T-3610

INTERNATIONAL EXPLORATION DECISION MAKING FOR INDEPENDENT OIL COMPANIES: CASE STUDIES IN AREAS OF PAKISTAN, CHINA, AND ALGERIA

by

William H. Smith

A thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Doctor of Philosophy (Mineral Economics).

Golden, Colorado

Date 30 May, 1989

Signed: William H. Smith
William H. Smith

Approved: Roderick G. Eggert
Dr. Roderick G. Eggert
Thesis Advisor

Golden, Colorado

Date 5/30/89

John E. Tilton
Dr. John E. Tilton
Coulter Professor and Head,
Mineral Economics Department

ABSTRACT

This study evaluates the economic attractiveness of oil and gas exploration in specific areas of Pakistan, China, and Algeria, and in doing so, guides an exploration manager of an independent oil company through project evaluation of a firm's first international exploration venture, once strategic planning has emphasized the need for this type of project. Favorable exploration economics still exist overseas because larger fields remain to be found there than can be expected to be found in the United States.

Strategic planning helps a firm to adjust appropriately to future changes, such as changes in oil prices, and determines the type of project to invest in. The net present value (NPV) calculated from the risk-adjusted cash-flow model determines whether a firm should invest in an individual project. Many parameters, including geologic, engineering, cost, prices, and political risk, are not precisely known prior to the investment decision. The model used here uses ranges and distributions rather than point values for these stochastic variables. Multiple iterations of the cash-flow model (simulation) yield a distribution of possible NPV's.

Case studies in fold and thrust belts of Pakistan,

China, and Algeria illustrate the use of the evaluation methodology. A gas and condensate project in Pakistan and an oil project in Algeria are recommended for investment because of their expected positive NPV's, but the oil project of northwestern China is not recommended because of the negative NPV.

The profitability of the Pakistan case is sensitive to the amount of condensate produced with the gas. Source rock studies could locate areas of maximum liquids and enhance the expected NPV. The average case is profitable for geologic risk below 1:16.7; the success ratio in the study area as well as the rest of Pakistan has been 1:4.

The remoteness of the northwest basins of China and the resulting high costs from exploration though development and production are the major factors in the negative NPV, even though fields of 25 million to 2.2 billion barrels may be expected.

Oil fields, ranging from 60 to 850 million barrels can be expected to be found in the eastern Saharan Atlas of Algeria. Geologic risk is assumed to vary from 1:5 to 1:15, with 1:10 most likely. By comparison, the average project is economic for all geologic risk below 1:38.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ABBREVIATIONS

Abbreviation	Term
ARE	Anschutz Ranch East
bbl	barrel
BCF	billion cubic feet
BOPD	barrels oil per day
BTU	British thermal unit
C	centigrade
CI & C	Consolidated Industrial & Commericial
CNOGC	Chinese Nat. Oil & Gas Corporation
CNOOC	Chinese Nat. Offshore Oil Corp.
cu	cubic
DCFROR	discounted cash flow rate of return
Dev	deviation
DST	drillstem test
FLN	Nationale Liberation Front
ft	feet, foot
gal	gallon
GNP	gross national product
GOR	gas-oil ratio
km	kilometer
kw	kilowatt
lb	pound
m	meter
M	thousand
max	maximum
Mcf	thousand cubic feet
mi	mile
MIGA	Multilateral Invest. Guarantee Agency
min	minimum
mm	millimeter
MM	million
MMcfg	million cubic feet gas
MMcfgpd	million cubic feet gas per day
MW	megawatt
NPV	net present value
OGDC	Oil and Gas Development Corporation
OPEC	Organ. of Petrol. Exporting Countries
OPIC	Overseas Private Investment Corp.
psi	pounds per square inch
R & D	research and development
sq	square
Std	standard
TCF	trillion cubic feet
TOC	total organic carbon
yr	year

ACKNOWLEDGEMENTS

Several individuals made this study possible. The faculty of the Mineral Economics Department and Dr. Wright of the Petroleum Engineering Department presented the economic tools in class in an interesting and challenging manner. Dr. Eggert, my thesis advisor, provided guidance, organization and encouragement during the course of this work. I would also like to thank the other committee members, Drs. Davis, Dobozi, Petrick, Rudawsky, and Simmons, for their time and comments.

The Anschutz Corporation provided employment during this time and use of their non-confidential data base, both of which are greatly appreciated. This study would not have been possible without this financial and informational support.

Special thanks go to my wife, Donna, and my children, Andy, Eric, Matt, and Jessica, for their support and sacrifices during the past three years. I greatly appreciate Donna's typing the manuscript and its numerous revisions.

Chapter 1

INTRODUCTION

The mid-1970s through the early 1980s were good times for oil exploration and production companies. Increasing crude oil prices made most of them successful. When oil prices went from well over $30 per barrel to below $30 in 1981, rather than the expected $40 to $60, some companies started experiencing financial difficulties.

The oil price shock of 1986, when prices fell from $28 per barrel to below $10, hurt all exploration and production companies and is the motivation for this study. The present recovery in prices, $12 to $20 per barrel, has allowed some companies to prosper, while others have suffered. The oil industry has experienced three prior downturns (1949, 1958, and 1971), but none as severe as the current one (Megill, 1988a). The current downturn is the first in which oil prices have decreased significantly.

The leadership role is the key to survival in a hostile environment (Hall, 1980). This role can be attained by being the lowest cost producer, having a differentiated product, or both. Crude oil and natural gas are not products that can be differentiated in the market, so the exploration and production company must become a lower cost producer. Adelman (1970) wrote, "Exploration is <u>never</u> for minerals as such, always for cheaper minerals."

Larger fields remain to be found internationally than in the mature producing areas of the United States, which results in lower exploration and development costs per barrel of oil discovered. Many smaller or independent oil companies have no previous international exploration experience. A goal of this study is to minimize the impact of that lack of experience.

1.1 Purpose and Scope

The purpose of this study is two-fold: 1) to evaluate the economic attractiveness of oil and gas exploration in specific fold and thrust belts of Pakistan, China, and Algeria, and 2) to serve as a guide to evaluating foreign exploration ventures for exploration managers, who although experienced in domestic exploration and decision making, are not experienced or knowledgeable in foreign exploration.

The contribution of this study is the application of simulation, commonly used in some other fields, to international exploration, where only limited information may be available. The methodology presented is a thought process, rather than a mechanical inputting of values into a computer program. The information is directed toward independent oil companies. All integrated or major oil companies currently explore internationally, and most have large economic/planning staffs that aid the decision makers in such matters.

Personal experience has shown that most independents lack such staffs, and the exploration decision makers, although intelligent, have had no exposure to numerical evaluation and formal decision-making training (Smith, 1988). Reservoir engineers use economic evaluations more than do explorationists, but their evaluations are commonly done after an exploratory well has been drilled and before completion and development. The exploratory expenditures of an international project are much larger than those of an onshore domestic project, therefore the explorationist needs to do an economic evaluation prior to the exploration commitment. A survey by Boyle and Schenck (1985) confirms that smaller oil firms use less sophisticated evaluation techniques than larger firms.

The study concentrates on exploration in less developed countries, those most in need of foreign investments and which show the greatest geologic potential. The methodology presented, however, is applicable to projects in any country, including the United States. Oil is the primary exploration target, with gas as the target limited to countries where a gas distribution system is in place, with demand exceeding supply. Case studies of the Central Fold

Belt of Pakistan, the Tarim and Junggar Basins of northwestern China, and the eastern Saharan Atlas Fold Belt of Algeria use the project evaluation methodology.

1.2 Methodology and Organization

A company can have more opportunities and maximize its financial results by being one of the first to recognize changes in the business environment and adjusting its operation more quickly than its competitors, rather than simply playing "follow the leader." The proper use of strategic planning prepares the firm for future changes. Chapter 2 reviews strategic planning in general, exploration planning in particular, and how both can be applied to the smaller company.

Chapter 3 explains why under current conditions oil companies should explore internationally, and why the less developed countries need the foreign investor, creating the opportunity for profitable exploration.

The strategic plan chosen determines the type of projects in which the firm invests, but does not evaluate the individual projects of the selected type. Chapter 4 covers the methodology used in the evaluation of individual projects: a risk-adjusted cash-flow model on a Lotus 1-2-3 spreadsheet, a Monte Carlo simulation with the @ RISK add-in, and the input parameters for the model. Information sources for evaluating international exploration projects are included in Appendix A.

Chapters 5, 6, and 7 evaluate exploration ventures in the Central Fold Belt of Pakistan, the Tarim and Junggar Basins of northwestern China, and the eastern Saharan Atlas Fold Belt of Algeria. These areas were chosen because of their interest to the author's employer, The Anschutz Corporation. Important factors behind this interest are 1) favorable geology, as evidenced by productive basins nearby; 2) acreage available or believed to be available in the near future; and 3) thrust belt tectonics, in which Anschutz has had economic success and seismic and geological expertise in the Wyoming-Utah Overthrust Belt. The Pakistan case will be treated in more detail than the others, both to illustrate the methodology in detail, and because as an English-speaking country, more data are understandable by the author. The computer spreadsheet for Pakistan is included in Appendix B.

Chapter 7 summarizes, discusses to what extent this methodology could be applied to other industries, and makes recommendations for further studies.

Chapter 2

A REVIEW OF STRATEGIC PLANNING

Strategic planning is the first step in decision making. After the basic question of which business a firm should be in has been answered, more specific decisions can be made. The use of strategic planning determines the types of projects in which a firm invests, but does not address individual projects.

The world in which an oil exploration and production firm operates has changed significantly in a relatively short time and continued changes should be expected. "Business as usual" is no longer a valid operating strategy.

2.1 The Concept of Strategic Planning

Strategic planning is the development of plans to make the most of opportunities and to counteract the possible negative impact of change in the business environment (Naylor, 1983).

The primary purpose of strategic planning is optimizing the "fit" between a firm and its current and future environments (Wilson, 1983). Planning is often confused with forecasting. Planning provides strategies, which relate what a firm <u>should do</u>. Forecasting gives estimates of <u>what will happen</u> if the strategy is implemented in a given environment (Armstrong, 1983). Planning is very useful for organizations facing complex tasks, large changes, uncertainties, and inefficient markets.

The total failure of energy price forecasters is a major factor in the current disenchantment of strategic planning in energy companies (Sawhill, 1983). The well-phrased answer to this opinion is "what must be dumped is not strategic planning, but the narrow, mistaken notion that developing a strategy is somehow dependent on accurate forecasting." In the energy world, the future will always be uncertain, so management needs a flexible strategic plan that allows it to turn unexpected events into a source of competitive advantage, rather than to react defensively to such events.

2.2 Stages of Planning

Four phases in the evolution of strategic planning have been identified (Blass, 1983). It is helpful for a manager to examine the characteristics of the organization, identify its stage of strategic planning, and understand the characteristics needed to advance into progressive stages.

Most companies are found in phase 1, "financial planning," where the goal is to meet the budget. Targets are usually financial, although exploration firms may have as an objective the finding of x barrels of oil.

Phase 2 or "forecast-based planning" involves predicting the future. Thoughts of market share, market leadership, and development of new technologies are indications that a company has moved from the first to the second phase. Multiyear budgets, analyses of the gaps between targets and forecasts, and a static allocation of resources are other functions characteristic of a firm in this stage.

The third phase is "externally oriented planning," and can be called the beginning of strategic planning. This stage represents a large jump from previous stages in the effectiveness of strategic decision making. Communication is a key here - top management informing other levels of management about the corporate goals and strategies, and encouraging feedback from line management. Functions in this stage include a thorough situation and competitive analysis, evaluation of strategic alternatives, and "dynamic" allocation of resources. A goal of this paper is to encourage independent exploration companies, who may have no planning or a lower level of planning, to advance into this third phase of strategic planning.

The goal of the fourth phase, "strategic management," is creating the future for the firm. Very few companies, such as General Electric or Texas Instruments, ever reach this advanced stage. Key elements are widespread strategic thinking by all managers, coherent management processes where plans, goals, business cycles, and management incentives reinforce each other, and a supportive value system and climate which contribute to management's world view.

2.3 Strategic Planning Framework

Any complex task seen in its entirety for the first time seems overwhelming and too complicated to tackle. This same task broken down into well-defined steps that logically lead into the next step appears to be simpler and less intimidating to the first time user. The following framework has been used by John Argenti (1986), a British strategic planning consultant.

2.3.1 Objectives and Targets

The objective of the firm must be understood before correct strategic planning can be done. The assumed objective of a firm is the maximization of the wealth of the shareholders, the legal owners of the firm (Guzman, 1984). "The object of the investment, or capital budgeting decision is to find real assets that are worth more than they cost" (Brealey and Myers, 1984). The wealth of the firm, and ultimately the wealth of the shareholders, is maximized by finding oil and gas that is worth more than the finding, developing, operating, and time-value-of-money costs. Risk-adjusted net present value, discussed in Chapter 4 and utilized in the three case studies, is a decision tool used in accomplishing this objective. The overall corporate objective can be met by achieving intermediate goals which have targets associated with them, most of which are financial.

2.3.2 Forecasts and Gaps

Forecasts of the firm's expected performance are then compared with its objectives and targets. Argenti suggests making both a pessimistic and an optimistic forecast because of the uncertainty in estimating the current status and the future. Gaps are the amounts by which targets exceed forecasts.

2.3.3 Strengths and Weaknesses

Before steps are taken to reduce or remove a gap, a firm's abilities should be addressed. An assessment of a firm's strengths and weaknesses is used to allow it to move towards its strengths and away from its weaknesses (Quick and Schuyler, 1988). An obvious strength is what a company knows and has been successful at.

An independent oil company, because of its small size, cannot possess many strengths. If one dominant strength can be identified, a workable exploration plan can be conducted around the particular niche in which the firm excels (McCormick, 1985).

Three or four strengths and an equal number of weaknesses may be listed, narrowing the infinite number of threats and opportunities that are relevant for the firm. Technical expertise, managerial ability, and financial resources should be addressed.

2.3.4 Threats and Opportunities

This title points to the positive as well as the negative influences of changes in the world around us. An excellent analogy of threats and opportunities analysis is the radar system (Wilson, 1983). The radar provides continuous scanning of 360 degrees of the horizon, warning of other vessels, rocks, and other obstacles, as well as locating clear water where progress can be made safely. Special attention should be paid to how the successful competitors are reacting to changes, such as emphasizing international exploration over domestic exploration.

Accurate assessments of the current status and of the future are very difficult, making the use of multiple scenarios very useful. Scenarios are descriptions of plausible alternative futures that bound the range of future uncertainties (Mandel, 1983). Two to four scenarios are generally sufficient, and it is not necessary to assign probability estimates to these various scenarios. The heart of a scenario is a central theme that is relevant to the end use of the process. A low oil-price scenario and a high oil-price scenario should be considered by an explorationist.

The less developed countries of the world are becomming more receptive to direct foreign investment. This presents an opportunity for the competent exploration firm to profitably explore in these countries by using the most advanced technology and interpretational skills developed in the mature basins of the United States, even with the threat of continued low oil prices. Chapter 3 of this study reviews in more detail the threat of poor financial results from continued exploration in the mature producing areas of the United States and opportunities for profitable international exploration.

2.3.5 Alternate Strategies

Operational strategies enable a firm to minimize the potential effects of the threats and to maximize benefits from identified opportunities. Multiple strategies are generated to identify all the options available to the company. An exploration strategy may include a balanced portfolio of investing in frontier (immature, high-risk) areas with the expectation of long-term, high returns, while simultaneously investing in more mature basins that provide a lower risk cash flow, although lower rate of return (Castleman, 1985).

The risk sharing, or working interest taken, becomes important in the context of this study. Independent oil companies do not have large budgets, and international exploration ventures are larger in scope and more costly than domestic plays. The size of the interest that a firm takes in a given project influences the total number of projects in which it can participate, and ultimately the probability of success of the overall exploration program.

2.3.6 Evaluation of Strategies

Each alternate strategy is judged by its ability to meet the objectives of the firm (Armstrong, 1983). Naylor (1983) suggests the use of a scenario-strategy matrix to evaluate the preferred strategy or strategies. The optimal strategy is robust, or helps the company in all scenarios. The future cannot be predicted accurately, but by considering the feasible future outcomes and their implications, the firm can be better prepared to face the future and to prosper.

The strategy of continued exploration only in mature basins, where both expected field size of discoveries and success ratio are declining (the latter from depletion of available fields for discovery), combined with the scenario of continued low oil prices, is unable to meet most corporate financial targets. An alternate strategy of doing at least part of the exploration internationally is recommended in this study.

Oil exploration is a risky business. Prospect evaluation, risk analysis, and strategic planning do not eliminate the risk of individual projects. The proper use of strategic planning would allow this failure of individual projects without causing the overall exploration program and the company to fail.

2.3.7 Action Plans and Budgets

The strategic plan selected is implemented through action plans and budgets. Capital investments are made in strategies, not in discrete projects (Lyons, 1983). An exploration strategy for an independent oil company might include a portfolio of project types. Such an action plan might allocate one-third of the budget to exploration close to existing production, one-third to exploration to moderately mature areas, and the remaining one-third to international exploration.

Management and personnel have the budget as a guide to the allocation of resources: human, cash flow, and capital. Company activities fulfilling the strategic plan are then compatible with the corporate goals.

2.3.8 Monitor Results

Strategic planning has four characteristics that create the need for periodic review and evaluation (Prager and Shea, 1983). First, strategic decisions determine the course of the entire company and should be reviewed as often as feedback becomes available. Second, a strategy takes years to fully accomplish. The ability of a strategy to meet the corporate goals becomes much more evident with time. Third, a strategy is based on assumptions of the external environment, and is therefore uncertain and subject to change. Fourth, strategy is not a neat package, but a pattern of input parameters and resulting decisions. It is helpful to step back and determine whether the pattern is holding together.

A monitoring system should allow for corrective action (Armstrong, 1983). Planning involves a trade-off between consistency and flexibility. The only real measure of performance is the financial result, but the lag time between initial exploration expenditures and measurable financial results makes this direct measurement difficult (Megill, 1985). Management must have a subjective feel for the exploration performance before hard quantitative measurements become available.

2.4 Use of Strategic Planning in This Study

A strategic planner should go through all the planning steps for the specific company. This study does not address strategic planning from the viewpoint of a specific company with quantified financial parameters, and therefore some of the steps are not used here.

The corporate objective of maximizing firm and shareholder wealth is implemented by investing in only those projects with a positive risk-adjusted net present value, discussed in Chapter 4 and utilized in the three case studies. An exploration firm can be exposed to more projects that meet this objective by taking a global view of threats and opportunities (Chapter 3).

This study assumes that the selected strategy includes international exploration, although not all independent exploration firms have the financial resources, technical ability, or risk-taking desire to implement this strategy.

Once the decision to explore internationally has been made, the hydrocarbon potential, fiscal terms, and political risk of countries are revived. Attractive areas within the selected countries are then evaluated in more detail and become the case studies.

Chapter 3

RATIONALE FOR INTERNATIONAL EXPLORATION

A situation analysis (threats and opportunities) shows that opportunities for profitable international exploration exceed those in the mature producing areas of the United States. Exploration and production firms can have lower per barrel finding and development costs by exploring internationally where larger fields remain to be found. The less developed countries need petroleum exploration and production on their land, but often cannot accomplish this themselves because of financial and technological constraints.

3.1 The Need to Explore Internationally

To remain profitable, an oil company should expand exploration to foreign areas where larger fields can be found. This is because of the size distribution of the oil fields, the order of field discovery, and the maturity of exploration in the United States compared to the rest of the world. On the average, 30 times as much oil is discovered in the rest of the free world per foot of exploratory drilling than in the lower 48 states because of distribution, order, and maturity characteristics (Ivanhoe, 1985).

3.1.1 Field Size Distributions

The sizes of oil fields within a geologic province tend to approximate a log-normal distribution. A mathematical explanation is offered by Capen, Clapp, and Campbell (1971). The Central Limit Theorem states that sums of random samples tend to have a normal distribution. The size of an oil field is determined by the product of many factors, including area, thickness, porosity, water saturation, and recovery factor. A corollary to the Central Limit Theorem states that the products of random variables tend to have a log-normal distribution.

Figure 1 is an example of a log-normal field size distribution. The largest field is over 3 times as large as the second largest field. The largest field contains more oil than the next 10 fields combined. (Three are too small to plot on the graph.) This dominance of a few large fields also applies to the entire lower 48 U.S. states (Ivanhoe, 1980). Sixty percent of production comes from 275 fields (or 1.3 percent of the fields) while the remaining 21,000 smaller fields (or 98.7 percent) supply the remaining 40 percent of production.

3.1.2 Order of Field Size Discoveries

The largest fields tend to be found early in the exploration of a region. At the lowest level of technology,

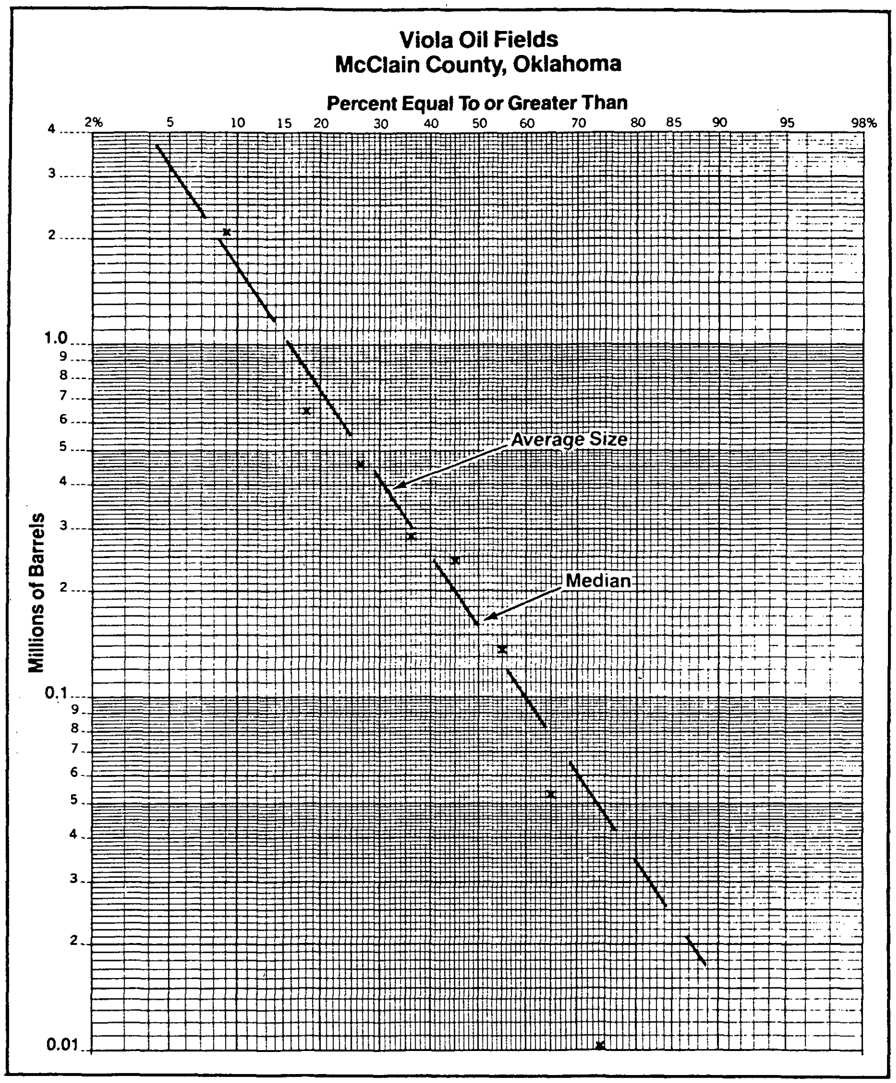

Figure 1. Log-normal Field Size Distribution
Source: Megill, 1988b, p. 4-1.

Note: Megill drew the line on the graph apparently honoring the larger fields more than the smaller fields.

random drilling finds the larger fields before many of the smaller fields because of their larger surface areas and therefore chance of discovery. As geological and geophysical techniques are used, the rate at which the larger fields are discovered accelerates because of larger geological and geophysical anomalies, aiding ease of detection.

Several attempts have been made to derive an equation that matches the observed discovery order. Arps and Roberts (1958) estimated the frequency of discovery in the Denver-Julesburg Basin as

$$F_W = F_O \left(1 - e^{-CAW}\right) \qquad 3.1$$

where F_W is the frequency of fields of size area A discovered by W wells, F_O is the total fields of size A available, and C is the efficiency of exploration. As the field area size A increases, it takes fewer wells W to discover a set percentage of the total fields available. Therefore at an equal level of wells W, a higher percentage of the larger fields have been found than the percentage of smaller fields found.

Another model is proposed by regression analysis from the North Sea (Eckbo, 1979)

$$D_j = L\, e^{-bj} \qquad 3.2$$

where D_j is the expected size of discovery number j, L is a constant, and b is the discovery decline rate. If political and timing differences between the British and Norwegian sides were removed, L would be estimated at 1,011.61 million barrels, and b would be -0.028166. This translates into the first expected discovery being 984 million barrels, the 11th expected discovery being 742 million barrels, and the 51st expected discovery being 241 million barrels.

3.1.3 Maturity of Exploration

The cumulative exploration effort in the United States far exceeds that of the rest of the world. Figure 2 shows the number of exploratory wells as of the end of 1975 for the United States and other regions of the world, set in representative areas of the respective regions. The observation that the larger fields tend to be found earlier in an area's exploration history suggests that further exploration in the traditional producing areas of the United States will find mainly small fields, while exploration in the rest of the world will still find more large accumulations.

3.1.4 Exploration Economics

Kuuskraa, Morra, and Hockheiser (1985) estimate that crude prices must climb from less than $30 per barrel in

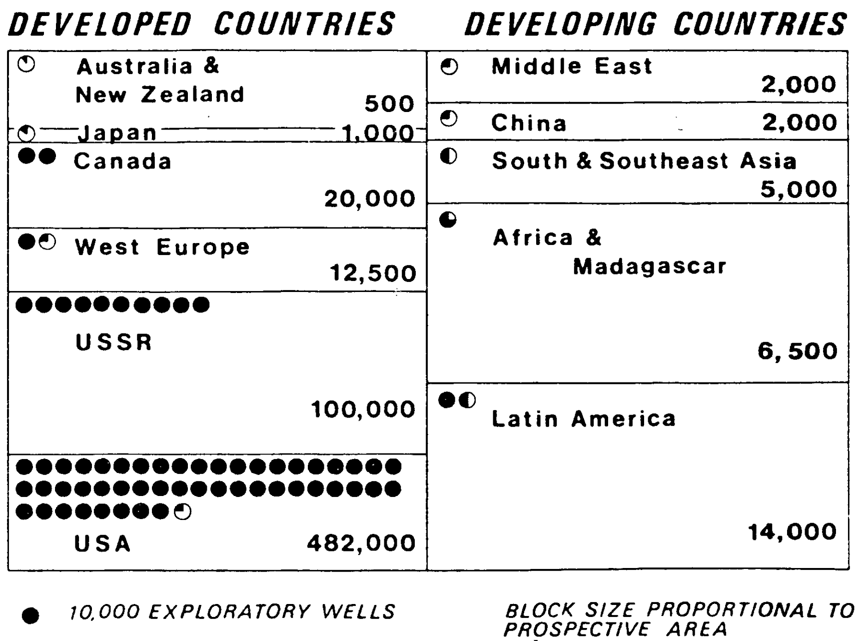

Figure 2. Exploration Drilling Density
Source: Wood, 1980, p. 27.

1990 to $80-$100 per barrel by 2010 for the United States to replace reserves and maintain the current 8.2 million barrels of oil per day production rate. Since the 1986 oil-price drop, very few people expect prices to attain those lofty levels in slightly over 20 years. Given these numbers, an oil exploration firm has four choices: 1) fail to replace reserves and slowly liquidate through production; 2) try to replace reserves at costs greater than prices, and force the firm into financial disaster; 3) replace reserves while remaining profitable through much better than industry average performance; or 4) explore internationally, where larger reserves result in lower finding and development costs. The theme of this study is to implement option number 4.

3.1.5 Oil Company Response

The 17 largest oil companies, or majors, have been responding to these economic differentials by shifting larger percentages of their exploration and production budgets to foreign areas (Lichtblau, 1987). In 1984, 36 percent of the expenditures went for foreign activities; in 1985, 39 percent; and in 1986, 55 percent.

In February 1986, the international rig count exceeded the U.S. rig count for the first time in modern history (Zoba, 1987). All indications are that this historical turning point will not be reversed, and that international exploration will continue to exceed that of the United States.

The trend to increased international exploration is not limited to the majors. Garnet Resources was formed in 1987 by a group of Houston investors pooling $10 million. Those funds will all be spent looking for oil internationally (Business Week, 1988).

3.2 The Need for Investment in Less Developed Countries

The less developed countries need local petroleum production, but often cannot successfully establish this production because of financial and technological constraints.

3.2.1 The Demand for Energy

The accelerating growth in demand for oil in developing countries is caused largely by economic growth. Economic growth increases the demand for all inputs, and in the developing stage, a nation's demand growth for energy exceeds its economic growth.

In Pakistan, the demand for petroleum products is growing at an annual rate of 10 percent, while economic growth, measured as Gross Domestic Product, has a growth rate of 6 percent (Ministry of Petroleum and Natural

Resources, 1987). Reasons given for this demand growth are industrial growth, increased mechanization of agriculture, supply of commercial energy (electricity) to rural areas, and increased transportation activity.

Two obvious solutions to a country's energy demands are to purchase oil, or to explore for and develop local supplies. The purchasing of oil is a major financial drain and contributes to balance-of-payment deficits in most oil importing countries, including the United States. If a country is to explore and produce hydrocarbons on its own, both finances and technical expertise become constraints.

3.2.2 Financial Constraints

Many developing countries are faced with huge debts, partly as a result of and compounded by persistently low commodity prices in the 1980s. The low-income countries suffered a 30 percent drop in trade value, led by falling commodity prices, between 1979 and 1982 (Clausen, 1983). An index of 27 commodity prices decreased 14 percent from the start of 1984 to mid-1985 (Commodity Research Bureau, 1985).

As a result of these diminished foreign exchange earnings in the less developed countries, loan repayments have been delayed and banks have been less willing to make new loans. The present debt crisis became headline material in August 1982 when Mexico was unable to service its foreign debts (Truell, 1988a). Several banks, led by Citicorp and J.P. Morgan, have cut back lending to Latin American countries (Truell, 1988b).

Oil importing developing countries need domestic oil production as import substitution, but they cannot obtain the financing to make the risk expenditures of petroleum exploration.

3.2.3 The Need for Technology

To be competitive in the world oil market, an oil producer, whether a private exploration/production firm, or a national oil company, must minimize the finding costs per barrel. Seismic information is the most useful in defining drillable prospects and is the major exploration expense prior to drilling. Therefore the remainder of this section will concentrate on the seismic technique.

Ritchie (1986) points out that the dual goals of improved success ratio and increased well productivity, both important to oilfield economics, often can be achieved by three-dimensional (3D) seismic surveys. More dry hole footage is drilled in development wells than in exploration wells, which emphasizes the fact that the role of seismic data need not stop at the exploration stage.

The number of seismic recording channels (acquisition) and the speed of computer operations (processing) have both grown almost exponentially since 1950 (Barry, 1981). The increased quantity and quality of information available from a seismic survey requires increased interpretational skills to get the maximum benefit from the information.

U.S.-based explorationists have an advantage in understanding geological concepts because the lower 48 states are the most explored part of the world. The increased density of wells, geophysical data, and geological studies aid in understanding the geological processes, and this understanding can be extrapolated into other parts of the world where less information is presently available.

The personal computer (PC) and specialized programs or software created for use on the PC have greatly aided the geological interpretation of seismic data by modeling the seismic response of an input geological feature. One such system, MIRA, has been created by Oklahoma Seismic Corporation. Their sales brochure of July 1987 lists 122 MIRA systems in operation, with 115 of those in the United States. Of the 7 systems located internationally, 6 were in foreign subsidiaries of U.S.-based oil companies, and the remaining system was at the University of Leeds in London. Not a single system was used by a firm or institution based in a less developed country.

The fact that the MIRA system was developed and marketed first in the United States has given U.S. users an advantage in knowing of and using this tool. Gee (1981) credits the high level of research and development investment in the military and aerospace industries as being the prime factor in the growth of technology-intensive industries in the United States. The geophysical industry has greatly benefited from the advancements in electronics, instrumentation, and computers, all of which are important to the military/aerospace programs.

3.2.4 The Need for Multiple Perspectives in Exploration

White (1981) conducted a short study that concludes that multiple, independent evaluations of a frontier area reduce the risk that commercial resources go undetected. Between 1954 and 1978, 2,755 wildcat tracts in the Gulf of Mexico were offered under the federal leasing program. Of these tracts, 544 have produced oil or gas. The percentage of 544 tracts that received bids from each of the ten larger firms exploring in the Gulf of Mexico was tabulated. The values ranged from 28.7 percent to 51.7 percent, with an average of 40.0 percent.

Assuming these larger firms evaluated all the tracts before each sale, on the average, an individual firm failed to identify as drillable prospects 60 percent of the later-productive tracts. If d is the probablity that a firm will identify a deposit as a prospect and 1-d is the probability that it will fail to identify a deposit as a prospect, the probability D_n that the deposit is identified by at least one firm, given that n different firms each independently review the tract, is given by

$$D_n = 1 - (1 - d)^n \qquad 3.3$$

If one company had an exclusive right to explore an area, there is a 60 percent chance it would overlook a commercial field; there is a 40 percent chance the field would be identified as a prospect, be drilled, and become a discovery. If ten firms of equal ability each viewed the prospective tract from a different perspective, there would be a 99.4 percent chance of the prospect being identified, and later drilled.

A country can get its resources discovered and developed much more quickly by encouraging many firms to explore within its borders, and taking advantage of the higher detection percentage from multiple perspectives.

Chapter 4

METHODOLOGY OF PROJECT EVALUATION AND DECISION MAKING

This chapter explains decision making, once the corporate strategies have been developed by an exploration company. Guzman (1984) lists four steps in investment decisions: 1) generation of opportunities; 2) determination of magnitude and timing of cash flows; 3) valuation of cash-flow streams and ranking of opportunities; and 4) periodic re-evaluation of these decisions. This chapter concentrates on the second and third step by using a cash-flow model. An explorationist routinely does the first step for the exploration company. The fourth step is an after-the-fact review of the second step.

The first section describes the cash-flow model from which decisions are made. Following sections discuss the input parameters to this model and the uncertainties of these parameters. Some of the more useful sources of information for input parameters are included in Appendix A.

4.1 Decision Making from the Cash-Flow Model

The basic decision to be made on any potential project is whether or not to invest, and if so, the level of the investment. A secondary decision is the amount of indirect information, primarily seismic, that should be acquired prior to exploratory drilling. All of these decisions depend on the results of the cash-flow model.

4.1.1 Cash-Flow Model

Three common types of profit models are the financial model, the tax model, and the cash-flow model (Thompson and Wright, 1985). The cash-flow model measures the flow of money into and out of the company's treasury. Taxes are costs which must be paid by the company, so the tax model is used in making a complete cash-flow model. For economic analyses, always use the cash-flow model. It is the only model that accurately relates the timing of cash movement into and out of the company. Figure 3 illustrates the major components and relationships of the cash-flow model used in this study. Input parameters supplied by the author are shown on the left side. These inputs combined with standard equations give the intermediate and final results shown on the right side. For example, geologic parameters determine the field size; engineering parameters and field size determine the production volumes; prices and production volumes determine revenue; and costs and production volumes determine capital investments and operating expenses.

<u>4.1.1.1 Input Parameters and Equations.</u> Geologic and reservoir engineering parameters are estimated by

INPUT		RESULTS
Geologic Parameters	→	Field Size
Engineering Parameters	→	Production Volumes
Oil Prices	→	Revenue
Costs	→	- Capital Costs and Expenses
Fiscal Terms	→	- Government Payments
		Annual Project Cash Flow
Political Risk	→	Annual Remittances
Geologic Risk	→	Annual Risked Remittance
Discount Rate	→	Expected Net Present Value

Figure 3. Cash-Flow Model Diagram

explorationists from their study of the region. The desired outputs from these parameters are size of the field, number of wells, timing and amount of production, and size of production facilities. Annual oil price projections and costs combined with these data give annual revenues, capital costs, and expenses.

The equation for oil field size is

$$EUR = 7758\ A\ H\ Por\ (1-Sw)\ RF/Bo \qquad 4.1$$

where EUR is Estimated Ultimate Recovery in barrels, 7758 is the constant for barrels per acre foot, A is the productive area in acres, H is the reservoir thickness in feet, Por is the reservoir porosity as a decimal, RF is the recovery factor or decimal fraction of volume of oil in place divided by the volume of oil recoverable and Bo is oil formations volume factor, which is reservoir barrels divided by stock tank barrels (Thompson and Wright, 1985).

The reader is referred to Thompson and Wright (1985) for a complete discussion of how engineering parameters determine the production volumes. Operating expenses determine the economic limit of production, which combined with the length of the petroleum agreement and production decline characteristics, determines the ultimate recovery per well. The field size divided by the ultimate recovery per well determines the needed number of producing wells. The number of producing wells multiplied by the initial production rate, modified by the production decline characteristics, give the production volumes for the field over time.

Some of the variables are partially dependent on other variables. The reader is referred to Newendorp (1975) for an excellent discussion. For example, initial production rate can be a function of pay thickness multiplied by porosity. This dependency is not used in any of the case studies because insufficient data exists to establish this relationship. In these case studies, formation pressure, temperature, and drilling costs are functions of depth, and production facility costs and operating costs are functions of daily production and number of producing wells.

Two basic approaches for handling escalation of future cash flows are 1) making the analysis with escalated dollar values for all costs and revenues, or 2) making the analysis using constant purchasing power dollar values for all costs and revenues (Stermole, 1984). This study uses escalated, or nominal dollar analyses because 1) costs often escalate at a different rate from the hydrocarbon prices, and 2) some government contracts dictate a sliding scale discount, royalty, or production split based on current oil prices.

The output of the model after combining technical and economic parameters and subtracting government payments is the gross revenue stream by year over the life of the successful project.

To incorporate political risk, a quantitative estimate is made of the probability that the firm will receive the positive cash flow from the project each year. No political risks are assigned during the negative cash flow, or investment stage, as all governments are eager to receive investments.

The cash flows are then adjusted for geologic risk. The simplest division of geologic outcomes is dry hole versus commercial producer. Past success ratios are a useful first approximation for these probabilities. The geologic risk factor is applied to the cash flow model by multiplying all development and production costs and all revenues by the decimal chance of commercial success. The exploration costs, or those expended before determining if the prospect is commercial, are unaffected, as they are spent in every case. Only in those cases where a commercial discovery is made are the development and operating costs incurred, and revenue received. The resulting output at this stage of the cash-flow model is the annual risked cash-flow stream.

The resulting cash flows are those that could be expected on the average if many prospects of this type were tested, the successful ones developed and produced, and the varied political events occurred in the various countries.

The methodology this far has produced a stream of future cash flows. To consistently evaluate cash-flow streams and to provide a meaningful comparison between potential projects, all cash flows need to be discounted to the present. The reader is referred to Stermole (1984) for a discussion of the concepts of discounting, net present value (NPV), and discounted cash flow rate of return (DCFROR).

The discount rate for a risky project is commonly raised arbitrarily to "account" for the risk. This is incorrect, as the cash flows in the model have already been adjusted for risk, and the "risk-free" interest rate should be used (Guzman, 1984). This study uses a discount rate of 10 percent, approximately 1 percent above the current yield on U.S. government bonds (Wall Street Journal, 1988).

4.1.1.2 Methods of Risk Adjustment. Few of the input parameters are known precisely, so the possible range of each variable should be used with the full range of all other input variables in the cash-flow model through simulation (Gehman, Baker, and White, 1981).

Newendorp (1975) lists the six steps of a simulation analysis:

1. Define all the variables.
2. Define the relationships or equations which tie all variables together.
3. Sort the variables into those known with certainty and those unknown, random, or stochastic.
4. Define the distributions for all stochastic variables.
5. Perform the repetitive simulation runs.
6. Define the probability range and expected value of the desired profitability output.

Simulation is simply the step of repeating the model computations many times, and allowing the uncertain variables to be assigned random values within their possible ranges to provide a range of potential model results.

The random values of the stochastic variables are selected by Monte Carlo sampling. The computer generates a random number between zero and one, and then samples the cumulative probability curve at the point corresponding to the random number. The ouput from this sampling is a value of the variable. Simulation software called @ RISK is added to the Lotus 1-2-3 spreadsheet to accomplish this analysis.

Sensitivity analysis consists of considering each uncertain variable separately by changing is distribution shape and/or range and observing how the resulting profitability distribution changes (Petrick, 1985). This complete analysis points out those variables that have the most significant effect on the profitability, which may indicate the need for additional information to give more precise estimate of these critical variables.

4.1.1.3 Model Outputs. NPV is the sum of all annual discounted cash flows, both negative and positive, from the entire project life. The underlying goal of all quantitative methods is to maximize the value of the firm for its shareholders (Petrick, 1985). This is accomplished by investing in projects with the maximum positive NPV. The decision rule for deciding between mutually exclusive alternatives is to choose the investment with the largest positive expected NPV (Stermole, 1984).

DCFROR is the discount rate or rate of return at which discounted costs equal discounted revenues, or NPV equals zero. The decision criterion for a project is that the DCFROR must be equal or greater than the discount rate. The ranking of competing projects by DCFROR does not consistently maximize the wealth of the firm. It is however routinely calculated to satisfy managers, who are accustomed to making decisions based solely on this number.

4.1.2 Level of Working Interest

Gambler's ruin is the possibility that even if all risks are correctly estimated, a long series of consecutive losses will cause the "gambler" to lose all his money and force him from the game before he has a winner (Newendorp, 1975). The way to hedge against this disaster is to get out of the business altogether, get a larger supply of money, or take a smaller working interest in a larger number of ventures.

A firm has made the strategic decision to remain in the exploration business, rejecting the first option. In most smaller companies, the availability of risk capital is limited, so the second option is not possible. This leaves the third option, which makes good sense; the concept of expected value in situations involving risk and uncertainty depends on averaging the results from repeated trials. A single prospect does not have repeated exploratory wells drilled on it, but the company can participate in the drilling of an exploratory well on each of many different prospects to increase the likelihood that an expected value result will be realized. The proper use of strategic planning would allow the failure of individual projects without causing the overall exploration program and/or the company to fail.

McCray (1975) has developed a formula for calculating the fractional participation, f, in large ventures. This formula, modified for this study is

$$f \leq (B/rC)\ (NPV/Z\ Sd)^2 \tag{4.2}$$

where:

B = total budget available
r = geologic risk ratio, the number of similar exploratory projects to be drilled to get one discovery
C = discounted present value of risk expenditures of the project
NPV = mean or expected net present value of the successful project
Z = number of standard deviations
Sd = standard deviation of NPV of the project

International exploration ventures often have minimum work commitments of \$5 to \$40 million dollars, spread out over a 3- to 6-year period. The correct value for B would be the budget available over the multi-year work commitment period, not just the annual budget.

The variable r, the geologic risk ratio, is multiplied by the risk capital per project, because if the geologic risk is 1:4, on the average the risk expenditures must be spent on four similar projects to get one discovery.

The variable Z is the number of standard deviations from the expected value or mean of a normal distribution necessary to include a specified percentage of the area under the curve (Walpole and Myers, 1985). The area under the curve can be thought of as level of confidence; 0.95 of the area under the curve implies that 95 percent of all cases will fall within this area, and there is a 5 percent risk that the results will fall outside this area.

The standard deviation of the expected net present value of the project is given by @ Risk, a simulation program, and is a measure of the variability or scatter of the computed NPV's around the mean value. The larger this scatter, the smaller working interest the firm should take, because of the uncertainty in expected project profitability.

For example, if B = \$30 million (MM), C = \$17MM, r = 5, NPV = \$50MM, Sd = \$40MM, and the firm wants a 99 percent chance of expected profitability in this multi-year program (Z = 2.326), the firm takes no more than

$$f \leq (30/5x17)\ (50/2.326x40)^2$$

or a 10 percent working interest. This would allow investment in ten similar projects to spread the risks.

Constraints to investing smaller amounts in even more projects are 1) the limiting number of quality opportunities available, and 2) the administrative overhead and staff burdens of monitoring many projects (Smith, 1988).

McCray did not include the geologic risk ratio in his formula. The geologic risk ratio was added to the equation for use in this study because of the need to spend the risk expenditures on multiple projects to expect one successful venture. The amended equation is used in this study to determine optimal level of participation in successful case studies.

4.1.3 Level of Information

The economic rule for the acquisition of additional data is similar to that of other items; purchase should be made if the value received from the data exceeds its costs (Guzman, 1984). Costs are the direct purchase price and the opportunity cost of delayed production, both of which can be calculated. Placing a value on the benefits received is more difficult. Information has a value if and only if it has a chance of changing a decision. In petroleum exploration, changes in decisions are affected by reducing the uncertainty (giving more precise estimates) and by changing the probability of success.

Currin (1986) derived a set of equations to mathematically determine the optimal amount of indirect information to be acquired. In petroleum exploration indirect information is primarily geological and geophysical, while only the drilling of wells gives direct information.

$$X = -(1/b) \ln [C/(q\ a\ b\ \ NPV)] \qquad 4.3$$

where:

X = the optimal units of indirect information
b = constant of value of knowledge (Eq. 4.5)
C = cost per unit of indirect information
q = maximum success probability with infinite amount of indirect information
a = constant of random risk (Eq. 4.4)
NPV = net present value of successful projects

$$a = 1 - Pso/q \qquad 4.4$$

where Pso = probability of success with zero indirect data.

The value for b is calculated assuming the probability of success for a given level of indirect information.

$$b = - \{\ln[(1 - Ps/q)/a]\}/Y \qquad 4.5$$

where Ps = probability of success when using Y units of indirect information. Estimates for q, the maximum success probability with an infinite amount of indirect information, range from 0.2 or 0.3 for seismic definition of stratigraphic traps to 0.8 for gas detection by direct hydrocarbon indicators on high resolution seismic data.

A numerical example clarifies this procedure. A successful project would have a NPV of $35 million, the probability of success of random drilling is .04, the q value is 0.5, and 50 kilometers (km) of seismic, costing $5000/km increased the probability of success to .15.

$$a = 1 - Pso/q = 1 - .04/.5 = .92$$

$$
\begin{aligned}
b &= -\{\ln[(1 - Ps/q)\ /a]\}/Y \\
&= -\{\ln[(1 - .15/.5)\ /.92]\}/50 \\
&= 0.0055
\end{aligned}
$$

$$
\begin{aligned}
X &= -(1/b)\ \ln[C/(q\ a\ b\ NPV)] \\
&= -(1/\ 0.0055)\ \ln\ [5000/(.5x\ .92\ x\ 0.0055\ x \\
&\quad 35{,}000{,}000)] \\
&= 522.57
\end{aligned}
$$

The optimal level of seismic data to be acquired on this prospect is 523 km, including the current 50 km.

This methodology is based on exploration risk (or probability of failure) decreasing exponentially with increasing knowledge. An implied assumption by Currin is that each incremental unit of information adds an equal amount of knowledge. Logic and experience say that this is not valid. The first seismic line in an unknown area adds much more information than does the second or 52nd line. This methodology could still be used if the knowledge gained by additional information also declined exponentially. The equations are fairly cumbersome, and frequent use might not be made of them, but the thought process involved and the understanding of the sensitivity of the variables are important, and therefore the method is reproduced here. The equations are used in the case studies to test their application in fold and thrust belts.

4.2 Revenue

The previous section presented an overview of this study's methodology. The remaining sections of this chapter discuss more fully the data and information necessary to implement the methodology.

Revenue comes from the sale of produced hydrocarbons. (Revenue can also come from the sale of the property, but the buyer evaluates the property on expected net cash flow from hydrocarbon sales.) The variables which determine the amount of revenue received are the volume of hydrocarbons produced (and assumed simultaneously sold) and the price received. The timing of the first revenue received is determined by the start of production. A realistic scheduling of exploration, appraisal, and development is necessary to have a reasonable estimate of the timing of first production.

4.2.1 Production Volume

The geologic parameters are combined to obtain the expected field size. These parameters also partially determine the productive rates of the wells.

In the United States, state oil and gas commission rules determine the spacing of wells, which in turn determine the numbers of wells drilled in a specified size of field. A company holds a lease and receives production as long as the wells are producing. In foreign countries, few if any spacing rules exists, but the length of the production license specified in the petroleum agreement is the constraint. The ideal production schedule has the producing wells reaching their economic limit at the end of the license. The reader is referred to Thompson and Wright (1985) for complete discussion of the economic limit of production, production decline characteristics, and annual production volumes.

4.2.2 Oil Prices

This study assumes that oil prices will vary from $10 to $18 per barrel with $13 most likely, adjusted for inflation, until 1995. Price increases from 1995 until 2000 are assumed to be 3 to 5 percent above the inflation rate, 5 to 8 percent above the inflation rate from the year 2000 to 2005, and back to the inflation rate after the year 2005.

These assumptions are based on 1) $10 being both the historical floor in real terms (Oil & Gas Journal, 1987b), and the price at which the high-cost producers cease operation (Mittman, 1988); 2) $18 being the long range real price above which fuel substitutes start decreasing the demand for oil (Oil & Gas Journal, 1988a); 3) $13 most likely being in the lower part of the price range reflecting OPEC members' tendency to exceed production quotas; and 4) the timing of increases in real oil prices corresponding to assumed timing of capacity overhang diminishing significantly.

Oil prices have been soft since 1986 because world productive capacity exceeds demand by at least 7 million barrels per day (Oil & Gas Journal, 1989c). World demand has increased from 50.7 million barrels per day in the first quarter of 1988 to 51.7 in 1989, for a gain of one million barrels per day, a 2 percent annual gain (Oil & Gas Journal, 1989d). No accurate numbers exist for the change in world productive capacity, but most reports suggest that it is less than that of the demand and enough excess capacity will disappear by the year 2000 to see significant increases in oil prices (Oil & Gas Journal, 1989b).

4.3 Costs

The economics of hydrocarbon exploration and production are not only affected by the volumes of hydrocarbons found, but also by the costs. Costs can be divided many different ways, but for this study, they have been divided into exploration (expended before making a commercial discovery), development and production (expended after the commercial discovery), and fiscal (paid to the government).

4.3.1 Exploration Costs

Exploration costs include geological and geophysical surveys, exploratory drilling, and overhead or administrative costs of these activities. Seismic expenditures make up the majority of geological and geophysical costs. Companies and geophysical contractors already working in the area can be helpful in these estimates. The final expenditure is dependent on the amount of seismic acquired, as well as the cost per mile.

Drilling costs vary extremely by depth and location of the well. A well outside the United States costs an average of three times what it does in the United States (McNally, 1988). Logistics take up substantial parts of international drilling budgets, because of the lack of infrastructure and support facilities. Cost estimates can be obtained from companies and contractors working in the area of interest.

Direct costs of establishing and staffing a local office in the host country as well as a percentage of annual home office expenses can be charged to a project as administrative costs.

4.3.2 Development and Production Costs

Development and production costs are those made only after a discovery has been declared commercial. Capital costs are investments made that will generate benefits for more than one year (Thompson and Wright, 1985). Expenses are expenditures that only benefit the current period, such as salaries and utilities.

Major capital expenditures include development drilling, production facilities, and possibly pipelines. Cost estimates can be made by gathering information from local sources, or getting estimations for costs of specific items in the United States and then estimating a factor of how much the foreign investment would cost over the same physical investment in the United States (Koerner, 1989).

Operating costs, transportation fees, and administrative costs are the main production expenses. The company may have to pay transportation fees if the point of sale of the hydrocarbons is a distance from the production facilities.

4.3.3 Cost Escalation

International projects commonly take 30 or more years from start of exploration until production ceases. Cost estimates which are reasonable today could be very low when applied to situations several years in the future. This problem can be minimized by escalating each year the amount that the cost item is expected to increase (Stermole, 1984). Cost escalations do not necessarily follow the rate of inflation, but we seldom have enough data to differentiate between the two rates. If the inflation rate in the host country is considerably different from that of the United States, the best escalation rate may be a mixture of the two countries' inflation rates, depending on mixture of local content and imported goods to cost items. (Expected inflation is discussed later in section 4.4.2.)

4.3.4 Fiscal Terms

With the exception of parts of the United States and parts of Canada, mineral wealth is the property of the state (Nancarrow, 1982). Host governments usually have the dual but contradictory desires of maximizing their revenue from the exploitation of the resources, and encouraging further exploration by foreign investors. The allocation of risks and economic benefits between the investor and the host country is determined by the petroleum agreements and tax structure of the host country (Blinn et al., 1986).

4.3.4.1 Petroleum Agreements. Petroleum agreements are made between the host government and the investor. The agreements are subject to the laws of the land, and therefore, they are often referred to as petroleum legislation. The five major types of petroleum agreements (Broadman, 1985) are 1) concession or lease from the government; 2) production sharing contract where the firm shares production with the government; 3) government participation as an equity partner through a joint venture; 4) non-risk service agreements, where the company provides exploration and/or development services for a set fee; and 5) risk service contracts, which combine features of non-risk service contracts and production-sharing contracts.

4.3.4.2 Taxation. All companies operating within a country, regardless of the type of petroleum agreement, are subject to the tax laws of that nation. The forms that host country taxes can take include acreage rentals, bonuses, royalties, and income taxes.

This discussion has mentioned the major points of agreements and taxation for use by the project evaluator. A tax accountant and/or tax lawyer should be consulted before final decisions and commitments are made.

4.4 Risks

Very few of the input parameters used in the model are known precisely. The uncertainties of the values are sources of risk, the risk that the results will not be as expected.

4.4.1 Geologic Risk

The initial reserve and production calculations assume no geological risk. The second part of prospect reserve analysis is estimating the geologic risk, either as a fractional chance of discovery, or as a ratio (the reciprocal of the fraction) which corresponds to the number of similar exploratory projects that must be drilled to get one discovery (Gehman, Baker, and White, 1981). The geologic risk can be estimated from either past success ratios or a calculated adequacy factor. The chance that each geologic factor (source, trap, reservoir, and seal) is adequate for a commercial hydrocarbon accumulation is estimated. The geologic risk (fractional chance) is the product of all individual adequacy factors. For example if the trap is considered certain, its adequacy is 1.0; the source has a 50 percent chance, its adequacy is .5; the reservoir has an 80 percent chance of being adequate, its factor is .8; and the seal has a 30 percent risk of being broken, its factor is .7. The resulting overall factor is 1.0 x .5 x .8 x .7 = .28, or a 28 percent chance of having at least the minimum potential, and a 72 percent chance of being dry.

Even when the exploratory well is successful in discovering a commercial field, the individual geologic and production values are probably different than expected. Therefore, a range of possible values and the distribution of these possibilities should be used as simulation model input, rather than point values. A common distribution is triangular, in which the lowest value is the minimum, an intermediate value is the most probable or most likely, and the highest value is the maximum (Newendorp, 1975).

Rose (1987) strongly suggests recording pre-drilling estimates of volume, production, and risk factors, and conducting postmortem analysis of these predictions. All explorationists can make better estimates after being shown behavioral biases and patterns involved in previous estimating.

4.4.2 Economic Risk

Important economic risks or uncertainties concern oil prices, capital costs, expenses, and inflation/escalation rates. Oil price discussion and the resulting triangular distribution ($10, $13, $18/barrel) were presented previously in this chapter.

Costs and expense estimates should be handled in the same manner as the geologic parameters, with ranges and distributions. The accuracy of estimates is increased by dividing the total cost into incremental parts and estimating the ranges and distributions of each part.

There is seldom enough information available to differentiate between cost escalation and inflation. The annual U.S. inflation rate has varied from 2.7 to 3.9

percent in the past 5 years (Council of Economic Advisers, 1988), but current concerns are that the rate could be approaching 7 percent (Sebastian, 1989). Therefore a triangular distribution of 3, 5, and 7 percent is used to estimate expected U.S. inflation rate.

The fiscal terms may not be known with certainty at the time of initial project evaluation, as some terms are negotiable with the host government. The terms, however, will be fixed and known before the firm makes the commitment to invest in the project. The initial uncertainties of fiscal terms should not be input as ranges in the simulation, but should be input as discrete values in separate runs of the simulation. The results of this sensitivity analysis guides the firm in negotiations with the government, in particular the minimum acceptable terms.

4.4.3 Political Risk

The lengthy planning and operational horizons of oil and gas projects make them vulnerable to long range changes within the host country. Political risk phenomena are economically motivated without regards to global location, local culture, ethnic, religious, or any other factors of a sociological nature (Proehl, 1985). The trigger for political risk is economic dissatisfaction.

Proehl (1985) presents political risk analyses as a two step process: 1) identify the possible events and 2) estimate the probability of occurrence for these events. Lax (1983) believes the two steps involve 1) forecasting the relevant political events, and 2) evaluating the impact that these events would have on the firm. Combining these two opinions results in a more complete three step process: 1) identify the relevant political events, 2) estimate the probability of occurrence, and 3) evaluate the impact that these developments would have on the firm.

Projected cash flows can be multiplied by the probabilities of occurrence of alternate outcomes to determine their expected values (Lax, 1983; Newendorp, 1975; Stermole, 1984). The cash flows in this study are multiplied by the probabilities of the firm receiving the funds unrestricted by government action. The failure to integrate political risks into projected cash flows is the same as assuming an ideal political environment with no risks.

Political risk insurance can be in the form of insurance policies, or by taking strategic actions aimed at reducing risk. Multi-sourcing of the project financing is an action that helps to reduce political risk (Lax, 1983).

Insurance against political risk for U.S. firms is offered by the government-sponsored Overseas Private

Investment Corporation or OPIC (Zakariya, 1987). Coverage is available for up to 90 percent of the investment, generally not to exceed $100 million per project, but must be applied for prior to the commitment with the government.

The OPIC insurance covers 1) inability of the investor to convert earnings in local currency into dollars; 2) loss of investment due to expropriation, nationalization, or confiscation; and 3) loss of income and loss of assets due to political actions, such as war and civil strife (Overseas Private Investment Corporation, 1988). Base annual cost for oil and gas projects during production phase are quoted per $100 of coverage:

Coverage	Rate
Inconvertability	$0.30
Expropriation	$1.50
Political violence	$0.75

A new organization offering political risk insurance is the Multilateral Investment Guarantee Agency (MIGA), an agency of the World Bank (Moran, 1988). MIGA can insure international investments against loss from expropriation, breach of contract, inconvertibility, and war or civil disturbance. If a host government causes such a loss, it faces a direct claim from an agency of the World Bank. The desire of the host government to avoid this claim and its associated stigma could result in MIGA offering a better form of political risk insurance at possibly lower premiums.

The decision on whether or not to obtain insurance can be made in the cash-flow model for the larger firms by choosing the case, insurance versus no insurance, with the larger positive net present value. The smaller firm should not expose itself to risk when potential losses could cause financial disaster for the firm, therefore the insurance is recommended. The percentage of the positive cash flows that are affected by political risk would be the percentage of the investment not covered by insurance.

Chapter 5
PAKISTAN CASE STUDY

Petroleum exploration interest in Pakistan is caused by 1) major petroleum production in foreland areas with an adjacent sparsely explored thrust and fold belt that is available for leasing, and 2) favorable fiscal terms in a country with an attractive investment climate (Khin, 1988).

5.1 General Information

Pakistan is located on the Indian sub-continent of Southern Asia, and has been an important ally of the United States in an area of political instability (Walsh, 1988). The land area covers 750,000 sq km or 310,000 sq mi, which is about the size of California (Bilinski and Hancher, 1988).

Pakistan is the world's ninth most populous country with 100.7 million people (American Embassy Islamabad, 1987). Urdu is the national language, but most people understand English, an official government language. An estimated 97 percent of the people are Muslim. Literacy is about 26 percent.

The government has undergone several changes since independence in 1947. Democratic elections held in November 1988 were won by the Pakistan People's Party, headed by Benazair Bhutto, the daughter of the former (1973-1977) President Zulfikar Ali Bhutto.

Per capita gross national product (GNP) is estimated at $330, making Pakistan one of the poorer countries in the world (American Embassy Islamabad, 1987). Real growth in the GNP of 5.4 percent from 1986 to 1987 is only slightly above the population growth rate of 3.1 percent. This makes it difficult to improve the economic status of the individual. The consumer price index increased 4.8 percent during the 1985-86 fiscal year.

The current exchange rate is 19.35 rupees per U.S. dollar (Wall Street Journal, 1989b) compared to an average of 15.25 in 1985, 16.14 in 1986, and 17.18 in 1987. Determination of the foreign currency exchange rate is described as a managed float (American Embassy Islamabad, 1987).

5.2 Case Study Site

The petroleum geology of Pakistan was examined briefly and the study area was selected as that area having the greatest potential for additional major hydrocarbon discoveries. This study covers the Central Fold Belt of Pakistan (see Figure 4), bounded to the north by 32 deg N latitude, to the south by 27 deg N latitude, to the west by the west edge of the Indian subcontinent plate as defined by

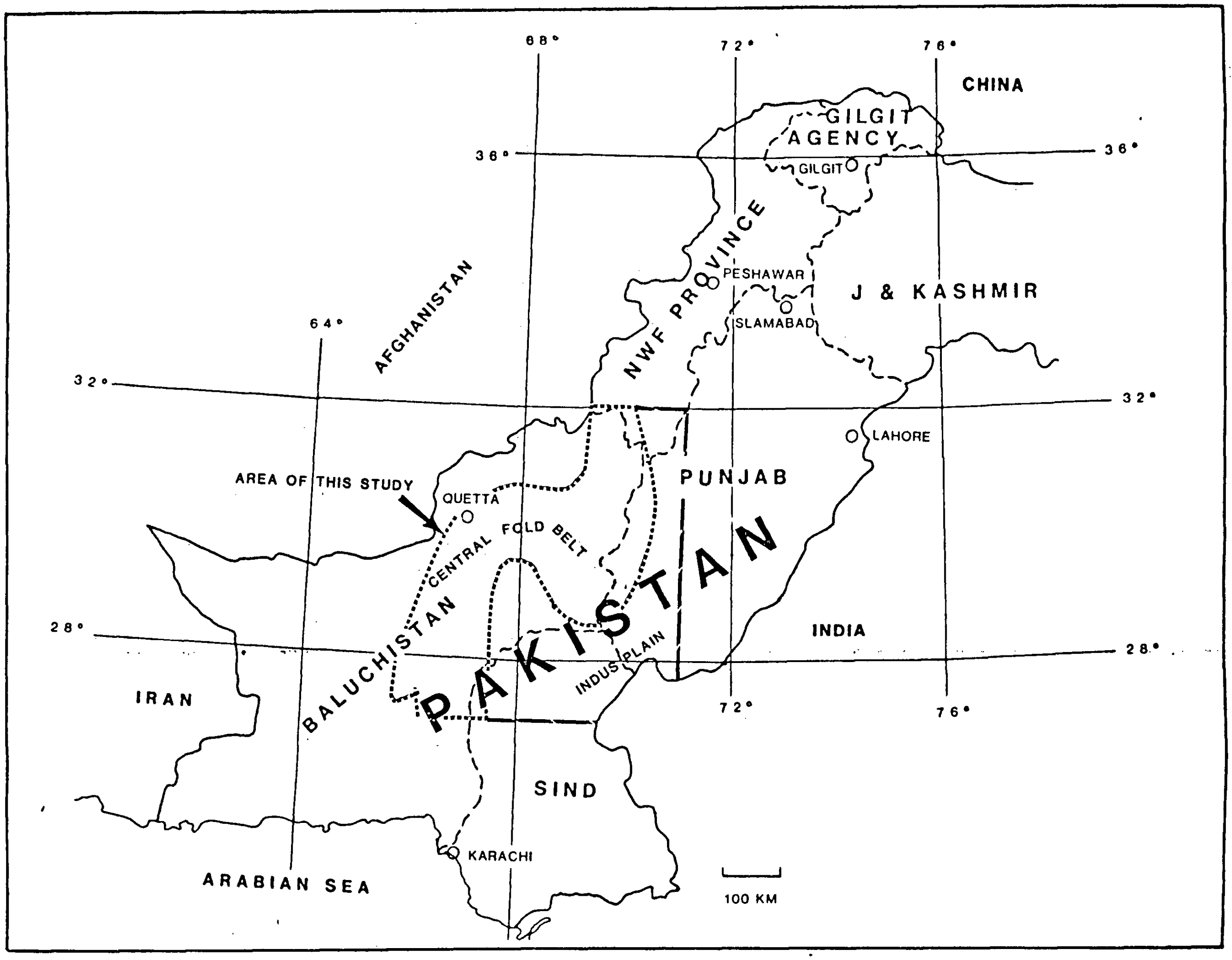

Figure 4. Pakistan Index Map
Source: Times Atlas of the World, 1983b, Plate 31.

the ophiolite zone, and to the east by the leading edge of the fold belt, as defined by the surface contact between Miocene and older rocks in the fold belt and Pleistocene and younger rocks in the foreland (Kazmi and Rana, 1982). This area covers 112,000 sq km or 43,000 sq mi. Specific petroleum and geologic data from the adjacent foreland of the Indus Plain are useful in evaluating the fold belt. This area extends eastward to the border with India and to 71 deg E longitude, and covers 88,000 sq km or 34,000 sq mi.

Elevations within the study area vary from 300 m (1000 ft) at the Indus River to 2000 m (6500 ft) in hills of the Sulaiman Range. Rainfall is generally less than 100 mm (4 inches) per year (Ministry of Petroleum and Natural Resources of Pakistan, 1988c).

5.3 Hydrocarbon Assessment

The Ministry of Petroleum and Natural Resources has made great efforts to inform the world's oil companies of the petroleum potential of Pakistan. It hosted a 3-day symposium in Islamabad in January 1988; the papers presented at that conference are published in Petroleum For the Future (Raza and Sheikh, 1988) and are important sources for this study. The symposium was attended by 285 Pakistanis and 143 foreigners, including representatives from 25 foreign oil companies with no working interest in Pakistan at that time.

The ministry also held one-day conferences in London and Houston in December 1988 to inform companies of the hydrocarbon potential and to introduce the new system of offering concession areas for competitive bidding.

Companies which have shown a genuine interest in exploring in Pakistan are also allowed to review data of previous exploration efforts in the archives of the Oil and Gas Development Corporation or OGDC (Smith, 1988).

5.3.1 Past Exploration

The first production in what is now Pakistan was at the Khattan oil seeps in the study area, where about 23,000 barrels were produced from shallow wells in the late 1800s for use by the railroad (Directorate General of Petroleum Concessions, 1988). The Sui giant gas field was discovered in the study area in 1952. Six more gas fields were found in the Indus Plain region by 1960.

The state oil company, the Oil and Gas Development Corporation (OGDC), was established in 1961. Exploration successes by OGDC, Union Texas in the Lower Indus Basin, and Occidental in the Potwar Basin now account for most of Pakistan's oil production.

At the end of 1987, 184 exploratory wells had been drilled in the country, resulting in 46 oil and gas discoveries (Hydrocarbon News, 1988). This represents 0.22 exploratory wells per 1,000 sq km of sedimentary basin. The study area has had 13 exploratory wells in 112,000 sq km, for a drilling density of 0.12 exploratory wells per 1,000 sq km. These densities compare with 301 exploratory wells per 1000 sq km in the sedimentary basins of the United States.

5.3.2 Current Production

Pakistan's production in December 1988 averaged 45,882 barrels oil per day (BOPD) and 1,273 million cubic feet of gas per day or MMcfgpd (Foreign Scouting Service, 1989b). Both oil and gas production in 1988 were at record highs, up 8.7 and 5.6 percent respectively from the previous year.

Official government estimates are 273 million barrels of original recoverable oil reserves and 23 trillion cubic feet (TCF) of original recoverable gas reserves (Directorate General of New and Renewable Energy Resources, 1987). Cumulative production of oil and gas are 155 million barrels and 5 TCF respectively, leaving 118 million barrels and 18 TCF remaining recoverable reserves.

Almost 94 percent of the gas production comes from four fields in and adjacent to the study area. Sui produces 752 MMcfgpd, Mari produces 281 MMcfgpd, Pir Koh contributes 131

MMcfgpd, and 30 MMcfgpd comes from Kandhkot.

Development drilling is in progress at two additional fields on the east and south fringes of the study area, Dhodak and Loti. Dhodak will produce oil, gas, and condensate, while Loti will be strictly a gas producer.

5.3.3 Petroleum Geology

Figure 5 shows the geologic formation names of the Indus basin as well as brief descriptions of the regional geologic setting over time, and is a visual aid to the following discussion.

The Indo-Pakistani plate (as referred to by the Pakistanis), the Arabian plate, and Africa were connected as part of the Gondwanaland continental plate during Paleozoic time (Directorate General of Petroleum Concession, 1988). Gondwanaland started fracturing and separating during the Permian. The Indo-Pakistani plate started drifting north-northeastward in the Triassic, and marine sedimentation occurred along its margins.

The Indo-Pakistani plate first collided with the Eurasian plate in the Eocene at the north end of Pakistan. Full scale collision in the Oligocene caused the majority of the compressional tectonic features that occur in the study area. The height of the Himalaya Mountains is caused by this continued collision.

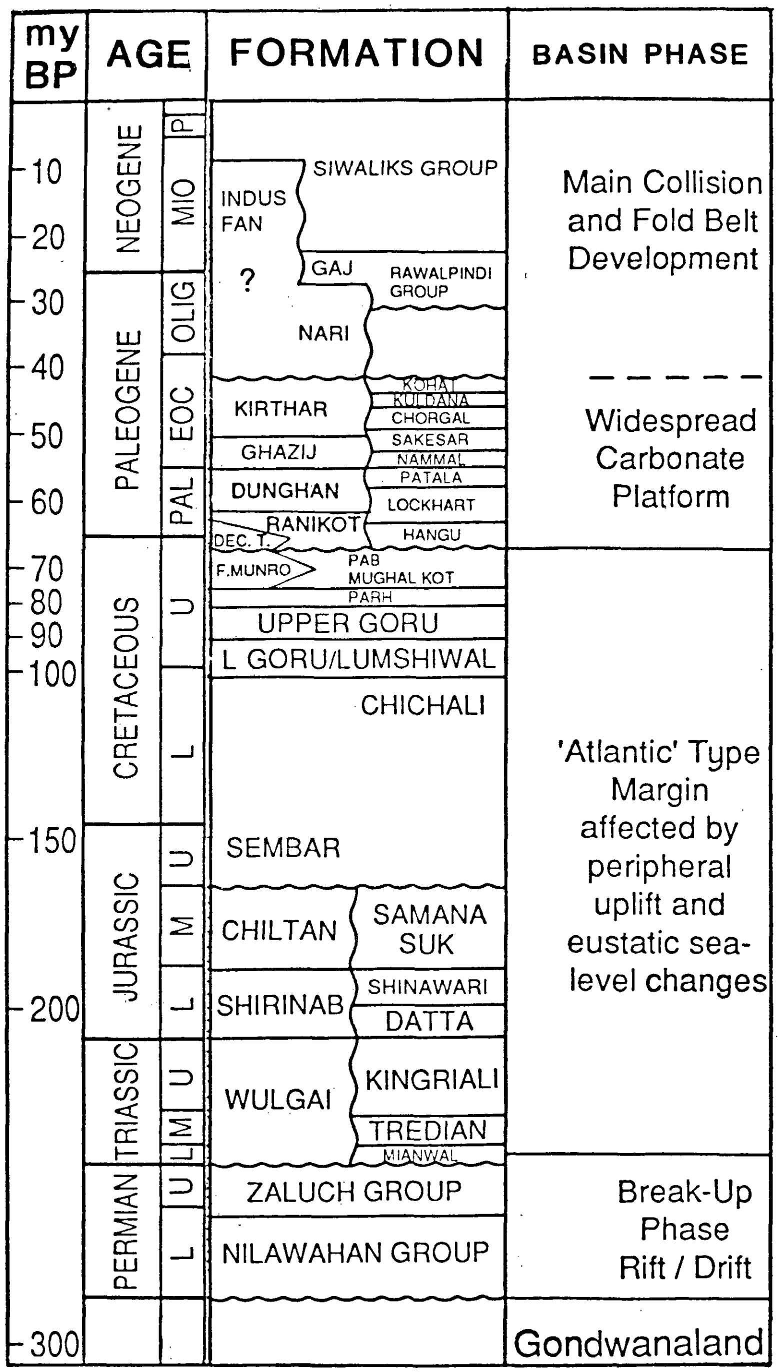

Figure 5. Indus Basin Geologic Column
Source: Ministry of Petroleum and Natural Resources, 1988c, plate 1.

The changing paleo-environment from continental plate in the Paleozoics, to marginal marine in the Permian through the Cretaceous, and restricted marine in the lower Tertiary created a variety of sediments that are important to the current hydrocarbon potential of the study areas.

5.3.3.1 Source Rocks. Identification of adequate source rocks that are not thermally overmature (heated to temperatures above which hydrocarbons cannot remain as liquids over geologic time) is the principal limiting factor in the oil potential of the Indus Basin (Gautier, 1988). Most of the identified source rocks are pre-Cretaceous and have yielded oil in the past, but are now overmature for oil generation.

Black shales of the Lower Cretaceous Sembar Formation have had total organic carbon (TOC) measured in the 1-2 percent ranges in the southern part of the study area (Malik et al., 1988). The Upper Cretaceous Mughal Kot Formation has source rock potential locally near 32 deg N at the north edge of the study area, but here the whole Cretaceous and Jurassic sequence is overmature (Porth et al., 1987). Elsewhere in the Sulaiman Range, rocks of this age show an irregular thermal maturity, and more geochemical sampling and analyses are necessary to high grade areas of maximum oil potential.

The giant gas reserves of the Indus Plain adjacent to the study area are believed to have been sourced from the Middle Eocene Kirthar Formation in which total organ carbon (TOC) has been measured as high as 11 percent. Unfortunately, the Eocene sediments have been exposed and eroded from the uplift of the Sulaiman Range in much of the study area (Kazmi and Rana, 1982). The commercial production from the Upper Cretaceous Pab Sandstone at Loti and Pir Koh (gas) and at Dhodak (oil, gas, and condensate) is the best evidence that the Sembar can be an adequate source in the study area.

<u>5.3.3.2 Reservoir Rocks.</u> Table 1 summarizes the geologic and engineering information on the 23 exploratory wells drilled in the study area and the adjacent Indus Plain (OGDC Archives, 1988). The oldest formation penetrated is the Triassic at Jhatpat, on which no information is available. The Jurassic-age Chiltan is a reservoir-quality limestone, but is overmature in the Tadri and Jandran wells. At Jandran pipeline quality gas was tested from the Cretaceous, but the Jurassic gas was 85 percent carbon dioxide, 8 percent nitrogen, and 7 percent methane.

Cretaceous-age reservoir quality sands can be found in the Goru, Mughal Kot, and Pab Sandstones. The Goru is the primary reservoir of the Union Texas discoveries in the

Table 1. Well Data of Pakistan Study Area and Indus Plain

WELL	FORMATION	YEAR	TOT DEPTH ft	AREA ac	THICK ft	POROSITY %	WATR SAT %	DEPTH ft	TEMP deg C	PRESS psi	PROD mcfgpd	GAS bcf	GOR x1000	BTU
BANNH	MIOCENE	1957	13001											
DHANDI	PAB	1984	5400											
DHODAK	PAB	1977	8694	3100		21		7375		3270		700	18.5	1152
DOMANDA	EOCENE	1960	11183											
GIANDARI	JURASSIC	1958	12007											
JACOBABAD	SUI	1958						3314						284
		1974	15302											
JANDRAN	MUGHAL KOT	1975	8058	6000	99	18	34	2238	42	1725	13500			910
JHAL	CRETACEOUS	1982	16404											
JHATPAT	TRIASSIC	1974	15302											
KANDHKOT	SUI MAIN	1959	6821	24000	100	18.5		4100	88	1949	2500	424		826
	PAB	1987						13415	149	10500				
KHAIRPUR	SUI MAIN	1957	11670		130			2030	48	1100		1000		121
KOT RUM	PAB	1979	15742											
LOTI	SUI MAIN	1985	7388		75	7	30							
	RANIKOT	1985	7388		160	12	50				14000	1910		
	PAB	1985	7388		100	15	50							
MARI	KIRTHAR	1957	11110	218000	250	19		2262	57	1154	30275	3940		790
MAZARANI	SUI MAIN	1958	10111		90	9		6260	60	2939	29000		147	976
PIR KOH	SUI	1977	9187	5100								27		
	PAB	1977	9187					7100			81200	5150		
RHODO	PAB	1974	8108		89			4850			4000	700		
SAKHI SARWAR	PALEOC	1976	15030											
SANNI	PLIOCENE	1983	4170											
SUI	SUI UP	1952	10056		50	18	20	3350	89	1936	400	3300	2000	933
	SUI MAIN	1952	10056	47000	757	12	20	3685	91	1964	46000	8600	2000	933
TADRI	JURASSIC	1975	5990											
UCH	SUI MAIN	1955	11000		250			4147	78	2050		2500		308
ZIN	SUI MAIN	1954	6385					2975	61		3000	100		484

Source: OGDC Archives, 1988.

lower Indus Plain (Soulsby and Kemal, 1988a). The Goru can be highly over-pressured, as a development well at Kandhkot measured 10,500 psi at 4090 m or 13,415 ft for a pressure gradient of .78 psi/ft, compared to hydrostatic pressure gradient of .43 psi/ft (Foreign Scouting Service, 1987). Jandran had 99 feet of net gas pay in the Mughal Kot, with porosities varying from 10 to 24 percent. Water saturations ranged from 20 to 44 percent. This net interval was tested by three separate drillstem tests (DST's) which gauged 3.1 MMcfgd, 7.2 MMcfgpd, and 7.22 MMcfgpd, for a formation total of 17.5 MMcfgpd. The pressure gradients varied from .77 to .86 psi/ft. The well was abandoned in 1975 as being non-commercial (OGDC Archives, 1988).

The Pab Sandstone is widely distributed over the study area and is productive at Dhodak, Loti, and Pir Koh. The most impressive DST rate recorded from the Pab is at Pir Koh where 81.2 MMcfgpd were tested (OGDC Archives, 1988). By comparison a 17 m (56 ft) interval at Pir Koh No. 5 tested 4.8 MMcfgpd. Porosities ranged from 8 to 10 percent at Dhodak and 7 to 12 percent at Pir Koh.

The Paleocene-age Ranikot sands produce gas at Loti and Pir Koh, where the porosities range from 5 to 20 percent and 7 to 12 percent respectively (Malik et al., 1988).

All of the above-mentioned formations are potential reservoirs within the study area. Triangular distributions used for reservoir paramaters in simulation of the cash-flow model are: thickness in feet (55, 100, 160), porosity (.05, .12, .25), water saturation (.15, .35, .60), pressure gradient in psi/ft (.43, .44, .86), and initial production rate or IP in MMcfgpd (4, 14, 30). A triangular distribution is used to represent many of the stochastic parameters because its shape corresponds to the probability distribution observed in many variables - a higher number of values within the mid part of the range and a decline in the number of values as the boundaries of the range are approached. The minimum and maximum values used in the distribution cover or slightly exceed the range of observed values in the study area, and the most likely value chosen is an approximation of the most frequently observed value. For example, reservoir thickness in feet is given the triangular distribution 55, 100, 160 because 1) 55 ft is a conservative approximation of the 17m (56 ft) sand recorded in Pir Koh No. 5, 2) 100 ft approximates the 89, 99, and 100 ft values observed, and 3) 160 ft is the thickest pre-Eocene reservoir observed. The author is confident that this distribution is a reasonable approximation of thicknesses that have been and will be found. Thinner zones may be found, but these probably would be non-commercial, and are part of the geologic dry hole risk.

The porosity range is probably accurate, as 5 percent is a reasonable economic cut-off, and consolidated sediments seldom have porosities above 25 percent. The water saturations used are consistent with both those observed locally and general reservoir engineering knowledge. Likewise the pressure gradient distribution is constrained by local and general knowledge: .43 psi/ft, or hydrostatic gradient is the normal low limit; most gradients are only slightly above this value (.44); and few gradients exceed the .86 observed, which is approaching lithostatic pressure gradient of about 1.0, an absolute maximum. The range of initial production rates probably errs by not including the high-end tests (81 MMcfgpd observed vs. 30 MMcfgpd used), but the author prefers to be conservative (rather than too optimistic) by not extending the range to include a value that may be only an outlier.

The gas-oil-ratio (GOR) varies from 18,500 cu ft per barrel at Dhodak (610,000 MMcfg and 33 million barrels of oil) to 2,000,000 at Sui (one-half barrel of condensate per MMcfg) (Tainsh, Stringer, and Azad, 1959). The distribution of liquid content of the gas is assumed to be triangular between these end points; therefore the GOR x 1,000 is 1,000/(.5, 1, 54). The calculated gas reserves are divided by the GOR to obtain the expected liquid reserves in the field. The range used includes the end points observed, and the most likely value used is strongly shifted towards the high GOR (low liquid content), which agrees with the observed values.

The most important reservoir to date in Pakistan is the Eocene-age Kirthar Limestones, locally divided into the Sui Main and the Sui Upper pays (Tainsh, Stringer, and Azad, 1959). Pay thicknesses as great as 757 ft have been measured in the 8.6-TCF Sui gas field. This section has been eroded from most structures in the study area.

5.3.3.3 Traps. The structural traps in the study area and the adjacent part of the Indus Plain are huge. The Mari gas field is productive over 340 sq mi or 218,000 acres (Hayat, 1988). The Sui field is productive over 47,000 acres, on a structural axis that can be traced with certainty for 34 miles (Tainsh, Stringer, and Azad, 1959). The Jandran structure was mapped from surface geology and air photos as having 6,000 acres of structural closure (OGDC Archives, 1988).

Many large mapped surface anticlines remain to be drilled in the fold belt (Soulsby and Kemal, 1988b). An important 85-km long seismic line was recorded by Amoco in the study area in 1975 (OGDC Archives, 1988). Only seismic lines of this magnitude are long enough to see multiple structures and to understand the structural style. Interpretation of this line (see Figure 6) shows that the surface anticlines with the oldest rocks exposed and with the steepest dips are caused by antithetic or back thrust faults, moving in the direction of the force or to the north. The larger subsurface structures are bounded on the south by the primary reverse faults, have flatter dips and are partially covered by the antithetic block structures.

Drilling the seismically defined main fault blocks should find larger closures with younger formations preserved than has the previous method of drilling the most prominent surface anticlines such as Jandran.

Area of accumulation is given a triangular distribution of 5,000, 24,000, and 47,000 acres. This distribution does not include the Mari-sized field because interpretation of surface structures from satellite photos and subsurface structures from seismic data shows that structures within the fold belt are limited to Sui-sized (47,000 acres) and smaller (Smith, 1988). This range is used with confidence based on observations in the study area and the knowledge that 5,000 acres is the minimum area for a commercial gas field in this region. Depth to the pay is given a triangular distribution of 2,000, 7,000, and 13,000 feet.

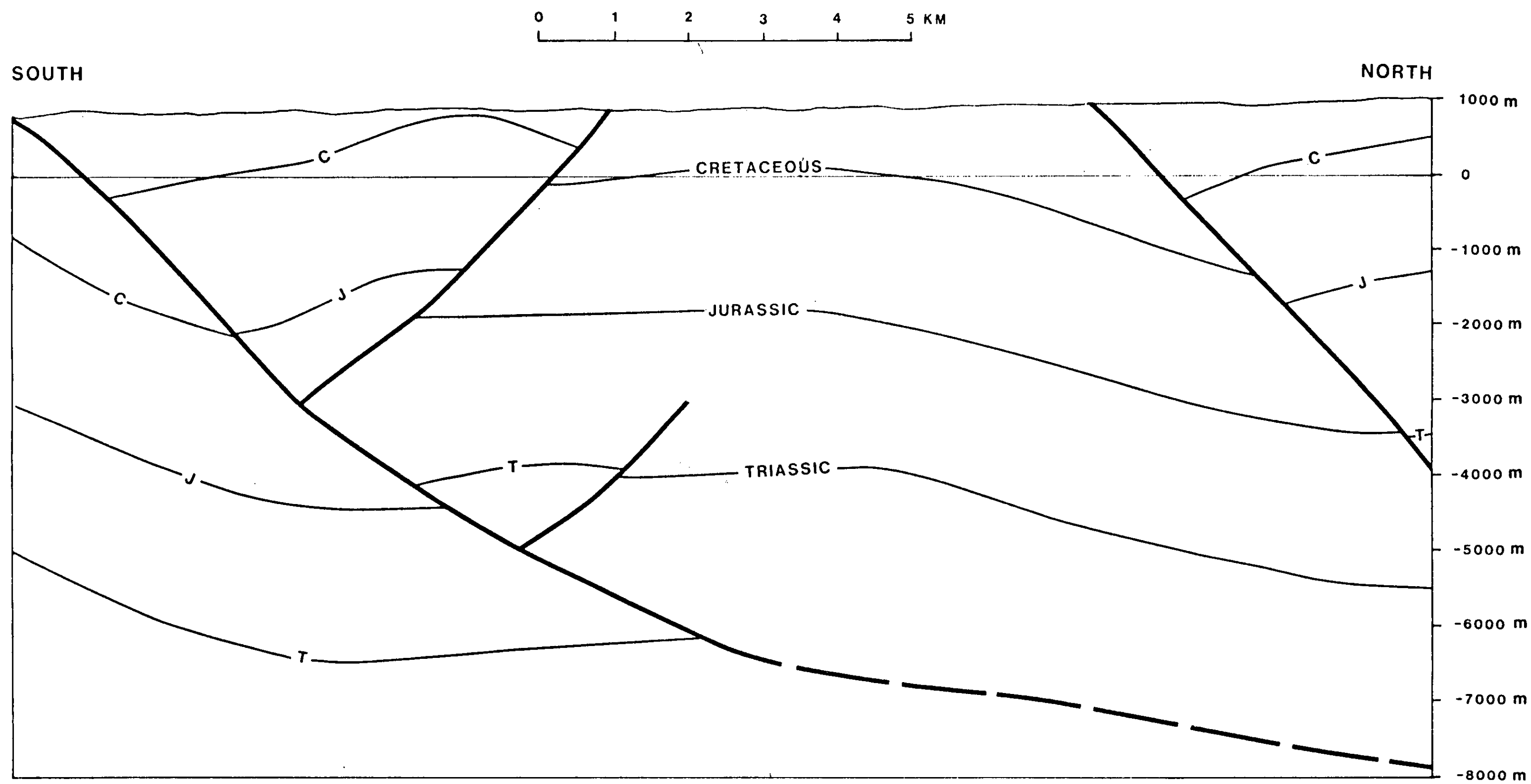

Figure 6. Pakistan Structural Cross Section
Modified From: OGDC Archives, 1988, Line W16-EU.

This range is constrained by observations, the fact that gas reserves decrease as pressure (a function of depth) decreases, placing 2,000 feet as an upper limit, and the thermally overmature nature of this area, which suggests that the non-flammable gas content would increase above economic limits at depths greater then 13,000 feet.

5.3.3.4 Geologic Risk. The 46 oil and gas fields discovered in Pakistan through 1987 from the drilling of 184 exploratory wells give a success ratio of 1:4, or 25 percent (Hydrocarbon News, 1988). Within the study area and the adjacent Indus Plain, 23 exploratory wells have found four producing fields (Sui, Mari, Kandhkot, and Pir Koh) and two additional fields currently being developed (Dhodak and Loti). This gives a success ratio of 1:3.83 or 26 percent, which is comparable to the national average.

Mahmood and Akram (1988) estimate that 13 development wells must be drilled to complete ten producers, for a 1:1.30 or 77 percent success ratio.

Here, exploration risk is given a triangular distribution of 1:2, 4, and 6. The author is confident of the mid-point of this range because of its correlation to the geologic dry hole risk observed both in the country in the study region. Exploration has not progressed to the point where depletion of available discoveries is a factor.

The width of the range, however, is a subjective judgment and other range widths could be argued for successfully. Development dry hole risk is given a triangular distribution of 5, 10, and 25 percent. This improvement over the published 23 percent risk can be achieved through greater use of geophysics in the development phase. Single point sensitivity cases are also run on the exploration risk.

5.4 Costs

Labor productivity in Pakistan is low because of shortages of skills, high absenteeism, dietary deficiencies, and generally poor living conditions (Bilinski and Hancher, 1988). The chronic shortage of skilled craftsmen and technicians within Pakistan could be moderating as the labor exodus to the lucrative Middle East market is slowed by depressed oil revenues.

Basic wages for laborers are about \$3.50 per day, for semiskilled workers \$6, and for skilled workers \$12 per day. Fringe benefits often make the total labor costs per worker about three times the wages. Foreign firms are expected to pay higher wages and provide better benefits than do the locally-owned firms.

5.4.1 Exploration Costs

The Ministry of Petroleum and Natural Resources (1988c) has suggested the minimum work program for each block available for concession. Blocks 28 and 29 are within the study area and contain 6,400 and 6,100 sq km respectively. The amounts of seismic to be acquired in the first two years are 300 km (28) and 500 km (29).

Field geology required includes source rock and biostratigraphy sampling. The recording of 1,200 to 1,500 gravity stations is also required. One exploratory well is mandatory and a second well is contingent upon the seismic results.

5.4.1.1 Seismic Costs. Seismic acquisition per crew varies from 59 to 122 km per month for OGDC crews and 63 to 221 km per month for the contractor crews of CGG and SSL (Foreign Scouting Service, 1988e). Average seismic costs in the foothills south of the study area were $3,000 per km when production was 100 to 150 km per month (Yunis Khan, 1988). This implies the monthly cost per crew could be in the $300,000 to $450,000 range.

In this case seismic costs are calculated from triangular distributions of total kilometers recorded (300, 400, 500), crew costs per month ($300,000; $450,000; $600,000), and production in kilometers per crew month (100, 125, 150). Crew costs have been increased on the higher end to reflect the need for helicopter support in some of the more rugged terrain. The range of production per crew month is narrower than observed because 1) helicopter support will keep production from falling in the rugged areas as it does on crews without this support, and 2) the high production rates observed in the Indus Plain are not possible in the mountains. The incremental costs to acquire gravity data concurrent with the seismic data are too small to significantly change overall costs. The total seismic costs are estimated by multiplying the amount of seismic program by the monthly crew cost and dividing by the production per crew-month.

<u>5.4.1.2 Exploratory Drilling Costs.</u> Estimated casing point costs for a 10,000 ft (3,000 m) exploratory well near the study area are $2.3 million for 105 days of rig time (Deschamps, 1988). This calculates to a daily cost of $22,000 and a footage cost of $230. Location costs would be additional.

By comparison, a 16,000 ft (4,900 m) well in the Potwar Basin to the north costs $7.8 million at casing point and uses 243 days of rig time. The calculated incremental costs are $478 per foot and $32,000 per day. The reasons for higher costs are 1) larger rigs are more expensive to operate; 2) formation pressure problems necessitate the running of additional strings of casing; and 3) drilling penetration rates slow at greater depths.

Canada Northwest recently drilled a 9,941 ft (3,030 m) dry hole in the fold belt south of the study area, which took 115 days from spud to abandonment (Foreign Scouting Service, 1988e). This drilling averaged 86 ft per day, compared with 95 ft per day for the estimated 10,000 ft well and 66 ft per day for the prognosed 16,000 ft well.

In this study exploratory dry hole costs are estimated by multiplying the triangular distributions of daily well costs ($22,000; $25,000; $32,000) by the drilling depth, dividing by the penetration rates in ft per day (66, 86, 95), and adding location preparation costs ($300,000; $500,000; $1,000,000). All of these ranges are based on enough information to be reasonable, but additional data could easily change these estimates.

5.4.1.3 General and Administrative Costs. An expatriate staff of three costs $500,000 per year for salaries, international transportation, housing, and other benefits (Yunis Khan, 1988). Local staff, local transportation, and overhead add $200,00 per year. A triangular distribution of 20 percent (subjective) on either side of this estimate is used in this study.

5.4.2 Development and Production Costs

No direct development and operating costs are available from Pakistan, and therefore estimates from U.S. fields are used and increased by a foreign cost factor. The Pakistan production facility costs are varied between 100 and 200 percent (subjective) of comparable U.S. costs due to lack of infrastructure and the need to import skilled technicians for the installations. Operating costs are not increased, because cheaper local labor offsets the higher costs of the relatively fewer skilled workers.

5.4.2.1 Capital Costs. Well completion costs are very high because of the need for special tubulars to minimize the corrosion of the carbon dioxide and water found in the study area. Stainless steel 3.5-inch tubing costs $39 per foot and 7-inch casing costs $110 per foot (Self, 1988). Completion costs are estimated at $150 per foot plus a triangular distribution ($.7, $1, $1.2) million for non-tubular expenditures.

Appraisal and development casing point costs are estimated to be distributed (.8, .9, 1.0) and (.5, .7, .9) times (subjective) the exploratory well costs respectively. These drilling costs are lower than the earlier costs because of decreased geologic uncertainty such as pressure and increased infrastructure.

Production facility costs are estimated from the Anschutz Ranch East (ARE) field in northeastern Utah, which has similar gas compositions to the gas fields of Pakistan (Huzyk, 1988). The ARE unit produces 39,000 barrels per day of condensate, 14,000 barrels per day of natural gas liquids, and 540 MMcfgpd from 28 producers. Gas composition is 17 percent nitrogen, 1 percent carbon dioxide, 67 percent methane, and 15 percent ethane and higher hydrocarbons. Reservoir pressure is maintained by injecting nitrogen in 17 injector wells.

Flowlines need to be of non-corrosive stainless steel, and therefore cost $500,000 each. Facilities for separating, treating, and stabilizing the liquids and dehydration of the gas cost $75 million for a 300-MMcfgpd operation. An ammonia refrigeration chiller plant to remove non-flammable gas and to maximize liquid recovery costs $100 million for the same size operation. A 40-megawatt cogeneration facility to provide electricity for all operations costs $20 million.

In this study facility costs are incremented by the number of producing wells and the maximum daily gas production and then varied 20 percent (subjective) either side of these estimates. The author has taken these cost estimates from published articles and petroleum engineers, and does not have the personal experience in this specialty to express a confidence level.

5.4.2.2 Expenses. The Anschutz Ranch East field is operated by Amoco Production Company, which has 80 employees at the field, 10 more at their Evanston, Wyoming, field office, and an unknown number of additional employees in their Denver office involved in the operation of the field (Koerner, 1989). Contract services cost an additional $300,000 per month.

Personnel costs in Pakistan are tabulated:

20 expatriates @ $150,000/yr	$ 3.0 MM
20 local professionals @ $50,000/yr	1.0 MM
40 technical assistants @ $20,000/yr	.8 MM
40 laborers @ $10,000/year	.4 MM
	$ 5.2 MM

Office, local transportation, supplies, and workovers add an estimated $2 million per year and the third party services add $3.6 million per year (Koerner, 1989). The average operating cost per well for the Anschutz Ranch East-type field is $390,000 per well. Estimates 30 percent (subjective) on either side of this value are used in the model.

The Pakistan government purchases both oil and gas at the production facilities from the operator (Ministry of Petroleum and Natural Resources, 1988a). The government charges the operator a transportation fee for the oil, but not for the gas. The oil transportation fee is calculated to the nearest oil refinery, which would be either Karachi or Multan. The study area is located from 100 to 500 km (60 to 300 miles) from the closest refinery.

A 6-inch pipeline having a crude capacity of 18,000 BOPD costs $57,600 per mile in Colorado (True, 1986). Assuming a desired 15 to 20 percent annual revenue to investment ratio, and negligible variable operating costs, the tariff charged by the government would be $.00132 to $.00175 per barrel per mile before the foreign escalation factor was calculated.

5.4.3 Cost Escalation

Pakistan has a managed float on its foreign exchange rate which follows the differences in inflation rates of its major trading partners (Bilinski and Hancher, 1988). In this study, real cost escalation in Pakistan is approximated by the U.S. inflation rate of 3 to 7 percent annually with 5 percent being the most likely.

5.5 Gas Supply, Demand, and Prices

Most of the hydrocarbon production from the study area is natural gas, and gas is usually not in high demand in developing countries. Given this combination, a special section is necessary to explain Pakistan's current gas supply/demand, future projections, and the implications for gas prices.

5.5.1 Gas Supply

Gas accounted for 34.2 percent of Pakistan's total energy supply in 1987. Estimated remaining proven recoverable gas reserves are 18 TCF (Directorate General of New and Renewable Energy Resources, 1987) and current gas production is 1,273 MMcfgpd (Foreign Scouting Service, 1989b).

Aman Khan (1988) estimates that production could be increased to a maximum of 1,800 MMcfgpd through intensive development of the six fields currently classified as commercial. Hak and Haider (1988) project gas production from new fields yet to be found at 576 MMcfgpd in the year 2005.

5.5.2 Gas Demand

Pakistan has the largest (12,000 km) gas transmission and distribution network in Asia (Khan and Ahmad, 1988). Primary uses of gas in 1987 were as follows (Khan, 1989):

Gas Use	Percent
Power generation	33.02
Fertilizer	28.83
General industry	21.05
Domestic	12.80
Commercial	2.76
Cement	1.54

Gas usage is severely limited by production and transportation bottlenecks. The cement industry used only 21 percent as much gas in 1987 as it did in 1982 because of these restrictions. The burlap industry has been decimated because jute, the raw material for making burlap, is now being burned at the cement plants to replace the unavailable gas (Kundi, 1988).

Figure 7 shows the current and projected curves for unconstrained demand and demand under current constraints. Assumptions made in constructing the constrained demand curve are 1) the number of residential, commercial, and industrial customers added in each five-year plan would follow government guidelines (unspecified); 2) gas use in fertilizer plants would be limited to feedstock requirements and a portion of steam-raising requirements; 3) gas would only be used in those smaller cement plants producing less than 100,000 tons per year; 4) gas for power generation at the second unit of the Pakistan Steel plant would be curtailed; and 5) fuel utilization at new power plants would be as currently specified by Water and Power Development

Authority (unstated). The unconstrained demand scenario is not truly unconstrained because the fertilizer, cement, and power industries are planned sectors of the economy, and gas demand would be even higher if these industries competed more directly for gas suppliers. The supply scenario of intensive development of existing fields would satisfy the constrained demand until 1998, but would only satisfy the unconstrained demand until 1990.

Pakistan currently produces about 7,000 megawatts (MW) of electricity, and will need 25,000 MW by the end of the century (Dawn Lahore Bureau, 1989). Assuming that the

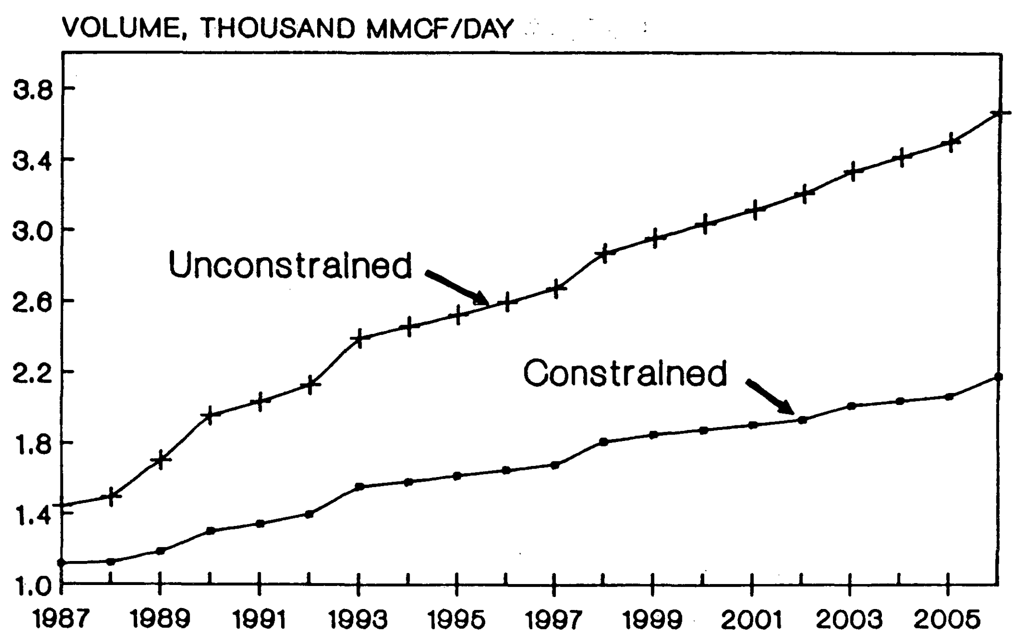

Figure 7. Pakistan Gas Demand Scenarios
Source: Aman Khan, 1988, p. 259.

source mix for power generation remains fixed would create an additional gas demand of 832 MMcfgpd. This mix assumption and the resulting gas volume are probably very conservative because the capital investment per kilowatt (kw) of installed power plant is much less for gas than other sources, as shown on the following tabulation (Jonchere, 1987). The lead time for construction of gas turbine power plants is one-half or less than that of other types of plants. The investment and timing advantages of gas-turbine power plants would suggest that the share of gas used in electrical power generation in Pakistan would increase, causing gas demand to exceed Khan's constrained scenario even without increased demand in other gas use sectors.

Type of Power Plant	$/Kw
Gas turbines	250 - 300
Combined gas/steam cycle	500 - 600
Steam coal	1,000 - 1,200
Nuclear	1,500 - 2,500
Hydro	1,500 - 4,000

5.5.3 Gas Prices

Non-associated gas, coming from wells with a gas-oil-ratio (GOR) of more than 10,000 cubic feet per barrel, is priced at 66 percent of the international price of fuel oil on a BTU basis, less a negotiated discount (Ministry of Petroleum and Natural Resources, 1988a). Associated gas, coming from wells with a GOR of less than 10,000, has traditionally been priced lower than non-associated gas, but new contracts now call for the highest price being paid in the country for comparable gas, which is expected to be the same as non-associated gas. The Ministry of Petroleum and Natural Resources has recommended that gas prices be based on 100 percent, rather than 66 percent, of fuel oil parity minus discounts, to encourage more gas exploration and production (Ahmad, 1988).

Futures prices of crude and heating oil on the New York Mercantile Exchange as quoted on Reuters News Service (January 4 and March 2, 1989) were used to establish a range of price ratios between the commodities. Conversion factors from the Petroleum Economist (1989) were used to convert fuel oil and gas to BTU's and to compare gas prices as per the Pakistan formula to crude oil prices in Table 2.

Table 2
Gas and Crude Oil Price Relationships

Month 1989	Crude $/bbl	Heating Oil $/gal	Heating Oil Btu/lb	Gas $/Mcfx.66	Mcf/bbl $/$ x.66
Feb.	17.08	.5265	18,300	2.78	.1629
May	16.10	.4427	18,300	2.34	.1454
April	18.42	.5095	18,300	2.69	.1463
July	17.28	.4635	18,300	2.45	.1418

Source: Reuters News Service, 1989; Petroleum Economist 1989, p. 45.

A triangular distribution (.1418, .1458, .1629) is used in the model to calculate the base Pakistan gas price from the crude oil price projected from Chapter 4 (triangular $10, $13, $18, plus escalation). Negotiated discounts have been 15 percent at daily production below 30 MMcfgpd, 20 percent in the incremental production of 30 to 50 MMcfgpd, and 30 percent on the incremental production above 50 MMcfgpd (Alexander, 1988).

The resulting gas prices are low compared to some of the alternate sources. Studies on the costs of importing gas by pipeline from Iran and as liquified natural gas (LNG) from Qatar and Indonesia are summarized in Table 3.

Table 3

Imported Gas Costs, $/Mcf

MMcfgpd Delivered	300			500		
Inlet Gas Cost, $/Mcf	0.50	1.00	1.50	0.50	1.00	1.50
Pipeline						
Iran to Karachi	2.13	2.63	3.13	1.89	2.39	2.89
Iran to Sui	2.37	2.87	3.37	2.08	2.58	3.08
LNG						
Qatar to Karachi	2.82	3.42	4.02	2.56	3.16	3.76
Indonesia to Karachi	3.50	4.10	4.70	3.21	3.81	4.41

Source: Aman Khan, 1988, p. 257.

The pipeline from Iran provides the cheapest alternate gas source, but the present political unrest in Iran prevents entities from making the $700 to $800 million investment.

5.6 Fiscal Terms

Pakistan offers petroleum concession agreements on exploration acreage (Ministry of Petroleum and Natural Resources, 1988a). The primary exploration term is 3 years, with up to three 1-year renewals possible. If successful exploratory and appraisal wells and supporting engineering/economic studies define a commercial discovery, a lease of the productive area may be applied for. The primary term of the lease is 20 years, with a 5-year extension possible if commercial production remains.

The Oil and Gas Development Corporation or OGDC, the government oil company, has a 5 percent working interest through exploration and appraisal, and the option to take a 50 percent working interest through development and production. If OGDC exercises this option, it does not reimburse the firm for past exploration costs.

Rentals of 1,000 rupees per sq km ($133.61 per sq mi) must be paid at the beginning of the exploration period. Bonuses to be paid are $2 million at discovery, $3 million when production reaches 10,000 BOPD or gas equivalent, $5 million when production reaches 25,000 BOPD or gas equivalent, $5 million when production reaches 25,000 BOPD or gas equivalent, and $7.5 million when production reaches 50,000 BOPD or equivalent. Rentals may be expensed on

Pakistan income tax, but the bonuses, paid entirely by the foreign firm, cannot be expensed or capitalized.

Royalty is 12.5 percent of the wellhead value of annual gross production. Wellhead value is defined as the amount realized from the sale reduced by the costs to gather, process, treat, and transport the hydrocarbons from the wellhead to the point of sale in Pakistan. The government is the purchaser of oil, and a discount applies to price paid, ranging from none at prices below $10 per bbl to 15 percent on prices above $34.

The income tax rate is 55 percent, with royalties credited against this tax. Income taxes paid in Pakistan qualify as foreign tax credits against U.S. taxes on foreign income. Machinery and plants (production facilities) are depreciated 10 percent per year from the year in which they are first placed in use. An additional 40 percent depreciation can be taken in the first year on plant and machinery placed in operation after June 30, 1981. Below ground installation in oil concerns (producing wells) are depreciated 100 percent in their first year of use (Ministry of Petroleum and Natural Resources, 1988b). Losses can be carried forward.

A depletion allowance of 15 percent of the wellhead value is allowed, provided that the allowance does not exceed 50 percent of the profits before the deduction of the allowance. An additional restriction on income tax is that the aggregate of royalty and income tax must not be less than 50 percent of the profits before deduction of the royalty and depletion allowance.

5.7 Political Risk

Pakistan's policy for a decade has been to encourage private sector investment, particularly in projects requiring sophisticated technology and large capital investments (Bilinski and Hancher, 1988). The Foreign Private Investment (Promotion and Protection) Acts of 1976 protect against expropriation and provide adequate compensation for acquisitions. The Acts also guarantee the rights of the foreign investor to repatriate profits and recovered investment funds.

The desires of the government appear to be favorable for foreign investors, but the stability of the government needs to be evaluated. Pakistan is bordered by Iran, Afghanistan, China, and India, with whom it has had two wars and numerous border skirmishes. The instability of any of these neighbors can have a negative influence on Pakistan. There are about three million Afghan refugees inside Pakistan (Kempe, 1988). The costs to care for these refugees are greater than the amount of international aid received, and their presence is not welcomed by some in Pakistan.

The election of a woman, Benazir Bhutto, as Prime Minister of Islamic Pakistan has produced mixed signals on the country's political stability. The U.S. State Department was very encouraged by the peaceful way the elections and transfer of leadership were conducted (McQueen, 1988). More recently Islamic fundamentalists have called for Bhutto's ouster, declaring that a woman cannot rule an Islamic state (London Observer Service, 1989). Past changes in governments in Pakistan have not caused contracts to be voided, suggesting that contractural risk in Pakistan is low.

The biggest risk in Pakistan is operational disruption from civil uprising. This problem is particularly acute in the study area, which includes tribal areas of the Baluchistan Province. The backwardness and medieval tribal practices of the area limit the power of the provincial and federal governments (Akbar, 1989). Some tribal chiefs or "nawabs" prefer that their people not be exposed to the modern world, but be kept dependent on the nawab. Special attention must be given to establishing a liaison with the nawabs of the area in which the firm wishes to operate.

The risk of political events disrupting the positive cash flows of a petroleum project in Pakistan is estimated between 5 and 20 percent, with 10 percent most likely. These estimated numbers are subjective, the author's judgments of the probability that political events, primarily operational disruptions, will stop the project's cash flows. Sensitivites are run to test how changes in these estimates affect calculated profitability. OPIC insurance is available for projects in Pakistan, subject to the 90 percent limit on the first $100 million invested. The political risk is only applicable to the percentage of the firm's development investment that is not covered by the OPIC insurance. The cell formulas in Appendix B show how this risk and insurance coverage are factored into the cash flow that the firm expects to receive.

5.8 Pakistan Cash-Flow Model

Table 4 summarizes the distribution and ranges of the important input variables used in the model. The spreadsheet and a listing of cell formulas are included in Appendix B.

5.8.1 Pakistan Model Results

Figure 8 graphically displays the distribution of net present value (NPV) of the Pakistan model, using 1,000 iterations on the @ RISK/Lotus 1-2-3 simulator. The single

Table 4. Pakistan Model Assumptions

Parameter	Distribution	Values
Geologic		
Area, acres	Triangular	5,000; 24,000; 47,000
Net Pay, feet	"	55, 100, 160
Porosity	"	.05, .12, .25
Recovery Factor	"	.4, .55, .75
Water Saturation	"	.15, .35, .6
Gas Oil Ratio x 1,000	"	1,000/.5, 1, 54
Inert Gas Content, %	"	0, 10, 30
Depth, feet	"	2,000; 7,000; 13,000
Pressure Gradient, psi/ft	"	.43, .44, .86
Geologic Risk, 1:	"	2, 4, 6
Initial Production, MMcfgpd	"	4, 14, 30
Costs		
Seismic, km	Triangular	300, 450, 600,
Seismic Crew Costs, $MM/month	"	.3, .4, .5
Seismic Acquisition, km/month	"	100, 125, 150
Exploratory Drilling Location, $MM	"	.3, .5, 1
Exploratory Drilling Costs $M/day	"	22, 25, 32
Exploratory Drilling Rates, ft/day	"	66, 86, 95
Appraisal Drilling Costs, % of Exploration	"	80, 90, 100
Development Drilling Costs, % of Exploration	"	50, 70, 90
Completion, Non-tubular Costs, $MM	"	.7, 1.0, 1.2
Production Facility Costs, $MM/well	"	.4, .5, .6
Operating Costs, $MM/well	"	.27, .39, .51
Transportation Costs, $/Bbl/mile	Uniform	.00132, .00175
Transportation, Miles	Triangular	60, 180, 300
Fiscal		
Political Risk	Triangular	.05, .1, .2

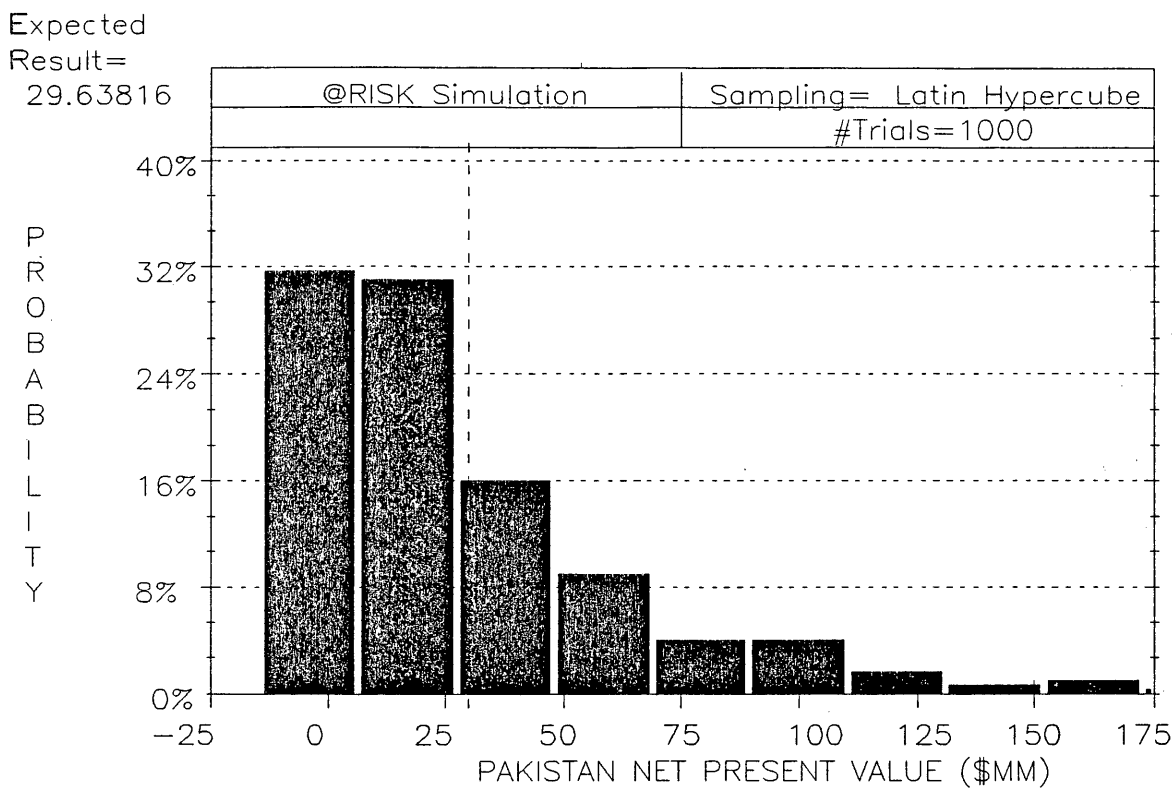

Figure 8. Pakistan Net Present Value Distribution

NPV from the case where all stochastic variables are at their expected value, $27.3 million, is less than 8 percent below the mean NPV, $29.6 million, from the multiple iterations. The discounted cash flow rate of return (DCFROR) is 15.1 percent in the expected value case. Table 5 summarizes these results.

Sensitivities are NPV increasing to $134 million when geologic risk is removed (standard deciation is $149MM); NPV being positive for all geologic risk less than 1:16.7 (chance of commercial discovery greater than 6 percent); NPV increasing to $51.8 million where gas oil ratio (GOR) is decreased to 19,000; and NPV decreasing to $15.7 million when GOR is increased to 1,667,000. Increasing the range of political risk from (.05, .1, .2) chance of political events disrupting the positive cash flow from the project to (.0, .1, .4) decreases the mean NPV to $25.2MM, and increases the percentage of cases with negative NPV's (19.6 to 22.6).

5.8.2 Recommendations

It is recommended that a petroleum concession for gas/oil exploration and production activities in the Central Fold Belt be negotiated with the Pakistan government, based on positive profitability indications of this case study. An important factor in this recommendation is the NPV's being positive through all reasonable ranges of geologic

Table 5

Pakistan Model Results

Parameter	Expected Value Case	Simulation Min	Simulation Mean	Simulation Max
Base Case				
NPV, $MM	27.3	-15.1	29.6	509
(Std Dev = $42.1MM, 19.2% Negative)				
Gas, BCF	1,828	128	1,804	8,541
Oil, MM Bbl	34	.2	34	239
DCFROR, %	15.1			
No Geologic Risk Case				
NPV, $MM	135	-25.5	134	1,354
(Std Dev = $149MM, 10.5% Negative)				
Political Risk (.0, .1, .4) Case				
NPV, $MM	24.5	-14.9	25.2	350
(Std Dev = $38.7MM, 22.6% Negative)				
GOR = 19,000 Case				
NPV, $MM	51.8			
GOR = 1,667,000 Case				
NPV, $MM	15.7			
Breakeven (0 NPV) Geologic Risk Case				
Geologic Risk, 1:	16.7			

risk. This recommendation is made only for the study area. The petroleum geology and resulting economics are enough different for the Potwar Basin (smaller oil fields) and the Lower Indus Basin (smaller oil and gas fields) that separate models should be made before any investment decisions are made for other regions in Pakistan.

<u>5.8.2.1 Level of Working Interest.</u> The maximum level of working interest that a smaller firm should take in this venture, assuming a \$30 million multi-year budget, \$8.56 million of discounted exploration expenditures, and the desire for a 95 percent confidence level of a profitable exploration program, is given by eq. (4.2).

$$f \leq [30/(4 \times 8.56)]\ [134/(1.645 \times 149)]^2$$

$$f \leq .26 \text{ or } 26 \text{ percent working interest.}$$

<u>5.8.2.2 Level of Information.</u> The optimal amount of seismic data to acquire prior to drilling is calculated from eq. (4.3 - 4.5), with the following assumptions:

Cost per km of seismic = \$3,600
Probability of success, no seismic = .17
Probability of success, 400 km seismic = .25
Probability of success, infinite seismic = .50
NPV successful project = \$134,000,000

$$a = 1 - .17/.50 = .66$$

$$b = -\{\ln[(1 - .25/.50)/.66]\}/400 = .000694$$

$$X = -(1/.000694) \ln [3600/(.50 \times .66 \times .000694 \times 134{,}000{,}000)]$$
$$= 3088 \text{ km of seismic}$$

This amount is much greater than the amount an experienced explorationist would recommend. Four possibilities for this discrepancy are that 1) the theory is basically flawed; 2) probabilities of success with various levels of seismic are in error; 3) the marginal value of additional seismic data does not decline exponentially; and 4) explorationists relying solely on intuition when determining the size of a seismic program make incorrect decisions. None of these possibilities can be ruled out, but the third is probably the most valid in this case.

The exponential decline of the value of additional seismic data may be appropriate in areas where the surface gives no information on subsurface structures and dominant structural trends do not exist. In the study area, structures follow a very dominant trend which is obvious from surface data. Two or three dip-oriented regional seismic lines, each 80 km long, add a lot of understanding of the subsurface structures and calibrate the interpretation of the surface geology. A 200- to 300-km detail program over the most attractive structure would optimize the location of the exploratory well. Any seismic above this recommended level would have less value than that predicted by exponential decline. Therefore the theory, the probabilities of success, and the explorationist could all be correct, but this method is not applicable in areas of excellent surface geological information.

Sensitivity analyses show that NPV is inversely proportional to GOR or directly proportional to the amount of liquids found in the gas. Geochemical information on whether the source rocks are oil-prone or gas-prone, and on degree of thermal maturation would be very useful in maximizing the liquids found. Ideally some of this information could be obtained prior to selecting the concession acreage.

Chapter 6

CHINA CASE STUDY

China has identified the energy, transportation, and communication technology sectors as priority areas in its official 5-year plan (Office of Technology Assessment, 1987). Not all of these needs can be supplied internally, so foreign investment is being encouraged. China has revised its tax laws to make investment risk more attractive (Gargan, 1988). Tax losses in unsuccessful exploration ventures in one area can be used to offset taxes on a successful development project elsewhere in the country.

6.1 General Information

China in the study refers to the People's Republic of China, also known as Mainland China or Red China, and not to Taiwan. China's land area, the third largest in the world, covers 9,326,410 sq km or 3,600,870 sq mi (Central Intelligence Agency, 1987). The terrain varies from high mountains and desert plateaus in the west to plains and low hills in the east.

China is the world's most populous country with more than one billion people and an annual growth rate of almost one percent. More than 93 percent of the people are of the Han Chinese ethnic division, with the remainder representing a multitude of lesser nationalities (Central Intelligence Agency, 1987).

The communists have ruled China since 1949. The real power lies with the Communist Party's Politburo while the National People's Congress ratifies the party's programs.

Per capita Gross National Product (GNP) for 1986 was estimated as $250. The real GNP growth rate has increased from 7.8 percent in 1986 to a projected 10 percent for 1988 (American Embassy Beijing, 1988).

The inflation rate, as measured by the retail price index, increased 6 percent in 1986 and 7.3 percent in 1987, but is projected as 15 percent in 1988. These inflationary forces have caused China to cut investments planned in many industries other than energy or transportation (Leung, 1988). The current exchange rate is 3.722 Renminbi yuan per U.S. dollar (Wall Street Journal, 1989a).

6.2 Case Study Site

This study is limited to the Junggar and Tarim Basins in northwestern China (see Figure 9). These basins have been indentified as the most prospective in China, and by some as the most prospective in the world. A consortium of Exxon, Shell, and Chevron was prepared to sign a contract on the area in 1986, but when oil prices fell below $9 per barrel, they decided not to make the investment (Pan, 1987).

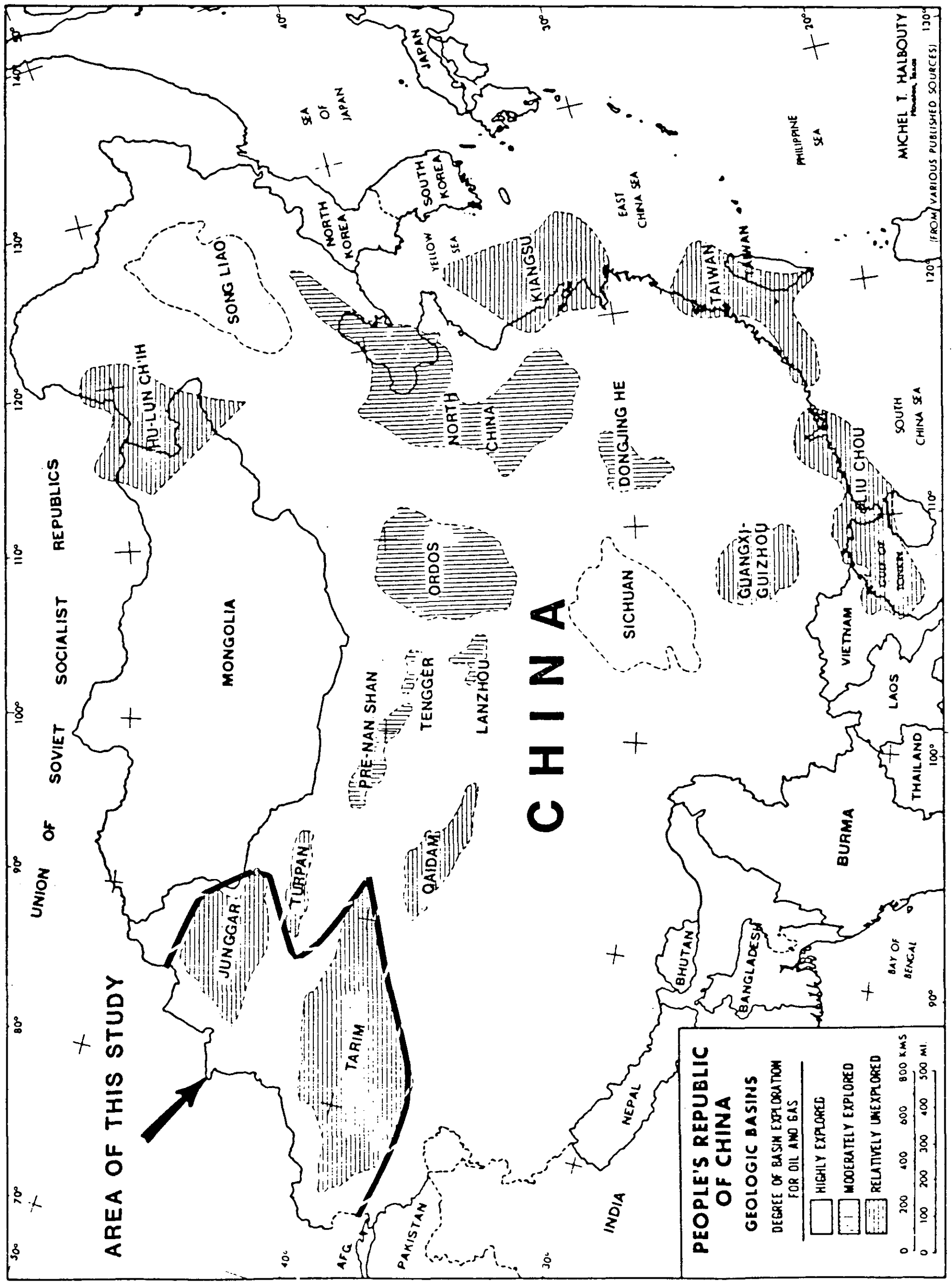

Figure 9. China Index Map
Source: Halbouty, 1981, p. 134.

Later reports are that this trio and another group consisting of British Petroleum, Nippon Oil, Mitsubishi, C. Itoh, BHP, and Petrobras have petitioned the Chinese government to open the northwest basins for exploration by foreign firms (Foreign Scouting Service, 1988b).

The latest news casts doubt on the ability of foreign firms to obtain petroleum agreements in these basins. China plans to spend 1.5 billion yuan ($403 million) over the next two years in the Northwest Xinjiang Uygur Autonomous Region, which includes the Junggar and Tarim Basins (Foreign Scouting Service, 1989a). Plans are to acquire 20,000 km of seismic and drill 50 exploratory wells in the Tarim Basin alone.

6.3 Hydrocarbon Assessment

Information on the petroleum geology and petroleum production of China has become much more plentiful since the early 1970s (Cooper et al., 1981). A giant step forward was the formation in 1982 of Stanford University's Industrial Affiliates Program, which included a geological assessment of the northwest basins of China (Stanford-China Project Research Group, 1988).

6.3.1 Past Exploration

Between 1100 and 1200 A.D., oil was produced from hand-dug tar pits and wells along the southern margin of the Junggar Basin and along the southern, western, and eastern margins of the Tarim Basin (Cooper et al., 1981). The first modern commercial field was established at Dushanzi in the southwestern part of the Junggar in 1897 by Chinese and Russian drillers.

The remoteness of the area hindered development, and the area stood idle until 1949, when the Russians were again helping the Chinese. Karamay oilfield discovered at this time on the west flank of the Junggar has an estimated ultimate recovery of 730 million barrels.

Political differences between China and the USSR caused all Soviet technicians to leave by 1961. The cultural revolution of 1966-1969 prevented further progress from being made. China then turned westward and by 1972, imports of U.S. technology were on the upswing.

Seismic service contracts have been awarded to western contractors. CGG of France has had three seismic crews working in the Junggar, and GSI of Texas has had three seismic crews in the Tarim (Foreign Scouting Service, 1988c).

6.3.2 Current Production

China produced 2,680,000 BOPD in 1987, with over one-half of that production coming from 2 giant fields in northeastern China, Daquing and Shengli (Foreign Scouting Service, 1988c).

Karamay is the most important producer in northwestern China (Riva, 1986). This field, located on the northwestern flank of the Junggar, produces 73,000 BOPD from 2,000 wells. Estimated production from the Wuerke oil field, located northeast of Karamay, is 15,000 to 20,000 BOPD. Minor production comes from the Qigu and Dushanzi fields, located in the southern part of the Junggar.

Oil production data on the Tarim Basin are unavailable. Riva (1986) did report that a processing plant was under construction at the Kekeya field along the southwestern margin. Future plans call for the construction of a refinery and a chemical fertilizer plant. Oil is also being produced from the Shacan field along the basin's western margin.

6.3.3 Petroleum Geology

The Junggar Basin covers 132,000 sq km (51,000 sq mi) and contains 646,000 cu km (157,800 cu mi) of sediments (Riva, 1986). Proven reserves in 1980 were estimated at 87.7 million barrels, with 4.9 billion barrels listed as potential (Cooper et al., 1981).

The Tarim is one of the largest intermontane basins in the world, covering 500,000 sq km or 194,000 sq mi (Riva, 1986). The volume of sediments is estimated at 2,550,000 cu km or 622,000 cu mi. Proven reserves were estimated in 1980 were 50 million barrels, with 5.0 billion barrels being the estimated potential (Cooper et al., 1981).

<u>6.3.3.1 Source Rocks.</u> The source rocks of the Junggar and Tarim rival the best petroleum source rocks in the world (Carroll et al., 1988). Upper Permian lacustrine shales along the southern margin of the Junggar have measured total organic content (TOC) ranging from 3 to 34 percent. Triassic-Jurassic lake beds and coals and Tertiary lacustrine shales may also provide sources. These Tertiary shales are locally up to 11 km (36,000 ft) thick in the Urumqi foredeep at the south end of the Junggar.

In the Tarim, Permian and Jurassic coals are excellent liquid sources, but the Triassic coals appear to be gas-prone. TOC's of the coal range from 0.75 to 96 percent. In a 4,000-m interval, 1,300 m was classified as source material.

<u>6.3.3.2 Reservoirs.</u> A wide range of reservoirs exist in northwestern China. The giant Karamay oil field produces

from Triassic sandstones and conglomerates of an alluvial fan along the edge of the Junggar (Riva, 1986). The nearby Wuerhe oil field produces from sands of Triassic, Jurassic, and Cretaceous-age. The Qigu oil and gas field at the south end of the Junggar produces from lower Jurassic sandstones. The Dushanzi oil field produces from sandstones in the Early Cretaceous, Oligocene, and Miocene. The China National Petroleum Corporation's recent discovery, No. 2 Lunnan in the Tarim, flowed 4,289 BOPD from 30 ft of Triassic pay (Oil & Gas Journal, 1989a). Oil was found in 11 formations totaling 198 ft, and included Ordovician, Jurassic, Lower Cretaceous, and Upper Tertiary reservoirs. The Yiqikelike field along the northern margin of the Tarim has oil in Miocene sediments (Riva, 1986). The Shacan field produces 5,000 BOPD from fractured Ordovician carbonates at about 18,000 ft. In this study triangular distributions are used for porosity (.08, .14, .17), net pay in feet (30, 200, 525), recovery factor (.15, .25, .35), and initial production in BOPD (500, 1,000, 6,000), based on limited local information and basic reservoir knowledge. The author does not have as high a degree of confidence in these estimates as in the Pakistan estimates, because of less information available on China.

<u>6.3.3.3 Traps.</u> China's eastern basins were formed by extensional forces and are referred to as rift basins. The western basins, including Junggar and Tarim, were formed by compressional forces of continental plate collisions (Riva, 1986). The collision of the Tarim microplate with Asia occurred at the Carboniferous-Permian boundary (Xiao, 1988). The Tertiary collision of India with Eurasia created compressional structures that overprinted all previous structures (Coleman, 1988).

The Yiqikelike field is located on a surface anticline covering 15.5 by 3 miles or 30,000 acres (Riva, 1986). Estimated productive area of Yahela field is 6,900 acres, while the area of the Central Tarim Basin Uplift is 2.5 million acres (Pan, 1987).

Even in the presence of such dominant structures, the most important oil field of the region, Karamay, is a stratigraphic trap (Riva, 1986). For this study the productive area is given a triangular distribution in acres of 5,000, 6,900, 30,000, with the smaller value being the assumed minimum commercial field area. The greatest weakness of these estimates is that the maximum productive area could be much larger.

<u>6.3.3.4 Geologic Risk.</u> The commercial discovery ratio in the southern part of the Junggar the past few years is

reported to be 1:7 (Forman, 1988). It is assumed that proper exploration techniques in the Junggar and Tarim Basins would yield a similar success ratio, varying from 1:3 to 1:11, with 1:7 the most likely. Confidence in this range is moderate: the range is comparable to success ratio in other producing areas of the world, but no hard facts are available here other than one verbal comment.

6.4 Costs

Qualified Chinese personnel cost 30 percent less than others doing similar work in southeast Asia (Foreign Scouting Service, 1988c). However getting qualified personnel to work for a foreign company can be very difficult. The Chinese consider such ventures as much less secure than state-run enterprises (Ignatius, 1988). Therefore accurate estimates of the number of employees necessary and their costs are difficult to obtain.

A major factor in costs in northwest China is the remoteness of the area. The Junggar and Tarim Basins are near the center of Eurasia, the largest land mass on the earth, which place them further from a coast than other areas. The two basins are 2,100 miles west of Beijing, China's capital, and are separated from the industrialized eastern part of China by some of the largest deserts and some of the most rugged mountains in the world (Scott, 1982). This remoteness increases costs in all phases of exploration, development, and production.

6.4.1 Exploration Costs

Signature bonuses of $1 million plus the purchase of data packages for a similar amount are common entry costs to petroleum exploration in China (Foreign Scouting Service, 1988c; Crawford, 1988). These data packages are necessary for high-grading areas of maximum petroleum potential.

6.4.1.1 Seismic Costs. The center of both the Junggar and Tarim are covered with sand dunes (Hongze, 1988). These dunes cause data quality to deteriorate and make transportation difficult. The best data is obtained by shooting in the valleys between the dunes. Vibroseis, primacord, and dynamite sources all provide adequate data quality between sand dunes, but where a large amount of dry sand is present, the dynamite source in a pattern of 6- to 9-m holes gives better deep data. Shooting 60- to 70-fold data is suggested to get an acceptable signal-to-noise ratio.

GSI's seismic contract in the Tarim has rates of around $10,000 per km (Pan, 1987). For lack of better information, a range of 20 percent either side of this cost estimate is applied to all future seismic work. Assuming a contract area of 20,000 sq km or 7,800 sq mi, 500 km of reconnaissance seismic and 500 km of detailed seismic would be needed to delineate a drillable prospect. These estimates are in addition to whatever regional lines would be purchased from the Chinese.

<u>6.4.1.2 Exploratory Drilling Costs.</u> Two published numbers for drilling costs in northwest China show a wide variation. Kexiang (1986) stated that two wells drilled to an average depth of 16,545 ft (5,044 m) in 1984 cost $317 per ft. This cost per ft was 2 to 6 times that of deep wells in other parts of China, emphasizing the high costs of these remote basins.

Recent drilling of a 18,000-ft (5,500-m) well in the Taklimakan Desert of the central Tarim cost $823/ft (<u>Oil & Gas Journal</u>, 1989a). These costs are assumed to be casing point costs with completion costs being an additional 25 percent of casing point costs.

<u>6.4.1.3 General and Administrative Costs.</u> Sun Orient Exploration Company, a subsidiary of Sun Oil Co., estimated that it costs $1.3 million per year to maintain an office in China (Crawford, 1988). Estimates 30 percent (subjective) on either side of this value are used in the simulation model.

6.4.2 Development and Production Costs

Less information is available on development and production costs in China than is available on exploration costs. The estimates therefore must have wide ranges to maintain any level of confidence.

6.4.2.1 Capital Costs. Casing point costs of appraisal wells are assumed to be around 90 percent (80, 90, 100), and development well costs around 71 percent (60, 65, 80) of the exploratory well casing point costs. Completion costs are assumed to be the same in all categories of wells.

Production facilities are assumed to cost \$75-\$100 million plus \$1-\$2 million per well, based on experience in the Rocky Mountains and in Saudi Arabia (Koerner, 1989).

The transportation of the produced oil from this remote location to a market is a major expense of uncertain magnitude. The largest reported pipelines in China are 720-mm or 28-inch, with a capacity of about 400,000 BOPD (Oil & Gas Journal, 1988c).

Costs for the closest comparable sized U.S. pipeline, 30-inch from Wyoming to California, averaged \$620,000/mi or \$390,000/km (True, 1988). These costs were broken down to 40 percent material, 36 percent labor, 19 percent engineering and management, and 5 percent right of way and damages. Material is further divided to 17 percent pump stations and equipment and 23 percent line pipe and fittings.

The following assumptions are made from pipeline costs in China: 1) line pipe and fittings can be obtained from South Korea or Japan at 90 percent of their cost delivered to the United States; 2) pumps and equipment costs are 150 percent of their comparable costs in the United States; 3) labor costs are 90 percent of the U.S. costs; 4) engineering and management costs are twice those in the United States; and 5) right of way and damages are one-half of the U.S. costs. These cost changes result in an estimated $735,000 per mile in China or 119 percent of the U.S. costs.

By comparison, a lengthy 36-inch pipeline in the United States costs $760,000 per mile, and a 42-inch pipeline costs $800,000 per mile (True, 1986). A handy rule of thumb for calculating pipeline capacity is given by Brunett (1989):

$$\text{Capacity in BOPD} = D^2 \times 500 \qquad 6.1$$

where D is the diameter in inches. Therefore a 30-inch line would have 450,000 BOPD capacity, a 36-inch line 650,000 BOPD capacity, and a 42-inch line 880,000 BOPD capacity.

Assuming the same percentage increase of U.S. costs for Chinese costs, the investment necessary per mile of daily barrel of capacity would be $1.63 for the 30-inch line,

$1.39 for the 36-inch line, and $1.08 for the 42-inch line. The larger the productive capacity of the fields in the area, the lower the unit pipeline investment.

An optimistic assumption of the production capacity of a basin has the maximum daily production of the region near 880,000 BOPD, and the firm and its Chinese state oil company partner paying their share of a 42-inch pipeline, with their share determined by their field's projected maximum daily production. The pipeline investment cost is a distribution of 20 percent on either side of $1.08 per mile per daily barrel of capacity multiplied by the expected maximum daily production for each case multiplied by the distribution of expected distance to the coast.

Urumqi, the major city in the Junggar, is connected to eastern China and the coastline by a 2,100-mile railroad (Times Atlas of the World, 1983a). A 450-mile stretch of this right of way from Yumen to Langhou already contains a crude oil pipeline (International Petroleum Encyclopedia, 1985). An additional 400 miles from Urumqi would reach any potential oil field in the Junggar. A 1,400-mile line from Yumen, 600 miles east of Urumqi, could reach any potential oil field in the Tarim. Therefore a 2,500- or 3,000-mile pipeline, the majority of which would be along an existing railroad, could reach any discovery in one of the basins.

Additional pipeline length would be necessary to serve both basins.

6.4.2.2 Expenses. Western operating technology and efficiency must be used to avoid the labor-intensive practices of China. The Petroleum Administration Bureau employes 200,000 workers at Daquing, China's largest oil field (Iwamoto, 1988). Daquing produces 1.1 MMBOPD from 8,000 producing wells. Production costs are estimated to be below \$10/bbl, perhaps near \$4/bbl (Oil & Gas Journal, 1987a).

Operating costs are estimated from a Saudi Arabia report, with fixed costs having a triangular distribution around \$3 million (2, 3, 4) per year and variable costs being uniformly distributed around \$100,000 (80,000; 120,000) per well per year (Koerner, 1989). An additional \$2 million (1.4, 2.0, 2.6) per year are added as general and administrative costs to support the operation.

Transportation variable costs range from \$0.005 to \$0.02 per barrel per 100 miles (Burnett, 1989).

6.4.3 Cost Escalation

The inflation rate in China has increased from 6 percent in 1986 to an estimated 15 percent in 1988 (American Embassy Beijing, 1988). In an economy of completely flexible exchange rates, the foreign exchange rates are determined by the relation between domestic inflation rate and the inflation rates of major trading partners, resulting in the real cost escalation being that of its trading partners.

As a centrally-planned economy, China is assumed to not have flexible exchange rates. Escalation of costs are assumed to be influenced equally by the inflation rates in the United States (3-7 percent) and in China (6-15 percent).

6.5 Fiscal Terms

Although China had many production-sharing contracts with western oil companies in its offshore area, it has not made any agreements on the mainland (Cooper et al., 1981). Hopes and expectations among the companies are that the Chinese will soon allow foreign participation in its less explored and more remote areas, in particular the Junggar and Tarim Basins (Gargan, 1988).

The Chinese National Offshore Oil Corporation (CNOOC) has full authority for offshore petroleum exploration and associated joint ventures with foreign firms (*Foreign Scouting Service*, 1988c). The Chinese National Oil and Gas Corporation (CNOGC) is assumed to have parallel responsibility for the onshore regions.

Previous offshore bid rounds had signature bonuses of

$1 million. License term is for seven years, and the production period is 15 years, although an extension for an additional 15 years may be granted. The foreign firm pays all exploration and appraisal costs. The state oil company then has the right to participate for 51 percent working interest in development and production. CNOOC does not repay past exploration costs. Royalty is 12.5 percent, but is waived on fields producing less than 20,000 BOPD. There is also a Consolidated Industrial and Commercial (CI&C) Tax of 5 percent of gross production.

Thirty percent of the annual gross production is available for cost recovery. Costs are recoverable in the following order: operating costs, exploration costs in the contract area, and development costs for the subject field. A 9 percent compound interest may be applied to unrecovered development costs.

The oil remaining after royalty, CI&C tax, and cost recovery is termed "remainder oil." This remainder oil is split by negotiated "X" factors, which change with level of production. X percent of the production is called "allocable remainder oil," which is split 51-49 between CNOOC and the firm. The rest of the oil or 100-X percent is called "share oil" and belongs entirely to CNOOC.

The effective corporate tax rate is 50 percent. The tax base is determined by revenue received from sales of cost recovery oil and allocable remainder oil less operating expenses and depreciation. Fixed assets are depreciable over six years straightline.

In this study, it is assumed that oil fields in the northwest basins have long production lives, with a 15-year extension resulting in a 30-year production period. The X factors range from 90 percent for the first 3.5 million barrels per year to 50 percent for production over 70 million barrels per year.

6.6 Political Risk

China is described as "a lumbering giant that has tottered half-way out the tightrope of economic reform . . . afraid to go forward . . . and yet afraid to go back" (House, 1989). These steps towards reform have created opportunities for foreign firms, but these changes have also upset the status quo and created uncertainties.

Decentralization has permitted the growth of thousands of small, unregulated industries, which now account for 25 percent of industrial output. The resulting overheated economy has inflation running as high as 30 percent in some urban areas. City dwellers on fixed incomes have not benefited from the economic reforms as have the rural peasants and the entrepreneurs. Their feelings have gone from frustration to discontent and quiet anger.

Earlier in this study it was mentioned that economic dissatisfaction is a trigger for political risk. A moderating factor in China is that its Confucian ethic doesn't produce political dissidents or clashes (House, 1989). Memories of the Cultural Revolution of 1966-1969 cause some to question the moderating effect of this ethic.

Doing business in China can lead to an unusual type of contractural risk. After the contract is signed, the Chinese may reopen discussion on a previous controversial item of negotiations (Pye, 1986). This is done because they consider the parties to now be old friends who can bring matters up anytime. Rather than leaving the reader thinking that a signed contract has little meaning to the Chinese, Pye concluded his article by stating that they place a great deal of value on loyalty, and they will uphold their side of an agreement while they are trying to get further concessions.

China's imperfect and arbitrary legal and regulatory systems pose constant operational problems for the foreign investors (American Embassy Beijing, 1988). There is hope for the future, as China has applied to participate in the General Agreement on Tariffs and Trade (GATT) and is working on bilateral investment treaties with its major economic partners.

The bilateral investment treaty with the United States has been stalled over Chinese unwillingness to provide adequate guarantees for U.S. investors. The Overseas Private Investment Corporation (OPIC) does provide political risk insurance for U.S. investors in China.

The oil potential of China's northwest basins is a case where political risk could be to the advantage of the foreign investor. Of China's estimated 12.6 billion barrels of proven plus probable oil, approximately 11 billion or 87 percent are within 350 miles of the USSR border (Meyerhoff, 1973). Part of the Soviet's motive for helping the Chinese explore for oil in the northwest basins from 1949 to 1961 was to develop reserves close to their border. China could obtain international insurance against a move by the USSR into these areas by allowing consortiums of multinational oil companies to explore, develop, and produce the petroleum reserves. This way the Soviets would face the wrath of not only China, but also of most developed nations by any transgression. Unfortunately, there is no indication that the Chinese share this view.

This study assumes an average 10 percent risk (5, 10, 20) of adverse political events hindering the remittance of expected profits from a profitable Chinese project to the home country of the foreign investor.

6.7 China Cash-Flow Model

Table 6 summarizes distributions and values of stochastic variables used in the China cash-flow model.

6.7.1 China Model Results

Figure 10 is the bar graph from @ RISK showing the distribution of net present value (NPV) from 1,000 iterations. The NPV's range from -$60.9 million to $319.6 million with a mean of -$2.3 million, compared to the -$13.5 million of the expected value case. The large discrepancy between the mean of the multiple iterations and the single value of the expected value case is caused by truncating losses at the amount of sunk costs after drilling the exploratory well and four appraisal wells. Otherwise losses as large as $252 million occur, which would not be allowed to happen in reality. Sixty nine percent of the cases have negative values, and the standard deviation is $43.6 million. Table 7 summarizes the results of simulation and sensitivity analyses.

The distribution of oil field size is recorded by @ RISK, ranging from 25 million to 2.2 billion, with the mean of 489 million, close to the expected value output of 485 million barrels. The wide range of values for both

Table 6

China Model Assumptions

Parameter	Distribution	Values
Geologic		
Area, Acres	Triangular	5,000; 6,900; 30,000
Net Pay, feet	"	30, 200, 525
Porosity	"	.08, .14, .17
Recovery Factor	"	.15, .25, .35
Water Saturation	"	.25, .33, .45
Depth, feet	"	3,500; 10,000; 22,000
Geologic Risk, 1:	"	3, 7, 11
Initial Production, bopd	"	500; 1,000; 6,000
Costs		
Seismic Costs $/km	"	8,000; 10,000; 12,000
Exploratory Drilling, $/ft	"	317, 600, 823
Appraisal Drilling, % of Exploration	"	80, 90, 100
Development Drilling, % of Exploration	"	60, 65, 80
Completion, $/ft	"	79, 150, 206
Production Facilities Base, $MM	Uniform	75,100
Production Facilities $MM/well	Uniform	1, 2
Pipeline Length, miles	Triangular	2,100; 2,500; 3,000
Operating, $M/well/ year	Uniform	80, 120
Fiscal		
Political Risk, %	Triangular	5, 10, 20
China Inflation, %	"	6, 10.5, 15
U.S. Inflation, %	"	3, 5, 7

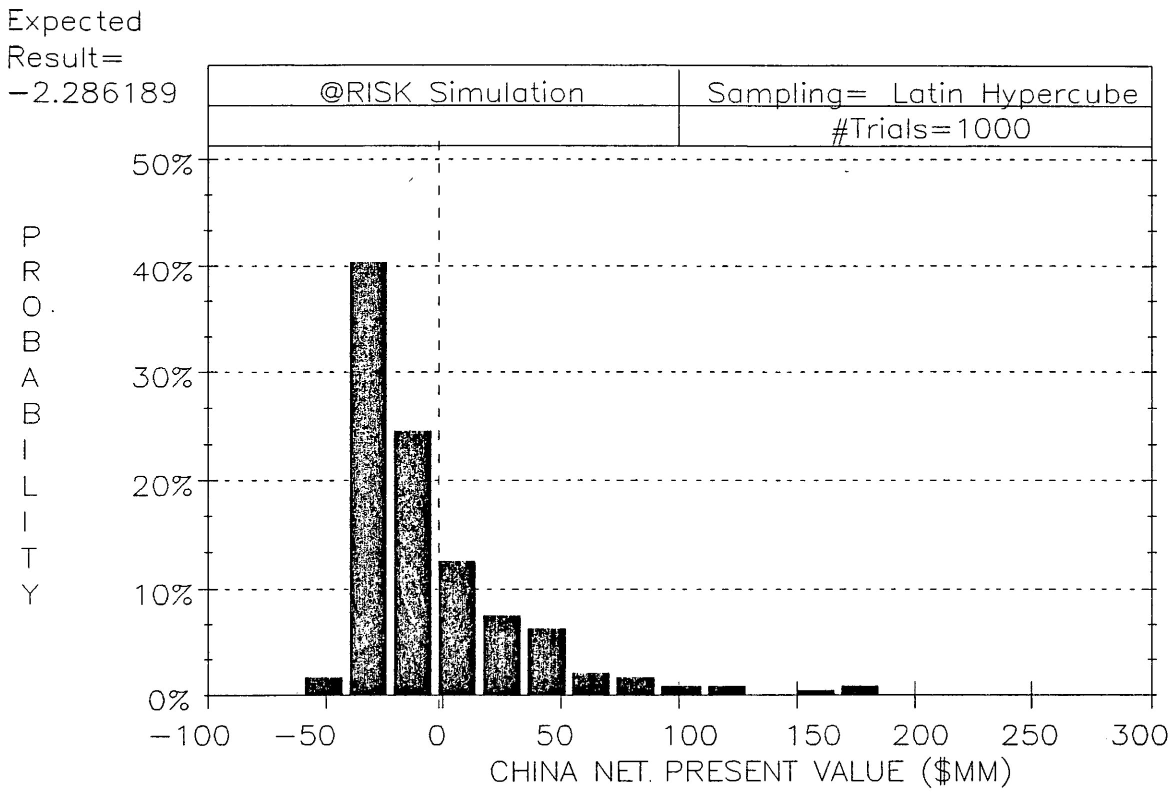

Figure 10. China Net Present Value Distribution

Table 7

China Model Results

Parameter	Expected Value Case	Simulation Min	Simulation Mean	Simulation Max
Base Case				
NPV, $MM	-13.5	-60.9	-2.3	320
(Std Dev = $43.6MM, 69.0% Negative)				
Oil, MM Bbl	485	25	489	2,200
DCFROR, %	8.3			
No Geologic Risk Case				
NPV, $MM	43	-114	114	1,970
(Std Dev = $263MM, 49.9% Negative)				
X Factors = 100 Case				
NPV, $MM	6.0			
DCFROR, %	10.7			
Breakeven (0 NPV) Geologic Risk Case				
Geologic Risk, 1:	2.88			

profitability and field size is an indication of the lack of precise information and resulting wide ranges of input variables.

Discounted cash flow rate of return (DCFROR) is 8.3 percent for the expected value case. The NPV of the expected value case with no geologic risk is $43 million. The mean NPV from simulation with no geologic risk is $114 million, but 49.9 percent of these cases still have negative NPV's. This suggests that the development and operating costs compared to the size of oil fields, not the success ratio, are the major concerns here. The NPV goes from positive to negative in the expected value case as the geologic risk is increased above 1:2.88 or 35 percent.

An additional sensitivity is conducted by setting all X factors at 100 percent. The resulting expected value results are NPV $6.0 million and DCFROR 10.7 percent.

6.7.2 Recommendations

It is recommended that exploration and petroleum projects in the northwest basins of China not be pursued, based on the current information available to the author and the resulting negative profitablilty expectations.

The simple sensitivity analyses conducted rule out negotiable government terms and geology as the main culprits of the lack of profitability. Setting the X factors to 100 percent or giving the government oil company no Share Oil and limiting their oil split to that of a normal working interest partner showed only marginal profits for the foreign investors. This attempted solution is probably impractical politically.

The negative NPV of the expected value case shows that an almost 500-million-barrel field is unprofitable, so the problem is not solely of small field sizes from imprecise geologic data. The necessary 35 percent or better success ratio is unrealistically high for a frontier region with so many unknowns.

The main problem seems to be the high level of development costs and the time delay between investment and production. Unrecovered development costs compounded annually at the allowed 9 percent interest rate increase in the expected value case, as the production available annually for this cost recovery is less than the added interest expense.

The fact that several international oil companies are eager to operate in these basins and that the government oil company is planning increased expenditures here in the near future indicate that not all firms share the view of this study. The discrepancy probably lies in the quality of cost data available to this author. Rather than conform to the positive evaluation of these firms by lowering input costs until the desired level of profitability is reached in the model, this study recommends that the project not be pursued. However, because of the magnitude of potential oil discoveries in northwestern China and the large uncertainties of input variables, eyes and ears should be kept open for any additional information, particularly on costs, that would give valid reasons for re-evaluating this case. A firm may consider forming a consortium with other similar sized firms and placing a joint representative in China to obtain information not otherwise available.

This negative recommendation does not apply to any other areas in China. Other regions, particularly those closer to population centers, would have lower investment and operating costs, thereby improving the project profitability. Expected oil field sizes, however, may be smaller. Therefore, a cash-flow model should be made for the particular area of interest before any investment decisions are made.

Chapter 7
ALGERIA CASE STUDY

Exploration interest in Algeria is based on 1) known major production (Algeria is a member of the Organization of Petroleum Exporting Countries, or OPEC), 2) a sparsely explored overthrust zone, and 3) recent petroleum legislation more favorable to foreign investors (Foreign Scouting Service, 1988a).

7.1 General Information

Algeria is the second largest country in Africa, covering almost 2.5 million sq km (920,000 sq mi), about one-third the size of the continental United States. (Bureau of Public Affairs, 1985). Three terrain zones are 1) a fertile coastal plain along the Mediterranean, 2) the mountain ranges of the Tellian Atlas and the Saharan Atlas and the intermediate high plateau, and 3) the Saharan Desert.

Algeria's population exceeds 20 million and is growing at an annual rate of 3.1 percent. The ethnic backgrounds are Arabs and Arabized Berbers. Over 99 percent are Sunni Moslems. Languages are Arabic, Berber, and French, with French being the official government language. Many of the people employed in travel-related businesses have a working-level use of the English language while most technical and managerial employees of Sonatrach, the Algerian state oil company, have an excellent command of English (Smith, 1988).

Algeria declared its independence from France on July 5, 1962, and formed a republic following the policy of "state capitalism" in which the government owns all major companies (Jaffe, 1988). The government is run by the sole political party, the National Liberation Front (FLN). Chadli Bendjedid was first elected president in 1979 (Bureau of Public Affairs, 1985) and appears to be headed for a third 5-year term (Anou, 1988).

Per capita Gross Domestic Product (GDP) was estimated at $2,645 for 1986, and the consumer price index was estimated to rise by 10 percent in the same year (American Embassy Algiers, 1987). The current exchange rate is 6.35 dinars per U.S. dollar (Wall Street Journal, 1989a) compared to an average of 5.02 dinars in 1985.

7.2 Case Study Site

This study (see Figure 11) is limited to an area of 80,000 sq km or 31,000 sq mi of the Saharan Atlas Mountains, which are a fold belt. The frontal thrust of the Saharan Atlas forms the southern limit of this area and the frontal thrust of the Tellian Atlas forms the northern limit. The Atlas High Plateau lies to the northwest of the

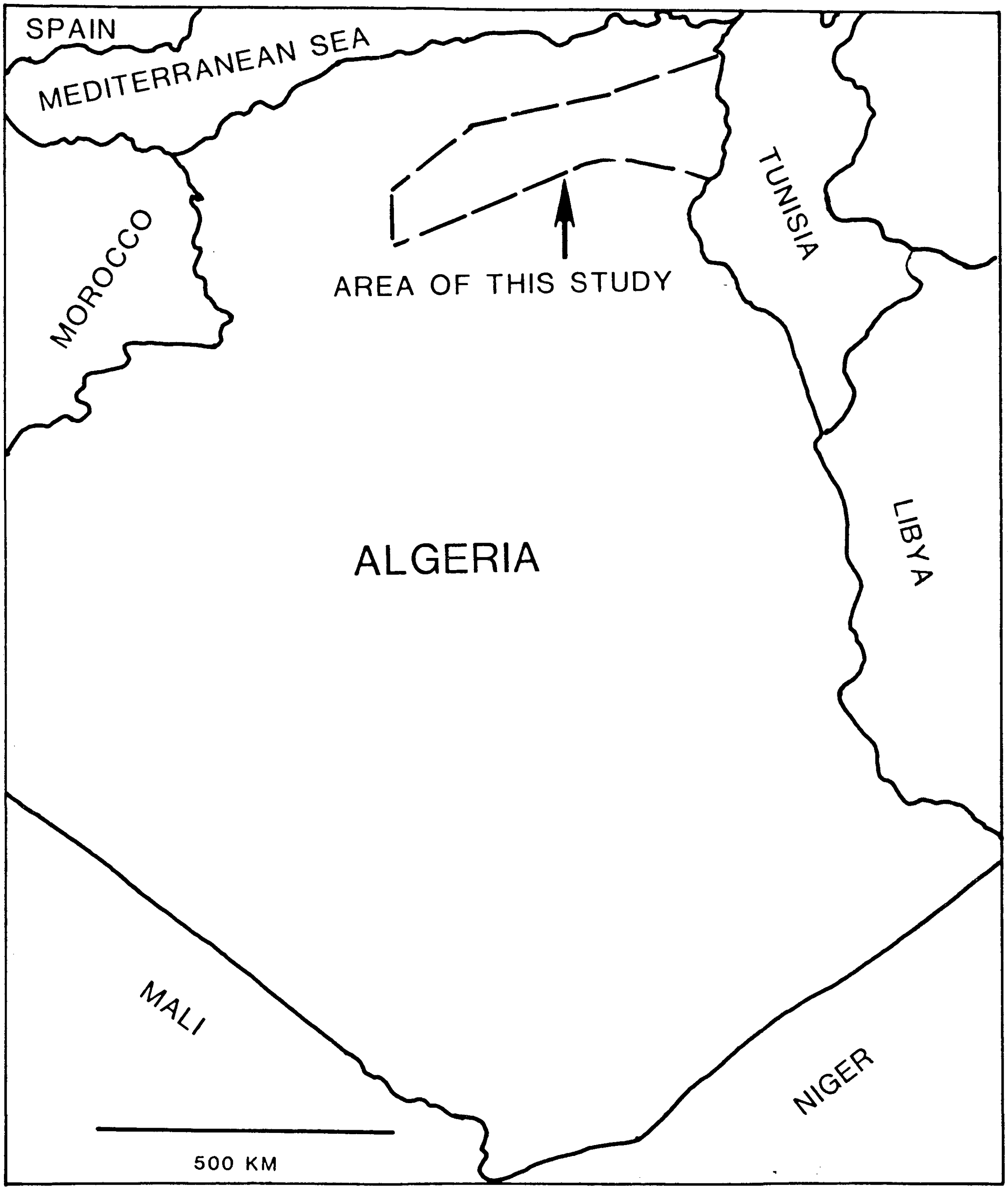

Figure 11. Algeria Index Map
Source: Sonatrach, 1988, Carte des Bassins.

study area. The eastern limit is the Algerian-Tunisian border, and the western limit is 2 degrees east latitude.

The western extension of the Saharan Atlas to the Algerian-Moroccan border was excluded because higher uplift and deeper erosion had removed most of the Mesozoic-age source and reservoir rocks on the structures (Service De La Carte Geologique, 1952). The study area lies entirely within Sonatrach District I.

7.3 Hydrocarbon Assessment

Most recent exploration within Algeria has been conducted by Sonatrach, and the results of these efforts have not been reported to service companies such as Petroconsultants' Foreign Scouting Service, but Sonatrach is very cooperative in making data available to individual companies that visit Algeria. Visitors on the first trip are given an overview of the geology and exploration results of the entire country. Maps showing the location of all wells, seismic lines, and oil and gas fields, and stratigraphic sections from the various basins are given to the visiting oil companies for their future reference. On subsequent visits the company narrows its area of interest, and seismic and well data are made available for review, with selected copies given for presentation to the company's management.

7.3.1 Past Exploration

The first significant discovery in the Algerian Sahara, which covers the Central Basin, was the Hassi er R'Mel gas discovery in 1956 (Magloire, 1970). An estimated 70 trillion cubic feet (TCF) of gas are contained within a Permo-Triassic sandstone reservoir. The super-giant oil field of Hassi Messaoud (25 billion barrel reserves) was also discovered in 1956 (Balducchi and Pommier, 1970). The reservoir is Cambrian-age sandstones on a domal structure. Following these early successes, most of the exploration in Algeria concentrated on the eastern half of the Algerian Sahara. A total of 77 oil fields and 54 gas fields have been discovered in Algeria, but none of the subsequent fields have even been in the giant class (Riva, 1984).

Djebel Onk is the only field producing from the Saharan Atlas. The field was discovered in 1959 on a surface anticline (Djeroumi, 1988). The reservoir is Senonian-age (Upper Cretaceous) limestones at a depth of 1,100 to 1,200 m (3,600 to 3,900 ft). Of the 32 exploratory wells drilled in this area of study, only Djebel Onk and a new discovery, GKN -1, made in October, 1988, have found commercial hydrocarbons (Djeroumi, 1988).

7.3.2 Current Production

Algeria, as a member of the Organization of Petroleum Exporting Countries (OPEC), has been one of the few countries to observe its production quota at 650,000 to 700,000 BOPD, largely because it would be hard pressed to significantly increase its output (Oil & Gas Journal, 1988b). Algeria's quota at the end of 1988 was 695,000 BOPD (Oil & Gas Journal, 1988d). A total of 840 wells in 44 oil fields produced an average 649,000 BOPD in 1987, for a cumulative 7.5 billion barrels by the end of 1987 (Oil & Gas Journal, 1988f). Secondary recovery through either gas or water injection has begun in about 85 percent of the fields (Riva, 1984).

Algeria is also a major producer of natural gas and natural gas liquids. These liquids fall outside of the OPEC production quotas. In 1983 gas production was almost 2 BCF of gas per day (Riva, 1984) and 300,000 barrels per day of natural gas liquids or condensate (Central Intelligence Agency, 1988). This liquid production had increased to an estimated 400,000 barrels per day in 1988 (Foreign Scouting Service, 1988d). Daily gas production is currently 10 BCF per day, with 35 or 40 percent used domestically or exported and the remainder flared or re-injected.

7.3.3 Petroleum Geology

The petroleum geology of the Saharan Atlas is largely unrelated to that of the highly productive Central Basin to the south. Table 8 shows the stratigraphic sequence of the productive area. The main source is the Upper Silurian shales, and the reservoir can be the sandstones of either the Lower Triassic or the Cambrian, all of which is capped by the Upper Triassic salt. This salt acts as the decollement surface on which the thrust sheets in the study area slide. Surface structures within the fold belt may or may not have any relationship to structure of the underlying Palezoic section. Only regional seismic lines of high quality will give structural information of these deeper rocks. The Cretaceous and Jurassic section is thickening northward into the Saharan Atlas to over 5,000 m (16,400 ft), which would place the Paleozoics below the geothermal oil window and at expensive drilling depths at most locations.

7.3.3.1 Source Rocks. The present location of the Saharan Atlas was the hinge line between platform carbonates to the south and basinal shales to the north during much of the Cretaceous (Djeroumi, 1988). Cutting samples from wells drilled in the area of the study have measured total organic content (TOC) ranging from 1.0 to 3.8 percent in

Table 8

Stratigraphic Section of the Central Basin, Algeria

Age	Thick, (ft)	Lithology	Remarks
TERTIARY			
Neogene	Thin	Continental	
Eocene	300-500	Limestone	
CRETACEOUS			
Senonian	300-1650	Limestone	Reservoir
Turonian	200-430	Limestone, shale	Reservoir
Cenoman.	175-650	Sandstone, shale limestone	Source
Aptian	50-100	Limestone, shale	
Neocom.	600-2400	Sandstone, shale, limestone	
JURASSIC			
Malm	300-2100	Sandstone, shale, limestone	
Dogger	900-1375	Salt, anhydrite, shale, limestone	
TRIASSIC			
Kueper	0-5300	Salt	Seal, Decollement
Muschelkalk	0-350	Carbonate, shale	
Bunter	0-650	Sandstone	Reservoir
PERMIAN	0-650	Sandstone,	Reservior
		Hercynian Unconformity	
CARBONIFEROUS	0-4250	Shale, sandstone	
DEVONIAN	0-3250	Sandstone, shale	
SILURIAN	150-2900	Shale, sandstone	Source
ORDOVICIAN	2300	Sandstone, shale	
CAMBRIAN	650	Sandstone	Reservoir

Source: Hamilton and Stoeckinger, 1974, Table A-8.

Cretaceous-age shales. A geothermal gradient of 1.67 deg C per 100 m places the top of the oil window at 2,200 m (7,200 ft) assuming 1,500 m of post-thrusting erosion (Hamilton, 1988).

7.3.3.2 Reservoir Rocks. Limestones of the Upper Cretaceous are the reservoirs at both Djebel Onk and GKN-1. Djebel Onk has a maximum of 150 ft of pay, while the GKN-1 discovery well has 150 m (490 ft) of fractured Turonian limestone averaging 10 percent porosity from a depth of 3,100 to 3,250 m or 10,170 to 10,660 ft (Djeroumi, 1988). Individual tests over unspecified intervals have flow rates as high as 2,000 BOPD with no water. The base of pay sets on Cenomanian-age shales, therefore the total hydrocarbon column is not yet known.

Triangular distributions used for reservoir parameters in this model are: thickness of pay in feet (150, 400, 500); porosity (.08, .10, .12); water saturation (.25, .33, .45); initial production rate in BOPD (1,000; 2,000; 5,000); and depth to pay in feet (3,500; 9,000; 15,000).

The lower limit of pay thickness is based on Djebel Onk (150 ft) being a marginally commercial field (Djeroumi, 1988). The most likely and maximum pay-thicknesses are inexact, with the one value at GKN-1 (490 ft) being the only control point. Porosities and water saturation values are based on general knowledge of carbonate reservoirs and the limited information from GKN-1. The initial production rates used are high because fractured carbonates are typically high-volume producers. The range includes the individual tests at GKN-1, the only control point. The range of depth to pay includes those of the two producers and is limited at the high end by the base of the geothermally determined oil window.

7.3.3.3 Traps. Structural traps are very easy to identify from surface geology in the study area. Surface anticlines of over 500 sq km (200 sq mi) can be seen on the regional geologic map (Service De La Carte Geologique, 1952). Djebel Onk, drilled on a surface anticline, is productive from 15 to 20 sq km or 3,700 to 5,000 acres (Djeroumi, 1988). A triangular distribution of 3,700, 5,000, 10,000 acres is used in the model for productive area. The lower end of this range is an economic limit, but the other values are inexact and probably conservative.

The timing of formation of the traps is one of the challenges of exploration in the area. The present day structures were formed by the thrusting and folding at the end of Eocene, or 38 millions years ago. Source rocks could have entered the oil window as early as 60 million years ago in Uppermost Cretaceous. Well control is too sparse-

32 wells in 31,000 sq. mi - to map paleo-structures. While a dense grid of seismic data exists in the desert-covered Paleozoic producing area to the south, the study area has very little seismic data, due primarily to the rough terrain and associated higher acquisition costs in the mountains. The seismic lines that have been shot in the study area are often too short (5 to 10 km) to be able to accurately map paleo-structures. A series of regional (50- to 100-km long) seismic lines would be the first step in understanding paleo-structures, and relating to present day structures.

The Upper Cretaceous shales which are considered to be the source rocks are also excellent seals where they are not eroded. This erosion of Cretaceous and even some Jurassic-age rocks in the western half of the Saharan Atlas is the main reason this area was excluded from the study.

7.3.3.4 Geologic Risk. Prior to the recent discovery at GKN-1, which was located on good seismic control, Djebel Onk was the only commercial field found from 31 wildcats. Therefore, the success ratio in the absence of regional seismic lines and geochemical data is assumed to be 1:31.

With the acquisition and proper interpretation of seismic and geochemical data, the individual geologic adequacies are estimated as trap .8, source .7, reservoir .75, seal .8, and timing of trap versus timing of oil migration as .3. Multiplying all of these factors gives a composite adequacy factor of .10 or a 1:10 geologic risk of making a commercial discovery. This study uses a triangular distribution of 1: 5, 10, 15 for geologic risk in the simulation.

7.4 Costs

Even though Algeria is a less developed country, costs are high because of the socialist political system and the resulting high labor costs. Algerian labor "is overprotected and overpaid, needs a lot of supervision, is low in efficiency, and takes excessive leaves" (American Embassy Algiers, 1988). Algerians are extremely status conscious and are willing to perform duties only within their job descriptions.

7.4.1 Exploration Costs

Work commitments made in petroleum agreements with the government specify a minimum amount of seismic acquisition and usually include the drilling of an exploratory well.

7.4.1.1 Seismic Costs. The only seismic crews currently operating in Algeria are state owned. Contractors have crews in Tunisia and Morocco that could be mobilized to Algeria for a flat fee of $200,000 (Dikoff, 1988). Crew operating costs would be around $700,000 per month.

Helicopter support, if necessary, would be extra. Production is estimated at 80 to 150 km per crew month.

A minimum work program includes a 200 km reconnaissance seismic program in the second contract year followed by a 200 km detail program the next year.

Total seismic costs in the reconnaissance and detail phases are calculated from multiplying crew costs per month ($600,000; $700,000; $800,000), by the length of each phase of the program in km (200, 250, 300), dividing by the crew production in km per month (80, 100, 150), and adding the mobilization fee of $200,000. The estimates were supplied by an experienced contractor, and appear to be reasonable, therefore the author feels confident in these cost estimates.

7.4.1.2 Exploratory Drilling Costs. Drilling penetration rates in the fold and thrust belt are one-half of the rates in the adjacent foreland of the desert. The BNM-1, a 3,890 m (12,760 ft) dry hole drilled in the fold belt near the town of Biskra, took 264 days from spud date to total depth for an average of 14.7 m per day (48.3 ft per day). By comparison the nearby SNJ-1 dry hole, drilled to 4,522 m (14,830 ft) in the foreland, took 173 days to reach total depth, for an average of 26.1 m per day (85.7 ft per day). Wells in the interior of the fold belt have had penetration rates as low as 36 ft per day. Steep dips, older rocks, and greater tectonic compaction slow the drilling in the thrust belt.

Daily rig costs from information in Pakistan of $20,000 per day for a 10,000 ft well (Deschamps, 1988) to $32,000 per day for a 16,0000 ft well (Chaulker, 1988) are also used in estimating costs in Algeria. Dividing the range of daily costs by the range of daily penetration rates results in exploratory dry hole costs of $233 to $865 per ft. Location costs are estimated at $500,000. A triangular distribution of costs per ft of $210, $540, $870 is used in the model. This wide of a range is believed to include most real possibilities.

<u>7.4.1.3 General and Administrative Costs</u>. The only way not to be overcome by Algerian bureaucracies and often contradictory regulations is to have a large local staff (American Embassy Algiers, 1988). A typical administrative office consists of four expatriate administrators, a secretary, an accountant, a financial consultant, and two lawyers, one for taxes and one for labor problems. Local administrative costs are estimated at $700,000 per year, with an additional $300,000 home office expense, and varied 20 percent (subjective) either side of this value.

7.4.2 Development and Production Costs

The successful explorer is faced with capital investment costs of developing the newly discovered field, and with operating expenditures.

7.4.2.1 Capital Costs. The costs of appraisal wells to casing point are estimated around 90 percent (80, 90, 100) of comparable costs of the exploratory well. Casing point costs of development wells are estimated around 71 percent (60, 65, 80) of the comparable costs of the exploratory well. These costs reductions are from an increased infrastructure in the area, and increased geological knowledge of the areas, allowing faster drilling with less danger of unexpected high pressure zones or lost circulation zones. Completion costs are assumed to be constant from exploratory to appraisal and development wells. The program allows the number of development wells drilled per year to vary from 6 to 12, 18, or 24, depending on the total number needed. Development dry hole risk is given a triangular distribution of 10, 15, 20 percent.

The cost of production facilities is extremely inexact, varying from \$100 to \$200 million (\$150 million most likely), depending on the amount of gas and water and their corrosive contents. These numbers are derived from those at Anschutz Ranch East field (Huzyk, 1988). Any additional information on gas and water compositions would be helpful in limiting the uncertainty of this large cost, and would make the economic evaluation more meaningful. Sensitivity analysis on this variable is made by changing the range to $50, $150, $400 million.

7.4.2.2 Expenses. Operating costs are estimated to be similar to those in Saudi Arabia (Koerner, 1989). Fixed operating costs are estimated around $3.75 (2.5, 3.75, 5.0) million per year, while variable operating costs are extimated around an additional $100,000 (80,000, 100,000, 120,000) per well per year. A significant part of these costs is payroll burden, estimated at three times payroll due to the socialist labor laws in Algeria.

7.4.3 Cost Escalation

The consumer price index has increased 9 percent in 1985, 10 percent in 1986, and a projected 11 percent in 1987 (American Embassy Algiers, 1987). The Algerian dinar per U.S. dollar exchange rate has slipped from 5.02 in 1985 to 6.36 at the end of 1988 (Wall Street Journal, 1988). This average 8 percent devaluation per year approximates the difference in inflation rates between the two countries. Therefore, the projected U.S. inflation rate of 5 percent (3, 5, 7) is used to escalate Algerian costs when expressed in terms of U.S. dollars.

7.5 Fiscal Terms

Algeria revised its petroleum legislation with Law 86-14 August 19th, passed on that date in 1986 (Enterprise Nationale Sonatrach, 1988). Through its constitution, the Algerian State has a monopoly on hydrocarbon exploration, production, and transportation. This law provides the framework whereby foreign entities may form joint ventures with Sonatrach.

The four acceptable types of agreements are partnership, production sharing, joint stock company, and service contract. Two characteristics common to all types of contracts are that the foreign company assumes all the exploration risk and that Sonatrach has a minimum of 51 percent of the production.

There is no such thing as a standard contract and all terms are negotiable (Djellali, 1988). All previous contracts are confidential, so negotiations covering a year or more are not uncommon in arriving at an agreement. Sonatrach has certain confidential guidelines that the contracts must meet, with areas in the western part of the country away from production having very generous guidelines, while areas nearer production have more stringent guidelines.

Algerian legal experts and tax authorities are necessary to determine what terms are possible under the various type of contracts, and which is most advantageous to the foreign firm. In this study the production-sharing contract will be used in evaluation because 1) most contracts signed recently are production sharing (Anou, 1988), and 2) in spite of the confidentiality of contracts, some details of Agip's and CEPSA's production-sharing contracts have been published, furnishing a starting point for contract terms (Oil & Gas Journal, 1988b).

The Agip and CEPSA agreements both cover blocks in the eastern Paleozoic producing area and have similar terms. The Agip agreement, signed at the end of 1987, is the first agreement under the new law. The foreign firm pays all exploration expense through the appraisal wells, and shares development expenses 50-50 with Sonatrach. All exploration expenses are recovered from production revenue. Oil production is shared 65-35 in favor of Sonatrach up to 15,000 BOPD, with a sliding scale to 87.5-12.5 over 75,000 BOPD.

Prior to 1986 Algeria had a reputation for sound and conservative financial management, but rising national debt from low oil prices and continued social programs has international bankers concerned (American Embassy Algiers, 1987). Some banks have halted medium-term lending, citing country limits. Therefore the recommeded new production-sharing contract does not have Sonatrach funding any of the development.

The petroleum contract blocks are divided into 3 categories: 1) Normal or zone N, which includes currently producing blocks; 2) Zone A, blocks adjacent to current production; and 3) Zone B, all other blocks, which are away from production (Enterprise Nationale Sonatrach, 1988). Royalties are 20 percent in Zone N, 16.25 percent in Zone A, and 12.5 percent in Zone B. Likewise, the income tax varies by the zone of operation: 85 percent in N, 75 percent in A, and 65 percent in B.

An attractive feature of the production-sharing contract is that Sonatrach pays the royalty and income tax on the entire production. Therefore the firm is not directly concerned with the Algerian tax rate, but will still have to pay U.S. income taxes, as the production share given to Sonatrach does not qualify for foreign tax credit (Slater, 1988).

If commercial gas quantities are discovered, Sonatrach gets to develop the field and receive all the production (Enterprise Nationale Sonatrach, 1988). The foreign firm does receive reimbursement of past expenses and a possible bonus. Transportation of hydrocarbons by pipeline can be done only by Sonatrach, which bears all transportation costs.

Oil cannot be sold at a price less than the price Sonatrach is receiving from their sales. The foreign firm is allowed to remit outside of Algeria the sum of net profits and depreciation.

This study assumes that 50 percent of the gross production is available for cost recovery of current expenses and unrecovered capital expenditures. In this model, Sonatrach will not fund any of the development costs, therefore the production split is shifted 5 percent to the foreign firm from the Agip and CEPSA agreements. The resulting split is 60-40 up to 15,000 BOPD, increasing to 82.5-17.5 above 75,000 BOPD, with the split still being in favor of Sonatrach.

7.6 Political Risk

Algeria enjoyed relative political stability from 1965 to the fall of 1986 (Bureau of Public Affairs, 1985). The country has had one political party, the Nationale Liberation Front or FLN, which was the leading force in the fight for independence from France from 1954 to 1962. In the 1960s the FLN eliminated all opposition, including those who disagreed with the party's socialist creed

(Ibrahim, 1988).

The economy is now in shambles because of continued socialist programs, low oil revenues, and the FLN's monopoly on the government. Seventy percent of the population is now under 24 years old, and these young people do not feel a strong loyalty to the party that gave the country its independence. The burgeoning population and economic problems mean that much of the population cannot be supplied with basic needs, such as ample food and running water (Revzin, 1988). The ruling elite still enjoy the good life and this has created a serious schism within the Algerian people.

Riots in Constantine in November 1987 were triggered by poor living conditions (New York Times, 1988). Much more severe riots in Algiers in October 1988 were over the same problem. The statement was made previously in this study that "the trigger for political risk is economic dissatisfaction." Algeria currently fits this description.

The political reforms undertaken by the FLN congress in Algiers on November 27-29, 1988, addressed many of these problems and the people appear to be willing to give President Chadli Bendjedid time to shift some of the political power from the FLN to representatives elected by the general public, and to shift the economy from being socialist-based to more free enterprise (Anou, 1988). The contents of the 1986 petroleum law and Sonatrach's eagerness to cooperate with foreign exploration groups are positive evidence that the Algerian government has already seen the need for more foreign investment in their economy. Therefore the contractural risk is considered to be low if there is not a revolutionary change in government in Algeria, which is estimated (subjective) at having a 5 percent chance of occurrence.

The main risk in Algeria appears to be operational. Riots and other civil disobedience add to the costs through work stoppages, added security expenses, destruction of material and facilities, and general delay in operations. An entirely subjective estimate of 10 percent operational risk would give a combined risk of 14.5 percent, or an 85.5 percent chance that projected cash flows could actually be realized. A triangular distribution for political risk of 5, 15, 20 percent is used in this model.

7.7 Algeria Cash-Flow Model

Table 9 summarizes the distributions and values of the stochastic variables used in the Algeria cash-flow model.

Table 9

Algeria Model Assumptions

Parameter	Distribution	Values
Geologic		
Area, acres	Triangular	3,700; 5,000; 10,000
Net Pay, feet	"	150, 400, 500
Porosity	"	.08, .1, .12
Water Saturation	"	.25, .33, .45
Depth, Feet	"	3,500; 9,000; 15,000
Geologic Risk, 1:	"	5, 10, 15
Initial Production, bopd	"	1,000; 2,000; 5,000
Costs		
Seismic Crew Costs, $M/month	"	600, 700, 800
Seismic Program, km	"	400, 500, 600
Seismic Production, km/month	"	80, 100, 150
Exploratory Drilling Costs, $/ft	"	210, 540, 870
Appraisal Drilling, % of Exploratory	"	80, 90, 100
Development Drilling, % of Exploratory	"	60, 65, 80
Production Facilities, $MM	"	100, 150, 200
Fixed Operating, $MM /year	"	2.5, 3.75, 5
Variable Operating, $M/well/year	"	80, 100, 120
Escalation, % /year	"	3, 5, 7
Fiscal		
Political Risk, %	"	5, 15, 20

7.7.1 Algeria Model Results

Figure 12 is the graphic display of the net present value or NPV of the Algeria model cash flows from 1,000 iterations. The NPV's range from $-13.3 million to $122.1 million with the mean of $27.9 million, compared to the single expected value of $26.9 million. Three percent of the cases have negative values. The standard deviation is $19.7 million. Table 10 summarizes the results of the simulation and sensitivity cases.

Field sizes range from 63 to 853 million barrels, with a mean of 311, extremely close to the single expected value of 309. Discounted cash flow rate of return (DCFROR) is 24.5 percent in the expected value case.

The mean NPV of simulations is $350 million with no geologic risk, and turns negative only after geologic risk is increased to more than 1:38. The standard deviation of NPV simulation with no geologic risk is $174 million.

Changing the production facility cost range from 100, 150, 200 ($ million) to 50, 150, 400 lowers the mean NPV from $27.9 million to $26.7 million and increased the percentage of negative cases from 3.0 to 4.3 percent. These small changes indicate that the profitability of this project is not very sensitive to cost changes of this magnitude.

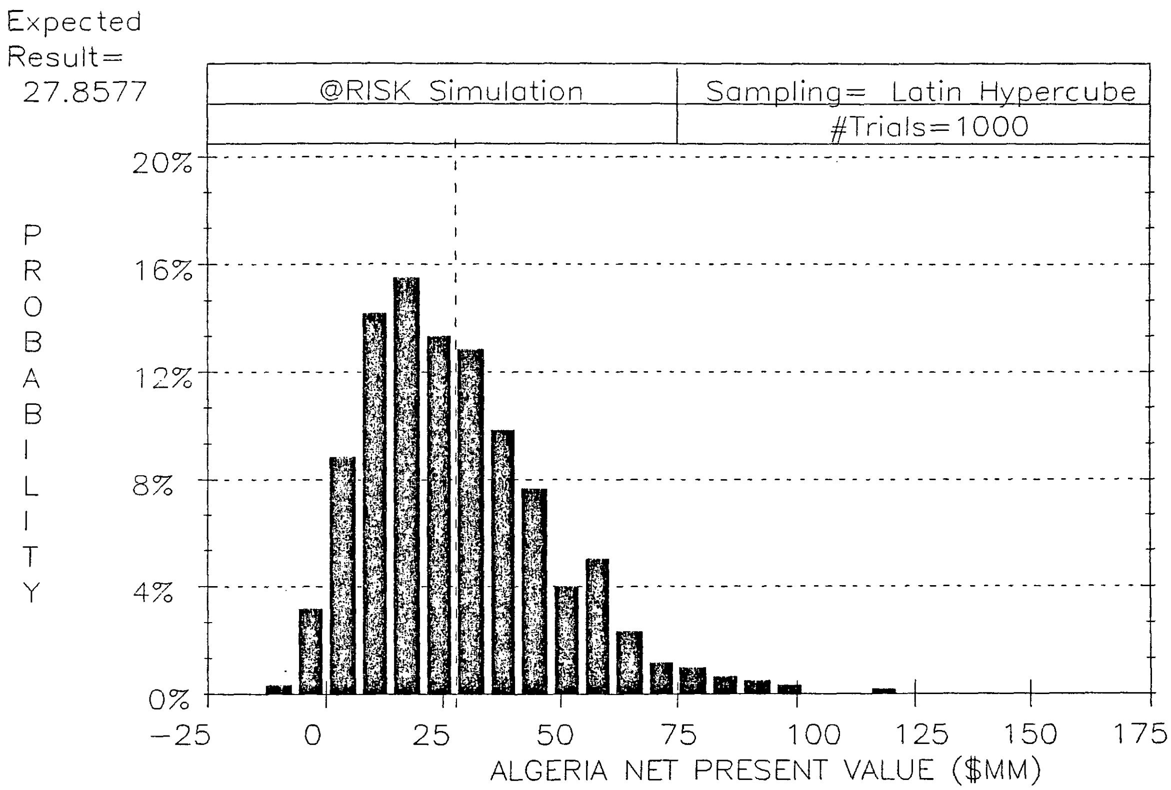

Figure 12. Algeria Net Present Value Distribution

Table 10

Algeria Model Results

Parameter	Expected Value Case	Simulation Min	Simulation Mean	Simulation Max
Base Case				
NPV, $MM	26.9	-13.3	27.9	122.1
(Std Dev = $19.7MM, 3.0 % Negative)				
Oil, MM Bbl	309	63	311	853
DCFROR, %	24.5			
No Geologic Risk Case				
NPV, $MM	355	-14.9	350	1,133
(Std Dev = $174MM, 0.1% Negative)				
Production Facilities, $MM (50, 150, 400) Case				
NPV, $MM	25.7	-16.1	26.7	143.1
(Std Dev = $20.9MM, 4.3 % Negative)				
Breakeven (0 NPV) Geologic Risk Case				
Geologic Risk, 1:	38			

7.7.2 Recommendations

It is recommended that the Algeria project be pursued, as it has a positive NPV over all reasonable ranges of geologic risk, assuming the use of adequate information.

7.7.2.1 Level of Working Interest. The maximum desired level of working interest determined from eq. (4.2) is

$$f \leq [30/(10 \times 9.58)]\,[350/(1.645 \times 174)]^2$$

$f \leq .47$ or 47 percent working interest, assuming a \$30 million multi-year budget, 1:10 geologic risk, \$9.58 million of discounted risk expenditures, and the desire for a 95 percent confidence level of a profitable exploration program. This case points to an example where the working interest should be less than, not equal to, the calculated value. On the average, exploration expenditures of \$95.8 million (10 projects x \$9.58 million per project) are needed to get one discovery. The working interest taken should be no more than the budget divided by the expenditure, or .31 (31 percent). Eq. (4.2) can be used without modification where the term in the second bracket is less than or equal to 1.0. Where that term is greater than 1.0, as in the Algeria case, the working interest should be determined as discussed here, which is in effect setting the value in the second bracket of eq. (4.2) equal to 1.0.

7.7.2.2 Level of Information. The optimal level of indirect information or seismic is calculated from eq. (4.3 - 4.5) with the following assumptions:

Cost per km of seismic = \$8000
Probability of success, no seismic = .03
Probability of success, 400 km = .1
Probability of success, infinite seismic = .25
NPV successful project = \$350,000,000

$$a = 1 - .03/.25 = .88$$

$$b = - \{\ln[(1 - .1/.25)/.88]\} /400 = .000957$$

$$x = -(1/.000957) \ln [8000/(.25 \times .88 \times .000957 \times 350{,}000{,}000)]$$

$$= 2320 \text{ km of seismic.}$$

This amount of seismic seems too high. This problem is similar to that of Pakistan. In a thrust belt with good surface geology, the value of additional seismic data does not increase exponentially, a key assumption of this methodology. Because of this problem, this methodology should not be used here to determine the optimal amount of seismic data. The knowledge base and intuition of the explorationist should be used here, as it has been in most cases in exploration. The recommended seismic program is two 100-km dip oriented lines in the reconnaissance phase followed by a detail program of 200 km over the most attractive structure seen on satellite photos and confirmed by the reconnaissance seismic.

Chapter 8

SUMMARY AND RECOMMENDATIONS

The purpose of this study, stated in Chapter 1, is 1) to evaluate the economic attractiveness of oil and gas exploration in specific areas of Pakistan, China, and Algeria, and 2) to serve as a guide for evaluating foreign exploration ventures by independent oil companies, which may not have previously explored internationally. The methodologies used and the results of the case studies, however, can be used by all sizes of companies, including the integrated or major oil companies.

The rapid and dramatic changes in oil prices from the early 1970s to the present underscore the need for strategic planning, reviewed in Chapter 2. Strategic planning is the development of plans to make the most of opportunities and minimize the threats of change in the business environment. A global assessment of opportunities is necessary for the exploration firm. The need to turn exploration efforts from domestic to international is based on economics. The current lower oil prices do not make the smaller fields remaining to be found in the mature producing areas of the United States profitable, but the larger fields remaining to be found internationally can still be explored, developed, and produced profitably.

Strategic planning determines the type of projects that the firm should invest in (international exploration in this study), but does not evaluate the individual projects. Only those projects which are expected to have a positive net present value (NPV) after risk adjustment are pursued. The NPV is calculated from the cash-flow model, determined from annual revenue less expenditures.

Very few input parameters in the cash-flow model are known precisely. The largest unknown is the chance of exploration finding a commercial hydrocarbon accumulation. Other uncertainties concern geologic reservoir parameters, political risks, and economic values. The cash-flow model is adjusted for these uncertainties by using a distribution and range for each variable rather than a point value. The Lotus 1-2-3 spreadsheet becomes a Monte Carlo simulator with the add-in program of @ RISK. Multiple iterations of the model are run to give a distribution of NPV's, rather than a single value.

8.1 Case Studies

Case studies of specific areas in Pakistan, China, and Algeria use the described methodology. The numerical results of these cases are summarized:

Case	NPV $ MM	DCFROR %	Calculated % working interest
Pakistan	29.6	15.1	26
China	- 2.3	8.3	0
Algeria	27.9	24.5	31

8.1.1 Pakistan Case Study

It is recommended that a hypothetical exploration company with a $30 million exploration budget spread over a three-year period take a 20 to 33.3 percent (1/5 to 1/3) working interest in a gas and gas-condensate project in Pakistan's Central Fold Belt. This level of working interest is based on 1) the 26 percent interest calculated from eq. (4.2), and 2) the knowledge that all calculations are approximate, rather than exact. This spreading of the firm's exploration expenditures over several projects increases the likelihood of the overall exploration program succeeding even though the majority of the individual projects may fail.

Gas reserves ranging from 100 BCF to 8.5 TCF can be expected from Cretaceous and Paleocene reservoirs. Expected oil or condensate volumes ranges from 200,000 to 240 million barrels. NPV's, assuming geologic risk varied from 1:2 to 1:6, range from $15 million loss to $500 million profit, with a mean value of $30 million profit. Almost 20 percent of these cases show losses.

Sensitivity analyses show that 1) the average case becomes uneconomic when geologic risk is increased above 1:16.7, 2) increase in political risk within reasonable limits has very little affect on expected profitability, and 3) the expected profitability is greatly increased by added liquid content of the gas.

8.1.2 China Case Study

It is recommended that a firm not invest in exploration in the northwestern basins of China, based on negative expected profitability of the cash-flow model. The Tarim and Junggar Basins of this area are considered by many in the oil industry to have the best potential for giant oil discoveries outside of the Middle East, but the large costs of exploring, developing, operating, and transporting oil from this remote region would cause many of these discoveries to be unprofitable.

One-half of all projects, assuming <u>no</u> geologic risk, have negative NPV's, even though the field sizes range from 25 million to 2.2 billion barrels, with a mean of 490 million barrels. Sensitivities show that improving fiscal terms improves profitability only slightly.

This negative recommendation does not apply to other areas of China. Projects in other areas should be modelled before any investment decision is made.

8.1.3 Algeria Case Study

It is recommended that a firm take a 25 to 33.3 percent (1/4 to 1/3) working interest in an oil exploration prospect in the eastern Saharan Atlas of Algeria. This recommendation is based on expected profitability of $30 million, assuming a geologic risk of 1:10 (varying from 1:5 to 1:15) and expected field sizes of 60 to 850 (mean 300) million barrels. Only 3 percent of these risked cases have negative NPV's.

Sensitivity analyses showed that profitability was only slightly diminished by doubling both the range width and maximum probable production facility costs. The average case becomes uneconomic only after geologic risk was increased to more than 1:38.

8.2 Other Applications of This Methodology

This study concentrates on international petroleum exploration, but the techniques used and thought processes discussed can be useful in other situations. If one of the firm's strengths is its superior understanding and resulting success in a domestic oil exploration play, its selected strategy will include continual investment in this play. The evaluation techniques can be used as presented, although the range of geologic, cost, and political risk parameters should be narrower than in the international cases.

The mining industry faces many of the same unknowns in exploration as does the oil and gas industry (Woodall, 1988). Mineral development also requires massive amounts of capital, making the evaluation of future price ranges, projected production rates, foreign cost factors, and political risk as important as in these case studies. The decision points in the mining industry from conception of prospect idea through exploration and appraisal to development may differ from those in the petroleum industry, and therefore the decision making process should be adjusted accordingly.

Research and development (R & D) face many uncertainties as does natural resource exploration, and exploration many even be thought of as a specialized form of R & D (Eggert, 1987; Woodall, 1988). The primary function of R & D is to provide future products for the firm. Long range strategic planning and risk evaluation should be as useful in this function as in the petroleum exploration business.

The correct evaluation of merger and acquisition target firms is dependent on reasonable estimates of future cash flows of the target firms (Ten Eyck, 1987). The uncertainties of the future can be bounded by scenarios, and then the ranges and distributions of all variables that impact the firm's future cash flows can be handled as in this study to arrive at a distribution of the net present value (NPV) of the firm.

The types and amounts of hazardous wastes expected to be found and their associated removal costs in environmental cleanups can be modeled by the methods presented in this study (Ryan, 1989).

All types of businesses could benefit from some level of strategic planning and the use of the basic principles of cash flow, discounting, and net present value.

8.3 Recommendations for Further Study

Questions on two areas of optimization have been raised in the author's mind during the course of this study and are suggested as topics for further study.

1. A substantial part of capital investments in a successful hydrocarbon project are made on production facilities and pipeline which are sized according to peak or initial production. In the models presented, the production rates start declining immediately, and therefore the full capacity of the installed production facilities is only used briefly.

Linear programming techniques exist for optimizing the size of an operation, given the certain values of revenue, costs, and constraints (Hesse and Woolsey, 1980). A method of utilizing stochastic variables as input parameters to a linear program or of incorporating a linear program as an integral part of the simulation model could result in a different production profile than used in this study and increase the calculated project value.

2. McCray's (1975) formula (eq. 4.2) for calculating the fractional participation in large ventures is affected by the standard deviation or degree of scatter in the calculated NPV's. The greater this scatter, the smaller working interest the firm should take because of the uncertainty in the expected profitability of the project. It is implied that some of the scatter is caused by negative NPV's, or losses. It is possible for a successful project to have a large scatter of NPV's, all positive.

It is suggested as a minor project that McCray's formula be re-worked to include the percentage of negative NPV's. @ RISK gives this value as well as the standard deviation from targeted variables in the simulation. The re-worked equation should avoid giving answers that are too high because of a small data scatter, such as in the Algeria case.

REFERENCES CITED

Adelman, M.A. 1970. Economics of exploration for petroleum and other minerals. _Geoexploration_ 8 (no. 3/4): 131-150.

Ahmad, Shahid. 1988. Speech given at Pakistan Ministry of Petroleum and Natural Resources presentation to the oil industry, Houston, Texas, 6 Dec.

Akbar, Syed. 1989. Bugti rides tall in Baluchistan. _The Muslim_ (Pakistan English newspaper). 18 Feb.

Alexander, Frank. 1988. Telephone interview with author, 25 March.

American Embassy Algiers. 1987. _Foreign economic trends and their implications for the United States and Algeria_. Washington D.C.: GPO.

_______. 1988. Object lessons from a U.S. project in Algeria. Telex to U.S. Department of Commerce. Washington D.C., March.

American Embassy Beijing. 1988. _Foreign economic trends and their implications for the United States - Peoples Republic of China_. Washington D.C.: GPO.

American Embassy Islamabad. 1987. _Foreign economic trends and their implications for the United States - Pakistan_. Washington D.C.: GPO.

Anou, Menouar. 1988. Interview with author, 28-30 Nov.

Argenti, John. 1986. Strategic planning short course material. Switchbrook, U.K.: Argenti Systems Ltd.

Armstrong, J. Scott. 1983. Strategic planning and forecasting fundamentals. In _The strategic management handbook_. Ed. Kenneth J. Albert: 2-1 to 2-32. New York: McGraw-Hill.

Arps, J.J., and T.G. Roberts. 1958. Economics of drilling for Cretaceous oil on east flank of Denver-Julesburg Basin. _American Association of Petroleum Geologists Bulletin_ 42 (no. 11): 2549-2566.

Barry, Kevin M. 1981. Quo vadis? Geophysical technology in the search for hydrocarbons. In Exploration and economics of the petroleum industry. Ed. Martha L. Landwehr. Vol. 19: 25-55. New York: Matthew Bender.

Balducchi, A. and G. Pommier, 1970. Cambrian oil field of Hassi Messaoud, Algeria. In Geology of giant petroleum fields, AAPG Memoir 14: 477-488. Tulsa: American Association of Petroleum Geologists.

Bilinski, Stanislaw K. and Renee S. Hancher. 1988. Marketing in Pakistan. Overseas business Reports OBR 88-0. Washington D.C.: GPO.

Blass, Walter P. 1983. Optimizing the corporate planning function. In The strategic management handbook. Ed. Kenneth J. Albert. 6-3 to 6-21. New York: McGraw-Hill.

Blinn, Keith W., et al. 1986. Comparative economic and fiscal analysis. Chap. 13 in International petroleum exploration & exploitation agreements. New York: Barrows.

Boyle Jr., H.E. and G.K. Schenck. 1985. Investment analysis: U.S. oil and gas producers score high in university study. Journal of Petroleum Technology (Apr.): 680-690.

Brealey, Richard and Stewart Myers. 1984. Principles of Corporate finance. 2nd. ed. New York: McGraw-Hill.

Broadman, Harry G. 1985. Incentives and constraints on exploratory drilling for petroleum in developing countries. Annual Review of Energy Vol. 10: 217-249.

Brunett, Tom. 1989. Interview with author, 7 Feb.

Bureau of Public Affairs, U.S. Department of State. 1985 Background notes - Algeria (Oct.) Washington D.C.: GPO.

Business Week. 1988. Why oil drillers are scouting far from home. 28 March: 72H-72J.

Capen, E.C., R.V. Clapp, and W.M. Campbell. 1971. Competitive bidding in high-risk situations. SPE-AIME paper 2993.

Carroll, A. et al. 1988. Reconnaissance of sedimentary organic matter and thermal-burial history, Junggar and Tarim basins, northwestern China. In Stanford-China geosciences industrial affiliates program 1988 annual review. Stanford, Calif.: Stanford-China Project Research Group.

Castleman, Breaux B. 1985. Strategies for exploration and production companies. In Exploration and economics of the petroleum industry. Ed. Janice R. Moss. Vol. 23; 12-1 to 12-19. New York: Matthew Bender.

Central Intelligence Agency. 1987. The world factbook 1987. Washington D.C.: GPO.

Chaulker, Bruce. 1988. Interview with author, 25 July.

Clausen, A.W. 1983. Let's not panic about Third World debts. Harvard Business Review 61 (no. 6):106-114.

Coleman, Robert G. 1988. Sutures and the Junggar Basin. In Stanford-China geosciences industrial affiliates program 1988 annual review. Stanford, California: Stanford-China Project Research Group.

Commodity Research Bureau. 1985. The commodity price trend. In CRB Commodity year book 1985. :5T. Jersey City, N.J.: Commodity Research Bureau.

Cooper, Bryan et al. 1981. Far East oil and energy summary 1981. Geneva, Switzerland: Petroconsultants.

Council of Economic Advisers. 1988. Implicit price deflators for gross national product. Economic Indicators (September): 2. Washington: GPO.

Crawford, Jay. 1988. Interview with the author, 28 June.

Currin, Kathleen A. 1986. Development of cost effective hydrocarbon exploration programs through optimization of exploration expenditures. Master's thesis, Colorado School of Mines, Golden, Colo.

Dawn Lahore Bureau. 1989. Canada offers help in power sector. Dawn (Pakistan English newspaper). 8 Feb.

Deschamps, B. 1988. Telex to author, 27 May.

Dikoff, Christo. 1988. Telephone conversation with author, 21 Dec.

Directorate General of New and Renewable Energy Resources. 1987. Energy year book 1987. Islamabad, Pakistan: Ministry of Petroleum and Natural Resources.

Directorate General of Petroleum Concessions. 1988. Pakistan: Review of hydrocarbon potential. Islamabad, Pakistan: Ministry of Petroleum and Natural Resources.

Djellali, Rached. 1988. Interview with author, 29 Nov.

Djeroumi, Zerrouk. 1988. Interview with author, 28-30 Nov.

Eckbo, Paul Leo. 1979. A basin development model of oil supply. In Advances in the economics of energy and resources. Ed. Robert S. Pindyck. Vol. 2: 39-58. Greenwich, Conn.: JAI Press.

Eggert, Roderick G. 1987. Class lecture, ME 580. Spring semester, Colorado School of Mines, Golden, Colo.

Enterprise Nationale Sonatrach. 1988. Technical and financial aspects of the Law 86-14 August 14th concerning activities of prospection, research exploration and pipe transportation of hydrocarbons. Algiers: Sonatrach.

Foreign Scouting Service. 1987. Pakistan. October. Geneva, Switzerland: Petroconsultants.

_______. 1988a. Algeria annual review - 1987. March. Geneva, Switzerland: Petroconsultants.

_______. 1988b. Far East summary - China. March. Geneva, Switzerland: Petroconsultants.

_______. 1988c. China annual review 1987. May. Geneva, Switzerland: Petroconsultants.

________. 1988d. Algeria - production. Nov. Geneva, Switzerland: Petroconsultants.

________. 1988e. Pakistan. Nov. Geneva, Switzerland: Petroconsultants.

________. 1989a. China. Jan. Geneva, Switzerland: Petroconsultants.

________. 1989b. Pakistan. Jan. Geneva, Switzerland: Petroconsultants.

Forman, John. 1988. Interview with author, 29 Feb.

Gargan, Edward A. 1988. China looks for help to keep its oil flowing. The New York Times. 16 May: C6.

Gee, Sherman. 1981. Technology, transfer, innovation, and international competitiveness. New York: John Wiley & Sons.

Gautier, Donald L. 1988. Strategy for development of Pakistan's hydrocarbon resources. In Petroleum for the future. Eds. Raza and Shiekh. 205-206. Islamabad, Pakistan: Hydrocarbon Development Institute of Pakistan.

Gehman, Harry M., Robert A. Baker, and David A. White. 1981. Prospect risk analysis. In Energy modeling III: Dealing with energy uncertainty. 231-245. Chicago: Institute of Gas Technology.

Guzman, Jaime. 1984. An application of financial economics and geostatistics to mineral exploration decision making. Ph.D. diss., Colorado School of Mines, Golden, Colo.

Hak, Shahid K. and Waquar Haider. 1988. Integrated framework for energy supply analysis. In Petroleum for the future. Eds. Raza and Sheikh. 317-341. Islamabad, Pakistan: Hydrocarbon Development Institute of Pakistan.

Halbouty, Michel T. 1981. Methods used and experience gained in the exploration for new oil and gas fields in highly explored (mature) areas. In Petroleum geology in China. Ed. John F. Mason. 132-141. Tulsa: PennWell Publishing Co.

Hall, William K. 1980. Survival strategies in a hostile environment. Harvard Business Review 58 (no. 5): 75-85.

Hamilton, Neil W. 1988. Inverview with the author, 5 Dec.

Hamilton, N.W. and W.T. Stoeckinger. 1974. Petroleum geology - economics Western Mediterranean - N.W. African region. Madrid, Spain: Petroleum Mediterraneo, S.A.

Hayat, Mahmood Aslam. 1988. Mari gas field - production and prospects. In Petroleum for the future. Eds. Raza and Sheikh. 183-199. Islamabad, Pakistan: Hydrocarbon Development Institute of Pakistan.

Hesse, Rick, and Gene Woolsey. 1980. Applied management science. Chicago: Science Research Associates, Inc.

Hongze, Huang. 1988. Seismic prospecting in the Zhungaer basin desert. Geophysics: The Leading Edge of Exploration. March: 16-22.

House, Karen Elliott. 1989. Communist giants are too burdened at home to lead much abroad. Wall Street Journal. 6 Feb., A1, A4.

Hydrocarbon News (Pakistan). 1988. International symposium on "Petroleum for future" 2 (no. 2): 2-5.

Huzyk, S.L. 1988. Anschutz Ranch facilities' expansion ups production. Oil & Gas Journal. 13 June: 35-38.

Ibrahim, Youssef M. 1988. Algerians now seeking power shift. New York Times. 27 Nov.

Ignatius, Adi. 1988. Foreign firms hiring workers in China hit a Catch-22: Obstinate ex-employers. Wall Street Journal. 30 March.

International Petroleum Encyclopedia. 1985. China opens doors to equipment, technology.: 7-33. Tulsa: Pennwell Publishing.

Ivanhoe, L.F. 1980. Evaluating petroleum exploration activities in foreign countries. Oil & Gas Journal. 5 May: 342-349.

_______. 1985. Oil discovery rates and projected discoveries of the free world. In Exploration and economics of the petroleum industry. Eds. Janice R. Moss. Vol. 23: 4-1 to 4-61. New York: Matthew Bender.

Iwamoto, Bryan. 1988. The miracle of Daquing. Geophysics: The Leading Edge March: 26-30.

Jaffe, George. 1988. The background to the riots in Algeria. Middle East International. 21 Oct.

Jonchere, Jean-Pierre. 1987. LNG and the domestic market: How attractive are they for producing countries in the Pacific Area? Paper read at conference, Asia-Pacific conference on gas market, Jakarta, Indonesia. Oct.

Kazmi, Ali H. and Riaz A. Rana. 1982. Tectonic Map of Pakistan, 1:2,000,000. Islamabad, Pakistan: Geological Survey of Pakistan.

Kempe, Frederick. 1988. Pakistan's Zia sees turmoil for Afghanistan. Wall Street Journal. 15 April: p. 22.

Kexiang, Li. 1986. Penetration rates increase in deep Chinese wells. Petroleum Engineer International Sept.: 60-63.

Khan, Abdul Majid. 1989. Energy and role of oil and gas in Pakistan. The Muslim (Pakistan English newspaper). 19 Feb. A9.

Khan, Aman R. 1988. Natural gas utilization and demand management in Pakistan. In Petroleum for the future. Eds. Raza and Sheikh. 253-269. Islamabad, Pakistan: Hydrocarbon Development Institute of Pakistan.

Khan, Mahmood Ali, and Masrur Ahmad. 1988. Status of gas exploration and development in Pakistan. In Petroleum for the future. Eds. Raza and Sheikh. 159-166. Islamabad, Pakistan: Hydrocarbon Development Institute of Pakistan.

Khan, Yunis. 1988. Interview with author, 2 Aug.

Khin, Jimmie Aung. 1988. Its starting to warm up out here. World Oil August: 101-113.

Koerner, Hal. 1989. Interview with author, 30 Jan.

Kundi, Ayub Khan. 1988. Interview with author, 18 Mar.

Kuuskraa, Vello A., Frank Morra, Jr., and H. William Hochheiser. 1985. Replacement costs of domestic crude oil. In Economics and the explorer. Ed. Robert E. Megill. 5-25. Tulsa: American Association of Petroleum Geologists.

Lax, Howard L. 1983. Political risk in the international oil and gas industry. Boston: International Human Resources Development Corporation.

Leung, Julia. 1988. Beijing orders cuts in investment. Wall Street Journal. 10 Oct.: A8.

Lichtblau, John H. 1987. Major's role in U.S. exploration and production will continue to shift. Oil & Gas Journal. 9 Nov.: 35-38.

London Observer Service. 1989. Pakistani mullahs call for ouster of Bhutto. Rocky Mountain News. 4 March: 52.

Lyons, James F. 1983. Strategic management and strategic planning in the 1980's. In The strategic managment handbook. Ed. Kenneth J. Albert. 3-1 to 3-18. New York: McGraw-Hill book Co.

Magloire, Philippe R. 1970. Triassic gas field of Hassi er R'mel, Algeria. In Geology of giant petroleum fields, AAPG Memoir 14: 489-501. Tulsa: American Association of Petroleum Geologists.

Mahmood, Ashfaq, and Mohammad Akram. 1988. Petroleum sector investment requirements of Pakistan. In Petroleum for the future. Eds. Raza and Sheikh. 303-316. Islamabad, Pakistan: Hydrocarbon Development Institute of Pakistan.

Malik, Zakauddin et al. 1988. Petroleum potential and prospects in Pakistan. In Petroleum for the future. Eds. Raza and Sheikh. 71-99. Islamabad, Pakistan: Hydrocarbon Development Institute of Pakistan.

Mandel, Thomas F. 1983. Future scenarios and their uses in corporate strategy. In The strategic managment handbook. Ed. Kenneth J. Albert. 10-1 to 10-21. New York: McGraw-Hill.

McCormick, Sanford E. 1985. What is needed for the independent to survive and prosper in today's difficult environment and why so many did not. In Exploration and economics of the petroleum industry. Ed. Janice R. Moss. Vol. 23: 3-1 to 3-37. New York: Matthew Bender.

McCray, Arthur W. 1975. Petroleum economics and economic decisions. Englewood Cliffs, N.J.: Prentice-Hall.

McNally, Rick. 1988. 106 international deep wells drilled for less than $1 billion. Petroleum Engineer International June: 16-23.

McQueen, Cheryl. 1988. Telephone interview with the author, 22 Nov.

Megill, Robert E. 1985. Long-range exploration planning. Tulsa: PennWell Publishing.

_______. 1988a. Oil "busts" getting longer, more severe. In The business side of geology. 2.5-2.6 Tulsa: American Association of Petroleum Geologists.

_______. 1988b. Figure field size distribution quickly. In The business side of geology. 4.1-4.2. Tulsa: American Association of Petroleum Geologists.

Meyerhoff, A.A. 1973. Geopolitical implications of Russian and Chinese petroleum. In Exploration and economics of the petroleum industry. Ed. Virginia S. Cameron. Vol. 11: 70-127. New York: Matthew Bender.

Ministry of Petroleum & Natural Resources. 1987. A proposal on petroleum policy and the measures to increase the level of petroleum exploration and development by the international petroleum industry in Pakistan. Islamabad, Pakistan: Government of Pakistan.

_______. 1988a. Model petroleum concession agreement. Islamabad, Pakistan: Government of Pakistan.

_______. 1988b. Rules and tax regulations. Islamabad, Pakistan: Government of Pakistan.

_______. 1988c. Technical discussion of concession areas. Islamabad, Pakistan: Government of Pakistan.

Mittman, Robert. 1988. A simple model of oil prices. International Association for Energy Economics Newsletter (1): 3.

Moran, Theodore H. 1988. Shaping a future for foreign direct investment in the Third World. The Washington Quarterly (Winter): 119-130.

Nancarrow, W.G. 1982. International exploration agreements: The pressure for change. In Exploration and economics of the petroleum industry. Ed. Martha L. Landwehe. Vol. 20: 203-216. New York: Matthew Bender.

Naylor, Michael E. 1983. Planning for uncertainty: The scenario-strategy matrix. In The strategic management handbook. Ed. Kenneth J. Albert: 22-1 to 22-11. New York: McGraw-Hill.

New York Times. 1988. A long march to change for modern-day Algeria. 27 Nov.

Newendorp, Paul D. 1975. Decision analysis for petroleum exploration. Tulsa: Penn-Well Books.

Office of Technology Assessment. 1987. Technology transfer to China. Washington D.C.: GPO.

OGDC Archives. 1988. Data review by author, 12-15 Sept.

Oil & Gas Journal. 1987a. EIA: 5.5 million b/d possible in China. 3 Aug.: 62-64.

_______. 1987b. Chevron: OPEC to dominate to 2000. 26 Oct.: 86-87.

_______. 1988a. U.S. and OPEC need to better in their key oil market roles. 25 Jan.: 15.

_______. 1988b. North African producers cooperate to improve outlook. 20 June: 52-55.

________. 1988c. China's pipeline construction picks up. 29 Aug.: 22-23.

________. 1988d. Decline cited in U.K. oil production costs. 14 Nov.: 30.

________. 1988e. Market alert for start of OPEC oil cut. 5 Dec.: 20-21.

________. 1988f. Worldwide production. 26 Dec.: 50-89.

________. 1989a. China search pays off in Tarim basin, other areas. 2 Jan.: 18-19.

________. 1989b. Most OPEC member's production capacities slip. 9 Jan.: 29.

________. 1989c. Consultant sees $12-15 /bbl average OPEC price in 1989-90. 16 Jan.: 15.

________. 1989d. Higher world demand, new OPEC quota are encouraging signs. 30 Jan.: 61.

Overseas Private Investment Corporation. 1988. <u>Investment insurance handbook</u>. Washington: OPIC.

Pan, Percy. 1987. Interview with author, 8 July.

Petrick, Alfred Jr. 1985. Mineral investment and finance. In <u>Economics of the Mineral Industries</u>. Ed. W.A. Vogeley, 4th ed.: 227-301. New York: AIME.

<u>Petroleum Economist</u>. 1989. Conversion factors used in oil industry. (Jan.): 45.

Porth, H. et al. 1987. <u>Results of organic geochemical analyses on surface rock samples</u>. Islamabad, Pakistan: Hydrocarbon Development Institute of Pakistan.

Prager, Allan J., and Mary Beth Shea. 1983. The strategy audit. In <u>The strategic managment handbook</u>. Ed. Kenneth J. Albert. 8-1 to 8-15. New York: McGraw-Hill.

Proehl, Thomas S. 1985. Political risk analysis in large scale mineral investments. Ph.D. diss., Colorado School of Mines, Golden, Colo.

Pye, Lucian E. 1986. The China trade: Making the deal. Harvard Business Review 64 (no. 4):74-80.

Quick, Allen N. and John R. Schuyler. 1988. An expert system for strategic planning. Oil & Gas Journal. 8 Aug.: 75-79.

Raza, Hilal A. and Arshad M. Sherkh (Eds.). 1988. Petroleum for the future. Islamabad, Pakistan: Hydrocarbon Development Institute of Pakistan.

Revzin, Philip. 1988. North Africa's cities, full of jobless youths, cast shadow on Europe. Wall Street Journal. 3 Nov.: A1, A17.

Ritchie, W. 1986. Role of the 3D seismic technique in improving oilfield economics. Journal of Petroleum Technology July: 777-786.

Riva, Joseph R., Jr. 1984. North African petroleum: Congressional Research Service. Report No. 84-216 SPR. Washington D.C.: GPO.

_______. 1986. The petroleum endowment of the People's Republic of China. Congressional Research Service Report No. 86-102 SPR. Washington D.C.: GPO.

Rose, Peter R. 1987. Dealing with risk and uncertainty in exploration: How can we improve? American Association of Petroleum Geologists Bulletin 71 (no. 1): 1-16.

Ryan, Joseph D. 1989. Interview with author, 8 March.

Sawhill, John C. 1983. How to rescue strategic planning in energy. Oil & Gas Journal. 28 Feb.: 90-92.

Scott, R.W. 1982. Oil and gas in China. In Exploration and economics of the petroleum industry. Ed. Martha L. Landwehe. Vol. 20: 101-111. New York: Matthew Bender.

Sebastian, Pamela. 1989. Consumer price rise of 0.5% is projected for February following January gain. Wall Street Journal. 20 March: A2.

Self, Sam. 1988. Interview with author, 22 July.

Service De La Carte Geologique. 1952. _Carte geologique de L'Algerie_. Scale 1:500,000. 2nd ed. Algiers,: Gouverenmant General De L'Algerie.

Slater, Craig. 1988. Internal Anschutz memo to author, 19 Dec.

Smith, William H. 1988. Sixteen years personal experience in oil exploration.

Sonatrach. 1988. _Carte des bassins_. Algiers: Sonatrach.

Soulsby A. and Arif Kemal. 1988a. A review of exploration activity in Pakistan. _Oil & Gas Journal_. 21 Nov.: 56-58.

_______. 1988b. Source rock maturity key to new plays. _Oil & Gas Journal_. 28 Nov.: 81-83.

Stanford-China Project Research Group. 1988. 1988 annual review. Stanford, Calif.: Stanford University.

Stermole, Franklin J. 1984. _Economic evaluation and investment decision methods_. 5th ed. Golden, Colo.: Investment Evaluation Corp.

Tainsh, H.R., K.V. Stringer, and J. Azad. 1959. Major gas fields of West Pakistan. _Bulletin of the American Association of Petroleum Geologists_ 43 (no. 11): 2675-2706.

Ten Eyck, Diana. 1987. Class lecture in ME 545. Spring semester, Colorado School of Mines, Golden, Colo.

Thompson, Robert S. and John D. Wright. 1985. _Oil Property Evaluation_. Golden, Colo.: Thompson-Wright Associates.

Times atlas of the world. 1983a. China and West Pacific, Plate 17. New York: Times Books.

_______. 1983b. Pakistan, Plate 31. New York: Times Books.

True, Warren R. 1986. Interstate systems reflect industry slowdown in 1985. _Oil & Gas Journal_, Pipeline economics report. 24 Nov.: 39-69.

_______. 1988. New construction up; revenue incomes continue to decrease. Oil & Gas Journal, Pipeline economics report. 28 Nov.: 33-64.

Truell, Peter. 1988a. Debt cure hinges on reactions to Brazil. Wall Street Journal. 5 Feb.: 12.

_______. 1988b. Since '87 loss reserves, Latin debt crisis has grown. Wall Street Journal. 19 May: 6.

Wall Street Journal. 1988. Treasury bonds, notes, & bills. 6 Dec.: C17.

_______. 1989a. World value of the dollar. 9 Jan.: C19.

_______. 1989b. World value of the dollar. 13 Feb.: C17.

Walpole, Ronald E. and Raymond H. Myers. 1985. Probability and statistics for engineers and scientists. 3rd ed. New York: MacMillan.

Walsh, Mary Williams. 1988. Pakistan waits to see if president's death brings martial law. Wall Street Journal. 22 Aug.: P 1.

White, Loring P. 1981. Estimating the value of multiple perspectives in exploration. In Energy modeling III: Dealing with energy uncertainty: 261-265. Chicago: Institute of Gas Technology.

Wilson, Ian. 1983. Time benefits of environmental analysis. In The strategic managment handbook. Ed. Kenneth J. Albert.: 9-1 to 9-19. New York: McGraw-Hill.

Wood, P.W.J. 1980. The future availability of petroleum worldwide. In Exploration and economics of the petroleum industry. Ed. Martha L. Landwehr. Vol. 18: 1-45. New York: Matthew Bender.

Woodall, Roy. 1988. The role of mineral exploration toward the year 2000. Geophysics: The Leading Edge of Exploration Feb.: 35-37.

Xiao, Z., et al. 1988. Sandstone provenance studies, north Turpan basins, Xinjiang. In *Stanford-China geosciences industrial affiliates program 1988 annual review*. Stanford, California: Stanford - China Project Research Group.

Zakariya, Hasan S. 1987. Political risks of transnational petroleum investment: The mitigating role of national and international insurance programmes. *OPEC Review* (Spring): 1-23.

Zoba, Tim Jr. 1987. International exploration prospects. Paper read at meeting, Denver International Petroleum Society. 4 Nov.

Appendix A

INFORMATION SOURCES

The addresses and phone numbers of the organizations and firms mentioned should be useful to anyone contemplating their first foreign exploration venture.

Libraries are inexpensive sources of information, and as such should be considered the first source. Personal or company libraries may include recent issues of publications as the Oil & Gas Journal, World Oil, and professional society bulletins from the American Association of Petroleum Geologists (AAPG), the Geological Society of America (GSA), and the Society of Exploration Geophysicists (SEG). Articles in these publications include both regional and specific area subjects.

Colorado School of Mines Library
14th and Illinois Street
Golden, Colorado 80401
Telephone: (303) 273-3000

The Arthur Lakes Library contains over 233,000 pieces of technical data, of which about 114,000 are maps. Many of these maps are on Colorado and other parts of the western United States, but geologic maps of many foreign countries are also available. A lesser number of geophysical maps, particularly gravimetric and magnetic, are on file. Books and reports on geology, petroleum geology, and petroleum production are available and useful.

Special borrower cards are available for a fee for Colorado residents who are not students, faculty, or staff of the Colorado School of Mines. For an additional fee computerized searches such as Bibilography and Index to Geology or Petroleum Abstracts can be conducted. The result is a printout bibliography of citations to articles, conferences, patents, dissertations, and technical reports on the desired subject. The reference librarian can assist in this activity.

U.S. Geological Survey Library
Stop 914, Box 25046
(Building 20, 6th Avenue and Kipling Street)
Denver Federal Center
Denver, Colorado 80225
Telephone: (303) 236-1000 Reference

The USGS Library is another source for explorationists in the Denver area. Access to and the availability of data is more restricted than at the Mines library. Individuals may review data in the library, but cannot check out the material. Loans are only made to other libraries, including company libraries. Data availability is hindered by the fact that USGS employees may check out materials indefinitely.

Any listing of information service companies is incomplete, but the author has found the following companies useful sources of information. Such a listing, however, does not constitute an endorsement, nor does the omission of other companies have any negative connotations.

Petroconsultants S.A.
8-10, Rue Muzy-1211
Geneva 6, Switzerland
Telephone: (22) 368811
Telex: 27763 PETRCH
Telfax: 862852

or

Petroconsultants Inc.
2 Houston Center, Suite P-330
909 Fannin Street
Houston, Texas 77010
Telephone: (713) 654-1368
Telex: 4620521 PETCON
Telefax: 6501783

or

1658 Cole Blvd. Suite 135
Golden, Colorado 80401
Telephone: (303) 237-3020

Petroconsultants offers many information services to an international petroleum exploration firm. These include monthly scouting reports, specialized petroleum geology reports, an exploration target service, economic data, computerized mapping, economic analyses, and country compendia.

Foreign Scouting Service was the origin of Petroconsultants, and is the base from which many of their other services are built. This service is a monthly scouting report covering the changes in petroleum exploration rights, exploration activity, exploratory drilling, development drilling, and production of each country. Additionally, a review and activity synopsis map are issued twice a year. This service cannot be purchased for each country separately, (except for Australia), but must be purchased by regions. These regions are:

Latin America
Northwestern Europe Offshore
Europe
North Africa
Central and Southern Africa
Near East
Far East
Australia

Special reports on petroleum geology may cover a single basin, a group of basins, or an entire country. No regular pattern exists to the issuing of these reports, but is determined by level of exploration interest in an area and the availability of other up-to-date reports. Subjects include stratigraphy, tectonic history and structure, exploration history, petroleum occurrence, and the resulting recommended prospective areas.

These two above-mentioned reports give Petroconsultants an unparalleled data base from which they can produce other information services. Combining the changes in petroleum exploration rights from the Foreign Scouting Service with the petroleum geology information results in the Exploration Targets Service. This annual report can be purchased for each of five regions of the world. More than 250 selected "most attractive" basins in 75 countries (outside the United States) are covered.

Economic data available from Petroconsultants include Cost Estimator, Country Petroleum Risk, and Petroleum Contracts Service. Cost Estimator is a new service available in five regions of the world, with annual updates expected. Costs covered are exploration, development investment and operating, with many sub-categories as a function of depth to pay and water depth or terrain. The Estimator consists of an instruction manual and floppy disk for use on IBM PC and compatibles.

Country Petroleum Risk lists and compares 30 political risk variables and 20 criteria impacting the exploration/production environment in each of 90 countries.

Petroleum Contracts Service is available on a country-by-country basis for each of 25 countries currently. Contractural and taxation terms are analyzed in a consistant format that aids country-to-country comparisons.

Petroconsultants has digitized 1:50,000 scale maps of most of the world. From this cartographic data base, called

Mundo Cart, maps at any scale, showing any combination of co-ordinates, boundaries, physiographic and cultural features, and petroleum information, can be made.

GIANT is the international petroleum economics software designed by Petroconsultants for use on IBM-PC/XT and compatible computers. Input parameters are provided by Cost Estimator, Petroleum Contracts Service, and the user. Output is in the form of a spreadsheet, allowing sensitivity cases by varying input parameters.

The Oil and Gas Compendia allows a company to purchase parts or all data packages individually on more than 140 countries.

Robertson Research International Ltd.
Llandudno, Gwynedd LL30 1SA
United Kingdom
Telephone: (0492) 81811
Telex: 61216 (ROBRES G)
Telefax: (0492) 83416

or

Robertson Research (U.S.) Inc.
Post Oak Tower, Suite 660
5051 Westheimer Road, Suite 660
Houston, Texas 77056
Telephone: (713) 622-9568
Telefax: (713) 622-9713

Robertson Research sells non-exclusive geological reports. As interest in an area increases, Robertson determines if there are enough potential purchasers to cover the investment of researching and writing the report. The report may be limited to a single basin, or country, or cover a larger region. Robertson's specialties are source rock and stratigraphic studies, but their reports often include additional subjects as exploration history, structural geology, and petroleum legislation.

<u>Barrows Company, Inc.</u>
116 East 66th Street
New York, N.Y. 10021
Telephone: (212) 772-1199
Telex: 4971238/Barrows

Barrows publishes legislative and taxation references for the international energy industry. Basic Oil Laws & Concession Contracts contain in English the complete text of oil laws, contracts and concessions in all countries. The reports are divided into seven regions:

1. Middle East
2. Europe
3. North Africa
4. South & Central Africa
5. Central America & Caribbean
6. South America
7. Asia & Australia

This report is up-dated by regular supplements.

Some consultants or consulting groups research areas or regions of interest to exploration companies and offer the reports for sale. These groups advertise their reports in trade journals, such as the <u>Oil & Gas Journal</u>, at exhibit booths at professional society conventions, and in mailed flyers to all companies listed in trade directories as having international exploration groups.

Study groups composed of a university geology department, and funded by industry participants are benefical to both sides. The university provides research-oriented staff who guide graduate students in research and interpretational projects. The industry funding provides much needed financial support for the project and for the university staff. In return the industry participants receive the latest information on high quality research, often unavailable in all but the largest corporations.

<u>Paleogeographic Atlas Project</u>
University of Chicago
Department of Geophysical Services
5734 South Ellis Avenue
Chicago, Illinois 60637
Dr. Fred Ziegler
Telephone: (312) 702-8146

The Chicago project reconstructs Mesozoic - Cenezoic continental plates, and combines over 45,000 measured lithofacies to construct paleo-lithofacies maps. Plate reconstruction is accomplished by digitizing linear magnetic anomalies in each ocean basin and reversing anomaly by anomaly, recording the position of plate boundaries over time. Understanding the relative motion of the plates helps in predicting the structural style in the involved sedimentary basins.

The resulting paleo-lithofacies interpretation allows extrapolation of known geologic conditions in a given time interval on one continent to another lesser known continent which was juztaposed to the known area in the past. Conditions favorable for hydrocarbon generation and entrapment in producing areas may be related to similar conditions in previously un-explored areas. Industry participants also benefit by having access to an accurate and continuously updated database of stratigraphic control.

<u>Stanford - China Geosciences Industrial Affiliated Program</u>

Department of Geology
Stanford School of Earth Sciences
Stanford University
Stanford, California 94305
Professor Stephen Graham
Telephone: (415) 723-0507

While the Chicago study looked at the entire world, the Stanford study concentrates on the tectonics and basin analysis of western China. Studies include tectonics and paleomagnetism to understand plate motions, the effect of tectonics on local sedimentation, and hydrocarbon resource evaluation.

Chinese graduate students and other Stanford personnel are able to visit areas in western China which are difficult for western company employees to get permission to visit. In return for their financial support of the study, the industry affiliates receive preprints of research results, attendance at technical review meetings, and consultation with individual students and researchers.

Foreign government agencies have become much more efficient in recent years in collecting technical data from companies exploring within their borders and making these data available for review to companies interested in further exploration. Most countries have a ministry or department of natural resources, hydrocarbons, or geology, or even a government oil company charged with this responsibility.

In the pre-1970s, multi-national oil companies operating in a foreign country paid their taxes and/or royalties and furnished little else to the host government. As the government started exercising more of the sovereign powers in the 1970s, the firms were required to furnish all geological, geophysical, well, and production data to the host country, and the appropriate agencies were established to receive, organize, and store these data.

<u>U.S. Government Agencies</u>
Foreign Economic Trends and Their Implications
  for the United States
Annual subscription:
  Superintendent of Documents
  GPO
  Washington, D.C. 20402

Single copies:
Publication Sales Branch
Room 1617
U.S. Department of Commerce
Washington D.C. 20230

The staffs of American embassies in foreign capitals, in cooperation with the U.S. Department of Commerce, prepare reports for each country entitled Foreign Economic Trends and Their Implications for the United States. The Foreign Economic Trends (FET) of a particular country include key macro-economic indicators and a discussion of the resulting investment climate for foreign, especially American, firms.

<u>Petro Canada International Assistance Corporation (PCIAC)</u>
101 6th Ave. S.W.
Calgary, Alta, Canada T2P 3P4
Telephone: (403) 296-5584

PCIAC is associated with Petro Canada and provides funding and exploration services for less-developed countries. The data collected are public information and can be obtained from either PCIAC or the appropriate agency of the host country.

Independent oil companies' exploration budgets are relatively small and the financial committments of an international exploration project are often quite large, therefore a firm often takes a partial working interest, and seeks partners for the remaining working interest. The selling company gives technical sales presentations to prospective companies so that an evaluation of the project and a decision on whether or not to participate can be made. The direct benefit to the prospective buyer may be an opportunity to participate in an economically attractive prospect. An indirect benefit is exposure to petroleum geology and exploration concepts of the selling firm on a particular part of the world. Careful notes on the presentation should be taken and filed by country for future reference.

The hiring of experienced individuals is a direct method to gain access to information. Caution should be exercised to ensure that the explorationist hired is an innovative thinker and prospect generator. Some experienced explorationists can accurately describe the geologic setting of proven hydrocarbon accumulations in areas of the world they have worked, but are incapable of going the next logical step of predicting where similar presently unknown accumulations might be found.

Appendix B

PAKISTAN CASH FLOW SPREADSHEET

ECONOMIC ANALYSIS

PAKISTAN: CENTRAL FOLD BELT
(Million $US unless noted)

NPV @DIS 27.30 DCFROR % 15.08

INPUT PARAMETERS

GEOLOGICAL		COSTS		ENGINEERING		FISCAL		PRICES		OIL DISCOUNT SCHEDULE		
AREA ac	25333	G & G	1.44	IP mmcf	16.00	OGDC %	50.00	$/BBL	13.67	$/BBL	% DISC	FLOOR
NET PAY ft	105	EXPL DHC	2.95	LIFE yr	21.00	ROY %	12.50	$/MCF	2.05	0.00	0.00	0.00
POROSITY	0.14	APPR DHC	2.65	QEL mmcf	0.60	TAX %	55.00			10.00	5.00	10.00
REC FACTOR	0.57	DEV DHC	2.06	b	0.50	POL RISK	0.12			20.00	7.00	19.00
SW	0.37	COMP EXP	2.07	Di	0.15	DISC %	10.00			30.00	10.00	27.90
GOR x1000	54	OPC/WELL	0.39	EUR bcf	62.85	BONUS				34.00	15.00	30.60
DEPTH ft	7333	TRANS/BO	0.40	NO. PROD	29	M BOPD	$MM					
TEMP deg F	227	PROD FAC	381	WDRL/YR	12	DISCOVER	2.00			GAS DISCOUNT SCHEDULE		
PRESS psi	4229	US ESC %	5.00	INERT %	13.33	0.00	0.00			MMCFGPD	% DISC	NET
COMPRESS	0.69	DH FAC	0.13			10.00	3.00			0.00	15.00	0.00
GAS BCF	1828	FOR FAC	1.44	GEOL RISK		25.00	8.00			30.00	20.00	25.50
OIL MMBO	34			1:	4.00	50.00	15.50			50.00	30.00	41.50

CAL YEAR	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
PROJ YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
WELLS DRILLED															
Expl Dry Holes															
Expl Producers				1											
Appr Dry Holes															
Appr Producers					2										
Dev Dry Holes						0	2	1	1	0	0	0	0	0	0
Dev Producers						12	10	4	0	0	0	0	0	0	0
TOTAL PER YEAR				1	2	12	12	5	1	0	0	0	0	0	0
CUMULATIVE PRODUCERS				1	3	15	25	29	29	29	29	29	29	29	29
US PRICE INDEX	100.00	105.00	110.25	115.76	121.55	127.63	134.01	140.71	147.75	155.13	162.89	171.03	179.59	188.56	197.99
EXPENSES 100%															
G & A	0.70	0.74	0.77	0.81	0.85										
Rentals	0.42														
Geol & Geoph	0.20	0.38	0.79	0.42	0.88										
Dry Holes	0.00	0.00	0.00	0.00	0.00	0.00	5.53	2.90	3.05	0.00	0.00				
Total	1.32	1.11	1.57	1.23	1.73	0.00	5.53	2.90	3.05	0.00	0.00				
CAPITAL COSTS 100%															
Expl Drilling				5.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
Appr Drilling				0.00	11.47	0.00	0.00	0.00	0.00	0.00	0.00				
Dev Drilling				0.00	0.00	63.23	55.33	23.24	0.00	0.00	0.00				
Prod Facilities						88.28	139.03	145.99	102.19						
Total				5.80	11.47	151.51	194.36	169.22	102.19	0.00	0.00				

WORK INTEREST %	95.00	95.00	95.00	95.00	95.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
NET EXPENSES	1.25	1.06	1.49	1.17	1.64	0.00	2.76	1.45	1.52	0.00	0.00				
NET CAP COSTS	0.00	0.00	0.00	5.51	10.90	75.75	97.18	84.61	51.10	0.00	0.00				
OIL PRICE $/BBL	13.67	14.35	15.07	15.82	16.61	17.44	19.01	20.72	22.59	24.62	26.84	29.25	32.62	36.37	40.55
After Discount	12.98	13.63	14.31	15.03	15.78	16.57	18.06	19.27	21.01	22.90	24.96	27.21	29.36	30.91	34.47
GAS PRICE $/mcf	2.05	2.15	2.26	2.38	2.49	2.62	2.86	3.11	3.39	3.70	4.03	4.39	4.90	5.46	6.09
Aft Disc Inert	1.51	1.59	1.67	1.75	1.84	1.93	2.10	2.29	2.50	2.29	2.50	2.74	3.06	3.43	3.83
PRODUCTION															
Mmcfgpd										464.00	401.51	350.85	309.20	274.56	245.42
BOPD X 1000										8.58	7.43	6.49	5.72	5.08	4.54
BCF/Year										157.54	136.99	120.22	106.35	94.75	84.95
MMBO/Year										2.91	2.53	2.22	1.97	1.75	1.57
Cum BCF										157.54	294.54	414.76	521.11	615.85	700.80
Cum MMBO										2.91	5.45	7.67	9.64	11.39	12.96
GROSS REVENUE										427.19	405.94	389.37	383.25	378.71	379.84
- Operating										17.55	18.42	19.34	20.31	21.33	22.39
- Transport										1.80	1.65	1.52	1.41	1.32	1.24
WELLHEAD VALUE										407.84	385.88	368.51	361.53	356.07	356.21
NET REVENUE										203.92	192.94	184.25	180.77	178.03	178.10
- Expenses	1.25	1.06	1.49	1.17	1.64	0.00	2.76	1.45	1.52	79.53					
- Surf Depr										109.36	14.26	14.26	14.26	14.26	14.26
- OPIC Insurance				0.13	0.38	2.12	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30
- Loss Forward		1.25	2.31	3.80	5.09	7.11	9.22	14.28	18.03	21.84	9.11	0.00	0.00	0.00	0.00
Subtotal	-1.25	-2.31	-3.80	-5.09	-7.11	-9.22	-14.28	-18.03	-21.84	-9.11	167.27	167.69	164.21	161.47	161.54
DEPL ALLOW										0.00	28.94	27.64	27.11	26.71	26.72
ROYALTY										25.49	24.12	23.03	22.60	22.25	22.26
TAXABLE INCOME	-1.25	-2.31	-3.80	-5.09	-7.11	-9.22	-14.28	-18.03	-21.84	-9.11	138.32	140.06	137.09	134.77	134.83
- Income Tax	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.52	60.82	59.51	58.48	58.51
- Bonus						2.00				15.50					
NET CASH FLOW	-1.25	-1.06	-1.49	-6.80	-12.91	-77.87	-102.24	-88.36	-54.91	96.60	107.01	98.11	96.37	95.00	95.04
REMITTANCES	-1.25	-1.06	-1.49	-6.80	-12.91	-77.87	-102.24	-88.36	-54.91	88.45	97.98	89.83	88.24	86.99	87.02
Cum Remit	-1.25	-2.31	-3.80	-10.60	-23.51	-101.38	-203.62	-291.98	-346.89	-258.44	-160.46	-70.62	17.62	104.60	191.62
Cum @ Discount	-1.25	-2.22	-3.44	-8.56	-17.38	-65.73	-123.44	-168.78	-194.39	-156.88	-119.11	-87.62	-59.50	-34.31	-11.39
GEOL RISK REMIT	-1.25	-1.06	-1.49	-6.80	-3.23	-19.47	-25.56	-22.09	-13.73	22.11	24.50	22.46	22.06	21.75	21.75
Cum Risk Remit	-1.25	-2.31	-3.80	-10.60	-13.83	-33.30	-58.86	-80.95	-94.67	-72.56	-48.07	-25.61	-3.55	18.20	39.95
Cum @ Discount	-1.25	-2.22	-3.44	-8.56	-10.76	-22.85	-37.28	-48.61	-55.02	-45.64	-36.19	-28.32	-21.29	-14.99	-9.27

CAL YEAR	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
PROJ YEAR	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
OIL PRICE $/BBL	45.21	50.41	52.93	55.58	58.36	61.28	64.34	67.56	70.94	74.48	78.21	82.12	86.22	90.53	95.06
After Discount	38.43	42.85	44.99	47.24	49.61	52.09	54.69	57.42	60.30	63.31	66.48	69.80	73.29	76.95	80.80
GAS PRICE $/mcf	6.79	7.57	7.95	8.35	8.76	9.20	9.66	10.14	10.65	11.18	11.74	12.33	12.95	13.60	14.28
Aft Disc Inert	4.29	4.81	5.07	5.35	5.64	5.95	6.29	6.64	7.01	7.40	7.81	8.26	8.72	9.22	9.74
PRODUCTION															
Mmcfgpd	220.69	199.52	181.25	165.38	151.51	139.31	128.53	118.96	110.41	102.75	95.87	89.65	84.02	78.90	74.24
BOPD X 1000	4.08	3.69	3.35	3.06	2.80	2.58	2.38	2.20	2.04	1.90	1.77	1.66	1.55	1.46	1.37
BCF/Year	76.59	69.41	63.19	57.78	53.03	48.84	45.13	41.83	38.88	36.23	33.84	31.68	29.72	27.94	26.31
MMBO/Year	1.42	1.28	1.17	1.07	0.98	0.90	0.83	0.77	0.72	0.67	0.63	0.59	0.55	0.52	0.49
Cum BCF	777.39	846.80	909.99	967.77	1020.80	1069.64	1114.77	1156.60	1195.48	1231.71	1265.55	1297.23	1326.94	1354.88	1381.19
Cum MMBO	14.38	15.67	16.83	17.90	18.88	19.79	20.62	21.40	22.12	22.79	23.41	24.00	24.55	25.07	25.55
GROSS REVENUE	383.20	388.64	372.96	359.48	347.88	337.89	329.32	321.98	315.74	310.46	306.05	302.44	299.54	297.29	295.66
- Operating	23.51	24.69	25.92	27.22	28.58	30.01	31.51	33.08	34.74	36.48	38.30	40.21	42.23	44.34	46.55
- Transport	1.17	1.12	1.07	1.03	0.99	0.96	0.93	0.90	0.88	0.86	0.85	0.83	0.82	0.81	0.80
WELLHEAD VALUE	358.52	362.83	345.96	331.23	318.31	306.93	296.89	288.00	280.12	273.12	266.91	261.39	256.49	252.15	248.31
NET REVENUE	179.26	181.42	172.98	165.62	159.15	153.46	148.44	144.00	140.06	136.56	133.45	130.70	128.25	126.07	124.15
- Expenses															
- Surf Depr	14.26	14.26	14.26	14.26											
- OPIC Insuran	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30
- Loss Forward	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	162.70	164.86	156.42	149.06	156.86	151.17	146.15	141.70	137.76	134.27	131.16	128.40	125.95	123.78	121.86
DEPL ALLOW	26.89	27.21	25.95	24.84	23.87	23.02	22.27	21.60	21.01	20.48	20.02	19.60	19.24	18.91	18.62
ROYALTY	22.41	22.68	21.62	20.70	19.89	19.18	18.56	18.00	17.51	17.07	16.68	16.34	16.03	15.76	15.52
TAXABLE INCOME	135.81	137.64	130.48	124.21	132.99	128.15	123.88	120.10	116.75	113.78	111.14	108.80	106.71	104.87	103.24
- Income Tax	58.94	59.75	56.59	53.83	58.53	56.40	54.52	52.85	51.37	50.06	48.90	47.86	46.94	46.13	45.41
- Bonus															
NET CASH FLOW	95.61	96.69	92.48	88.79	78.43	75.58	73.07	70.85	68.88	67.13	65.58	64.20	62.98	61.89	60.93
REMITTANCES	87.55	88.54	84.67	81.30	71.81	69.21	66.91	64.87	63.07	61.47	60.05	58.78	57.66	56.67	55.79
Cum Remit	279.17	367.71	452.38	533.68	605.49	674.70	741.61	806.49	869.56	931.03	991.07	1049.86	1107.52	1164.19	1219.98
Cum @ Discount	9.57	28.83	45.59	60.21	71.95	82.24	91.28	99.25	106.29	112.53	118.08	123.01	127.41	131.34	134.85
GEOL RISK REMIT	21.89	22.13	21.17	20.33	17.95	17.30	16.73	16.22	15.77	15.37	15.01	14.70	14.42	14.17	13.95
Cum Risk Remit	61.84	83.97	105.14	125.47	143.42	160.72	177.45	193.67	209.44	224.80	239.82	254.51	268.93	283.10	297.04
Cum @ Discount	-4.03	0.79	4.98	8.63	11.57	14.14	16.40	18.40	20.16	21.72	23.10	24.33	25.43	26.42	27.30

```
G1: '  ECONOMIC ANALYSIS
F3: '     PAKISTAN: CENTRAL FOLD BELT
F4: '     (Million $US unless noted)
F6: 'NPV @DISC
G6: @IF(AE98<F98,F98,AE98)
J6: 'DCFROR %
K6: @IRR(0.3,B96..AE96)*100
G8: '   INPUT PARAMETERS
A10: [W16] '    GEOLOGICAL
D10: '      COSTS
G10: '  ENGINEERING
J10: '      FISCAL
L10: '       PRICES
N10: '  OIL DISCOUNT SCHEDULE
A11: [W16] 'AREA ac
B11: (F0) @TRIANG(5000,24000,47000)
D11: 'G & G
E11: @TRIANG(0.3,0.4,0.5)*@TRIANG(300,450,600)/@TRIANG(100,125,150)
G11: 'IP mmcf
H11: @TRIANG(4,14,30)
J11: 'OGDC %
K11: 50
L11: '  $/BBL
M11: @TRIANG(10,13,18)
N11: "$/BBL
O11: "% DISC
P11: "FLOOR
A12: [W16] 'NET PAY ft
B12: (F0) @TRIANG(55,100,160)
D12: 'EXPL DHC
E12: @TRIANG(0.3,0.5,1)+B17*@TRIANG(22,25,32)/(@TRIANG(66,86,95)*1000)
G12: 'LIFE yr
H12: 21
J12: 'ROY %
K12: 12.5
L12: '  $/MCF
M12: @TRIANG(0.1418,0.1458,0.1629)*M11
N12: 0
O12: 0
P12: 0
A13: [W16] 'POROSITY
B13: @TRIANG(0.05,0.12,0.25)
D13: 'APPR DHC
E13: +E12*@TRIANG(0.8,0.9,1)
G13: 'QEL mmcf
H13: +E16*1000/(M12*(1-K12/100)*365)
J13: 'TAX %
K13: 55
N13: 10
O13: 5
P13: 10
A14: [W16] 'REC FACTOR
B14: @TRIANG(0.4,0.55,0.75)
D14: 'DEV DHC
E14: +E12*@TRIANG(0.5,0.7,0.9)
G14: 'b
H14: 0.5
J14: 'POL RISK
K14: @TRIANG(0.05,0.1,0.2)
N14: 20
O14: 7
P14: 19
A15: [W16] 'SW
B15: @TRIANG(0.15,0.35,0.6)
```

```
E15: @TRIANG(0.7,1,1.2)+B17*0.00015
G15: 'Di
H15: @IF(((H11/H13)^H14-1)/(H12*H14)>0.15,0.15,((H11/H13)^H14-1)/(H12*H14))
J15: 'DISC %
K15: 10
N15: 30
O15: 10
P15: 27.9
A16: [W16] 'GOR x1000
B16: (F0) 1000/@TRIANG(0.5,1,54)
D16: 'OPC/WELL
E16: @TRIANG(0.7,1,1.3)*0.39
G16: 'EUR bcf
H16: (F2) (H11^H14)*(H11^(1-H14)-H13^(1-H14))*365/(H15*(1-H14)*1000)
J16: '       BONUS
N16: 34
O16: 15
P16: 30.6
A17: [W16] 'DEPTH ft
B17: (F0) @TRIANG(2000,7000,13000)
D17: 'TRANS/BO
E17: @TRIANG(60,180,300)*E21*@UNIFORM(0.00132,0.00175)
G17: 'NO. PROD
H17: (F0) @ROUND(B21/H16,0)
J17: "M BOPD
K17: "$MM
A18: [W16] 'TEMP deg F
B18: (F0) 73+B17*@UNIFORM(0.017,0.025)
D18: 'PROD FAC
E18: (F0) +E21*(@TRIANG(0.4,0.5,0.6)*H17+95+H17*H11/3)
G18: 'WDRL/YR
H18: (F0) @IF(H17>25,12,6)
J18: 'DISCOVER
K18: 2
N18: '  GAS DISCOUNT SCHEDULE
A19: [W16] 'PRESS psi
B19: (F0) +B17*@TRIANG(0.43,0.44,0.86)
D19: 'US ESC %
E19: @TRIANG(3,5,7)
G19: 'INERT %
H19: (F2) @TRIANG(0,10,30)
J19: 0
K19: 0
N19: 'MMCFGPD
O19: ' % DISC
P19: '    NET
A20: [W16] 'COMPRESS
B20: @TRIANG(0.6,0.7,0.78)
D20: 'DH FAC
E20: @TRIANG(0.05,0.1,0.25)
J20: 10
K20: 3
N20: 0
O20: 15
P20: 0
A21: [W16] 'GAS BCF
B21: (F0) +B11*B12*B13*B14*(1-B15)*B19*0.52*43.56/((B18+460)*B20*14700)
D21: 'FOR FAC
E21: @TRIANG(1,1.33,2)
G21: '   GEOL
H21: 'RISK
J21: 25
K21: 8
```

```
O21: 20
P21: (N21-N20)*(1-O20/100)+P20
A22: [W16] 'OIL MMBO
B22: (F0) +B21/B16
G22: '      1:
H22: @TRIANG(2,4,6)
J22: 50
K22: 15.5
N22: 50
O22: 30
P22: (N22-N21)*(1-O21/100)+P21
A24: [W16] 'CAL YEAR
B24: (F0) 1989
C24: (F0) 1990
A25: [W16] 'PROJ YEAR
B25: (F0) 1
C25: (F0) 2
A27: [W16] 'WELLS DRILLED
A28: [W16] '  Expl Dry Holes
A29: [W16] '  Expl Producers
E29: (F0) 1
A30: [W16] '  Appr Dry Holes
A31: [W16] '  Appr Producers
F31: (F0) 2
A32: [W16] '  Dev Dry Holes
G32: (F0) @ROUND(F36*$E$20-@SUM($B32..F32),0)
H32: (F0) @ROUND(G36*$E$20-@SUM($B32..G32),0)
A33: [W16] '  Dev Producers
G33: (F0) @IF(F36+$H$18-G32<=$H$17,$H$18-G32,$H$17-F36)
H33: (F0) @IF(G36+$H$18-H32<=$H$17,$H$18-H32,$H$17-G36)
A34: [W16] '  TOTAL PER YEAR
E34: (F0) @SUM(E28..E33)
F34: (F0) @SUM(F28..F33)
A36: [W16] 'CUMULATIVE PRODUCERS
E36: (F0) +D36+E29+E31+E33
F36: (F0) +E36+F29+F31+F33
A38: [W16] 'US PRICE INDEX
B38: (F2) 100
C38: (F2) +B38*(1+@TRIANG(0.03,0.05,0.07))
D38: (F2) +C38*(1+@TRIANG(0.03,0.05,0.07))
A40: [W16] 'EXPENSES 100%
A41: [W16] '  G & A
B41: @TRIANG(0.8,1,1.2)*0.7
C41: +$B41*C38/100
D41: +$B41*D38/100
A42: [W16] '  Rentals
B42: 0.42
A43: [W16] '  Geol & Geoph
B43: 0.2
C43: 0.25*E11*C38/100
D43: 0.5*E11*D38/100
E43: 0.25*E11*E38/100
F43: 0.5*E11*F38/100
A44: [W16] '  Dry Holes
B44: ((B28*$E$12)+(B30*$E$13)+(B32*$E$14))*B38/100
C44: ((C28*$E$12)+(C30*$E$13)+(C32*$E$14))*C38/100
A45: [W16] '  Total
B45: @SUM(B41..B44)
C45: @SUM(C41..C44)
A47: [W16] 'CAPITAL COSTS 100%
A48: [W16] '  Expl Drilling
E48: +E29*($E$12+$E$15)*E38/100
F48: +F29*($E$12+$E$15)*F38/100
```

```
E49: +E31*($E$13+$E$15)*E38/100
F49: +F31*($E$13+$E$15)*F38/100
A50: [W16] '  Dev Drilling
E50: +E33*($E$14+$E$15)*E38/100
F50: +F33*($E$14+$E$15)*F38/100
A51: [W16] '  Prod Facilities
G51: 0.2*$E$18*E38/100
H51: 0.3*$E$18*F38/100
I51: 0.3*$E$18*G38/100
J51: 0.2*$E$18*H38/100
A52: [W16] '  Total
E52: @SUM(E48..E51)
F52: @SUM(F48..F51)
A54: [W16] 'WORK INTEREST %
B54: 95
C54: 95
D54: 95
E54: 95
F54: 95
G54: 100-$K$11
H54; 100-$K$11
A55: [W16] 'NET EXPENSES
B55: +B54*@SUM(B41..B44)/100
C55: +C54*@SUM(C41..C44)/100
A56: [W16] 'NET CAP COSTS
B56: +B54*@SUM(B48..B51)/100
C56: +C54*@SUM(C48..C51)/100
A58: [W16] 'OIL PRICE $/BBL
B58: +$M$11
C58: +B58*(1+@TRIANG(0.03,0.05,0.07))
D58: +C58*(1+@TRIANG(0.03,0.05,0.07))
E58: +D58*(1+@TRIANG(0.03,0.05,0.07))
F58: +E58*(1+@TRIANG(0.03,0.05,0.07))
G58: +F58*(1+@TRIANG(0.03,0.05,0.07))
H58: +G58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.03,0.05))
I58: +H58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.03,0.05))
J58: +I58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.03,0.05))
K58: +J58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.03,0.05))
L58: +K58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.03,0.05))
M58: +L58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.03,0.05))
N58: +M58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.05,0.08))
O58: +N58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.05,0.08))
P58: +O58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.05,0.08))
Q58: +P58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.05,0.08))
R58: +Q58*(1+@TRIANG(0.03,0.05,0.07)+@UNIFORM(0.05,0.08))
S58: +R58*(1+@TRIANG(0.03,0.05,0.07))
T58: +S58*(1+@TRIANG(0.03,0.05,0.07))
U58: +T58*(1+@TRIANG(0.03,0.05,0.07))
V58: +U58*(1+@TRIANG(0.03,0.05,0.07))
W58: +V58*(1+@TRIANG(0.03,0.05,0.07))
X58: +W58*(1+@TRIANG(0.03,0.05,0.07))
Y58: +X58*(1+@TRIANG(0.03,0.05,0.07))
Z58: +Y58*(1+@TRIANG(0.03,0.05,0.07))
AA58: +Z58*(1+@TRIANG(0.03,0.05,0.07))
AB58: +AA58*(1+@TRIANG(0.03,0.05,0.07))
AC58: +AB58*(1+@TRIANG(0.03,0.05,0.07))
AD58: +AC58*(1+@TRIANG(0.03,0.05,0.07))
AE58: +AD58*(1+@TRIANG(0.03,0.05,0.07))
A59: [W16] '  After Discount
B59: @IF(B58*(1-@VLOOKUP(B58,$N$12..$P$16,1)/100)<@VLOOKUP(B58,$N$12..$P$16,2),@VLOOKUP(B58,$N$12..$P$16,2),B58*
     (1-@VLOOKUP(B58,$N$12..$P$16,1)/100))
C59: @IF(C58*(1-@VLOOKUP(C58,$N$12..$P$16,1)/100)<@VLOOKUP(C58,$N$12..$P$16,2),@VLOOKUP(C58,$N$12..$P$16,2),C58*
     (1-@VLOOKUP(C58,$N$12..$P$16,1)/100))
```

```
B61: +B58*@TRIANG(0.1418,0.1458,0.1629)
C61: +C58*@TRIANG(0.1418,0.1458,0.1629)
A62: [W16] '  Aft Disc Inert
B62: +B61*(1-$O$20/100)*(1-$H$19/100)
C62: +C61*(1-$O$20/100)*(1-$H$19/100)
A64: [W16] 'PRODUCTION
A65: [W16] '  Mmcfgpd
K65: +K36*$H$11/(1+$H$14*$H$15*(K25-$K$25))^(1/$H$14)
L65: +L36*$H$11/(1+$H$14*$H$15*(L25-$K$25))^(1/$H$14)
A66: [W16] '  BOPD X 1000
K66: +K65/$B16
L66: +L65/$B16
A67: [W16] '  BCF/Year
K67: +K69-J69
L67: +L69-K69
A68: [W16] '  MMBO/Year
K68: +K67/$B16
L68: +L67/$B16
A69: [W16] '  Cum BCF
K69: +$H$11^$H$14*($H$11^(1-$H$14)-(L65/$H$17)^(1-$H$14))*0.365*$H$17/($H$15*(1-$H$14))
L69: +$H$11^$H$14*($H$11^(1-$H$14)-(M65/$H$17)^(1-$H$14))*0.365*$H$17/($H$15*(1-$H$14))
A70: [W16] '  Cum MMBO
K70: +J70+K68
L70: +K70+L68
A72: [W16] 'GROSS REVENUE
K72: +K67*K62+K68*K59
L72: +L67*L62+L68*L59
A73: [W16] '  - Operating
K73: +$E$16*$H$17*K38/100
L73: +$E$16*$H$17*L38/100
A74: [W16] '  - Transport
K74: +K68*$E$17*K38/100
L74: +L68*$E$17*L38/100
A75: [W16] '  WELLHEAD VALUE
K75: +K72-K73-K74
L75: +L72-L73-L74
A77: [W16] 'NET REVENUE
K77: @IF(K75>0,K75*K54/100,0)
L77: @IF(L75>0,L75*L54/100,0)
A78: [W16] '  - Expenses
B78: +B54*@SUM(B41..B44)/100
C78: +C54*@SUM(C41..C44)/100
D78: +D54*@SUM(D41..D44)/100
E78: +E54*@SUM(E41..E44)/100
F78: +F54*@SUM(F41..F44)/100
G78: +G54*@SUM(G41..G44)/100
H78: +H54*@SUM(H41..H44)/100
I78: +I54*@SUM(I41..I44)/100
J78: +J54*@SUM(J41..J44)/100
K78: +K54*@SUM(E48..K50)/100
A79: [W16] '  - Surf Depr
K79: 0.4*K54/100*@SUM(G51..K51)+0.06*K54/100*@SUM($G$51..$K$51)
L79: 0.06*K54/100*@SUM($G$51..$K$51)
A80: [W16] '  - OPIC Insurance
E80: 0.0255*0.9*@IF(@SUM($E$56..E56)>100,100,@SUM($E$56..E56))
F80: 0.0255*0.9*@IF(@SUM($E$56..F56)>100,100,@SUM($E$56..F56))
A81: [W16] '  - Loss Forward
C81: @IF(B87>0,0,-B87)
D81: @IF(C87>0,0,-C87)
A82: [W16] '  Subtotal
B82: +B77-B78-B79-B80-B81
C82: +C77-C78-C79-C80-C81
```

```
A84: [W16] 'DEPL ALLOW
K84: (F2) @IF(@IF(0.5*K82<0.15*K77,0.5*K82,0.15*K77)>0,@IF(0.5*K82<0.15*K77,0.5*K82,0.15*K77),0)
L84: (F2) @IF(@IF(0.5*L82<0.15*L77,0.5*L82,0.15*L77)>0,@IF(0.5*L82<0.15*L77,0.5*L82,0.15*L77),0)
A85: [W16] 'ROYALTY
K85: @IF(K77>0,$K$12*K77/100,0)
L85: @IF(L77>0,$K$12*L77/100,0)
A86: (H) [W16] 'TAX WORK
B86: (H) @IF($K$13/100*B87>0.5*B82,$K$13/100*B87-B85,0.5*B82-B85)
C86: (H) @IF($K$13/100*C87>0.5*C82,$K$13/100*C87-C85,0.5*C82-C85)
A87: [W16] 'TAXABLE INCOME
B87: +B82-B84
C87: +C82-C84
A88: [W16] '  - Income Tax
B88: @IF(B86>0,B86,0)
C88: @IF(C86>0,C86,0)
A89: [W16] '  - Bonus
G89: +$K$18
K89: @VLOOKUP(K66+K65/6,$J$19..$K$22,1)
A90: [W16] 'NET CASH FLOW
B90: +B77-B56-B78-B80-B85-B88
C90: +C77-C56-C78-C80-C85-C88
A92: [W16] 'REMITTANCES
B92: @IF(B90<0,B90,B90*(1-@TRIANG(0.05,0.1,0.2)*(1-0.9*@IF(@SUM($B56..B56)>100,100,@SUM($B56..B56))/@SUM($B56..B56))))
C92: @IF(C90<0,C90,C90*(1-@TRIANG(0.05,0.1,0.2)*(1-0.9*@IF(@SUM($B56..C56)>100,100,@SUM($B56..C56))/@SUM($B56..C56))))
A93: [W16] 'Cum Remit
B93: +B90
C93: +B93+C92
D93: +C93+D92
A94: [W16] 'Cum @ Discount
B94: +B93
C94: +B94+(C92/((1+$K$15/100)^(C25-1)))
D94: +C94+(D92/((1+$K$15/100)^(D25-1)))
A96: [W16] 'GEOL RISK REMIT
B96: +B92
C96: +C92
D96: +D92
E96: +E92
F96: +F92/$H$22
G96: +G92/$H$22
A97: [W16] 'Cum Risk Remit
B97: +B96
C97: +B97+C96
D97: +C97+D96
A98: [W16] 'Cum @ Discount
B98: +B96
C98: +B98+(C96/((1+$K$15/100)^(C25-1)))
D98: +C98+(D96/((1+$K$15/100)^(D25-1)))
```