$$P_c = \frac{I/Q_p}{\int_o^T e^{-(r+a)t} \, dt}$$

A discount rate of 12% (r) is used with a project lifetime of 25 years (T). The optimal decline rate (a*) is calculated to be 24% (I/Q = 10,000) and 17% (I/Q = 15,000) for the Campos basin and 39% (I/Q = 5000) in the Northeast and Sergipe-Alagoas basins. These were calculated assuming a constant oil price of $30 per barrel (a* was also calculated for a variety of oil prices, see Table 3-7). These optimal economic decline rates are very high. But investment cost is an increasing function of the decline rate and increasing investment cost to increase the decline rate will lead to a lower optimal decline rate. Thus the true optimal decline rate is between an assumed rate of 12% per year and 17% per year when the marginal capital coefficient is taken into account. Using an iterative procedure (see eq. 5-3, Chapter 5) the "true" decline rate was estimated to be about .15.

In order to calculate the cost per barrel decline rates of .12 and .15 were used. Operating costs for the Campos basin are estimated to be $1.50 per barrel based on similar costs for North Sea platforms and Gulf of Alaska (Adelman and Paddock, 1980, Beck, 1977). Using these factors in the above equation an oil production cost of $10.70/bbl ($1980), for a = .12, and $11.70/bbl for a = .15 were calculated for the Campos basin. Similar calculations for the Northeast and Sergipe-Alagoas basins are around $3.50 per barrel (a = .12) and $3.80/bbl (a = .15). Thus the cost per barrel increases about 8% if a = .15 with the estimated decline rate of a = .12. Peak production in each of these basins is 30,000 bbl per day. PETROBRAS has estimated past exploration costs per barrel to be \$2 to \$3.

3-5. Minimum Economic Reservoir Size

As discovery proceeds to smaller and smaller fields a point is reached where the discovered field sizes are no longer economic to develop. This minimum eeconomic reservoir size (MERS--as defined by Eckbo 1977) varies with the price of oil, production charactersitics of the field (decline rate, etc.), and physical conditions such as water depth whch affect the investment cost.

The net present value of a block of reserves according to Adelman (1978) can be approximated by:

$$NPV = \frac{PQ_p}{a + r} - I$$

P = oil price

Q_p = peak production (bbl/day)

a = decline rate

r = discount rate

I = investment cost

The reserves (R) can be expressed as:

$$R = Q_p \int_0^T e^{-at} \; d$$

as $T \to \infty$ then $R = Q_p/a$ or $Q_p = Ra$.

Using the expression in the net present value formula it becomes

$$NPV = \frac{P\ Ra}{(a + r)} - I$$

The minimum economic reservoir size results when the investment rate of return equals r, the discount rate. Thus, if NPV = 0 we can estimate the minimum economic reservoir size (R) which provides only a rate of return r. This is the minimum size field one would want to develop at oil price P.

$$R = \frac{I(a + R)}{P\ a}$$

The offshore oil production regions of Brazil can be classified into two similar types. The first type is the Northeast and Sergipe-Alagoas basins both of which are in shallow water (50-100 ft) and have small deposits. The second type is the Campos basin which has several large fields in deep water (400-500 ft.). The development costs, as well as platform costs and capital coefficients, for an average field in these two types of basins are given in Table 3-7. Using the formulas above, the MERS and optimal decline rate can be calculated for various prices of oil. The optimal decline rate is calculated to be higher for the small shallow reservoirs (around 39% for P = \$30/bbl) as compared to lower decline rates for the Campos fields (from 17 to 24%). It may not be technically possible to produce oil at this optimal rate, due to reservoir charactersitics or due to lags in the rate of field development. The MERS is therefore calculated using the optimal rate as well as a lower rate of 10% (shown in Table 3-7). For current oil prices (\$30/bbl) the minimum economic field size for the Campos basin is around 15 million barrels and for the other shallow basins it is around 2 million barrels.

Table 3·5: Details of Planned Campos Basin Offshore Production System

Offshore Oil Production Platform & Pipelines	Water Depth (ft)	Depth to Oil (ft)	Number of Production Wells	Number of Injection Wells	Estimated Initial Peak Oil Production bbl/day (yr.)		Estimated Peak Gas Production $10^3 m^3/d$.
Garoupa	398	11,400	7	8	60,000 (1983)	200,000 to 250,000	380 (1985)
Namorado I	480	10,000	7	3	24,000 (1984)		420 (1984)
Namorado II	562		9	11	36,000 (1984)		640 (1984)
Cherne I	386	8,700	14	5	50,000 (1988)		120 (1988)
Cherne II	469	6,240	14	8	63,000 (1988)		180 (1988)
Enchova	383	7,000	10	7	64,000 (1984)	175,000	1500 (1981)
Badejo	309	8,800	6	5	12,000 (1984)		240 (1984)
Pampo	357	5,830	12	8	100,000 (1987)		350 (1985)
		TOTAL	79	55		275,000 to 325,000	
Garoupa Early Production System					5-20,000 (1981)		
Enchova Early Production System					15,000 (1979)		

Submarine Pipeline System (24" oil pipeline (165,000 b/d max), 22" oil pipelines (198,000 b/d max) two 12" gas pipelines (5.4 mm^3/d max), 85 km from fields to shore).

Onshore Pipeline System (32" oil pipeline (440,000 b/d max) - 18" gas pipeline (3.5 mm^3/d max).

SOURCE: Brazil Energy (Jan. & July 1980), World Oil, Petrobras Publications. (Scope of Brazilian Effort in Exploration and Production of Hydrocarbons). Offshore September 1980.

Table 3-5: Cost Details of Planned Campos Basin Offshore Production System

Offshore Oil Production Platforms & Pipelines	Water Depth (ft)	Estimated Total Development cost[a] (Oct. 1978 million U.S. $)	Updated Total Development cost (Aug. 1980 million U.S. $)	Platform Cost[b] (1980 million U.S. $)
Garoupa	398	304	534	45
Namorado I	480	414	730	80
Namorado II	562			80
Cherne I	386	365	641	82
Cherne II	469			83
Enchova	383	364	640	70-90
Badejo	309	188	670	110
Pampo	357	182		
Garoupa Early Production system		214	370	
Enchova Early Production system		53	93	
Submarine Pipeline system		356	625	
Onshore Pipeline system		235	412	
TOTAL (million U.S.$)		2,675	4,700[b]	560

[a]Scope of Brazilian Effort in Exploration and Production of Hydrocarbons, Petrobras 1979.

[b]"Campos Cost Greater than Expected", Offshore, September 1980.

Table 3-7 Minimum Economic Reservoir Size for Offshore Brazilian Basins

	Northeast and Sergipe-Alagoas basins	Campos basin
Water depth (ft)	50 to 100	350 to 480
Number of platforms per reservoir	1 to 6	1 to 2
Platform cost (million $ 1980)[a]	2 to 7	45 to 85
Approximate total development cost per reservoir[b] (million $ 1980, without pipelines)	* 30 (10 to 60)	250 (200 to 500)
Capital coefficient (I/Q_p in $/daily bbl)	5000	10,000 (8,000 to 13,000)
MERS at P = $20/bbl In million barrels[c]	4 (a=.10) 2 ($a=a^*=.29$)	28 (a=.10) 21 ($a=a^*=.17$)
MERS at P = $30/bbl In million	2 (a=.10) 1.5 ($a=a^*=.39$)	18 (a=.10) 13 ($a=a^*=.24$)
MERS at p = $40/bbl	1.5 (a=.10) 1 ($a=a^*=.47$)	14 (a=.10) 7 ($a=a^*=.29$)

[a] Offshore, September 1980, "Campos Costs Greater than Expected".

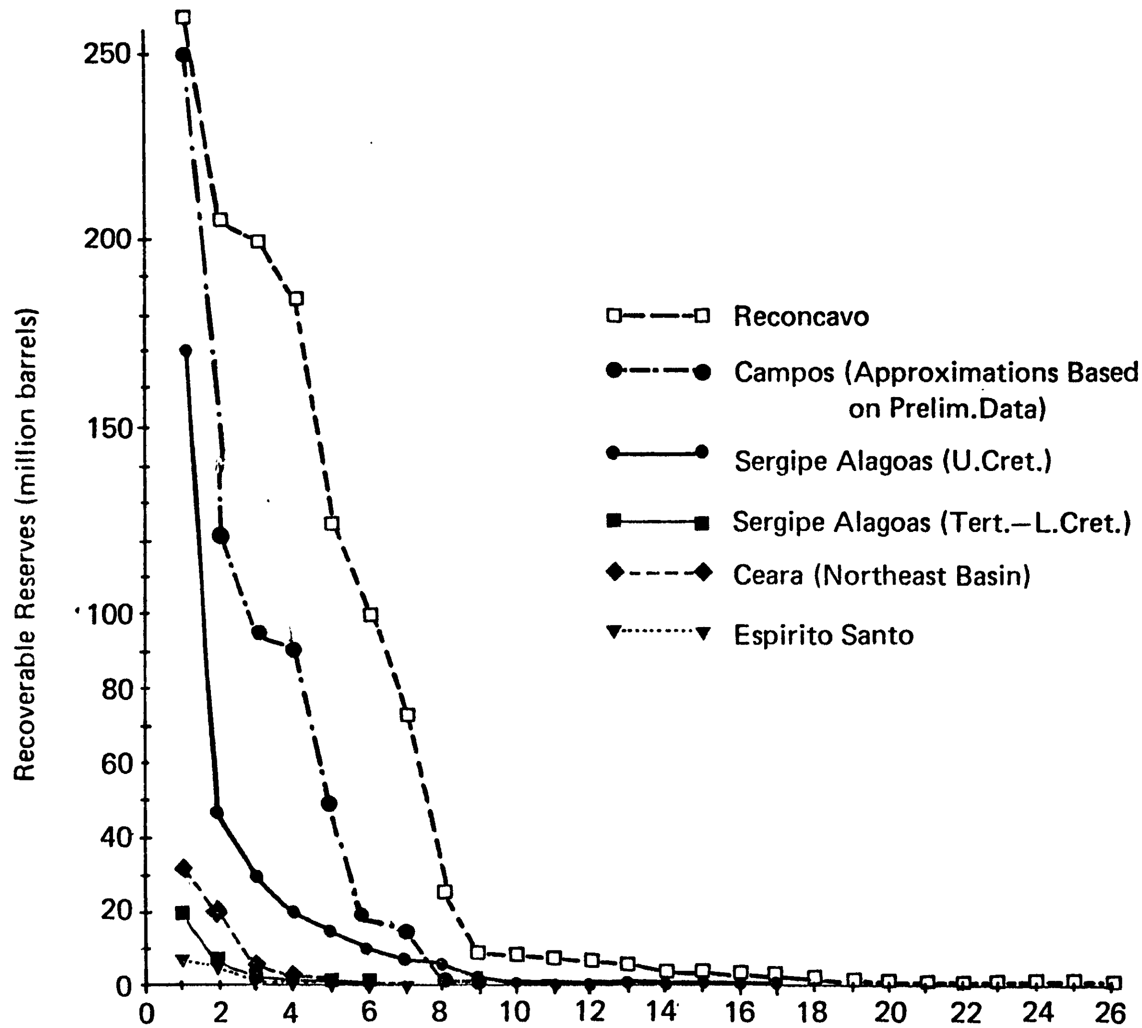
[b] "Scope of Brazilian Effort in Exploration and Production of Hydrocarbon" Petrobras 1978; Offshore September 1980; Economics of Offshore Oil and Gas Supplies, Beck p138. Development cost per reservoir for the Campos basin varies from $200 to $500 million, it is estimated that future reservoirs found could be developed at about $250 million.

[c] MERS is minimum economic reservoir size (in million barrels recoverable oil) given by R - I (a+r)/Pa, I is total development cost, the discount rate r=.12, optimal decline rate is $a^* = (365Q_p Pr/I)^{1/2} - r$.

*10 modular platform/$45 million (79)

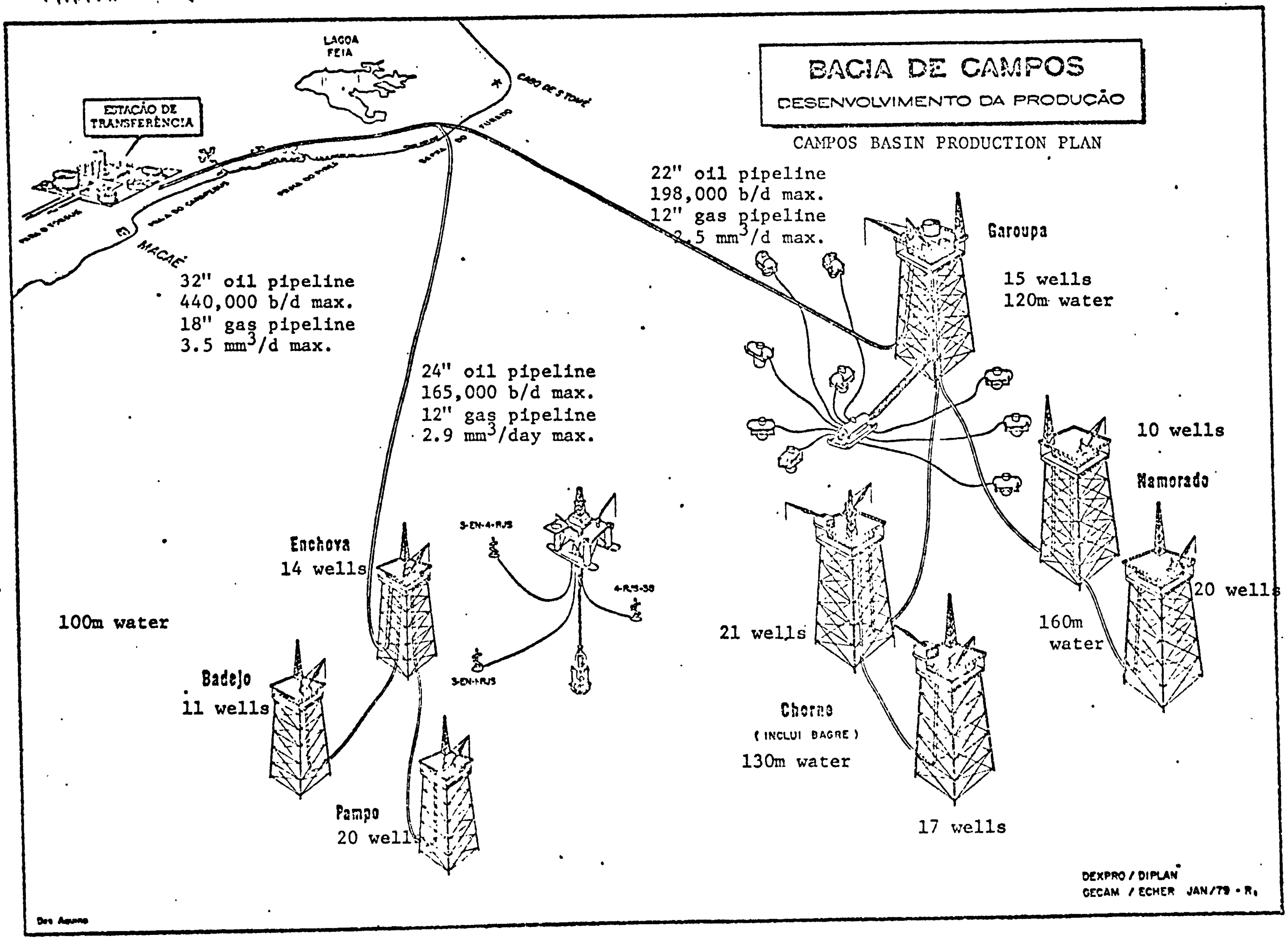
Annexes

Annex 3-1



SOURCE: IIASA World Oil Database.

Annex 3-2


BACIA DE CAMPOS
DESENVOLVIMENTO DA PRODUÇÃO
CAMPOS BASIN PRODUCTION PLAN
LAGOA FEIA
ESTAÇÃO DE TRANSFERÊNCIA
MACAÉ
22" oil pipeline
198,000 b/d max.
12" gas pipeline
2.5 mm³/d max.
32" oil pipeline
440,000 b/d max.
18" gas pipeline
3.5 mm³/d max.
24" oil pipeline
165,000 b/d max.
12" gas pipeline
2.9 mm³/day max.
Garoupa
15 wells
120m water
10 wells
Namorado
20 wells
160m water
21 wells
Chorne
(INCLUI BAGRE)
130m water
17 wells
Enchova
14 wells
100m water
Badejo
11 wells
Pampo
20 wells
3-EN-4-RJS
4-RJS-38
3-EN-1-RJS
DEXPRO / DIPLAN
GECAM / ECHER JAN/79 - R1

4-1. Current Methods Used to Estimate Undiscovered Oil and Gas Resources

A methodology to estimate undiscovered resources which is applicable to all basins is desirable, but the amount of detailed geologic and exploratory information varies considerably from frontier to mature basins. The most detailed basin information is where oil has been located and oil reserves have been well documented. In frontier areas only general geologic parameters are known and only a few exploration holes have been drilled. In certain frontier regions a few exploration holes and general geology may be sufficient information for some experts to dismiss the possibility of finding commercial oil. This divergence in viewpoints represents the basic question one must deal with in resource appraisal: Are oil and gas resources in a particular region unknown because they are not there or because there has been insufficient exploration to find them For those who rely on geologic judgement, large regions may have low resource potential. For others, who are only convinced by actual drilling results, some of these large regions with few drill holes are expected to contain substantial resources. During later stages of the exploration process, quantifiable geologic and exploration statistics may produce relatively accurate estimates of undiscovered resources. But in the early stages of the exploration process it is necessary to use all available information, including productive use of prior geologic judgment.

There exists an extensive body of literature on oil and gas resource appraisal methods. Excellent summaries of various methods have been made by Grenon (1975), Haun (1975), Kaufman(1980), and Miller (1980). Figure 4-1 (from Miller, 1980) summarizes methodologies used for frontier, immature and mature regions. The main methodologies that have been used are subjective probability, volumetric yield, discovery rate (or exploration effort), and discovery process models with field size distributions.

Subjective probability methods are based on expert geologic judgment of possible resources in an area. It has the benefits of being applicable to an area of any size and may provide very useful insights if the geologist has had extensive experience. This method also has serious drawbacks as it may result in a wide variation of resource estimates which cannot be reconciled.

Volumetric yield methods utilize average yields (usually barrels of oil per cubic foot of rock) for all basins or geologically similar basins. These types of estimations are heavily dependent on geologic judgment and do not give estimates of field sizes or other deposit characteristics. Advantages of this method, when applied carefully, are that it can be used worldwide and used for a frontier region of any size.

Discovery rate (or exploration effort) methods are used for immature and mature basins. Most models of this sort are based on the fact that the number of wells needed to find the remaining (smaller) deposits in a region increases at a rapid rate (usually assumed to be an explonential rate). As more and more wells are drilled the discovery rate (in barrels/well or barrels/foot) decreases in an

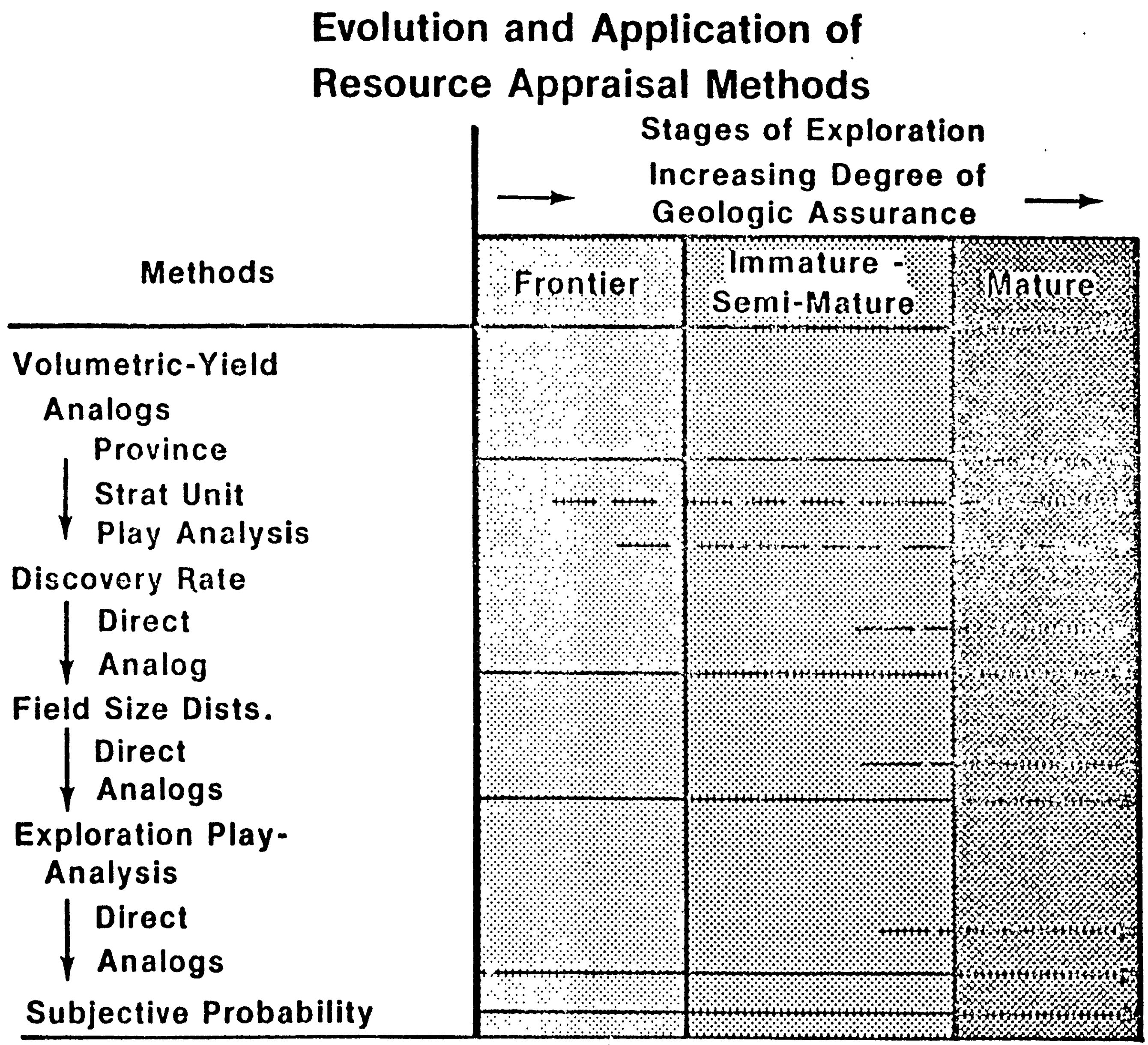


Figure 4-1 Resource Appraisal Methods Applicable for the Various Stages of Exploration in a Petroleum Province with an Increasing Degree of Geologic Assurance.

exponential fashion. Discovery rate models extrapolate this decrease in barrels discovered per unit of exploration effort. These models do not give expected field sizes and are poorly suited for use in frontier areas.

Recent developments have concentrated on the use of field size distributions in order to estimate the remaining resources in a partially explored play. A field is defined by Nehring (1978) as follows:

> A field is defined as a producing area containing in the subsurface (1) a single pool uninterrupted by permeability barriers, (2) multiple pools trapped by a common geologic feature, or (3) laterally distinct multiple pools within a common formation and trapped by the same type of geologic separation where the lateral separation does not exceed one-half mile. Giant oil fields are all fields containing at least 500 million barrels of known recoverable crude oil. Super-giant oil fields are all fields containing at least 5 billion barrels of known recoverable crude oil.

An offshore field generally has at least one platform per field. A group of geologically similar fields which occur close to each other (lateral separation greater than one-half mile to several dozen miles) that are formed by similar geologic processes are defined as a play. The concept of a play is a very useful one for analysis. The field size distribution within a play is usually skewed (sometimes approximated with a lognormal distribution) such that the largest field contains 20 to 60 percent of the total reserves in the play. Figure 4-2 (from Klemme, 1978) shows that for most basins that contain a play with at least one giant field, the largest 5 fields contain 85 percent of the total reserves. All types of geologic sedimentary basins show

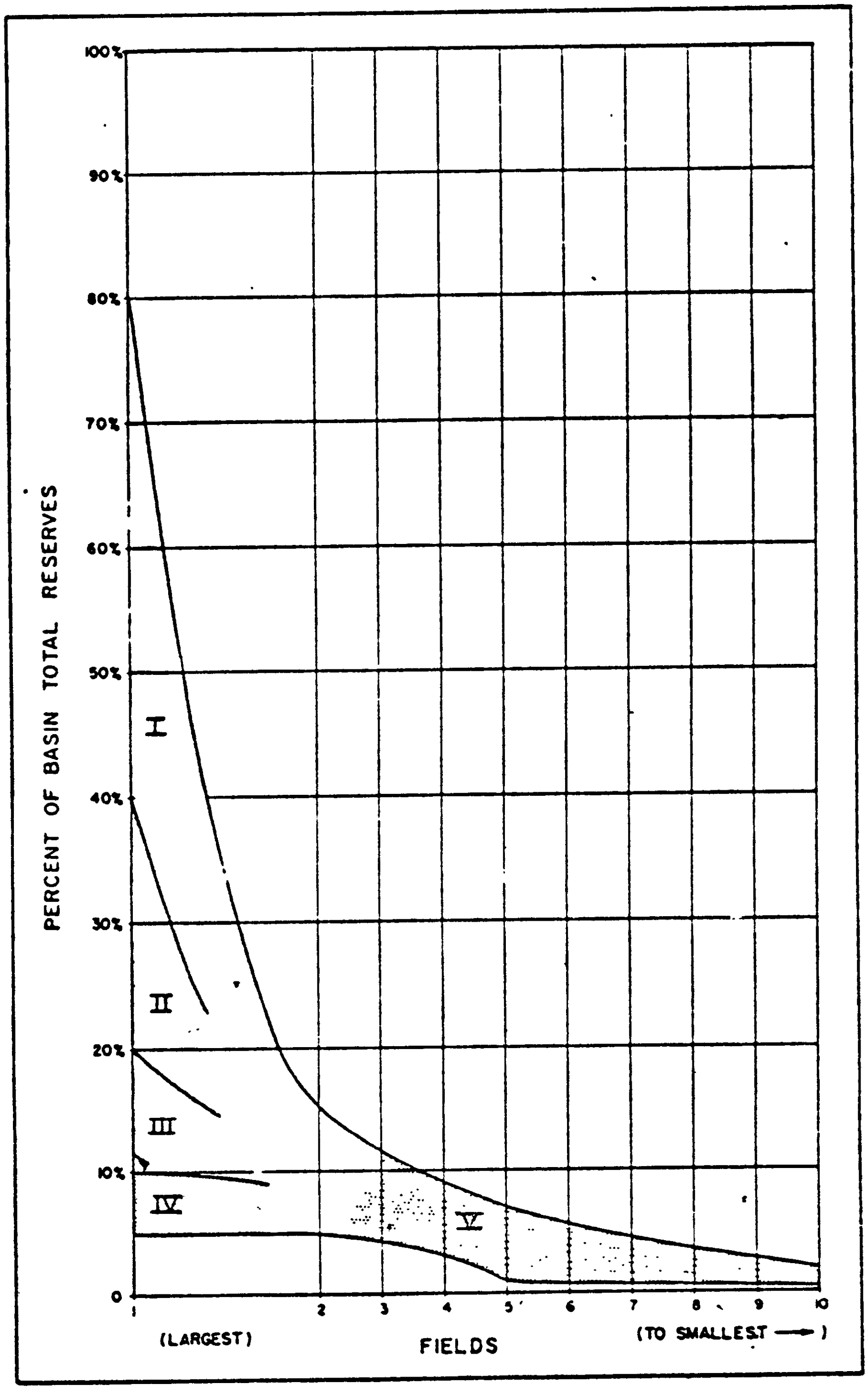


Figure 4-1 Field-size spread of basins with giant fields

Figure 4-2 (cont).

There appear to be five groupings of the largest or two largest fields in present basins:

I Presence in any type of basin of a supergiant or one disproportionately large field. In cratonic basins this is often related to extensive regional arches that retain sufficient cover. In intermediate basins (mainly Types 6 and 7) the presence of supergiants appears relatively unpredictable.

II This grouping might be considered a more average or normal distribution.

III Represents large cratonic Type 2 and large intermediate Type 4A and 4B basins, due to absence of a single regional arch and abundance of individual traps. It is the pattern in extremely prolific basins.

IV Typical of deltas

V Generally from 1 to 5 percent of total reserves, this represents the average larger field size. One can predict reserves with more assurance from this curve. The risk for finding one of the three or four largest fields in any basin increases as the basin develops, because the largest fields are usually found early in development.

On the average, a large field contains 25 percent of a basin's reserves; fields from the 3rd to the 10th largest appear to contain from 1 to 3 percent of basin's reserves.

Source: Klemme (1978), see Appendix B for details of basin types.

this highly skewed distribution except for deltas which follow a more even distribution (largest field contains around 9 percent of total reserves). These atypical deltaic field size distributions are found mainly in three provinces, the Mississippi Delta, Texas Gulf Coast, and Niger Delta. Since two of the three provinces are in the U.S., some analysts have improperly extrapolated these atypical field size distributions and their concentrated drilling history to non-deltaic regions outside the U.S.

Worldwide, a typical play has a skewed field size distribution. Since a few fields are so much larger than the others, one would expect the order of discovery to be proportional to the size of the fields. For example, Figure 4-3 shows that the largest deposits were discovered first in the Midland Basin and the reservoir size declined as more and more wells were drilled. This principle is the basis for most field size distribution models. Kaufman and Barouch (1976) have assumed that deposits within a play are discovered proportional to size and that the distribution of deposits is lognormal. They then assume the exploration process is one of sampling without replacement and project the size of future discoveries conditional on the size of reservoirs already found. An example of this discovery size decline phenomena is shown in Figure 4-4. This sophisticated approach developed by Kaufman (1976) and similar work by Smith (1980) produce the best statistical results for fields and plays where a large number of fields have already been discovered.

It is important to distinguish the types of undiscovered resources

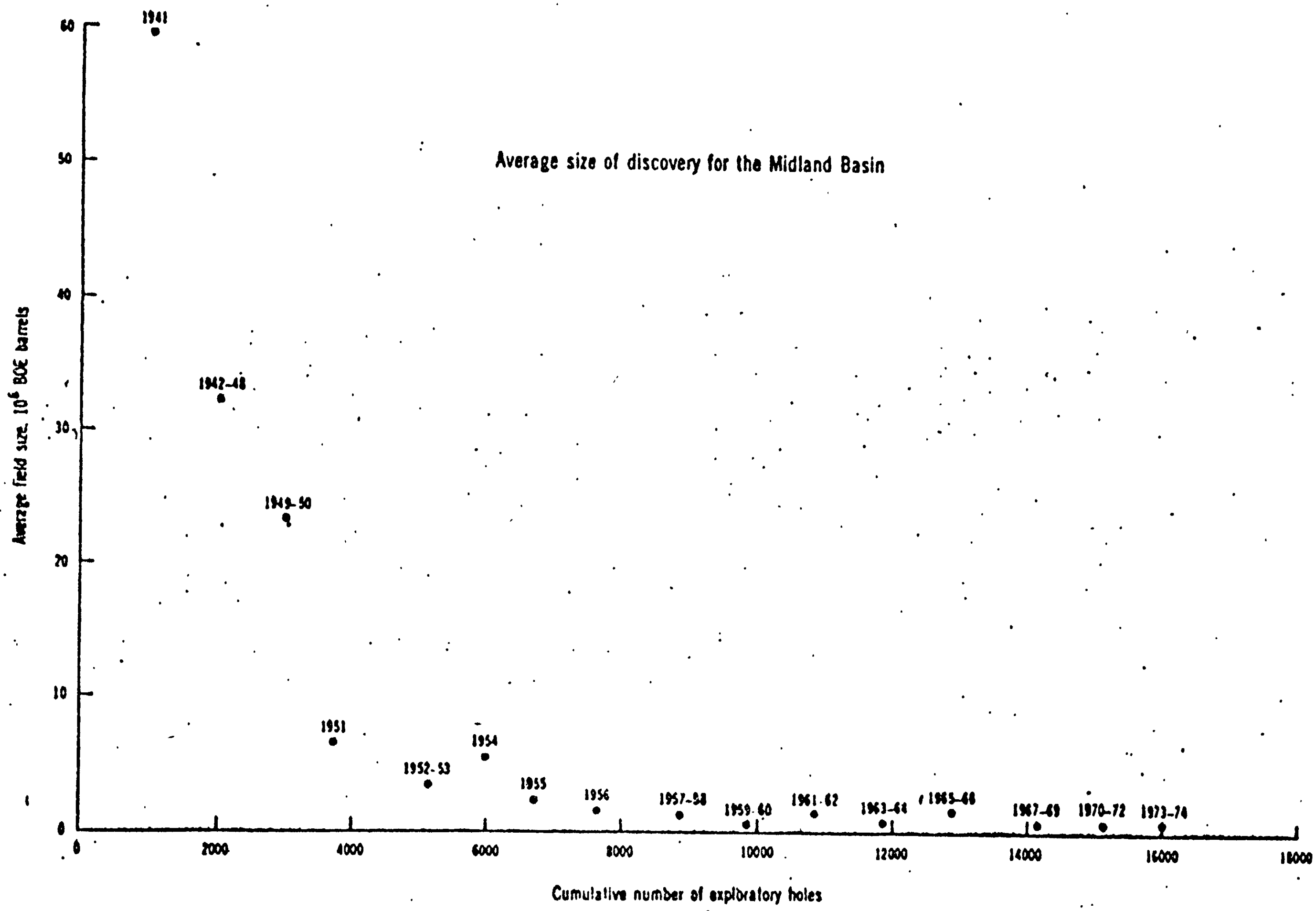


Figure 43. Average Size of Discovery for the Midland Basin

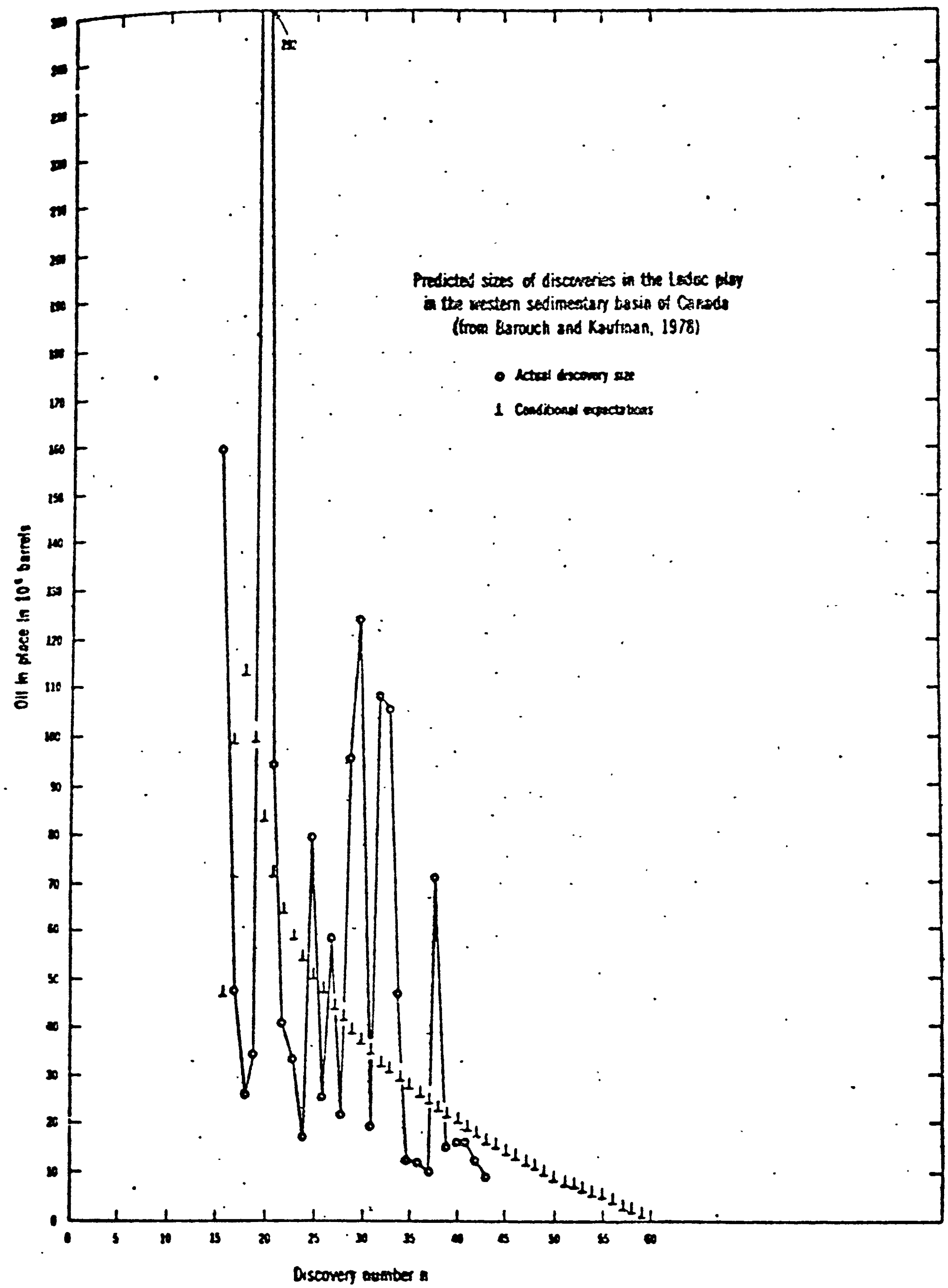


Figure 4-4 Predicted Sizes of Discoveries in the Leduc Play in the Western Sedimentary Basin in Canada (from Barouch and Kaufman. 1978).

that models deal with. There are two classes of undiscovered resources which need to be estimated, first are the undiscovered oil fields in already discovered plays and second are the undiscovered oil plays in the sedimentary basins. Most resource appraisal models deal with the former, such as those models described above. Since the known oil fields in Brazil are small, remaining resources in known plays are expected to be relatively small. Thus for Brazil, the crucial question is the amount of oil in the second class of undiscovered resource (undiscovered plays in a group of sedimentary basins). In this study, two different methods will be used to estimate undiscovered resources. The first method will be to use an exponential decay method to estimate the undiscovered fields in known plays. This will be described in the next section. The second method will be to develop and apply a Bayesian exploration model to estimate the amount of undiscovered oil in undiscovered plays, which is described in detail in section 4-3.

4-2. Method Used to Estimate Undiscovered Oil Resources in Known Plays

Work by Eckbo (1977) and by Smith (1980) have made use of the observation that the discovery size decline curve can be approximated with an exponential decline. This method captures the main principle of discovery proportional to size which is the basis for the more sophisticated models. It has proved to be a simple, relatively accurate method to estimate the number and size of remaining reservoirs which are larger than the minimum economic reservoir size within an oil field or oil play. The exponential decay method will be used here (as opposed to more sophisticated methods) to estimate the undiscovered resources in known plays for two reasons. First, small data sets will not produce robust results when used in the more sophisticated models (such as those of Kaufman (1976) and that of Smith (1980)) so the simple exponential decay method produces a good approximation. Second, in a play that has only a few economic fields the number of remaining undiscovered economic fields is expected to be small, whether or not the exponential decay method or more sophisticated methods are used.

As discovery proceeds to smaller and smaller fields a point is reached where the discovered field sizes are no longer economic to develop. This minimum economic reservoir size (MERS--as defined by Eckbo 1977) varies with the price of oil, production characteristics of the field (decline rate, etc.), and physical conditions such as water depth which affect the investment cost. This MERS is more important offshore due to rapid cost increases as water depth increases. The method used to calculate undiscovered resources in known plays will be to fit an exponential decline in field size using the order of discovery of known fields. Expected undiscovered resources in known plays equal the sum of undiscovered fields greater than MERS.

4-3. Method Developed in This Study to Estimate Oil and Gas Resources in Undiscovered Plays

The previous section outlined the various methods used to estimate undiscovered oil resources in known plays. Subjective assessment of resources or geologic analogs are the only methods commonly used to estimate the total undiscovered resources in new plays in a frontier region. These methods are subject to wide variation due to the wide variety of subjective geologic opinion about a particular unexplored region. The goal of this section is to develop a new method of estimating the number and size of undiscovered plays (e.g., groups of fields) in a partially explored basin or group of geologically similar basins. The approach developed here contains two components:

1) Exploration data are used to update prior estimates of the resource base in a region consisting of partially explored basins (which have similar geologic history).

2) Estimates of the economic return to future exploration investments (i.e., net present value (NPV)) of various alternative exploration programs are calculated, as well as the variance and distribution of returns of these investment programs.

The goal of this analysis is to provide a method of evaluating oil exploration programs which can compare directly with alternative investments (such as synthetic fuel production). This type of exploration modelling is designed to be particularly useful for evaluating additional investments in exploration when initial exploration has produced only modest results. Although the technique developed here could be applied at a disaggregated level, the modelling procedure developed here is to be used at an aggregate level as a component in energy sector planning. The model will be applied to Brazil and the results used to compare exploration with alternative shale oil and alcohol production options.

Summary of Model

The goal of this model is to use data from exploration to update initial prior estimates of the resource base and project probabilities of future discovery. The model uses prior estimates of the probability that a certain number of plays exist in a region and revises that initial probability based on the likelihood of occurrence of the observed discovery pattern. The following steps describe the basic features of the model:

1) Geologic basins are divided into groups with similar geologic history. Based on the initial geologic assessment of the basin charactersitics, the prior probabilities that plays with giant fields (> 500 mill. bbls) and plans with commercial fields exist are assigned to the basin (or group of similar basins).

2) An intial prior probability on the efficiency of the exploration process is established. Past studies have shown that a randomly placed exploration well can be thought of as "exhausting an area" equal to the presumed target area (this type of random exploration is defined as having exploration efficiency of one). Past analysis on exploration in the U.S. has shown that exploratory wells drilled on the advice of geologists require, on the average, 2 to 4 times fewer wells to exhaust an area of a basin than random drilling. Based on this information, reasonable prior values of exploration efficiency range from 1 to 4.

3) A likelihood function is developed that estimates the probability that the actual observed discovery sequence would have occurred if a certain number of plays exist and if the exploration

efficiency is true efficiency. One probability is calculated for each combination of plays and exploration efficiency. The likelihood function is based on a model of cumulative exhaustion of basin area by both dry and successful exploration wells.

4) The initial prior probabilities (from 1 and 2) are mutiplied by the likelihood probabilities (from 3) and results normalized so that the sum of all probabilities equals one. The resulting numbers equal the revised (or posterior) probability that a specific number of plays is the true state of nature and that the exploration efficiency is the true efficiency of the exploration process. The updating process is completed in two stages, first for the discoveries from an intital block of wells and then for the discoveries from a second block of wells. Updating is done in two stages because the precision of the results increases and the range of exploration efficiency is narrowed. An example will help clarify this point. If there have been three plays discovered in an offshore region (several basins) with 250 wells, it is uncertain whether exploration has been relatively efficient and few plays remain to be discovered or whether exploration has been inefficient and many more plays exist. The data can be broken into two stages for analysis. Suppose it is found that 3 plays were discovered with 100 wells and 0 plays were then discovered with the next 150 wells. Assuming that the efficiency of exploration has been constant, it is much more likely that few (if any) plays remain to be found and that exploration has been efficient as opposed to the unlikely event that many more plays remain to be found and that exploraiton has been

inefficient. By updating in two stages, results are more precise. In this case the posterior probabilities are high that little oil remains to be discovered.

5) The same model described above can be used to project expected discoveries from future exploration wells. It makes use of the exploration efficiency calculated by the past exploration history. By using the size and net present values of an average play in the type of basin in question, the model calculates a probability distribution of economic return and barrels of oil expected to be discovered with a block of future exploration wells. These economic return calculations are completed in Chapter 5 based on the results from this chapter.

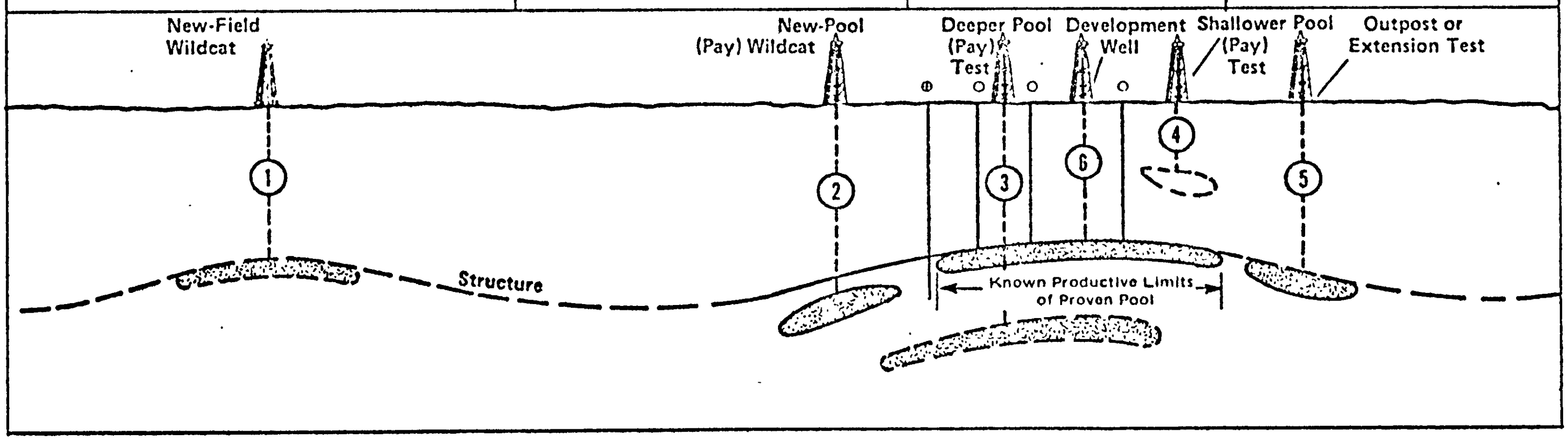
Several simplifications have been made in the above description, but the basic features of the model have been covered. The model was tested on exploration data from the three types of sedimentary basins in Brazil. The results for the offshore basins are simalar to the example above. A sensitivity analysis was performed and the range of final results was relatively narrow. The final results are similar to other available appraisals of oil resources in Brazil. (For the results see Tables 8 and 9.) The next several sections describe the features of the model in detail.

3-A. Steps in the Exploration Process

The exploration-production process for oil and gas can be broken into three main components:

1) Surveying--A general geologic history is compiled, reflecting

OBJECTIVE OF DRILLING				INITIAL CLASSIFICATION ϕ WHEN DRILLING IS STARTED	FINAL CLASSIFICATION AFTER COMPLETION OR ABANDONMENT			
					SUCCESSFUL ● ○ ■		UNSUCCESSFUL Φ	
Drilling for a new field on a structure or in an environment never before productive				1. NEW-FIELD WILDCAT	NEW FIELD DISCOVERY WILDCAT		DRY NEW-FIELD WILDCAT	
Drilling for a new pool on a structure or in a geological environment already productive	NEW POOL TESTS	Drilling outside limits of a proved area of pool		2. NEW-POOL (PAY) WILDCAT	NEW-POOL DISCOVERY WELLS *(Sometimes extension wells)*	New-Pool Discovery Wildcat *(Sometimes an extension well)*	DRY NEW-POOL TESTS	DRY NEW-POOL WILDCAT
		Drilling inside limits of proved area of pool	For a new pool below deepest proven pool	3. DEEPER POOL (PAY) TEST		Deeper Pool Discovery Well		DRY DEEPER POOL TEST
			For a new pool above deepest proven pool	4. SHALLOWER POOL (PAY) TEST		Shallower Pool Discovery Well		DRY SHALLOWER POOL TEST
Drilling for long extension of a partly developed pool				5. OUTPOST or EXTENSION TEST	EXTENSION WELL *(Sometimes a new-pool discovery well)*		DRY OUTPOST OR DRY EXTENSION TEST	
Drilling to exploit or develop a hydrocarbon accumulation discovered by previous drilling				6. DEVELOPMENT WELL	DEVELOPMENT WELL		DRY DEVELOPMENT WELL	



LAHEE CLASSIFICATION OF WELLS, AS APPLIED BY CSD

Figure 4-5. AAPG and API Classification of Wells

Source: The American Association of Petroleum Geologists. "North American Drilling Activity," in AAPG Bulletin, Vol. 63, No. 8, Figure 8, titled "AAPG and API Classification of Wells," p. 1202. ©American Association of Petroleum Geologists, Tulsa, Oklahoma. Reprinted with permission of the publisher.

seismic lines and magnetic profiles completed.

2) Exploration drilling--

- Type 1 newfield wildcats are defined as exploration wells which are searching for new plays, (i.e. fields within undiscovered plays) in those areas where oil has not previously been discovered.
- Type 2 newfield wildcats are exploration wells are defined as those wells drilled to find new fields within known plays where at least one field has already been located.
- Exploration and extension wells drilled within and around the edges of an already discovered field. These wells are the new-pool, deeper-pool, shallower-pool and outpost wells defined by the Lahee system (Figure 4-5).

3) Development wells--Wells drilled into pools within fields, which are perceived as commercial for the purpose of production. Offshore production entails drilling development wells from a platform with ship loading or pipeline delivery to shore.

3-B. A Model of the Exploration Process

There are many ways to think about modeling the exploration process, some of which are simple, others which are very complex. We will begin with a simplifed way of modeling exploration and then make it more realistic. If we know that there is a target (of projected circular area A) that exists in a region of area B, a simple method of exploration would be to drill wells (newfield wildcats Type 1) on a grid spacing equal to the diameter of the target. A well would discover the oil field sooner or later. The maximum number of wells needed to be drilled would be B/A, which is the inverse of the probability of finding the field with the first wildcat. In this way a dry hole can be thought of "exhausting" a certain area. The concept of a dry hole exhausting area has been carefully studied (Singer and Drew, 1976, and Drew and Root, 1978) for target sizes with various elliptical shapes and orientations. It was shown that a single well will on the average exhuast an area equal to the assumed target size (i.e., projected area) for non-circular as well as circular targets.

Exploration with random drilling is not used in the real world because it is too expensive. It is cheaper to hire geologists who can interpret seismic data and subsequent drilling data in order to reduce the number of exploration wells that need to be drilled. The maximum number of wells needed to find the oil field with increased exploration efficiency would then be B/eA, where e = 1 for random drilling and e > 1 for dilling more "efficient" than random drilling. Arps and Roberts (1959) used this formulation and estimated e to equal 2.75 based on the following information:

> According to the annual A.A.P.G. statistics on exploratory drilling, the success ratio between wildcatting on technical advice such as geology and/or geophysics over the period 1944-1956 is 2.75 times as good as the success ratio for wildcats which were drilled for non-technical reasons. it is the opinion of the authors that this ratio for the Denver-Julesberg Basin was probably not as high as the 2.75 United States average because of the nature of the traps

> involved, and for the purposes of this estimate we have therefore used a ratio of two.

When efficiency is modelled in this way values of e greater than one can be interpreted as reducing the size of the sample space (effective basin area). Kaufman (1980) points out that this interpretation does not hold if e is not a constant function of the areal extent of the field, i.e. if e varies from size class to size class. It will be assumed in this model that e will be constant over the field size classes under consideration. The estimates of e involve calculation of success ratios. Success is defined as finding a commercial deposit, but a commercial deposit is dependent on specific physical and economic conditions. As the conditions vary the success ratio and thus e may vary. We will therefore only use this estimate of e as a rough guideline and use a wide range of possible prior values of e in the analysis.

There are several ways in which exploration efficiency may be greater than the efficiency of random drilling:

1) The area of the structural trap which holds the oil field usually has a larger projected area than the area of the field. (The structural trap area was found to be twice that of the productive area of the oil field as measured for 30 fields in Brazil.) Seismic data can outline the location of the structural trap or locate uplifted blocks above which oil deposits may occur. Thus a single well may exhaust a larger area than just the productive area of the field.

2) Exploration in a region with uniform sedimentary layers may have an exploration efficiency greater than random drilling, since a small amount of information (geochemical or physical) from one well may be able to condemn a large region as unsuitable for oil formation or oil accumulation.

Let's now assume that there is an oil play in the region which consists of n fields and the productive play area A_T is defined as the sum of all the productive field areas ($A_T = \sum_{i=1}^{n} A_i$). The field size distribution in the play is skewed with a large fraction of the total reserves (~40 percent) are in largest field. If the productive areas of all the fields in the oil play are touching each other then the play can be considered one "target." A new field wildcat (Type 1) that is drilled into the area is all that is needed to "discover" the play. The maximum number of new field wildcats (Type 1) needed to explore the region for oil plays is equal to B/eA_T. Subsequent new field wildcats (Type 2) 2) are then drilled to discover the remaining fields in the play.

It may be necessary to adjust this simplified model since several wells (not just one) may be needed before a well actually strikes oil in the play since there are "dry" areas on the sides of the trap and oil fields are usually somewhat separated although may be considered close together when compared to the region as a whole. The efficiency of exploration for a play (group of fields) increases in regions with simple geology and where trap area is greater than productive oil area. On the other hand, the overall efficiency is reduced somewhat due to the separation of deposits within the play. The overall exploration efficiency for a play is still likely to be greater than 1 but the exact efficiency is unknown.

The description of the process so far assumed that only one play exists. When exploration is undertaken explorationists have only a rough guess as to the number and size of plays in a region. After complete exploration of the region the number and size of plays is known with certainty and a calculation of the exploration efficiency could be made. Most (if not all) current exploration efforts are incomplete, with basins or regions partially explored. Since our ultimate objective is to provide estimates of the true resource state (i.e., the number and size of plays in a region), prior assessments of the resource state could be updated with observed exploration data to provide a revised estimate of the resource state. A description of the exploration process must include some measure of exploration efficiency, and different assumptions about past exploration efficiency will produce different estimates of the true resource state. It will be shown that by <u>simultaneously</u> updating the exploration efficiency jointly with the estimate on the resource state in a two stage process, the revised estimates of the resource state are much more precise than updating only in one stage. This updating process is completed in two stages, first for the discoveries from an initial block of wells and then for the discoveries from a second block of wells. Updating is done in two stages because the precision of the results increases and the range of exploration efficiencies is narrowed. An example will help clarify this point. If there have been three plays discovered in an offshore region (several basins) with 250 wells, it is uncertain whether exploration has been relatively efficient and few plays remain to be discovered or whether exploration has been inefficient and many more plays exist. The data are broken into two stages for analysis. Suppose it is found that 3 plays were discovered with 100 wells and 0 plays were then discovered with the next 150 wells. Assuming that the efficiency of exploration has been constant, it is much more likely that few (if any) plays remain to be found and that exploration has been efficient as opposed to the unlikely event that many more plays remain to be found and that exploration has been inefficient. By updating in two stages, results are more precise. In this case the posterior probabilities are high that little oil remains to be discovered. The process of updating involves the use of Bayes theorem. Its application is discussed in the following section.

3-C. Bayesian Analysis Applied to the Exploration Process

The Bayesian updating process is performed frequently in the minds of explorationists. For example, if a geologist believes with high probability that 10 plays (which contain at least one giant field each) exist in a certain region he will revise his probability estimates substantially downward if the first 500 wells turn up only one play containing a giant field. Bayes theorem quantifies this updating process with the following formula:

$$\frac{P'(S_i)\, L(S^*/S_i)}{\sum_{i=1}^{n} P'(S_i) L(S^*/S_i)} = P''(S_i)$$

where $P'(S_i)$ = prior probability that state S_i is the true state of nature

$L(S^*/S_i)$ = likelihood that the observed sample S^* would result, conditional on S_i being the true state of nature

$P''(S_i)$ = posterior (or revised) probability that state S_i is the true state of nature.

Each state of nature $S_i = f(g_i, c_i)$ is defined in this study to be the number of plays (g_i) which contain at least one giant field and number of plays (c_i) which contain at least one commercial, non-giant field. The procedure developed in this study uses a joint prior probability $P'(S_i, e_i)$ that a certain state (S_i) is the true state of nature and that the exploration efficiency (e_i) is the true exploration efficiency. The probabilities are updated in two stages with likelihoods for the first stage determined by the sample (number of giant field plays and number of commercial field plays discovered) derived from the first set of exploration wells. The estimated posteriors become the priors for the second stage. The second stage likelihoods are determined by the sample derived from the subsequent exploration wells. The model can be summarized as follows:

1) $$\frac{P'(S_i,e_i)L(S^*,w^*/S_i,e_i)}{\sum_{i=1}^{n} P'(S_i,e_i)L(S^*,w^*/S_i,e_i)} = P''(S_i, e_i)$$

2) $$\frac{P''(S_i,e_i)L(S^{**},w^{**}/S_i,e_i)}{\sum_{i=1}^{n} P''(S_i,e_i)(L(S^{**},w^{**}/S_i,e_i)} = P_i'''(S_i,e_i)$$

where $P'(S_i, e_i) = P'(S_i)P'(e_i)$ = prior joint probability that S_i is the true state of nature and that e_i is the true exploration efficiency. (These priors are assumed to be independent since the actual deposits of oil that exist are independent of the oil company's efficiency of exploration.)

$S_i = f(g_i,c_i)$ = state of nature, the number of plays with at least one giant field (g_i) and number of plays with at least commercial field (c_i).

$L(S*,w*/S_i,e_i)$ = Likelihood that the observed sample S* (number of giant-field plays and number of commercial-field plays) would be discovered with w* new field wildcat wells (Type 1) conditional on S_i and e_i being the true states.

$P''(S_i',e_i')$ = Posterior probability that S_i and e_i are the true states.

$L(S*,w*/S_i,e_i)$ = Likelihood that the observed sample S** (additional giant-field plays and commercial-field plays discovered) with w** additional exploration wells conditional on S_i and e_i being the true states.

$P'''(S\ ,\ e\ )$ = Posterior probability after the second stage.

This section has outlined how Bayesian inference can be used to estimate the probability that a certain resource state is the true state of nature conditional on exploration history. To use this approach we must obtain: 1) the prior probability that the resource state is the true state, 2) the prior probability that a certain exploration efficiency is the actual efficiency, and 3) the likelihood that the observed exploration history would occur conditional on the prior states. Each of these will be dealt with in turn.

3-D. Prior Estimate of Oil Play and Oil Field Sizes

In order to use the updating procedure described in the previous section a prior probability estimate on the resource state for a region must be obtained. A resource state is defined to be the number of plays (which contain at least one giant field) and the number of plays (which contain at least one commercial field). A prior estimate could be obtained from one or more expert geologists who have access to detailed information on the area in question. Alternatively, a prior estimate may be obtained through a worldwide comprehensive study of basins of similar geologic type. This latter approach uses a minimum of subjective input and allows various basins worldwide to be evaluated and compared. The best publicly available comprehensive study of all major basins around the world has been completed by Klemme (1975, 81). The basin classification scheme used was developed by Halbouty, et al. (1981) and Klemme (1975). Petroleum geologists agree with this classification of all major basins worldwide (several hundred in total) for 81-91 percent of the basins. The work by Klemme (1975) has compared the field size distribution, oil trap character, degree of exploration, richness (barrels per cubic mile), probability of finding commercial producton and the probability of finding giant fields for each of the eight basin types (Figure 4-6). Appendix B gives these details as well as the location and extent of exploration of the eight types of basins. One of the best attributes of the Klemme (1975) classification is that oil potential is assessed at a disaggregated level, but not at a too disaggregated level where each basin becomes a special case. These prior probabilities also have the advantage of being made in the context of a globally consistent oil assessment by an oil expert with wide international experience. Other basin classifications put qualitative rankings on oil potential but the Klemme study attaches quantitative estimates.

The following steps suggest a method by which rough prior estimates could be obtained for a group of sedimentary basins:

1) Divide the basins up into groups of similar geologic type according to the basin classification system outlined by Klemme.

2) Use the probability of giant-field plays (p_1) and probability of commercial-field plays (p_2) for each basin as estimated by Klemme (see Figure 4-6 and Appendix B).

3) If the region consist of more than one basin the binomial probability model is the model which gives the probability that exactly X_i plays occur in n basins of the region. The probability of having g "giant field" plays and c "commercial field" plays occurring in n basins is calculated by multiplying the binomial probability for g giant plays in n basins and the binomial probability for c plays in n basins.

"YARDSTICK" FOR BASIN EVALUATION

	BASIN TYPE	↓RECOVERY PER CUBIC MILE OF SEDIMENTS	CHANCE OF COMMERCIAL PRODUCTION	CHANCE OF PRESENCE OF GIANTS	FIELD SIZE * LARGEST FIELD (10th LARGEST FIELD)
CRATONIC BASINS	1. CRATONIC INTERIOR	35,000 HIGH 18,000 AVERAGE 3,500 LOW	30%	20%	—
	2. CRATONIC MULTICYCLE (LARGE)	250,000 120,000 25,000	80%	65%	10% TO 50% (1.9% TO 0.6%)
	(SMALL)	75,000 40,000 7,500	50%	30%	30% ± (2% ±)
	3. CRATONIC RIFT	450,000 140,000 20,000	70%	50%	30% (1.7%)

↓ OR EQUIVALENT GAS
* BASED ON ULTIMATE RECOVERY OF TOTAL BASIN RESERVES

Yardstick for basin evaluation, cratonic basins

"YARDSTICK" FOR BASIN EVALUATION

	BASIN TYPE	RECOVERY PER CUBIC MILE OF SEDIMENTS	CHANCE OF COMMERCIAL PRODUCTION	CHANCE OF PRESENCE OF GIANTS	FIELD SIZE LARGEST FIELD (10th LARGEST FIELD)
INTERMEDIATE BASINS	4. INTEMEDIATE EXTRACONTINENTAL 4A. CLOSED	600,000 * 150,000 10,000	80%	50%	14% (2%)
	4B FOREDEEP	60,000 25,000 1,000	40%	10%	14% (2%)
	4C OPEN	300,000 160,000 3,000	50%	65%	30% (0.6%)
	5. PULL-APART	? (PRESENTLY AVERAGE 40,000)	30%	20%	?
	6+7 INTERMONTANE	4,000,000 180,000 5,000	20%	40%	35% (1.3%)
	8. DELTA	220,000 190,000 ?	50%	FEW GIANTS	6% (1.5%)
	AVERAGE ALL BASINS	50,000 TO 100,000	50%	50%	25% (1.5%)

* MIDDLE EAST

Figure 4-6 Yardstick for basin evaluation, intermediate basins

Figure 4-6 (cont.)

Note: The probabilities for giant and commercial fields were calculated (according to Klemme) as follows:

"In this study, the remaining nonproducing basins of each type were plotted and the relative amount of exploration graphed [from Annex B]. All of the relatively unexplored basins together with half of the moderately explored basins were determined and compared to the risk [probability] for finding production and the risk of finding giants [Table 6] for each respective type. The number of basins that might ultimately develop were then related to the percentage of present proven world reserves that each basin type respresents (sections, Fig. 12-3 through 12-9). In some instances, the calculated figures were revised. In the case of Type 4 basins, the estimates were considerably downgraded because the presence of the Mideast high reserve basin in this category "skews" the input for calculations. In the case of Type 8 deltas, the estimates were upgraded due to the fact that giant fields in these basins represent less than 20 percent of their total reserves. In Type 6 and 7 basins, a higher estimate was given than calculated because of both the size and the virgin nature of untested offshore basins of this type which would, in effect, lower the risk of discovery and volumetrically increase the reserves for an individual basin. Although the present rate of giant reserves to nongiant reserves is 75 percent and 25 percent respectively, a factor of 30 percent to 42 percent was used for nongiant reserves.

These reserves [world reserves] total over 500 x 10^9 barrels (68 x 10^9 metric tons) of oil equivalent and when combined with the additions expected in the previously discussed prolific basins or provinces of the Mideast and West Siberia, indicate that a reasonable figure of around 1,000 x 10^9 barrels (136 x 10^9 metron tons) of undiscovered reserves in oil equivalent might be expected. This does not include an estimate of the deep oceanic basins or Antarctica and its environs. It is estimated that over 42 percent of these reserves would come from offshore.

This estimate is about two-thirds the magnitude of those presented at the 9th World Petroleum Congress in Tokyo in 1975 and those estimated by Weeks in 1959. It is slightly more than one-half the estimate of the worldwide undiscovered reserves made by the U.S. National Academy of Sciences in 1975.

Probability = [binomial for g in n basins] [binomial for c in n basins]
of state

$$f(g, c) = \left[\frac{n!}{g!(n-g)!} p_1^g (1 - p_1)^{h-g}\right]\left[\frac{n!}{c!(n-c)!} p_2^c (1 - p_2)^{n-c}\right]$$

p_1 = probability of giant-field play in a single basin

p_2 = probability of commercial-field play in a single basin

The probabilities p_1 and p_2 are assumed to be independent, i.e. the occurrence of a "giant field" play is not significantly correlated with the occurrence of a "commercial field" play in a particular basin. This seems to be a reasonable assumption based on data from basins worldwide.

4) If additional geological information can be obtained about the particular basins in question then the priors may be adjusted accordingly which provide an indication that certain basins are richer (or poorer) than average. The sensitivity of the results to be adjusted priors can then be determined.

3-E. Prior Estimate of Exploration Efficiency

Exploration efficiency of 1 is defined to be random drilling. An exploration efficiency of 2 implies that only one half the number of wells are needed to exhaust an area as compared with random drilling. Since the exploration efficiency is unknown the initial calculations will assume a diffuse prior such that several exploration efficiencies are equally likely (e.g., e = 1, 2, 3 or 4). The work of Arps and Roberts (1958) and Drew and Root (1978) suggest that the most likely value for e is between 2 and 3. Although we may believe e is close to

2, a sensitivity analysis will be performed to test a variety of priors.

3-F. Likelihood Calculations

The goal of this section is to calculate the likelihood that the observed sample (S_j^*, the number of giant-field plays and number of commercial-field plays) would be discovered with w* exploration wells conditional on a specific state of nature (S_i) and a specific efficiency of exploration (e_i) being the true state. This section provides a discussion of the key assumptions and outline of the model. A detailed discussion of its derivation and relation to alternative models is provided in Appendix A.

The key assumptions of the model are:

1) Fields are clustered in groups (a play) whose area is very small relative to the exploratory area as a whole.
2) Two play sizes exist, giant-field play and commercial-field plays. Each possible combination forms a resource state.
3) The area that an exploration well exhausts (whether dry or wet) is equal to the target size. The target size can be the productive area of the play (as in Model B) or a fraction of it (as in model A).
4) The likelihood of any one well finding a large play is independent of the likelihood of that well finding a small play. The efficiency of exploration is the same for a large play as a small play. Note that even with this assumption, a region can be fully explored for large plays before it is fully

explored for small plays, because the large play is a bigger target.

5) Exploration is undertaken for region as whole. Wells are not heavily concentrated in one small portion leaving the remaining area unexplored.

The exploration process is modelled as sampling without replacement from a region of area B where dry wells and wet wells exhaust an area equal to the play productive area (A_{tg}) times the exploration efficiency (e). This process can be thought of as sampling from a sample space of N (=B/eA_t). Assuming one exploration well is all that is needed to discover the target play and g* discoveries (giant-field plays) have been discovered with w wells (type 1 wildcats). Recall that type 1 wildcats are the number of newfield wildcats up to and including the discovery of the first field in the play. The probability that g* discoveries would be made with w wells from a sample space of N containing exactly g_1 targets (true underlying state is given by the hypergeometric distribution.

$$L(g^*,w^*/g_i,e_i) = \frac{(N - g_i)!}{N!} \frac{w^*!}{(w^* - g^*)!} \frac{(N - w^*)!}{(N - g_i - w^* + g^*)!} \frac{g_i!}{g^*!}$$

N = B/e_iA_{tg} sample space

A_{tg} = productive area of the giant-field play (equal to the sum of all field areas).

e_i = exploration efficiency (random drilling equals one).

w* = number of wells drilled in region (type 1 new field wildcats).

g^* = number of giant-field plays discovered with w^* wells.

g_i = true number of giant field plays in region.

A similar calculation can be made for commercial field plays using the number of small plays found (c_i) with w^* wells using a sample space of $N = B/e_iA_{tc}$(A_{tc} is the productive area of a small play). The likelihood for a specific state (a state being a combination of large and small plays) is:

$$L(S^*, w^*/S_i, e_i) = L(g^*, w^*/g_i, e_i)L(c^*, w^*/c_i, e_i)$$

(Likelihood for state S), (Likelihood for large plays) (Likelihood for small plays)

$$S_i = f(g_i, c_i)$$

As can be seen, this utilizes the assumption that the likelihoods in searching for large and small plays are independent. They may not be completely independent if a large play overlaps a small play, which becomes more likely the larger the number of plays. In the example we are dealing with (offshore Brazil) the sample space is around 211+(=N=B/eA) and only a few sample discoveries have been made. The assumption of independence of the likelihoods is reasonable for this case since any bias caused by overlap would be very small since there are so few plays for such a large region.

Two versions of the approach outlined above have been developed. The version of the simpler model, model B, assumes that the play is one continuous unit and that one well (type 1) is all that is needed to discover the play. The area exhausted by a dry well is also assumed equal to the play productive area. If we consider a sub-area of the region which is 5 times the play productive area (A_t), then model B assumes that 5 wells are needed to exhaust this sub-area. The area exhaustion per well is $5A_t/5 = A_t$. The sample space for the region is taken as $N = B/e_iA_t$.

In reality a play is composed of several fields in close proximity. By assuming that dry and wet wells exhaust the same area, the results may be biased. If there is a dry play composed of several "dry" structures, several wells will be needed to determine that the area is dry while we have assumed only one type 1 well is needed to determine if it is wet. In order to correct this bias, model A assumes a play is not a continuous unit but dispersed into several pieces.

Model A assumes that a play can be modeled as five pieces of equal area that represent the 5 major fields (that account for 90 percent of play reserves). These pieces are dispersed over a region about 5 times as large as the play productive area (using field dispersion plays from around the world from Petroconsultants data as a guide). In model B only 5 wells were needed to "exhaust" the sub-area. In model A the play is dispersed and more than 5 wells are needed to exhaust the sub-area. Since the process is one of sampling without replacement the hypothesis is an appropriate distribution. It can be shown using the hypergeometric that there is only a 10 percent chance that none of the 5 fields would be found if 8 wells are drilled. In other words, to be 90 percent certain that a sub-area of size 5 A_T does not contain a play, only 8 wells need be drilled. The area exhausted per well is thus $5A_T/8 = .63\ A_t$. Whether or not the sub-area contains a wet play (of 5 fields) or a dry play (of 5 dry structures), the area exhausted per well is the same (.63 A_t). The factor .63 can be though of as an exploration efficiency e_p, of a field in a dispersed play just as e_i is the exploration efficiency of a play in the region. The sample space in model A is $N = B/e_i e_p A_t = B/e_i(.63)A_t$. Model A seems to be a more realistic description of the exploration process.

3-G. Calculation of Posterior Probabilities

The previous sections described the calculation of the priors on resource state, priors on exploration efficiency and likelihoods. Both priors are defined so they sum to one. For example, the seven continental margin type basins offshore Brazil can be modelled with prior probabilities for 15 states which sum to one. Four priors on efficiencies (which also sum to one) are multiplied by the 15 state priors to get 60 joint priors, the sum of which is one. There are 60 likelihoods multiplied by the corresponding state priors which are then normalized to produce 60 posterior probabilities. This whole process is repeated for sample data from the second round of wells to get the final posterior probabilities. By summing over efficiencies, four posteriors on efficiency are found and by summing over states, the posterior probabilities for 15 resource states are found. These posteriors are multiplied by the average size of large and small plays to get the expected amount of oil to be discovered. With such an enormous number of calculations to be performed a detailed FORTRAN program was developed to make the computations (see Appendix A).

4-A. Application of Model to Estimate Undiscovered Petroleum Resources in Brazil

4-A. Petroleum Geology of the Brazilian Sedimentary Basins

The types of basins that occur in Brazil are typical of basins which cover large areas of South America and Africa. Thus an understanding of oil supply from these types of basins will add to an understanding of the potential resources of these two continents.

Two main groups of sedimentary basins exist in Brazil, large onshore cratonic basins and small (partly onshore) marginal basins along the eastern coast and continental shelf. The onshore cratonic basins are the Parana (southern Brazil, 1,200,000 Km^2), the Paraniba (northeast, 600,000 Km^2), the Amazon (north, 1,000,000 Km^2), see Figure 4-7, and the small far western Acre basin. These basins generally consist of Paleozoic sediments 3,500 to 6,000 meters thick and are classified by Klemme as Type 1 (interior) basins. The deepest sediments are continental deposits overlain by Silurian marine rocks in the Amazon and western Parana. Most of these basins are composed of carboniferous marine sediments overlain by continental sediments. The Parana basin is very large in area but is not known to contain large petroleum accumulations. In fact, this type of basin contains only 1 percent of known oil reserves worldwide. These stable basins have had little tectonic movement to form traps for oil, and the geothermal heat flow is not conducive to oil formation. Parana contains some sub-commercial oil deposits, and a small gas has recently been discovered in the Amazon (the Jurua field).

Petrobras (the Brazilian state oil company) had hoped that the Acre

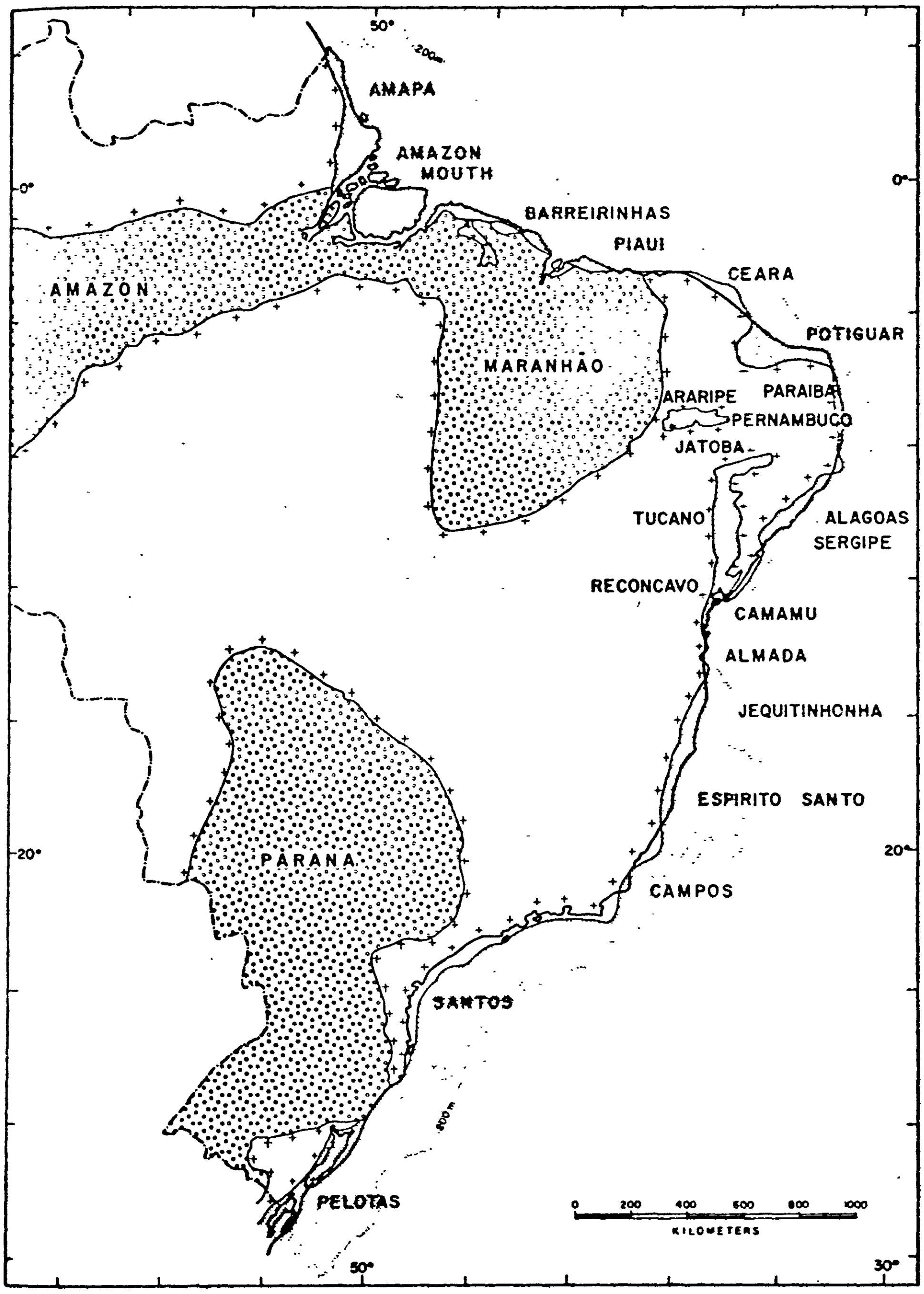


Fig. 47 Index map of the sedimentary basins of Brazil. Open circles – Paleozoic basins; small dots – Mesozoic-Cenozoic basins (after Ponte and Asmus, 1978).

basin, in far western Brazil, was an extension of oil-breaing structures in Peru, but exploration has shown the sediments to be too thick and the structures found to consist of non-oil-bearing precambrian ridges. Although exploration is incomplete in these large onshore basins, it is unlikely that large commercial petroleum fields will be found.

The petroleum potential is more encouraging in the marginal rift (type 2) and continental margin (type 5) basins, which lie both offshore and onshore. These basins formed when South America pulled apart from Africa, leaving several sediment-filled rift valleys. The deepest sediments are continential in nature, overlain by evaporites which themselves are overlain by limestone and shallow marine sediments. Figure 4-8 is a map of offshore marginal basins. Evaporites and some salt diapirs with subsidence structures, as well as limestone deposits, occur largely along the northeast and the southern coasts (evaporites are not present along the north coast). These structures and sediment types increase the probability of the presence of oil formation in these continential margin basins. The formation of horsts and tilted fault blocks allowed trapping of hydrocarbons generated by shale source rocks of lower Cretaceous age with reservoirs in upper Jurassic sandstones.

The major marginal basis are the Reconcavo, Campos and Sergipe-Alagoas basins. The Reconcavo is a true "rift" (type 3) basin and is mostly onshore. The Campos basin and Lower Cretaceous section of the Sergipe-Alagoas basin are type 5, pull-apart continental margin

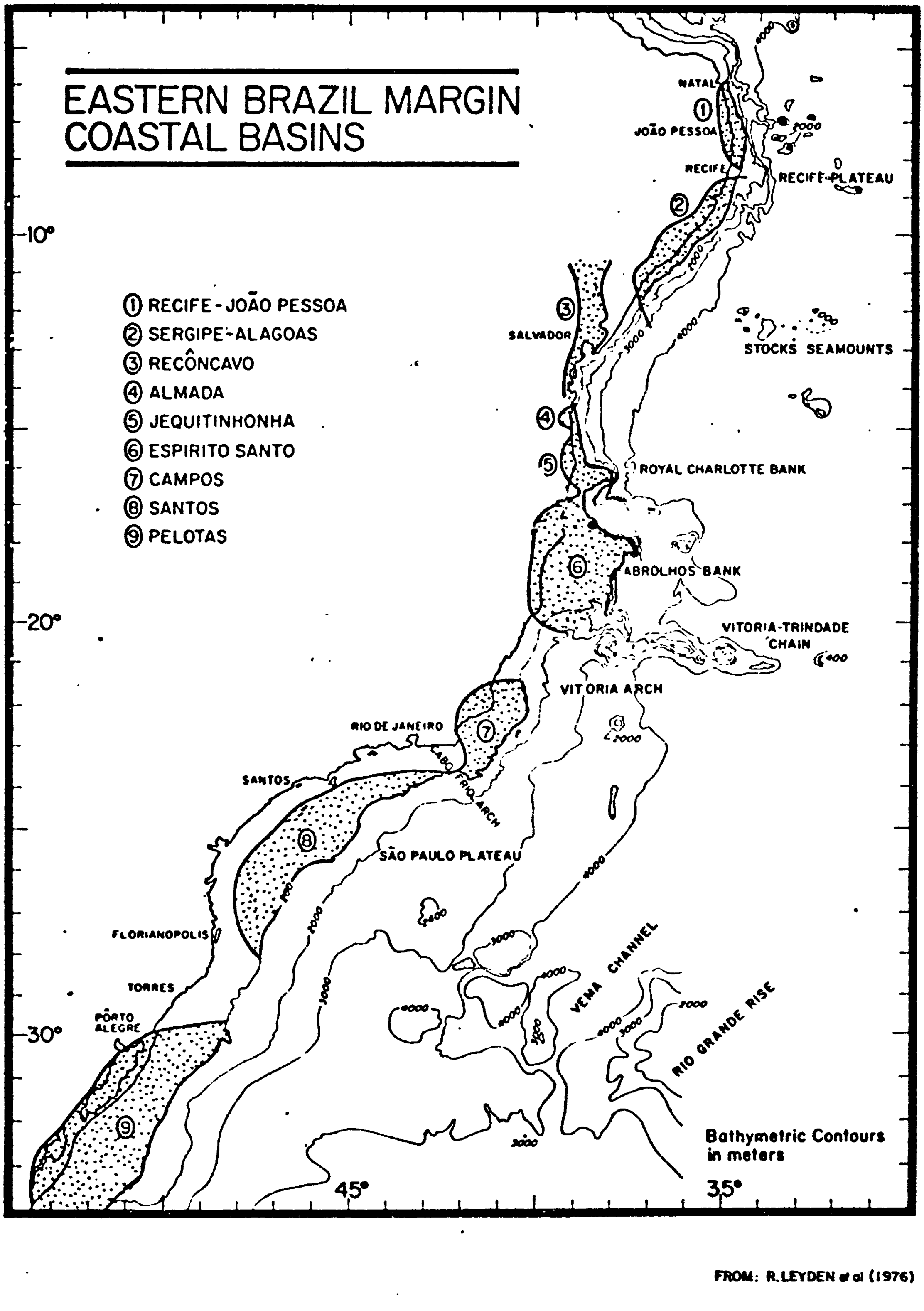


Figure 4-8. Eastern Brazil Margin Coastal Basins.

basins. These three basins are very similar structurally, with the oil occurring mainly in traps above upflifted fault blocks. These three basins contain 85 percent of Brazil's known recoverable reserves, as shown below:

Basin Name	Percent of Known Recoverable Reserves
Reconcavo	53 percent
Campos	32 percent
Sergipe-Alagoas	11 percent
Espirito Santo	2 percent
Potiguar-Ceara	2 percent

The Reconcavo basin is the oldest producing region in Brazil. It is in a mature stage of development. Seven fields, of the 43 total fields, contain 95 percent of the original reserves. Production is declining at 8 percent/year, the secondary recovery techniques are being applied. Oil traps are largely structural traps, and oil is being produced from non-marine reservoir rocks. Approximately two-thirds of the primary recoverable oil has already been produced.

The second major petroleum basin is the recently discovered offshore Campos basin. Oil is found in structural traps related to uplifted blocks. Major fields and recoverable reserves in Campos are: Namorado, Cherne, Pampo, Garoupa and Enchova fields. Proved recoverable reserves of the basin are 540 m bbls with only 6.2 m bbls already produced (as of June 1979). The Namorado field is an unusually large alluvial gravel fan, and it contains 160 million barrels, one-half of the Campos reserves.

The third major petroleum basin is Sergipe Alagoas. The main field is Caromopolis with 186 m bbls of recoverable reserves, about one-half of which has already been produced. Recoverable reserves of the entire basin are 250 m bbls, about half of which has already been produced. Most of the reserves are located in Lower Cretaceous sediments, but four small deposts have been located in Upper Cretaceous and Tertiary turbidite fan sediments.

The remaining marginal basins like the Santos, Pelotas, Espirito Santo and Recife basin are also continental type 5 basins. The north coast basins formed by lateral east-west transform movements. Some very small oil deposits have been found in the eastern Espirito Santo basin, a commercial play in the northern Ceara and Potiguar basins. The last basin type is the Amazon delta, which is a type 8 Tertiary delta with few rollover tectonic structures.

4-B. Estimates of Resources in Undiscovered Fields in Known Plays

The offshore oil producing regions of Brazil can be classified into two similar types. The first type is the Northeast and Sergipe-Alagoas basins both of which are in shallow water (50-100 ft) and have small deposits. The second type is the Campos basin which has several large fields in deep water (400-500 ft). The development costs, as well as platform costs and capital coefficients, for an average field in these two types of basins were given in Chapter 3. A detailed discussion of the calculation of MERS was given in Chapter 3. The MERS was calculated using the optimal rate as well as a lower rate of 10 percent (shown in Table 4-1; calculated in Chapter 3). For current oil prices ($30/bbl) the minimum economic field size for the Campos basin is around 15 million barrels and for the other shallow basins it is around 2 million barrels.

The amount of oil remaining within a known oil play can be approximated with an exponential decay in the field size until the MERS is reached. These calculations were made for the three partially explored plays offshore Brazil (see Table 4-2). Discovery decline in the Campos Basin is shown in Figure 4-9. Regressions were run to explain the expected size of discovery (Sd) as a function of discovery order. The log form of the exponential decay equation is ln(Sd) = K - ad, where K is a constant and a is the decay rate in the field size. Results show the decay in discovery size and show relatively good statistical results given the small number of sample points. The decay rate in field size is found to be 23 to 33 percent. The expected reserves from fields greater than MERS to be discovered in these known plays is calculated to be 170 to 200 million barrels of recoverable oil. Another rough way to calcuate remaining reserves in known plays using the size distribution from Klemme is to multiply the reserves of the largest by 3 to 4 times. Using this rough rule of thumb we get 230 mmb of undiscovered oil which compares well to the result from the exponential decay method (170 to 200 mmb). Although more sophisticated methods than the exponential decay model could be applied, the results from other models would likely project roughly the same expected reserves to be found (170 to 250 million bbls - small by global

Table 4-1 Minimum Economic Reservoir Size for Offshore Brazilian Basins

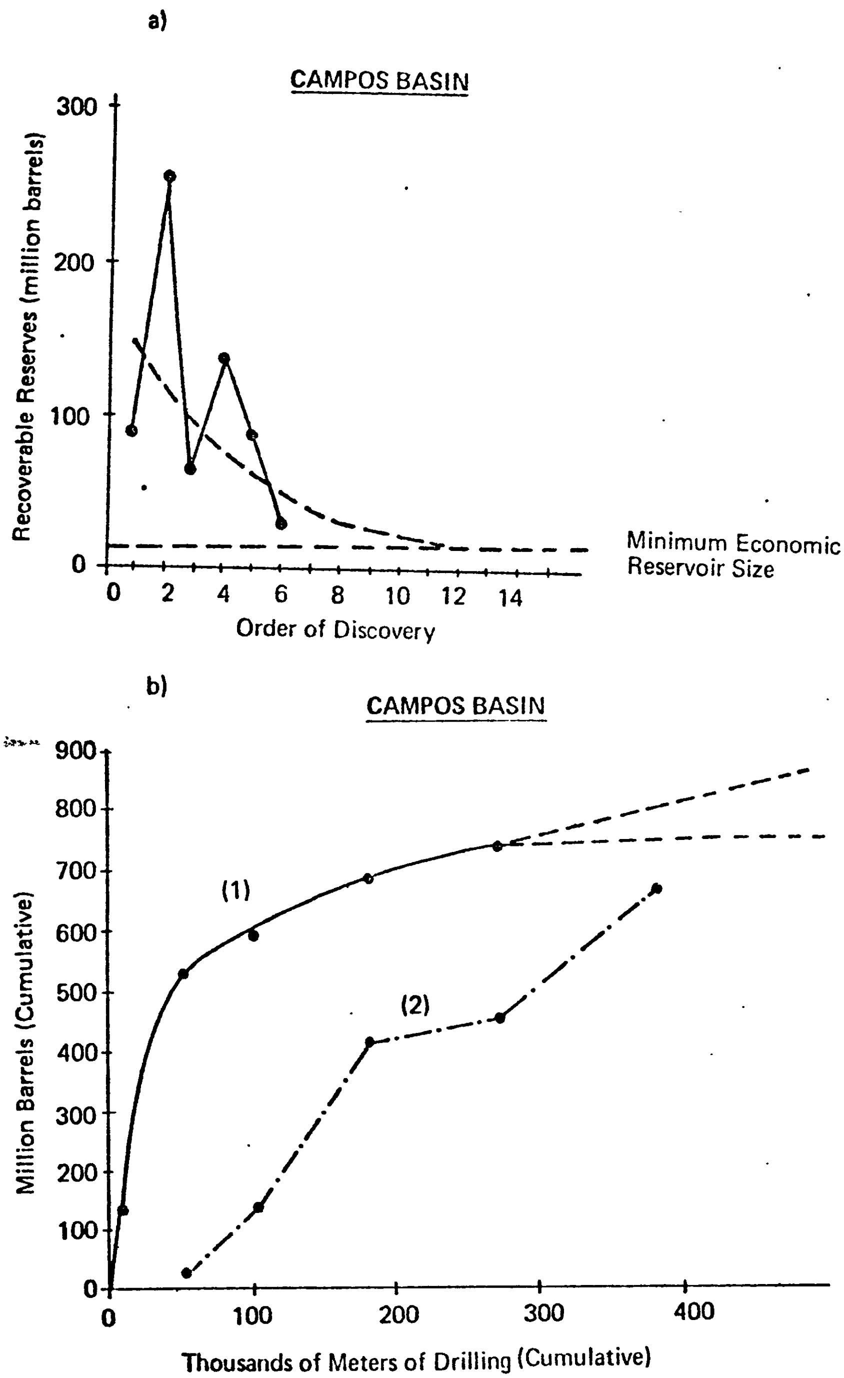
	Northeast and Sergipe-Alagoas basins	Campos basin
Water depth (ft)	50 to 100	350 to 480
Number of platforms per reservoir	1 to 6	1 to 2
Platform cost (million \$ 1980)[a]	2 to 7	45 to 85
Approximate total development cost per reservoir[b] (million \$ 1980, without pipelines)	30 (10 to 60)	250 (200 to 500)
Capital coefficient (I/Q_p in \$/daily bbl)	5000	10,000 (8,000 to 13,000)
MERS at P = \$20/bbl In million barrels[c]	4 (a=.10) 2 ($a=a^*=.29$)	28 (a=.10) 21 ($a=a^*=.17$)
MERS at P = \$30/bbl In million	2 (a=.10) 1.5 ($a=a^*=.39$)	18 (a=.10) 13 ($a=a^*=.24$)
MERS at p = \$40/bbl	1.5 (a=.10) 1 ($a=a^*=.47$)	14 (a=.10) 7 ($a=a^*=.29$)

[a] Offshore, September 1980, "Campos Costs Greater than Expected".

[b] "Scope of Brazilian Effort in Exploration and Production of Hydrocarbon" Petrobras 1978; Offshore September 1980; Economics of Offshore Oil and Gas Supplies, Bock p138. Development cost per reservoir for the Campos basin varies from \$200 to \$500 million, it is estimated that future reservoirs found could be developed at about \$250 million.

[c] MERS is minimum economic reservoir size (in million barrels recoverable oil) given by $R - I\,(a+r)/Pa$, I is total development cost, the discount rate r=.12, optimal decline rate is $a^* = (365Q_p Pr/I)^{1/2} - r$.

Fig. 4-9



(1) Reserves of field assigned to discovery well vs. meters of cumulative exploration drilling.

(2) Campos reserves as reported (note lag in total reserves relative to (1)).

Table 4-2. Expected Sizes of Undiscovered Reservoirs in Known Petroleum Plays in Brazil

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E[Sd] = expected size of deposit d in million barrels recoverable oil

d = order of discovery

MERS = minimum economic reservoir size

Campos Basin, MERS = 15 mill. bbls.

$$\underset{(\text{s.e.})}{\ln (E[Sd])} = \underset{(0.69)}{5.21} - \underset{(0.17)}{0.23d} \qquad R^2 = 0.31$$

$$E[Sd] = 183e^{-0.23d}$$

Expected size of next discovery = $E[S_7]$ = 36 mml. bbls.

Remaining reserves of reservoirs greater than MERS = 120 mill. bbls, 5 reservoirs.

Sergipe-Alagoas Basin (offshore) MERS = 1.5 mill. bbls

$$\underset{(\text{s.e.})}{\ln (E[Sd])} = \underset{(0.56)}{3.58} - \underset{(0.12)}{0.33d} \qquad R^2 = 0.60$$

$$E[Sd] = 35.8e^{-0.33d}$$

Expected size of next discovery = $E[S_8]$ = 3 mill. bbls.

Remaining reserves of reservoirs greater than MERS = 6 mill. bbls, 3 reservoirs.

Northeast Basin, MERS = 1.5 mill. bbls.

$$\underset{(\text{s.e.})}{\ln (E[Sd])} = \underset{(0.38)}{3.7} - \underset{(0.14)}{0.25d} \qquad R^2 = 0.63$$

$$E[Sd] = 40e^{-0.25d}$$

Expected size of next discovery = $D[S_5]$ = 11 mill. bbls.

Remaining reserves of reservoirs greater than MERS = 45 mill. bbls, 9 reservoirs.

standards), since the models assume the largest fields are discovered early in the exploration process and the largest fields found to date are still rather small. The more important question for Brazil is the amount of reserves expected to be found in new plays, since the amount expected to be found in known plays is rather small.

4-C. Relevant Data and Parameters to Estimate Resources in Undiscovered Plays

The goal of this section is to calculate the parameters needed to estimate the expected amount of oil and gas in undiscovered fields in the Brazilian sedimentary basin. The approach that will be use is the Bayesian inference approach developed earlier in the first part of this chapter (Section 3A to 3G). The result of this approach is an estimate of the probability that a certain amount of oil exists conditional on the observed exploration history. This result can be used to estimate the most likely outcome of further exploration drilling and the expected net present value of an exploration program. To use this approach in a region (group of sedimentary basins of similar geologic type), the prior probablity that a resource exists must be obtained as well as the likelihood that the observed exploration history would occur given that the resource exists. The estimation of each of these parameters will be dealt with in turn.

A study of all sedimentary basins around the world by Klemme estimates the probability of finding a commercial oil field and the probability of finding a giant oil field in eight types of geologic basins. The number of basins in Brazil of each type are shown below:

Table 4-3

Type of Basin	Number of basins in Brazil	Probability of Commercial Field	Probability of Giant Field
Continental Margin (5)	7 (all mostly offshore)	0.3	0.2
Delta (8)	1 (offshore)	0.5	~0
Cratonic (1)	4 (all onshore)	0.3	0.2
Rift (3)	1 (onshore)	0.7	0.5

In the case of Brazil the basin types are simple and there is no disagreement among geologists as to the classification of basins in the types shown above. The two largest plays are the Campos and Reconcova. The largest field in each of these basins is only around 260 million bbls so they would be classified as "commercial-field" plays, not "giant field" plays. There are two other commercial-field plays in other basins with total recoverable reserves of 100 to 250 million barrels. Of these 4 plays 3 are offshore in the continental margin type basins. For the moment we will concentrate on calculating parameters for continental margin basins. For the purposes of this model we need the size of a play which is expected to be found. Since we do not know what will be found, we will approimate the average size of a giant-field play by using the average field sizes and reserves of plays in type 5 continental margin type basins from around the world (see Table 4-4). The approximate size of an average giant field play is estimated to be 1330 million bbls. The approximate size of a

Table 4-4

Giant Fields and Producing Fields Worldwide in Passive Continental Margin Type 5 Basins

1) Fields in Basins listed by Klemme (1977)	Total Recovery
Northwest Shelf, Australia	~ 700 (nat. gas liq.) (~ 300) (nat. gas liq.) (250)
Angola-Congo, West Coast Basin	
Malongo W	900
Malongo N-S	600
Emeraude (Congo)	(420)
Loango (Congo)	(300)
Gabon, West Coast	
Grondin	(400)
Brazil, Sergipe-Alagoas Basin	
Carmopolis (onshore)	(185)
Siririzinho (onshore)	(50)
Camorim	(30-40)
Caioba Guariceuma	(20)
2) Additional Giants and Producing Fields (details released after Klemme 1977 article)	
India, West Coast	
Bombay High	1500
Bassoin	450
Brazil, Campos Basin	
Namorado	(260)
Cherne	(~120)
Garoupa	(~80)
Canada, Grand Banks	
Hibernia	1000 total

Source: "Giant Oil Fields of the World", Nehring, 1978 commercial field which is likely to be found offshore Brazil is estimated to be 275 million bbls total reserves. These are average sizes from commercial-field plays in continental margin basins around the world. It could be argued that the average size of a commercial-field play around the world may be somewhat larger than the sizes that remain to be found. A counter argument is that the continental margin basins are largely unexplored and that sizes found so far are representative of average sizes to be discovered. A sensitivity analysis will be performed using a variety of play sizes.

We have already discussed using Klemme's estimates of the probability of play existence in a single basin. We need to use these probabilities in the binomial distribution to get the probability of existence in a group of similar basins. If there is a 0.2 probability of finding a giant-field play in one type 5 basin then binomial probability distribution can be used to calculate the probability of finding exactly one (or two, ...) giant fields in seven type 5 basins, as discussed in Section D. Similar calculations can be made for commercial-field plays. The probabilities of a certain state (e.g., 1 giant-field play and 2 commercial-field plays) occurring in seven basins is found by multiplying the respective binomial probabilities. This is true as long as the correlation of giant-field plays and commercial-field plays is small for the region as a whole. This correlation appears to be small based on the data from the worldwide basin study and classification method used by Klemme. The above binomial calculations provide a series of prior estimates for various resource states which may exist in the region.

The productive area of an oil play is another parameter needed for our model, it is defined to be equal to the sum of the productive areas of all the fields. Table 4-5 shows the productive area of fields in various size classes of fields. The areas of the fields are nearly the same as the areas calculated by Arps and Roberts (1959), also given in Table 4-5. The measured areas can be cross-checked using the fact that the projected area of a sphere is proportional to the volume to the two-thirds power. Indeed, there is an excellent fit using area (Km^2) = 2 (reserves in mill. bbls)$^{2/3}$ for reservoirs from 0.5 to 1.28 million bbls. This relation does not hold as well for larger deposits. This was also pointed out (Haun, 1976) and by Arps and Roberts (1952) who calculate that area (Km^2) = 2.1 (billion bbls.)$^{0.784}$. It appears that ultimate recovery increases slightly faster than areal extent since large deposits have a thicker and higher density oil column. Table 4-5 also gives the areas of oil plays (i.e., a group of fields in close proximity which have a skewed distribution). A billion barrel play such as that in the Reconcavo basin has a productive area of 237 Km^2. This is the area in which an exploration well would actually strike oil. The productive area and the area of the structural trap together are about 450 Km^2. This is the area in which an exploration well would strike oil or obtain a strong indication from structural information that oil is nearby. The productive area of an average commercial-field play is defined as the sum of the field productive areas. The productive play area for an

Table 4-5 Productive Areas of Fields and Plays

Field Size (million bbls recoverable)	Average Size (million bbls)[1]	Calculated Productive Field Area (Km^2)[2]	Previously Calculated Productive Field Area (Km^2)[3]
.5 to 2	1	3	2.3
2 to 8	4	6	5
8 to 32	16	16	16
32 to 128	64	36	37
128 to 512	256	55	n.a.

Giant-Field Play:	Play Size (million bbl recoverable)	Productive Area of Play (Km^2)[4]	Hypothetical Play (million bbl recoverable)	Estimated Play Productive Area (Km^2)
Bombay High Region (India)	1450	810		570 (H)
				380 (M)
Hibernia (Canada)	1000+	200-400 (preliminary data)	1330	280 (L)
Commercial-Field Play:				
Campos Basin (offshore)	670-880	240		
Sergipe-Alagoas (offshore)	330	170		200 (H)
			275	170 (M)
				130 (L)
Northeast Basin (offshore)	110	130		
Reconcavo (onshore rift basin, long expl. history)	1200-1300	237		

[1]Average size is defined as median between ln of field size interval.

[2]Calculated from data on 30 reservoirs in Brazil and Mexico (IIASA World Oil Data Base derived from Petroconsultants Field Records).

[3]Arps and Roberts, 1959.

[4]Productive area of play is defined as sum of field productive areas.

"average" commercial field play with the largest field containing 130 million barrels is approximately 170 Km^2 based on the aress of fields which make up the play. This figure is also approximately equal to the average the known commercial-field plays in Brazil. In the subsequent analysis an average commercial-field play productive area is taken to be 170 Km^2. This productive area could range from a high value of 200 Km^2 to a low value of 130 Km^2 (see Table 5). For a giant-field play the median productive area is calculated to be 380 Km^2 for a play which is an average size giant-field play (based on the areas of fields which make up the play, see data in Tables 4-4 and 4-5). The largest field in this representative play is 700 million barrels. The area might range from a high value area of 570 Km^2 to a low value of 280 Km^2.

Prospective area of a basin is defined as the area where an explorationist would be willing to site exploration wells. The definition here is used in a broad sense. The entire basin area is used except for those areas where potential oil plays are almost certainly not to occur. For offshore basins the shelf areas with very thin sediment cover and extensive volcanic plateaus are not counted. Offshore areas include places where water depth is less than 200 m. Onshore the prospective area is somewhat harder to determine. The basins have an enormous extensive area. Prospective areas for these basins are taken from geologic evaluations by Mesner (1964); Sanford (1960); and Pamplona (1978). These authors define the general areas within the basins which may contain oil. Table 4-6 summarizes basin prospective areas.

Well data are derived from Petrobras publications and the AAPG journal. Type 1 newfield wildcats are used in the model. These wells are defined as all wells up to an including the first discovery of a field in a play. Since only 3 plays have been discovered (in the continental margin basins), great care was taken to review drilling data and eliminate the type 2 new-field wildcats which are clustered in the play to drill for remaining fields in the play. See Annex 4-1 for a listing of wells drilled by basin as listed by Petrobras. Annexes 4-2 through 4-4 give detailed type 1, type 2 and extension well data for the continental margin type basins. Annex 4-7 shows offshore well locations. Detailed well data from the AAPG journal point out that almost all the wells (offshore wells particuarly) were drilled to basement rock. Due to this fact the effect of depth on the discovery process is assumed to be negligible. The well data in these Annexes show that there were 100 type 1 wells drilled by 1975 in the offshore continental margin basins, and 240 drilled by 1980. Thus, the first block of 100 wells discovered 3 "commercial field" plays and the second block of 140 wells found no plays. These are the key data needed for the 2 stage updating process.

At this point we have compiled all the necesary model parameters for the offshore margin basins. Table 4-7 shows a summary of all the key parameters which are used in the FORTRAN computer program to produce the base case results. These parameters are for the seven continental margin type basins, which have a calculated total prospective area of 158,000 Km^2 for regions with water depth down to 200 meters (this composes most of all of the basin area). Prior probabilities on the existence of oil

Table 4-6. Sedimentary Basins of Brazil

Name of Basin	Type of Basin[1]	Prospective Area[2] (km^2)	
Offshore			
Santos	5	45,000	
Campos	5 (100-1,000 mill. bbl. oil field)	21,100	
Espirito Santo	5	15,600	
Bahia	5	15,600	
Sergipe-Alagaos	5 (100-200 mill. bbl. oil field)	14,000	
Potiguar	5 (100-200 mill. bbl. oil field)	21,250	
Barreirinhias	5	26,000	
Amazon Delta	8 (non-commercial gas field)	31,500	
Onshore			
Upper Amazon	1 (gas field)	140,000	
Middle and Lower Amazon	1 (very small oil and gas)	200,000	(middle, 130 lower, 70)
Parnaiba	1	70,000	
Parana	1	145,000	
Reconcavo	3 (1,200 mill. bbl. oil field)	20,000	

[1]Type of basin is based on classification by Klemme (1975).

[2]Prospective area of offshore basins (less than 200 meters water depth) is area of basin minus area of very shallow shelf regions and volcanic plateau of the Espirito Santo shelf. Exploratory area of onshore cratonic basins were taken from geologic evaluations (Mesner, 1964; Sanford, 1960; Pamplona, 1978).

Table 4-7. Summary of Key Data Used for Base Case for Continental Basins (Type 5) in Brazil

Number of basins	7 (offshore)
Total prospective area	158,000 Km^2
Water Depth	0 to 200 meters

	1975 (end)	1980 (end)
Number of exploratory wells drilled		
Type 1 newfield wildcats	100	240
Type 1 + Type 2 newfield wildcats	123	347
Total exploratory wells	147	441

Number of Type 1 wells drilled in first set (i.e. up to end 1975)	100
Number of Type 1 wells drilled in second set (i.e. from 1976 to end 1980)	140

	Giant-Field Plays	Commercial-Field Plays
Prior probability per basin	0.2	0.3
Average size (mmb)	1330	275
Productive area (Km^2)	380(M)	170(M)
Discoveries until end 1975	0	3
Discoveries 1976 until end 1980	0	0

Prior Probabilities on Exploration Efficiency

Efficiency	Prior
1	.25
2	.25
3	.25
4	.25

plays are from Klemme. Prior probabilities on the exploration efficiency are assumed to be equally likely for each efficiency from 1 to 4, as we believe that true efficiency should lie within this broad range. The first set of 100 exploration wells discovered 3 small plays and the second set of 140 wells discovered no plays. These facts allow for the updating process to be completed in two stages. The updating process using these parameters compose the base case. Results and sensitivity analysis is discussed in the next section.

4-5. Estimates of Undiscovered Resources

The model described in the previous sections was applied to the 7 continental margin basins, 1 offshore delta and 4 onshore cratonic basins. The Reconcavo rift basin was not studied because of its very mature stage of development. Since all the recent plays discovered (three total) have been in the continental margin basins the bulk of the modelling effort is devoted to understanding the undiscovered resources in these 7 continent margin offshore basins. The initial prior probabilities for each possible resource state (states for the groups of 7 offshore basins) were multiplied by the prior probabilities on exploration efficiency (equal likelihood for efficiencies 1 through 4). Each of these results were multiplied by the likelihood that the observed exploration history would occur conditional on the resource state being the true state and the exploration efficiency being the true efficiency. The likelihood function is based on a model of exploration represented as areal exhaustion using sampling without replacement. The parameters used to calculate the likelihood function include the play productive area, basin prospective area, number of new field wild cats and observed play discoveries (as discussed in section 3-F). The product of the priors and the likelihoods are normalized according to Bayes Theorem, to sum to one.

The process is repated in a second round using the results from the first round as "priors" for the second round and using likelihoods calculated from observed discoveries of the second block of wells. The final posterior probabilities give the most likely probabilities of oil occurrence and the most likely probabilities of the past exploration efficiency.

The above process was complete for the continental margin basins. The same process was repeated for the deltaic basin and the onshore cratonic basins, but since there were no discoveries observed only a one step updating process was necessary. The model was then used to generate the probabilities of future discovery by calculating the sum of all probabilities which generate a certain discovery pattern (i.e. the unconditional probabilities). These probabilities of future discovery converge to the probabilities of oil occurrence at the point where there are enough exploration wells to exhaust the prospective area.

5-A. Continental Margin Basins

The prior probabilities (derived from priors calculated by Klemme) are dispersed broadly over the 15 possible states for the 7 basins.

They decline generally in value as the number of fields increases as shown in Table 7. Four priors were placed on the exploration efficiency with each efficiency from 1 to 4 equally likely. The posterior probabilities were calculated by updating the prior in two stages, with 3 small plays discovered with the first 100 wells and 0 plays discovered with the next 140 wells. All basic parameters for the calculation were given in Table 4-7 with detailed computer results given in Appendix A. Base case results are derived from the most likely parameter values (Table 4-7) and the most realistic description of the exploration process (model A). Base case results (Table 4-8) show a very significant narrowing of probabilities for various states. For example, the prior probability that no large plays and three small plays are all that exist offshore Brazil was 0.048 (as can be seen from Table 4-8). The posterior probability is 0.479. Since three plays have already been found, this implies that there is a 48 percent chance no more will be found. This together with the other results shown in Table 4-8 imply that there is a 48 percent chance no more plays exist, a 33 percent one small play exists, a 13 percent chance 2 more small plays exist and a 2 percent chance one large play exists.

The prior probabilities on exploration efficiency are 0.25 for each efficiency from 1 to 4. The posterior probabilities on the exploration efficiency focus on the higher values, with an 80 percent chance of the exploration efficiency being 3 or 4. This reflects the information incorporated in the fact that 3 plays were discovered quickly and no more discovered with the second block of wells. These results indicate

METHODS FOR THE ECONOMIC
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Table 4-8 Prior and Posterior Probabilities for Resource States in Continental Margin Basins Offshore Brazil

State[1] no. of large plays	no. of small plays	Prior Probability[2]	Posterior Probability Base Case (Model A)[3]	Posterior Probability (Model B)[4]
0	3	.048	.479	.797
0	4	.020	.334	.146
0	5	.005	.129	.033
1	3	.083	.023	.006
1	4	.036	.028	.008
1	5	.009	.012	.004
2	3	.062	.006	.002
2	4	.027	.007	.002
2	5	.007	.004	.001
3	3	.026	.002	<.001
3	4	.011	.002	<.001
3	5	.003	.001	<.001
4	3	.007	<.001	<.001
4	4	.003	<.001	<.001
4	5	.001	<.001	<.001
Exploration Efficiency				
1		.25	.04	.05
2		.25	.16	.13
3		.25	.28	.31
4		.25	.52	.51

---

[1]A large play is defined as a play with at least one giant field (giant-field play). Average play size is 1330 million bbls (all fields). A small play is a commercial-field play (with average size 275 million bbls).

[2]Prior probabilities are for the seven continental margin basins. These probabilities are generated from Klemme's estimate for an average continental margin basin (.2 probability of a giant-field play and a .3 probability of a commercial-field play per basin). Priors for states with fewer than 3 small plays are not shown, likelihoods for these states are zero.

[3]Model A assumes a play composed of 5 major fields dispersed over region that is 5 times greater than the productive area of the play.

[4]Model B assumes that a play is a single unit (not dispersed).

that it is 14 times more likely that the exploration process has been efficient (with an efficiency of 4 and implying little oil remaining to be found) as opposed to inefficient exploration (with an efficiency of 1 implying large amounts of oil may remain to be found). The expected amount of oil remaining to be discovered can be calculated using the average expected sizes of the oil plays (1330) million bbls for a large play, 275 million bbls for a small play). The expected amount of oil to be found in the continental margin basins is 250 million bbls.

Base case results just discussed are for model A, which assumes a play is composed of 5 major fields dispersed over an area 5 times greater than the productive area of the play. This represents an average play as observed from Petroconsultants data. Exploration for this type of play is a more realistic description of the exploration process. Model B (results also shown in Table 4-8) is a simpler model where a play is one continuous unit. As can be seen expected probabilities of additional oil are smaller, reflecting the fact that exploration wells exhaust more area in model B than model A. Model B was included to give some idea of the sensitivity of the results to continuous play model as opposed to a dispersed play model, but for the remainder of the analysis the more realistic dispersed play model (A) will be used.

In order to test the sensitivity of the results of model A to changes in various parameters, 12 different sensitivity analyses were run on the computer. The results are shown in Table 4-9. In all the cases the posterior on the efficiency of exploration strongly indicates

Table 4-9

State: no. of large plays	State: no. of small plays	Base Case A1	Case A2 (deposit sizes down 30 percent)	Case A3 (prospective area up 20 percent)	Case A4 (prospective area down 20 percent)
0	3	.48	.48	.39	.62
0	4	.33	.33	.35	.27
0	5	.13	.13	.10	.06
1	3	.02	.02	.03	.03
1	4	.03	.03	.02	.01
1	5	.01	.01	.02	.01
Exploration Efficiency					
1		.03	.04	.05	.04
2		.16	.16	.17	.14
3		.28	.28	.29	.30
4		.52	.52	.50	.52
E[Amt] (mmb)		250	172	331	156
E(Amt], next 50 wells		64	45	70	65
E[Amt], next 100 wells		125	88	127	90
E[Amt], next 200 wells		176	124	224	121
E[Amt], next 500 wells		237	167	307	150

Table 4-9 (cont.)

State: no. of large plays	State: no. of small plays	Case A5 (if a play is extension of onshore play)[1]	Case A6 (if 1 large and 2 small discovered)	Case A7 (prior on eff. changed)[2]	Case A8 (prior on state down 50 percent)
0	3	.48	.40	.44	.66
0	4	.32	.35	.36	.26
0	5	.09	.18	.10	.04
1	3	.02	.03	.03	.02
1	4	.02	.02	.03	.01
1	5	.01	.01	.02	.01
Exploration Efficiency					
1		.04	.04	.03	.02
2		.16	.17	.23	.12
3		.28	.27	.41	.28
4		.52	.50	.33	.58
E[Amt] (mmb)		241	318	275	130
E(Amt], next 50 wells		58	93	69	33
E[Amt], next 100 wells		115	180	131	66
E[Amt], next 200 wells		88	242	192	95
E[Amt], next 500 wells		229	306	268	122

[1]Sergipe-Alagoas might be considered extension of onshore play, in this case additinal area and additional onshore wells are added to the base case parameters.

[2]Prior on efficiency set at p = .1 (for e = 1), p = .4 (for e = 2), p = .4 (for e = 3), p = .1 (for e = 4).

Table 4-9 (cont.)

State: no. of large plays	State: no. of small plays	Case A9 (prior on state up 50 percent)	Case A10 (both play areas up 25 percent)	Case A11 (both play areas down 25 percent	Case A12 (prior for giant .1 commercial .3)
0	3	.32	.78	.27	.70
0	4	.34	.13	.25	.23
0	5	.15	.04	.11	.06
1	3	.03	.02	.12	.004
1	4	.04	.02	.13	.007
1	5	.02	.01	.05	.002
Exploration Efficiency					
1		.09	.05	.03	.03
2		.21	.15	.16	.18
3		.26	.29	.33	.36
4		.44	.51	.48	.43
E[Amt] (mmb)		447	112	592	110
E(Amt], next 50 wells		115	41	136	32
E[Amt], next 100 wells		221	58	235	60
E[Amt], next 200 wells		304	88	400	90
E[Amt], next 500 wells		426	107	565	100

that exploration has been efficient, 3 to 4 times that of random drilling. The expected amount of oil remaining to be discovered varies from 90 to 330 mmb for 10 of the cases and in the 400 to 600 mmb range for 2 cases. The reasons why higher expected amounts may occur are when prior probabilities are 50 percent higher or if the average productive areas of plays are reduced 25 percent. For the average areas of all plays to be lower means that remaining play areas be substantially smaller than those found. Although this event is unlikely, it cannot be ruled out (stranger occurrences have happened in oil exploration). There are, however, several strong reasons to believe that the expected amount to be discovered is in the 100 to 300 mmb range (i.e the range of the base case and 10 of the 12 sensitivity analyses).

1) Average size (mmb) of remaining plays in this basin type may be smaller than average sizes of already discovered plays.

2) Exploration may indeed be more efficient than the 3 to 4 range calculated due to improved technology and high cost of offshore drilling. This would imply little remaining to be found.

3) This model assumes that the exploration efficiency is constant over the exploration period. It may indeed be the case that exploration efficiency changes, but if it changes, it is more likely to increase (rather than decrease) as the technology improves and geologic environments become better understood. If the efficiency increases over time, this implies there is less undiscovered oil remaining than predicted by the constant efficiency model.

4) If it is believed that the priors on the state are too high, or

if the prospective area is actually smaller or if play areas larger, then little oil remains to be discovered. Here is a strong possibility that geologists who are experts on Brazilian Basins would reduce the prospective area and may believe priors are somewhat high.

Given all the uncertainties involved the plain fact that all the various sensitivity analyses produce results in the rather narrow range of 100 to 600 mmb is encouraging for the validity of the model. This amount of oil is small by global standards. But to look at the expected value of oil remaining to be found can itself be misleading. It is more useful to look at the probabilities calculated. For most all the cases there is a 50 percent chance nothing remains to be found, 33 percent chance one small play remains, 13 percent chance 2 small plays remain and 4 percent chance a giant-field play remains.

The results indicate that exploration by Petrobras has been relatively efficient and the majority of offshore oil has been found. This has some valuable policy implications for Petrobras. Petrobras is in a dilemma if it claims to be efficient in oil exploration and simultaneously claims that large undiscovered fields remain to be discovered. The extensive exploration program Petrobras has undertaken has served to reduce the uncertainty surrounding the resource base and thus reduce their bargaining strength with major oil companies interested in exploration risk contracts. (More analysis of this problem will be done later.)

The analysis of oil resources in the Amazon delta and onshore basins is somewhat simpler since no plays have been discovered. Deltas typically contain numerous small oil fields instead of a skewed distribution. Given that 57 wells have not located a single oil deposit the model implies only an 11 percent chance of 650 mmbs (see Annex 4-5). Onshore basins are enormous in area and the chances are 80 percent that hydrocarbons are gas (instead of oil). The model projects a 15 percent chance of 250 mmb and a 10 percent chance of 1400 mmb with discoveries slow to be found due to the large areas involved (see Annex 4-6).

A summary of all production reserve and resource data is compiled in Table 4-10. Cumulative production has been 1051 mmb (6/79) and remaining proved and probable reserves are 1467 mmb. This study calculates 176 mmb left to be discovered in fields in known plays and 500 mmb expected to be found in new plays (with a range from 0 to 1600 mmb). The results from this study are compared to other available resource estimates for Brazil, in Table 4-11. The results from this study compare reasonably well (within 3 percent) to industry estimates provided in Adelman-Paddock (1979). This study estimates 1817 mmb onshore and 1377 offshore. The industry estimates are 1700 onshore and 1600 offshore. World Energy Report (1980) estimates are based heavily on Brazilian government estimates are put at 4546 mmb total resources.

Table 4-10 Summary of Production, Reserve and Resource Data for Brazil (million bbls)

Region	Cumu-lative Production 6/79	Proved Recover-able Reserves 6/79	Remaining Proved + Probable Recoverable Reserves	Estimate of Resources in Fields in Known Plays	Estimate of Resources in in Undis-covered Plays
Reconcavo (onshore)	870	445	475	5	
Segipe-Alagoas					
onshore	129	141	150	6	
offshore	41	50	95		
Northeast Basin (oofshore)	5	49	87	45	
Campos Basin	6	541	660	120	
Other					
Continental Margin Basins (offshore)				.48 chance of 0 .33 chance of 275 .13 chance of 550 .05 chance of 1605 E(V) = 245	
Amazon Delta (offshore)				.89 chance of 0 .11 chance of 650 E(V) = 67	
Onshore Cratonic Basins				.75 chance of 0 .15 chance of 250 .10 chance of 1400 E(V) = 188	
Totals	1051	1226	1467	176	500
Total Production, Reserves and Resources	3194	onshore-1817 offshore 1377			

Source: Cumulative production and proved reserves from Petrobras; proved and probable reserves from IIASA world oil database based on Petroconsultants data; resource estimates calculated in this study.

Table 4-10 Comparison of Alternative Estimates of Oil Reserves and Resources in Brazil (million barrels)

Gray (1981, this study):	
Cumulative Production (6/79)	1051
Proved Recoverable Reserves (6/79)	1226
Probable Reserves	241
Resources from Undiscovered Fields in Known Plays	176
Expected Resources in Undiscovered Plays	533
TOTAL	3194
	(1817 onshore,
	1377 offshore)
Adelman and Paddock (1980):	
Cumulative Production (1975)	900
Proved Reserves (1975)	700
Total Ultimate Discoverable	3300
	(1700 onshore,
	1600 offshore)
World Energy Conference (1980):	
Cumulative Production (1978)	1031
Proved Reserves (1978)	1140
Estimated Additional Resources	
- Known Petroleum Regions	1818
- Other Regions	557
	4546

4-7. Application of Model to Project the Probability of Future Oil Discoveries as a Function of Future Exploration Wells.

In the previous sections historical discovery data were used to estimate the probabilities that a certain resource state and a certain exploration efficiency were the true underlying state of nature. In this section the model was run for blocks of future exploration wells using the base case results. The new discovery likelihoods were multiplied by each of the state probabilities and the results added to produce the "unconditional" probabilities for all the various possible future discoveries. The results for the offshore marginal basins are given in Table 4-11. As can be seen from the Table, the probability that 100 more wells (type 1 wildcats) will discover 1 small play is 0.26, and a 0.68 chance that no plays will be found. As more and more wells are drilled, the prospective area becomes exhausted and the probabilities eventually equal the base case posterior probabilities calculated earlier (in Tables 4-7 and 4-8). In the case of the offshore marginal basins, 500 more wells "exhaust" the prospective area. An expected amount of oil discovered can then be calculated for each level of future exploration (as shown earlier in the sensitivity analysis in Table 4-8).

The rate at which oil is expected to be discovered is important information for evaluating an exploration program. The returns to exploration diminish rather rapidly for the offshore marginal basins (Table 4-11). Returns are greater for 500 to 200 wells as compared to 200 to 500 wells.

Table 4-11 Probabilities of Discovery of Oil Plays Offshore Brazil[1]

Number of Wells[2]	No Plays	Probability of discovery of: 1 small play (~ 275 mmb)[3]	2 small plays (~ 550 mmb)	1 large and 1 small play (~ 1330 + 275 mmb)
100	.68	.26	.04	.02
200	.56	.32	.09	.03
300	.53	.32	.11	.04
400	.50	.33	.12	.05
500	.48	.33	.13	.05

[1]These are the probabilities of new plays discovered in all continental margin basins of Brazil, which includes all basins except the Amazon delta.

[2]Wells are type 1 wildcat wells exploring for unknown plays, which do not include wildcat wells exploring for new fields in the immediate vicinity of know oil plays.

[3]The average size of small (commercial field) plays is estimated to be 275 mmb, and 1330 mmb the average size of large (giant field) plays in this geologic type of basin.

The probabilities of discovery as a function of future exploration wells for the onshore cratonic basins are given in Table 4-12. The returns to exploration onshore diminish rather slowly, but the number of wells required is very large (1200 wells to "exhaust" the prospective area). This is due to the enormously large basin areas to explore. This was calculated using an assumed exploration efficiency of 3 (using the efficiency of offshore basins, 3-4, as a guide). Since no oil plays in cratonic basins have been found, the two-stage updating procedure was unable to refine our prior estimate of efficiency. The efficiency in onshore basins may be higher for structural traps than stratigraphic traps, and if the overall efficiency is greater than 3, the rate of expected discovery would be somewhat grater than shown in Table 4-12.

The probability of oil discovery in the Amazon delta is shown in Table 4-13. It is assumed here that if there is any oil found in the delta it will be found in one play which consists of roughly 10 fields of equal size. Deltas typically contain more uniform field size distributions than other basins. The example probabilities in Table 4-13 are the probabilities of discovery of a certain number of fields. As the number of wells drilled approaches 300 the probability approaches 1 that all 10 fields will be found conditional on one play existing. The probability that one play exists in the light of past dry holes, however, was estimated earlier in this chapter to be only 0.11.

Table 4-12 Probabilities of Discovery of Oil Plays in the Onshore Cratonic Basins[1] of Brazil

Number of Wells	Probability of Discovery of: No Plays (0 mmb)	1 Small Play (~ 250 mmb)	1 Large and 1 Small Play (1250-1400 mmb)
100	0.93	0.04	0.025
500	0.81	0.12	0.07
1000	0.76	0.14	0.09
1200	0.75	0.15	0.10

[1]Onshore cratonic basins are the Amazon, Maranhao and Parana basins. These probabilities were calculated with the model and basic parameters from Annex 4-6.

Table 4-13 Probability of Discovery of Oil in the Amazon Delta,[1] Offshore Brazil

Number of Wells	Probability of Discovery of: No plays or fields (0 mmb)	One oil play	Number of fields found
50	0.98	0.02	2 (~ 130 mmb)
100	0.95	0.05	3 (~ 165 mmb)
200	0.92	0.08	6 (~ 390 mmb)
300	0.89	0.11	10 (~ 650 mmb)

[1]A delta, if it contains any oil is expected to have one play wih fields of roughly equal size. Here it is assumed that if oil is found, up to 10 fields of average size (65 mmb per field based on average sizes worldwide-- Nehring) may be discovered. Probabilities were calculated from model and parameters shown in Annex 4-5.

The probabilities of oil discovery for the groups of basins shown in the previous three tables are calculated for various blocks of future exploration wells. An equivalent method of calculating the expected value of future exploration is to assume 100 more wells are drilled and recalculate the posterior probabilities for each possible outcome. The results from this approach are shown in in Table 4-14 (for the offshore marginal basins). The probabilities of discovery with 100 additional wells (i.e. 200 wells total) are calculated conditional on the outcome of the first 100 wells. By folding back this probability tree, the expected value for 200 wells (mmb discovered) is the same as calculated by the first method. This form of presenting the probabilities does have advantages for decision makers in formulating an exploration strategy, once costs and benefits are attached the various options can be weighed. Since exploration is sequential in nature it can be stopped at any point. This approach allows a decision maker to formulate plans, such as - If 100 more wells produce no discoveries, exploration will be stopped, if 100 more wells find one small play, exploration will be continued, etc. The next chapter will use the probabilities (Tables 4-11, 4-12, 4-13) and conditional probabilities (Table 4-14) to calculate net present values and strategies for exploration programs.

At this point it is useful to summarize the expected rate of oil discovery for the various basin groups in Brazil, as shown in Table 4-15. These are expected amounts but previous Tables give a more accurate picture of the skewed distribution of possible outcomes. In

Table 4-14 Conditional Probabilities of Oil Play Discovery in Offshore Marginal Basins in Brazil

Number of wells	Probability of Discovery of: No plays	1 small play (~275 mmb)	2 small plays (~550 mmb)	1 large play (~1330 mmb)
100	.68	.26	.04	.02

Conditional on plays discovered with first 100 wells	After 100 wells drilled, conditional probabilities of discovery with 100 additional wells (i.e. 200 total) are: No Plays	1 small play	2 small plays	1 large play
No plays discovered	.83	.14	.027	.003
One small discovered	.89	.10	.006	.001
Two small discovered	.995	.004	.0005	.001
One large discovered	.825	.135	.026	.007

Table 4-15 Summary of Expected Amount of Oil (million bbls) to be Discovered as a Function of Wildcat Exploration Wells (cumulative wells and cumulative amounts)

1. Offshore - Continental Margin Basins

Undiscovered Plays[1]		Undiscovered Fields in Known Plays[2]	
Wells(type 1)	Amount(mmb)	Wells(type 2)	Amount(mmb)
50	64	30	72
100	125	60	112
200	176	80	133
500	237		

2. Offshore - Amazon Delta

Undiscovered Plays[1]	
Wells(type 1)	Amount(mmb)
50	3
100	10
200	32
300	72

3. Onshore - Cratonic Basins

Undiscovered Plays[1]	
Wells(type 2)	Amount(mmb)
100	47
500	130
1000	170
1200	180

[1] From Tables 4-11, 4-12, 4-13.

[2] 90 percent in Campos Basin, 10 percent in Northeast and S-A Basin. Calculated from discovery rate trends in Figure 4-9.

order to translate these results into a meaningful geologic and economic evaluation, costs and benefits must be assessed and then discounted at the appropriate cost of capital. This is the subject of the next chapter.

ANNEXES

Listing of Oil Wells Drilled in Brazil up to April 30, 1979

	Basin	Wildcats	Extention & Development	Total drilled in meters
	Acre	11	—	25,384
	Upper Amazonas	20	—	32,558
	Middle and Lower Amazonas	126	—	232,419
	Marajó	14	—	31,125
	Bragança—Vizeu	2	—	4,168
	São Luiz	13	—	26,842
O	Barreirinhas	58	—	137,013
N	Maranhão	24	—	47,999
S	Potiguar	5	—	7,280
H	Coastline PB/PE	1	—	406
O	Sergipe — Alagoas	420	741	1,231,817
R	Jatobá	2	—	3,586
E	Tucano North	2	—	8,366
	Tucano Central	13	—	30,950
	Tucano South	79	15	196,982
	Recôncavo	710	2,208	3,529,575
	Almada	3	—	4,160
	Jequitinhonha	3	—	12,005
	Cumuruxatiba	3	—	4,030
	Mucuri	1	—	590
	Espírito Santo	77	27	194,421
	Campos	1	—	2,620
	Paraná	71	—	163,489
	Pantanal — MT	12	—	2,624
	Pelotas	7	—	3,570
Onshore total		1,678	2,991	5,933,979
	Amapá/Pará	36	—	122,546
	Barreirinhas	8	—	21,531
	Piauí/Ceará	32	—	78,986
O	Potiguar	31	24	133,481
F	Sergipe/Alagoas	98	83	383,676
F	Recôncavo	7	—	14,375
S	Camamu	2	—	6,945
H	Almada	6	—	14,416
O	Jequitinhonha	6	—	18,855
R	Cumuruxatiba	24	—	70,263
E	Mucuri	3	—	7,581
	Espírito Santo	35	—	113,332
	RJ — Campos	112	8	342,047
	SP/PR — Santos	10	—	32,793
	Pelotas	1	—	5,200
Offshore total		411	115	1,366,027

Source: Petrobrás — DEPEX.

Annex 4-2

Exploratory Wells Drilled in Continential Margin
Type Basins Offshore Brazil (by end 1975)

	New-Field Wildcats		Total Exploratory Wells[1]
	Type 1	Type 1 + Type 2	
Campos Basin	~16	25	29
Sergipe-Alagaos Basin	~18	30	50
Northeast Basin (Ceara and Potiguar)	~10	12	12
Other Basins[2]	~56	56	56
Total	~100	123	147

[1]New-field wildcats plus new-pool tests plus extension wells.

[2]Other includes all remaining offshore basins except Amazon Delta

Source: Derived from data from Brazil Energy (Dec. 5, 1979), APPG World Development Issues (1968-1979).

Annex 4-3

Exploratory Wells Drilled in Continential Margin
Type Basins Offshore Brazil (by end May 1979)

	New-Field Wildcats Type 1	New-Field Wildcats Type 1 + Type 2	Total Exploratory Wells[1]
Campos Basin	~30	75	112
Sergipe-Alagaos Basin	~35	70	98
Northeast Basin (Ceara and Potiguar)	~24	35	40
Other Basins[2]	~94	94	94
Total	~183	274	344

[1]New-field wildcats plus new-pool tests plus extension wells.

[2]Other includes all remaining offshore basins except Amazon Delta

.

Source: Derived from data from Brazil Energy (Dec. 5, 1979), APPG World Development Issues (1968-1979).

Annex 4-4

Exploratory Wells Drilled in Continental Margin
Type Basins Offshore Brazil (by end 1980)

	New-Field Wildcats Type 1	New-Field Wildcats Type 1 + Type 2	Total Exploratory Wells[1]
Campos Basin	~36	90	142
Sergipe-Alagaos Basin	~35	73	104
Northeast Basin (Ceara and Potiguar)	~34	45	56
Other Basins[2]	~139	139	139
Total	~240	347	441

[1]New-field wildcats plus new-pool tests plus extension wells.

[2]Other includes all remaining offshore basins except Amazon Delta

Source: Derived from data from Brazil Energy (Dec. 5, 1979 and March 24, 1980, August 10, 1980), APPG World Development Issues (1968-1979). Data for 1980 are from estimates of drilling to be completed made in the first six months of 1980.

Annex 4-5

Summary of Key Data for Amazon Delta Offshore Brazil

Number of basins	1 (type 8)
Deposit size distribution	largest field 9-10 percent of total reserves
	appoximately 10 of equal size
Average field size	65 million barrels
Productive area	36 Km^2
Prior probability	0.5 of 10 commercial fields
	0 of any giant fields
Prospective areas	31,500 Km^2 (delta only)
	62,000 Km^2 (delta and surrounding carbonate shelf)
Discoveries (up to end 1980)	0 commercial fields
Wells drilled (up to end 1980)	
By Petrobras	50
By Foreign Oil Companies	11
	61 (57 in delta only)

Likelihood

$L(w = 57, c - 0, e = 3, B = 31{,}500, c_i = 10) =$ .11 chance of 650 mmb

.89 chance of 0 mmb

$E[amt] = .5(.11)(65)(10) = 72$ mmb

Annex 4-6

Summary of Key Data and Results for Onshore Cratonic Basins (Type 1)

Four basins with total prospective area[1] 555,000 Km^2

Probability of large play .1 to .2 per basin (productive are 360 Km^2

small play .2 to .3 per basin[2] (productive area 150 Km^2)

Probability of gas[3] .8, probability of oil .2

Number of newfield wildcats drilled 227, end 1980

Exploration efficiency = 3

Number of oil plays discovered 0

Average size of commercial-field play in type 1 basin 250 mmb

giant field play in type 1 basin 1000 mmb

Results

.75 chance of 0 mmb

.15 chance of 250 mmb E(V) = 188

.10 chance of 1400 mmb

E(Amt. discovered)

100 wells	47 mmb
500 wells	130 mmb
1000 wells	170 mmb

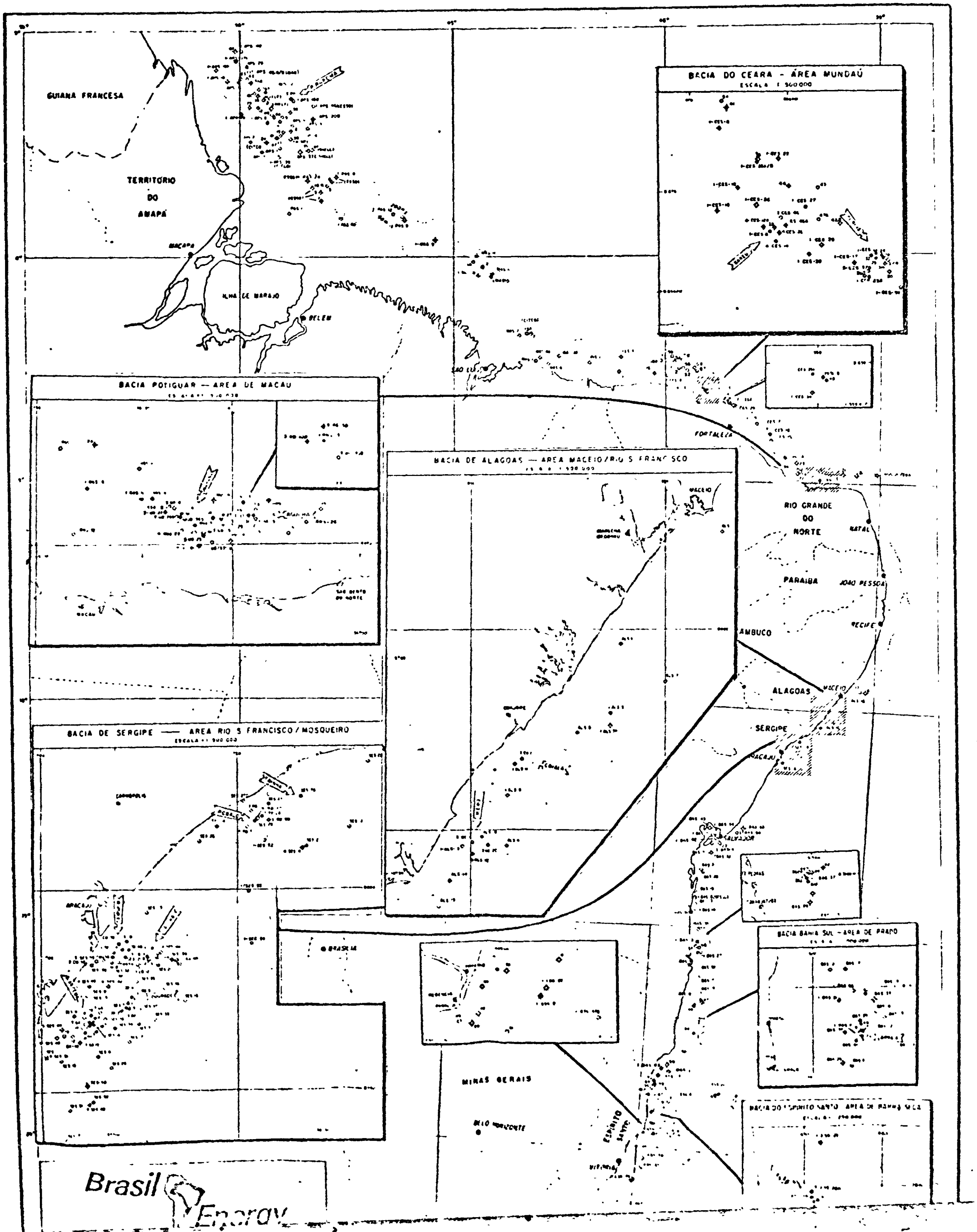
---

[1]From Table 4-6.

[2]From Klemme 1978.

[3]Eighty percent of Paleozoic hydrocarbons are gas. Onshore basins are large Paleozoic and have characteristics more conducive to gas formation, not oil.

Annex 4-7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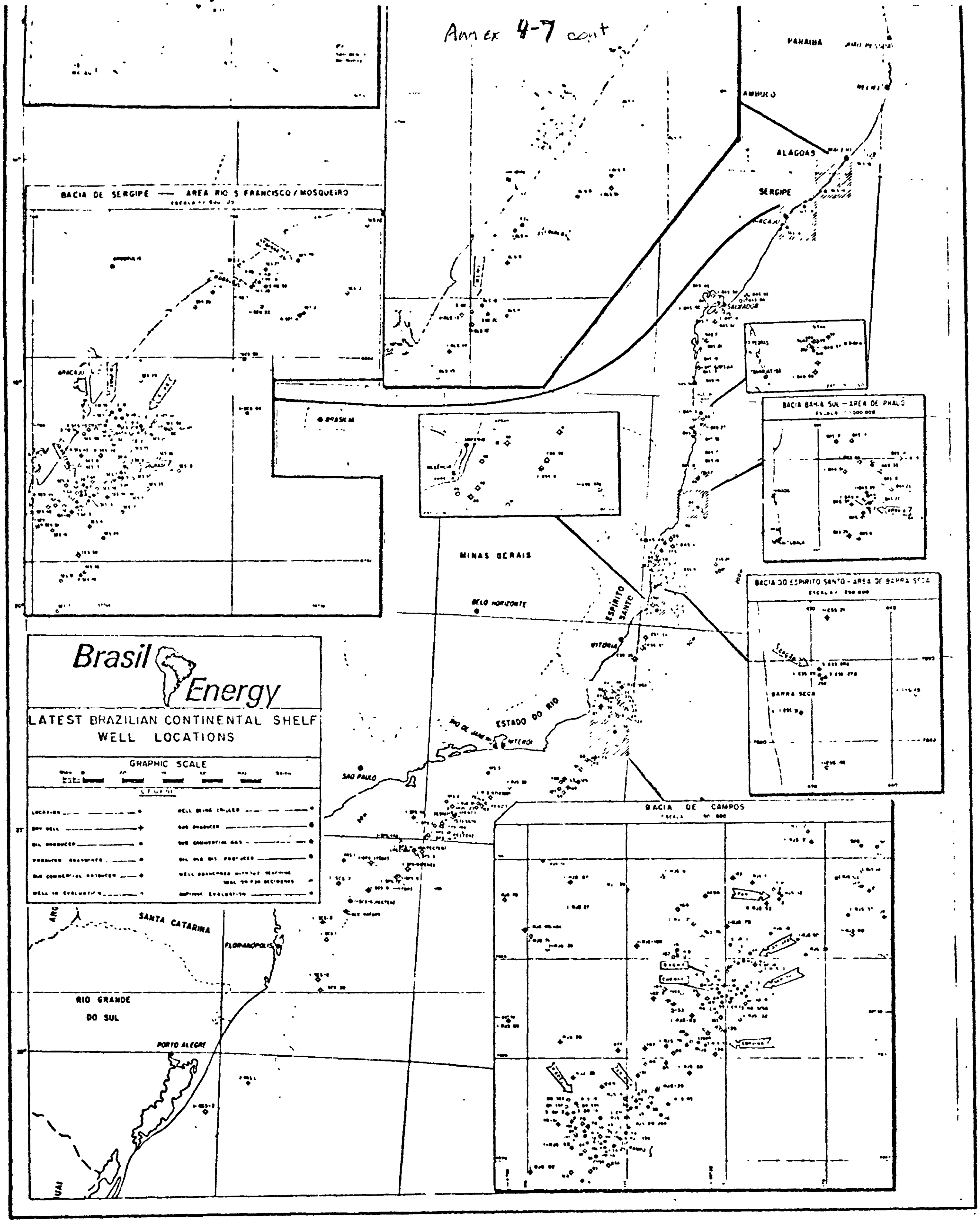
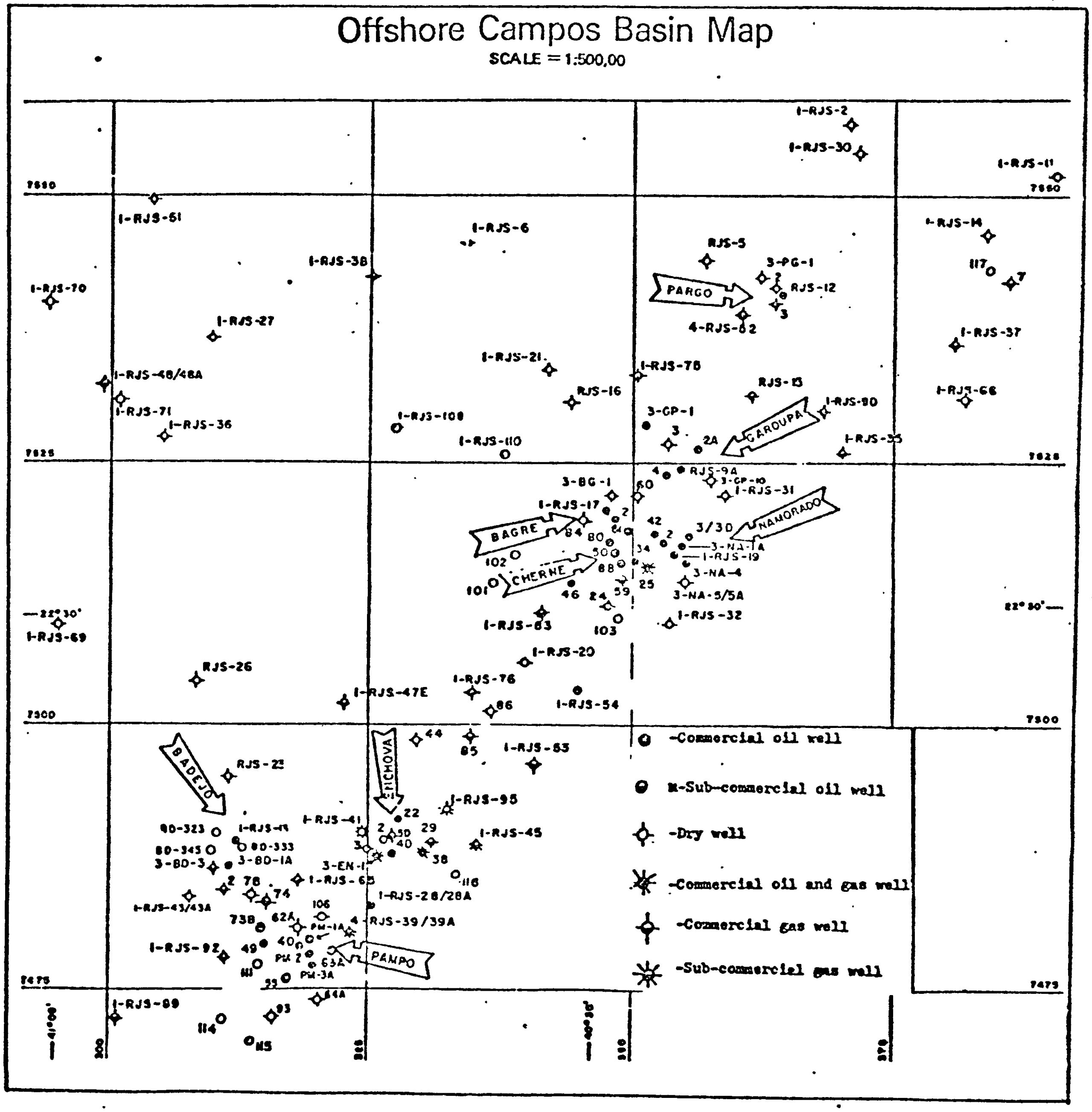
GUIANA FRANCESA
TERRITORIO DO AMAPÁ
MACAPA
ILHA DE MARAJO
BELEM
BACIA POTIGUAR — AREA DE MACAU
FORTALEZA
BACIA DE ALAGOAS — AREA MACEIO/RIO S. FRANCISCO
RIO GRANDE DO NORTE
NATAL
PARAIBA
JOAO PESSOA
RECIFE
ALAGOAS
MACEIO
SERGIPE
ARACAJU
BACIA DE SERGIPE — AREA RIO S FRANCISCO / MOSQUEIRO
SALVADOR
BRASILIA
BACIA BAHIA SUL - AREA DE PRADO
MINAS GERAIS
BELO HORIZONTE
ESPIRITO SANTO
VITORIA
Brasil Energy

Annex 4-7 cont



Annex 4-7 cont.



BRAZIL ENERGY

APPENDIX A – DERIVATION AND DISCUSSION OF LIKELIHOOD CALCULATION AND BAYESIAN UPDATING METHODOLOGY

1) Empirical Approach to Calculate Likelihood

The first is an empirical calculation using exploration data around the world, the second approach makes use of a probabilistic exploration process model. To make an empirical calculation of the number of wells it takes to find a play of a given size the minimum we need to know is the total number of fields in the basin, field size, and the area of the basin. Examples from a few basins are given below:

Offshore Basin	Number of wells until field discovered	Area of Basin Km^2	Field Size (mill. bbls)
Sergipe-Alagaos (Brazil)	2	14,000	~180
Campos (Brazil	18	23,000	~800-1000
Grand Banks (Canada)	41	102,000	~1500-5000 (Hibernia)
Scotia Shelf (Canada)	~18	~45,000	~200

One procedure to calculate the likelihood would be to estimate the number of wells to discovery divided by basin area ($W/B = \lambda$). This could then be used as the mean Poisson "arrival time" of the field discovery where the probability of discovery would be a Poisson distribution

$$p = e^{-\lambda} \left(\frac{\lambda^{W}}{W!}\right).$$

There are several problems with this empirical approach. The exploration process is different onshore vs. offshore and it is different today as compared with the past. If we are trying to model the modern exploration process then data from partially explored basins is truncated because we do not know how many fields will ultimately be found. If we use data from well explored basins (mostly onshore) then these do not give an accurate representation of the modern exploration process (particularly offshore exploration). This empirical approach will be abandoned at this point in favor of a more comprehensive exploration process that is used in this study.

2) Probabilistic Exploration Model to Calculate Likelihood

The second approach is to measure the probability of the observed discovery history occurring given that a certain state of nature exists. In order to do this it is assumed that a field consists of numerous fields in close proximity and similar geologic origin. The productive area of the oil of all the fields in the play is defined to be the productive area of the play. For the moment the play is considered to be one continuous target such that one well (type one exploration well) drilled into the target will discovery the play. It is also assumed that the area that a dry hole exhausts is the area of the target play area

(A_j), which lies within a basin of area B (as shown by Drew and Root, 1978). If we begin with the assumption that exploration can be modelled by random drilling, then the probability of hitting an oil field of area A_j on the first well (H_{1j}) in a basin of area B, conditional on state i (S_i) existing is:

$$p(H_{1j}/S_i) = \frac{n_j A_j}{B}$$

where state S_i consists of n_j plays each of area A_j.

The probability of a dry hole occurring on the first well (D_i) is:

$$p(D_i/S_i) = 1 - \sum_j p(H_{1j}/S_i)$$

The probability of hitting a play of area A_j on the second well, conditional on the first well being dry is:

$$p(H_{2j}/S_1,\ D_1) = \frac{n_jA_j}{B-A_j} = \frac{\text{Area of oil size class } j}{\text{Total Area - area exhausted by first dry well}}$$

Similarly, the probability of the second well being dry, conditional on the first being dry is:

$$p(D_2/S_i,\ D_1) = 1 - \quad p(H_{2j}/S_i\ ,\ D_1) = 1 - \sum_j \frac{n_jA_j}{B-A_j}$$

More generally, the probability of well w being dry, conditional on S_i existing and all previous wells being dry is:

$$p(D_w/S_i,\ D_{w-1}) = 1 - \quad p(H_{wj}/S_i,\ D_{w-1})$$

where,

$$p(H_{wj}/S_i,\ D_{w-1}) = \frac{n_jA_j}{B-(w-1)A_j}$$

These probabilities can be multiplied to give the probability that all wells from 1 to k will be dry:

$$p\left(\begin{matrix}\text{all wells } w=1\\ \text{through K dry}/S_i\end{matrix}\right) = \prod_{w=1}^{k} \left(1 - \sum_j \frac{n_jA_j}{B-wA_j}\right)$$

It also can be expanded to give the probability of any discovery sequence occurring. For example, the probability of k dry wells occurring, then a discovery of size A_i, then M dry wells occurring is:

$$p\left({k \text{ dry}, \atop M \text{ dry}} 1 \text{ size } A_1{}'/S_i\right) = \prod_{w=1}^{k} \left(1 - \sum \frac{n_j A_j}{jB - wA_j}\right) \times \left(\frac{n_1 A_1}{B - KA_1}\right) \times$$

$$\prod_{w=K+1}^{k+1+M} \left(1 - \sum_j \frac{n_j A_j - 1A_1}{B - (k+1+M)A_j}\right)$$

The above formulation gives the likelihood for the discovery sequence occurring conditional on the existence of n_i fields are area A_j.

The approach described above explicitly accounts for sampling without replacement with area being exhausted by both dry wells and discoveries. The exact sequence of dry and wet wells is not usually known but it is usually easy to find out that a certain number of plays were discovered by a specific number of wells (e.g., 3 plays discovered with 1200 type one wildcat exploration wells). The formulation above can be shown to reduce to a hypergeometric distribution which accounts for sampling without replacement. Consider a region of area B where w* wildcat wells (type 1) have discovered g* plays, each of productive area A_T. The likelihood that g* dicoveries would have been found conditional on g_i tagets being the true underlying state is given by the hypergeometric distribution.

$$L(g^*, w^*/g_i, e_i) = \frac{(N - g_i)!}{N!} \frac{w^*!}{(w^* - g^*)!} \frac{(N - w^*)!}{(N - g_i - w^* + g^*)!} \frac{g_i!}{g^*!}$$

N = sample space = $B/e_i A_{tg}$

A_{tg} = productive area of the giant-field play (equal to the sum of all field areas).

e_i = exploration efficiency (random drilling equals one).

w^* = number of wells drilled in region (type 1 new field wildcats).

g^* = number of giant-field plays discovered with w^* wells.

g_i = true number of giant field plays in region.

BASE CASE RESULTS

Model A - Play is defined as productive area A_t. Model A assumes that play is composed of five pieces (fields) dispersed over an area 5 x A_t. Sample space is thus Basin Area/e(.63)A_t.

Updating - Stage 1

0 giant-field plays, 3 commercial-field plays discovered with 100 wells (type 1 newfield wildcats)

Case 1 e = 1
Case 2 e = 2
Case 3 e = 3
Case 4 e = 4

Updating - Stage 2

no plays found in next 140 wells

Case 5 e = 1
Case 6 e = 2
Case 7 e = 3
Case 8 e = 4

Posterior probabilities from Stage 2 are final results

NOTE:

A2 is likelihood of giant-field play discovery conditional on state

A1 is likelihood of commercial-field play discoveries conditional on state

Fields on computer printout actually refer to plays

```
      DIMENSION A(4),PROBA(4,6,6),PRIOR(50),AC(6),APRI(50),PRC(15),
     1PRG(15),APRO(50),POST(50),PRIOR2(50),AX(10)
      DIMENSION W(4),ND(4),SPTL(10),APTL(10,50),APTLF(10,50)
      READ(5,*) B,LOM,WTBD,(A(I),I=1,2),LOM2
      READ(5,*) (AC(IJ),IJ=1,6)
      READ(5,*)(AX(I),I=1,6)
      READ(5,*) BAS,PPG,PPC
      READ(5,*) BADS,SADS,BADS2,SADS2
      READ(5,*) IY,IX,IZ,IW,JN
      READ (5,*) PVB,PVS,PCW,D
    5 FORMAT (1X,6(F4.1,1X))
              AB1=A(1)*1000.
              AB2=A(2)*1000.
              WRITE(6,4) B,AB1,AB2,LOM,BAS,PPG,PPC
    1 FORMAT(1X,F10.3,1X,I3,1X,2(F7.3,1X))
    4 FORMAT(1X,24HAREA OF BASIN(10E03KM2):,F10.3,/,1X,
     139HPRODUCTIVE AREA OF LARGE DEPOSITS(KM2):,F7.3,/,1X,
     239HPRODUCTIVE AREA OF SMALL DEPOSITS(KM2):F7.3,/,1X,
     332HNUMBER OF WELLS ALREADY DRILLED:,2X,I3,/,1X,
     439HNUMBER OF SEDIMENTARY BASINS IN REGION:,1X,F7.3,/,1X,
     541HPRIOR PROBABILITY OF BIG FIELD PER BASIN:,1X,F7.3,/,1X,
     643HPRIOR PROBABILITY OF SMALL FIELD PER BASIN:,1X,F7.3,/)
   50 FORMAT(F10.5)
      ANR=1.
      LP=1
      DO 7 NGFL=1,5
      GFLD=NGFL-1.
      CALL FACT(GFLD,GFT)
      CALL FACTM(BAS,GFLD,GFTM)
      PRG(NGFL)=(GFTM/GFT)*(PPG**GFLD)*
     1((1-PPG)**(BAS-GFLD))
      DO 8 NCFL=1,6
      CFLD=NCFL-1.
      CALL FACT(CFLD,CFT)
      CALL FACTM(BAS,CFLD,CFTM)
      PRC(NCFL)=(CFTM/CFT)*(PPC**CFLD)*
     1((1-PPC)**(BAS-CFLD))
      PRIOR(LP)=PRG(NGFL)*PRC(NCFL)
      PRIOR2(LP)=PRIOR(LP)
      LP=LP+1
    8 CONTINUE
    7 CONTINUE
      NB=0
      ALOMS=LOM
      MD1S=BADS+1
      MD2S=SADS+1
      DO 400 KX=1,2
      IF(KX.EQ.1) GO TO 946
      IF(KX.EQ.2)GO TO 999
  999 DO 937 KZ=1,30
      LOM=LOM2
      BADS=BADS2
      SADS=SADS2
  937 CONTINUE
  946 CONTINUE
```

```
      MD1=BADS+1
              MD2=SADS+1
      ND1=MD1-1
      ND2=MD2-1
      ND(1)=MD1
      ND(2)=MD2
      ND(3)=MD1
      ND(4)=MD2
      A(3)=A(1)
      A(4)=A(2)
      ALOM2=LOM2
      ALOM=LOM
      SMPTL=0
      DO 40  ILM=1,IY
      ABC=ILM*WTBD
      DO 40  IK=1,IX
      C=AC(IK)
      KN=1
      NB=NB+1
      IF(NB.LT.IW)WRITE(6,11) NB,ND1,ND2,C
   11 FORMAT(50X,12HCASE NUMBER:,I3,/,50X,19HALREADY DISCOVERED:,
     1I4,2X,10HBIG FIELDS,/,65X,4HAND:,I4,2X,12HSMALL FIELDS,/,50X,
     223HEXPLORATION EFFICIENCY:,F4.1)
      DO 23  J=1,JN
      IF(KX.EQ.1)AN=B/(C*A(J))
      IF(KX.EQ.2)AN=B/(C*A(J))-ALOMS
      IF(J.EQ.3.OR.J.EQ.4)AN=(B/(C*A(J)))-ALOM-ALOMS
      IF(AN.LT.8.) AN=8.
      AN=AINT(AN)
      IF(J.EQ.3.OR.J.EQ.4) W(J)=ABC
      IF(J.EQ.1.OR.J.EQ.2)W(J)=ALOM
      DES=W(J)
      IF(AN.LT.DES) GO TO 43
      GO TO 44
   43 W(J)=AN
   44 CONTINUE
      DO 23  JK=1,6
      ALD=JK-1.
      DO 23  KL=JK,6
              ALS=KL-1.
      CALL FACTM(AN,ALS.ANS)
      CALL FACTM(W(J),ALD,AOMD)
      ANOM=AN-W(J)
      ALSD=ALS-ALD
      CALL FACTM(ANOM,ALSD,ANSWD)
      CALL FACT(ALSD,ASD)
      CALL FACT(ALS,AS)
      CALL FACT(ALD,AD)
      DIV=AD*ASD*ANS
      PROBA(J,JK,KL)=AOMD*ANSWD*AS/DIV
   23 CONTINUE
   10 FORMAT(15X,E12.5)
      IF(NB.LT.IW)WRITE(6,31)
   31 FORMAT(1X,112(1H-))
      IF(NB.LT.IW)WRITE(6,32)
```

```
32   FORMAT(1X,1H+,2(13H  NUMBER OF +),5X,5HPRIOR,6X,1H+,4X,
    19HA2(W2/A2),3X,1H+,4X,9HA1(W1/A1),3X,1H+,3X,11HPRIOR TIMES,
    22X,1H+,3X,11HPROBABILITY,2X,1H+)
     LW1=INT(W(1))
     LW2=INT(W(2))
     IF(NB.LT.IW)WRITE(6,33) LW1,LW2
33   FORMAT(1X,1H+,26H BIG FIELDS +SMALL FIELDS+,16X,1H+,3X,
    14H(W2=,I4,1H+,4X,1H+,3X,4H(W1=,I4,1H),4X,1H+,3X,
    210HLIKELIHOOD,3X,1H+,2X,10H POSTERIOR,2X,1H+)
     IF(NB.LT.IW)WRITE(6,31)
     SOM=0
     DO 25 LF=MD1S,5
     DO 25 LG=MD2S,6
     KL=6*(LF-1)+LG
     LY=LF-MD1S+1
     LH=LG-MD2S+1
     IF(KX.EQ.1)PRIOR(KL)=PRIOR2(KL)*AX(IK)
     IF(KX.EQ.2)PRIOR(KL)=APTLF(IK,KL)
     IF(KX.EQ.1)APRI(KL)=PRIOR(KL)*PROBA(1,MD1S,LF)*PROBA(2,MD2S,LG)
     IF(KX.EQ.2)APRI(KL)=PRIOR(KL)*PROBA(1,MD1,LY)*PROBA(2,MD2,LH)
     SOM=SOM+APRI(KL)
     SPTL(IK)=SOM
     APTL(IK,KL)=APRI(KL)
25   CONTINUE
     SMPTL=SMPTL+SPTL(IK)
     DO 26 LF=MD1S,5
     DO 26 LG=MD2S,6
     KL=6*(LF-1)+LG
     LY=LF-MD1S+1
     LH=LG-MD2S+1
     APRO(KL)=APRI(KL)/SOM
     KN=KN+1
     KF=LF-1
     KG=LG-1
     IF(NB.LT.IW.AND.KX.EQ.2)WRITE(6,35) KF,KG,PRIOR(KL),
    1PROBA(1,MD1,LY),PROBA(2,MD2,LH),APRI(KL),APRO(KL)
     IF(NB.LT.IW.AND.KX.EQ.1)WRITE(6,35) KF,KG,PRIOR(KL),
    1PROBA(1,MD1S,LF),PROBA(2,MD2S,LG),APRI(KL),APRO(KL)
26   CONTINUE
35   FORMAT(1X,1H+,2(5X,I2,5X,1H+),5(3X,F10.8,3X,1H+))
     IF(NB.LT.IW)WRITE(6,31)
     IF(NB.LT.IW)WRITE(6,36)SOM
36   FORMAT(1X,1H+,2(12X,1H+),2(16X,1H+),5X,5HTOTAL,6X,1H+,3X,F10.8,
    13X,1H+,16X,1H+)
     IF(NB.LT.IW)WRITE(6,38)
40   CONTINUE
     WRITE(6,789)SMPTL
789  FORMAT(34HPRIOR X LIKELIHOOD, POSTERIOR,SUM=,2X,F10.5)
     DO 792 LR=1,IX
     SMDD=0
     WRITE(6,770)AC(LR)
770  FORMAT(13HEXPLOR. EFF.=,2X,F4.1)
     DO 791 LK=MD1S,5
     DO 791 LI=MD2S,6
     LQ=6*(LK-1)+LI
```

```
      APTLF(LR,LQ)=APTL(LR,LQ)/SMPTL
      SMDD=SMDD+APTLF(LR,LQ)
  791 WRITE(6,788) APTL(LR,LQ),APTLF(LR,LQ)
      WRITE(6,709) SMDD
  709 FORMAT(24HPOSTERIOR ON EFFICIENCY=,2X,F10.8)
  788 FORMAT(2(5X,F10.8,5X))
  792 CONTINUE
      GO TO 400
  998 SUMUP=0
      PRODEC=0
      TVL=0
      VARPV=0
      VAR=0
      VARD=0
      SD=0
      IF(NB.LT.IZ)WRITE(6,69)
      IF(NB.LT.IZ)WRITE(6,70)
      IF(NB.LT.IZ)WRITE(6,71)
      IF(NB.LT.IZ)WRITE(6,69)
      DO 66 IL=1,4
      DO 66 IJ=1,5
      NBF=IL-1
      NSF=IJ-1
      DEC=0.+NBF*1600.+NSF*310.
      VL=NBF*PVB+NSF*PVS-(PCW/100.)*ABC
      SUMD=0
      DO 67 LF=IL,4
      DO 67 LG=IJ,5
      KL=5*(LF-1)+LG
      SUMD=SUMD+(PROBA(3,IL,LF)*PROBA(4,IJ,LG)*POST(KL))
   85 FORMAT(3X,6(F10.5,2X))
   67 CONTINUE
      SUMUP=SUMUP+SUMD
      PRODEC=PRODEC+SUMD*DEC
      TVL=TVL+SUMD*VL
      VAR=VAR+(SUMD*((DEC-PRODEC)**2))
      SD=SQRT(VAR)
      VARD=SD**2
      AVL=AINT(VL)
      VARPV=VARPV+(SUMD*((VL-TVL)**2))
      SDPV=SQRT(VARPV)
      IF(NB.LT.IZ)WRITE(6,68) NBF,NSF,SUMD,AVL
   69 FORMAT(30X,61(1H-))
   70 FORMAT(30X,'+ADDITIONAL FIELDS DISCOVERED + PROBABILITY  +  ',
     1'AMOUNT OF OIL+')
   71 FORMAT(30X,1H+,6X,3HBIG,5X,5HSMALL,4X,1H+,14X,1H+,
     11X,12H(10E06 BBLS),1X,1H+)
   68 FORMAT(30X,1H+,2(6X,I2,6X,1H+),2X,F10.5,2X,1H+,1X,F12.3,1X,1H+)
   66 CONTINUE
      IF(NB.LT.IZ)WRITE(6,69)
      IF(NB.LT.IZ)WRITE(6,72)SUMUP
      IF(NB.LT.IZ)WRITE(6,69)
      PRODEC=PRODEC
      NABC=ABC
      VARD=VARD
```

```
      TVL=TVL
      VARPV=VARPV
      SDPV=SDPV
      WRITE(6,73) PRODEC,NABC
      WRITE(6,98)VARD,SD,C
      WRITE(6,901) TVL,VARPV,SDPV,D
901   FORMAT(10HTOTAL NPV:,F12.3,2X,8HVAR NPV:,F12.3,2X,
     17HSD NPV:,F12.3,2X,14HDISCOUNT RATE:,F10.5,/)
98    FORMAT(3HVAR,F10.5,2X,6HST DEV,F10.5,7HEX EFF:,F4.1,/)
73    FORMAT(30X,37HTOTAL AMOUNT OF OIL TO BE DISCOVERED:,F12.3,2X,
     110H10E06 BBLS,/30X,5HWITH:,I4,10HMORE WELLS)
72    FORMAT(30X,1H+,14X,1H+,5X,5HTOTAL,4X,1H+,2X,F10.5,2X,1H+,14X,1H+)
38    FORMAT(1X,112(1H-)/)
400    CONTINUE
410    CONTINUE
      STOP
      END
      SUBROUTINE FACTM(A,B,C)
      LB=INT(B)
      LA=INT(A)
      IF (LB.EQ.1) GO TO 15
      IF(LA.LT.1.AND.LB.GT.0) GO TO 18
      IF(LB.LT.1.OR.LA.LT.1) GO TO 17
      LF=INT(B-1.)
      C=A
      DO 2 I=1,LF
      AI=I
2     C=C*(A-AI)
      GO TO 16
15    C=A
      GO TO 16
17    C=1.
      GO TO 16
18    C=0.
16    CONTINUE
      RETURN
      END
      SUBROUTINE FACT(A,C)
      LA=INT(A)
      IF(LA.LT.2) GO TO 20
      C=1
      MA=INT(A)
      DO 3 I=1,MA
3     C=C*I
      GO TO 21
20    C=1.
21    CONTINUE
      RETURN
      END
```

BASE CASE RESULTS

Model A - Play is defined as productive area A_t. Model A assumes that play is composed of five pieces (fields dispersed over an area 5 x A_t. Sample space is thus Basin Area/e(.63)A_t.

Updating - Stage 1

0 giant-field plays, 3 commercial-field plays discovered with 100 wells (type 1 newfield wildcats)

Case 1 e = 1
Case 2 e = 2
Case 3 e = 3
Case 4 e = 4

Updating - Stage 2

no plays found in next 140 wells

Case 5 e = 1
Case 6 e = 2
Case 7 e = 3
Case 8 e = 4

Posterior probabilities from Stage 2 are final results

NOTE:

A2 is likelihood of giant-field play discovery conditional on state

A1 is likelihood of commercial-field play discoveries conditional on state

Fields on computer printout actually refer to plays

1AREA OF BASIN(10E03KM2): 158.000
PRODUCTIVE AREA OF LARGE DEPOSITS(KM2):240.000
PRODUCTIVE AREA OF SMALL DEPOSITS(KM2):110.000
NUMBER OF WELLS ALREADY DRILLED: 100
NUMBER OF SEDIMENTARY BASINS IN REGION: 7.000
PRIOR PROBABILITY OF BIG FIELD PER BASIN: 0.200
PRIOR PROBABILITY OF SMALL FIELD PER BASIN: 0.300

CASE NUMBER: 1
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 3 SMALL FIELDS
EXPLORATION EFFICIENCY: 1.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 100+	A1(W1/A1) (W1= 100)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.01189580	1.00000000	0.00032833	0.00000391	0.00154550
0	4	0.00509820	1.00000000	0.00122441	0.00000624	0.00247010
0	5	0.00131097	1.00000000	0.00285368	0.00000374	0.00148036
1	3	0.02081764	0.84802431	0.00032833	0.00000580	0.00229359
1	4	0.00892185	0.84802431	0.00122441	0.00000926	0.00366573
1	5	0.00229419	0.84802431	0.00285368	0.00000555	0.00219691
2	3	0.01561324	0.71894902	0.00032833	0.00000369	0.00145837
2	4	0.00669139	0.71894902	0.00122441	0.00000589	0.00233063
2	5	0.00172064	0.71894902	0.00285368	0.00000353	0.00139690
3	3	0.00650551	0.60935313	0.00032833	0.00000130	0.00051502
3	4	0.00278808	0.60935313	0.00122441	0.00000208	0.00082313
3	5	0.00071693	0.60935313	0.00285368	0.00000125	0.00049331
4	3	0.00162638	0.51632190	0.00032833	0.00000028	0.00010910
4	4	0.00069702	0.51632190	0.00122441	0.00000044	0.00017437
4	5	0.00017923	0.51632190	0.00285368	0.00000026	0.00010450
				TOTAL	0.00005322	0.02105770

CASE NUMBER: 2
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 3 SMALL FIELDS
EXPLORATION EFFICIENCY: 2.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 100+	A1(W1/A1) (W1= 100)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.01189580	1.00000000	0.00263211	0.00003131	0.01238993
0	4	0.00509820	1.00000000	0.00910012	0.00004639	0.01835840
0	5	0.00131097	1.00000000	0.01965956	0.00002577	0.01019849
1	3	0.02081764	0.69604862	0.00263211	0.00003814	0.01509199
1	4	0.00892185	0.69604862	0.00910012	0.00005651	0.02236208
1	5	0.00229419	0.69604862	0.01965956	0.00003139	0.01242262
2	3	0.01561324	0.48383868	0.00263211	0.00001988	0.00786808
2	4	0.00669139	0.48383868	0.00910012	0.00002946	0.01155828
2	5	0.00172064	0.48383868	0.01965956	0.00001637	0.00647642
3	3	0.00650551	0.33587581	0.00263211	0.00000575	0.00227581
3	4	0.00278808	0.33587581	0.00910012	0.00000852	0.00337211
3	5	0.00071693	0.33587581	0.01965956	0.00000473	0.00187329
4	3	0.00162638	0.23284644	0.00263211	0.00000100	0.00039443
4	4	0.00069702	0.23284644	0.00910012	0.00000148	0.00058443
4	5	0.00017923	0.23284644	0.01965956	0.00000082	0.00032466
				TOTAL	0.00031754	0.12565070

CASE NUMBER: 3
ALREADY DISCOVERED 0 BIG FIELDS
AND 3 SMALL FIELDS
EXPLORATION EFFICIENCY: 3.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 100+	A1(W1/A1) (W1= 100)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.01189580	1.00000000	0.00893939	0.00010634	0.04207969
0	4	0.00509820	1.00000000	0.02845548	0.00014507	0.05740553
0	5	0.00131097	1.00000000	0.05658084	0.00007418	0.02935156
1	3	0.02081764	0.54337895	0.00893939	0.00010112	0.04001408
1	4	0.00892185	0.54337895	0.02845548	0.00013795	0.05458764
1	5	0.00229419	0.54337895	0.05658084	0.00007053	0.02791080
2	3	0.01561324	0.29412252	0.00893939	0.00004105	0.01624425
2	4	0.00669139	0.29412252	0.02845548	0.00005600	0.02216059
2	5	0.00172064	0.29412252	0.05658084	0.00002863	0.01133075
3	3	0.00650551	0.15858221	0.00893939	0.00000922	0.00364934
3	4	0.00278808	0.15858221	0.02845548	0.00001258	0.00497847
3	5	0.00071693	0.15858221	0.05658084	0.00000643	0.00254550
4	3	0.00162638	0.08516449	0.00893939	0.00000124	0.00048996
4	4	0.00069702	0.08516449	0.02845548	0.00000169	0.00066841
4	5	0.00017923	0.08516449	0.05658084	0.00000086	0.00034176
				TOTAL	0.00079291	0.31375790

CASE NUMBER: 4
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 3 SMALL FIELDS
EXPLORATION EFFICIENCY: 4.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 100+	A1(W1/A1) (W1= 100)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.01189580	1.00000000	0.02114540	0.00025154	0.09953600
0	4	0.00509820	1.00000000	0.06153548	0.00031372	0.12414044
0	5	0.00131097	1.00000000	0.11180383	0.00014657	0.05799874
1	3	0.02081764	0.39024389	0.02114540	0.00017178	0.06797570
1	4	0.00892185	0.39024389	0.06153548	0.00021425	0.08477879
1	5	0.00229419	0.39024389	0.11180383	0.00010010	0.03960889
2	3	0.01561324	0.15083045	0.02114540	0.00004980	0.01970464
2	4	0.00669139	0.15083045	0.06153548	0.00006211	0.02457545
2	5	0.00172064	0.15083045	0.11180383	0.00002902	0.01148171
3	3	0.00650551	0.05772524	0.02114540	0.00000794	0.00314220
3	4	0.00278808	0.05772524	0.06153548	0.00000990	0.00391892
3	5	0.00071693	0.05772524	0.11180383	0.00000463	0.00183093
4	3	0.00162638	0.02187106	0.02114540	0.00000075	0.00029763
4	4	0.00069702	0.02187106	0.06153548	0.00000094	0.00037120
4	5	0.00017923	0.02187106	0.11180383	0.00000044	0.00017343
				TOTAL	0.00136348	0.53953433

CASE NUMBER: 5
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 0 SMALL FIELDS
EXPLORATION EFFICIENCY: 1.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 140+	A1(W1/A1) (W1= 140)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.00154550	1.00000000	1.00000000	0.00154550	0.00476858
0	4	0.00247010	1.00000000	0.89520955	0.00221125	0.00682272
0	5	0.00148036	1.00000000	0.80132991	0.00118625	0.00366013
1	3	0.00229359	0.74910390	1.00000000	0.00171814	0.00530123
1	4	0.00366573	0.74910390	0.89520955	0.00245825	0.00758483
1	5	0.00219691	0.74910390	0.80132991	0.00131876	0.00406897
2	3	0.00145837	0.56081927	1.00000000	0.00081788	0.00252353
2	4	0.00233083	0.56081927	0.89520955	0.00117020	0.00361058
2	5	0.00139690	0.56081927	0.80132991	0.00062777	0.00193694
3	3	0.00051502	0.41960573	1.00000000	0.00021611	0.00066679
3	4	0.00082313	0.41960573	0.89520955	0.00030920	0.00095401
3	5	0.00049331	0.41960573	0.80132991	0.00016587	0.00051179
4	3	0.00010910	0.31375945	1.00000000	0.00003423	0.00010562
4	4	0.00017437	0.31375945	0.89520955	0.00004898	0.00015111
4	5	0.00010450	0.31375945	0.80132991	0.00002627	0.00008107
				TOTAL	0.01385464	0.04274790

CASE NUMBER: 6
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 0 SMALL FIELDS
EXPLORATION EFFICIENCY: 2.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 140+	A1(W1/A1) (W1= 140)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.01238993	1.00000000	1.00000000	0.01238993	0.03822855
0	4	0.01835840	1.00000000	0.77346277	0.01419954	0.04381200
0	5	0.01019849	1.00000000	0.59796065	0.00609829	0.01881599
1	3	0.01509199	0.38864625	1.00000000	0.00586544	0.01809753
1	4	0.02236208	0.38864625	0.77346277	0.00672211	0.02074075
1	5	0.01242262	0.38864625	0.59796065	0.00288696	0.00890757
2	3	0.00786808	0.15000379	1.00000000	0.00118024	0.00364158
2	4	0.01165828	0.15000379	0.77346277	0.00135262	0.00417345
2	5	0.00647642	0.15000379	0.59796065	0.00058091	0.00179237
3	3	0.00227581	0.05749046	1.00000000	0.00013084	0.00040369
3	4	0.00337211	0.05749046	0.77346277	0.00014995	0.00046265
3	5	0.00187328	0.05749046	0.59796065	0.00006440	0.00019870
4	3	0.00039443	0.02187690	1.00000000	0.00000863	0.00002662
4	4	0.00058443	0.02187690	0.77346277	0.00000989	0.00003051
4	5	0.00032466	0.02187690	0.59796065	0.00000425	0.00001310
				TOTAL	0.05164398	0.15934467

CASE NUMBER: 7
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 0 SMALL FIELDS
EXPLORATION EFFICIENCY: 3.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 119+	A1(W1/A1) (W1= 140)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.04207969	1.00000000	1.00000000	0.04207969	0.12983483
0	4	0.05740553	1.00000000	0.[illegible]62961	0.03614422	0.11152124
0	5	0.02935156	1.00000000	0.[illegible]581490	0.01161778	0.03584612
1	3	0.04001409	0.0	1.00000000	0.0	0.0
1	4	0.05458764	0.0	0.62962961	0.0	0.0
1	5	0.02791080	0.0	0.39581490	0.0	0.0
2	3	0.01624425	0.0	1.00000000	0.0	0.0
2	4	0.02216059	0.0	0.62962961	0.0	0.0
2	5	0.01133075	0.0	0.39581490	0.0	0.0
3	3	0.00364934	0.0	1.00000000	0.0	0.0
3	4	0.00497847	0.0	0.62962961	0.0	0.0
3	5	0.00254550	0.0	0.39581490	0.0	0.0
4	3	0.00048996	0.0	1.00000000	0.0	0.0
4	4	0.00066841	0.0	0.62962961	0.0	0.0
4	5	0.00034176	0.0	0.39581490	0.0	0.0
				TOTAL	0.08984166	$\boxed{0.27720219}$

CASE NUMBER: 8
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 0 SMALL FIELDS
EXPLORATION EFFICIENCY: 4.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 64+	A1(W1/A1) (W1= 140)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.09953600	1.00000000	1.00000000	0.09953600	0.30711359
0	4	0.12414044	1.00000000	0.45945942	0.05703750	0.17598647
0	5	0.05799874	1.00000000	0.21014035	0.01218787	0.03760510
1	3	0.06797570	0.0	1.00000000	0.0	0.0
1	4	0.08477879	0.0	0.45945942	0.0	0.0
1	5	0.03960889	0.0	0.21014035	0.0	0.0
2	3	0.01970464	0.0	1.00000000	0.0	0.0
2	4	0.02457545	0.0	0.45945942	0.0	0.0
2	5	0.01148171	0.0	0.21014035	0.0	0.0
3	3	0.00314220	0.0	1.00000000	0.0	0.0
3	4	0.00391892	0.0	0.45945942	0.0	0.0
3	5	0.00183093	0.0	0.21014035	0.0	0.0
4	3	0.00029763	0.0	1.00000000	0.0	0.0
4	4	0.00037120	0.0	0.45945942	0.0	0.0
4	5	0.00017343	0.0	0.21014035	0.0	0.0
				TOTAL	0.16876131	$\boxed{0.52070510}$

Results from Model B

Resutls that follwo are of the same form as the previous results from Model A, except a play is considered one homogenous unit (target size A_t). Regional sample space is $\frac{\text{Basin Area}}{e\ A_t}$

1AREA OF BASIN(10E03KM2): 158.000
PRODUCTIVE AREA OF LARGE DEPOSITS(KM2):380.000
PRODUCTIVE AREA OF SMALL DEPOSITS(KM2):170.000
NUMBER OF WELLS ALREADY DRILLED: 100
NUMBER OF SEDIMENTARY BASINS IN REGION: 7.000
PRIOR PROBABILITY OF BIG FIELD PER BASIN: 0.200
PRIOR PROBABILITY OF SMALL FIELD PER BASIN: 0.300

NUMBER: 1
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 3 SMALL FIELDS
EXPLORATION EFFICIENCY: 1.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 100+	A1(W1/A1) (W1= 100)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.01189580	1.00000000	0.00121400	0.00001444	0.00289016
0	4	0.00509820	1.00000000	0.00434732	0.00002216	0.00443556
0	5	0.00131097	1.00000000	0.00972860	0.00001275	0.00255242
1	3	0.02081764	0.75903612	0.00121400	0.00001918	0.00383904
1	4	0.00892185	0.75903612	0.00434732	0.00002944	0.00589181
1	5	0.00229419	0.75903612	0.00972860	0.00001694	0.00339041
2	3	0.01561324	0.57569402	0.00121400	0.00001091	0.00218380
2	4	0.00669139	0.57569402	0.00434732	0.00001675	0.00335150
2	5	0.00172064	0.57569402	0.00972860	0.00000964	0.00192960
3	3	0.00650551	0.43630093	0.00121400	0.00000345	0.00068960
3	4	0.00278808	0.43630093	0.00434732	0.00000529	0.00105833
3	5	0.00071693	0.43630093	0.00972860	0.00000304	0.00060901
4	3	0.00162638	0.33040243	0.00121400	0.00000065	0.00013056
4	4	0.00069702	0.33040243	0.00434732	0.00000100	0.00020036
4	5	0.00017923	0.33040243	0.00972860	0.00000058	0.00011530
				TOTAL	0.00016622	0.03326645

NUMBER: 2
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 3 SMALL FIELDS
EXPLORATION EFFICIENCY: 2.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 100+	A1(W1/A1) (W1= 100)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.01189580	1.00000000	0.00977508	0.00011628	0.02327152
0	4	0.00509820	1.00000000	0.03087313	0.00015740	0.03149984
0	5	0.00131097	1.00000000	0.06090734	0.00007985	0.01597980
1	3	0.02081764	0.51690817	0.00977508	0.00010519	0.02105115
1	4	0.00892185	0.51690817	0.03087313	0.00014238	0.02849439
1	5	0.00229419	0.51690817	0.06090734	0.00007223	0.01445516
2	3	0.01561324	0.26598185	0.00977508	0.00004059	0.00812411
2	4	0.00669139	0.26598185	0.03087313	0.00005495	0.01099662
2	5	0.00172064	0.26598185	0.06090734	0.00002787	0.00557856
3	3	0.00650551	0.13623464	0.00977508	0.00000866	0.00173380
3	4	0.00278808	0.13623464	0.03087313	0.00001173	0.00234684
3	5	0.00071693	0.13623464	0.06090734	0.00000595	0.00119055
4	3	0.00162638	0.06945294	0.00977508	0.00000110	0.00022098
4	4	0.00069702	0.06945294	0.03087313	0.00000149	0.00029911
4	5	0.00017923	0.06945294	0.06090734	0.00000076	0.00015174
				TOTAL	0.00082644	0.16539377

NUMBER: 3
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 3 SMALL FIELDS
EXPLORATION EFFICIENCY: 3.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 100+	A1(W1/A1) (W1= 100)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.01189580	1.00000000	0.03320579	0.00039501	0.07905293
0	4	0.00509820	1.00000000	0.09071898	0.00046250	0.09256053
0	5	0.00131097	1.00000000	0.15466869	0.00020277	0.04057927
1	3	0.02081764	0.27536231	0.03320579	0.00019035	0.03809433
1	4	0.00892185	0.27536231	0.09071898	0.00022287	0.04460343
1	5	0.00229419	0.27536231	0.15466869	0.00009771	0.01955450
2	3	0.01561324	0.07436788	0.03320579	0.00003856	0.00771619
2	4	0.00669139	0.07436788	0.09071898	0.00004514	0.00903463
2	5	0.00172064	0.07436788	0.15466869	0.00001979	0.00396085
3	3	0.00650551	0.01968563	0.03320579	0.00000425	0.00085105
3	4	0.00278808	0.01968563	0.09071898	0.00000498	0.00099647
3	5	0.00071693	0.01968563	0.15466869	0.00000218	0.00043686
4	3	0.00162638	0.00510368	0.03320579	0.00000028	0.00005516
4	4	0.00069702	0.00510368	0.09071898	0.00000032	0.00006459
4	5	0.00017923	0.00510368	0.15466869	0.00000014	0.00002831
				TOTAL	0.00168685	0.33758879

NUMBER: 4
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 3 SMALL FIELDS
EXPLORATION EFFICIENCY: 4.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 100+	A1(W1/A1) (W1= 100)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.01189580	1.00000000	0.07871062	0.00093633	0.18738621
0	4	0.00509820	1.00000000	0.18148130	0.00092523	0.18516523
0	5	0.00131097	1.00000000	0.26068032	0.00034174	0.06839269
1	3	0.02081764	0.02912621	0.07871062	0.00004773	0.00955123
1	4	0.00892185	0.02912621	0.18148130	0.00004716	0.00943602
1	5	0.00229419	0.02912621	0.26068032	0.00001742	0.00348604
2	3	0.01561324	0.00057110	0.07871062	0.00000070	0.00014046
2	4	0.00669139	0.00057110	0.18148130	0.00000069	0.00013879
2	5	0.00172064	0.00057110	0.26068032	0.00000026	0.00005127
3	3	0.00650551	0.00000565	0.07871062	0.00000000	0.00000058
3	4	0.00278808	0.00000565	0.18148130	0.00000000	0.00000057
3	5	0.00071693	0.00000565	0.26068032	0.00000000	0.00000021
4	3	0.00162638	0.0	0.07871062	0.0	0.0
4	4	0.00069702	0.0	0.18148130	0.0	0.0
4	5	0.00017923	0.0	0.26068032	0.0	0.0
				TOTAL	0.00231726	0.46375102

NUMBER: 5
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 0 SMALL FIELDS
EXPLORATION EFFICIENCY: 1.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 140+	A1(W1/A1) (W1= 140)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.00289016	1.00000000	1.00000000	0.00289016	0.00787765
0	4	0.00443556	1.00000000	0.83112180	0.00368649	0.01004818
0	5	0.00255242	1.00000000	0.69059396	0.00176268	0.00480451
1	3	0.00383904	0.55555552	1.00000000	0.00213280	0.00581332
1	4	0.00589181	0.55555552	0.83112180	0.00272045	0.00741507
1	5	0.00339041	0.55555552	0.69059396	0.00130078	0.00354550
2	3	0.00218380	0.30785561	1.00000000	0.00067230	0.00183246
2	4	0.00335150	0.30785561	0.83112180	0.00085753	0.00233736
2	5	0.00192860	0.30785561	0.69059396	0.00041003	0.00111760
3	3	0.00068960	0.17015660	1.00000000	0.00011734	0.00031983
3	4	0.00105833	0.17015660	0.83112180	0.00014967	0.00040795
3	5	0.00060901	0.17015660	0.69059396	0.00007156	0.00019506
4	3	0.00013056	0.09380430	1.00000000	0.00001225	0.00003338
4	4	0.00020036	0.09380430	0.83112180	0.00001562	0.00004258
4	5	0.00011530	0.09380430	0.69059396	0.00000747	0.00002036
				TOTAL	0.01680711	0.04581079

NUMBER: 6
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 0 SMALL FIELDS
EXPLORATION EFFICIENCY: 2.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 107+	A1(W1/A1) (W1= 140)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.02327152	1.00000000	1.00000000	0.02327152	0.06343061
0	4	0.03149984	1.00000000	0.61533458	0.01938451	0.05283592
0	5	0.01597980	1.00000000	0.37804615	0.00604110	0.01646609
1	3	0.02105115	0.0	1.00000000	0.0	0.0
1	4	0.02849439	0.0	0.61538458	0.0	0.0
1	5	0.01445516	0.0	0.37804615	0.0	0.0
2	3	0.00912411	0.0	1.00000000	0.0	0.0
2	4	0.01099662	0.0	0.61538458	0.0	0.0
2	5	0.00557856	0.0	0.37804615	0.0	0.0
3	3	0.00173380	0.0	1.00000000	0.0	0.0
3	4	0.00234684	0.0	0.61538458	0.0	0.0
3	5	0.00119055	0.0	0.37804615	0.0	0.0
4	3	0.00022098	0.0	1.00000000	0.0	0.0
4	4	0.00029911	0.0	0.61538458	0.0	0.0
4	5	0.00015174	0.0	0.37804615	0.0	0.0
				TOTAL	0.04869713	0.13273257

NUMBER: 7
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 0 SMALL FIELDS
EXPLORATION EFFICIENCY: 3.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 38	A1(W1/A1) (W1= 140)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.07905293	1.00000000	1.00000000	0.07905293	0.21547270
0	4	0.09256053	1.00000000	0.33014351	0.03055825	0.08329189
0	5	0.04057927	1.00000000	0.10793149	0.00437978	0.01193786
1	3	0.03809433	0.0	1.00000000	0.0	0.0
1	4	0.04460343	0.0	0.33014351	0.0	0.0
1	5	0.01955450	0.0	0.10793149	0.0	0.0
2	3	0.00771619	0.0	1.00000000	0.0	0.0
2	4	0.00903463	0.0	0.33014351	0.0	0.0
2	5	0.00396085	0.0	0.10793149	0.0	0.0
3	3	0.00085105	0.0	1.00000000	0.0	0.0
3	4	0.00099647	0.0	0.33014351	0.0	0.0
3	5	0.00043686	0.0	0.10793149	0.0	0.0
4	3	0.00005516	0.0	1.00000000	0.0	0.0
4	4	0.00006459	0.0	0.33014351	0.0	0.0
4	5	0.00002831	0.0	0.10793149	0.0	0.0
				TOTAL	0.11399090	0.31070244

NUMBER: 8
ALREADY DISCOVERED: 0 BIG FIELDS
AND: 0 SMALL FIELDS
EXPLORATION EFFICIENCY: 4.0

NUMBER OF BIG FIELDS	NUMBER OF SMALL FIELDS	PRIOR	A2(W2/A2) (W2= 8	A1(W1/A1) (W1= 132)	PRIOR TIMES LIKELIHOOD	PROBABILITY POSTERIOR
0	3	0.18738621	1.00000000	1.00000000	0.18738621	0.51075429
0	4	0.18516523	1.00000000	0.0	0.0	0.0
0	5	0.06839269	1.00000000	0.0	0.0	0.0
1	3	0.00955123	0.0	1.00000000	0.0	0.0
1	4	0.00943802	0.0	0.0	0.0	0.0
1	5	0.00348604	0.0	0.0	0.0	0.0
2	3	0.00014046	0.0	1.00000000	0.0	0.0
2	4	0.00013879	0.0	0.0	0.0	0.0
2	5	0.00005127	0.0	0.0	0.0	0.0
3	3	0.00000058	0.0	1.00000000	0.0	0.0
3	4	0.00000057	0.0	0.0	0.0	0.0
3	5	0.00000021	0.0	0.0	0.0	0.0
4	3	0.0	0.0	1.00000000	0.0	0.0
4	4	0.0	0.0	0.0	0.0	0.0
4	5	0.0	0.0	0.0	0.0	0.0
				TOTAL	0.18738621	0.51075429

Appendix B - Basin Classification by Klemme

from: World Oil and Gas Reserves from Analysis of Giant Fields and Petroleum Basins - H.D. Klemme.

Type 1 Basins

Type 1 basins (Fig. 12-3) lie in the interior of cratonic areas. They are flat, single-cycle, saucer-shaped basins generally located near precambrian shield areas. The sediments consist primarily of Paleozoic platform deposits which display basement-controlled structural and sedimentary traps. Only two basins, the Illinois and the Eromango or Cooper, contain giant fields. In this type of basin, reservoir rocks include both sandstones and carbonates. In general, Type 1 interior basins have low hydrocarbon-recovery rates and entry into them as a 50 percent or less probability of commercial success. The basins are typified by low-sulfur, high-gravity crude oil.

Type 2 Basins

Outward from the interior basins, near the margins of cratons, Type 2 intracontinental composite basins are present (Fig. 12-4). They range in size from subcontinental miogeosynclines to small intermontane basins. Like the interior basins, these multicycle types usually have an intial cycle of Paleozoic platform sediments. In some of them this cycle has been tectonized by Hercynian orogeny; orogenic clastics are often deposited unconformably upon the first-cycle sediments. There are 24 intracontinental basins with 120 giant fields, which represent nearly a quarter of the world's oil and gas reserves. Reservoirs in Type 2 basins are about equally divided between Paleozoic and Mesozoic ages, and are dominantly sandstones. The crude oil types are similar to those in Type 1 basins.

Where giant fields are present, large basins of this type average 120,000 barrels of recoverable oil or gas-equivalent per mi^3 of sediments, while the smaller bains average 40,000 barrels. Basins of this type have better than a 50 percent chance of commercial discovery, and two of three contain giant fields. Most of the world's reserves of Paleozoic oil and gas are found in basins of this type.

Field sizes in the Type 1 basins occur in two general patterns: either one giant or supergiant field which contains over 50 percent of the basins' reserves, or in small fields, the largest of which is rarely more than 10 percent of the basin's reserves. Either kind may be relatively rich. The supergiants are associated with the major tectonic arches preserved in many of these basins and this, plus long-distance migration, may account for their presence whereas abundant structural traps with many stratigraphic variations seem to account for the basins with small fields.

Type 3 Basins

Another type of cratonic basin is the Type 3 graben or rift-type basin (Fig. 12-5), which may represent an area of incipient seafloor spreading that has remained dormant. Such basins are of small to medium size, linear, and down-faulted. There are six basins of this type, with a total of 40 giant fields which contain 10 percent of the world's reserves. Reservoirs are about equally divided between standstones and carbonates, while the crude oil is generally high-gravity and low in sulphur. One out of two basins produces hydrocarbons and one out of two producing basins contains giants.

Type 3 basins with giant fields are fairly rich, averaging 140,000 barrels of oil or gas-equivalent per mi^3 of sediments. Evaporites or thick shale sequences often act as basinwide caprock to trap any oil generated below them. Many of these basins contain almost entirely gas, others mainly oil. Facies appear to control hydrocarbon type. On average, the four largest fields in this type of basin contain from 10 to 20 percent of the basin's total reserves. A high success rato is experienced in these basins, of which four of the six have been found since World War II.

Some Type 3 basins appear to be superimposed as a third cycle on large Type 2 basins. An example is the Mesozoic-Tertiary graben system superimposed on the North Sea Type 2 basins. This graben system predates the opening of the North Atlantic.

In general, most cratonic basins contain high-gravity crude. They are estimated to contain over three-quarters of the world's gas reserves and 90 percent of total Paleozoic hydrocarbons. They are more predictable in recoverable reserves than are the intermediate crustal basins.

INTERMEDIATE CRUSTAL BASINS (Mobile Zone)

The intermediate crustal zone covers less than a quarter of the land area of the world, but it accounts for more than half of the hydrocarbons. Most intermediate crustal basins appear to be related to the postulated tectonics of sea-floor spreading. Nearly all their reserves are Mesozoic and Tertiary--in other words, formed during the period of theoretical post-Permian sea-floor spreading.

Type 4 Basins

Type 4 extracontinental basins (Fig. 12-6) downwarp into small ocean basins. Some extend all the way to offshore land masses (Type 4A), as in the Tethyan realm of the Middle East Arabian/Iranian basin and in Eastern Venezuela; others are open and appear simply to submerge offshore (type 4C) as in the Gulf Coast, North Slope, and East Asia. Still others, often termed "foredeeps", are present along the narrow portions of Tethys, such as the Molasse trough, the Indus basin, and Assam (Type 4B). In this basin type the statistics are skewed because of the super-rich Arabian/Iranian basin. Twelve of these basins have 105 giant fields and 50 percent of the world's reserves.

Reservoirs in 4A and 4B types are mainly Mesozoic and are dominantly carbonate, whereas 4C basins are mainly sandstone. They appear to contain average amount of gas, except for the high gas content in the 4B foredeep subdivision, and intermediate-gravity crude oil with intermediate to high sulphur content.

The risk of exploring in these basins historically appears to entail a 50 percent chance of finding commercial production and a one-in-three chance of finding a giant field.

Type 5 Basins

Type 5 pull-apart basins (fig. 12-7) may be the end phase of a

Type 3 cratonic-rift basin which has been separated by distances of oceanic scale. It is difficult to determine the time and rate of spreading of some Type 3 rifts if they have passed into Type 5 pull-apart basins. For example, tens of miles of separation are reparted to occur in the Red Sea rift, hundreds in the Davis Strait, and thousands in Coastal West Africa and eastern South America. Pull-apart basins are located on both sides of the Atlantic and Indian Oceans and include only four or five giants, located in the offshore lower Congo basin and off the Northwest shelf of Australia. They generally form linear coastal basins characterized by down-to-the-sea tilted fault-block structures containing Mesozoic and Tertiary sediments: these apepar to lie along what many marine geologists believe to be the separated margins of continental plates.

The statistical experience factor with these basins does not permit much speculation. To date, the success ratio in significant commerical discovery is about one in three.

There appear to be at least two subtypes of pull-apart basins. One is the parallel pull-apart type of basin, which has often resulted in salt deposition along linear rifts during early stages of develoment. Mesozoic salt is found offshore in eastern Canada, the United States, Brazil, and west and south-west Africa. The other subtype appears to have been formed by the motion of the east-west transform movements during sea-floor spreading, which formed the basins between northern Brazil in South America and Liberia to Dahomey in Africa. This type seems to lack salt deposition and often displays a different tectonic framework. In addition, many of these basins combine both Type 3 rift and Type 5 pull-apart characteristics as, for example, in the Grand Banks off Newfoundland there appears to be a combination of Mesozoic rift-like horst and grabens overlain by an Upper Cretaceous and Tertiary seaward-dipping fan of sediments. Dependent on influx of clastic sediments, these basins contain either dominantly sandstone and shale or almost entirely carbonate banks.

Types 6 and 7 Basins

Types 6 and 7 second-cycle intermontane basins (Fig. 12-8) parallel the subduction zones between the continents and ocean basins. They are small, second-cycle Tertiary basins located either transverse to, or along the strike of older deformed eugenosynclines formed previously at the continental margin. Typical of these basins are multi-pay zones of interbedded sand and shale or basal carbonate reefs. Thirteen of these basins contain 40 giant fields and represent 10 percent of the world's reserves. These small, rich basins consist predominately of Tertiary clastics, with evaporites generally absent. Traps are either combination type or anticlinal uplifts above active basement blocks, formed in what has often been termed rhombochasms located in the crushed zone of actively-moving plates along subduction zones. Generally, the gas content of these basins is below average and their crude oil, although variable, tends toward low to intermediate gravity. Recovery of hydrocarbons, as in the case of other intermediate crustal basins, is highly variable, ranging from small amounts to 4 x 10^6 barrel per mi^3 of sedements. Offshore extension of production in these basins has occurred in the Caspian Sea off Baku, in the Java Sea, off the Los Angeles and Ventura basins, off Peru, and in the Cook Inlet.

Before World War I, four out of five such basins yielded hydrocarbons in commerical quantities; this ratio is now one out of five. About one out of two of the basins have giant fields.

Type 8 Basins

Type 8 late Tertiary delta basins (Fig. 12-9) with commercial production include the Niger, Mississippi, and Mahakan deltas, to which the Nile delta and portions of the Mackenzie delta appear to be new additions. Discoveries have been made recently in the offshore portion of the Rangoon, Amazon, and Mekong deltas. Statistics are not firm, but there is a remarkable correlation between the Niger and Mississippi basins. In these, there is a tendency for the largest fields to represent less than about 5 percent of the basin's total reserves, and they appear to have three times as much gas as normal. Roll-over structures and flowage structures act as traps.

About one out of two explored deltas has commercial production and all appear to have a few giants. The giants represent much less than 75 percent of the basin reserves.

OCEANIC BASINS

Oceanic basins of the continental rise and abyssal plains (Fig.

12-10) are estimated to contain half of the world's marine sediments (Emory 1974) and in many deep-water areas the sedimentary section reaches a substantial thickness, conducive to oil generaion, with evidence of structural traps providing areas for accumulation. Deep-ocean basins are untested with regard to petroleum; however, organic-rich sediments have been recovered in some of the Joides deep-sea drilling project cores. The greatest unanswered concern is whether deep-ocean basins develop reservoir rocks.

There now is insufficient evidence to evaluate the resources of these basins and an estimate at this time would be unsatisfactory. When sufficeint data are forthcoming and future drilling furnishes the industry with one or more analogs of these basin types, resource estimates may be attempted. A truly worldwide estimate of petroleum resources must remain incomplete until more data are available.

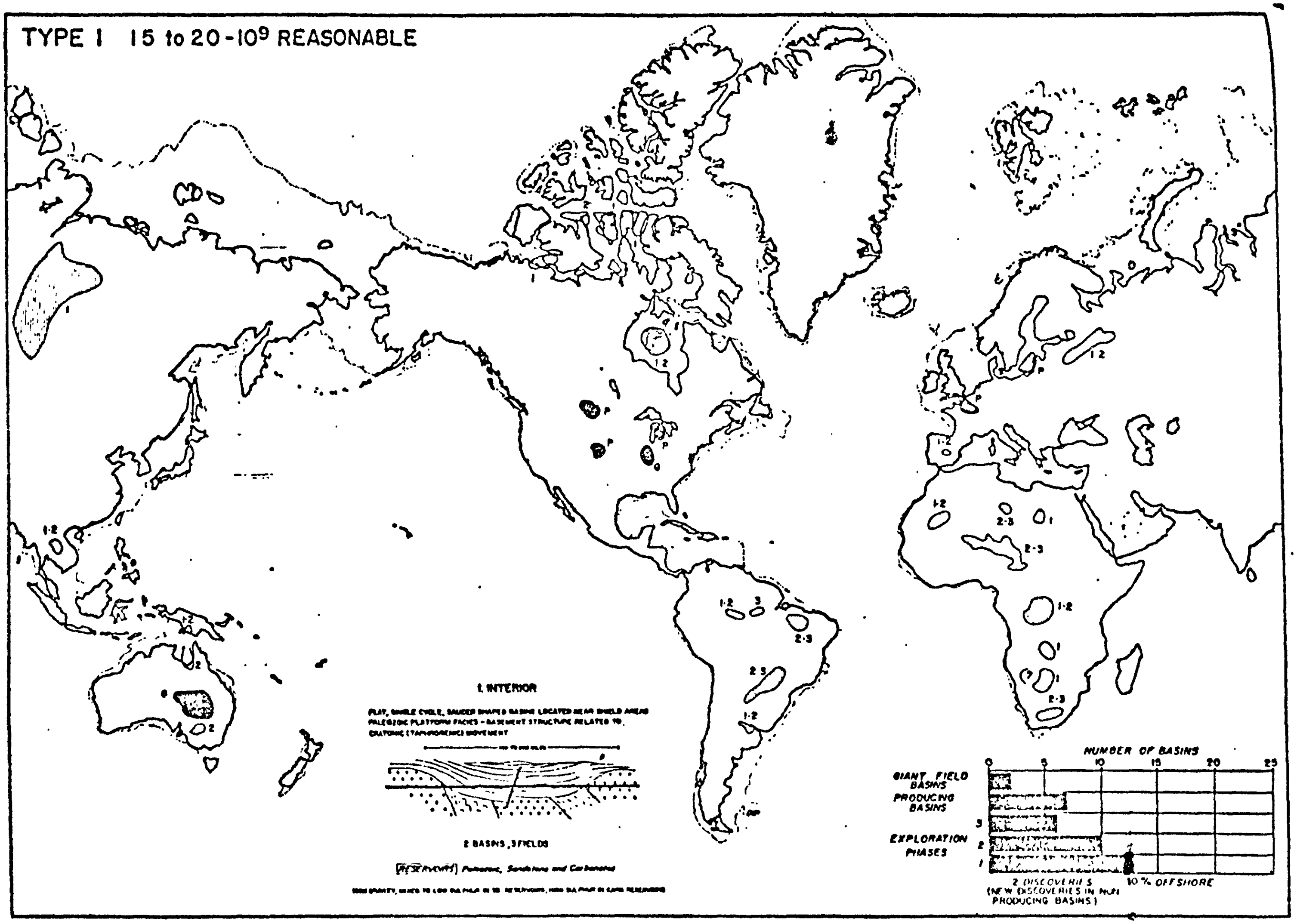
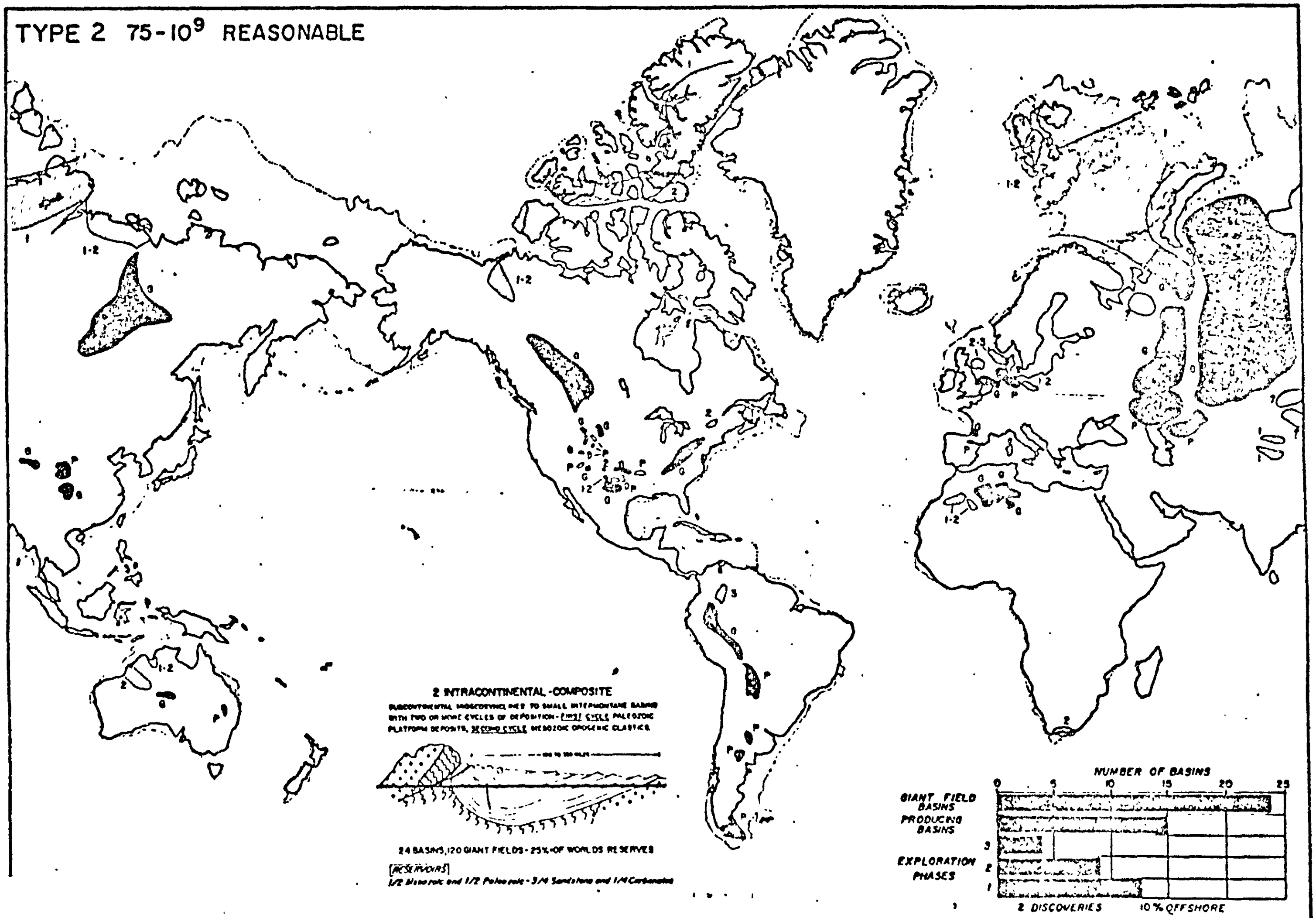


Figure 12-3.--Map of interior basins


TYPE 2 75-10⁹ REASONABLE
2 INTRACONTINENTAL -COMPOSITE
SUBCONTINENTAL MOGEOSYNCLINES TO SMALL INTERMONTANE BASINS WITH TWO OR MORE CYCLES OF DEPOSITION - FIRST CYCLE PALEOZOIC PLATFORM DEPOSITS, SECOND CYCLE MESOZOIC OROGENIC CLASTICS
24 BASINS, 120 GIANT FIELDS - 25% OF WORLDS RESERVES
[RESERVOIRS]
1/2 Mesozoic and 1/2 Paleozoic - 3/4 Sandstone and 1/4 Carbonates
NUMBER OF BASINS
0
5
10
15
20
25
GIANT FIELD BASINS
PRODUCING BASINS
EXPLORATION PHASES
3
2
1
2 DISCOVERIES
10% OFFSHORE

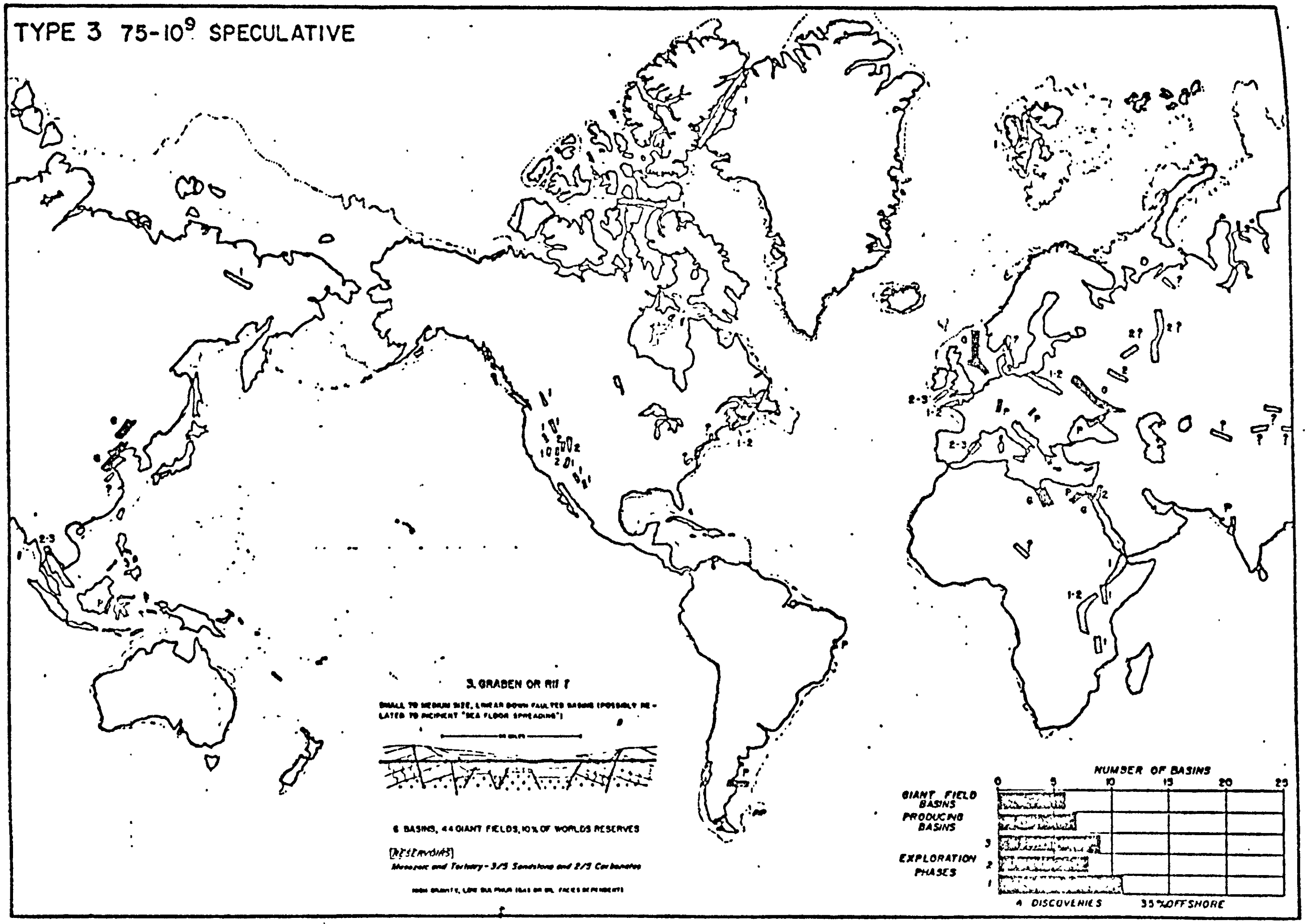
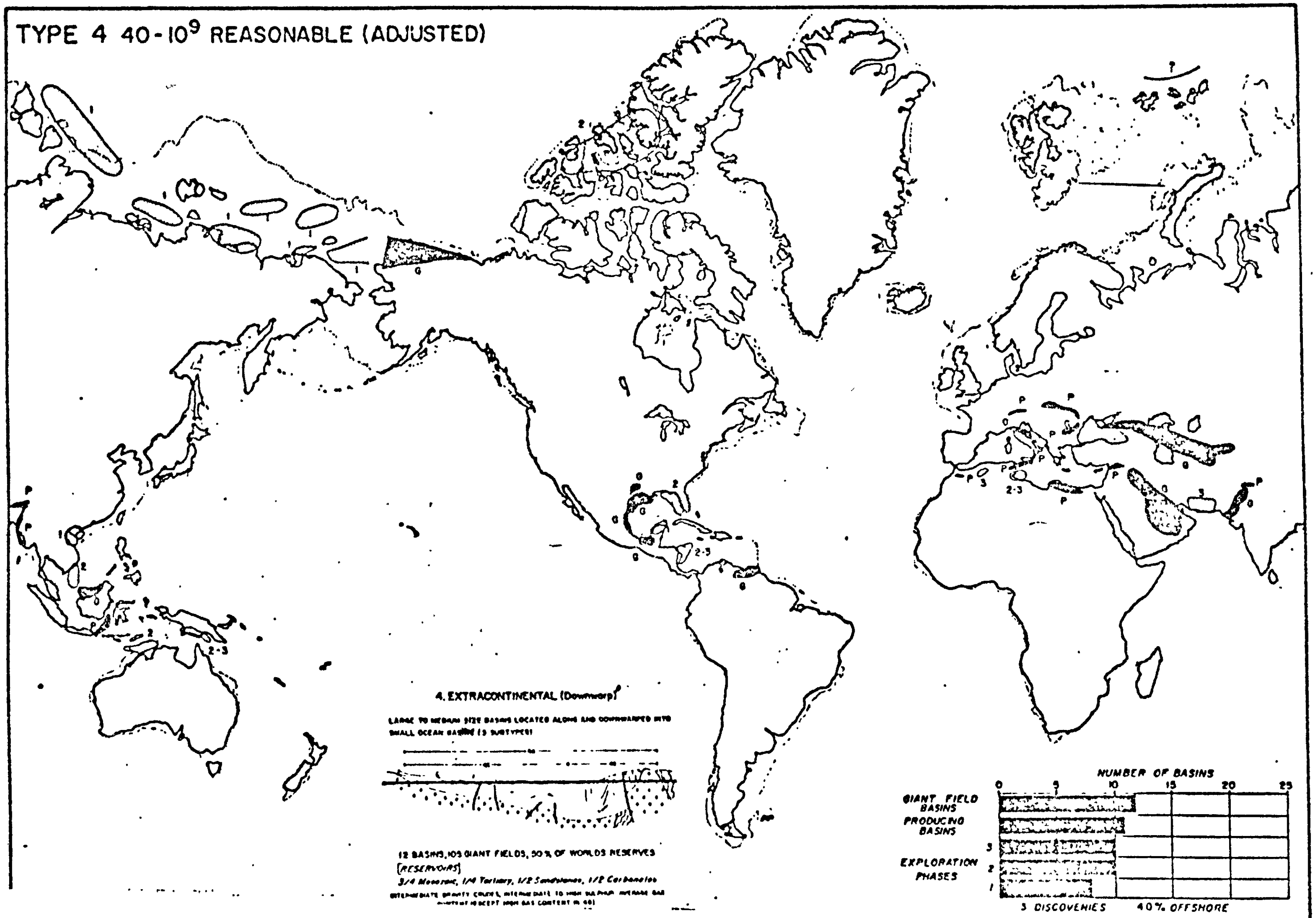
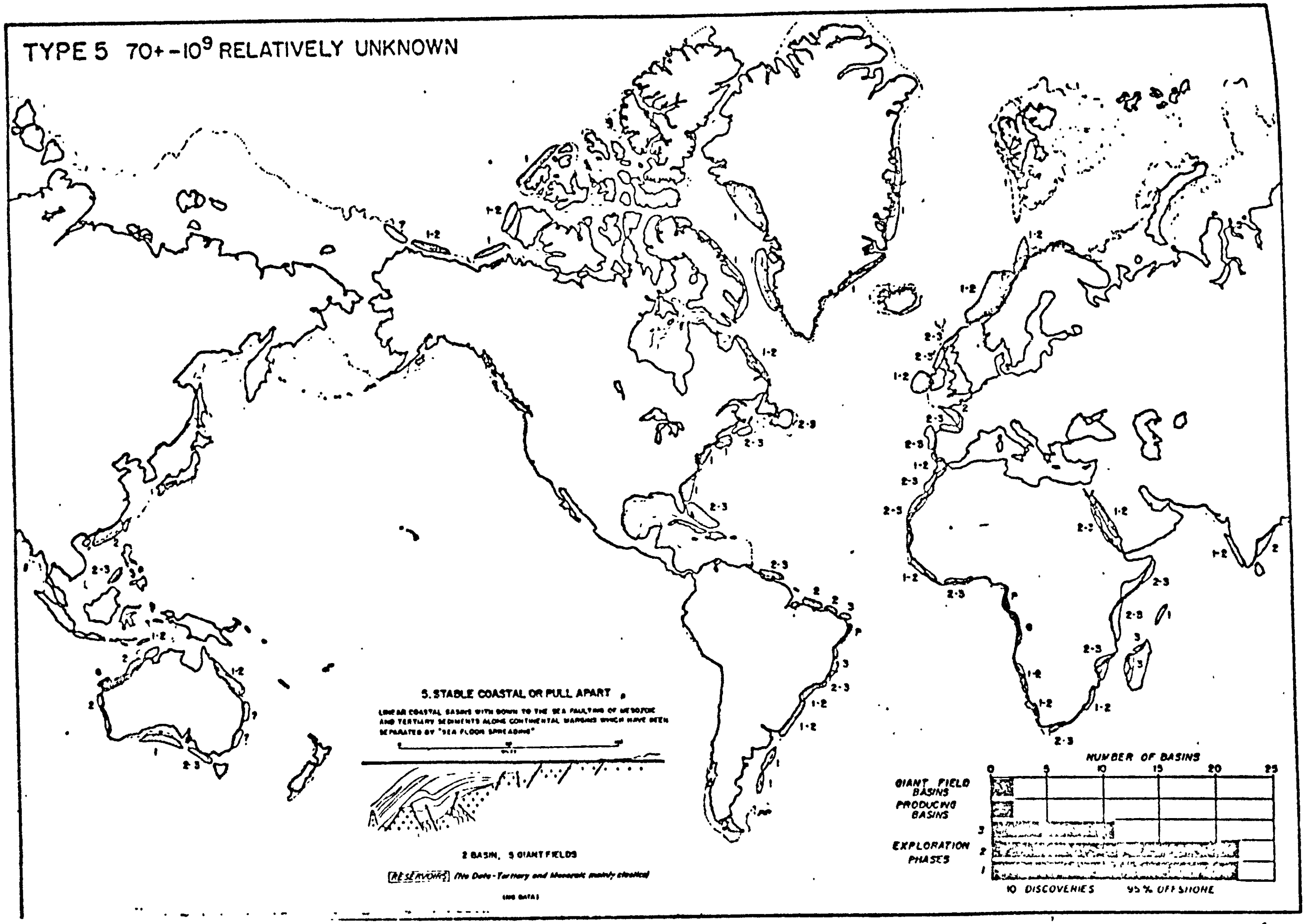
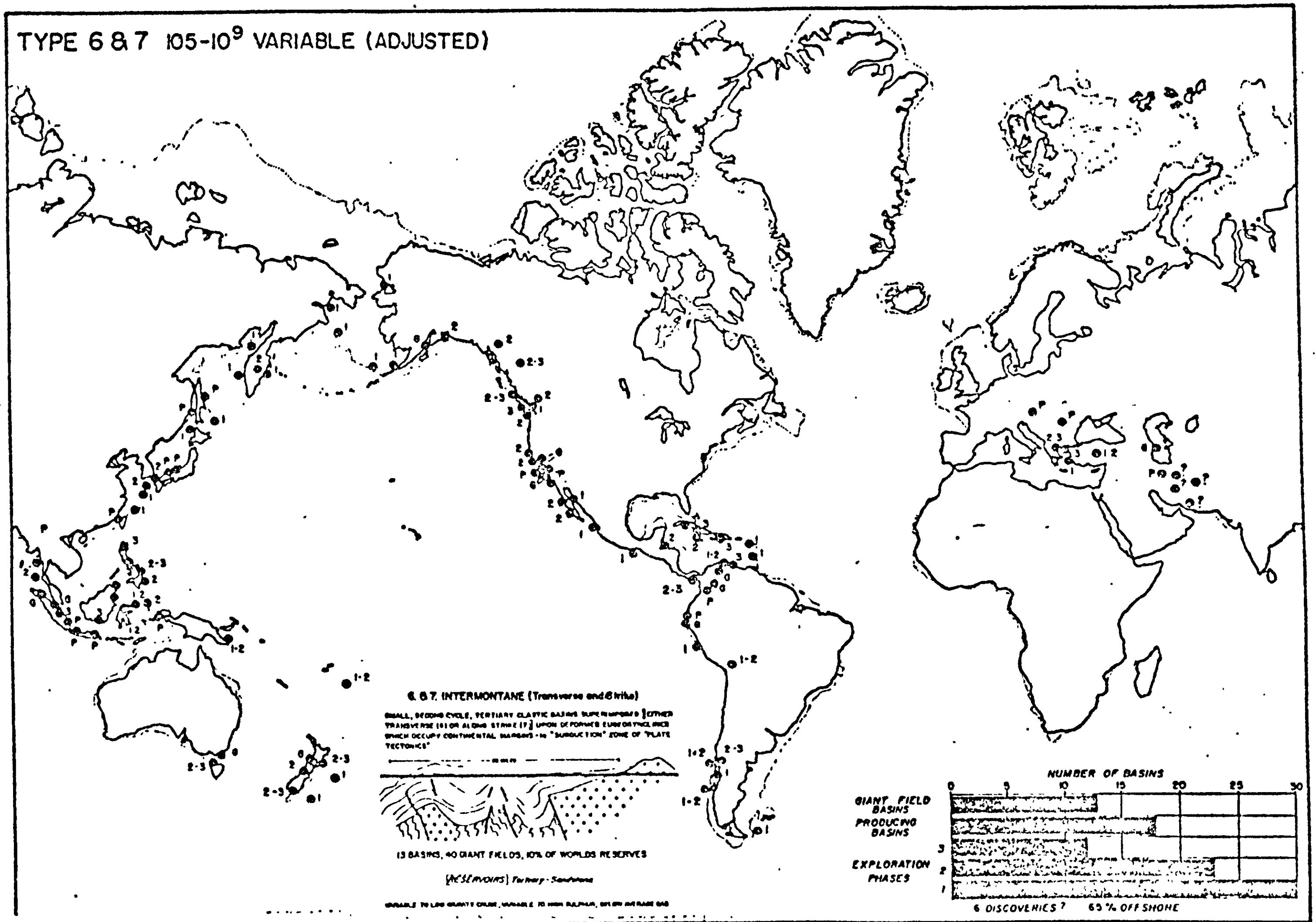


Figure 12-5.--Map of graben or rift basins


TYPE 4 40-10⁹ REASONABLE (ADJUSTED)
4. EXTRACONTINENTAL (Downwarp)
12 BASINS, 105 GIANT FIELDS, 50% OF WORLDS RESERVES
[RESERVOIRS]
NUMBER OF BASINS
0
5
10
15
20
25
GIANT FIELD BASINS
PRODUCING BASINS
EXPLORATION PHASES
3
2
1
3 DISCOVERIES
40% OFFSHORE



TYPE 5 70+-10⁹ RELATIVELY UNKNOWN
5. STABLE COASTAL OR PULL APART
LINEAR COASTAL BASINS WITH DOWN TO THE SEA FAULTING OF MESOZOIC AND TERTIARY SEDIMENTS ALONG CONTINENTAL MARGINS WHICH HAVE BEEN SEPARATED BY "SEA FLOOR SPREADING"
2 BASIN, 5 GIANT FIELDS
RESERVOIRS (No Data - Tertiary and Mesozoic mainly clastics)
(NO DATA)
NUMBER OF BASINS
0
5
10
15
20
25
GIANT FIELD BASINS
PRODUCING BASINS
EXPLORATION PHASES
3
2
1
10 DISCOVERIES
95% OFFSHORE


TYPE 6 & 7 105-10^9 VARIABLE (ADJUSTED)
6 & 7. INTERMONTANE (Transverse and Strike)
13 BASINS, 40 GIANT FIELDS, 10% OF WORLDS RESERVES
NUMBER OF BASINS
0
5
10
15
20
25
30
GIANT FIELD BASINS
PRODUCING BASINS
EXPLORATION PHASES
3
2
1
6 DISCOVERIES ?
65 % OFFSHORE

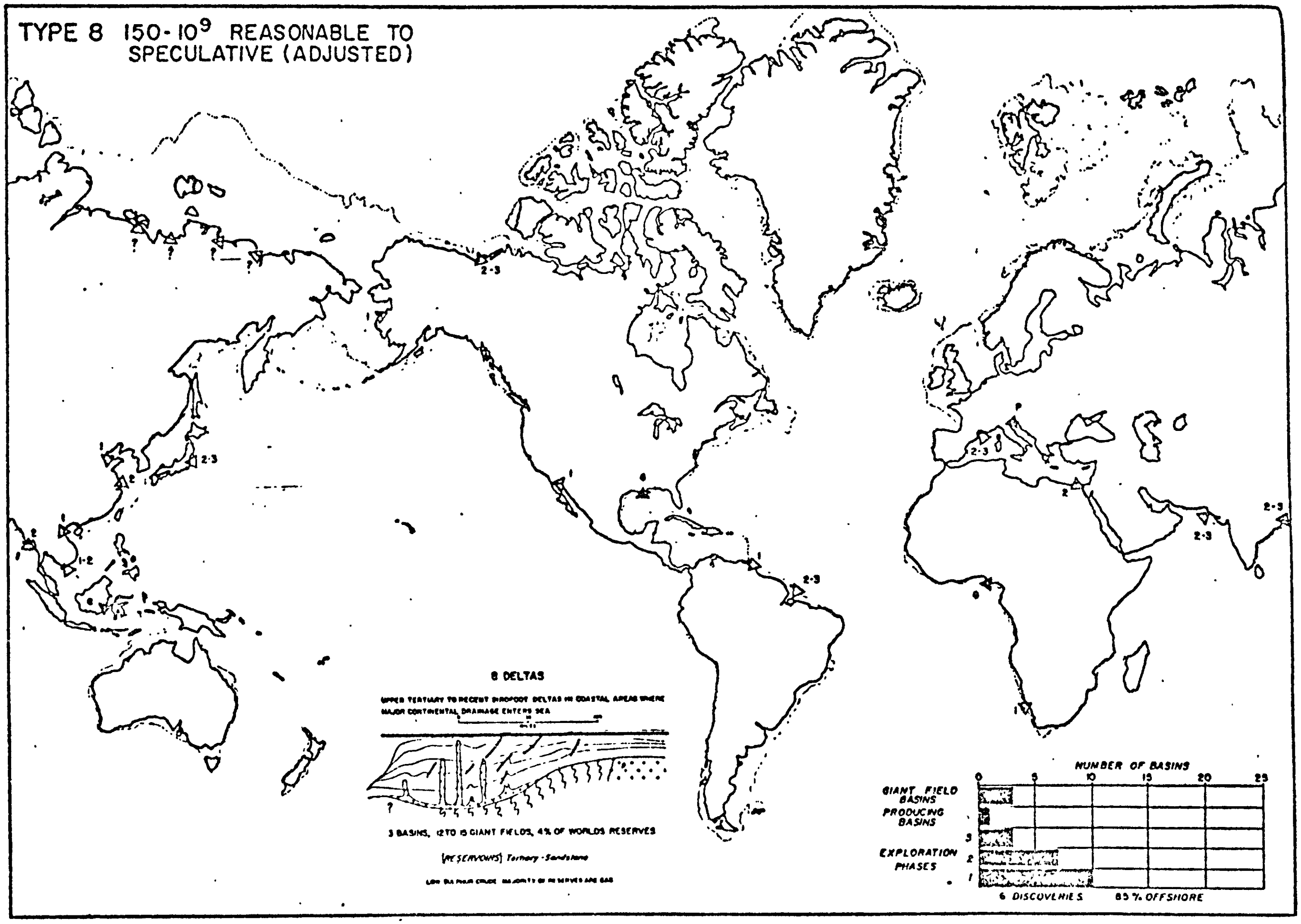


Figure 12-9.--Map of deltas

Appendix C - Geology and Structure of the Brazilian Sedimentary Basins

Maranhao Basin

The Maranhao Basin is located entirely within the Brazilian shield. Sedimentation has been controlled by vertical differential movements of Precambrian basement blocks. Although the current coastline is on the northeast of the basin, the Paleozoic coastline was to the west-northwest. From the Silurian to the Carboniferous five episodes of highly constructive deltas have been recognized (Carozzi, 1980). Late Devonian icesheets interfered with the delta formation producing glacio-deltaic deposits. Thoeleitic maginas were introduced in the form of numerous sills and dikes in the Mesozoic (200-120 Ma).

Exploration in the Maranhao has been in two distinct phases. The first phase was a search for structural traps undertaken in the 1950's as a joint study of the Middle Amazon and Maranhao basins. There appears to have been only mild deformation of Ordovician and pre-Jurassic strata. Two regions were discussed as having oil potential (Mesner (1964)). The first region is in the southwestern corner of the basin where deformation was moderate and little diabase intrusions have occurred. Oil may be trapped in structures in this region. The second region has a potential only for stratigraphic traps related to the deltas. Of particular interest is the Cabecas sandstones that overlie the shales in the Pimenteiras formation.

The second major phase of exploration has been from 1970 to the present. Carozzi (1980) states that there are no significant results from the search for structural traps in the 50's and 60's in the Maranhao or Middle Amazon basins. His work concentrates on the potential for delta related stratigraphic traps. Among the three major sandstone systems, the best potential is in the south and southeast part of the basin. However, two of the sandstone systems have their reservoir properties reduced by diagenetic cementation. This leaves the third (Cabecas formation) the best target for exploration. The best potential is in southwerstern areas of the basin where sandstones under the lower distributary to the delta interfinger with shales of the underlying Pimenteiras formation. The area of the region of interest is calculated to be approximately 70,000 km^2. The age and heat due to diabase intrusions indicate that any original oil had a high probability of being turned into gas. If we assume an average subsidence rate of 10m/Ma beginning in the Silurian, the peak oil generation would occur at 280 Ma and gas generation after 360Ma, or Late Cretaceous time (figures from Tissot 1980). The additional heat added during the early Mesozoic (due to diabase intrusions) would most likely increase the rate of gas generation.

Parana basin

The Parana has a similar history to that of the other interior basins. The base of the Parana, however, is composed of black, marine related lacustrine bituminous shales of lower Devonian age. These are overlain by successive cycles of lower Pennsylvania glacial deposits. Glacial cover was extensive at that time. Five distinct glacial advances and minor maritime transgressions have been recognized (Sanford 1960). Extensive diabase and basalt flows were formed in the Triassic and Jurassic.

Only very small oil shows have been found in the Parana basin. There are several major factors which imply this basin is an unfavorable one for oil occurrence. There is no record of compression forces or anticlines since the Devonian. Regional dips are low (1°). There is an overabundance of coarse clasticsand few good marine shales. There exists a possibility that small oil or gas deposits remain in some fault traps along the eastern hingeline of the basin. If some oil existed prior to the basalt intrusions it could have migrated after the basalt overburden and trapped by fault block. The overall prospects are not favorable and seismic exploration is hampered by basalt flows. Using a map of possible oil locations long the eastern hingeline by Sanford (1960) a prospective area of 145,000 km^2 was calculated.

Amazon basin

In most ways the Amazon basin developed in the same fashion as the Parnaiba basin except that the sedimentary cycles were incomplete in the Amazon. Deltas in the Amazon basin were small and dispersed along the coastline by longshore currents. There is verying little interfingering of various delatic members. The marine transgression came from the west in the upper Amazon and from the east in the middle Amazon. Glaciation was less dramatic in the Amazon basin than in the Maranhao basin. There are extensive Mesozoic basalt flows in the Amazon which may have been a failed rift system during the opening of the Atlantic (Bally 1980). The Amazon basin has an enormous area. The search for structural traps has produced no significant results. The best potential appears to be in the central middle Amazon with oil or gas deposits related to small deltaic structures. The middle and upper Amazon basins have prospective areas of 270,000 km^2 based on the general region where small stratigraphic and delatic reservoirs might be found.

Summary of onshore basin potential

All major cratonic basins have the same general history. Initial subsidence was in the pre-Paleozoic or early Paleozoic with subsidence along Precambrian lines of weakness. Basin fill consists large of continental clastics and some deltaic deposits (best delta formations were the Maranhao). Extensive glaciation followed. Basaltic dikes, sills and flows were formed in the Mesozoic as old rift zones were reactivated. All basins have few compressional features and the search for structural traps has produced no significant results.

Other cratonic basins around the world which contain giant oil fields have structural traps (e.g., Illinois basin) and giant fields, if they occur, are just barely over 500 million barrels (the definition of a giant field). The field size distributions in such basins are skewed with 40 percent of reserves in one field. If there appear to be no significant structural traps and only stratigraphic (or delta related) deposits, then the field size distribution should follow a much less skewed distribution with no giant fields and the largest field containing 9 percent of play reserves. This latter case is the one that appears to be the case in Brazil. Brazilian cratonic basins appear to have a much lower potential than the "average" cratonic basin defined by Kelmme. Thus exploration in the onshore basins represents a two-stage exploration problem. The first stage was an initial survey for structural traps and the current exploration effort is concentrating on stratigraphic traps. If we believe that the basins have been fully explored for giant fields (which are in structural traps), as is implied by Carozzi (1980), then the posterior on exploration efficiency is calculated to 12 or larger[1]

---

[1] expl. eff. for play = $e_p = \frac{B}{e_f A} = \frac{555{,}000 \text{ km}^2}{(.63)(360 \text{ km}^2)(200 \text{ wells})} = 12$

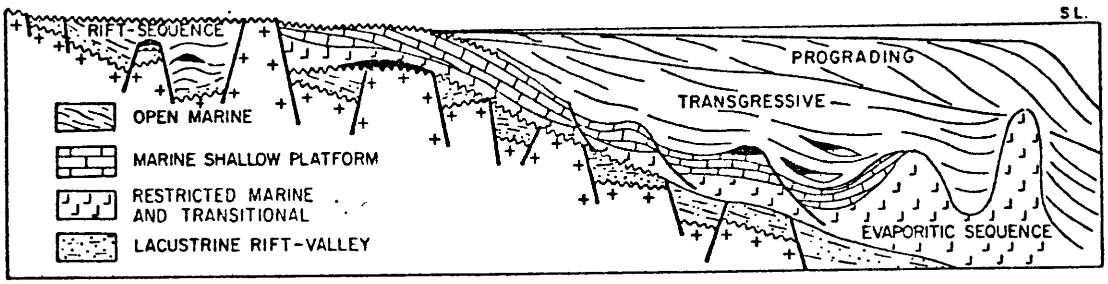
e_f = expl. eff. of field within a play (at the 90 percent confidence level) (up to 25 of most all of the basin area is considered prospective area). This exploration efficiency is the multiple of the target size exhausted by an exploration wildcat. If we believe that it is very likely that only stratigraphic deposits exist in the onshore basins, then the probabilities assessed by Klemme (.2 for a giant-field play and .3 for a commercial-field play) for an average cratonic basin are too high. Reasonable estimates might be .25 chance of a commercial field-play (gas or oil) and 0 (or very low) chance of a giant-field play, since only deltaic type field distributions would be present. Also, due to the old age and high heat flow in these basins it is likely that only gas deposits may exist. Since 80 percent of Paleozoic hydrocarbons are gas, we will use this as the probability of gas vs. oil.

Continential Margin basins

The continential margin basins of Brazil consist of basically seven semi-connected basins which are partly onshore but mostly offshore, and also one rift type basin which is completely onshore (Reconcavo). These basins were formed in four stages as South America was pulled apart from Africa. The four stages are the pre-rift arch stage, intracratonic rift-valley stage, restricted marine stage and continental margin stage. The first stage was simple arching and uplifting of a north-south segment where rifting begins with the subsidence of a north-south trough. This occurred in the Jurassic. The second stage is a rift valley system filled with continential sediments or associated with extrusion of large amounts of basaltic lava in the cratonic basisn. This occured in the Late Cretaceous and resembled the present day rift valley in Africa. Transform faulting began on the northeast coast. The restricted marine environment occurred when there was still partial blockage of ocean water flow into the rift valley along the east coast. This allowed thick evaporites to form. The last stage was the open-marine stage, where platform carbonate gave way to continental margin sediments and a progressive seaward tilting of the margin. See Figure C-1 for an idealized cross-section of the margin.

Five systems have been identified in the continental margin basins. These are shown in Figures with types of oil fields, trap, reservoir rock and source rock. One of the major systems is when upthrown blocks pushed Jurassic sandstones into contact with overlying Necomian shales. Some of the largest fields formed this way, particularly in the Reconcavo basin. The second system consists of anticlinal structure with deltaic sandstones as reservoirs and lacustrine shales. The Aptian system is composed of sandstone reservoirs over fault blocks and transitional shale source rocks. Field sizes are from 30 to 170 million bbls. The fourth system is the Albian-Santonian system consisting of Garoupa and Namorado fields (130 and 260 mill. bbls. respectively). Reservoirs are calcarenite or sand. The last system is the Late Cretaceous-Tertiary system with turbidity sandstone reservoirs and slope shale source rocks. These field are small, .5 to 20 million bbls in size. Very detailed descriptions of fields and basins have been written by Ponte (1977).

The important aspects of the geology in these basins are those that relate to the model parameters in this study. These are prior probability of giant and commercial fields, field size distribution in plays and basin prospective areas. Since there has been incomplete exploration worldwide of continental margin basins it is hard to judge whether Brazilian basins are average. They do not appear particularly prolific but have three fair-sized commercial-field plays. It is



PETROLEUM HABITATS	TYPE OF TRAPS	RESERVOIRS	SOURCE ROCKS
③ MARINE TRANSGRESSIVE	. STRATIGRAPHIC SAND LENSES. . COMBINATION: UPTHROWN SIDE OF GROWTH FAULTS COMBINED WITH POROSITY VARIATIONS AND SAND LENSES.	. TURBIDITE SANDSTONES. . CALCARENITES.	MARINE TRANSGRESSIVE SHALES.
② RESTRICTED MARINE AND TRANSITIONAL	. PALEOGEOMORPHIC STRUCTURES OVER BASEMENT HIGHS, CONTEMPORANEOUS WITH THE RESERVOIR ROCKS.	. BLANKETS OF BASAL SANDSTONES AND CONGLOMERATES . FRACTURED BASEMENT ROCKS.	TRANSITIONAL EUXINIC SHALES ASSOCIATED TO THE EVAPORITIC SEQUENCE.
① LACUSTRINE: RIFT-VALLEY	. ANTICLINAL STRUCTURES LOCATED IN REGIONAL FAULT – TROUGHS . STRATIGRAPHIC SAND LENSES	. DELTAIC LACUSTRINE SANDSTONES.	PRODELTAIC LACUSTRINE SHALES ASSOCIATED TO THE RIFT-VALLEY SEQUENCE.
	. UPTHROWN BLOCKS OF NORMAL FAULTS, ASSOCIATED OR NOT TO LOCAL UNCONFORMITIES	. FLUVIATILE SANDSTONE BLANKET.	

Fig. C1 Idealized geologic cross-section of the Brazilian continental margin, with the main characteristics of the petroleum habitats.

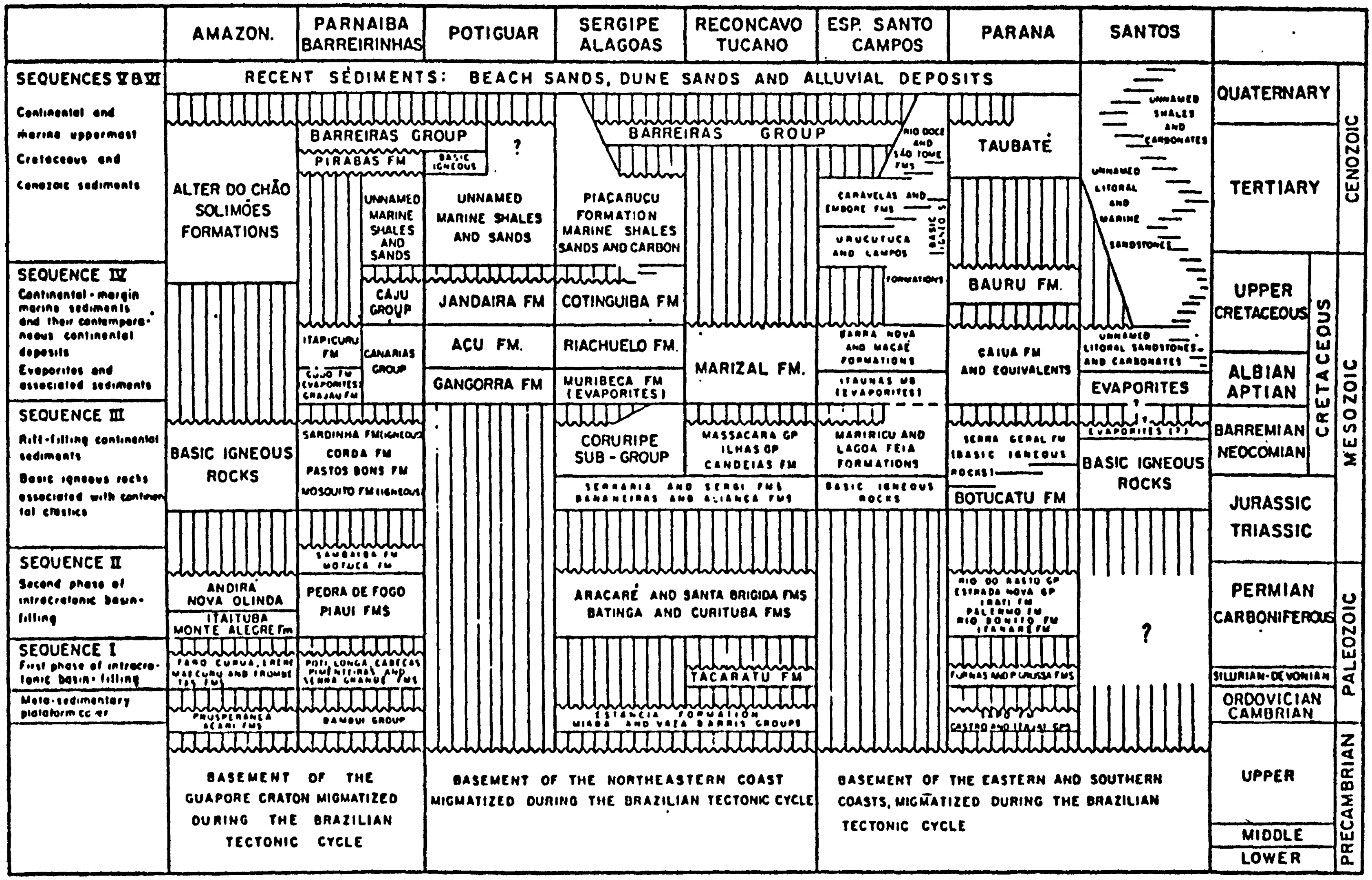
PETROLEUM HABITATS	PETROLEUM PROVINCES				
	CAMPOS	ESPIRITO SANTO BAHIA SUL	RECÔNCAVO - TUCANO	SERGIPE - ALAGOAS	CEARÁ POTIGUAR
MARINE TRANSGRESSIVE	PARGO ENCHOVA BAGRE NAMORADO GAROUPA PAMPO	FAZ. CEDRO CAÇÃO		GUARICEMA DOURADO BREJO GRANDE MERO TAINHA	AGULHA
RESTRICTED MARINE AND TRANSITIONAL	BADEJO	RIO ITAUNAS SÃO MATEUS RIO PRETO		CARMÓPOLIS SIRIRIZINHO RIACHUELO CAMORIM MATO GROSSO TAB. DO MARTINS	UBARANA XARÉU CES-19
CONTINENTAL LACUSTRINE RIFT-VALLEY BASIN			CANDEIAS MIRANGA ARAÇAS TAQUIPE DOM JOÃO AGUA GRANDE BURACICA BOA ESPERANÇA MATA DE S JOÃO	ENG. FURADO S.M. CAMPOS CAIOBA	

Fig. C2 Distribution of the main oil fields in the five Brazilian petroleum provinces, classified according to the three main petroleum habitats.

interesting to note that by matching Brazilian basins with the west coast of Africa the author found that oil plays in Brazil filled in the gaps in the oil occurrences in Africa--Brazil has fewer plays, which may have derived from asymmetric seafloor spreading in the Atlantic (Gray 1980). More of the rift valley floor may have been left attached to Africa. For lack of better prior probabilities for continental margin basins, Klemme's probabilities have been used with a sensitivity analysis. In light of the deposit sizes worldwide in this type of basin, however, it seems as though the probability of giant fields (.2) is an unusually large fraction of the probability of commercial fields (.3). Giant field plays are less frequent and a probability of .1 seems more likely based on Known basins worldwide. Field size distributions within plays for these types of basins fit well with Klemme's observations. The largest field contains 40-50 percent of play reserves. Prospective areas are defined as all those areas less than 200 m of mater where sediments are thick enough to possibly contain oil. Those areas with very thin cover or areas with shallow volcanic cover were eliminated. Total prospective area is calculated to be 158,000 km^2.

Amazon Delta

Oil traps in deltas are usually sand deltas, structure related to diapirs or rollover structures. Young deltas tend to be gas prone. The Amazon delta began to form after the Mesozoic rifting event. In the Miocene the uplift of the Andes initiated heavy influx (60-fold increase) of terrigenous sediment onto the delta. During glacial periods with low sea level the sediment is emptied directly onto the outer margin. During high sea level stands (as today) sediment is transported along the inner shelf. This delta contains few rollover structures and productive plays would most likely involve clastic reservoirs and diapir related reservoirs. A large portion of the fan is in very deep water. Of the portion which is in water less than 200 m 57 wells have been drilled in an area of 31,500 km^2. According to Klemme there is a 50 percent chance that an average delta contains oil. If it does, the largest field contains only 9 percent of play reserves. The likelihood of drilling 65 dry wells and finding no deposits if approximately 10 exist (each about 65 million bbls) is only .11. This gives an expected amount of oil of 72 mmb (see Annex 14). Deltas require a considerable number of wells to determine whether or not oil is present.

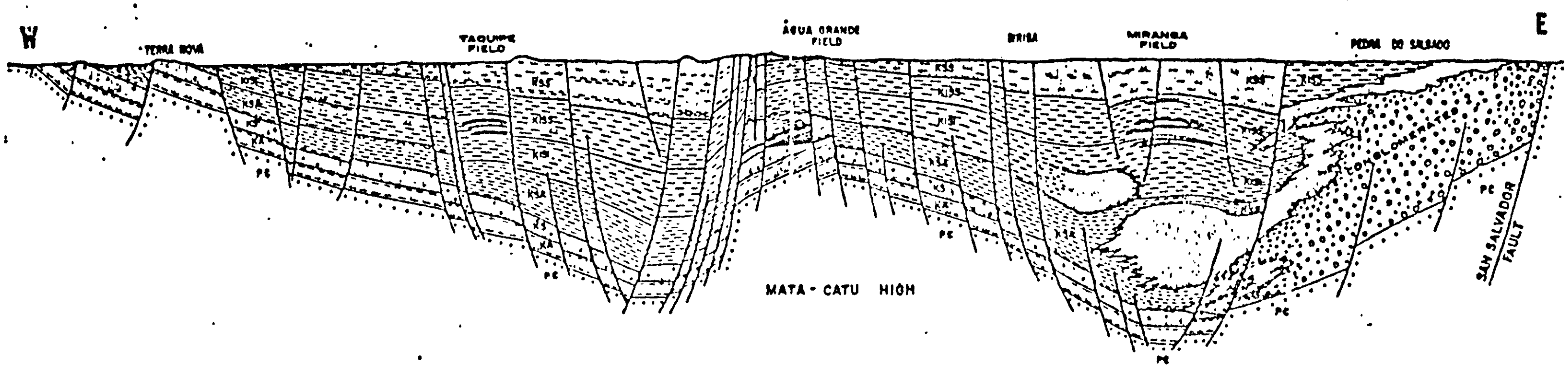


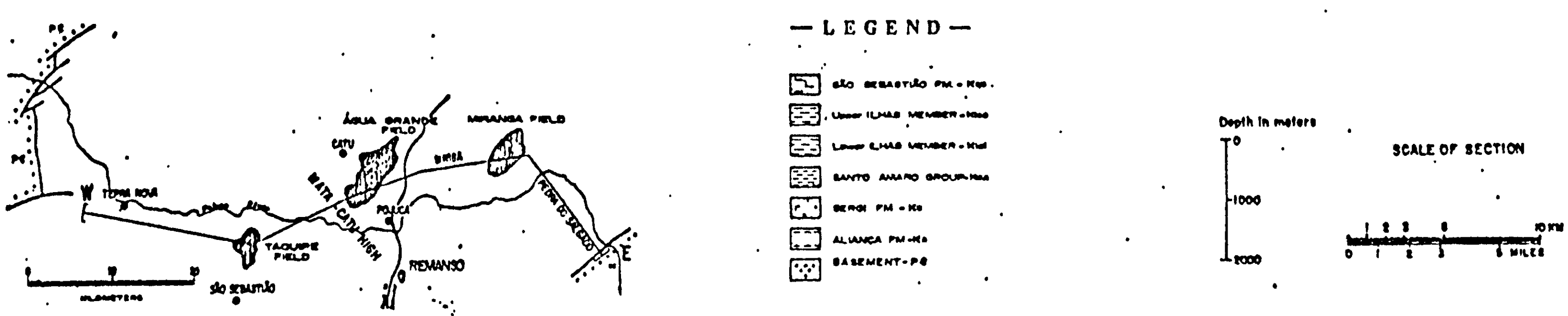
Stratigraphic correlation chart of the main Brazilian sedimentary basins.

BRAZIL

RECONCAVO BASIN

REGIONAL SCHEMATIC W E CROSS SECTION THROUGH THE RECÔNCAVO BASIN



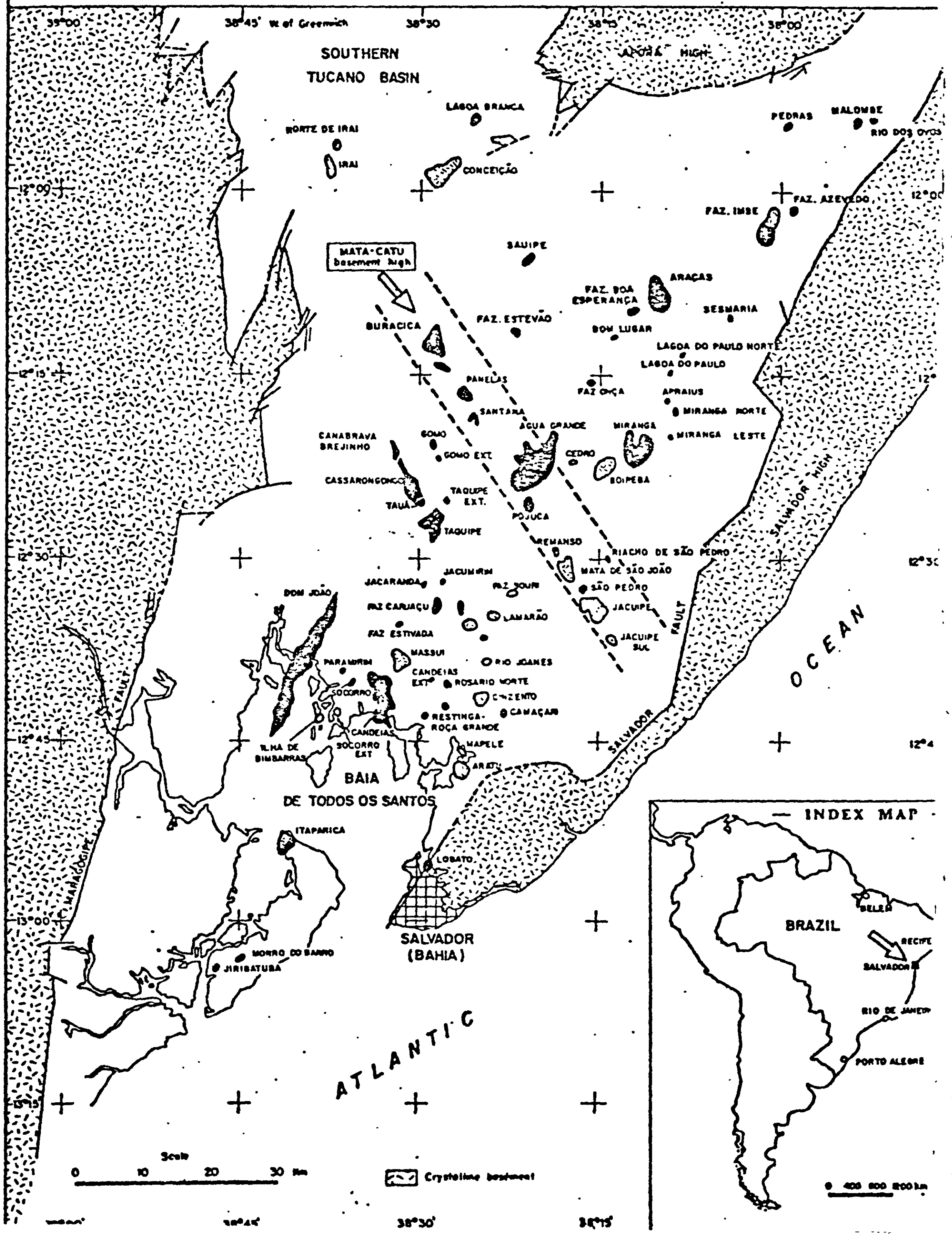


After I. GHIGNONE in AAPG, MEMOIR 14, 19

BRAZIL

RECÔNCAVO BASIN

Oil and gas field location map



Offshore Campos Basin Map

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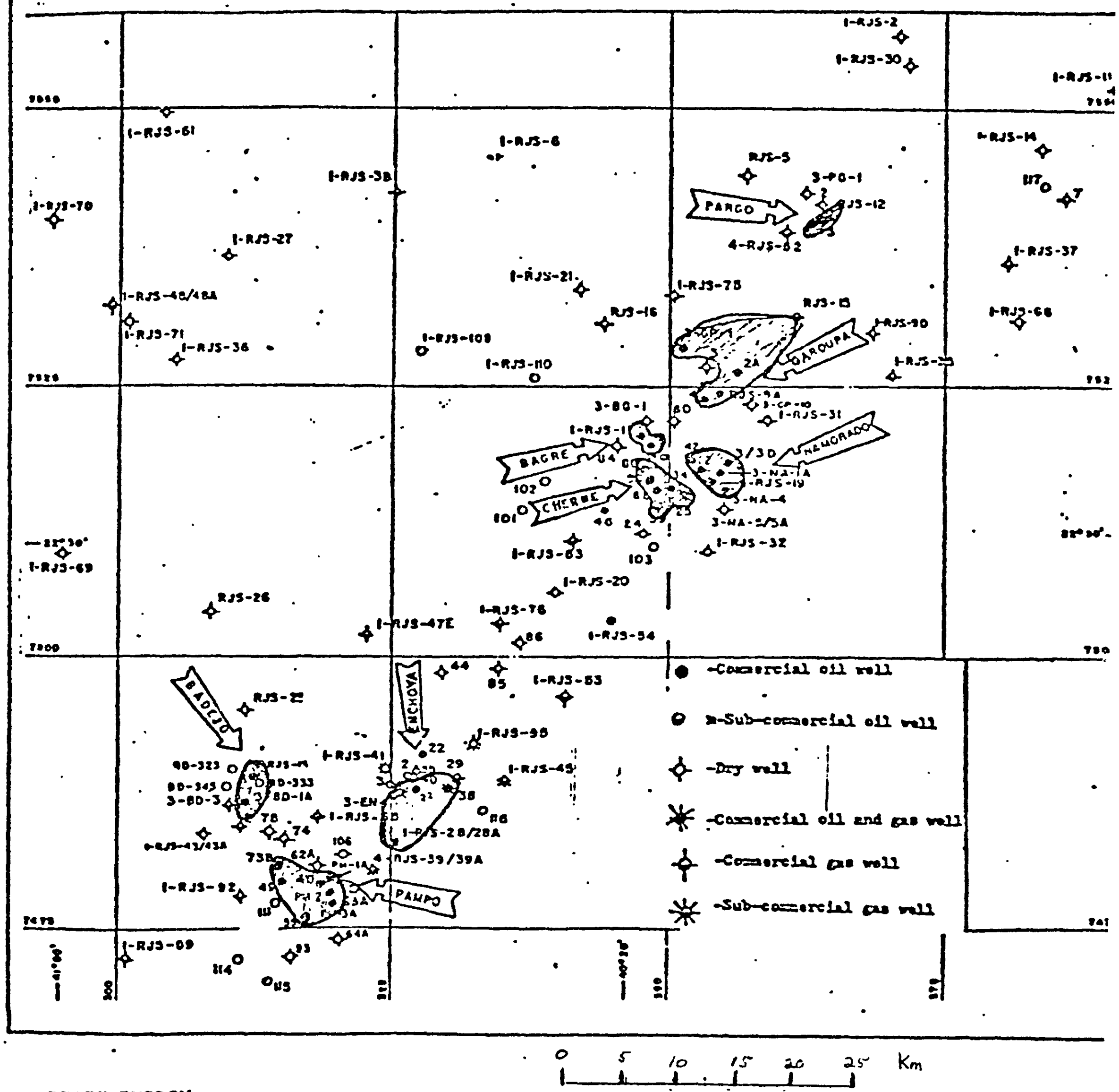


BRAZIL ENERGY

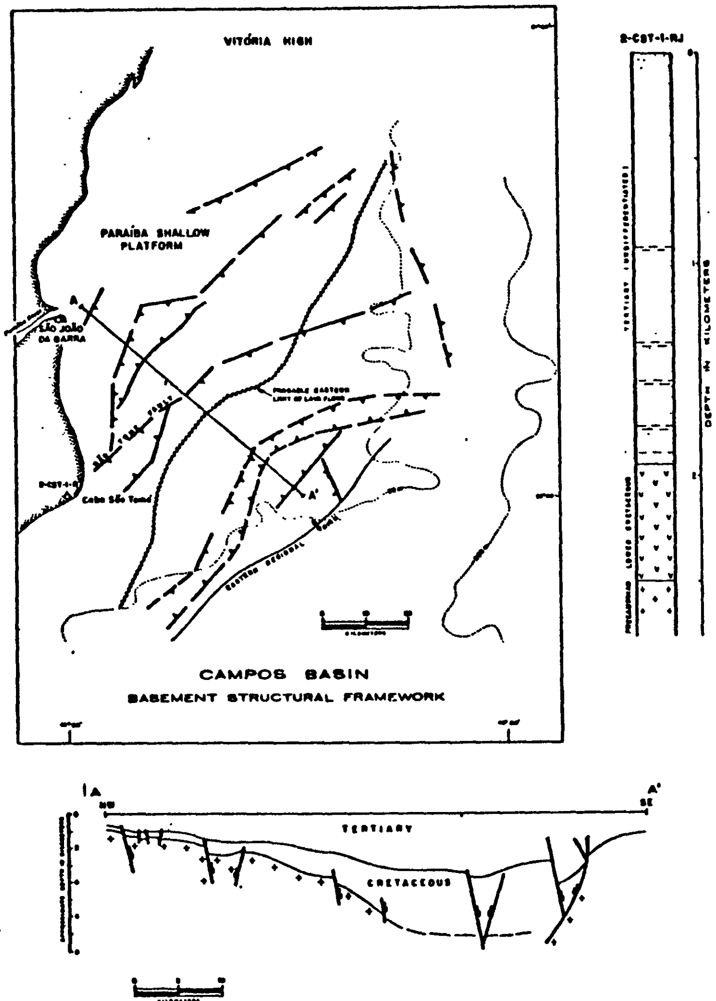
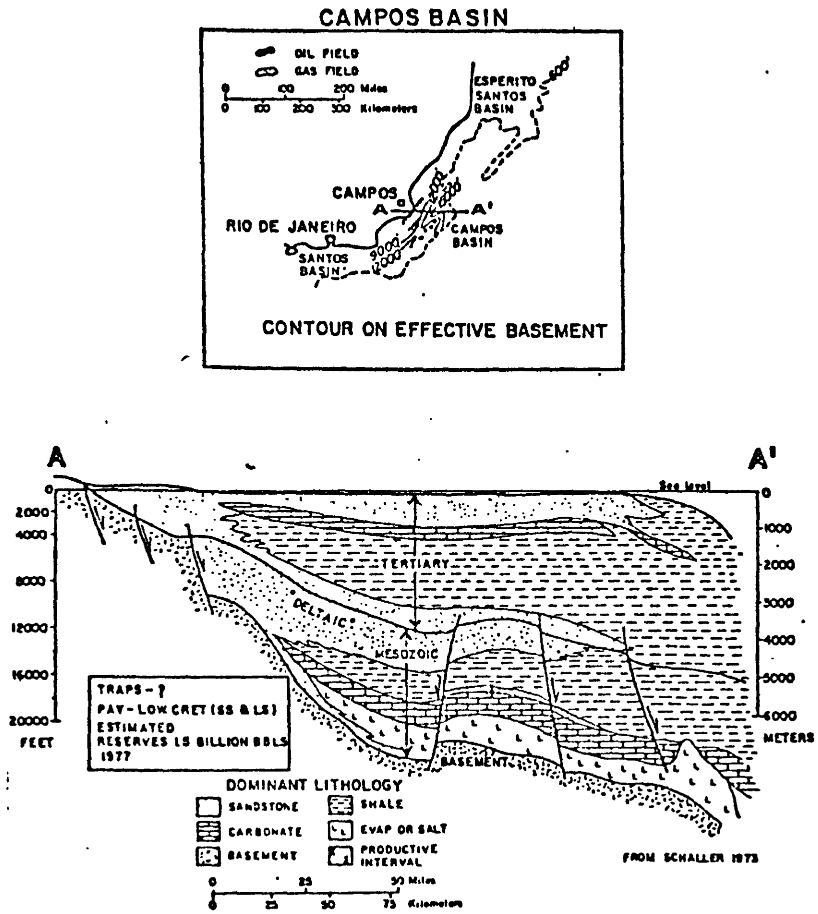


Fig. 14. Campos basin: basement structural framework; geologic cross section based on seismic data and stratigraphic column of the well 2-CST-1-RJ (Cabo São Tome).



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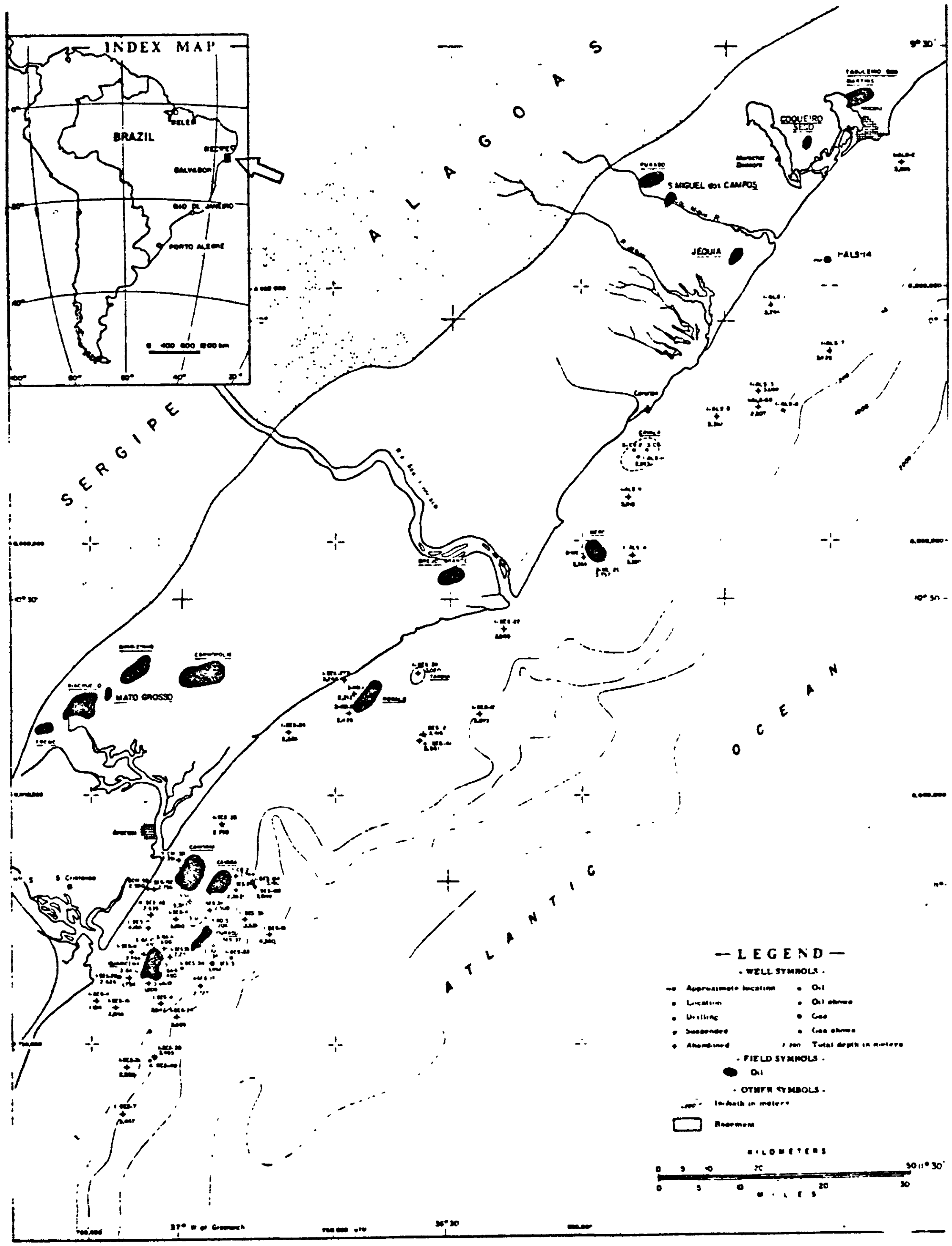

INDEX MAP
BRAZIL
RECIFE
SALVADOR
RIO DE JANEIRO
PORTO ALEGRE
ALAGOAS
SERGIPE
COQUEIRO SECO
S MIGUEL dos CAMPOS
JEQUIA
MATO GROSSO
ATLANTIC
OCEAN
— LEGEND —
- WELL SYMBOLS -
- FIELD SYMBOLS -
Oil
- OTHER SYMBOLS -
Basement
KILOMETERS
MILES
36° 30'
9° 30'
10° 30'

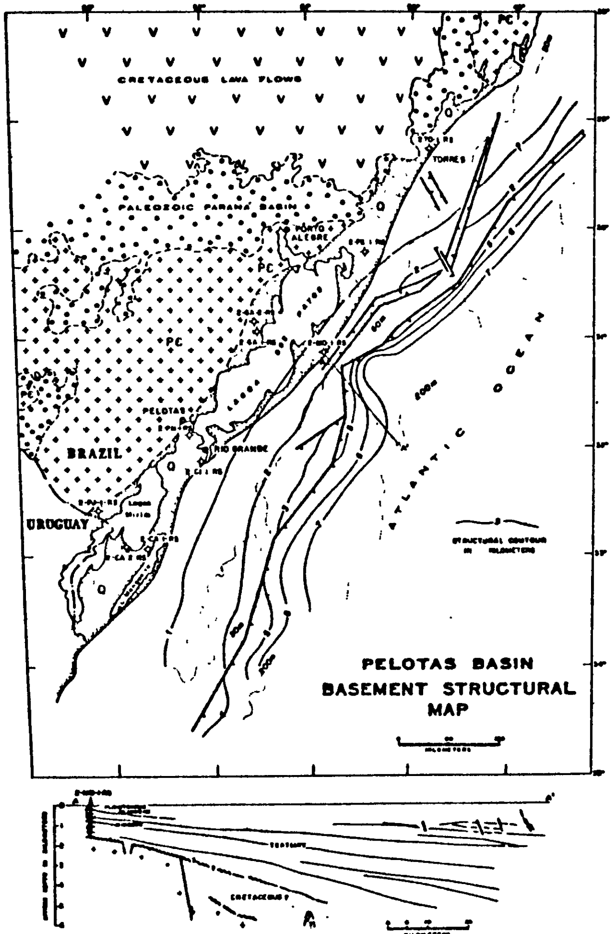


Fig. 16. Pelotas basin: basement structural map and geologic cross section based on seismic data.

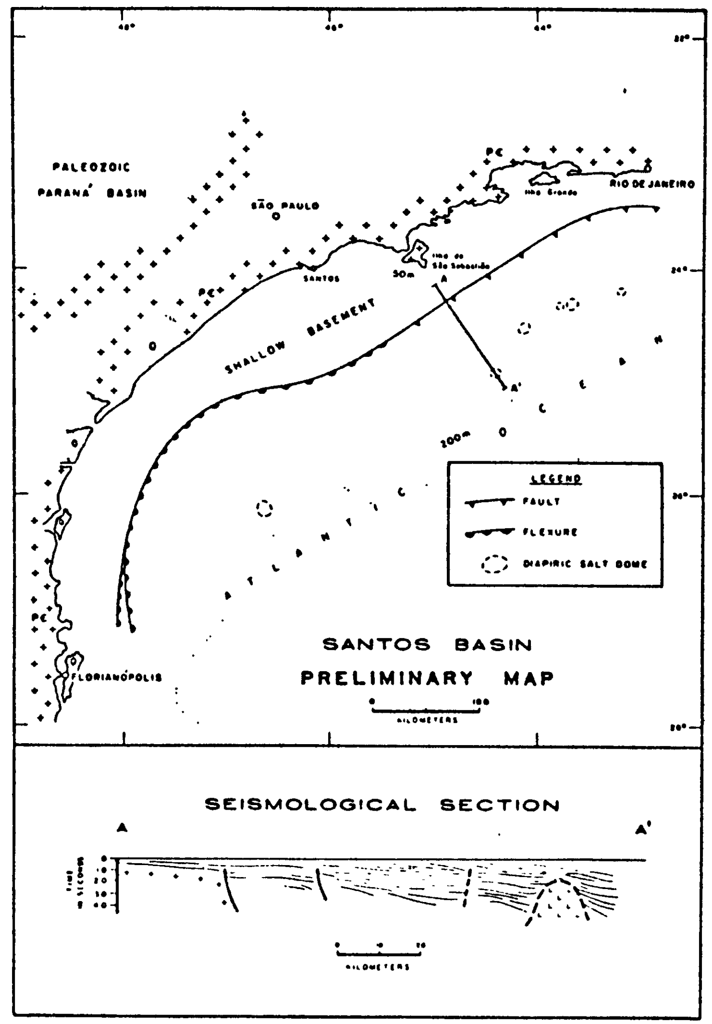


Fig. 15. Santos basin: preliminary structural map and seismologic section.

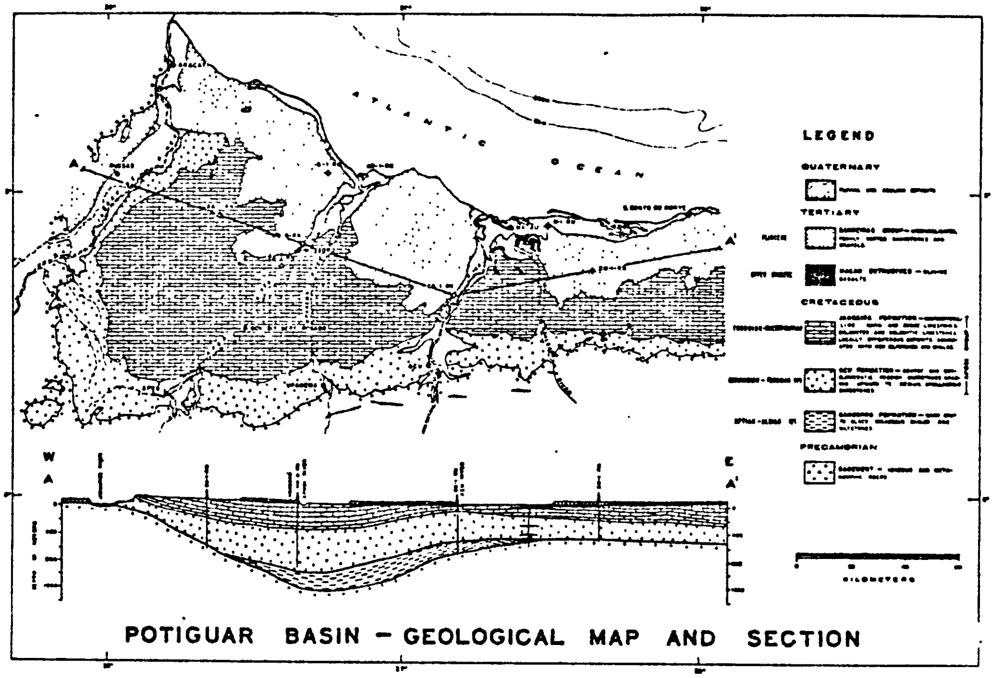


Fig. 18. Potiguar basin: geologic map and cross section

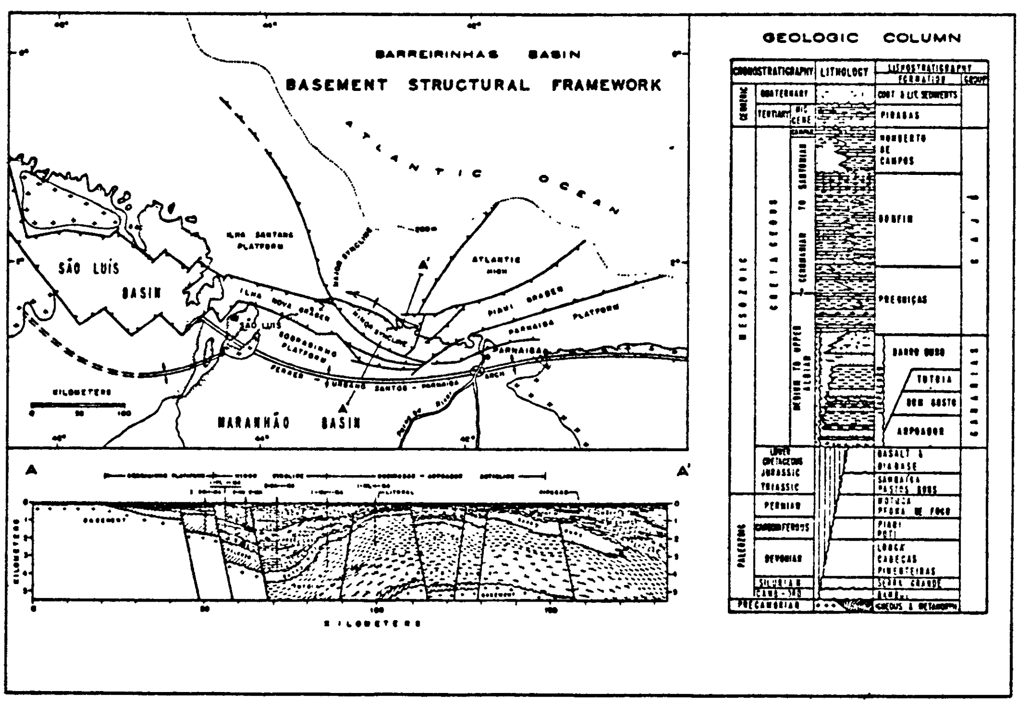
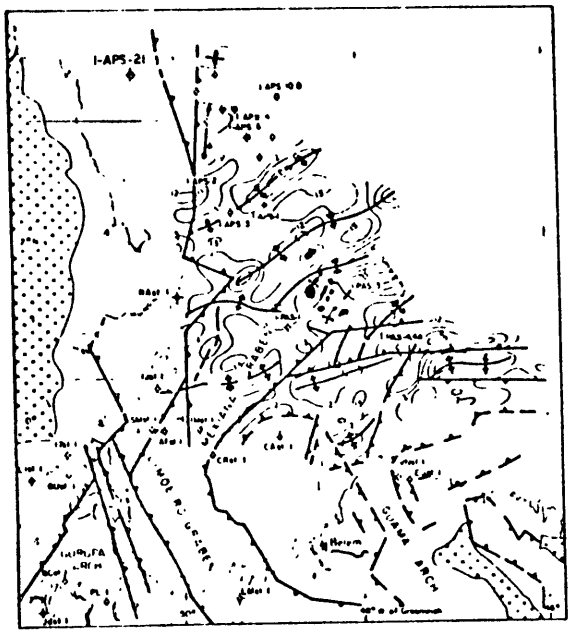
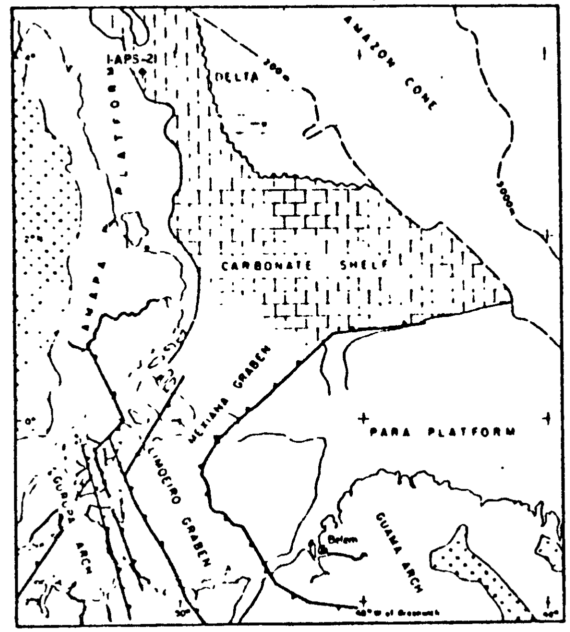


Fig. 17. Barreirinhas basin: basement structural framework, geologic cross section, and composite geologic column.

MAIN TECTONIC AND SEDIMENTARY FEATURES OF MARAJO GRABEN AREA

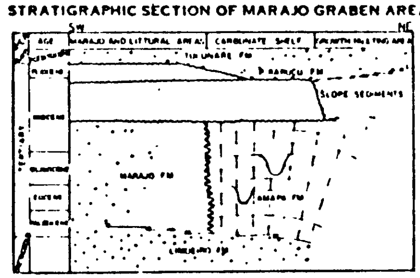




— LEGEND —

- Magnetic basement in km
- Major faulting
- Magnetic high
- Seismic high
- Local highs (reflection seismic)
- Dry well
- Oil shows
- Gas shows
- Gas discovery

STRATIGRAPHIC SECTION OF MARAJO GRABEN AREA

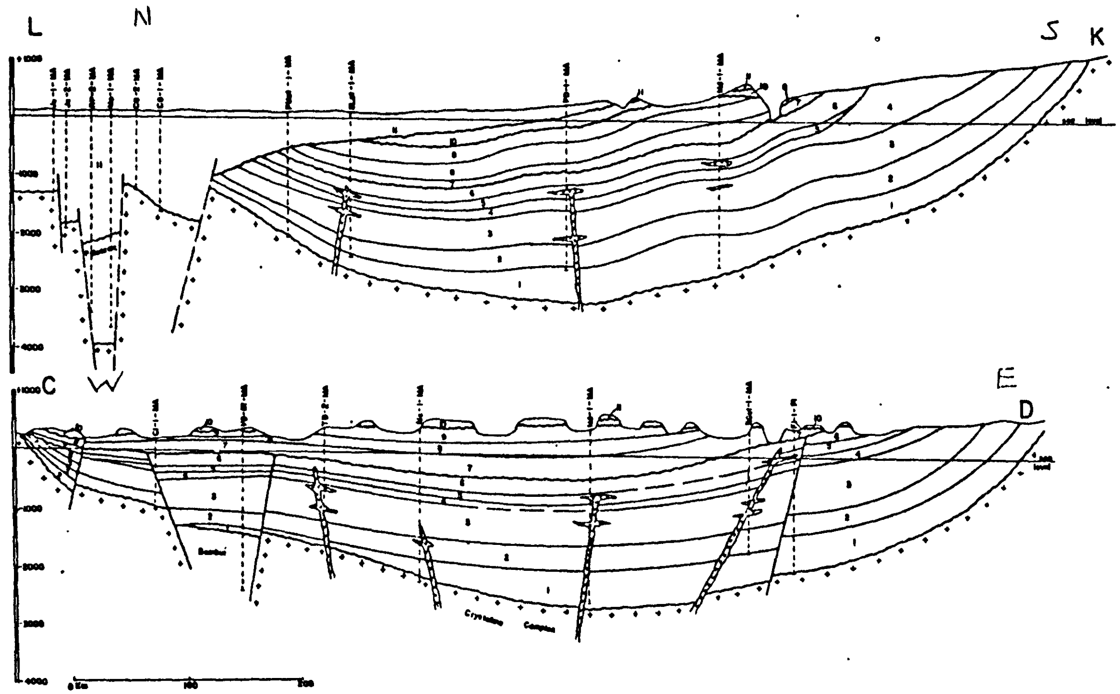


Deltaic and slope terrigenous sediments

Clastics sediments / Carbonate platform

Terrigenous sediments

After C W MARINHO AND W M REZENDE (1972)



Cross sections through the Parnaiba basin. (1) Serra Grande fm; (2) Itaim Member (Pimenteira fm); (3) Picos Member (Pimenteira fm); (4) Cabeças fm; (5) Longá fm; (6). Poti fm; (7) Piaui fm (8) Pedra de Fogo fm; (9) Motuca fm; (10) Sambaiba fm; (11) Cretaceous (Petrobrás, S. A.).

5-1. Method of Estimating the Economic Return, NPV and Variance of Future Exploration Programs

The previous chapter developed a model of oil exploration which estimates probability of play discovery as a function of future exploration wells drilled. Multiplying the probabilities of discovery by the amount of oil found in an average play (of that basin type) gave the expected amount of oil to be found with a given level of exploration effort. In a similar manner the net present value of an oil play can be multiplied by the probabilities to get an expected value of oil to be discovered. Once discounted exploration costs are subtracted the net present value of various oil exploration programs can be found. We will assume that a specific number of oil exploration wells (100 or 200 or 300 ...) are planned over a 5 year period. There are lags between initial exploration and discovery and lags between discovery and production.

If a block of exploration wells are drilled each year in equal numbers over the next 5 years, some plays may be discovered early and some later. On the average it is reasonable to model the play discovery early in the 5 year period since there are diminishing discoveries with additional wells. We will use the probabilities of discovery (Tables 4-11, 4-12, 4-13) for a certain number of wells (say 200 wells drilled over 5 years) and multiply these probabilities by the net present value of an oil play assuming that if a play is discovered, it is discovered on average in about 2 years.

The net present value of the play should also take into account the delay between discovery and initial production. This delay is estimated to be 2 to 5 years for "giant field" plays and 2 to 4 years for "commercial field" plays (based on data from fields offshore Brazil - see Annex 5-1). This is based on delays observed for plays already found offshore Brazil. The delay between initial exploration and initial production is therefore estimated to be about 5 years. Development expenditures are assumed to be made on average at the midpoint (2-3 years) of this interval. Once the expected value of the oil is calculated, the discounted costs of drilling the exploration wells (i.e. type 1 wells searching for oil plays) over 5 years is subtracted. The result is the net present value of the exploration program. The variance of the outcome can be calculated using the probabilities of discovery. Analysis of the exploration program can be from the viewpoint of exploration by Petrobras or from the perspective of exploration by the multinational oil company. The exploration risk contract terms for foreign oil companies in Brazil will be used for exploration programs involving multinational oil companies.

5-2. Net Present Value of an Oil Play

The goal of this section is to calculate the net present value of a hypothetical "giant field" play and a "commercial field" play. The major emphasis will be calculating NPV's for plays offshore Brazil. This offshore region is the area of greatest exploration activity and greatest expected oil potential. Analagous calculations will be made later for the Amazon delta and onshore basins.

The net present value of a play is the present value of the oil produced minus costs. As described earlier in chapter 3 the NPV of a block of oil reserves can be calculated as:

$$NPV = \frac{PQ}{a+r} - I \qquad \text{(eq. 5-1)}$$

This assumes a constant future oil price. For our purposes, we need to make a few changes in this simple formulation to give a more accurate estimate of NPV of a play. First, the price of oil need not remain constant over time. Second, costs involve development costs, operating costs and cost of drilling type 2 exploration wells to delineate fields in the play. A revised formula used to calcualte NPV of an oil play is give- in Table 5-1. The delay between initial exploration and the initial production of the first field is d (5 years for large plays, 4 years for small plays). If plays are discovered, they are assumed to be discovered realitvely early in the 5 year exploration program. It is assumed that on average development expenditures and expenditures to find remaining fields in the play are mde at 2 to 3 years after initial exploration and thus 2 to 3 years before initial production. Thus, in order to get the net present value of a play today, we need to discount the value of the oil and operating costs at $1/(1+r)^d$, and discount the development cost and exploration costs (to find remaining fields) at $1/((1+r)^{d/2}$. The oil price is assumed to grow from the present at at g (0, 3 percent and 5 percent per year), from a base of $30/bbl.

2.A. Offshore Marginal Basins

The plays offshore are assumed to be in 250 to 350 feet of water, the average depth of water in the offshore prospective areas. The

Table 5-1

Method of Calculating Net Present Value of an Oil Play

$$NPV = \frac{PQ_p}{a + r} - I \quad \text{for constant future oil price}$$

$$NPV = \frac{(1 + g)^d \, PQ_p}{(1 + r)^d (a + r - g)} - \frac{I}{(1 + r)^{d/2}} - \frac{IEE}{(1 + r)^{d/2}} - \frac{(OC)Q_p(a+r)}{(1 + r)^d (r)} \quad \text{(eq.5-2)}$$

Net Present Value	Value of Oil Produced	Investment Cost	Cost of Exploration Wells to Find Fields in Play	Operating Cost

P = oil price (\$1979)

g = growth rate of oil price (per year)

r = discount rate, a = decline rate

Q_p = peak production (mill bbl/yr)

I = development investment (million \$1979)

d = delay between initial exploration and initial production, investments made at time d/2, initial production starts at d years

OC = operating costs (\$ per bbl, OC constant per well)

IEE = number of wildcats to find and delineate 90 percent of oil in fields of play.

capital coefficients are estimated from coefficients of known offshore plays in 250-350 ft. of water (Chapter 3). The capital coefficient of small play (275 mmb) is taken to be $9000/bbl per day. For large play (1330 mmb) the capital coefficient is estimated to be $7000/bbl per day.

Application of the NPV formula developed here (shown in Table 5-1) was used to estimate the sensitivity of NPV to oil price and discount rate. As can be seen the net present value of a "giant field" play (table 5-2) and a "commercial field" play (table 5-3) show wide variations when different oil prices and different discount rates are used. The exact parameters used to calculate these NPV's are given in Annex 5-2 (large play parameters) and Annex 5-3 (small play parameters). These play NPV's are approximations only, and in some sense can be considered optimistic or best case estimates since longer delays on difficult development conditions would decrease the NPV somewhat.

The decline rate (a) for NPV calculations was taken to be 0.12, based on plans for offshore Brazil and other offshore areas (examples in Adelman and Paddock, 1980). Investment is an increasing function of the depletion rate since there are diminishing physical returns as more wells are drilled to pump oil faster. Although we feel it is reasonable to assume that our estimated capital coefficient ($7000/bbl per day of a play containing 1330 mill bbls) corresponds to a depletion rate of 0.12, it is important to do a sensitivity analysis to see the effect of different depletion rates and capital coefficients on the NPV of the oil play. The optimal depletion rates to maximize NPV is given in Adelman and Paddock (1980).

Table 5-2

Net Present Value of a Giant Field Play
Containing 1330 million bbls Offshore Brazil
(NPV in billion $1979, PV of oil produced in parenthesis)

Real Discount Rate	Annual Real Increase in Oil Price (from a Base of $30/bbl, 1979)			
	0%	1.5%	3%	5%
3%	22.9	29.5	38.3	54.9
5%	18.1 (22)	23.1 (27)	29.5 (33.5)	41.2 (45.2)
8%	12.8 (16.3)	16.2 (20)	20.5 (24)	27.9 (31.5)
10%	10.3 (13.5)	13.0 (16.3)	16.3 (19.5)	22.0 (25.3)
12%	8.3 (11.3)	10.5 (13.57)	13.1 (16.1)	17.6 (20.68)
15%	6.0	7.6	9.6	12.8
20%	3.5	4.6	5.8	7.8
25%	2.0	2.8	3.5	4.8
30%	1.1	1.6	2.0	3.0

Table 5-3

Net Present Value of a Commercial Field Play
Containing 275 million bbls Offshore Brazil
(NPV in billion $1979, PV of oil produced in parenthesis)

Real Discount Rate	Annual Real Increase in Oil Price (from a Base of $30/bbl, 1979) 0%	1.5%	3%	5%
3%	4.2	5.6	7.3	10.6
5%	3.3 (4.4)	4.7 (5.4)	5.6 (6.7)	7.9 (9.04)
8%	2.3 (3.3)	3.3 (4.0)	3.8 (4.8)	5.3 (6.3)
10%	1.7 (2.7)	2.3 (3.25)	2.9 (3.9)	4.1) (5.06)
12%	1.4 (2.26)	1.8 (2.7)	2.3 (3.22)	3.2 (4.14)
15%	0.9	1.2	1.6	2.3
20%	0.47	0.67	0.92	1.2
25%	0.18	0.32	0.45	0.8
30%	0.02	0.1	0.23	0.41

$$NPV = \frac{PQ}{a+r} - I$$

setting $\frac{d\ NPV}{dQ} = 0$ and P = marginal cost

optimal depletion rate = $a^* = (Pr/(dI/dQ))^{1/2} - r$ (eq. 5-3)

For the project as a whole I/Q = dI/dQ, but if we assume investment is an increasing function of a ($I=Ka^n$, K is a constant), then it can be shown that dI/dQ=(I/Q)n. Regression studies by Smith (1980) estimate that n=1.95, for onshore areas. Since an estimate of $7000/bbl per day is an average for the project as a whole, the marginal capital coefficient is 1.95 times the average if we apply Smith's estimate to our offshore region. Using this marginal capital coefficient in eq. 5-3 we can iterate to get an optimal decline rate of 0.17 (P=$30/bbl, r=.12). Using this optimal depletion rate for our estimated capital coefficient ($7000/bbl per day), the NPV of a giant play was calculated to be only 2-3% greater than with the assumed depletion rate (0.12). In this analysis here we will use depletion rate of 0.12 because it apparently makes little difference as compared to using the optimal rate. In addition, even if the target depletion rate is 0.17, it is likely that technical factors of offshore development may slow down optimal development to a depletion rate closer to 0.12.

Available exploration well costs for offshore and onshore Brazil are given in Annexes 5-4 and 5-5. The depth of these wells is usually between 8,000 to 11,000 feet according to Petroconsultants Brazil Field Records. The costs are somewhat higher for those offshore wells drilled by major oil companies as compared to those offshore wells drilled by Petrobras. Some of the quoted costs for the wells drilled by Petrobras are expected costs of future wells (3-4 million/well). As there have been real cost increases in the last several years and Petrobras cost quotes may have been understated, the average cost of new offshore wells searching for plays is probably somewhat higher ($5 million/well). The well costs quoted for the major oil companies may be the tail end of the range and may be somewhat overstated (7-10 million/well) so that the companies could fulfill contracted minimum exploration commitments with fewer wells. An average well cost of $5 million/offshore well will be used for the purposes of evaluating various levels of exploration. The net present cost of drilling 100 wells at 5 million/well over 5 years is $481 million (at a discount rate of 10%).

The NPV for various levels of exploration were calculated using the probabilities of discovery of offshore oil plays (Table 4-11), the NPV of oil plays (tables 5-2, 5-3), and well costs discussed above. The results are shown in in the next Table (5-4).

The net present present values shown in Table 5-4 are the difference between diminishing returns to exploration and linearly increasing costs of cumulative exploration. The optimal point to stop exploration is not where total cost equals total benefit (NPV=0 on Table 5-4). The optimal exploration program is where the marginal benefit equals marginal cost shown by the maximum NPV on Table 5-4. At a 10 percent real discount rate the maximum NPV is at 100 wells ($340

Table 5-4

Net Present Value of Offshore Oil Exploration Programs by PETROBRAS as a Function of Exploration Wells Drilled (NPV in millions of $1979)

Wells	Real Increase in Oil Price per Year (from $30/bbl in $1979)			
	0 percent	1.5 percent	3 percent	5 percent
A. (r=.10)				
50	194			
100	340	610	890	1,400
200	250	650	1,070	1,800
300	0	400	890	1,800
400	-400	160	690	1,700
500	-800	-280	270	1,300
B. (r=.12)				
50	122			
100	200	380	600	1,000
200	0	310	640	1,270
300	-270	0	400	1,130
400	-610	-280	140	950
500	-1,070	-720	-290	540
C. (IRR - percent)				
100	14	16	19	22
200	12	14	16	19
300	10	12	15	18

Note: A - real discount rate of 10 percent
B - real discount reate of 12 percent
C - Internal rate of return

Wells are type 1 exploration wells searching for new oil plays. All wells drilled by PETROBRAS, none by risk contractors.

million) if oil prices are expected to stay constant in real terms. For real increasing oil prices maximum NPV occurs at 200 wells. This implies that it is not profitable to explore for the last 50-100 million bbls, expected returns are too small.

2.B. Amazon Delta and Onshore Cratonic Basins

An evaluation of exploration programs for the offshore Amazon delta was made using probabilities of oil discovery (Table 4-13) and cost parameters similar to those used above for small offshore plays. At discount rates of 10 or 12 percent all exploration programs have negative NPVs. The internal rate of return for 50 wells drilled in the Amazon delta is calculated to be 1% if oil prices remain constant and 4.5% if oil prices increase at 5%/yr. Thus according to this model, exploration in the offshore Amazon delta appears uneconomic.

Returns from exploration in the onshore cratonic basins are somewhat more difficult to asssess with this model, than returns from exploration in the offshore basins. This is because past discoveries in the basins allowed one to calibrate the exploration efficiency. With no discoveries in the onshore cratonic basins the exploration efficiency cannot be estimated endogenously. The probabilities of oil play discovery calculated in Table 4-12 assume an exploration efficiency of 3. If these results are used, expected NPV peaks with the next 100 to 500 exploration wells. NPV varies from $150 to $400 million, depending if the oil price increases at 0 or 5 percent/yr, respectively. These estimates were made assuming play capital coefficients of $5000/bbl per day (small play containing 250 mmb) and $2500/bbl per day (large play containing 1000 mmb), along with cost estimate of 1 million per exploration well drilled. These estimates should be considered an upper bound for several reasons. As discussed in the Annex to Chapter 4, exploration efficiency for the large plays in these onshore basins may have been very much higher than 3, possibly up to 12. This would imply that the chance of finding a large play ("giant field play") is quite remote. If one assumes only small plays remain, the NPV of a 100 well exploration program drops to -$50 million (oil prices up at 0%/yr) and is $160 million (if oil price increases 5%/yr). NPV's could even be lower than this if the thick layers of hard basalt increase drilling costs substantially. It appears that large-scale exploration in these basins is expected to be profitable only if oil prices increase very rapidly. This is confirmed by the fact that PETROBRAS has allocated only 4 percent of its exploration budget to these basins over the next 5 years. Since oil exploration has the highest expected profitability in the marginal offshore basins, the remainder of this chapter will concentrate on exploration by PETROBRAS on foreign companies in these basins.

5.3. PETROBRAS Exploration Plans

PETROBRAS plans to spend $3.64 billion ($1980) on exploration over the five year period from 1981 to 1985 (according to "Brazil Energy" 8/24/80 and OGJ 2/16/81). Plans call for 1,781 exploratory wells. Seventy five percent of its expenditure ($2.8 billion) will be on 806 offshore exploration wells. About 300 wells will be drilled in the Campos basin (i.e. type 2 wells to find fields in the Campos basin play). The remaining 506 exploration wells will be drilled in other areas (i.e. most all are type 1 wells looking for new plays). Average drilling depth is expected to be 12,000 ft. in average water depth of 330 ft.

Onshore exploration plans call for 975 exploration wells at a cost of $832 million. About 85 percent of the wells will be drilled in the coastal basins (260 in the mature Reconcavo basin and 560 in other coastal basins). The remaining 155 wells are planned for the three large onshore cratonic basins.

5.4 Exploration Service Contracts

In October 1975 Brazil diverged from its policy of a Brazilian-only exploration program. PETROBRAS offered exploration service contracts to foreign oil companies to accelerate petroleum exploration in particularly difficult regions. Three rounds of international bidding were completed by late 1979, and 128 contracts have been signed with foreign oil companies (24 for offshore blocks and 4 for onshore blocks in the Amazon). Exploration contract terms are described below based on a brochure published by PETROBRAS.

Under the terms of these contracts the oil company pays a fee for the available geologic data. PETROBRAS then offers certain areas for which companies bid to provide exploration as a contract service to PETROBRAS. The contractor bears the "risk" of exploration. If there are no discoveries, the contractor is not reimbursed for his expenses and the contract is cancelled. Until mid-1979 the contracts contained a pre-agreed upon minimum investment commitment and minimum number of wells to be drilled for the three year exploration period. But in 1979 a second type of contract was offered which provided the companies with the option of drilling wildcats after the pre-agreed investment in seismic surveys was made. A bank letter of guarantee insures that the minimum inevestment will be made. The letter is used to guarantee payment to PETROBRAS of any shortfall between actual investment and minimum investment.

In the event of a commercial discovery, the contractor is responsible, technically and financially, for development. The contractor is reimbursed for exploration and appraisal expenses without interest, and for development expenses with interest. Furthermore, the contractor is entitled to remuneration proportional to oil production from the fields found and developed by him, which must be at the "maximum efficient rate". The term of remuneration from oil produced are set during contract negotiations. A proportion of the total oil produced in any quarter is multiplied by the price of crude oil to arrive at a quarterly remuneration to the contractors (in US dollars). The minumum and maximum shares for foreign oil companies are 20 and 35 percent (according to Brazil Energy Dec. 5, 1979). The price of crude oil is set by PETROBRAS to equal the worldwide long term contract crude oil sale price at the time of production. The contractor has an option to buy back oil at the same price during the following quarter unless a crisis in petroleum supply is declared by the Brazilian Government. The contractor is required to pay Brazilian income tax on his net taxable income (25% or as arranged by existing tax treaties). PETROBRAS is committed to make capital payments only up to the amount of net income from the fields in any quarter.

In the first round of bidding, 10 offshore blocks were offered and 4 were contracted. In the second round, 25 offshore blocks were offered and 13 contracted. The third round results were somewhat disappointing, 21 offshore blocks and 21 onshore blocks being offered but only 11 being contracted.

Minimum investment commitment is US$296 million and total investment by August 1979 has been US$298 million. Planned total investment for the first three rounds is US$343.7 million. Minimum seismic exploration committed is 31,210 km., with 41,580 km. already completed (costing US$17 million). The minimum number of wells to be drilled is 53. Twenty six have been drilled (all offshore), but no commercial discoveries have been made. The cost of the wells already completed was US$200 million.

In the beginning of the fourth round 124 blocks were offered (104 onshore, 20 offshore). But in January 1980 PETROBRAS eased the contract terms. Now complete basins are offered for bidding rather than blocks. If oil is discovered, payment will be made in oil rather than in dollar equivalent. Incentives are also provided for smaller private Brazilian companies to take up risk contracts, with assistance from PETROBRAS. The contracted company will now be allowed to participate in the evaluation of the field and in the production stage. The new terms were applicable in the fourth round which ended April 9, 1980.

Details of a recent risk contract signed between PETROBRAS and Paulipetro, a consortium of CESP (Sao Paulo Energy Company) and IPT (Sao Paulo Institute for Technological Research) were released January 1980. Paulipetro signed contracts for oil exploration in 17 onshore blocks in the Parana basin. The contract requires investment of 1.5 to 2 million US$ per block over the next three years for seismic work before deciding whether or not to drill or give up the area. Paulipetro will receive 37% of the value of any oil and gas discovered in cruzeiros equivalent to the world market price and will also be eligible for up to 13% of net profits from oil and gas discovered. When the field enters operation it is turned over the PETROBRAS. Paulipetro is building up a staff of 600 and subcontracting the seismic exploration. Cooperation from PETROBRAS is expected to be greater than with risk contracts between PETROBRAS and foreign companies.

We can use this information on current exploration service contracts to construct a simple model of the split of NPV between the oil companies and PETROBRAS. We will use the probabilities of discovery, the present value and present cost of oil produced and risk contract terms to calculate the NPV of exploration by a company and the share going to PETROBRAS. For a given block of exploration wells the fraction drilled by the foreign oil companies is denoted as f. If all exploration is done by the companies, f=1. The split of NPV is calculated as follows:

For a given block of exploration wells:

$$NPV_{TOTAL} = NPV_{OIL\ COMPANY} + NPV_{PETROBRAS}$$

$$NPV_{OIL\ COMPANY} = x(1-t)(\sum_{i=2}^{4}(fp_i)V_i) - fp_1(IE)$$

$$NPV_{PETROBRAS} = \sum_{i=2}^{4} p_i(f(1-x)V_i - C_i - IE) + tfXV_i$$
$$+ (1-f)(V_iC_i)) - (1-f)\ IE$$

p_i, i=2 to 4 = probability that oil in state i will be discovered

p_1 = probability that no oil will be discovered

V_i = present value of oil produced

C_i = present costs of oil play development

IE = present cost of oil exploration wells (wells exploring for plays)

X = contracted fraction of oil going to oil company (30 percent on average)

f = fraction of block of oil wells drilled by oil company (if f=0 all exploration is by Petrobras)

t = tax rate on corporate income in Brazil (25 percent)

$NPV_{OIL\ COMPANIES}$ is calculated net of Brazilian tax but betore U.S. or other tax.

Using this formulation above the NPV of an exploration program of wells drilled by the foreign oil companies is calculated (as shown in Table 5-5). The maximum NPV gives the optimal exploration level for the companies, given that PETROBRAS drills <u>no</u> exploration wells (i.e.

Table 5-5

Net Present Value of Offshore Oil Exploration Programs
with all Exploration Drilling by Foreign Oil Companies
(NPV in millions $1979)

	Real Increase in Oil Price per Year (from $30/bbl in $1979)			
Wells	0 percent	1.5 percent	3 percent	5 percent
A. (r=.10)				
50	-32	0	56	97
100	-47	10	183	197
200		-155	-56	237
300				125
400				30
B. (r=.12)				
50	-60	-35	-6	46
100	-90	46	9	102
200			-160	96
300				-37

A. real discount rate is 10 percent.

B. real discount rate is 12 percent.

type 1 exploration wells). Optimal exploration by the foreign oil companies stops short (about 100 wells) of the optimal exploration plan from the point of view of PETROBRAS.

The decision by the oil companies to explore in Brazil is dependent not only on the terms offered but on the amount of exploration undertaken simultaneously by PETROBRAS. An example using the model developed here helps show this point. If PETROBRAS does no exploration, oil prices increase 1.5 percent per year and a discount rate of 10 percent is used, the optimal exploration program for the oil companies will be to drill 100 wells with an expected NPV of +10 million \$1979 (political risks ignored for the moment). However, if PETROBRAS decides to drill 400 wells and the oil companies are planning to drill 100 wells (both programs drill wells over 5 years), the expected NPV of the oil company drops to -81 million \$1979. This is due to the fact that large scale extensive exploration by PETROBRAS resolves uncertainty in the resource base and quickly drives down the returns to exploration so that, on the average, the oil company program becomes less profitable.

Since optimal exploration by foreign oil companies is not optimal from the viewpoint of Brazil it is very useful to calculate how much Brazil would give up (in NPV terms) by letting foreign oil companies do all the exploration. These key results are shown in Table 5-6 (real discount rate r = 10 percent) and Table 5-7 (r = .12). For oil price increasing at a real rate of 0 or 5 percent per year, the loss the Brazil is estimated to be \$48 to \$440 million, respectively (regardless

Table 5-6

Comparison of the NPV of Exploration by PETROBRAS and Exploration by Foreign Oil Companies
(NPV in millions $1979, Real Discount Rate is 10 percent)

Wells	Real Annual Percentage Increase in Oil Price (base of $30/bbl, $1979)			
	0 percent	1.5 percent	3 percent	5 percent
(r .10)				
1. Optimal Exploration by PETROBRAS	340 (100 wells)	650 (200 w)	1,070 (200 w)	2,000 (200 to 250 w)
2. All Exploration by Foreign Oil Comp.				
a. Optimal Oil Comp. Exploration	0 (0 w)	10 (100 w)	183 (100 w)	237 (200 w)
b. PETROBRAS Share	0	600	600	1,560
3. Difference btw. PETROBRAS Share and Optimal Exploration by PETROBRAS (2b.-1.)	-340	-50	-180	-440
4. Planned Exploration by PETROBRAS	-800 (500 w)	-280 (500 w)	270 (500 w)	1,300 (500 w)
5. Difference btw Planned and Optimum Exploration by PETROBRAS (4.-1.)	-1140	-930	-800	-700
6. Benefit of Exploration by Companies Compared to Current Plan (2b.-5)	+800	+800	+330	+260

Table 5-7

Comparison of the NPV of Exploration by PETROBRAS and Exploration by Foreign Oil Companies
(NPV in millions $1979, Real Discount Rate is 12 percent)

Wells	Real Annual Percentage Increase in Oil Price (base of $30/bbl, $1979)			
	0 percent	1.5 percent	3 percent	5 percent
(r .12)				
1. Optimal Exploration by PETROBRAS	200 (100 wells)	380 (100 w)	640 (200 w)	1,270 (200 w)
2. All Exploration by Foreign Oil Comp.				
a. Optimal Oil Comp. Exploration	0 (0 w)	0 (0 w)	9 (100 w)	102 (200 w)
b. PETROBRAS Share	0	0	592	898
3. Difference btw. PETROBRAS Share and Optimal Exploration by PETROBRAS (2b.-1.)	-200	-380	-48	-372
4. Planned Exploration by PETROBRAS	-1,070 (500 w)	-720 (500 w)	-290 (500 w)	540 (500 w)
5. Difference btw Planned and Optimum Exploration by PETROBRAS (4.-1.)	-1,270	-1,100	-930	-730
6. Benefit of Exploration by Companies Compared to Current Plan (2b.-5)	+1,070	+720	+882	+358

of whether the discount rate is 10 or 12 percent). PETROBRAS could maximize NPV if it were to continue to explore up to the optimum point (100 to 200 wells). However, if PETROBRAS continues with current plans to drill at least 500 wells offshore searching for new plays, the result based on this model would be an expected present value loss of $700 million to $1,200 million ($1979), depending on whether the oil price increases at 0 or 5 percent in real terms. These results are approximately the same whether the real discount rate is 10 or 12 percent. If average exploration costs were lowered, NPV would be higher. On the other hand, if oil plays are found in deep water or delays greater than expected, NPV would be lower. In order for the NPV of current plans to become positive, one must assume oil price increasing rapidly, much lower exploration costs <u>and</u> oil found in relatively shallow water. Much lower discount rates (less than 7 percent) would also raise NPV. Since these conditions are possible but rather unlikely, the conclusion that can be drawn is that Petrobras should seriously question such ambitious exploration plans and revise plans in light of results obtained with the next 100-200 wells.

It is particularly difficult for an institution such as PETROBRAS to institute policies to wind down the rate of exploration once the optimum number of wells have been drilled. It is difficult from a technical and geologic viewpoint to determine the optimum level, and it is difficult for a state owned enterprise to do so from an institutional standpoint (as PETROBRAS has almost a complete monopoly on oil activities and easy access to the government budget). If it is difficult to prevent "over exploration", a preferable choice may be to let the oil companies do the exploration and accept the lesser of two evils. According to the results of this model the reduction in lost NPV that would occur by switching from current plans to exploration by the foreign oil companies is estimated to be between $1,000 million $1979 (if oil prices stay constant) and $300 million (if oil prices rise 5 percent per year in real terms). These results are roughly the same whether $r = .1$ and $r = .12$. It is important at this point to discuss in more detail the discount rate and differences between social project evaluation and private project evaluation.

5.5 Social vs. Private Project Evaluation

As discussed in Chapter 2 a social project evaluation (the viewpoint of the Brazilian government) differs from the private project evaluation (in this case, the viewpoint of the foreign companies) in three respects. These three differences are the value of oil, the value of foreign exchange and the discount rate. A social project evaluation uses the international price of oil plus a stockpile premium, the shadow of foreign exchange (to covert the domestic project components into international units) and the social discount rate.

The difference between social and foreign private evaluations caused by the first two adjustments (oil price and exchange rate) are very small. The stockpile premium calculated in Chapter 2 ($1 to $2 per barrel) is only 3 to 5 percent of the international oil price. The benefits of the oil exploration program to the foreign companies should thus be 3 to 5 percent of the international oil price. The benefits of the oil exploration program to the foreign companies should thus be 3 to 5 percent less than the benefits calculated for the Brazilian government due to this difference in oil value.

When the shadow exchange rate is used the costs of exploration and development are 5 to 10 percent lower for PETROBRAS than for the private oil companies. However, the private foreign companies may be more efficient than PETROBRAS and have lower costs. These lower costs may easily offset the difference in costs caused by the shadow price of foreign exchange adjustment. Thus, the overall difference between social and private NPV evaluations due to the the stockpile premium and the shadow price of foreign exchange are assumed to be small, negligible compared to other factors such as oil price, discovery size, and discount rate. Differences caused by the divergence of social and private discount rates may be much more important, however.

A detailed discussion of the CAPM approach to the calculation of risk-adjusted discount rates for oil exploration and production projects was completed in Chapter 2. Estimates of the social cost of capital and the cost of capital for foreign oil companies were both 10%, even though the betas and systematic risk premiums for each were different. If we believe that 10% reflects the true cost of capital, then the preceding results using $r = .10$ are relevant. However, there are other factors which need to be accounted for which may influence the choice of discount rate. From the viewpoint of the foreign oil company political risk of expropriation should be accounted for either by adjusting the cash flows or adjusting the discount rate upward. From the viewpoint of Brazilian society, the discount rate should be adjusted upward to account for the higher cost of capital induced by increasing costs of foreign borrowing (country risk premium). These additional adjustments to the discount rate are discussed in more detail below.

5.A. Political Risks for Major Oil Companies

The results presented above assume if oil is found by major oil companies they will be able to appropriate benefits according to the original contract terms. There always is a small chance that the oil companies will not get paid their share due to political change, war etc.(i.e. reasons independent of oil company exploration) or in the event the oil companies discover a major oil field and Brazil unilaterally changes the contract terms (i.e. due to events caused by the actions of the oil companies). To account for this possibility the cash flows could be adjusted to reflect various possible scenarios. If we take an example from Table 5-6 where 100 wells are drilled by the oil companies, 0 wells drilled by PETROBRAS, the discount rate is 10 percent, and oil prices stay constant, then the expected NPV is $-47 million. If we assume that if 1 or 2 small plays are found PETROBRAS wll not change the contract terms and if one giant play is found PETROBRAS reduces the benefit to that of 2 small plays, then the expected NPV drops to $-90 million.

An alternative to adjusting the cash flows is to adjust the discount rate. If the discount rate is adjusted upward 2 percent to NPV falls to $-90 million, or the same as adjusting the cash flows. It is more accurate to adjust the cash flows, different scenarios will lead to different results. Adjustments to the discount rate of 2-4 percent are similar to use and seem to give an spread of changes in NPV similar to adjusting the cash flows.

5.B. Adjustments Caused by Brazil's Foreign Debt Problem

The previous section discussed reasons why one may expect the discount rate for oil exploration projects undertaken by oil companies to be 2-4% higher than the discount rate calculated from the CAPM model 10%. This section discusses reasons why the cash flows (or discount rate) may need to be adjusted if the project is undertaken by a Brazilian public institution. In chapter 2 it was pointed out that as the country risk premium on foreign loans increases the equilibrium interest rate in the country rises. The country risk premium for Brazil is estimated to be 1-2 percent. When one institution borrows foreign funds it drives up the interest rate to all other borrowers. Thus the marginal cost of borrowing should be reflected in a additional interest rate premium of twice the country risk premium, or 2-4 percent. As argued by Baldwin, Lessard and Mason (1981), this premium shifts the risk return line upward. Thus a return on a riskless asset should be the U.S. riskless rate (2 percent) plus 2 to 4 percent. This results in a real social discount rate for oil exploration projects of 12 to 14 percent as opposed to 10 percent without this adjustment.

This adjustment for country risk reflects an additional cost to the Brazilians for financing oil exploration themselves, as opposed to letting foreign companies do the exploration. These costs in principle could be added to the cash flows but in practice it is much simpler to account for this effect through adjustments in the discount rate as discussed above.

Thus, the estimated discount rate may rise to 12-14 percent for the foreign companies (to account for political risks) and to 12-14 percent for Brazilian public enterprises (to account for the effects of country risk). Using these adjustments the calculations with a discount rate of 12 percent may provide more realistic results than those with a 10 percent rate.

Annexes--Chapter 5

Annex 5-1

Reservoir Name (water depth, feet)	Basin	Discovery Year	Delay Until Initial Production (yrs)	Approximate Delay Until Full Production (yrs)
Curima (147)	Northeast	1978	2	3
Agulha (60)	Northeast	1975	3	4
Ubarana (40)	Northeast	1973	3	4
Guaricema (82)	Sergipe	1968	5	6
Caioba (82)	Sergipe	1970	5	6
Dourado (80)	Sergipe	1970	6	7
Enchova (383)	Campos	1976	2*	8
Namorado (500)	Campos	1975	4*	9
Garoupa (398)	Campos	1974	5*	9
Pampo (357)	Campos	1977	10	10
Cherne (390)	Campos	1977	8	11

Source: Petrobras News, no. 43, July 1980.

*First fields discovered in play

Annex 5-2

Net Present Value and Field Size Distribution for a Hypothetical Offshore "Giant-Field" Play

1) Field Size Distribution:

Largest Field (mill bbls.)	700 (50-50% of play reserves)
Average Play Size (mill. bbls)	1330
Productive Area of Play	570 Km^2 (high), 380 (medium), 280 (low)

2) Key Cost Parameters:

Largest Field = 700 mill. bbls, Total Play Reserves = 1330 mill bbls = Q

Water Depth = 200-300 ft.

Peak Production of Play = 160 mill. bbls/yr = 430,000 bbl/d = Q_p

Decline Rate = 12 percent = .12 = a

Estimated Investment Cost[1] for Play = $3100 million ($1979) = I

Estimated Capital Coefficient = $7,000/peak bbl/d = I/Q_p

Average Delay (between initial exploration and initial production) =

5 years = d

Operating Costs = $2/bbl ($1979) = OC

Cost per new field wildcat[1] = $5.0 million

Number new field wildcats (type 2) to find 90 percent

play reserves[2] = 100

Investment in new field wildcat wells = 100 x 5.0 = $500 million ($1979)

[1]Investment costs and cost per well have already been adjusted for the shadow prices of foreign exchange (adjustment factor is .9 for production investment and .87 for exploration investment).

[2]Based on experience in the Campos Basin.

Annex 5-3

Net Present Value and Field Size Distribution for a
Hypothetical Average Offshore "Commercial-Field" Play

1) Field Size Distribution:

Largest Field (mill bbls.) 130 (50-50% of play reserves)

Average Play Size (mill. bbls) 275

Productive Area of Play 570 Km^2 (high), 380 (medium), 280 (low)

Productive Area of Play 200 Km^2 (high), 170 (medium), 130 (low)

2) Key Cost Parameters:

Largest Field = 130 mill. bbls, Total Play Reserves = 275 mill bbls = Q

Water Depth = 200-300 ft.

Peak Production of Play = 32 mill. bbls/yr = 87,000 bbl/d = Q_p

Decline Rate = 12 percent = a

Estimated Investment Cost[1] for Play = $800 million ($1979) = I

Estimated Capital Coefficient = $9,000/peak bbl/d = I/Q_p

Average Delay = 4 years = d

Operating Costs = $2/bbl ($1979) = OC

Cost per new field wildcat[1] = $5.0 million ($1979)

Number new field wildcats (type 2) to find 90 percent play reserves = 60

Investment in new field wildcats = 45 x 4.3 = $194 million ($1979)

[1]Investment costs and cost per well have already been adjusted for the shadow prices of foreign exchange (adjustment factor is .9 for production investment and .87 for exploration investment).

Annex 5-4

Cost of Drilling Wells Offshore Brazil

(All costs in millions US $)

		Source
1) $8.5/well ($1979)	$223/26 wells drilled by major oil cos.	Brazilian Business J/J 1980
2) $7.1/well ($1979)	$314/44 wells committed by major oil cos.	Brazilian Business J/J 1980
3) $10/well ($1979)	One well by Hispanoil 13,800 ft.	Brazilian Business J/J 1980
4) $7/well ($1980)	One deep offshore well 300 in water 5000 in depth	Brazil Energy, v.1 no. 4, 3/24/80
5) $3/well ($1980)	Average cost 165 wells by Petrobras in 1980	Petrobras News no. 43, July 1980
6) $3.86/well ($1980)	$23.13/6 wells in Campos Basin	Petrobras News no. 43, July 1980
7) $4.0/well ($1980)	$794 mill Cr$/5 wells 40Cr/$ Basin	Petrobras News no. 37, Jan., 1980
8) $3.5/well ($1980)	Planned $2.8 billion/806 wells 1981 by Petrobras	OGJ v. 79, no. 7 Feb. 16, 1981
9) $3.5/well ($1980)	Funds appropriated for 3 wells offshore	Brazil Energy Dec. 10, 1980

Annex 5-5

Cost of Drilling Wells Onshore Brazil

(All costs in millions US $)

		Source
1) $0.5/well ($1980)	Average for 45 wells in 1980	Petrobras News, no. 43, July 1980
2) $0.38/well ($1980)	One well Rio Grande de Norte major oil cos.	Petrobras News, no. 43, July 1980
3) $0.615/well ($1980)	148 mill. Cr$/6 wells in Amazon (40Cr$/$)	Petrobras News no. 37, Jan. 1980
4) $0.8544/well (Dec. $1980)	$832 million/975 wells, plans for '81-85	OGJ Feb. 16. 1981 v. 79, no. 7

CHAPTER 6 - SHALE OIL POTENTIAL IN BRAZIL

Brazil has the world's second largest shale oil resources which are calculated to be 842 billion barrels. This chapter is on the geology, production technology, costs, net present value and indirect costs and benefits of shale oil production in Brazil.

6-1 Geology and Reserves of Brazilian Oil Shale

The known resources of shale oil in Brazil are second only to the United States. According to the United Nations, total resouces of oil from shale in Brazil are at least 842 bilion barrels (U.S. resources are at least 1,158 billion barrels of oil).[1] There are 8 major occurrences of oil shale in Brazil (as shown in Annex). The highest quality deposits are in the Irati formation which winds its way for 1,700 km from the State of Sao Paulo to Uruguay. Substantial resources also occur in the oil shale of Paraiba in the State of Sao Paulo. The remaining oil shale deposits are mostly small and of lowgrade. These remaining deposits in north and northeastern Brazil are not likely to be developed in the foreseeable future.

The shale oil beds of Paraiba (Sao Paulo State) are 35 meters thick and contain 4% to 13% oil (7.5% average).[13] The measured resources are 119 million barrels of oil (under a 10 km^2 area) and inferred resources of 1.3 billion barrels of oil (under a 115 km^2 area).[12] Unfortunately, the moisture content of the rock is 37% by weight in the Paraiba deposits. This poses difficult exploitation problems which have focused PETROSIX studies on the Irati formation shale deposits (where moisture content is only 5%).

The Irati formation outcrops in a great "S" shape for 1,700 km in the states of Sao Paulo, Paraiba, Santa Catarina and Rio Grande do Sul. In Parana and Rio Grande do Sul, two distinct beds of oil shale occur separated by a sequence of shale and limestone. In Santa Catarina and Sao Paulo the oil shale, shale and dolomite are interbedded throughout the section.

The most widely accepted hypothesis for the formation of the Irati shale oil is that the melting of glacial ice in the Late Carboniferous allowed encroachment of seawater. An intracontinental basin containing water of reduced salinity allowed growth of vegetation which was deposited and eventually lead to the formation of kerogen or shale oil. Although the beds of the Irati formation generally have great lateral continuity, there are places where the stratigraphic location of the oil is irregular and places where the two major shale oil beds diverge into as many as 80 small beds.[13]

Three mining sites have been established after drilling grids on 400 m and 800 m spacing. Reserves of these three mining sites total over 1,260 million barrels. Two of the sites are in Rio Grande do Sul (240 million barrels of oil resources are under an area of 84 km^2 at Sao Gabriel and 463 million barrels are under an area of 191 km^2 at Dom Pedrito).[1] The third mining site at Sao Mateus do Sul in Parana contains 560 million barrels of measured oil reserves in a 4 km by 16 km mining area (64 km^2)[13]. See Annex 2. It is here that the PETROSIX prototype plant is in operation and where the 50,000 barrel/day commercial plant is proposed.

The Sao Maeus do Sul site contains two shale oil beds with the upper bed (6.5 m thick) averaging 6.4% oil content (19 gallons/ton)[1/] and the lower bed (3.2 m thick) averaging 9.1% oil content (28 gallons/ton). The overall average oil content is 7.4% (23 gallons/ton)[13] or .55 barrels of oil per ton of rock. The two beds are separated by 8.6 m of shale and limestone. The 4 km width of the proposed mining zone is set such that overburden in the zone is less than 30 m. This gives a strip ratio of 1 to 4 (i.e., thickness of overburden plus thickness of waste rock divided thickness of shale oil beds). Much of the shale oil beds are covered with only 5 m to 10 m of overburden (strip rato of 2). Oil reserves are 560 to 600 million barrels along with 10 million tons of sulfur, 4.5 million tons of LPG and 22 billion cubic meters of light fuel gas.[12]

6-2 PETROSIX Shale Oil Production Process

The "Superintendencia da Industrializacao do Xisto" (PETROSIX) was incorporaated into Petrobras in 1954. Initial research concentrated on th Paraiba Valley oil shale but the superiority of the Irati oil shale, in addition to economic factors shifted work priority to the Irati oil shale.

In 1965 Cameron Engineers (now the U.S. firm PACE) was awarded a contract to help build a small 1,000 barrel/day prototype plant at Sao Mateus do Sul. Plant design was tailored to the specific characteristics

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1/Fischer assay valves; based on 19.6 API oil where gallons/ton = .302 (weight % oil in rock).

of the Irati oil shale and the plant was first successfully operated in 1972, with a U.S. patent awarded in 1975. The prototype plant uses 2,200 metric tons/day of oil shale, that produces 1,000 barrels of oil, 36,500 cu m of light gas (900 BTU/cu m), 1.7 metric tons of sulfur and 75 barrels of LPG each day.[3] The plant is a modified gas cumbustion retort (similar to the U.S. Paraho process retort). It is an above ground retorting process which utilizes 19-28 gallon/ton grade oil shale (U.S. shale oil processes are similar, using 30-35 gallon/ton oil shale, in-situ production processes are used only for oil shale with less than 10 gallons/ton).[14]

Engineering plans have been completed for a commercial shale oil plant at Sao Mateus do Sul which would produce a net oil output of 45,000 bbls/day and utilizes 112,000 tons/day of oil shale rock.[4] A decision on whether to go ahead with the commercial plant is expected in mid-1981. If the plant is started in 1985 it is expected to be producing 22,500 bbls/day (net production). In mid-1986 the plant is planned to run at full capacity production synthetic crude at a rate of 51,137 bbl/day (gross production), which corresponds to 44,690 bbl/day (net production). In addition to the crude, 890 t/day of sulfur and 520 t/day of liquified gas will be produced.[12] Synthetic crude will be processed in a nearby refinery, producing approximately 30% gasoline, 30% diesel, 20% gas-oil and 20% fuel oil.

The PETROSIX process is feasible and on a small scale it is workable. Shale oil production is a multistage process which involves a tremendous amount of solid rock handling. The production process is outlined below[3,12]:

1) Mining - Topsoil is cleared off and the overburden waste rock is scraped away with 220 yd^3 and 140 yd^3 draglines. There is 321,000 tons/day of waste rock to be moved in order to mine 112,000 tons/day of shale rock. The shale rock is transported with 18 200-ton trucks to the processing area. The trucks return with spent shale for dumping at the mine site, which is then covered wth topsoil.

2) Solid Preparation - The shale rock is then crushed into 6-inch size pieces. The fine shale dust is briquetted.

3) Retorting - A battery of 18 retorts, of which 16 are in use at one time, are used to process the shale (for the 50,000 bbl/d plant). Shale is fed in the top of each of the retorts which are 36 inches (inside diameter) and produce 4,000 bbls/day each. As the shale slides down the retort, heated recycle gases vaporize off the shale oil which is then condensed. Recovery is 95% of the original oil.

4) Upgrading - The shale oil is upgraded or refined producing 30% gasoline, 30% diesel, 20% gas-oil and 20% fuel oil.

6-3 Production Costs and Evaluation of Shale Oil Investments

The evolution of shale oil production cost estimates in Brazil has closely paralled the evolution of such estimates in the United States. Original cost estimates in both countries made 10 years ago were on the order of a few dollars per barrel. After 10 years of experience with prototype plants in both countries cost estimates have escalated five-fold (in real terms). Even after the studies and evaluations of the seventies there still remains a great deal of uncertainty over the ultimate production costs from a full scale plant. In spite of this uncertainty over production costs, a great deal can be learned about the differences and similarities between shale oil production in Brazil and the U.S. through a comparison of recent cost estimates.

The rough breakdown of Brazilian shale oil production costs were provided in 1971 after an initial evaluation by Cameron engineers. Updated estimates of the cost breakdown were obtained from Petrobras in 1979. This breakdown of capital costs and operating costs are given in Table 61. A 50,000 barrel per day plan has estimated capital costs of 2,354 million dollars ($1978). Before these costs can be directly compared to costs in the United States the distortions due to the overvalued Brazilain $Cr must be removed. Distortions occur when the official exchange rate departs from the "free trade exchange rate", or shadow exchange rate, due to variety of import tariffs and export subsidies. Calculations based on data in the mid-1970's indicate the $Cr was overvalued by 30%. The estimated investment costs were made by Petrobras using the official exchange rate. In order to correct the distortion due to the overvalued exchange rate the fraction of the cost which was made originally in foreign exchange must be separated out. Expenditure in foreign exchange can take place directly through the purchase of foreign equipment or indirectly through the purchase of Brazilian equipment (a fraction of which eventually results in the expenditure of foreign exchange). This latter component (the indirect foreign exhange component) is estimated to be 20% based on input-output studies of the Brazilian construction industry (from personal communication World Bank Brazil Group). The direct foreign exchange components are calculated with data from the project evaluation made by Cameron Engineers. The overall average direct foreign exchange component is estimated to be 34%, but it is over 50% for mining investment (Annex 6-1 provides the breakdown of the components). The fraction of the investment (measured in $US) which is made only in local currency is divided by 1.3 (ratio of the shadow exchange rate to the official rate in $Cr/$US). The capital costs and operating costs were adjusted in this fashion the results of which are compared to U.S. shale oil production cost in Table 6-2.

There are several important differences between Brazilian and U.S. costs. Shale oil mining in Brazil is all surface mining with overburden less than 30 meters, thus costs per ton of rock mined are cheaper in Brazil. These lower costs are more than offset by the larger amounts or Brazilian shale that must be mined per barrel of oil, since Brazilian shale is about 60% as rich as U.S. shale. Overall mining capital costs are $800 million as compared to $300 million estimated in the U.S. Surface retorting are somewhat higher than the U.S. due to the larger amount of rock to be processed. Operating cost estimates are lower in Brazil. This is presumably due to lower labor costs, but could be revised substantially upward if there is a shortage of skilled labor during rapid development of shale oil. Costs due to environmental regulation are low in Brazil and there is no problem of water supply. Overall, capital costs per daily barrel are calculated to be $49,980/b/d in Brazil and $25,000 to $32,000/b/d for the U.S. (all in late $1979).

A variety of available cost estimates for the U.S. are compared to

Brazilian costs in Table 6-3. Current plans for shale oil estimate a cost of $22-38/bbl in the U.S. Some recent estimates including projected cost overruns push the cost per barrel into the $45-62/bbl range ($1979 15% return on all equity). Brazilian estmates without cost overruns are calculated to be $35-43/bbl.

Table 1

Investment and Operating Cost Estimates for a
50,000 bbl/day Shale Oil Plant in Brazil[1]

	Capital Costs (million $1978)	Operating Costs (million $1978/yr)
Mining	471	14.6
Retorting	706	29.2
Solid Prep.	471	7.3
Upgrading	353	14.6
Mis.	353	3.5
Total	2354	73
Total (Adjusted for Shadow Price of foreign exchange)	2083($1978)[2/]	59($1978)[3/]
	2260($1979)[4/]	64($1979)[4/]

1/Based on data from Petobras from engineering plans for Sao Mateus do Sul plant (51,137 bbl/day gross output, 44,690 bbl/day net output). (This data is an update of estimates presented at the 8th World Pet. Congress in 1971 by Bruni.)

2/Based on 34% average direct foreign exchange component (Cameron Engineers 1970 project appraisal), 20% of Brazilian expenditures indirectly in foreign exchange (personal communcation with World Bank Brazil group), and an exchange rate overvalued 30% in the '75-'79 period.

Adj. Factor = .885 = (.5 + (.34 + .2(.66))/1.3)

3/Based on a 20% direct foreign exhange component for operating costs (from Cameron Engineers 1970 appraisal)

Adj. Factor = .815 = (.2 + .8/1.3)

4/Based on an inflation rate of 8% from 1978 to 1979.

Table 2

Comparison of Brazilian Petrosix and U.S. Shale Oil Cost Estimates
(costs in millions $1978)

	PETROSIX[1] (51,000 bbl/d)	Tosco[2] (55,000 bbl/d	Paraho[3] (100,000 bbl/d)
Mining and Solids Preparation[4/]	(112,000 tons/d surface)	(66,000 tons/d underground)	(157,421 tons/d underground)
Capital Cost	832	270	750
Annual Oper. Cost	19	38	97
Surface Retorting			
Capital Cost	611	510	700
Annual oper. Cost	23	43	81
Upgrading			
Capital Cost	293	210	460
Annual Oper. Cost	12	5.2	55
Total			
Capital Cost	2,083	1,260	2,105
Annual Oper. Cost	59	110	254
Net Production (bbl/d)	45,000	43,000	90,000
Capital Cost ($ per bb/d)	46,288	29,300	23,388
($1979 per bbl/d)[5]	(49,980)	(31,644)	(25,260)

1/Based on data from Petrobras shown in Table , original investment cost estimates have been adjusted using the direct foreign exchange components derived from Cameron engineers 1970 project appraisal (see Annex).

2/"Shale Oil Economies Update", Nutter and Waitman, Tosco Corp., April 1978.

3/"Shale Oil: Potential Economies of Large Scale Production", Weiss, Ball, Barbera, MIT-79-012WP, 1979.

4/The Petrosix process uses Brazilian shale (20-23 gallons oil/ton) and the other technologies process U.S. shale (30-35 gallons oil/ton).

5/Based on an inflation rate of 8% from 1978 to 1979.

Table 3

Comparison of Capital Costs of Recent
Shale Oil Plant Cost Estimates ($1979)

U.S.	Capital Investment 50,000 BDPD plant ($ Billion)	Investment ($ per bbl/d)	Cost per barrel (15% return on all equity investment
1. Underground Mine Surface Retort 1/	1.2	24,000	22-26
2. Underground Mine Surface Retort (updated) 2/	1.44	28,800	28-38
3. Open Pit Mine Surface Retort 1/	1.2	24,000	24-26
4. Modified In Situ (MIS) 1/	1.0	20,000	15.24
5. Combined MIS/Surface 1/	0.9	18,000	15,21
6. Surface Retorting 3/	1.8	36,000	
7. Surface Retorting 4/	1.55	31,000	45-62 6/
8. Surface Retorting with estimated 30% real cost escalation 5/	2.34	54,750	
9. Petrosix (Surface Mine/ Surface Retort 45,000 bbl/d) 5/	2.2	46,000 to 50,000	35-43 8/

Note: Estimates numbered 2,6,7 and 8, were originally reported in $1980 and have been deflated back to $1979 assuming an inflation rate of 10%.

1/ "Overview of Synthetic Fuels Potential to 1990," Cameron Eng., 1979 Prepared for Synthetic Fuels Task Force.

2/ Updated Tosco Corp. estimate made in mid-1980.

3/ Average plant cost reported in 1980, N.Y. Times 8/4/80.

4/ Phillip Robinson, OTA estimate, N.Y. Times 8/4/80

5/ Roger Loper (Chevron Oil Shale Company) estimates ultimate cost of 5 to 6 billion dollars in 1988, (Equivalant to 30% real cost overruns and 10%/yr inflation). N.Y. Times 8/4/80

6/ Per barrel cost estimate of $45 is based on a plant cost of 1.55 billion (capital costs $16/bbl, operating costs $29/bbl). Estimate of $62/bbl by Robinson (OTA) - N.Y. Times 8/4/80.

7/ Estimates made in ths study based on Petrobras data.

8/ Capital Recovery Factor (15%) = $.15/(1-(1+.15)^{-30})$ = .1523 ($49,000 per b/d)(.1523)/365 = $20.4/bbl Capital Costs

Operating costs per bbl = ((64 million/yr)(30 yr)/45,000 b/d).1523/365 = $17.8/bbl

Total $38/bbl (20+18); For 10% return $27/bbl(14.5 + 12.5).

6-4 Direct Benefits of a 50,000 bbl/day Shale Oil Plant

Direct benefits of a shale plant in Brazil refer to the value of only the actual oil output and by product output. Side benefits such as the value of improved information on costs, etc. are not included. These side benefits (or costs) will be discussed in the next section. There is enough oil in the shale at the Sao Mateus do Sul location in Brazil to support a 50,000 bbl/d plant for 30 years, or 0.548 billion barrels. If it could be extracted instantly at $30/bbl, it is worth over $16 billion. If investment costs are in the $2-4 billion range, it would expect a profitable operation, but net present value calculations depend on the time frame of costs and benefits.

Net present value calculations were completed for the proposed 50,000 bbl/day plant built in 2 stages (first stage is built from 1980 to 1985, second stage is built from 1982 to 1987). Three scenarios of oil prices were used: 0%/yr, 3%/yr, 5%/yr increase in real terms from a base of $30/bbl ($1979). At full production 32 mill t/yr of sulfur is to be produced, worth approximately $32 million. For each bbl of oil 11.6 kg of LPG is produced. Late 1979 Carribbean prices of LPG are $.28/kg, or 11% of the value of a bbl of oil.

Several cases were run for delays in production and cost overruns using a range of discount rates. Two types of evaluations were made. The first is an economic (or social) evalaution with costs adjusted using the shadow price of foreign exchange and oil valued at international prices. The second is a financial (or commercial) evaluation which uses prices "seen" by the private sector. This evalaution uses the official exchange rate and therefore costs are unadjusted by the shadow price of foreign exchange. Also, a commercial operator may not receive the full value of an imported barrel of oil since domestic prices are held below international prices. As of January 1980 the ratio of the ex-refinery price to the Caribbean cargo price was .86 for regular gasoline, 1.39 for premium gasoline, 1.07 for kerosene, .82 for diesel and .27 for fuel oil. Using this as a measure of the ratio of domestic to international prices and weighting by the shale oil output share of each product, the average domestic sales value is 80% of the international sales value. Thus, if one assumes the Brazilian product prices will continue to remain below international levels, commericial shale oil producers will receive only 80% of the international value. The financial evaluation looks at the sensitivity of NPV to price of oil valued at 80% of its international value and with costs unadjusted by the shadow price of foreign exchange.

Net present values and internal rates of return for the 50,000 bbl/d plant are shown in tables 64 to 66. Estimates are based on all equity financing . Internal rates of return for the base case economic evaluation (with no cost overruns or delays) are estimated to be 18% or 23% depending on real oil prices increasing 0% or 3% per year, respectively. As past experience with shale oil cost estimates (as well as cost estimates with most new technologies) indicate the current estimates are usually too low. "Cost underruns" are rarely heard of with the development of new technologies. This base case analysis is thus an upper bound for return on investment with more likely returns below this level. A sensitivity analysis was completed for cost overruns of 30% and 50% and with delays in production. For cost of overruns of 30% (both investment and operating costs) and output cut back 50% for the first 10 years (after the start of construction) the internal rate of return declines to 9%, if oil prices rise 9%/yr and 14% if oil prices increase 3%/yr. If there are cost overruns of 50% and the time frame for investment and production is doubled the internal rate of return drops to 5% (if oil prices increase 0%/yr) and 9% (if oil prices increase 3%/yr).

Table 6-4

Net Present Value of Brazilian 50,000 bbl/d

Shale Oil Plant in Million $1979 (oil price $30/bbl, up 0%/yr)

Economic Evaluation	IRR (%)	Real Discount Rate 3	5	7	10	15	25
Base Case	18	5724	3847	2561	1317	224	-548
Costs up 30%	13	4750	2980	1777	524	-363	-1012
Costs up 50%	11	4087	2393	1245	157	-760	-1324
Costs up 30%,output 50% for 10yrs	9	3558	1931	850	-149	-947	-1361
Costs up 50%,output 50% for 10yrs	7.5	2894	1342	317	-618	-1344	-1674
Costs up 50% investment and production delayed (twice as long as Base Case)	5	1814	90	-698	-1202	-1395	-1267
Financial Evaluation							
Costs up 30%, output sold at international parity($30/bbl)	11	2709	1203	211	-693	-1388	-1693
Costs up 30%, output sold at 80% international parity ($24/bbl)	5	1232	123	-596	-1236	-1694	-1817

Table 6-5

Net Present Value of Brazilian 50,000 bbl/d

Shale Oil Plant in Million $1979 (oil price $30/bbl, up 3%/yr)

Economic Evaluation	IRR (%)	Real Discount Rate 3	5	7	10	15	25
Base Case	23	10658	7294	5025	2868	1016	-271
Costs up 30%	18	9684	6427	4240	2174	427	-743
Costs up 50%	16	9021	5840	3709	1709	31	-1047
Costs up 30%, output 50% for 10yrs	14	8245	5164	3126	1246	-269	-1149
Costs up 50%, output 50% for 10yrs	12.5	7582	4575	2594	778	-667	-1461
Costs up 50% output investment and production delayed twice	9	6170	2604	818	-415	-1073	-1180
Financial Evaluation							
Costs up 30%, output sold at international parity($30/bbl)	12	7395	4436	2487	702	- 710	-1480
Costs up 30%, output sold at 80% international parity ($24/bbl)	9	5205	1841	1303	-82	-1141	-1647

Table 6-6

Net Present Value of Brazilian 50,000 bbl/d

Shale Oil Plant in Million $1979 (oil price $30/bbl, up 5%/yr)

Economic Evalution	IRR (%)	Real Discount Rate					
		3	5	7	10	15	25
Base Case	24	12465	8700	6132	3656	1486	-76
Costs up 30%	21	11491	7834	5348	2964	898	-539
Costs up 50%	18	10828	7246	4816	2496	501	-851
Costs up 30%,output 50% for 10yrs	16	9862	6404	4087	1915	113	-1003
Costs up 50%,output 50% for 10yrs	14	9197	5814	3555	1446	-283	-1315
Costs up 50%, investment and production twice as long as base case	10	6880	3141	1229	-136	-919	-1127
Financial Evaluation							
Costs up 30%, output sold at international parity($30/bbl)	14	9012	5675	3448	1371	-328	-1335
Costs up 30%, output sold at 80% international parity ($24/bbl)	12	7723	4643	2614	756	-713	-1507

In order to compare different liquid fuel production options it would be helpful to have a probability distribution of returns on shale oil investment. No one really knows the cost of shale oil production and any estimate of the mean and variance of the returns is somewhat arbitrary. Petrobras has already included a 10% contingency in the estimates of shale oil investment cost. Exxon has included a 40% contingency based on a "process development allowance" for the EDS (Exxon Donor Solvent) project.[6] Roger Loper (Chevron Oil Company, ref. 8) estimates the ultimate current dollar cost of a 50,000 bbl/d plant to be $5 to 6 billion in 1988. This is equivalent to a 30% real cost overrun assuming inflation of 10%/yr. With this (admittedly scanty) information the case of 30% cost overruns with deals in production will be used as the mean, expected value. If we believe the distribution of returns is approximately normal and the base case (no cost overruns) is an upper bound return for a 50,000 bbl/d plant a rough probability distribution of returns can be created for comparison with other alternative investments.

Distibution of Returns for 50,000 bbl/d Shale Oil
(internal rates of return, in percent)

	Real Oil Prices Increasing		
	0%/yr	3%/yr	5%/yr
Probability			
.1	18	23	24
.2	13	18	21
.4	9	14	16
.2	7.5	12.5	14
.1	5	9	10

The real cost of capital for a shale oil investment was estimated earlier to be about 12%. This together with the distribution of returns indicate that there is a 30% chance the shale oil plant will be economic if oil prices do not increase in real terms and about a 70% chance that shale oil will be economic if oil prices increase at 3%/yr to 5%/yr. If oil prices increase at 3%/yr the expected NPV is 14% with a standard deviation in IRR of 25%. The variation in possible oucome is relatively wide. This variation and the large lump-sum investment for a shale oil plant may cause the managers of the investing firm of PETROBRAS to be rather risk-averse when considering such a huge, risky investment. While the total risk of the project may be relevant to PETROBRAS managers, only a portion of this risk (the non-diversifiable or systematic portion) is relevant to the Brazilian Planning Ministry. This non-diversifiable risk is low for energy projects in Brazil. While PETROBRAS may have only relatively few major projects in its investment portfolio the investment portfolio of the Planning Ministry is much larger, thus the failure (or success) of a shale oil plant is less risky in such a large portfolio. Large-scale investments in shale oil are less risky to Brazilian society than PETROBRAS, but if the risk could be spread to foreign firms (e.g., a joint-venture arrangement) the risk of shale oil may be even lower. Additional factors which may influence the evaluation of the shale program are discussed below.

6-5 Indirect Costs and Benfits of Shale Oil

In order to compare the shale oil production option to other liquid fuel production projects the indirect costs and benefits should be included. It may be difficult to quantify the indirect components but it is important at least to identify them qualitatively. Additional costs not included in the previous section are:

- Environmental costs of water pollution and mining scars on mined land. Petrobras is currently doing research on the degree of water pollution caused by shale oil mining. Water supplies are adequate and the region is not heavily populated. Waste rock has a larger volume than unmined rock, but the mining site is small 64 km^2 compared to the region as a whole. Although costs of land reclaimation and water purificaton are expected to increase the cost of shale oil they are not expected to be a limiting factor.
- Factor price inflation costs are expected to occur once a major shale oil program is started. Technical labor and certain industrial components may have very low supply elasticities and cost very high during initial construction of plants. Since there has been a tendency for interest in the Brazilian shale oil program to coincide with U.S. interest in the shale oil program, then factor price inflation may be a severe worldwide problem once a commitment to shale oil is made. If Brazil feels its should pursue shale oil production sooner than other countries maybe it should start building plant "out of phase" with other countries to reduce the effects of factor price inflation.
- Probably one of the most important additional costs of the shale oil program (as compared to other projects) is the cost of not being able to switch funds from shale to another project in the future should conditions change. Small alcohol plants and oil exploration wells are incremental investments which have much more flexiblity than even one $3 billion shale oil plant. Conditions that might change are a drop in the oil price, cheaper alternatives found (e.g. a major oil discovery) or actual shale oil costs too high relative to the oil price.

There are additional benefits to the shale oil program.

- The information value of reducing the variance of the cost of shale oil production. It is valuable for planning purposes to know what the costs of shale oil will be. Building a 25,000 bbl/d (or 50,000 bbl/d) commercial plant should be sufficient to increase knowledge on costs. Although calculation of the value of information is dependent on a wide range of assumptions a rough calculation was made. If starting a plant today would lead to a 250,000 bbl/d industry by the year 2000 and our current probabilities on shale oil costs are .3 of $35/bbl, .4 of $45/bbl and .3 of $52/bbl, then the value of starting now and not waiting 5 years to start production is calculated to be 1.17 billion (with a 10% real discount rate and real oil price up 3%/yr). This assumes the industrial scale plants are built if shale oil costs are low and no more than one plant built if costs are too high. The loss due to the extra costs of a small 25,000 bbl/d plant if shale oil is abandoned is calculated to be -251 million. Thus there is positive information value to starting now but this conclusion could be reversed with some different assumptions about future events (e.g. real oil prices may not go up 3%/yr). Although Brazil may require shale oil production sooner than other countries, which have cheaper domestic alteratives, research and development of a capital intensive shale oil industry is not Brazil's comparative advantage. Brazil may benefit from waiting until the U.S. completes the first research on a commercial scale plant and use the information generated by the U.S. synfuels industry.

- Some arguments have been made that shale oil is needed for national security. The argument is that secure shale oil is worth more than insecure imported oil supplies (i.e. supplies subject to disruption). This is a poor argument because during a disruption a large amount of oil is needed in a short time. Shale oil production provides a small amount of oil for a long time. The correct policy to handle a disruption is a sufficient oil stockpile.

Annex 6-1

Foreign Exchange Components of
Shale Oil Production in Brazil
(percent)

	Capital Investment		Operating Cost	
	Direct	Indirect	Direct	Indirect
Mining	62		39	
Retorting	22		7	
Solid Prep.	26		12	
Byproduct Recov.	27		14	
Misc.	7		8	
Average	34	20	20	0

Source: Cameron Engineers 1970 project evaluation of Irati Shale Oil Plant, Indirect Components are from World Bank Brazil projects department.

CHAPTER 7 - ALCOHOL PRODUCTION FROM BIOMASS IN BRAZIL

Brazil has the largest program to produce ethyl alcohol (ethanol) from biomass in the world. Almost all of the ethanol is produced from sugarcane. Numerous studies have addressed issues concerning alcohol production and production costs. The most extensive study has been completed by the World Bank. This chapter will provide a summary of important issues and alcohol production cost estimates. The major emphais will be to use analyses and data from the World Bank study to estimate the net present value and rate of return of the 5-year Brazilian Alcohol Program in order to compare the results to oil exploration and shale oil programs.

7.1 Ethanol Production Technology and Use in Engines

Ethanol can be produced from three types of biomass: (1) sugar-bearing materials (sugarcane, molasses and sweet sorghum) which contain carbohydrates in the form of sugar; (2) starches (such as corn, cassava or potatoes); and (3) celluloses (such as wood and agricultural residues). Sugar bearing materials have an advantage over other materials since their carbodyrate material is already in the fermentable, simple sugar forms. The sugar is fermented by yeast in a batch fermentation process and the ethanol distilled off to produce hydrous (94%) ethanol. Starch and cellulosic materials must be turned into simple sugars before fermentation. This is done through the addition of enzymes or acid. The resulting sugar is then fermented like any other fermentable sugar.

The production of alcohol through fermentation requires an energy input for distillation. Sugarcane has an advantage over other crops (like corn or cassava) since the bagasse (waste cane stalks) can be burned to provide heat and power for the distillation process. Ethanol from sugarcane in Brazil shows a positive energy balance generating 2 to 3 times as much energy as the production process consumes (according to a World Bank study on Alcohol from Biomass, 1980). This positive energy balance is derived wholly from the availability of bagasse. Alcohol produced from cassava with wood as an energy input shows only a slightly positive energy balance. Corn used to produce alcohol shows a net energy deficit with twice as much energy consumed in the process as contained in the produced ethanol (World Bank, 1980). Since sugarcane has advantages for alcohol production, as compared to other biomass inputs, the Brazilian alcohol program is based almost entirely on sugarcane.

Anhydrous ethanol can be used with gasoline (gasohol) in automobiles up to a concentration of 20%. Tests have shown that gasohol has a slightly higher octane rating than gasoline and that mileage performance is much the same as with gasoline. Thus the economic value of anhydrous alcohol when used in gasohol is equivalent to gasoline. However, straight ethanol (hydrous) has significantly different combustion properties than gasohol. Engines which run on straight ethanol require higher compression ratios to make use of the higher octane rating, and ethanol has a lower energy content than gasoline. The overall economic value of straight ethanol as motor fuel is estimated to be 85% that of gasoline. (More detailed analysis of ethanol production and use can be found in Noyes, 1979, World Bank, 1980, and Stauffer, 1981, Pode, 1979, Moreira and Goldemberg, 1979).

7-2 Brazilian Ethanol Program

Ethanol production has historically been linked to the Brazilian sugar industry. Since the 1930's ethanol derived from sugar has been blended with gasoline. This policy has been aimed at stabilizing sugar prices which have historically been highly variable. Depressed sugar prices from 1976 to 1979 provided a major driving force to expand the alcohol production program. In fact, sugar prices in 1976 fell to $150/ton compared with a 1974 peak of $1400/ton. Barzelay (1980) points out that in late 1975 Ministry of Agriculture officials initially favored an alcohol production program based on cassava, since it would have significant positive income distribution effects (particularly in the poorer northeast Brazil). However, the strong sugar cooperative (COPERSUCAR) in southeast and south Brazil lobbied for an incentive program for alcohol production from sugar instead. The National Alcohol Program was established in 1975 with an initial goal of 3 billion liters by 1980, produced almost exclusively from sugarcane.

The 1979 oil price rise provided additional impetus to the program and a production goal of 10.7 billion liters was set for 1985. The automobile producers strongly supported this expanded program as 660,000 all-alcohol cars would be required by 1985, since the alcohol limit of 20% in gasohol was reached in 1979-1980. Alcohol production in Brazil increased from 0.5 billion liters in 1975 to 4 billion liters in 1980. The stated goal of the Brazilian government is to produce 10.7 billion liters by 1985, 3.5 for alcohol gasoline mixture, 5.7 for straight alcohol engines and 1.5 for chemical feedstocks. This 1985 goal relies almost completely on sugarcane and will require approximately 2.7 to 3.1 million ha of land (depending on whether yields are 3500 l/ha or 3000 l/ha) in addition to the 1.6 million ha under sugarcane cultivation in 1979.

The rapid increase in alcohol consumption and production are the direct result of alcohol pricing policies and credit subsidies. Consumers have been encouraged to use straight alcohol as the pump price of alcohol in 1980 was 35% below the pump price of gasohol (adjusting for mileage loss alcohol prices should be only 15% lower than gasoline). Alcohol producers receive a guaranteed price of alcohol at the distillery which was 43% of the retail gasohol price in 1980. After alcohol distribution costs are taken into account, the price paid by the government for the alcohol comes to 56% of the retail gasohol price which is sold as hydrous alcohol at the pump at 65% of the retail gasoline price. Thus, the government receives a small margin on hydrous alcohol and a substantial margin on the anhydrous alcohol sold with gasoline.

The real incentive for alcohol producers comes in the form of subsidized credit through interest rates on loans which are substantially below the prevailing inflation rate (about 100% in 1980 and 1981). This interest rate subsidy was partially reduced in early 1981, as stated below:

> "The National Monetary Council (CMN) this month was expected to approve a new financing scheme for the National Alcohol program which would raise subsidized interest rates for the sector from the prevailing 2% to 6% to new range of 35% to 45%. The lower rates would prevail in the poorer North/Northeast, the higher rates in the industrialized South/Southeast."
>
> --"Brazil Energy"--1/24/81

Estimates of the total net subsidy due to the earlier credit program (i.e., loan rates of 2 to 6%) were reported to be up to 75% of production costs (Saint, 1980). Thus, the rapid increase in production is due to credit subsidies and price guarantees while the rapid increase in consumption is due to favorable retail price differentials.

Ethanol production is very lucrative from the private distiller's point of view. The question is whether this program is worthwhile from a social viewpoint. The rapid expansion of the alcohol program has led many to seriously question whether the benefits of the program outweight the negative aspects. The negative aspects of this program can be summarized as follows:

- Extensive and costly government subsidies
- Displacement of food and export crops and a rise in land costs and food prices, since sugarcane requires the best agricultural land.
- Pollution caused by stillage waste (12 liters is produced for every liter of alcohol).

- Worsening of income distribution (from concentration of land ownership in the hands of large landowners and from increased food costs for the poor who do not benefit from low-cost motor fuel).

7-3 Ethanol Production Costs

The goal of this section is to compare the financial and economic costs of ethanol produced from sugarcane as compared with imported fuel. An estimate of the NPV and economic rate of return on an average size alcohol plant will be calculated and the sensitivity of the results to variation in oil prices, sugarcane costs and land costs.

The average size ethanol production plant that uses sugarcane is 120,000 liters per day and the plant operates for 180 days per year. The investment cost of the plant is 7.6 million dollars ($1979).[1] Basic production parameters and capital costs for ethanol plants according to the World Bank are given in Table 7-1. As can be seen, each hectare of land can produce 19 bbls of gasoline equivalent (alcohol at 85% of gasoline value) and that yield per hectare is 46% higher for sugarcane than cassava.

Several studies have been completed to estimate the cost of ethanol production from sugarcane (AID, Univ. Sao Paulo, Stanford and the World Bank). Table 7-2 summarizes the key ethanol production cost

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[1]This figure has already been adjusted for the shadow price of foreign exchange. At the official exchange rate and a 75% domestic cost component the plant cost is $9.2 million (((.75)(9.2)/1.3) + (.25)9.2 = 7.6)

Table 7-1

Table 2
Ethanol production from different biomass materials

	Unit	Molasses	Sugarcane	Cassava[1]	Corn[1]
Yields					
Ethanol yield/ton of biomass	liters/ton	270	70	180	370
Biomass yield/hectare of land[2]	tons/hectare	...	50	12	6
Ethanol yield/hectare of land	liters/hectare	...	3,500	2,160	2,220
Processing plants					
Economic plant size range	liters/day	60–240,000	120–240,000	60–120,000	120–240,000
Number of operating days	days/year	180	180	275	275
Annual production in 120,000 liters/day plant:	– million liters/year	21.6	21.6	33.0	33.0
	– million U.S. gallons/year	5.7	5.7	6.9	6.9
	– tons/year	17,100	17,100	26,100	26,100
Installed cost of 120,000 liters/day plant in:					
Low-cost countries[3]	millions of U.S. dollars	6.8	7.6	9.1	9.1
Medium-cost countries[3]	millions of U.S. dollars	7.6	9.5	11.4	11.4
High-cost countries[3]	millions of U.S. dollars	11.4	14.3	17.2	17.2
Economics as gasoline additive					
Ex-plant biomass raw material cost for 10 per cent economic rate of return[4]					
At US$31/bbl f.o b. crude[5]	US$/ton	62	14	13	—
At US$35/bbl f.o.b. crude[5]	US$/ton	70	16	17	1.2[6]
At US$43/bbl f.o.b. crude[5]	US$/ton	85	20	23	1 8[6]
Ex-plant biomass raw material cost for 8 per cent economic rate of return[4]					
At US$31/bbl f.o b. crude[5]	US$/ton	65	14	16	—
At US$35/bbl f.o.b. crude[5]	US$/ton	73	17	19	1.4[6]
At US$43/bbl f.o.b. crude[5]	US$/ton	90	22	25	2.1[6]

Source World Bank
— Indicates negative figure
. . . Indicate data are not relevant, since molasses is a by-product
[1] Based on current plant designs and fuel oil as fuel source
[2] Based on current average yields in Brazil, except for corn, which is based on U S average
[3] Low cost country data for sugarcane plants based on Brazil costs Medium-cost countries, such as Thailand, are assumed to have costs about 25 per cent higher than low cost countries High-cost countries, such as Sudan, which have very limited domestic plant construction capabilities are assumed to have capital costs about 50 per cent higher than medium-cost countries These cost estimates are general indicators, and actual plant costs would depend on individual country, market, and site factors All costs in late-1979 U S dollars
[4] For medium-cost countries
[5] Assuming ethanol value equal to that of gasoline in volume terms Gasoline price assumed as 1 3 times that of ex-refinery light Arabian crude price, by volume this relationship assumed to go down with increased crude prices Crude price assumed to increase at 3 per cent per annum in real terms, gasoline price at 2 5 per cent per annum, and raw material cost at 1 per cent per annum
[6] For corn, US$/bushel One bushel weighs 56 lbs One ton is equivalent to 39 4 bushels

BRAZIL: CAPITAL COSTS OF ALCOHOL PLANTS
(late 1979 prices, in '000 US$)

	Capacity		
Capacity liters/day	20,000	120,000	240,000
Capacity US gallons/day	5,300	31,700	63,400
Engineering	135	400	680
Process Equipment	950	3,950	6,800
Utilities	220	925	1,620
Freight	60	225	300
Civil Works and Land	270	750	1,250
Erection	135	400	500
Sub-Total	1,770	6,650	11,150
Contingency	230	950	1,350
Installed Cost	2,000	7,600	12,500

Source: World Bank, Alcohol Production in Developing Countries, 1980 parameters (US ¢/liter) broken down into levelized investment cost, operating cost, and sugarcane production cost. In all cases the sugarcane production cost is one-half to two-thirds of the total alcohol production cost. Costs are for an average size 120,000 liter per day plant.

Two types of production cost are shown in Table 7-2, financial and economic. The financial costs use market prices and the official exchange rate. The only difference in the economic analysis is that foreign exchange is shadow priced at 30% above the official rate for the domestic cost component. No adjustments were made for the shadow price of labor as market prices roughly reflect opportunity costs in southeast Brazil. For both the financial and economic analysis by-product credits (or debits), taxes and subsidies were assumed to be zero, so the distortions caused by Brazil's credit subsidy policies are not included.

Estimates of the financial cost of ethanol vary from 26 to 34 US ¢/liter (in $1979) with estimates based on World Bank data the lowest. All of these costs are <u>greater</u> than the equivalent international gasoline price of 22 US ¢/liter. This equivalent gasoline price is derived assuming alcohol value is 85% of gasoline value and oil at $30/bbl. (Annex 7-1 shows the relationship between oil import price and gasoline economic value.)

The economic cost of alcohol, as calculated from World Bank data, is slightly less (21¢/liter) than the equivalent gasoline economic value (22¢/liter). This is due to adjustments for the shadow price of

Table 7-2 Comparisón of Various Estimates of Financial and Economic Costs of Ethanol Produced from Sugarcane in Southeast Brazil

(US cents per liter)

	Financial Analysis[1]				Economic Analysis[6]
	AID[2] (Poole)	Univ. Sao Paulo[3]	Stan-ford[4]	World Bank[5]	World Bank[5]
A. Levelized Investment Cost					
	4.2	4.6		4.4	3.6
B. Operating Cost					
	4.7	8.8		5.0	3.8
C. Sugarcane Production Cost					
	18.4	17.5		16.7	13.2
TOTAL	27.3 (\$1978)	30.9 (\$1978)	34.0 (\$1979)	26.1 (\$1979)	20.6 (\$1979)
TOTAL US ¢/liter (\$1979)[7]					
	29	33	34	26	21
Ethanol Economic Value, US ¢/liter (85% of gasoline value, oil \$30/bbl)				22	

[1]Market prices and official exchange rate used. Byproduct credits and taxes assumed to be zero.

[2]From Poole, A., "Ethanol and Methanol as Alternatives for Petroleum Substitution in Brazil," AID draft working paper, 1979.

[3]From Moreira, J. and Goldemberg, J., "Alcohol--Its Use, Energy and Economics--The Brazilian Outlook," Univ. Sao Paulo, IFUSF/P-230, 1979.

[4]From Barzelay, M., "The Political Economy of Alcohol Energy in Brazil," Stanford Student Energy Study Series, Series S-3, 1980.

[5]Estimates based on World Bank data from "Alcohol Production from Biomass in the Developing Countries," in 1980, and from personal communication, World Bank.

[6]Economic analysis is the same as financial analysis except for adjustments for the shadow price of foreign exchange (domestic cost component/1.3).

[7]Inflation from 1978 to 1979 taken to be 8%.

foreign exchange and the large domestic component of the production cost. The World Bank used these cost parameters, oil prices and investment and production patterns to calculate the internal rate of return and NPV for an average size distiller based on sugarcane. The internal rate of return was calculated by the World Bank for high, medium and low cost countries and for a variety of sugarcane costs and a variety of oil price increases. The detailed results are shown in Annex 7-1. Brazil is a low-cost country, in terms of investment and operating costs, and has low sugarcane production costs ($10/ton). The internal rate of return and sensitivity analysis for a sugarcane base plant in southeast Brazil is shown below:

Base Case Assumptions:

- 120,000 liter/day plant
- Operated 180 days/yr
- Sugarcane cost $10/ton
- Real cost increases:

    Oil price 3%/yr
    Land rental value 1%/yr
    Fertilizer 1.5%/yr
    Pesticide 1%/yr

	IRR
1. Base Case	19.5%
2. Oil prices up 0%/yr	11.0%
3. Oil prices up 5%/yr	26.0%
4. Land value up 30%	19.0%

5.	Land value increasing 5%/yr	19.0%
6.	Yields down 20%	17.0%
7.	Anhydrous alcohol value	24.0%
8.	Sugarcane costs up 20% ($12/ton)	14.0%
9.	Sugarcane costs down 20% ($8/ton)	29.0%
10.	Oil prices up 0%/yr and land rental value up 30% and yield down 20%	8.0%

(Source: World Bank, see Annex 7-1)

As can be seen the rate of return on an alcohol project is extremely sensitive to the oil price, a 1%/yr increase in the annual oil price leads to a 3% decrease in the IRR. The rate of return is quite sensitive to the raw material cost and yields, but is not very sensitive to land price increases. The minimum acceptable rate of return on an alcohol project was estimated in Chapter 2 to be 14%. This means that alcohol projects do not appear economic if oil prices rise less than 2%/yr or if sugarcane costs increase 20%.

The NPV of an average size plant with assumptions the same as the base case is given in Table 7-3. The plant NPV is extremely sensitive to the assumptions about the rate of increase of the oil price. At a 14% discount rate the NPV is -$2.7 million if oil prices remain constant in real terms and is positive if oil prices increase at 1.5%/yr. Using the NPV of an average plant and the construction schedule of plants for the $3.7 billion (5-year) alcohol program we can get a rough estimate of the NPV of the alcohol program. Currently 319 plants are planned to come on line from 1982 to 1985. These rough

Table 7-3

Net Present Value of an Ethanol Plant in Southeast Brazil and Estimated NPV of the 5-Year Brazilian Alcohol Program

1. NPV of 120,000 liter/day alcohol plant using sugarcane, in millions $1979.

Real Discount Rate	Annual Real Increase in Oil Price (from $30/bbl)		
	0%/yr	3%/yr	5%/yr
12%	-0.64	9.6	17.5
14%	-2.7	6.2	13.1
16%	-3.11	3.6	10.7

2. Estimated NPV of alcohol plants to come on stream 1982 to 1985 (average size plants 120,000 liter/day, 180 day/yr)

A. Number of Plants	Year Approved	Year On Stream
75	1980	1982
53	1981	1983
80	1982	1984
111	1983	1985
Total 319		

B. NPV (in millions of $1979)

Real Discount Rate	Annual Real Increase in Oil Price (from $30/bbl)		
	0%/yr	3%/yr	5%/yr
12%	-170	2,557	4,648
14%	-695	1,610	3,398
16%	-781	916	2,691

Source: Estimates from World Bank Data.

estimates are shown in Table 7-3. At a 14% discount rate the NPV of the program is very sensitive to the rate of increase in oil prices. If oil prices go up 0%/yr in real terms the NPV is estimated to be -$700 million ($1979) as compared to a benefit of $3,400 million if oil prices incrase 5%/yr.

These NPV estimates should be viewed as a lower bound, best case, for several reasons. The base case assumptions are optimistic with respect to increases in the cost of stillage disposal, increases in land rental value and yield level.

Production of 1 liter of alcohol produces a by-product of 12 liters of liquid stillage waste, currently being expelled into rivers. By 1985, 128 billion liters of stillage waste must be processed (possibly as fertilizer) if production goals are met. The base case assumes that no credit or debit is given for stillage. Two potential uses are animal feed or fertilizer. It is unlikely that much stillage will be used as animal feed in large quantities as it is costly to evaporate the liquids.

Use of stillage as fertilizer on fields near the distillery is possible but the large quantities of stillage available may lead to pollution. Much more work needs to be done to deal with this problem. In order to prevent extensive pollution a net debit for stillage processing equipment will lead to a lower NPV for the alcohol program.

The yields used for the base case appear to be relatively optimistic. Assumptions are that annualized yields in south and southeast Brazil are 50 metric tons per hectare. Recent annualized yields, however, in south and southeast Brazil are reported by Williamson, 1981 to be between 35 and 45 metric tons per hectare. If much marginal land is used for sugar production average yields may even drop slightly. Lower yields will reduce the NPV of the alcohol program. Lower expected yields will also increase the land area under sugarcane to 3.1 million ha (from 2.6 million ha), if the 1985 targets are to be met. This is 10% of all land currently under crops. While 10% is a small fraction of total cropped land, it is a larger percentage of the good agricultural land.

Expanded pressure on land availability from the simultaneous rapid expansion of sugarcane and other food crops may raise the rental value of land. Thus, the NPV of the alcohol program will drop, but this effect is expected to small as NPV is not very sensitive to the land rental value.

As the ethanol from biomass program expands beyond 1985, feedstocks other than sugarcane will have to become more significant since land suitable for cane will be limited in availability. Alternative crops are:

- Cassava--It has the benefits of growing on marginal land and can supplement the income of small farmers, particularly in the northeast. Disadvantages are that fuel for distillation, such as wood from firewood plantations, must be obtained. Also, the capital costs of cassava-based distilleries are about 30% higher than sugar-based distilleries, as starch must be converted to sugar.

- Sweet sorghum--This feedstock is potentially attractive due to its short growing cycle, amenability to mechanized farming, fermentable sugar and the presence of sorghum bagasse.
- Wood--Although wood requires acid hydrolysis before fermentation, it has several advantages. Eucalyptus plantations harvested every six years could provide 800 liters of ethanol per hectare per year, as well as a by-product of 60 tons per hectare per year of charcoal. Currently 100 to 200 million hectares of unutilized "cerrado" land might be used as it is unsuitable for sugarcane (source: personal communication, World Bank).

In summary, the current program to produce 10.7 billion liters of ethanol primarily from sugarcane appears socially profitable only if oil prices increase at 3 to 5% per year in real terms. The current rapid expansion of alcohol production and consumption is largely due to government subsidies. Future large-scale alcohol production from other biomass materials may be feasible, depending on the rate of increase of oil prices and the outcome of current research. It should be noted that sugarcane cultivation has had 100 years of research and development while there has been only 5 years of intensive research on crops grown to produce liquid fuels.

ANNEXES

Annex 7-1

ROUGH RELATIONSHIPS BETWEEN EX-REFINERY GASOLINE VALUES AND OIL PRICES

Ex-refinery gasoline value (US$/liter)	0.20	0.25	0.27	0.30	0.35
Ex-refinery gasoline value (US$/gallon)	0.76	0.95	1.02	1.14	1.32
Oil price delivered at refinery (US$/barrel) a/	24	31	33	37	46
Oil price f.o.b. Arabian Gulf (US$/barrel)	22	29	31	35	43

a/ Including international freight, port handling, storage and local transport costs.

ETHANOL PRODUCTION FROM SUGARCANE: ESTIMATED ECONOMIC RATE OF RETURN (in percent)

Wholesale Gasoline Price: US cents/liter (US cents/US gallon)	Medium Cost Countries				Low Cost Countries				High Cost Countries			
	25 (95)	27 (102)	30 (113)	35 (132)	25 (95)	27 (102)	30 (113)	35 (132)	25 (95)	27 (102)	30 (113)	35 (132)
Base Case at Different Ex-Distillery Sugarcane Costs												
US$ 8/ton	20	23	28	36	25	29	35	44	12	14	18	24
US$10/ton	15	19	24	32	19	23	29	39	8	11	15	21
US$12/ton	10	14	19	27	14	18	24	33	4	7	11	18
US$14/ton	5	9	15	23	8	12	19	28	-	3	8	15
US$16/ton	-	4	10	18	2	7	13	23	-	-	4	11
Sensitivity Analysis (Sugarcane at $12/ton)												
Future Oil Price Increases at 5% p.a. (in real terms)	18	21	26	34								
Future Oil Price Increases at 0% p.a. (in real terms)	-	4	11	20								
Annual Operating Days:160	8	12	16	24								
Annual Operating Days:210	13	17	23	32								
Plant Size: 20,000 (Lpd)	3	6	10	16								
Plant Size: 240,000 (Lpd)	13	17	23	32								

Lpd = Liters per day..

Source: World Bank, Alcohol Production in Developing Countries, 1980

Annex 7-1 LAND REQUIRED TO PRODUCE SUGARCANE OR CASSAVA FOR ETHANOL PRODUCTION IN VARIOUS REGIONS

	Yield[1] (MT/ha)	Realized Annual Yield[2] (MT/ha/year)		Land Requirement (1000 ha): 1 Billion Liters, high efficiency[3]	1 Billion Liters, low efficiency[4]	10.7 Billion Liters[5], high efficiency	10.7 Billion Liters[5], low efficienc
SUGARCANE							
Southeast	59.5	44.6		235	336	2,519	3,599
São Paulo[6]	66.9	50.2		209	299	2,238	3,197
South	45.5	34.1		308	440	3,295	4,707
Northeast	47.8	35.9		292	418	3,130	4,471
Bahia	38.0	28.5		368	526	3,942	5,632
		12 Month Maturity	18 Month Maturity	12 Month Maturity			
CASSAVA							
Southeast[6]	15.6	15.6	10.4	401	436	4,287	4,664
South	13.6	13.6	9.1	460	500	4,917	5,350
Northeast	10.5	10.5	7.0	595	648	6,369	6,930
low yielding sertão[7]	8.5	8.5	5.7	735	800	7,868	8,560

1 IBGE (5).

2 Sugarcane fields must be replanted after three cuttings, thereby removing them from production one of every four years. Cassava can generally be harvested in 12 months but is often left in the ground for up to 18 months since it is highly perishable crop once removed.

3 Sugarcane: 10.5 MT/1000 liters ethanol (involves processing of both sugar and molasses residue). Cassava: 6.25 MT/1000 liters ethanol.

4 Sugarcane: 15 MT/1000 liters; Cassava: 6.8 MT/1000 liters.

5 1985 goal; figures may be different than 10.7 x 1 b. requirement due to rounding of 1 billion liter number.

6 Or high yielding areas in other parts of country.

7 Interior lands, drought potential, little or no fertilizer.

Source: Williamson, 1981

CHAPTER 8

SUMMARY AND TENATIVE CONCLUSIONS

8-1 The Current Energy Situation in Brazil

The major problems the Brazilians must deal with when formulating energy investment policies are: long-term oil import price increases, short-term disruptions of oil imports, and the current foreign debt situation. The magnitude of these oil related problems can be seen from the following facts. Brazil imports 80% of the oil it consumes. The cost of oil imports increased from only $375 million in 1972 to $11 billion in 1980 (current dollars). The cost of oil imports was 55% of total export earnings in 1980. The Brazilian economy has not only been jolted by steep oil price increases but has also experienced the vulnerability of oil dependence when the Iran-Iraq war cut off 45% of its oil imports in 1980.

Foreign debt has grown rapidly since the late 1960's, caused in large part by heavy borrowing to finance oil imports in the mid-1970's. Total outstanding debt at the end of 1980 was $57 billion. Additional borrowing has been difficult and costly. Current interest rate premiums on foreign loans to Brazil have risen to 2.25% over the euromarket LIBOR rate.

In response to these pressures the Brazilian government has launched a massive domestic energy investment program, with plans to invest a total of $60 billion (constant $1979) over the next 5 year period, from 1981 through 1985. Sixty percent of this investment is to be electricity, and a third is earmarked for the liquid fuels sector. Of the $19 billion planned investment in the liquid fuels sector, one third is is to expand refining capacity and bring the offshore Campos basin oil fields into production. While these investments will have the effect of doubling domestic oil production by 1985, as compared with the 1978 level, oil imports in 1985 are expected to be the same, if not somewhat above, the 1978 level.

The longer term prospects for liquid fuel production depend on the success of planned investments in oil exploration, shale oil and alcohol production. Investment plans for these sub-sectors over the five year period from 1981 through 1985 are ambitious. They include planned expenditure of $3.7 billion (constant $1979) in oil and gas exploration, $3.6 billion in alcohol production (95% from sugarcane feedstock), and $1.1 billion for a 25,000 bbl/day shale plant which will later be expanded to 50,000 bbl/day.

8-2 Evaluation of Liquid Fuel Investment Options

The topic of this thesis is the economic and financial comparison of liquid fuel investment options in oil exploration, shale oil and alcohol from sugarcane. In order to evaluate and compare these options, methods of analysis were developed that have application not only to analysis of energy investments in Brazil but also to analysis of energy options in a variety of countries. New techniques developed here fall into two different categories. The first consists of a framework for evaluation of public energy programs that uses shadow prices and public discount rates adjusted both for project systematic risk and for risks associated with international borrowing. The second is the development of a Bayesian probabilistic oil exploration model that estimates the probability of future oil discovery and the net present value of various oil exploration programs. This exploration model allows oil exploration programs to be compared directly to other, more traditional projects, evaluations that were used for shale oil and by the World Bank for the alcohol program.

A. Metnodology for Evaluation of Liquid Fuel Investment Options

In order to evaluate the soundness of these ambitious liquid fuel production programs, it is necessary to state clearly the benefits that liquid fuel investment programs may provide. These benefits include:

1) Provision of domestic liquid fuel supplies that are competitive with imported supplies, mainly oil;
2) Reduction in the negative impact of short-term disruptions of oil imports;
3) Diversification of the country's economic base to reduce the negative impact of medium-term or long-term oil price increases on the economy;
4) Reduction in the negative impact of medium-term or long-term oil price increases on the foreign borrowing postion of the country

(through reduction in the size and variability of the oil import bill and debt service payments).

In order to evaluate properly an energy investment program in Brazil, or in numerous other countries, the methodology used should account for the benefits listed above. The four benefits will be considered in order below.

To evaluate the competitiveness of domestic liquid fuel supplies, a net present value approach (and in certain cases the internal rate of return method) was used to evaluate the economic viability of the investment programs. In order to complete a public project evaluation certain adjustments must be made to account for distortions that may cause opportunity costs for public projects to diverge from those observed in the market place. Adjustments that need to be made for all public projects, regardless of the type of project, are the application of shadow price of foreign exchange and the shadow price of labor, the use of international values for traded inputs and traded outputs, and an upward adjustment to the public discount rate to account for country borrowing risk. Project specific adjustments include changes in the public discount rate to account for systematic risk, and adjustments to account for specific project characteristics that may decrease or increase country borrowing risk. This framework will be related to the major benefits of liquid fuel investment programs.

A frequently stated benefit of domestic energy production is to minimize the impact of short-term disruptions in oil imports. The solution to a short-term oil import disruption is a project (such as an oil stockpile) that can provide a large amount of oil in a short period of time (weeks or months). Large scale liquid fuel investments provide small amounts of oil over a long period of time. Thus, the objective of long-term energy production should not be to handle short-term disruptions. The most cost effective method of dealing with oil import disruptions is a stockpile program. The cost of this program can be considered as "disruption insurance" that should be added to the cost of imported oil in order to compare "insecure" imported oil to more "secure" domestic liquid fuel sources. In this study a rough estimate of the cost of this "disruption insurance" (or stockpile premium) was made by dividing the cost of maintaining a 90-day stockpile by the current oil import level. The result is a premium of $1 to $2 per barrel of imported oil. The cost of an imported barrel of oil plus the stockpile premium (together a total of about $30/bbl, $1979) is thus the shadow value of a barrel of domestic liquid fuel. If perceptions of the expected length of an oil import disruption are longer than 90 days, say 180 days, the "stockpile premium" is higher, $3-4/bbl.

An additional benefit of energy investment programs may be the diversification of the country's economic base to increase the share of energy in the economy and thus reduce the negative economic impact of future increases in the price of imported oil. If the economy is completely diversified or if decision makers are not risk averse, then diversification would not be an objective of energy investment. However, in the case of Brazil (and other developing countries) the economy is not completely diversified and risk spreading through the public sector is not complete. Also, decision makers are risk averse since their decisions affect a large segment of the general public that prefers a smooth , as opposed to a highly variable, flow of income. Thus, in a situation of high oil import dependence, such as Brazil's current situation, a project that reduces dependence on oil imports provides an additional "diversification" benefit. The size of this benefit is a function of the expected variance of future oil prices. While in principle the "diversification" benefit of a liquid fuel project could be accounted for through adjustments to the cash flows of a project, in practice this benefit is most easily accounted for through adjustments to the project discount rate. Thus, liquid fuel projects that reduce the negative impact on the economy caused by potential oil price increases should be discounted at a lower rate than projects similar to those already in the economy. The use of these risk adjusted discount rates accounts for the systematic risk of the energy project relative to the rest of the economy. It appears that in many cases, if economic planners perceive the "diversification" benefit of an energy project, the reaction may well be to do the project regardless of cost. One strong point in favor of the risk adjusted discount rate approach recommended here is that it tells the planner whether or not to do a specific project (i.e. if the NPV is less than 0 at the appropriate risk adjusted rate) while accounting for the "diversification" benefit of the project.

Considering this precarious debt position in which Brazil is caught, an additional benefit of domestic liquid fuel investments may be to reduce the negative impact of future oil price increases on the foreign borrowing position of the country. In a country which is heavily in debt, a rapid rise in oil prices will not only have a negative impact on the economy, but also may well increase the size of the foreign debt and sharply increase the costs of further borrowing. Thus a liquid fuel project that reduces the level of oil imports will also reduce the oil import bill in the long-run. This may have the effect of reducing the risk which bankers perceive when lending to Brazil and lead to reduced real costs of borrowing. However, borrowing costs in the short-run are likley to increase as Brazilian institutions borrow to finance energy projects. The tradeoff to be analyzed is the additional costs of borrowing today to finance energy projects, which may lead to reduced costs of borrowing in the future if their energy investments are successful, as opposed to reduced costs of borrowing today and higher oil import bills in the future.

An additional cost of an investment program is the increased cost of foreign borrowing resulting from project expenditure. In order to get an estimate of the magnitude of the impact of Brazil's foreign borrowing on project evaluation, this study draws on previous work on the effects of country risk (Harberger,1976, and Baldwin, Lessard, and Mason,1981). As a country's foreign debt increases, the higher probability of default perceived by foreign lenders is likely to result in higher interest rates. The country risk premium is an additional cost of foreign borrowing that results from the inability of foreign lenders to enforce international contracts (somewhat analagous to bankruptcy costs within a country). Brazil is currently charged one of the highest premiums on loans, 2.25% over the floating euromarket LIBOR rate. The country risk premium added to the discount rate is a rough measure of the effect of increased borrowing costs to finance new energy investments. The measurement of the benefit of an energy project on future reduced borrowing costs is much more difficult, whether accounted for through adjustments to the cash flows or through adjustments to the discount rate. The magnitude of this benefit is determined by the effect of sharply higher oil prices on the behavior of the euromarket LIBOR interest rate and the risk of default perceived by bankers (i.e. their reaction by increasing the country risk premium or outright credit rationing). Uncertainty about these events makes the calculation of this benefit very hard to make. A thorough analysis of this issue is beyond the scope of this study, but preliminary analysis indicate that overall macroeconomic policies have a much more important effect on country risk than specific energy investment policies. As a first approximation, to adjust for this effect we will assume that externalities associated with additional liquid fuel investments (i.e. increased costs to other Brazilian borrowers) are offset by longer-run reduced costs of borrowing due to effect of energy projects on reduction of the oil import bill. This implies that the discount rate should be adjusted upward by the average country risk premium (2 percent), not the estimated marginal premium (4 percent).

In order to evaluate liquid fuel investments from the point of view of a Brazilian public institution, the project cash flows were discounted at the social risk adjusted cost of capital, investment cash flows are adjusted for the shadow price of foreign exchange (i.e. the Brazilian domestic component of investment should be divided by 1.3, as the Brazilian Cr is estmated to be overvalued by 30%), and the value of a barrel of domestic fuel is valued at the international price plus the stockpile premium. However, if the projects are to be undertaken by private foreign companies and the analysis to be done from their point of view, the project cash flows are discounted at the firm cost of capital (relative to the U.S. market) with necessary adjustments for perceived political risk. Also, in the private case the official exchange rate and the international oil price, without the stockpile premium, are used. A summary of the estmates of the risk adjusted cost of capital for liquid fuel projects in Brazil are shown below:

Project	Social Cost of Capital Risk	Risk Free Rate	Other Risk Premiums	Beta	Social Risk Premium
Oil	12.0	2	2	.7	12
Shale	12.0	2	2	.7	12
Alcohol	14.0	2	2	.84	12

Project	Multinational Firm Cost of Capital	Risk Free Rate	Political Risk Premium	Beta	Risk Premium on Market
Oil	12-14	1.3	2-4	.95	8.8

This gives results when discount rate (not cash flows) are adjusted for borrowing and political risks.

The estimated social cost of capital is 12% (real rate) for the oil exploration and shale oil programs. This is lower that an average project in the Brazilian economy which has an estimated social cost of capital of 18% (calculated using a beta of 1 and a country risk premium of 4%). This difference is a signal that a lower rate of return on oil projects should be accepted since they provide a benefit to the diversification of the economy and the foreign debt position.

The cost of capital to a multinational firm for an oil project in Brazil is also estimated to be 12%. While the risk premium on the U.S. market is lower, this is offset by oil project systematic risk that is higher to the companies that to Brazil. When political risk is included in the discount rate the final estimate is 12%.

While the estimation of these discount rates is are rough and subject to revision, this method brings important factors into the evaluation which are not accounted for with simpler social cost of capital calculations.

B. Methodology for Evaluation of Oil Exploration Programs

Uncertainty in the resource base and the wide range of outcomes of an exploration program has made the evaluation of oil exploration programs more difficult than other projects which have less variable costs and benefits. A detailed Bayesian probabilistic oil exploration model was developed to estimate the probabilities that a certain level of oil resources exist, the probabilities of future discovery and the net present value of various oil exploration programs.

The basic outlines of the methodology are:

1) Initial prior probabilities that each basin contains oil plays with giant fields and oil plays with commercial fields is established. These priors are estimated for each type of sedimenatry basin in the country (marginal basins, deltas, and cratonic basins), based on previous worldwide studies of oil resources in various basin types.

2) An initial prior probability on the efficiency of the oil exploration process is established based on efficiencies estimated for exploration in other regions.

3) Initial prior probabilities of resource state and exploration efficiency are both simultaneously updated in a two stage process using a discovery likelihood function based on past drilling data. The result is a revised estimate of the resource state, revised estimate of exploration efficiency and probabilities of future oil play discovery.

4) The updated probabilities on the resource state and discovery rate are multiplied by the expected NPV of potential oil plays to get an expected NPV of various exploration programs.

8-3 Summary of Results

1. The model results indicate that a relatively small amount of oil remains to be found in Brazil. Cumulative production by June 1979 was 1051 mmb, and remaining proved recoverable reserves were 1467 mmb. The expected amount of oil to be found in known oil plays is 150 to 200 mmb (most all in the Campos basin). Table 8-1 gives a summary of oil reserves and resources. Expected amount of oil to be found in new plays is estimated to be 500 mmb, with one half of this in offshore marginal basins. While the expected value in these basins is 250 mmb, the range of outcomes varies from a 48 percent chance of 0 mmb to a 5 percent chance of 1600 mmb. Results compare favorably, within several percent, to industry assesments.

2. The most profitable place to drill is in the Campos basin. Returns to exploration in the other offshore marginal basins are high for the next 100 to 200 wells and diminish rapidly thereafter. The rate of discovery of oil in the onshore cratonic basins is expected to be low, due to the low potential and enormous prospective areas. (Exploration only for oil, not gas, was modelled.) Additional exploration in the offshore Amazon delta is not expected to be profitable due to very low probabilities of finding large fields and the high production cost if small fields are eventually discovered. See Table 8-2.

Table 8-1 Summary of Production, Reserve and Resource Data for Brazil (million bbls)

Region	Cumu-lative Production 6/79	Proved Recover-able Reserves 6/79	Remaining Proved + Probable Recoverable Reserves	Estimate of Resources in Fields in Known Plays	Estimate of Resources in in Undis-covered Plays
Reconcavo (onshore)	870	445	475	5	
Segipe-Alagoas					
onshore	129	141	150	6	
offshore	41	50	95		
Northeast Basin (oofshore)	5	49	87	45	
Campos Basin	6	541	660	120	
Other					
Continental Margin Basins (offshore)				.48 chance of 0 .33 chance of 275 .13 chance of 550 .05 chance of 1605 E(V) = 245	
Amazon Delta (offshore)				.89 chance of 0 .11 chance of 650 E(V) = 67	
Onshore Cratonic Basins				.75 chance of 0 .15 chance of 250 .10 chance of 1400 E(V) = 188	
Totals	1051	1226	1467	176	500
Total Production, Reserves and Resources	3194	onshore-1817 offshore 1377			

Source: Cumulative production and proved reserves from Petrobras; proved and probable reserves from IIASA world oil database based on Petroconsultants data; resource estimates calculated in this study.

Table 8-2 Summary of Expected Amount of Oil (million bbls) to be Discovered as a Function of Wildcat Exploration Wells (cumulative wells and cumulative amounts)

1. Offshore - Continental Margin Basins

Undiscovered Plays[1]		Undiscovered Fields in Known Plays[2]	
Wells(type 1)	Amount(mmb)	Wells(type 2)	Amount(mmb)
50	64	30	72
100	125	60	112
200	176	80	133
500	237		

2. Offshore - Amazon Delta

Undiscovered Plays[1]	
Wells(type 1)	Amount(mmb)
50	3
100	10
200	32
300	72

3. Onshore - Cratonic Basins

Undiscovered Plays[1]	
Wells(type 2)	Amount(mmb)
100	47
500	130
1000	170
1200	180

[1]From Tables 4-11, 4-12, 4-13.

[2]90 percent in Campos Basin, 10 percent in Northeast and S-A Basin. Calculated from discovery rate trends in Figure 4-9.

3. The results indicate that exploration by PETROBRAS has been relatively efficient and the majority of offshore oil has been found. PETROBRAS is in a dilemma if it claims to have been efficient in oil exploration and simultaneously claims that large undiscovered fields remain to be found. The large scale exploration effort undertaken by PETROBRAS has reduced uncertainty in the resource base and thus reduced Brazil's bargaining strength with the major oil companies.

4. If all future exploration in the offshore marginal basins (outside the Campos basin) is undertaken by PETROBRAS the optimum exploration-level is expected to be 200 wells or less. Beyond this level expected diminishing marginal benefits of exploration are greater than marginal exploration cost. This implies that it is not profitable to explore for the last 50-100 mmb in these basins as expected returns are too small. The NPV to Brazil of exploration for new oil plays in the offshore marginal basins varies from about $300 million ($1979) to over $1 billion, depending on whether real oil prices increase at 0 or 5 percent per year in real terms.

5. The difference in NVP of the extensive exploration program planned by PETROBRAS in the offshore marginal basins and the optimal program is an expected present value <u>loss</u> of $700 million to $1,200 million, depending if the oil price increases in real terms at 5 or 0 percent per year. The model also indicates that the extensive PETROBRAS exploration program reduces the potential NPV of the exploration undertaken by foreign oil companies.

6. If all exploration for new oil plays in offshore marginal basins were undertaken by the oil companies with current exploration service contract terms, the optimal level of exploration stops short (about 100 wells short) of the optimal exploration level from the viewpoint of PETROBRAS. For real oil prices increasing at 0 or 5 percent per year the NPV loss to Brazil is estimated to be \$38 million to \$440 million. This represents the difference between the optimal exploration level of PETROBRAS and the expected PETROBRAS share of discoveries if foreign companies follow their optimum plan.

7. It appears particularly difficult for an institution such as PETROBRAS to institute policies to wind down the rate of exploration once the optimum number of wells have been drilled. It is difficult from a technical and geologic viewpoint to determine the optimum level, and it is difficult for a state-owned enterprise to do so from an institutional standpoint (as PETROBRAS has almost a complete monopoly on oil activities and easy access to the government budget). If it is difficult to prevent "over exploration", a preferable choice may be to let the foreign companies do the exploration and accept the lesser of two evils. According to the results of this model the reduction is lost NPV that would occur by switching from current plans to exploration by the foreign oil companies is estimated to be between \$1,000 million \$1979 (if oil prices stay constant) and \$300 million (if oil prices rise 5 percent/yr in real terms). These calculations assume that PETROBRAS and the foreign oil companies have the same efficiency. If the oil companies are more

efficient and have lower costs, the benefits to Brazil of utilizing the oil companies is greater.

8. Results here indicate that investment in a 50,000 bbl/day shale oil plant would only be feasible if oil prices are expected to increase at 3 to 5 percent per year and cost overruns are kept to less than 30 percent of current estimates. This assumes a base oil price of $30/bbl and costs adjusted for the shadow price of foreign exchange.

9. The rate of return on alcohol from sugar is very sensitive to the oil price. Given potential additional costs of stillage waste disposal, slightly lower yields on new lands and moderate rises in land costs, alcohol programs have low profitability unless oil prices rise at 3 to 5 percent/yr in real terms. These results are based on an economic analysis with a base price of $30/bbl and costs adjusted for the shadow price of foreign exchange.

A summary of the estimated NPV calculations is given in Table 8-3 and the relevant rates of return in Table 8-4. As can be seen, if oil prices increase at less than 3%/yr, the planned programs are estimated to have a negative NPV. If one believes that oil prices are going to increase at 0%/yr , then the current investment programs are justified only if; 1) the value of a marginal barrel of domestic oil is about $10/bbl above the current import cost ($28/bbl), or 2) the benefits of the liquid fuel projects to the diversification of the economy and to the foreign debt position are perceived to be large enough to accept a rate of return of 6 to 8%, or 10 to 12% lower than and average project (beta of 1 and discount rate of 18%). The implict beta of liquid fuel projects would then be .1 to .3. If oil prices do increase at 3 to 5%/yr, the investment projects appear to be socially profitable.

It is important to consider alternative policies with regard to oil exploration in order to guard against possible "over exploration". Such policies could be to allocate more acreage to foreign oil companies and/or to contract out exploration drilling activities, so that winding down exploration, when necessary, would be easier. The expansion of foreign participation in oil exploration and in shale oil would help reduce the risk of such investments to PETROBRAS.

A rough summary of the expected contribution of the 5-year liquid fuel investment plan is shown in Table 8-5. Onshore production from known fields is expected to decline to half of the 1980 value by 1990, but Campos basin production, which will peak in the late 1980's, will add substantially to the 1990 supply. Expected contribution of the oil exploration program is small, but there is a wide variation in possible levels. The difference between expected production of the planned program and the optimal program is very small, but the optimal program is substantially less expensive. Expected production from known reserves and the expected production from the 1980-1985 program are likely to triple production as compared to the 1980 production level.

Table 8-3

Summary--Net Present Value of Liquid Fuel Production Programs in Brazil

(millions constant $1979)

Program	Real Discount Rate (percent)	Expected Real Annual Oil Price Increase (from a base of $30/bbl) 0%/yr	3%/yr	5%/yr
1. Oil Exploration[1]				
A. Planned wells	12	-1,070	-290	540
B. Optimal	12	200	640	1,270
C. All Exploration by Foreign Oil Companies				
i) Oil Comp. Share	12	0	9	102
ii) Petrobras Share	12	0	592	898
2. Shale Oil (50,000 bbl/day)				
A. No cost increase	12	889	1,950	2,500
B. Costs up 30%, output 1/2 for 10 yrs.	12	-390	690	1,010
C. Costs up 50%, Investment and Production Delayed	12	-1,292	-635	-380
3. Alcohol Program				
A. Base case, straight alcohol from sugarcane	12	-170	2,557	4,648
	14	-695	1,610	3,398
	16	-781	916	2,691

[1]Exploration in offshore marginal basins.

Table 8-4

Real Internal Rates of Return on Liquid Fuel Projects in Brazil

(in percent)

	Annual Real Increase in Oil Price (base of $30/bbl.)		
Exploration by Petrobras	0%	3%	5%
100 wells	14	19	22
200 wells	12	16	19
300 wells	10	15	18
Shale Oil			
Base case	18	23	24
Costs up 30%	13	18	21
Costs up 30%--output 1/2 10 yrs	4	14	16
Costs up 50%--costs delayed	5	9	10
Alcohol from Sugarcane			
Base case	8	19	24

Capital Investment Costs ($1979/bbl/day)

Known Offshore Oil	
- Shallow	6,000
- Deept (300-400 ft.)	14,000
Shale Oil	
- Brazil	49,000
- (US)	(23,000-30,000)
Alcohol	
- Sugarcane	25,000-31,000

Table 8-5

Contribution of Expected Liquid Fuel Production to Total Domestic Supply in 1990

(Million Barrels Oil Equivalent per Year)

	1980	1990
Known Onshore Oil	40	20
Known Offshore Oil (mainly Campos)	20	130
Alcohol Capacity (in place 1980)	23	23
Expected Contribution of 1980-1985 Liquid Fuel Investment Program (cost, billion $1979)		
• Oil Exploration		
-Planned ($3.5 to 4.5)		25 [1]
-Optimal ($2 to 3)		20 [2]
• Shale Oil ($1.2 to 2.5)		9 to 18 [3]
• Alcohol ($4)		34 [4]
Total Production	83	270+ [5]
Total Consumption	385	450-520?

[1] Expected production, range is from 0 to a small chance of 100.

[2] Expected production if PETROBRAS stops at NPV maximum.

[3] Lower values for 25,000 bbl/d plant, higher for 50,000 bbl/d plant.

[4] Alcohol valued at 85% of oil equivalent.

[5] No contribution from additional investments from 1985 to 1990.

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