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ABSTRACT

A COMPUTER SIMULATION MODEL FOR USE IN PETROLEUM RESOURCES MANAGEMENT

by

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A method was developed to assess the future amount of oil and gas resources and activities in the Northern Region. The Alaskan Hydrocarbons Supply Model, adapted and referred to as the Petroleum Simulation Model, was used for estimating the potential oil and gas resources and activities on the Lewis and Clark National Forest. The undiscovered recoverable oil and gas resources were estimated to be 500 to 800 million barrels of oil and 2 to 4 trillion cubic feet of gas on the Lewis and Clark National Forest with a net present value of 10.5 billion dollars. Additional information provided by the simulator includes estimates of exploratory and developmental drilling footage, oil and gas production forecasts, and transportation development. The petroleum resources information generated could be integrated into the national forest planning and decision making process. The simulator is also useful in testing and developing management scenarios for petroleum resources.

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INTRODUCTION

Statement of the Problem

Today the nation's forests are at a turning point because the demands for all forest resources and uses are rapidly intensifying. The need for water and the increased demand for outdoor recreation is higher than imagined 50 years ago. Strong advocacies are present for the preservation of wilderness, wildlife, and natural research areas. The energy shortages have caused a dramatic return to the use of wood for heating homes and for the federal government to create incentives for increasing domestic energy production. At the same time the demand for forest products continues to grow. (Hewett and Hamilton 1982)

Because of the increasing public demand, conflicts over forest resource use have arisen and include preservation of wilderness, production of minerals from national forests, and regulations to protect water quality, ecosystems and aesthetic characteristics of recreational areas. As a result of these conflicts, the task of managing the national forests is becoming more complex both politically and technically.

If the growing public demand for various forest resources (e.g., timber, minerals, range, water, recreation) is to be satisfied, future planning and management of the national forests must consider all forest resources--renewable and nonrenewable, and surface and subsurface--in an integrated multi-resource plan. Historically, integrating minerals resource information into the forest planning process has been limited and in most cases ignored. Because of the increasing public demands for minerals from the national forest lands, integrating them into the forest planning process is necessary to help eliminate future conflicts between minerals and other forest resources.

Land managers have generally not considered minerals in the national forest planning process for several reasons. Firstly, land managers are often under the impression that the Forest Service does not have the authority to dispose of nor to produce minerals and, therefore, minerals cannot be considered in any plan. Another reason never expressed openly among land managers is the belief that any minerals operation is incompatible with the other more traditional forest resources and uses. Some land managers feel that since mineral resources occur below the surface, information about them is impossible to collect and, therefore, cannot be integrated into a forest plan. The purpose of this study is to help solve this dilemma by generating minerals resource information and by discussing how it can improve the management of the national forest lands when integrated into the planning process.

The Legal Framework for Minerals

Mineral activities on national forest lands are governed by a set of specific laws and regulations which define the procedures and conditions under which prospecting, exploration, and development of minerals can be conducted. The first federal law pertaining to minerals was passed in 1807 and since that time over eighty federal laws have been enacted (Maley 1979). Additionally, the forest land management planning laws and regulations influence the disposal and extraction of mineral resources. Together these statutes and regulations define the rules for managing federally-owned minerals.

Presently, federal minerals can be divided into the categories of locatable minerals, leasable minerals, and saleable minerals. Locatable minerals are those disposed of under the General Mining Law of 1872 (17 Stat. 91) on public domain lands, including national forests not otherwise restricted. Some examples include gold, lead, zinc, uranium, iron, and molybdenum. Because of some unique characteristics, uncommon varieties of sand, stone, gravel, cinders, pumice, and clay may also be considered locatable minerals. Under the 1872 Mining Law, these minerals are open to exploration, location, development, and production by any U.S. citizen where the use of the surface and subsurface resources is allowed as long as that use is reasonable and necessary for exploration and mining activities. Locatable minerals are disposed of through a claim location and patent system. A mining claim entitles the claimant to mineral possession for mining purposes from other claimants, whereas a patent establishes land ownership. The Secretary of Interior through the Bureau of Land Management administers the general mining laws with some functions conducted by the Forest Service. The Forest Service, in cooperation with the mining operator, is responsible for minimizing surface disturbances from mining activities. The Forest Service can also investigate the validity of mining claims. (USDA 1981a)

Historically, all minerals on public domain land were disposed of under the General Mining Law of 1872. However the passage of the Mineral Leasing Act of 1920 (41 Stat. 437), the Mineral Leasing Act for Acquired Lands of 1947 (61 Stat. 913), and the Geothermal Steam Act of 1970 (84 Stat. 1566) removed certain minerals from the 1872 General Mining Law. These minerals, known as leasable, include coal, phosphate, oil, oil shale, natural gas, sodium, potassium, and geothermal resources. The Mineral Leasing Act for Acquired Lands of 1947 made all minerals leasable on acquired lands. For example, a lead deposit on public domain land would be a locatable mineral, but on acquired land a leasable mineral. Leasable minerals are disposed of through a permit/lease system for all exploration and development. The Mineral Leasing Act of 1920 made provisions for royalty rates, rental rates, lease size and terms, and the issuance of prospecting permits prior to lease issuance with competitive bidding for certain deposits. The Department of Interior through the Bureau of Land Management is responsible for leasing under these Acts. The Forest Service cooperates with the Bureau of Land Management to insure that surface resources and other management concerns are coordinated with mineral activities. Lease applications are referred to the Forest Service from the Bureau of Land Management for consent or for recommendations to protect surface resources and environmental values before any mineral activities can be conducted. This authority provides the Forest Service with the opportunity to influence the character and extent of leasable mineral operations. (USDA 1981a)

The saleable minerals category was created with the passage of the 1947 Materials Act and the Multiple Use Surface Act of 1955. The major reason for this classification was the widespread occurrence and nonmetallic characteristics of the minerals. These are generally known as "common variety" minerals which primarily include sand, stone, gravel, and common clay. These materials are disposed of through a permit/sale system for both exploration and development. The Multiple Use Surface Act removed the common varieties of sand, gravel, pumice, and clay from the locatable category as well as provided for the multiple use of land and surface resources on mining claims. The Forest Service has the sole authority and discretion to dispose of these minerals on the national forest lands and specifies the terms and conditions of operations. (USDA 1981a)

Forest management and planning laws and regulations can also influence the exploration and development of mineral deposits due to surface impacts incidental to extraction. These laws and regulations include the 1974 Forest and Rangeland Renewable Resources Planning Act (RPA), the 1976 National Forest Management Act (NFMA), and the Land and Resource Management Planning Regulations.

The Forest and Rangeland Renewable Resources Planning Act of 1974 mandated that the Forest Service prepare a Renewable Resource Assessment each decade and a Renewable Resource Program to be updated every five years. In the 1980 RPA Assessment, minerals were recognized and discussed as a resource element in the management of the national forests because of the importance to the economy and the impacts that minerals can have on other surface resources (USDA 1980a). In addition, the goal of managing mineral areas on national forest lands was to permit the production of minerals, including leasable minerals, and to protect surface resources and environmental values by administering the laws and regulations which apply to mineral operations (USDA 1980b). Minerals were considered as one of several issues in the 1980 RPA Program and as a result were incorporated into the alternative analyses.

The National Forest Management Act which amended RPA mandated the development of a planning system. This statute led to the land management planning regulations published in 1979 which have been recently updated (USDA 1982a). The regulations state that minerals are one of several resource elements that must be integrated with the forest planning process. Specifically, the regulations state that the following shall be recognized in all national forest plans: 1) active mines within the area of land covered by the national forest plan; 2) outstanding or reserved mineral rights; 3) the probable occurrence of various minerals, including locatable, leasable, and common variety; 4) the potential for future mineral development; 5) access requirements for mineral exploration and development; and 6) the probable effect of renewable resource prescriptions and management direction on mineral resources and activities, including exploration and development (USDA 1982a). This information must be considered in the forest plans regardless of whether any current mineral development projects exist on the national forests.

In summary, the various mineral law statutes, along with the national forest land management planning laws and regulations, provide the Forest Service with the authority to influence minerals activities on national forest lands even though the agency has no direct responsibility for producing minerals. The extent of this authority depends upon the type of mineral. Although the primary mission of the Forest Service is to manage the renewable surface resources, the nonrenewable subsurface mineral resources must be integrated into the national forest planning process if the surface resources are to be adequately managed and protected. The land manager's goal on national forest lands must be one that works towards both encouraging minerals exploration and production as well as protecting other surface and subsurface resources from environmental damages.

The Need for Minerals Resource Planning

Many reasons exist for integrating minerals resource information into the national forest planning process. Minerals information might include the quantity, quality, and value of the resources as well as where and when these resources will most likely be found and developed. A primary reason for incorporating mineral resources into the national forest planning process is to prevent directing noncompatible surface uses into areas with high potential for pre-emptive minerals development use (USDA 1981a). Recently a situation in Colorado arose where a ski resort was constructed over a commercial molybdenum deposit. This situation resulted in a noncompatible surface use jeopardizing subsurface mineral resources development. These kinds of situations can be economically inefficient in that the net social welfare may be increased by developing the molybdenum deposit instead of the ski area.

Generally, minerals activities are in conflict with municipal watersheds and developed recreational sites. A possibility always exists of an unexpected mineral discovery, but knowledge about mineral resources and past exploration and mining activities can be valuable information in preventing land use conflicts. Minerals resource planning would help the land manager identify appropriate land use adjustments before the mineral development project begins (USDA 1981a). The integration of mineral resources into the national forest planning process would help land managers better assess how the exploration and development of subsurface mineral resources would impact the renewable surface resources and how the management of renewable surface resources could impact subsurface mineral resources.

Minerals resource development does not always have to result in a conflict situation. The potential for obtaining benefits for other surface uses from mineral development projects can also be incorporated into the overall national forest planning effort (USDA 1981a). For example, in some areas on the national forest lands in the Northern Region, harvesting timber is uneconomical because the value of the timber cannot cover the expense of the roads necessary to harvest the trees. In these situations a mineral development project in the area would pay for the roads necessary to develop the mineral deposit and the roads could then be used to harvest the timber. Land managers should not only look for opportunities to prevent land use conflicts but also for those situations where minerals development projects are compatible with other forest uses.

Mineral development projects can be quite large, often involving millions of dollars for capital investment. These larger projects can create significant environmental impacts as well as bring about social and economic change in local communities. Generally, local communities lack the expertise and financial capabilities to plan for potential mineral development projects and are unable to cope with many of the associated problems (i.e., severe housing shortages accompanied by dramatic price increases, increased demand for hospitals, schools, police, and fire protection).

The rapid oil and gas development that has occurred since 1975 in and around the Little Missouri National Grasslands in western North Dakota is a good example of how extensive oil and gas operations can impact communities, both socially and economically (Wenner 1980). Many of the towns in this area, although not boom towns (e.g., Watford City, Killdeer, and Dickinson), have experienced rapid population growth accompanied by many social and economic costs and benefits. Since 1976, the communities which have lacked sufficient knowledge about the future growth of oil and gas activities, have not had the orderly planning and expansion of public and commercial facilities and services to match the increased demand from rapid population growth. Thus, if oil and gas resources information were more readily available to these communities, many of the social and economic costs may have been mitigated and benefits enhanced.

Integrating minerals resource information into the national forest planning process is not only useful for better improving social and economic planning for local communities, but can also aid federal government agencies to plan for future budgeting and personnel needs. Future mineral activities can impact a federal government agency like the Forest Service in two ways. First, the activities usually generate direct surface impacts. These impacts usually cause a need for more personnel to administer the activities, more employee training to provide the necessary technical and managerial skills needed to understand how to best administer such activities, and a greater budget to cover these expenses. For example, on the Little Missouri National

Grasslands the increased Forest Service workloads from oil and gas activities coupled with tight budgets and employee travel restrictions have created problems for expanding the agency's minerals program to correspond to the growing need.

Secondly, mineral activities can change the demand for other forest resources and uses (i.e., recreation, timber, water) which in some cases can substantially change the forest workload and volume of business (USDA 1981a). For instance, a large scale mineral development project, creating an influx of new residents into a community, may increase the demand for recreational use of nearby national forests. The particular forests may find it necessary to change their management program to be more sensitive to recreation which may also cause necessary changes in workforce distribution and in budgeting requirements, often the single most consistent impact of an agency. Again, if minerals information were better integrated with national forest planning, projections of agency budgets, personnel needs and skills, and anticipated outputs due to mineral development projects could be better forecasted. Unexpected mineral development projects can cause imbalances among agency personnel, budgets, workload, and production goals (Wenner 1980). Thus integrating minerals resource information into the national forest planning process is necessary for improving land use management, for minimizing environmental, social and economic impacts, for improving administrative management of federal government agencies, and for better informing the public about how the land can be managed with respect to minerals.

Oil and Gas Resources and Activities in the Northern Region

Because of the energy shortages in the last decade, oil and gas exploration and development has increased dramatically in all areas across the continental United States. The Williston Basin[1] and the Western Overthrust Belt[2] have been some of the most active areas in terms of oil and gas exploration and development. Federal lands in the Northern Region are being increasingly impacted from these activities, creating a greater need for federal agencies (i.e. Forest Service, Bureau of Land Management) to better plan for these resources. A summary of the oil and gas activities and resources in the Northern Region would help to better define the situation and explain why there exists a growing need for the Forest Service to better integrate oil and gas resources into the national forest planning process.

The Northern Region of the Forest Service consists of over 25 million acres of land in the States of Montana, North Dakota, northern Idaho, northern South Dakota and extreme eastern Washington, representing 14 percent of the total land area. The presence of oil and gas resources in this region has been known since 1864 when several members of an immigrant train crossing the east flank of the Pryor Mountains on the Bozeman Trail noticed heavy oil on a stagnant pool of water. The first successful oil and gas wells were drilled and completed in 1905 and 1909, respectively. These discoveries were both

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[1] The largest oil basin in the United States encompassing over 100,000 square miles, extending into North and South Dakota, eastern Montana, and Saskatchewan, Canada.

[2] A strip of highly thrusted and folded strata extending from northern Alaska, southward through Canada and the western United States into Mexico (Ver Ploeg 1979).

located in Swiftcurrent Creek Valley, now part of Glacier National Park. Several years later in 1913, the first commercial gas field was discovered in Dawson County, Montana. The first commercial oil field discovery was made in 1915 in Carbon County, Montana, and was named Elk Basin.

Although these first field discoveries can be credited for starting the oil and gas industry in Montana, the industry was not firmly established until 1922 when the Kevin-Sunburst oil field was discovered. This field attracted national attention because of the size and production potential of 70 million barrels (USDI 1968). Since Kevin-Sunburst, hundreds more oil and gas field discoveries have been made east of the Continental Divide. Currently over 300 oil and gas fields are producing in Montana with over 200 more in western North Dakota. Until the discovery of the Williston Basin, oil production in Montana was very modest. The discovery of the Williston and Powder River Basins increased crude oil production dramatically and gave the state national significance once again. Since 1968, Montana's oil production has been declining even though many more oil fields are producing.

Oil and gas production in North Dakota started much later than in Montana. Since the discovery of oil and gas in 1951, over 200 oil and gas fields have been discovered which have produced over 1 billion barrels of oil (USDA 1980c). These fields were discovered in two phases. The first phase lasted from 1951 to 1972 when the oil industry believed all of the "easy oil" had been found (Blundell 1980). A new period of exploration, begun in 1973, was spurred by the Arab Oil Embargo, rising oil and gas prices, significant new field discoveries, more sophisticated finding techniques, and expiring oil lease dates. With an exploratory well success ratio of between 30 and 35 percent (Montana Oil Journal 1980), the activity in the Williston Basin is expected to continue for many more years. Unlike Montana, the crude oil production in North Dakota is still rising. Current estimates of undiscovered oil reserves range from 1.5 to 5 billion barrels (USDA 1980c).

The future production potential of the Northern Region is difficult to forecast but most geologists believe that it is very promising. Oil and gas industry experts are not only concentrating on areas that have been extensively explored and developed (i.e., Williston Basin, Powder River Basin) but are becoming more interested in the Western Overthrust Belt. Because the geology of this province is so complex and difficult to understand, the area has only been explored to a limited extent, even though the existence of petroleum in this area has been known since the early 1800's.

The first major oil discovery in the Western Overthrust Belt was at Turner Valley in Alberta, Canada, in 1924. This discovery led to the development of some 300 million barrels of oil and 16 trillion cubic feet of natural gas (Work 1980). Between 1924 and 1974 drilling efforts elsewhere in the Overthrust Belt yielded little but dry holes and became known as a driller's graveyard. However, in December 1974, there was a second major oil and gas discovery in the Overthrust Belt. The discovery known as Pineview Field in northeastern Utah, established the first commercial production of oil and gas in the Overthrust Belt of the United States. This discovery attracted many more prospectors, and northeastern Utah and southwestern Wyoming are now experiencing extensive oil and gas exploration and discoveries (e.g., Ryckmann Creek Field in Wyoming; Whitney Canyon Field; Painter Reservoir Field). As a result of these latest discoveries, estimates of the future potential have been revised upward. Recently, oil reserves in the Utah-Wyoming and Idaho portion of the Overthrust Belt have been projected to rival those of the "mammoth" Prudhoe Bay Field in Alaska (Lewiston Tribune 1982).

The Idaho and Montana portions of the Overthrust Belt have thus far not yielded a significant oil and gas discovery, and only a modest amount of exploratory drilling has taken place. Because there has not been a significant oil or gas discovery, estimates of the undiscovered recoverable resources have been more modest. The U.S. Geological Survey estimates range from 0 to 2 billion barrels of oil and from 0 to 25 trillion cubic feet of gas (Dolton et al. 1981).

Most of the exploratory drilling activity in western Montana has been in an area called the Rocky Mountain Front (part of the Overthrust Belt), which extends from Glacier National Park south to Highway 200. The Williams Exploration Company was credited with the first Montana Overthrust Belt oil and gas field discovery in early 1980. The field, known as Two Medicine, is located in Glacier County and initially produced 145 barrels of oil and 50,000 cubic feet of gas per day (Wash 1981). The same firm also discovered a modestly sized gas field known as Blackleaf Canyon in the spring of 1981 which is currently producing 6.1 million cubic feet per day from two wells (Montana Oil Journal 1981a). Oil and gas activity in the western Montana portion of the Overthrust Belt is at the highest level in history. Currently, there are half a dozen exploratory wells being drilled in western Montana scattered from the foothills along the Rocky Mountain Front to the deeper valleys of the state (Montana Oil Journal 1982). In addition, many more drilling projects are planned for western Montana in the near future. Thus, the oil and gas potential of western Montana remains attractive to many companies and a significant discovery similar to Pineview Field in Utah could cause this relatively modest activity to increase dramatically (Roundtree 1982).

Although oil and gas production and the associated activities have occurred in the Northern Region since the early 1900's, most of this activity has been on private and state lands. Since 1975, oil and gas activities have also been occurring on lands managed by the Forest Service, including both national forests and national grasslands. The more recent interest in these lands by the petroleum industry has been spurred by improved technology, rising petroleum prices, different ideas and theories about petroleum occurrence, and the federal government's effort to encourage domestic oil and gas development.

The oil and gas production and associated activities in the Northern Region of the Forest Service have been primarily concentrated on the Little Missouri National Grasslands in western North Dakota, administratively a part of the Custer National Forest. These lands lie within the geologic province known as the Williston Basin and encompass over 1.2 million acres intermingled with other federal, state, and private lands in a six county area (i.e., Billings, Golden Valley, Slope, McKenzie, Dunn, and Stark). These lands consist of dry rolling prairies and eroded "badlands" which were acquired by the Forest Service in 1938 and 1939 under the Bankhead-Jones Farm Tenant Act (50 Stat. 525).

Until 1978 grazing was the predominant use of the Little Missouri National Grasslands. Oil and gas production and activities were generally modest and did not disrupt traditional land use patterns significantly. As oil and gas prices rose and exploration techniques improved, interest in these lands increased dramatically. In 1980 oil and gas exploration and development in the Grasslands reached record levels with a return to the U.S. Treasury from royalties and permitting fees of over 35 million dollars which compares to about 2 million dollars in 1978.[3] In 1981 receipts were over 58 million dollars[3] which was over half of the total projected receipts from all sources (i.e., timber, range, recreation) in the Northern Region. Presently, there are over 400 producing oil and gas wells with over 100 drilling rigs on the Grasslands (USDA 1981b). The activity is expected to increase or at least stay the same for several more years.

Elsewhere in the Northern Region, oil and gas interest and activities are also increasing. By mid-summer (i.e., August 1982) there were 1,768 issued oil and gas leases, covering over 5.1 million acres, and 2,019 oil and gas lease applications, covering over 5.4 million acres, on the national forest lands in the Northern Region.[4] Most of the activity is in terms of seismic exploration with a limited amount of exploratory drilling on the Lewis and Clark and Helena National Forests.

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[3] Royalty statistics adapted from Royalty Accounting Statistics from the U.S. Department of Interior, Minerals Management Service compiled by R.C. Marshall, Economist, U.S. Department of Agriculture, Forest Service, Northern Region office.

[4] Monthly Minerals Leasing Report compiled by the U.S. Department of Agriculture, Forest Service Northern Region, Minerals and Geology Staff Unit.

Most of national forests lie within the western Montana portion of the Overthrust Belt which some experts believe holds great promise for establishing a new future oil and gas producing province (Cavanaugh 1982).

The impact of these oil and gas activities has not been without its problems. The increased Forest Service workloads from oil and gas activities on the Little Missouri National Grasslands coupled with tight budgets have created problems for expanding the minerals program on the Custer National Forest. In addition, the cumulative effects from the oil and gas activities have created many unexpected environmental, social, and economic impacts. Although the level of activity on the other national forests in the Northern Region has been rather modest to date, most national forest supervisors are becoming concerned about the levels of future oil and gas activity which might be expected on their forests. The lack of information on hydrocarbon resources in the Northern Region, however, makes it difficult to determine which national forests may experience rapid increases in future oil and gas activities. Thus, there exists a need to develop an information base for oil and gas resources of the Northern Region national forest lands which can be integrated into the forest planning process to prevent or to minimize the same management problems now facing the Little Missouri National Grasslands management staff.

Purpose and Objectives

The objective of this study is to develop a method for assessing the future amount of oil and gas resources and activities in the

Northern Region. The justification for such an appraisal can be separated into three categories.

(1) Land Use Planning. Often national forest land use planning which does not integrate information about oil and gas resources and activities into the forest planning process can result in directing noncompatible surface uses (e.g., primitive recreation) into areas of high oil and gas potential. The integration of information about oil and gas resources and activities into the national forest planning process can help improve the efficiency of land use allocation and prevent potential land use conflicts.

(2) Administrative Planning. In the past, predicting future personnel and budgeting needs were not critical because the demand for various oil and gas resources on federal lands was insignificant. However with greater public demand for oil and gas resources, coupled with tighter federal administrative budgets and a federal policy of increasing domestic energy production, there is a growing need by the Forest Service to make oil and gas activity forecasts. If the Forest Service had some predictions about future oil and gas activities in the Northern Region, future personnel needs required to administer any increase or decrease in such activities could be better projected.

(3) Assessing Environmental Impacts. Often a new oil or gas field discovery can create a temporary increase in exploration and development activity, causing social and economic changes to occur in surrounding local communities. The degree and permanence of the impacts depends upon the oil and gas field size, but generally few communities are prepared for even a modest change in social and economic conditions, whether positive or negative. If the Forest Service had a better idea

about the future level of oil and gas activities, some of the negative social and economic impacts on local communities could be eliminated or mitigated while enhancing beneficial impacts through better resources planning.

In order to predict the potential oil and gas activity in the Northern Region, it is necessary to estimate the potential undiscovered oil and gas reserves, the most likely place for oil or gas to be discovered, the amount of exploration and development drilling required to produce the reserves, and the time frame the reserves would be produced over. Because this information does not exist, it is difficult to make predictions of future oil and gas activities. As a result, oil and gas resources have not been adequately integrated into the planning process which has created a continuing problem for the Forest Service of how to plan for and manage these resources.

This study will attempt to predict the future amount of oil and gas resources and activities using an oil and gas simulation model. The information provided by this simulator includes estimates of the expected oil and gas reserves, estimates of exploratory and developmental drilling footage, oil and gas production forecasts, and transportation development (i.e., pipelines) that might result from the oil and gas development. The simulator in this study will be referred to as the Petroleum Simulation Model.

Simulator models are now used widely in many fields such as engineering, economics, business, forestry, and many other technical science fields for experimenting with complex systems. The technique has been used in natural resources management in a variety of ways such as timber harvesting and transport, hydrology, fire fighting, and wilderness recreation. A single individual has difficulty in estimating the size of potential oil and gas resources or in making a production forecast of potential supply because of the many variables and interrelationships among them which can influence the amount of resources present and produced. Usually the human mind cannot work with such a large number of variables but a computer can. The advantage of using a simulation model is that it can work with hundreds of variables and relationships both quickly and simultaneously in solving for a particular set of outputs.

The Lewis and Clark National Forest is the area used for the pilot study. The information this simulator provides should help determine what the potential quantity and value of oil and gas resources might be on the Lewis and Clark National Forest as well as the potential oil and gas activity levels. Using this information, better decisions should be made about how much oil and gas can be produced and how many Forest Service budgeting dollars may be required to secure a certain level of output. Additionally the Forest Service should be better able to formulate management alternatives with respect to these resources.

Plan of the Study

The first chapter describes the oil and gas supply process modeled by the Petroleum Simulator. Primarily this information is for background. Chapter 2 discusses the nature of simulation, past research related to simulating the oil and gas supply process, and a brief overview of the Petroleum Simulator. Chapters 3 and 4 discuss the Petroleum Simulator in detail as to the model structure, design assumptions, input data requirements, and the output. The results and evaluation from using the simulator on the Lewis and Clark National Forest are discussed in Chapter 5, as well as some different sensitivity tests of the data and simulator. Chapter 6 discusses the potential of the Petroleum Simulator for mineral resources management and planning. The entire study is then summarized.

CHAPTER I

THE OIL AND GAS SUPPLY PROCESS

Introduction

The oil and gas supply process is influenced by many geologic, economic, engineering, and political factors which make the process highly complex and difficult to simulate. This chapter provides some background knowledge for better understanding the technical terms and concepts used throughout the paper. Figure 1 is a schematic diagram of the supply process around which the discussion centers.

The Natural Occurrence of Oil and Gas

Petroleum is a generic term comprising a large and complex group of liquid, gaseous, and semisolid hydrocarbons[5] which often contain impurities such as water, sulfur, oxygen, and nitrogen. Petroleum is normally found in underground reservoirs as a fluid mixture of different hydrocarbon compounds. When delivered to the surface, the mixture is usually classified as crude oil, natural gas, and natural gas liquids (e.g., natural gasoline, butane, and propane). In common technical practice, the word "petroleum" is synonymous with crude oil and natural

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[5] Hydrocarbons are compound mixtures of hydrogen and carbon atoms in various proportions and arrangements.

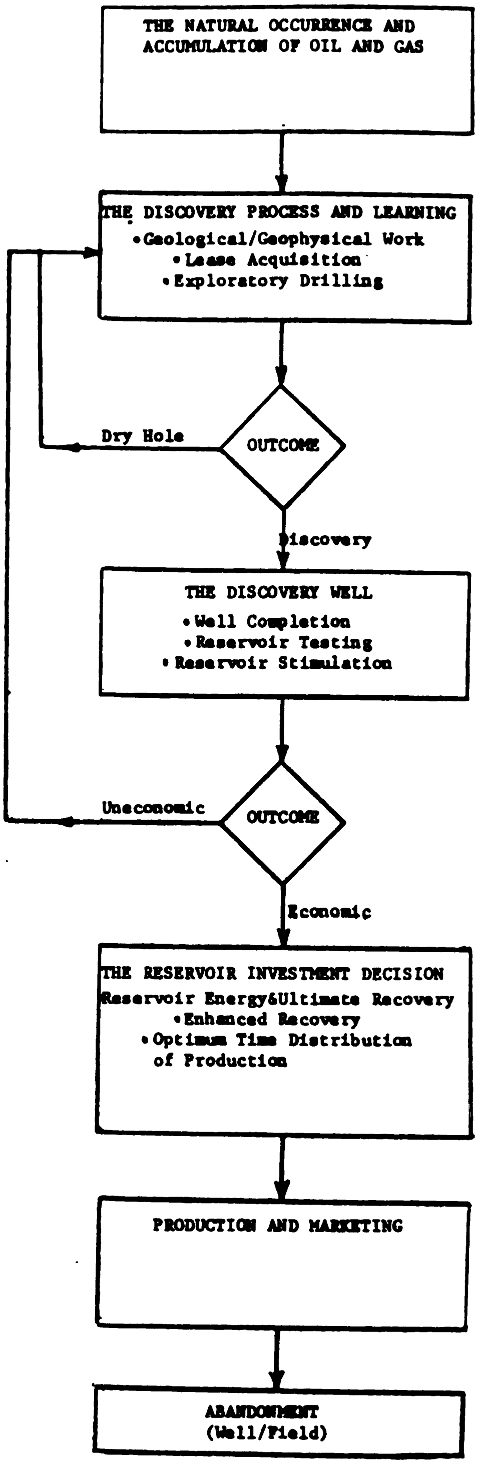


Figure 1. A schematic diagram of the oil and gas supply process.

gas. For convenience, this study refers to these substances as "oil" and "gas". (McDonald 1971; USDA 1980d)

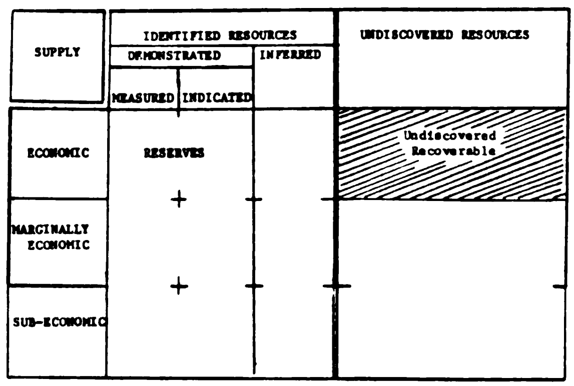
Crude oil, measured in barrels (42 gallons per barrel), is a mixture of hydrocarbons produced from wells in a liquid form. Natural gas, measured in cubic feet, is a mixture of gaseous hydrocarbons and can occur as associated gas, dissolved gas, or non-associated gas. Associated gas occurs as free natural gas, either in contact with or above an oil accumulation in a reservoir. Dissolved gas is mixed with crude oil, whereas non-associated gas does not occur with crude oil. Natural gas liquids occur with natural gas in a reservoir and are liquified at the surface in separators or gas processing plants. (Dolton et al. 1981)

Many theories explain the origin of petroleum, but the two most generally accepted are the organic and inorganic theories. The inorganic theory states that hydrogen and carbon deep in the earth were brought together under pressure and temperature to form oil and gas. The oil and gas then collected in natural traps underground.

The organic theory is more generally accepted among scientists. This theory hypothesizes that hydrocarbons were formed from dead animal and plant life, buried at the bottom of ancient seas and lakes. Mixing with sand, mud, and other sedimentary materials, the organic debris decomposed by pressure, temperature, and bacterial action, forming sedimentary layers. As more sedimentary layers accumulated over millions of years, the deeper layers were progressively compacted forming source beds of sedimentary rocks saturated with sea water and petroleum hydrocarbons from the decomposed animal and plant life. The same pressure and heat which created the petroleum hydrocarbons also created other layers of sedimentary rocks (e.g., sandstones, shales, and limestones). Some of these layers of sediments were very dense (e.g. shales), whereas others had void spaces between the particles of materials (e.g., sandstone or limestone). The liquid and gaseous petroleum hydrocarbons probably moved from the source rock into the more porous rock soon after their generation. Being lighter than water, the petroleum compounds moved upward through the more porous rock until a nonporous, impermeable rock layer was encountered. Subsequently all rock layers were folded, bent, or broken from movements of the earth's crust. Following these movements, the petroleum hydrocarbons migrated, vertically and/or horizontally, until trapped in the bends and folds. (McDonald 1971; Porter 1965)

The above description hypothesizing the origin, migration, and accumulation of petroleum indicates that four conditions must be satisfied for the formation of an oil and gas deposit. The first condition is that the oil and gas is formed from a source (i.e., buried land and sea life). The timing must have been right for the buried land and sea life to decay and recombine to form a mixture of hydrocarbons for the second condition. A third condition is that a reservoir (e.g., sandstone and limestone) or series of such rocks must have been present for the petroleum liquids to migrate into and to occupy vacant pore space. The last condition is that a local structure or trap (i.e., impermeable layer or section of rock) was available to cause the migrating petroleum to stop and accumulate in a deposit. The portion of the trap containing the petroleum liquids is known as the reservoir, and this is what the petroleum geologist looks for in searching for oil and gas.

The most common classification system and set of terms used for defining oil and gas resources is shown in Figure 2. This system, developed by the U.S. Geological Survey and U.S. Bureau of Mines in 1976, is used throughout this study. The terms are defined immediately following Figure 2 (Dolton et al. 1981).



SOURCE: Adapted from Dolton et al., 1981. Estimates of undiscovered conventional resources of oil and gas in the United States. U.S. Geological Survey Circular 860. p. 6.

Figure 2. A classification system for petroleum resources.

TOTAL RESOURCES - The total amount of oil and gas in the earth's crust without reference to any portion that is currently extractable. The terms oil and gas in-place are equivalent to total resources.

IDENTIFIED RESOURCES - The portion of total resources whose location and quantity is known or estimated.

UNDISCOVERED RESOURCES - The portion of total resources whose location and quantity is unknown and estimated from only broad geologic knowledge and theory. These are resources outside of known oil and gas fields.

ECONOMIC RESOURCES - The portion of total resources both identified and undiscovered that are economically extractable. Recoverable resources is a synonynous term.

RESERVES - The portion of identified resources that are economically extractable. Measured reserves are equivalent to proved reserves. Indicated reserves are those additional resources available from improved recovery techniques. Inferred reserves are those additional resources from extensions and revisions of known oil and gas fields.

UNECONOMIC RESOURCES - The portion of identified resources that includes the marginally economic and subeconomic resources which are not presently recoverable because of either technological or economic factors. The subeconomic resources are more uneconomic than the marginal economic resources.

SUPPLY - The portion of reserves (usually proven reserves) that are available for present day human consumption. The amount equal to current production.

POOL - An underground accumulation of oil and/or gas in a single discrete deposit. The term reservoir is equivalent.

FIELD - A single pool or set of multiple pools which are all grouped or related to a single geological structure or trap.

The Discovery Process

Petroleum exploration is the search for those traps that may have accumulated petroleum in commercial quantities. The discovery process consists of three separate and distinct phases which include pre-exploration, leasing, and exploratory drilling. This portion of the supply process is the most uncertain and in many situations the most expensive. In some areas where the risk is unusually high (e.g., Prudhoe Bay Alaska; Western Overthrust Belt), several firms may combine their capital investment resources in the search for petroleum to reduce the risk of loss to any individual firm. Whether a single entrepreneur or group of multi-national conglomerates searches for petroleum, all are faced with not knowing the chances of a dry hole or an oil or gas field discovery.

Types of Traps

Most petroleum traps can be categorized as structural, stratigraphic, or strati-structural. Structural traps were formed by either the folding or faulting of the reservoir rock from the movement of the earth's crust. Some of these traps are the easiest to find since there is evidence of them on the surface. Stratigraphic traps occur in sediments that have not been bent or broken (e.g., East Texas Oil Field). These traps result from variations in reservoir rock characteristics and are subtle and difficult to find. The last type, strati-structural, can have features of both structural and stratigraphic traps (e.g., Prudhoe Bay Field) and can also be quite subtle and almost as difficult to find as stratigraphic traps. Figure 3 shows several types of oil and gas traps. (USDA 1980d; Miller et al. 1975)

Almost universally, all traps contain salt water in addition to petroleum. Oil traps are usually found with gas present, either dissolved in the oil or partially dissolved in the oil and partly as a "cap" above the oil. In contrast, gas traps are usually found unassociated with oil. Both oil and gas traps can vary widely in physical properties and in content of impurities. Because of differences in weight, gas is found at the highest part of the trap, oil or oil with gas below the gas, and then salt water.

Preliminary Exploration

Before a firm or group of firms decide to drill an oil or gas well on a particular site, often several months or years of pre-exploration work are necessary to select a drill site. The predrilling search consists of both geological and geophysical work. The geological work includes the study of surface geological features (e.g., faults, outcroppings, and uplifts) that will provide information about potential subsurface traps. If these studies show the probable occurrence of oil and gas traps, on-the-ground geological mapping may follow.

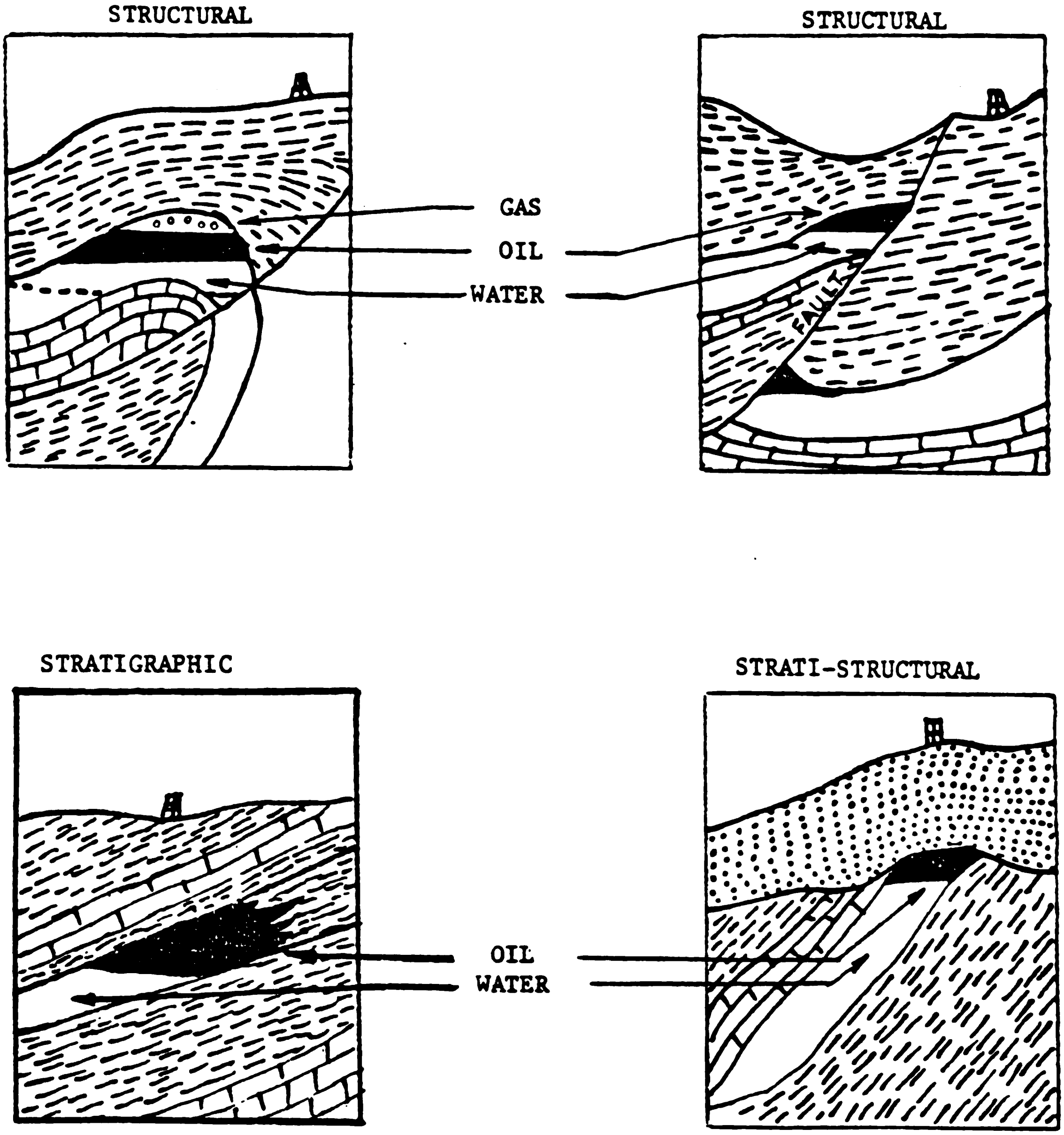
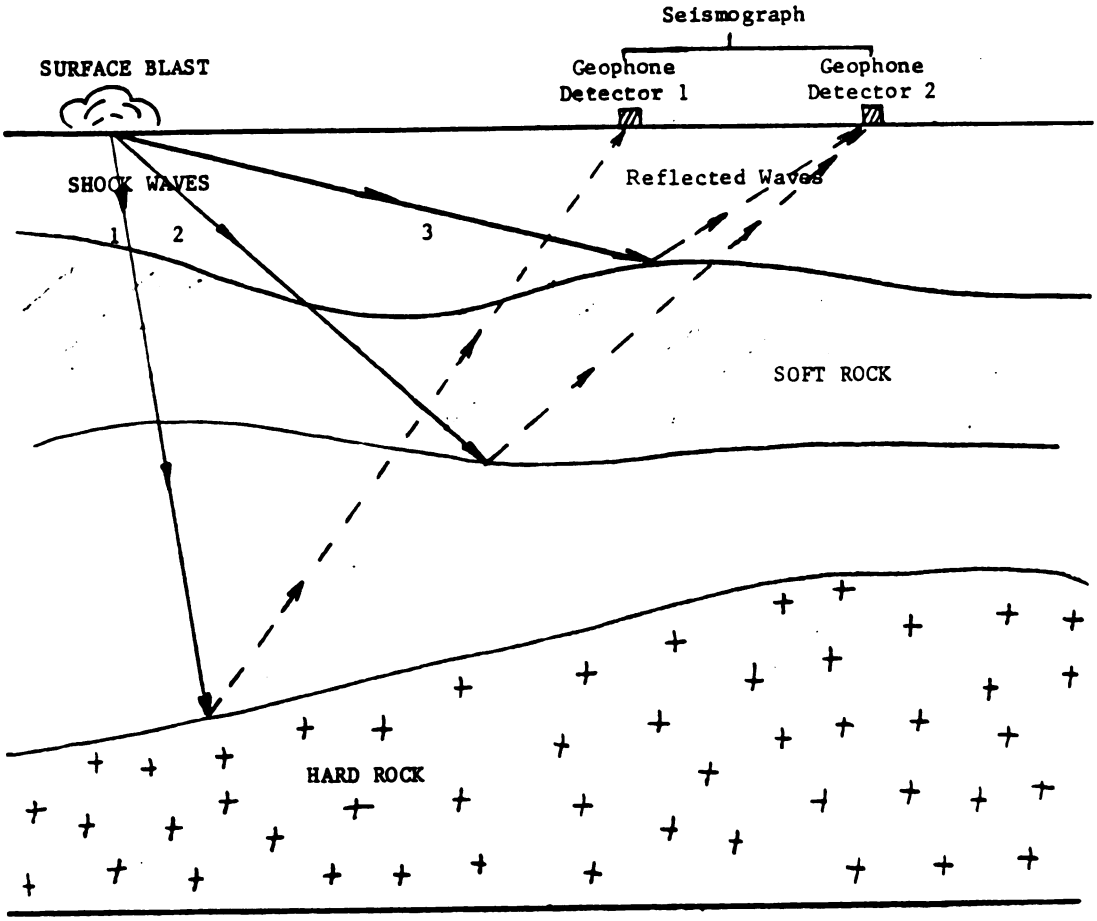


Figure 3. Some common types of oil and gas traps.

Geophysical methods often follow the geological work to obtain additional information about subsurface conditions. Seismic methods are the most popular of the geophysical methods. These surveys gather subsurface geological information by recording impulses from shock waves artificially generated. The basic concept of seismic testing is that different rocks have different sound-transmitting characteristics. For example, when a charge of dynamite is set off at the surface, the shock waves from the explosion travel downward striking successive layers of rock and are reflected back to where they are measured by an instrument known as a seismograph (Figure 4). By correlating the intensity of the reflected waves and the differences in the amount of time it took to travel down and back, due to variation in the rock, maps can be generated of the subsurface structures (USDI 1981). The shock waves are often generated by thumping, vibrators, or surface and subsurface explosives. To conduct seismic operations on national forest lands the explorer must secure a prospecting permit.

Seismic surveys and techniques are becoming more widely used because of the success in accurately defining subsurface structures. The series of major oil and gas discoveries in the Utah-Wyoming portion of the Western Overthrust Belt are directly related to seismic tests and refinements in these techniques. The development of light-weight seismic equipment transported by helicopter in the mid-seventies allowed explorers the opportunity of access to the inaccessible and environmentally sensitive areas typical of the Western Overthrust Belt. Additionally, rapid advances in computer processing capabilities are now providing geophysicists with greater interpretative techniques. For example, three-dimensional (3-D) surveys, as opposed to the traditional



SOURCE: Adapted from USDI, 1981. Oil and gas environmental assessment of BLM leasing program: Butte District. p. 23.

Figure 4. A schematic diagram of seismic testing.

two-dimensional surveys, record seismic reflections in three dimensions providing a more accurate and representative picture of the subsurface geology. The expense (i.e. 1 million dollars/square mile) of 3-D surveys is justified by the usefulness of discovering additional reserves and by reducing the growing cost of delineating and developing oil and gas fields (Petroleum Information Corporation 1981; Graebner et al. 1981). As advances in seismic exploration techniques continue, the petroleum industry moves closer to the elusive goal of pinpointing oil and gas deposits from the surface (Frazier 1981).

Leasing

If the results seem favorable for the occurrence of an oil or gas deposit after the preliminary exploration, the petroleum explorer acquires a lease to secure the right to drill and to produce any petroleum found. In consideration of the rights acquired, the explorer, if he has a competitive lease which is not typical of the Western Overthrust Belt, may make an immediate cash payment (i.e., lease bonus) to acquire the lease from other competitors, promises to pay a periodic lease rental fee, and, if oil or gas is found, promises to pay a royalty on any production realized to the land owner.

Any U.S. citizen or domestic corporation may lease national forest lands for oil and gas exploration. A lease may be obtained from the Department of Interior, Bureau of Land Management. The Forest Service cooperates with the Bureau of Land Management and makes lease recommendations to protect surface resources and uses involving national forest lands. These recommendations, known as lease stipulations, are an effective means for protecting the environment while allowing full enjoyment of the leasehold. The approved method for processing oil and gas leases in the Northern Region is shown in Figure 5.

Oil and gas leases are issued through competitive and noncompetitive processes. All submerged lands of the outer continental shelf and onshore lands on a known geological structure[6] of a producing field are leased on a competitive basis. The competitive lease lands are divided into tracts not exceeding 640 acres. The primary term of these leases is five years and as long as oil and gas is produced in commercial quantities thereafter. The lease is issued to the bidder offering the highest lease bonus, either by public auction or sealed bids. The annual rental rate is two dollars per acre before discovery and/or as otherwise prescribed in the lease. (McDonald 1979)

Noncompetitive leases are limited to 10,640 acres and may be rented for one dollar per acre annually for the first five years and three dollars per acre thereafter. The primary lease term is ten years. These leases are offered to the first applicant in the case where the particular parcel was previously unleased or to the winner of a drawing for previous parcels that have been expired, cancelled, relinquished, or terminated. Both competitive and noncompetitive leases pay royalties on any produced oil and gas. For purposes of conserving petroleum resources, the Secretary of Interior may waive, suspend, or reduce the royalty payments whenever it is necessary to promote development or allow for the economical operation of the lease. (McDonald 1979; USDA 1980d)

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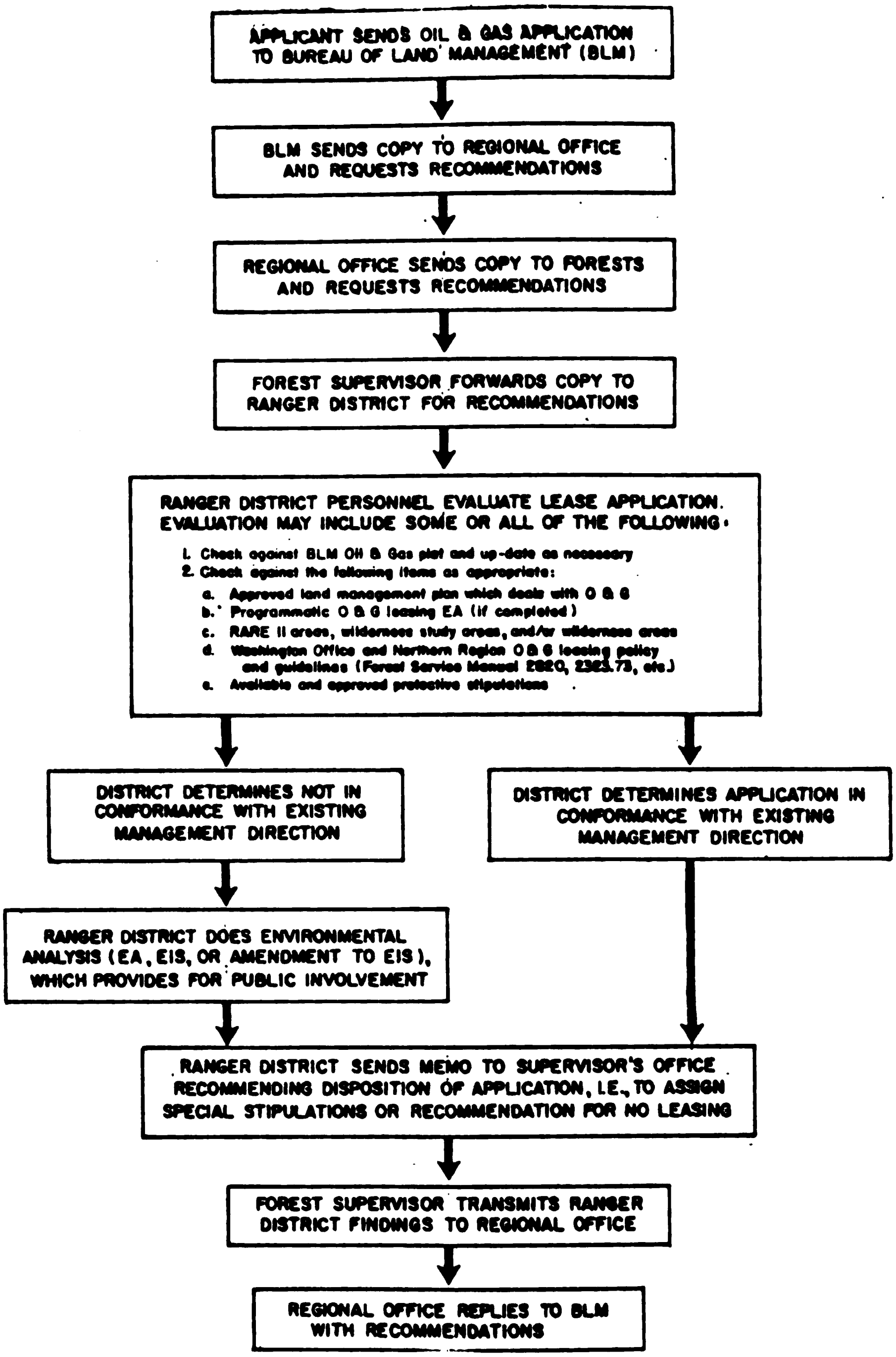
[6] A known geological structure is a trap in which an accumulation of oil and gas has taken place.



SOURCE: USDA, Forest Service 1980. Oil and gas activity in the Northern Region: an information document. Forest Service, R-1., p. 12.

Figure 5. The approved method of processing lease applications.

Exploratory Drilling

After preliminary seismic investigations have been completed and a lease has been obtained, exploratory drilling can proceed. Exploratory drilling may consist of stratigraphic test holes or exploratory wells. Stratigraphic test holes are usually shallower and drilled to acquire additional subsurface information. Exploratory wells are deeper and are drilled to test a probable subsurface structure for an oil or gas accumulation. If the exploratory well is dry, contains no commercial petroleum deposit, the explorer will plug the hole and abandon the site or plan for another exploratory well. A discovery of oil or gas usually leads to further testing and, if commercial quantities of oil and gas exist, preparations are made for production.

Before a planned exploratory well can be drilled on national forest lands, permission to drill the well must be granted by the Bureau of Land Management. Before a drilling permit can be approved, the explorer must provide a detailed operating plan to the Forest Service. The plan is reviewed and field inspections are scheduled to insure that the drilling site is feasible. Depending upon the sensitivity of the site, an environmental analysis or an environmental impact statement is prepared to determine if the drilling activities would have a significant impact on the environment. If no significant impact, the permit is issued and drilling commences. Usually, some general and specific stipulations may be applied to the permit to protect surface resources and uses. (USDA 1980d)

The desired location of the well is selected based on the geological and geophysical information. The principal concern is the location of the well relative to the probable subsurface structure.

Once the drill site is staked, access from local roads or highways is needed so the drilling rig and other heavy equipment can be moved onto the site. In rough and inaccessible terrain, typical of the Western Overthrust Belt, access and preparation of the drill site is one of the highest cost items in drilling a well. The size of the drill pad typically used in the Western Overthrust Belt is about 3 to 5 acres. The drill pad is prepared by clearing vegetation and leveling the area for the drill rig, mud pit, generators, storage facilities, vehicle parking, house trailers, and other equipment. Because drilling a well requires an adequate water supply (e.g. 20,000 gallons per day), a water source is established while the site is being prepared. Drilling sites are as self-sufficient as possible to minimize operating delays.

After the drill site has been prepared and the drill rig and support equipment moved onto the site, drilling commences. Drilling is accomplished with the use of rotary drill rigs. In drilling the well, the rig operator bores through numerous strata, some of which may be permeable and contain fresh water, salt water, or hydrocarbon compounds under pressure. The cuttings, or rock chips cut loose by the drill, are removed from the hole continuously through the circulation of drilling mud, or fluid, inside of the drill pipe. The geologist at the drill site examines the composition of the cuttings to identify the formation and structure from which the cuttings originated. If, on the basis of examining the cuttings, the formation may contain oil or gas, further tests and laboratory analyses are conducted.

Some of the problems encountered while drilling wells are high-pressure zones of oil, gas, or salt water, high concentrations of hydrogen sulfide gas, crooked holes, and lost equipment in the well hole. Protection from high-pressure zones is usually provided by the drilling mud (i.e. adding weighting material to the mud to increase its density to help overcome high pressures) and through well casing and cementing. In rare instances high-pressure zones can cause blowouts (an uncontrolled flow of fluids into the atmosphere), but these are controlled by blowout preventors. Blowout preventors are devices (i.e., large valves or metal rams) installed at the wellhead which seal off the well in the event of a blowout. Hydrogen sulfide gas is highly toxic and flammable, and sometimes occurs in lethal concentrations. Because of the problem, stringent safety precautions are taken and most hazards associated with the gas can be avoided. Crooked holes are a frequent and expensive problem in oil and gas drilling. Most drilling operations make an effort to keep the hole straight, but it is difficult to drill a straight hole 15,000 to 20,000 feet. Directional drilling can be used to keep holes straight, but such techniques are expensive and are avoided. Finally, lost equipment in the well hole, such as broken drill stem pipe, is also expensive, and, if it cannot be recovered, the hole may have to be abandoned or directionally drilled. (Porter 1965; USDA 1980d)

The drilling continues until the target depth has been reached. The depth of exploratory wells depends upon the geology of the area. In the Western Overthrust Belt, wells are commonly drilled to a depth of 10,000 to 15,000 feet. Wells of this depth range may require 6 to 9 months to drill. Because of the often rugged terrain and complex geology, an exploratory well in the Overthrust Belt may cost 6 to 12 million dollars.

The Discovery Well

An exploratory well becomes a discovery well when it yields commercial quantities of oil and gas. A producing well is completed with the installation of casing around a smaller gauge string of pipe, through which fluids are conducted to the surface, and the necessary control valves. Figure 6 is a schematic diagram of the well.

The purpose of the several strings of casing is to protect the hole from underground water and loose earth falling from the surface and to protect fresh water zones from drilling and produced fluids. Each string of casing run into the well is smaller than the previous string, since it must be run inside of casing already set. The well casing is permanently set in the well hole, minimizing repair and replacement costs. The tubing is a string of pipe through which the oil is produced. (American Petroleum Institute 1976)

Once the producing well is completed, the well begins to flow, producing fluids which are captured into a surface tank battery. These fluids are tested for their composition and measured to determine well flow rates. Other tests may include bottom-hole pressure tests to measure reservoir pressure at specified depth intervals. The purpose of these tests is to provide information to the reservoir engineer about production capabilities and reservoir pressure of the producing zones so that proper production practices can be established. (American Petroleum Institute 1976)

If these tests indicate the well can be an economical producer, but the rate of flow is not considered adequate, various well-stimulation treatments may be conducted. These treatments may include shooting, fracturing, acidizing, or chemically treating the

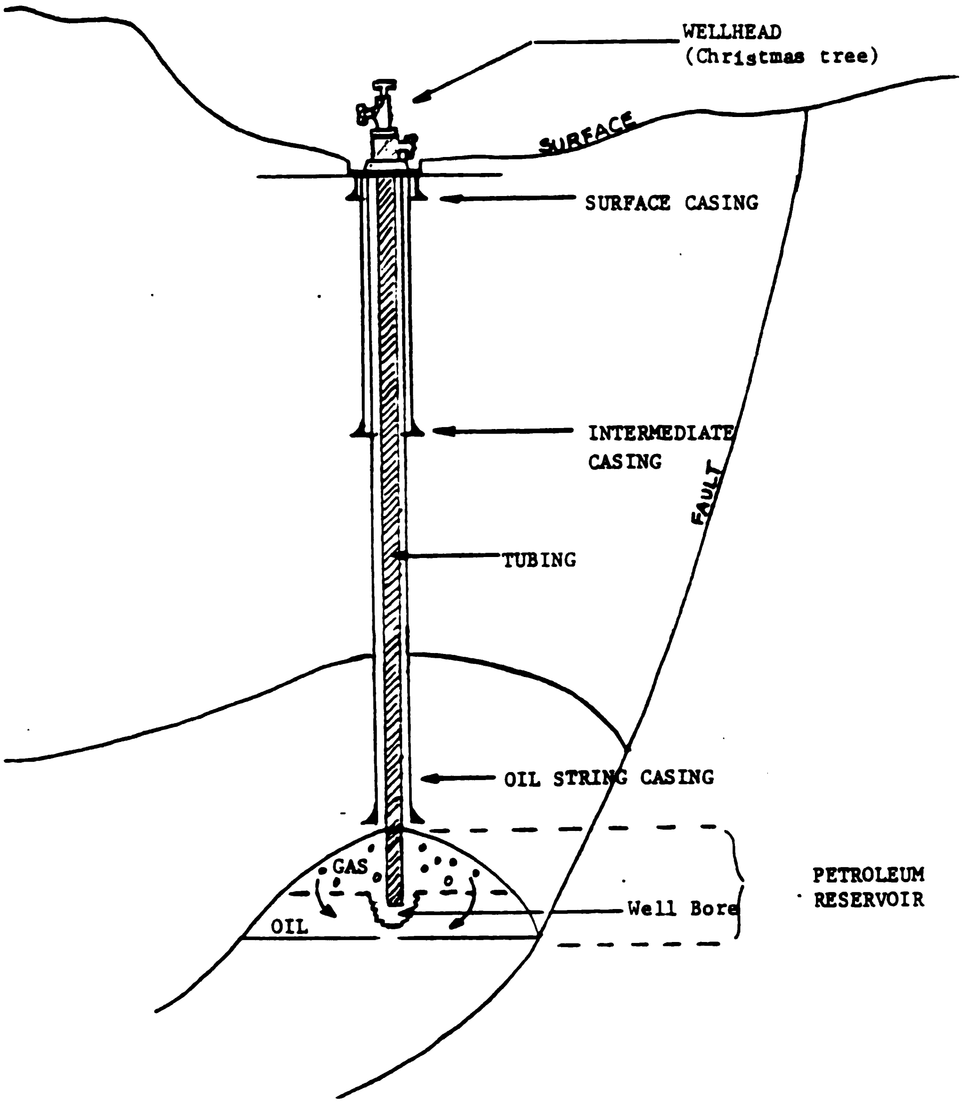


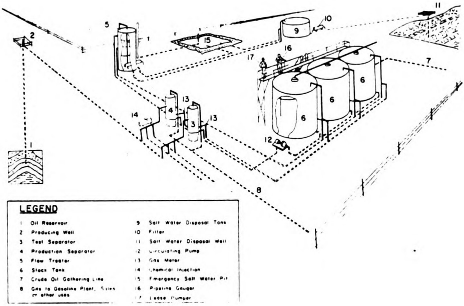
Figure 6. A sketch of a well from the surface to the oil producing formation.

reservoir. All of these treatments cause the flow of reservoir fluids to increase into the well bore. After various well tests and treatments are completed, the well is equipped with the necessary pumping equipment, flow lines, surface equipment to separate the reservoir fluids, and oil storage tanks. (American Petroleum Institute 1976)

Production in an oil field begins soon after the discovery well is completed. The surface equipment facilities may be temporary at first and become more permanent as more is learned about the reservoir. The extent of these facilities is controlled by expected future production, number of producing wells, volume of gas and water produced, and whether a unit agreement exists for managing the reservoir. Figure 7 shows the flow of oil from the reservoir to the central storage tank battery where it awaits shipment to a refinery, either by truck or by pipeline.

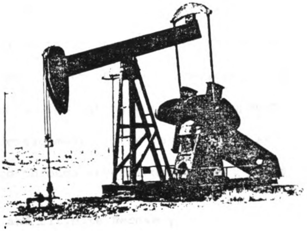
Naturally flowing oil wells require only a minimal amount of surface pumping equipment. Generally, however, the pressures in a reservoir are insufficient to force the fluids to the surface and as a result some method of artificial lift is necessary. The most common type of artificial lift used is the horsehead pump (Figure 8). These surface pumps are usually powered by either electric motors or internal combustion engines.

Production from a gas reservoir is more uncertain because, until a sufficient amount of gas reserves are proved and a pipeline to market has been constructed, gas wells are usually shut-in after completion. The period of time these wells are shut-in may be from several months to years. Because most gas wells produce under natural energy, pumping equipment is not required. The extent of the surface equipment will depend upon the amount and kind of natural gas. Large



SOURCE: U.S. Department of Interior, 1963.

Figure 7. A schematic diagram of flowing oil production.



SOURCE: USDI, 1981. Oil and gas environmental assessment of BLM leasing program: Butte District. p. 31.

Figure 8. A horsehead pump.

gas deposits with concentrations of hydrogen sulfide gas (H_2S) require gas plants to remove the H_2S. Removal of the H_2S is necessary since high concentrations are highly corrosive to pipelines. Additionally, the gas plants separate water and liquid gases from the natural gas. (USDI 1981)

The Reservoir Investment Decision

After sufficient performance data are obtained from the discovery well and the presence of a commercial oil or gas deposit has been determined, operators holding the leases proceed to develop the reservoir. The operator's basic problem is to determine and to implement the most profitable rate of production at each point in time of the reservoir life or determine and implement the time-distribution of production that maximizes the present value of the reservoir at a given acceptable rate of interest.

The primary purpose of reservoir development is to gain additional access to the petroleum by drilling more wells. However, development drilling also provides information on the productive acreage of the reservoir, variations in the thickness of the reservoir, estimates of oil and gas volumes, and the type of reservoir energy present. This information is useful for making future development and operating decisions. The development of the reservoir is an on-going process and many fields may go through several development phases. (McDonald 1971)

Reservoir Energy and Ultimate Recovery

Oil and gas deposits are initially found under a substantial pressure causing the petroleum fluids to move through the pore spaces of the reservoir rock and ultimately to the well bore. An oil or gas well produces because the hole creates a pressure loss, causing the reservoir fluids to move to the well bore in order to restore an equilibrium of pressures within the reservoir. Oil production declines with time as the reservoir pressure drops. (Porter 1965)

The driving forces or mechanisms which cause the oil or gas to flow through the reservoir rock and into the well bore consist of dissolved-gas drive, gas-cap drive and water drive (Figure 9). Two or more may function in combination, but usually one dominates. Gravity supplements all three and can be a major force in oil recovery. Because oil cannot move itself, usually the energy in the gas or salt water which is under substantial pressure displaces or drives the oil through the reservoir rock. (McDonald 1971)

Those reservoirs where various quantities of gas are dissolved in the oil are called dissolved-gas drive reservoirs. As the gas escapes from the oil and expands, it drives the oil through the reservoir and assists in lifting it to the surface. Usually the least efficient of the drive mechanisms, the maximum recoveries yield only 15 to 25 percent of the original oil in-place. Generally, production from a reservoir with a dissolved-gas drive peaks almost immediately and thereafter declines rapidly. (Levorsen 1954; McDonald 1971; American Petroleum Institute 1976)

In situations where more gas is present than the oil can hold, the extra gas forms a cap over the oil and provides additional energy for the production of oil. The gas cap expands into the pore spaces of the reservoir previously occupied by oil and gas, and, in this way, reduces the pressure loss. The gas-cap drive production process is more

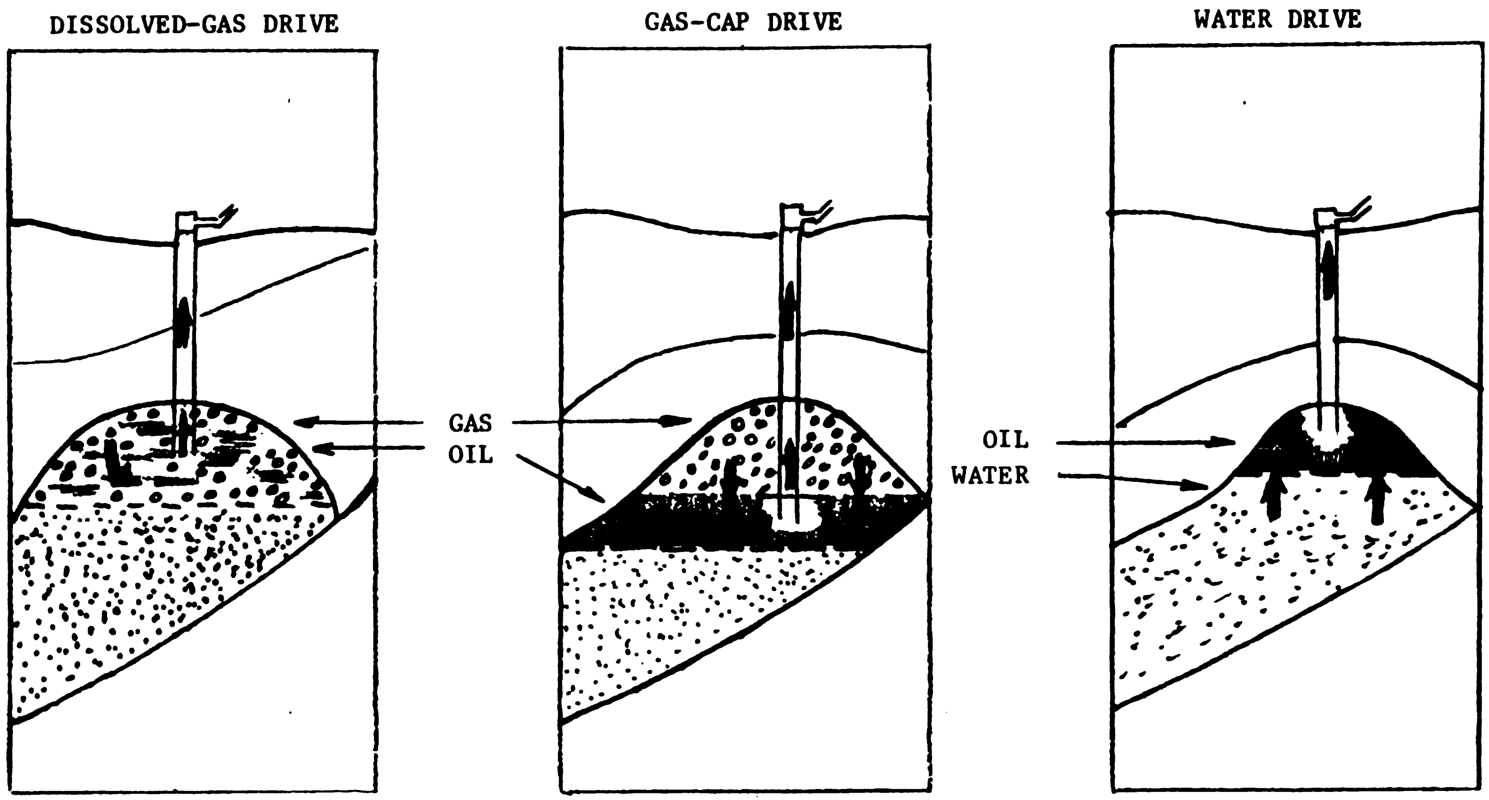


Figure 9. Drive mechanisms for petroleum reservoirs.

efficient since 25 to 50 percent of the original oil or gas in-place can be recovered. Production from such a reservoir usually has a longer period of peak production and declines less rapidly. (American Petroleum Institute 1976; Levorsen 1954)

Finally, the water drive reservoirs have tremendous quantities of salt water to store energy for producing oil and gas. Oil is displaced by the encroachment of water from below progressively pushing the petroleum to the well bore hole. Water drive mechanisms are capable of yielding up to 50 percent of the original oil in-place. The production history of these reservoirs typically follows a longer period of peak production than the other types of drive mechanisms before a decline in production occurs. (Levorsen 1954)

The high rate of expansibility of gas make non-associated gas reservoirs very efficient with recoveries of up to 85 percent of the original gas in-place. Gas reservoirs are under very high pressures and the pressure drop at the well bore simply causes the gas to flow to the surface. The only other driving force which may contribute to gas production is an external water drive. (Porter 1965)

<u>The Maximum Efficient Rate of Production</u>

The maximum efficient rate (MER) of production is the rate at which an oil or gas reservoir produces most efficiently (Figure 10). This rate is defined as the highest rate of production without waste. Waste is the inefficient use of reservoir energy to produce oil. The MER varies from one reservoir to another and from one stage of reservoir depletion to the next. For any reservoir, the MER of production can only be determined after enough oil and gas has been produced to identify the type of drive mechanism and the production rates causing the lowest decline in pressure. (Levorsen 1954)

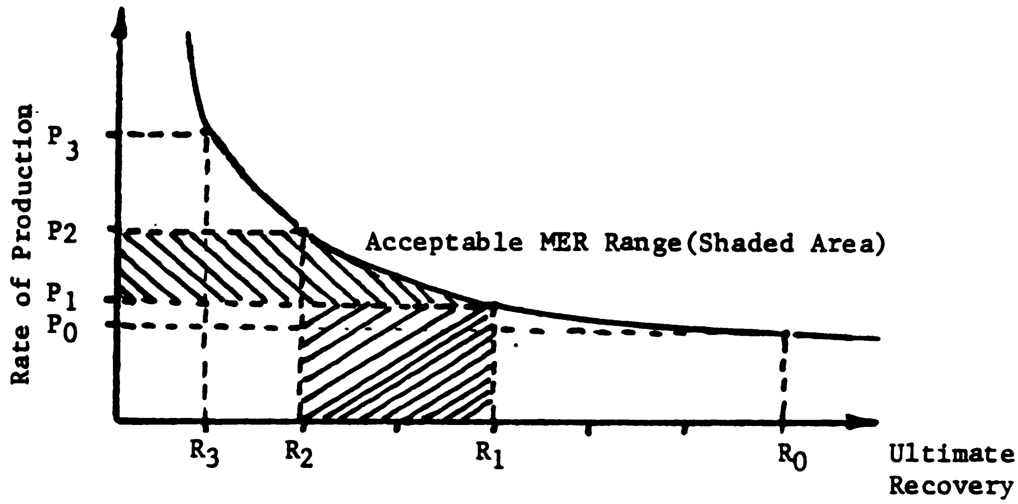


Figure 10. An illustration of the maximum efficient rate of production.

The ultimate oil recovery from most reservoirs is directly related to the rate of production. The relationship for a given drive mechanism is a maximum rate of production that will permit efficient recovery (P_2R_2). Production rates lower than this maximum may result in higher ultimate oil recovery (P_1R_1), but increases in production above this maximum usually leads to a loss in ultimate recovery (P_3R_3). A rate of production so low as to yield no return on investment would be uneconomic (P_oR_o). (McDonald 1971)

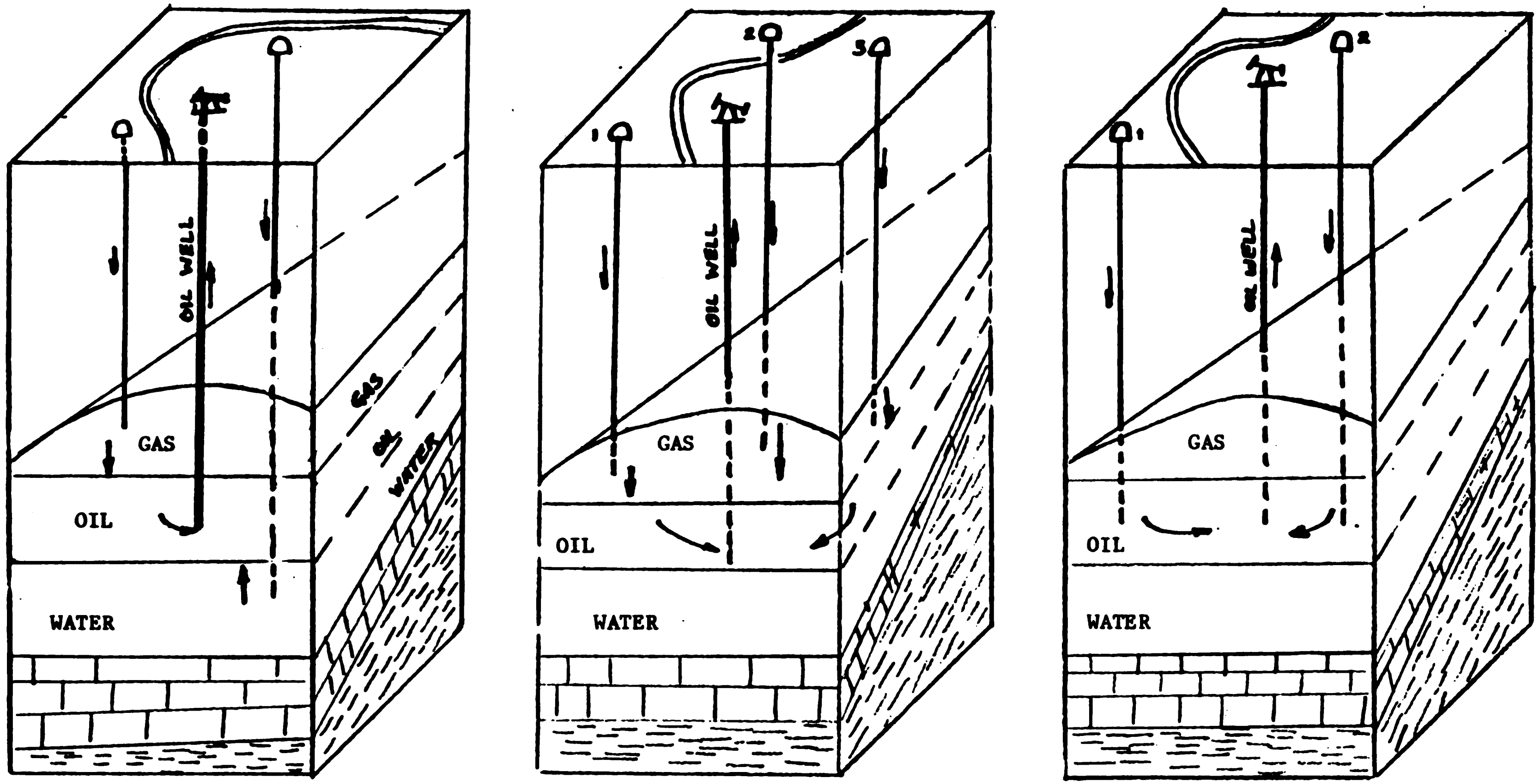
Ultimate recovery in both water drive and gas-cap drive reservoirs are sensitive to production. The MER of production for a water drive reservoir is the rate which does not cause water to encroach more rapidly than the oil can be expelled. Too rapid a production rate causes some of the oil in-place to be left behind which could otherwise have been recovered. Under a gas-cap drive reservoir, the MER of production is the rate at which the gas displaces the oil but does not by-pass the oil. (McDonald 1979)

Ultimate recovery from a dissolved-gas drive reservoir is not sensitive to the rate of production. The MER of production for such reservoirs is too slow to be profitable. In order to increase the rate of production to a profitable level, the reservoir pressure is permitted to decline rapidly. There is a low recovery of oil since only a limited amount of gas is available to expel the oil. In a non-associated gas reservoir ultimate recovery is usually not dependent upon the rate of production and therefore the MER does not apply for such a reservoir. (McDonald 1979)

Improving Recovery

The petroleum industry has invested great sums of money on the research of improving oil and gas recovery. Economically, unrecovered oil now left in abandoned oil fields may exceed 300 billion barrels (Kamath 1982). Improvements in petroleum extraction efficiency could substantially add to the nation's declining oil reserves. The three principal methods of improving recovery are oil and gas pressure maintenance, secondary recovery, and tertiary recovery (Figure 11).

The natural reservoir pressures cause the petroleum to move to the well bore and either flow to the surface or be pumped out. This initial stage is considered primary recovery. Because oil production under natural drive is accompanied by a declining reservoir pressure, the operator may find it economical to implement recovery techniques before the reservoir pressure has been substantially depleted. Pressure maintenance is usually achieved through gas injection, water injection,



PRIMARY RECOVERY
with
Pressure Maintenance Program

SECONDARY RECOVERY
with
Gas Injection Program

TERTIARY RECOVERY
with
Steam Injection Program

Figure 11. Three methods of oil recovery.

or a combination of these two. The pressure maintenance injections are usually confined to areas below the oil zone, in the case of water, or above the gas zone, if gas is injected. (McDonald 1971)

Secondary recovery is used when the primary natural drive has been completely or almost completely exhausted. The techniques are similar to pressure maintenance and primarily include gas injection, water flooding, and underground burning. Tertiary recovery uses advanced techniques of steam injection or chemical injection. Secondary recovery uses the same general principle of oil displacement as the initial natural drives, whereas tertiary recovery lowers the oil viscosity (thickness of oil) in the reservoir. Secondary and tertiary recovery techniques inject fluids in a geometric pattern throughout the reservoir rather than in a restricted area above or below the oil zone as in pressure maintenance. Because secondary recovery techniques provide very little improvement of recovery in non-associated gas reservoirs, the techniques are not used. Additionally, secondary recovery has been found to be more economically prudent for dissolved-gas drive reservoirs than for gas-cap or water drive reservoirs. (Porter 1965)

The economic attractiveness of these enhanced recovery techniques has been that no additional lease acquisition and exploration expense is necessary. At the same time the additional income is usually more certain than from another increment of exploration activity. Also very little development drilling is needed since old producing wells can often be used for injection purposes.

Reservoir Development and Production

The basic problem the operator of the oil or gas reservoir faces is determining the most profitable rate of production at each point in time of the reservoir life. Optimizing the rate of production and time-distribution of oil and gas extraction depends upon:

(1) the reservoir drive mechanism,

(2) alternative drive mechanisms,

(3) the maximum volume of reserves under each drive mechanism,

(4) the feasible rates of production under each drive mechanism using different number of wells,

(5) the costs of drilling and equipping additional wells,

(6) the potential loss of recoverable reserves under each drive mechanism at different production rates, and

(7) the future prices of oil and gas over the life of the reservoir. (McDonald 1971)

Because the optimum time-distribution of production is defined for only one point in time, changes in any of these factors would also change the optimum time-distribution of production. For example, a rise in expected future prices relative to current prices encourages postponement of current production. A decline in the costs of drilling and equipping wells tends to encourage additional development drilling and accelerate reservoir depletion.

Determining the optimum time-distribution of production consists of a two step process. The first step is to achieve the maximum net present value[7] of expected income within the limits of the existing

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[7] A measure of economic efficiency which is the sum of discounted net cash flows (benefits less costs) for every year in the life of a development project.

wells. When producing oil or gas, the operator has the choice of producing more in the earlier time periods as opposed to producing more in later time periods. Therefore, the operator must compare the discounted gains and losses of shifting some production between the present and future time periods. The operator would maximize the net present value of expected income when no further gain in the net present value can be made by shifting production from one time period to another. If an operator increases present production by 100 barrels, he foregoes, at some future period, the future net revenues returned from the 100 barrels. In addition to shifting production between time periods to maximize the net present value of expected income, the operator must also be aware that a loss of net revenues can occur due to a fraction of the oil which is not recoverable as a result of a too rapid rate of production. The significance of this latter factor, however, depends upon the sensitivity between current production and ultimate recovery. For some oil reservoirs this can be a significant factor (i.e., gas-cap; water drive) whereas for others (i.e., non-associated gas) this factor is insignificant. (McDonald 1971; 1979)

The second step in determining the optimal time-distribution of production is whether or not to increase the number of wells and achieve some higher net present value of the reservoir. If an operator adds more wells, increasing the present production capacity, and the net present value of income is larger, then the additional wells are worth installing. The maximum net present value of production is achieved by installing additional wells until the marginal well cost is equal to the marginal revenue produced from these wells. Any increase in the number of wells causes production to be more concentrated in earlier periods, and, consequently, the optimum rate of production with the additional wells is different from that of the original number of wells.

Thus the optimum time-distribution of production is determined by searching for that optimum number of wells and optimum present rate of output which maximizes the net present value of the reservoir property. These two optimums are codetermined and depend upon the many factors mentioned above. The optimum time-distribution of production is defined for one point in time, and changes as the above factors change with time.

Thus far the discussion has implied that each reservoir is developed and exploited as a unit by a single operator. Now assume that a reservoir is developed and depleted by numerous competitive operators. Under this situation each operator uses the above named factors for determining the maximum net present value of income, plus one other, the possibility of petroleum drainage across property lines. If operator A postpones production and operator B accelerates production, the result is that operator B's rapid production causes petroleum from operator A's property to drain into operator B's property. Therefore, operator A loses oil to operator B by postponing production until the future. Understanding this, operator A also accelerates production so that his oil is not lost to operator B. The impact of this situation is that the reservoir is exploited more rapidly with less ultimate recovery due to excessively dense drilling by both operators. This behavior will continue until the reservoir is depleted with neither operator concerned about the efficient use of reservoir energy or the loss in ultimate recovery.

This situation is typical of the common property problem where users of the petroleum reservoir (i.e., common property) have equal rights in the use of the resource and each user has the right to consume as much of the resource as he wants. Situations of this type can lead to the destruction of the resource. For example, at one time the western grazing lands were common property. Each rancher could use as much grass without limit to grow his animals and each understood that if he did not use all the grass possible, his neighbor would. The only way to exclude others was to consume the resource. The result was severe land erosion and loss of the resource. This has sometimes been referred to as "tragedy of the commons".

The effect of reservoir competition then creates an incentive for each operator to act in his best interest rather than the operators' as a whole, and the net present value of the reservoir is significantly reduced. However, the so called "tragedy of the commons" is not necessarily inevitable. Schmid (1978) indicates that where it is costly to exclude users of the common property resource, typical of the petroleum reservoir, a system of common property with learned habits of limited use is one alternative for solving the problem. In the case of petroleum reservoirs, the petroleum conservation regulations practiced by the states helped to restrain the private operators of the reservoir from exercising in the highly competitive behavior leading to the inefficient use of the reservoir. These regulations include well spacing, gas flaring, gas-oil ratio regulations, direct production restrictions, and unitization of reservoirs. The regulations have served in a similar manner as a "system of learned habits of limited use".

Except for unitization, the other forms of regulations do not insure that the reservoir is developed and exploited so that it will maximize the net present value. Unitization of petroleum reservoirs involves the pooling of private property interests of a single reservoir, an acceptance of a single management plan by all interested parties for the future operation of the reservoir, and the equitable allocation of costs and benefits among all participants under the unitization agreement. The concept on which such an agreement is based upon is that the reservoir is the natural producing unit and not the wells. The drive mechanism of the reservoir is common to all wells, and, if production increases at one well, it will necessarily reduce production at all other wells. The movement of fluids in the reservoir do not respect lease lines or areas served by various wells. Unitization is another alternative for solving the common property problem which manages the reservoirs more efficiently than many competing lease holders since it increases ultimate recovery, reduces the investment costs in development wells, and more closely maximizes the net present value of the reservoir.

Unitization, however, requires adequate knowledge of the reservoir and its environment, which can only be acquired after a substantial amount of development. Depending upon how early development is carried out, the future opportunities to reduce development and operating costs through unitization are limited. Unitization is difficult to accomplish where the reservoirs involved are very large and there are many diverse property interests. Problems inhibiting voluntary unitization include pride of ownership, lack of reservoir data, profitable obstructionism, mistrust, and fear of reduced production (Lovejoy and Homan 1967).

Voluntary unitization agreements can usually be implemented in cases where there are few lease holders of a common reservoir. (McDonald 1971)

Abandonment

Oil produced from the numerous wells is marketed to refining companies or pipeline companies. The oil is collected from lease tanks through field gathering lines and shipped through larger pipelines to a refinery. In some situations, the oil may be trucked to the refinery. A similar situation exists for gas, except that gas is always shipped through a network of pipelines. Before the gas is shipped, it must be conditioned to remove any hydrogen sulfide gas and is very often compressed for transport. Buyers of gas include large utilities who distribute it to their consumers and large industrial firms.

The pipeline transportation systems serve many fields and are thus used for long periods of time. Field life spans often last 20 years but vary due to the different characteristics. The number of producing wells in a field can vary from a few to several hundred. Some wells may stop producing early in the field life whereas others may produce for the entire life of the field. Once all of the reserves are depleted from the field, the field is abandoned. Generally after each well is abandoned, some form of reclamation takes place to prevent erosion, to control pollution, and/or to preserve scenic values. Reclamation may also occur after seismic exploration and exploratory drilling operations.

CHAPTER II

MODELING THE OIL AND GAS SUPPLY PROCESS

Introduction

Petroleum represents the major source of energy for the nation's industrial system and is a vital element for our national security. Past energy shortages of gasoline, heating oil, and natural gas have created a growing interest in estimating the remaining undiscovered oil and gas resources. The intent of this chapter is to review the various methods used for petroleum resource appraisal and to introduce the appraisal method for this study.

Petroleum Resource Appraisal in Perspective

Petroleum Resource Appraisal of the Past

The first survey of the nation's undiscovered petroleum resources was published in 1909 by the U.S. Geological Survey (McCulloh 1973). Since then many individuals and organizations have attempted to estimate the nation's petroleum resource potential. An interest has been maintained in appraising undiscovered petroleum resources to provide criteria for investments in the petroleum industry, to provide information about oil and gas supplies to the federal government in order to develop a domestic energy policy, and to provide the American public with information about future petroleum supplies since present trends indicate the end of an era of low-cost energy and the beginning of a greater dependence upon foreign oil.

Many methods of petroleum resource appraisal have been used in the past including the qualitative numerical grading systems and the various quantitative methods. The three quantitative approaches are geological/volumetric, geological/mathematical, and production/mathematical (Barss 1978). Table 1 summarizes the specific methods and whether the method applies to a prospect, play, or basin assessment. A prospect assessment uses a single potential oil or gas pool or field as the unit of analysis, whereas a play assessment uses a group of geologically similar prospects or pools. A basin assessment is the most aggregative, using a basin or larger volume of sedimentary rock that contains one or more plays as the unit of analysis. Although Table 1 provides a taxonomy of the methods used, the classification is not perfect and often a combination of more than one approach is used in making a petroleum resource assessment. (White and Gehman 1979)

Qualitative Methods

The numerical grading systems providing qualitative estimates of the petroleum resource potential are often used in situations where a rapid assessment of regional mineral resources is necessary in making some land management decisions. The technique usually consists of listing the major factors influencing the possible presence of oil or gas in a particular area. Some factors include proximity to source rocks, potential reservoir rock, and type of trap. The analyst considers each of these factors and assigns a relative scale or grade to each factor. A scale range might be one to four or one to one hundred with the highest number reflecting the greatest potential. Although the

Table 1. Methods of estimating undiscovered oil and gas resources.

Type of Method	Type of Assessment Prospect	Play	Basin
QUALITATIVE METHODS			
Numerical Rating Systems			
QUANTITATIVE METHODS			
Geological/Volumetric Approach			
Areal Yield	*	*	*
Volumetric Yield	*	*	*
Geochemical Material Balance	*	*	*
Geological/Mathematical Approach			
Geologic Analogy	*	*	*
Delphi	*	*	*
Department of Interior Method		*	
Production/Mathematical Approach			
Extrapolation of Historical Trends			*
Field Number and Size		*	*
Discovery Process		*	*

SOURCE: Adapted from White, D.A. and H.M. Gehman, 1979. Methods of estimating oil and gas resources. AAPG Bulletin Vol. 63, No. 12. December. Figure 2, p. 2185.

system forces the analyst to think about each factor separately, such a grading scale is often arbitrary. (Newendorp 1975)

The appraisal for the Roadless Area Review Evaluation (RARE II) used a numerical grading system. Several mineral categories were assessed (i.e., hardrock minerals, bulk commodity minerals, geothermal minerals, coal, uranium, crude oil, and natural gas) and rated on a numerical scale from 0 to 100 points. The method was subjective in that a concensus among several Forest Service geologists was reached about how many points to assign to a particular mineral commodity. If a commodity group received a rating between 1 and 49 points, the mineral resource potential was considered low; moderate potential was considered between 41 and 80 points; high potential received between 80 to 100 points. A zero or negative one was assigned if a mineral commodity group had no potential or an unknown potential, respectively. (USDA 1979)

Currently the Northern Region is using several different numerical grading systems in the forest planning process (USDA 1980e). These systems are being used primarily because of the limited geological data bases and the limited time available to conduct mineral resource assessment.

Quantitative Methods

The first approach considered under the quantitative methods is the geological/volumetric approach. The approach determines the oil or gas yield, expressed in terms of barrels of oil per cubic mile or barrels per exploratory foot, or in some other ratio of an explored basin, and applies this measure to a similar unexplored basin to determine petroleum potential. The volume of sediments is assumed to be reasonably well known in the unexplored basin. The petroleum potential of the unexplored area is calculated based on the hydrocarbon per unit area or volume of rock of the explored area. The accuracy and usefulness of the approach depends upon the degree of geological similarity or dissimilarity between the explored basin and the unexplored basin. (Barss 1978)

The geological/volumetric approach consists of the areal yield method, the volumetric yield method, and the geochemical material balance method. The areal yield is probably the simplest of the three methods. The petroleum potential is determined by multiplying the basin acreage by the estimated fraction considered productive and by a yield factor (e.g., barrels per productive acre). Weeks (1949) used this type of an analysis. Although areal yields can be computed quickly, the chief disadvantage is that the method does not account for geological variations in the third dimension, depth. As a result, this method has been largely replaced by the volumetric yield method. (White and Gehman 1979)

The volumetric yield method has been considered the workhorse of the assessment business. Using this method in prospect assessment, the petroleum potential is calculated by multiplying the potentially productive area in acres by an estimated net pay thickness factor in feet and by a yield factor in barrels per acre-foot. In this way the third dimension, depth, is taken into account. Newendorp (1975) and Megill (1979) have used this method in prospect assessment. Weeks (1975) has generally been credited with using this method for basin assessment. Others that have used this method include Hendricks

(1975), Cram (1971), and Klemme (1975). The method has also been applied in play assessment by Jones (1975).

The geochemical material balance method, widely used in the Soviet Union, is a special form of volumetric yield which considers the fundamentals of petroleum generation, migration, and entrapment. Similar to the volumetric yield, the determination of the petroleum potential is calculated by multiplying various factors together. Some of these factors include drainage area, source rock thickness, percent organic content, percent generated into hydrocarbons, percent migrated, percent trapped, and percent potentially recoverable. The method is applicable to either a prospect, play, or basin assessment. The advantage of the method is that it includes many of the chief factors influencing oil and gas occurrence, even though such factors can be difficult to specify. (White and Gehman 1979)

A second major approach of assessing undiscovered petroleum resources is the geological/mathematical approach. The approach consists of selecting an explored area with known geological structures and characteristics similar to the unexplored area being studied. The geological parameters influencing the volume of petroleum (e.g., structure fill, structure area, and net pay) in the unexplored area are subjectively expressed as probability distributions based on the known situation and the geology of the unexplored area. Using these distributions, a simulation technique is used to generate a single probability distribution of the petroleum potential. The approach can be used for assessing prospects, plays, or basins. The advantages are in describing estimates in terms of a probability and in assessing the potential in partially explored and unexplored areas. (Barss 1978)

The two primary methods considered under the geological/mathematical approach are geologic analogy and delphi. Geologic analogy is probably the most popular because it is used, in one form or another, in almost every method previously discussed. Geologic analogy states that if an untested area A looks geologically like a known producing area B, then it must have a similar oil and gas potential and content. Generally, if differences exist between areas A and B, some compensating factor is used in the assessment to account for the differences (White and Gehman 1979). Although it can be a simple method, some approaches to geologic analogy have used sophisticated computer techniques. A few users of geologic analogy for basin assessment include Weeks (1952), Klemme (1971, 1975), McCrossan and Porter (1973), and Pitcher (1976). Hambleton (1975) used the method for prospect assessment. The advantage of such a method is that it uses historical experience for making realistic and meaningful comparisons. The disadvantage is how the geologic differences are accounted for and the potential bias that may exist in the estimates as a result of these differences.

The delphi method estimates the quantity of the petroleum resource on a subjective basis by a team of experts. Each member of the group of experts reviews all available geological information of the area being studied and the results of other assessment analyses to construct individual probability curves of the potential petroleum resources. After the group reviews and agrees on the individual results, the individual probability curves are averaged together using simulation techniques. This method is commonly employed, but care must be taken in choosing the experts. In addition, the individual probability curves are difficult to construct because the expert must estimate a complex product, such as barrels of oil. The method has been used by Miller (1975) and Dolton (1981) for assessing the U.S. undiscovered recoverable oil and gas resources.

A third method under the geological/mathematical approach is the method the Department of Interior used for assessing the undiscovered petroleum resources of the National Petroleum Reserve in Alaska (USDI 1979). The method is a modification of the appraisal methodology used by the Geological Survey of Canada and uses a computer simulation (i.e., Monte Carlo) known as the Petroleum Activities and Simulation Model (PADS). The model makes use of geological/volumetric techniques, geologic analogy techniques, and delphi techniques in a play assessment. The geological parameters of the model are based on the subjective probability judgments of experts familiar with the geology of the area. The PADS model is composed of an integrated set of process-oriented submodels. Together the geologic, exploration, development, production, transportation, and economic submodels simulate a sequence of decisions regarding potential oil and gas activity over an extended period of time, given the uncertainty about the petroleum resource base. The outputs from the simulation model include a number of physical measures of resources (e.g., estimates of oil and gas in-place resources; oil and gas production forecasts), several measures of oil and gas activity (e.g., number of wells drilled, and miles of pipeline), and some economic measures of petroleum activity (e.g., costs and revenues). (Bugg and Miller 1981)

Many advantages exist for using the model. The model output is based on the specific geologic characteristics and uncertainty of the area of interest. The approach does not require geologic experts to make any implicit or explicit economic judgments. The model recognizes the regional component of geology, in that individual prospects or pools can be geologically correlated. Finally, the method does not require actual discoveries for assessment purposes; judgments are based on existing data and can incorporate the uncertainty in those data. (Bugg and Miller 1981).

The production/mathematical approach is a third category of methods for estimating undiscovered petroleum resources. The approach uses statistical procedures based on historical data for projecting future oil and gas potential and is usually applicable only in areas where a significant amount of oil and gas production has occurred. The most commonly used historical statistics are finding rates that relate exploratory footage drilled to the discovered volume of petroleum, the number of exploratory wells, or production rates over time. (White and Gehman 1979; Dolton et al. 1981)

Three methods considered under this approach are the extrapolation of historical trends, field number and size, and the discovery process. The most popular method has been the extrapolation of historical trends in basin assessments, which was developed by Davis (1958) and improved by Hubbert (1967, 1974). Hubbert (1967) plotted both the United States annual crude oil discovery rate and production rate between 1900 and 1960 in terms of billions of barrels. The data were fitted with a logistic curve which indicated that historically the production rate lagged behind the discovery rate by about 10 years. Extrapolating out 20 years to 1980, Hubbert predicted that the United States crude oil production rate would peak in 1967, since the discovery rate had peaked in 1957. The actual production rate peaked in 1970 with the discovery rate peaking in 1961. Thus, Hubbert was remarkably close to predicting when the United States oil production would begin to decline.

The field number and size method consists of projecting future oil and gas potential based on historical oil and gas field sizes and numbers. The method is applicable to either play or basin assessment. The estimates of petroleum potential are calculated by multiplying the number of potential oil and gas fields in an unexplored area (i.e., total number of prospects or fields multiplied by an assumed success ratio from an explored and geologically similar area) by the average field size, determined from an explored, geologically similar area. The method has been used by Ivanhoe (1976) and Nehring (1978, 1981) who applied this technique in a more sophisticated manner by using a range of values, in terms of probability distributions, for both field sizes and numbers, rather than just a single value such as an average. Using these input distributions and a computer simulation model, a probability curve for the assessment is generated which provides estimates of the petroleum potential. The advantage of this method is that it deals with prospects or fields which are the natural analysis unit of exploration. The disadvantage is the large amount of data required to define the prospects or fields, and not all prospects are easily defined. (White and Gehman 1979)

The discovery process method uses a probabilistic model of the discovery process, in basin assessment, to estimate the average size of field discoveries, barrels of petroleum discovered per exploratory well, or barrels of petroleum discovered per meter drilled. The central assumption is that the larger the deposit the more likely it is to be discovered in the discovery sequence. The parameters of these probabilistic models (e.g., ultimate number of oil and gas fields of a certain class size in the basin being studied; basin acreage; and cumulative number of exploratory wells) are estimated from past discoveries in the basin being studied. The method has been used by Arps and Roberts (1958), and Kaufman, Balcer and Kruyt (1975). Drew, Schuenemeyer and Bawiec (1982) have used this method for estimating future rates of oil and gas discoveries in the Western Gulf of Mexico.

The Significance of Petroleum Resource Estimates

Petroleum resource appraisal methods are many and varied with each method having its own benefits and limitations. As a result, the resource estimates, the final output from any resource appraisal, are also variable. McCulloh (1973) compared the more authoritative estimates of future undiscovered crude oil resources between 1900 and 1980 in relation to the United States cumulative production, plus proven reserves, and found that a large variation existed between the estimates and a general trend that all estimates are increasing with time. This trend is understandable because the area of consideration has been changing over time. For example, new producing regions and areas have been brought into production as a result of the changing economic and political environment. The extensive variability among resource estimates is a result of the changing level of geologic knowledge, the changing technology of exploring for and recovery of petroleum, the inconsistency in the use of terminology, the changing economic and political environments, the methodology used, and the geographical location of the area under consideration.

Numerous factors have to combine in time and place to form petroleum accumulations. Because this process is complex, man does not have the expertise to accurately predict the volume and location of petroleum. The level of geologic knowledge on which petroleum estimates are based is acquired through exploration drilling and the development of petroleum deposits. As more drilling and development occur over time, the body of geologic knowledge changes both conceptually and in terms of factual data collected. The process of exploration is a working-hypothesis system. Many situations exist of oil and gas accumulations being found in the same area where many years of extensive exploration had been done in the past with nothing more than a series of dry holes as results. The Western Overthrust Belt is a good example. Before 1970 most geologists would have thought the area had no potential for petroleum accumulations. However, the U.S. Geological Survey now estimates that significant deposits of oil and gas may exist in this province. As our geologic knowledge changes both in theory and factual evidence, so do the estimates of undiscovered petroleum deposits.

The changing level of technology in exploring for and in recovering oil and gas can also influence estimates of undiscovered petroleum resources. The petroleum exploration industry has enjoyed significant scientific advances in the last twenty years which have had a strong bearing on the estimation of petroleum resources and reserves. In addition, improving methods of oil and gas recovery could change reserve estimates.

The lack of adequately defined terms used in petroleum resource appraisal has caused a great deal of confusion among the public and among those in politics and government. In some cases total resources have been understood to mean proven reserves. Such a misunderstanding could have a disastrous impact on energy policy and the public's expectation about the size of our future petroleum supplies. Thus when interpreting estimates of petroleum potential the terms must be clearly defined.

Resource estimates change when the economics change. The petroleum increases in the last eight years have spurred an unprecedented amount of exploration in the United States for the more numerous smaller fields that have been ignored in the past. As a result of these price changes, the size of our future petroleum supplies has also changed. Additionally, federal and state government, by the imposition of a high tax and royalty structure on petroleum production, can create a disincentive for future exploration and development, which could also change the size of the petroleum resource estimates.

Different methods used for assessing petroleum resources can also cause oil and gas estimates to vary. Some methods require specific geological data (e.g., geochemical material balance method), whereas others may not require such data (e.g., extrapolation of historical trends). Some assessments include natural gas/liquids or assess quantities other than recoverable quantities (e.g., total resources). Finally some methods require a greater amount of subjective judgment from geologists (e.g., delphi) than other methods (e.g., extrapolation of historical trends). The variance of petroleum resource estimates is a result of the many geological, economical, and political uncertainties. An appreciation of these uncertainties by the public and various government agencies would provide a better understanding about the significance of the resource estimates and why concern exists in their application.

Oil and gas estimates represent a systematic aggregation of the conventional wisdom which permitted the number to be generated. In 1975 the U.S. Geological Survey's assessment of the western Rocky Mountain province (i.e., Idaho, Nevada, Utah, Arizona, and western Wyoming, Colorado and New Mexico) estimated the oil potential to be 2 to 8 billion barrels (Miller et al. 1975). Since 1975, several significant oil and gas discoveries have been made and the area continues to be under extensive exploration. Although, a large amount of undiscovered oil and gas was predicted to be found in 1975, such an estimate does not mean the apparent richness of this province was accurately forecasted, but it does lend credibility to the overall assessment for the province. The U.S. Geological Survey's most recent estimates now predict 6.9 to 25.9 billion barrels of undiscovered recoverable oil yet to be found (Dolton et al. 1981). Thus, a resource assessment should be viewed as a base for understanding and monitored through time for changing levels of knowledge (Masters 1979). Most assessments are evolutionary and not revolutionary, changing with the times as a steady influx of new technology occurs, deeper depths are explored, and new lands supplied to the process.

To be useful for policy decision making, resource estimates must be both reliable and credible. Reliable estimates are a function of the analyst's ability to organize and to express the conventional wisdom about the resource. The data set, defining the conventional wisdom about the resource, needs to be all-encompassing to be reliable. Credible estimates depend upon confidence in the data set and the manipulations of data in the assessment process. The method of assessment is an important element of credibility since different methods manipulate the data differently, and, thereby, provide varying estimates. If estimates of method A are reasonably close to those of method B then the estimates have more overall credibility. (Masters 1979)

Managers should understand that resource estimates are not meant to be precise, but rather provide guidance or targets in describing or quantifying the overall resource potential. Problems arise in the use of estimates by planners, economists, and politicians because of their indiscriminate use of the numbers (Barss 1978). Often this can cause an erroneous resource policy to be established which can be costly at times to individuals, organizations or the nation as a whole. The user of the estimates should be aware of the method used in the assessment and understand the many uncertainties inherent in the estimates. The methods of petroleum assessments and the associated estimates are not all based on the same set of data and assumptions and are not all prepared for the same purpose.

Simulation Techniques in Model Building

Simulation is a method for solving problems of real world systems by using models. A model represents reality in an idealized, less complicated manner and is easier to use for research purposes. It is simplified in that only the most relevant variables are represented. The technique is relatively new, first appearing in the literature in the late sixties. Today it is widely used among major petroleum companies and different government departments interested in oil and gas. The purpose of this discussion is to present some of the major ideas of simulation, to better understand the method as it relates to the oil and gas supply process.

The Purpose of Simulation

The simulation method has several synonyms such as random simulation, or Monte Carlo simulation. Simulation models attempt to mimic or simulate the modeled real system. Given the complexity of most real world systems, simulation is the only available technique for dealing with such problems. The method is best understood by contrasting it with the analytical method. (Newendorp 1975)

The analytical method can be best explained through the use of an example. Consider a hypothetical minerals investment project where the profit (dependent variable) from the operation is a function of four independent variables G, H, I, and J as described in the equation below.

$$\text{PROFIT} = 2G + \left({}^{1}/_{.5H}\right)\left(6.6I^{2}\right) - J$$

If the analyst knows exactly what the values for G, H, I and J should be, then substitution of the values into the equation will solve directly for profit. In this case, there exists no uncertainty with regard to the values for G, H, I and J. Mathematicians refer to this as a deterministic (analytical) computation. When such a situation exists and it is possible to construct an analytical model, the approach is superior to simulation.

However, the above situation does not often occur. Not only does uncertainty about what values to use for G, H, I and J exist, but sometimes relationships between variables are not understood. As an alternative, the analyst can use the technique of simulation to derive an answer to the profit equation. Uncertainty can be incorporated into the simulation model by quantitatively expressing each variable in terms of a probability distribution. Although at any point in time each variable has a specific value, the actual value is unknown, and, thus, specification in terms of a probability distribution allows all the values within the range to be considered.

Using simulation, a series of repetitive calculations of possible values of profit are made. The value of profit is computed using a specific value of each variable from the respective distributions. Each value of profit represents a different "state of nature" or possible combination of G, H, I and J. After numerous repetitive calculations of profit, a distribution is established expressing the possible range of values for profit.

The Mechanics of Simulation Analysis

The first step in any simulation study is to determine what system the analyst is interested in modeling and what indicator of value should be used to measure the system performance. In modeling an exploration drilling prospect, the analyst's objective may be to determine the expected profit or the expected oil reserves. Depending upon the objective, the variables used to measure the system will be somewhat different.

Once the analyst's objective is determined and the variables have been defined, the next step is to construct the model. The analyst must be familiar with the realities of the system being modeled in order to reduce the system to a logical flow diagram. This consists of linking the variables together as a set of relationships or mathematical equations. The analyst must learn to identify those critical variables of the system and incorporate them into the model. Variables that are not important are best left out of the model so the significance of the results obtained are not obscured. Once the objective is established, the variables specified, and the model defined, the analyst is ready to run the simulation.

The technique of performing simulation analysis is essentially a highly repetitive sampling process which is easily handled by a computer. Simulation analysis is performed by first converting the frequency distributions representing the range of values of each variable into cumulative distributions. This conversion rearranges the data in a way that is more suitable for simulation (Figure 12). Sometimes this step may not have to be done because the variables have already been immediately specified in terms of a cumulative distribution. Once the distributions are converted, random numbers[8] are generated which are used to sample from each of the cumulative distributions. Using random numbers to perform the sampling process is

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[8] Random numbers are dimensionless, positive numbers all of which have an equal probability of occurring. Random numbers are usually obtained from random number generators, a series of equations which when solved many times results in a sequence of numbers that are approximately random. (Newendorp 1975)

only one of several ways to sample distributions, but it is the most universally used in simulation analyses.

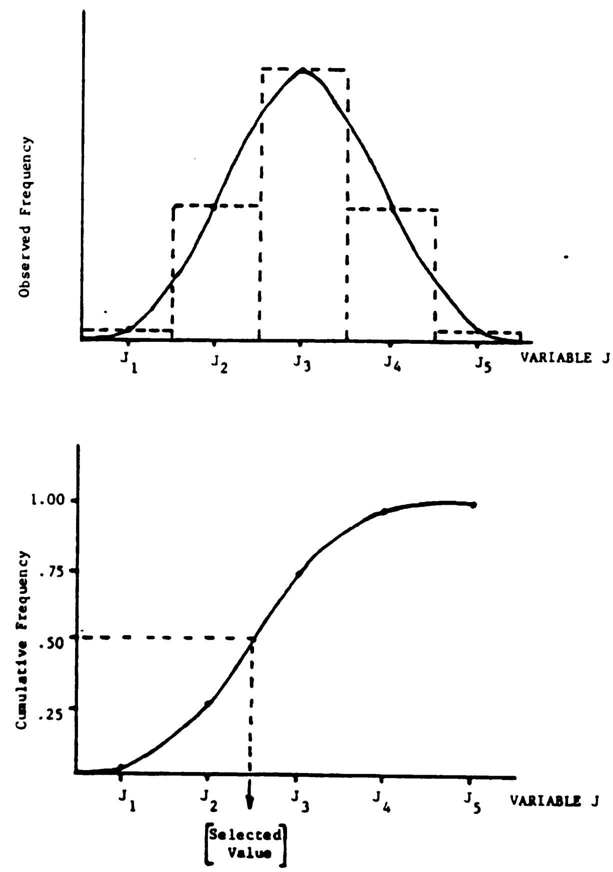


Figure 12. A frequency distribution of variable J and the corresponding cumulative distribution.

The last steps in performing simulation analyses are sampling from the cumulative distributions and computing the value of the event. The computer selects a random number between 0 and 1, say 0.50, and enters the vertical axis of the cumulative distribution at the 0.50 percentile (Figure 12). Tracing across to the cumulative distribution and down to the horizontal axis results in the choice of the parameter value. Repeating this procedure many times insures the values sampled from the parameter distribution over a series of passes are distributed exactly as in the original distribution. The values randomly selected from the parameter distributions are used in a series of equations, describing the relationships within the system, to determine the value of the event.

The final phase in a simulation analysis is validating the model which measures how accurately it predicts the behavior of the real system being modeled. The best method of validating a simulation model is by comparing the model output with performance data from the real system. But since actual data does not often exist, especially in the petroleum exploration business, validating the model output is done by knowledgeable people checking the credibility of the output under a variety of situations.

The Merits of Simulation

The chief advantage in using simulation analyses is to quantify the uncertainty existing in the real world about a particular system (e.g., oil and gas supply process) in terms of a range and distribution of possible values for the unknowns. The logic of simulation implies that in the absence of statistical data the method is still appropriate (Newendorp 1975). Another advantage is that simulation models often consist of many variables linked together by a set of relationships allowing professional judgments to be applied to one variable at a time rather than to all unknown variables simultaneously. Thirdly, simulation models are useful for conducting sensitivity analysis. By changing the values of different variables, the analyst can isolate those critical variables in the system which have the greatest influence on output. This additional information can be useful to the decision maker in guiding management decisions. Finally, the results from a simulation analysis can provide the decision maker with more information about the range and most likely value of the event being modeled.

Overview of the Petroleum Simulation Model

Introduction

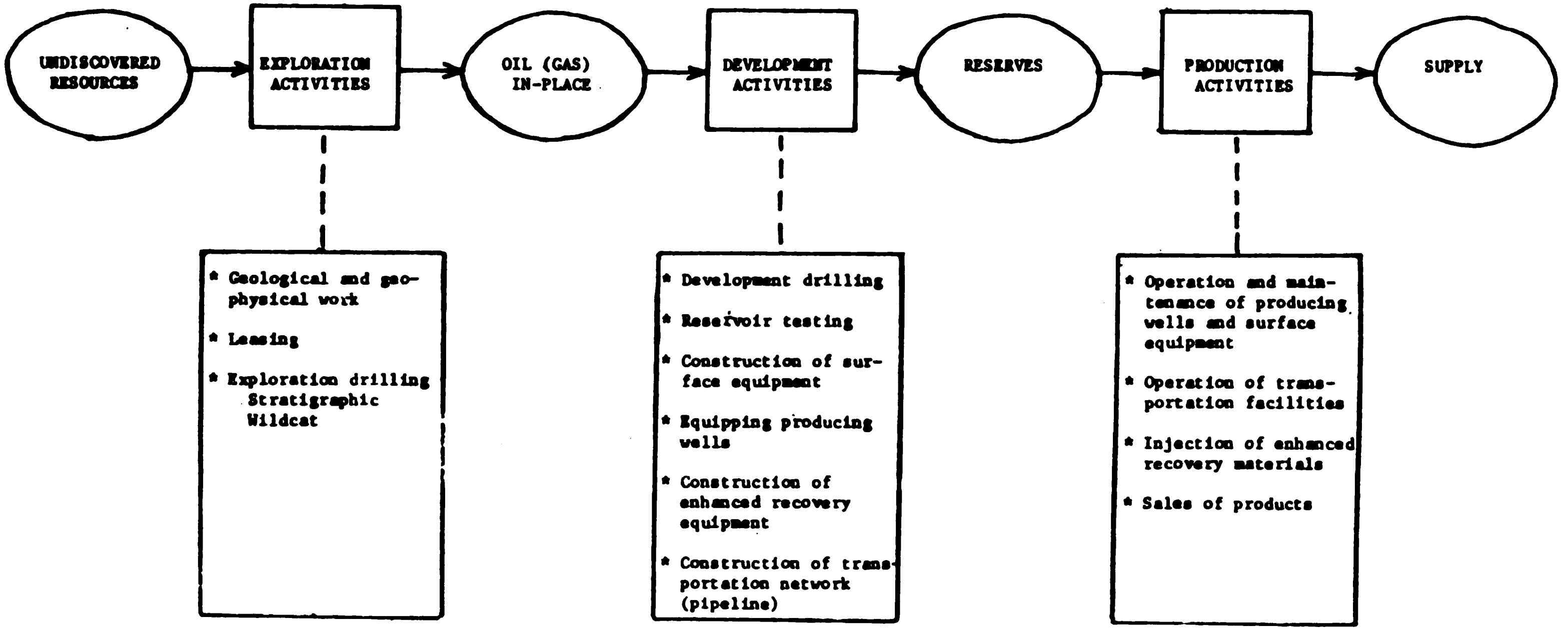
The petroleum simulation model used in this study is the same model the U.S. Department of Energy uses in forecasting Alaskan oil and gas production at different price levels (USDE 1979a). The model, known as the Alaskan Hydrocarbons Supply Model, is a part of the Midterm Energy Forecasting System with the output becoming part of the data base for the Midterm Energy Market Model. The model, developed by several private consulting firms under contract to the Department of Energy, is referred to in this study as the Petroleum Simulation Model (PSM).

Based on a literature review on minerals resource appraisal, the Alaskan Hydrocarbons Supply Model was selected as the appraisal procedure most suitable for meeting the study objectives. In addition, it was the only model available at the time that was both operational and accessible. The Petroleum Activity and Decision Simulation Model, discussed previously, was the only other model that might have been suitable but it was neither operational nor accessible. The Alaskan Hydrocarbons Supply Model was accessible to the Forest Service through an agreement with the U.S. Department of Energy, Division of Oil and Gas Analysis.

The Purpose of the Model

The PSM is the simulation procedure that will be used in forecasting oil and gas reserves and production on the Lewis and Clark National Forest. The model outputs provide some of the necessary information to meet the study objectives and to improve management decisions relating to petroleum resources. The model is a representation of the oil and gas supply process and is idealized because it incorporates only those geological, economical, and engineering factors and relationships of the supply process which are most significant in affecting oil and gas supply.

The oil and gas supply process which the PSM simulates can be described by first discussing the reservoir and then the investment decisions centering around the reservoir (USDE 1979a). Exploration converts undiscovered resources to discovered oil or gas in-place resources, development transforms the discovered resources to reserves, and production converts reserves into oil and gas supplies for consumption (Figure 13). Exploration activities, necessary to discover the reservoir, continue until the reservoir's physical dimensions are known. During this period, the total discovered oil or gas in-place resources are determined. After discovery, development activities will only take place if the reservoir oil and gas is economical to produce. This stage estimates the total reserves available under a particular set of economic and technological conditions. As more knowledge is gained about the reservoir, the reserves continue to grow until the economic limit is reached. Production begins once the surface equipment is installed and continues until all of the reserves have been produced, at which time the reservoir is abandoned. Abandonment does not mean all



SOURCE: Adapted from USDE, 1979. Alaskan Hydrocarbons Supply Model: Methodology Description. Technical Memorandum DOE/EIA-0103/22. January. Figure 2, p. 10.

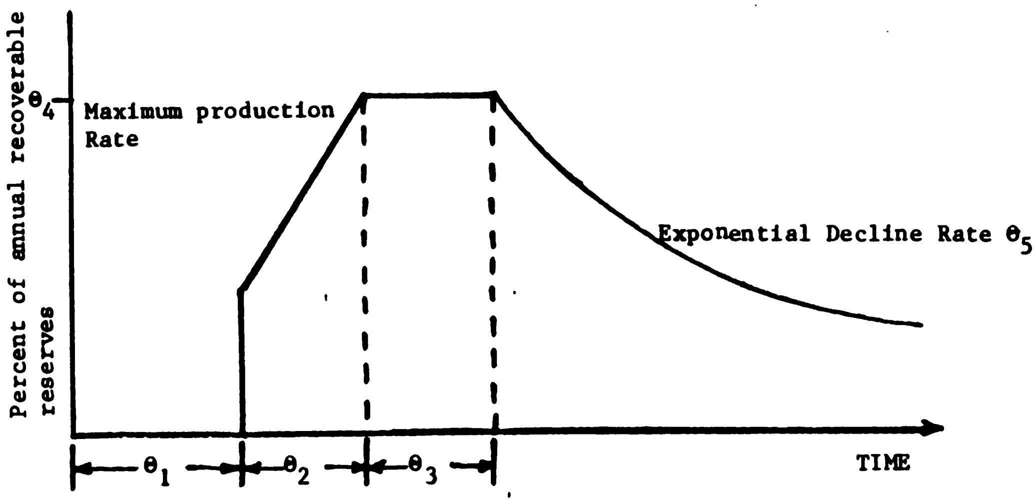
Figure 13. The oil and gas supply process as represented by the Petroleum Simulation Model.

the oil and gas resources have been exploited, but only those that were economical (i.e., reserves). Substantial quantities of uneconomic resources may remain in the reservoir for possible future use. The different exploration, development, and production activities encompassing the reservoir life do not start and stop as distinct activities, but greatly overlap.

The reservoir investment decision revolves around many exploration, development, and production activities. Some of these activities, as shown on Figure 13, normally account for most of the costs of locating, developing, and producing crude oil and natural gas. The model does not incorporate all investment costs, but only those that are most relevant toward influencing supply. An investment activity only occurs when the discounted revenues are large enough to earn a return on investment that is both acceptable to the firm and is competitive with other investments of similar risk. Theoretically, the firm develops the reservoir to the point where the marginal costs equal the marginal revenues of pumping a barrel of oil.

The development of a reservoir can be accomplished in several alternative ways. At one extreme a reservoir can be exploited rapidly (i.e., additional wells and enlarged production facilities), requiring a large initial investment. At the other extreme the reservoir may be exploited over a longer time period, requiring less investment in wells and surface equipment. Although the development of a reservoir can be complex, the model simplifies this decision process by using a generalized production profile.

The profile, as shown in Figure 14, is defined by using five key parameters -- θ_1, θ_2, θ_3, θ_4, and θ_5. The first three parameters are



SOURCE: Adapted from USDE, 1979. Alaskan Hydrocarbons Supply Model: Methodology Description. Technical Memorandum DOE/EIA-0103/22. Figure 3. p. 13.

Figure 14. A generalized production profile.

defined as the amount of time between initiation of exploration and start of production, the time period between the start of production and attaining peak production, and the length of time maximum production is sustained, respectively. The fourth parameter represents the maximum production rate as a percent of recoverable reserves, and the fifth defines the exponential decline rate of the reservoir until abandonment. Describing a production profile with these parameters can be done in many alternative ways with each requiring different amounts of investment capital as shown in Figure 15.

Discounted cash flow analysis[9] is used to evaluate the various reservoir investment decisions. One way to use the technique is to calculate a minimum acceptable price or lowest market price necessary to pay the costs for finding, developing, and producing a certain quantity of reserves with an acceptable return on capital. If the minimum acceptable price is greater (less) than the current price for oil or gas, the reservoir would be economically (uneconomically) viable. Thus, the model attempts to simulate the oil and gas supply process which revolves around the reservoir resources, and how the reservoir investment activities influence the oil and gas supply.

General Overview of the Model

The PSM is a Monte Carlo simulation model which forecasts petroleum reserves, production, and transportation development in unexplored areas. The model is not easily classified in Table 1 because it uses a combination of several methods for petroleum resource assessment (i.e.,

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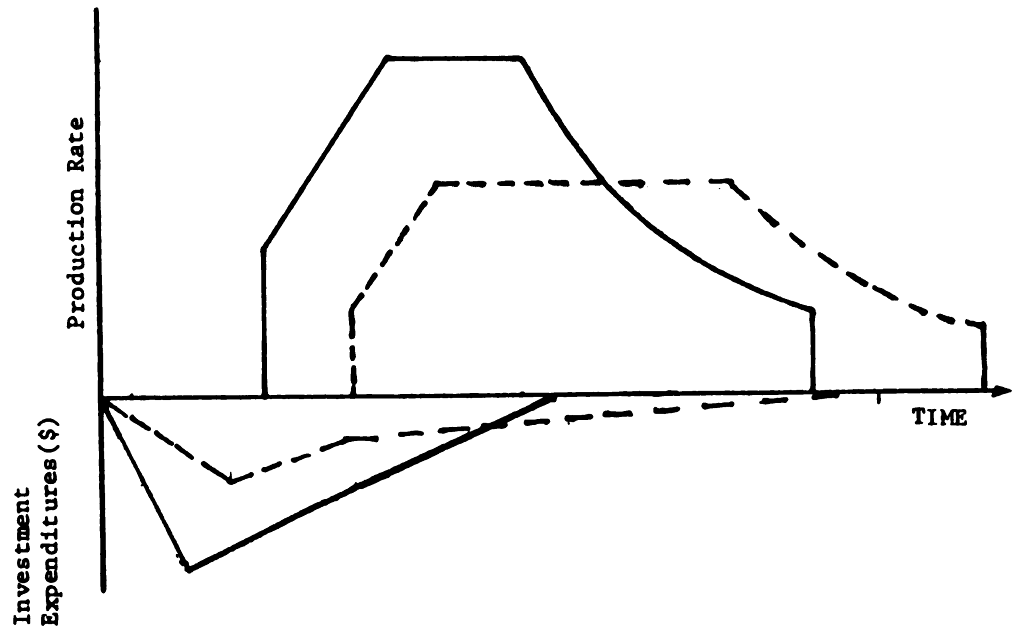
[9] A technique which considers the time value of money in comparing revenues and costs.



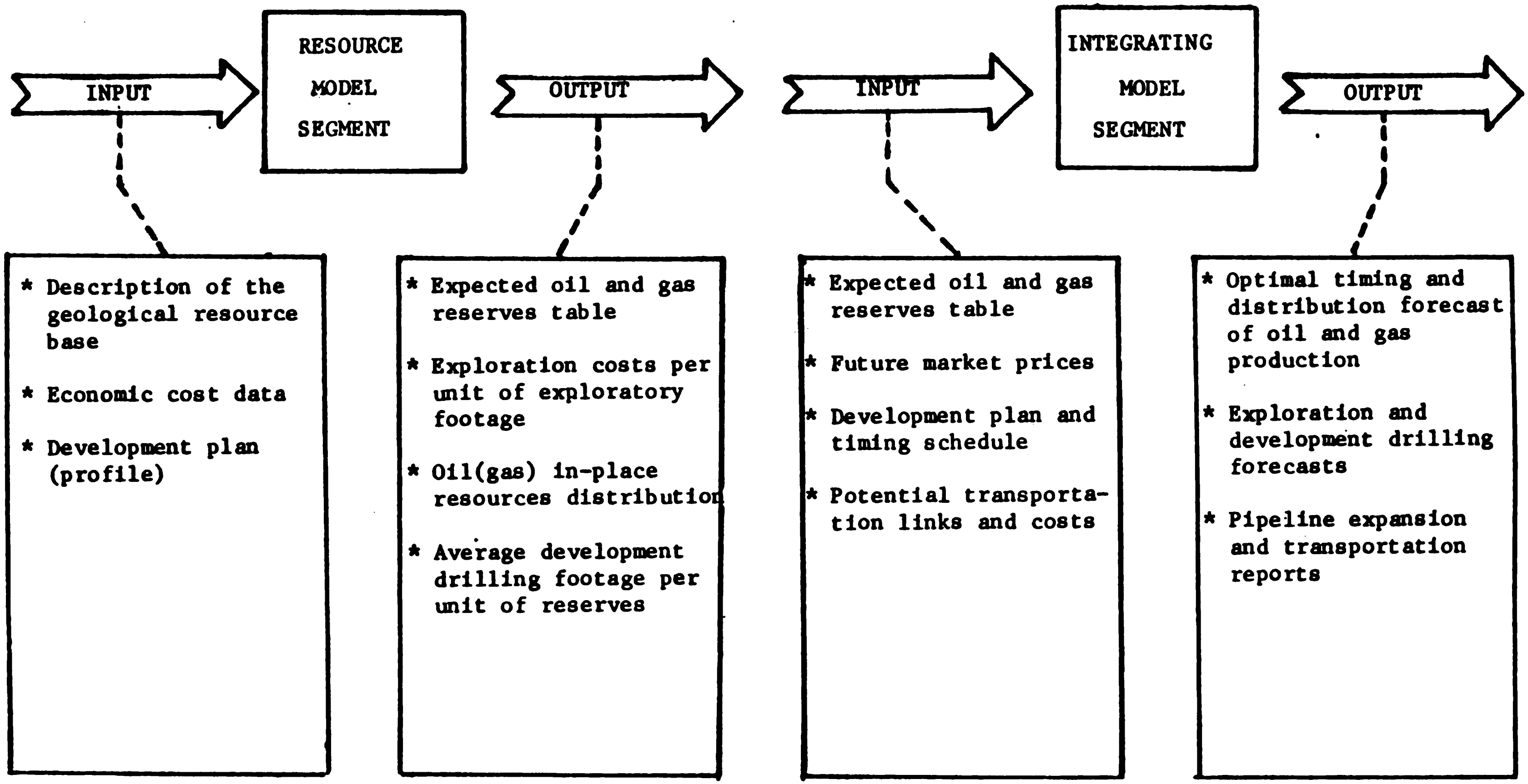
SOURCE: Adapted from USDE, 1979. Alaskan Hydrocarbons Supply Model: Methodology Description. Technical Memorandum DOE/EIA-0103/22. Figures 3 and 4. p. 14.

Figure 15. Alternative production and investment profiles.

geologic analogy and delphi techniques). For this study, individual prospects are each assessed for potential petroleum resources and then all prospects are aggregated together to provide an assessment for the play. The commodities included in the model are crude oil, associated and non-associated natural gas, and natural gas liquids. Other heavy oils, oil shale, and tar sands are not considered in the model.

The PSM is divided into a resource model segment and an integrating model segment (Figure 16). The resource model segment estimates oil and gas resources for each specified supply region, converts estimates into reserves, and categorizes reserves into a table by minimum acceptable supply prices and cumulative exploratory footage. The data requirements include 16 probabilistic geological variables and many economic cost variables associated with exploration, development, and production activities. The primary output from the resource model segment are the estimates of the expected petroleum reserves. These values represent oil and gas supply possibilities without reference to calendar time and serve as input into the integrating model segment. Some additional statistics reported which are used by the integrating model segment include the mean gas-oil and gas-liquids ratios, the average development drilling footage associated with each unit of reserves and supply price category, the exploratory drilling costs, and the oil and gas in-place resources distributions.

The objective of the integrating model segment is to forecast the timing and the extent of hydrocarbon production and transportation



SOURCE: Adapted from USDE, 1979. Alaskan Hydrocarbons Supply Model: Methodology Description. Technical Memorandum DOE/EIA-0103/22. Figure 5, p. 18.

Figure 16. The structure of the Petroleum Simulation Model.

development. This segment uses linear programming[10] as a solution technique. The objective function or goal of the linear program is to maximize the net present value of cash flows subject to a series of constraints. The linear programming model selects the levels and initiation dates for all investment projects (i.e., chooses the timing and extent of exploration, development, and production activities) to maximize total profits. The output from the integrating model segment consists of several output tables describing the amount and timing of the production and transportation activities. These tables include the oil and gas production forecasts, pipeline expansion and transportation reports, and exploration and development drilling forecasts.

In summary, the PSM provides regional oil and gas resource and reserve estimates and forecasts oil and gas production and transportation development. The model can be used to evaluate the sensitivity of the output forecasts to different assumptions as well as changes in key variables. In short, the PSM can analyze the effects of a wide range of variables and policies on the oil and gas supply.

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10 A mathematical programming model finds the value of a decision variable which maximizes (minimizes) the objective function subject to a set of constraints. Linear programming deals with models in which the objective function and constraints are linear expressions of the decision variable. (Hillier 1974)

CHAPTER III

PETROLEUM SIMULATION MODEL: PART I

Introduction

The first part of the Petroleum Simulation Model (PSM) is the resource model segment which has the objective of estimating the expected amount of undiscovered oil and gas reserves. The objective is accomplished by using Monte Carlo sampling techniques and discounted cash flow analysis. The resource model segment consists of two submodels, the resource description submodel and the basin exploration and evaluation submodel. The purpose of this chapter is to discuss the structure (i.e., basic mathematical relationships and underlying assumptions), the input data base, and the outputs of the resource model segment.

Resource Description Submodel

The purpose of the resource description submodel is to develop a multi-dimensional picture of the geological resource base. Monte Carlo sampling techniques in conjunction with the geological input variables, specified in terms of probability distributions, are used to describe the size, depth, and volume of petroleum contents for each structure.[11]

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[11] An underground geologic feature capable of forming a reservoir (trap) for oil and gas (see Chapter 1 for details). This is the unit of analysis in the model and the aggregation of these structures or prospects provides an estimate of the overall petroleum resource potential of a particular supply region.

The outputs from this submodel are intermediate (i.e., no final printout) and passed on to the basin exploration and evaluation submodel for further calculations. Figure 17 is a flow chart of the resource description submodel which can be divided into three categories: initialization, structure sampling, and calculation of potential reserves and number of exploration and development wells.

The initialization section consists of generating a set of random numbers, establishing the cumulative distributions for the geological variables, establishing the exploratory footage intervals, reading the input data, and calculating any constants needed for the execution of the program. In initializing the random number generator a set of uniformly distributed random numbers is generated between 0.0 and 1.0 to use in sampling values from each of the geological probability distributions. The sampling technique used in the model is simple random sampling. The second step in initializing the model is converting the frequency distributions of the geological variables to cumulative distributions. The purpose of such a conversion is to rearrange the data in a way that is more suitable for simulation analysis. Figure 12, in Chapter 2, graphically displays this procedure. Another preliminary step is establishing the exploratory footage intervals that are used for categorizing the oil and gas reserves. These intervals are determined using the following exponential function.

$$\text{EXPLORATORY FOOTAGE INTERVAL} = 50{,}000 * e^{(d*i)}$$

Where: $e = 2.71828$
$d = .20$ (constant)
$i = 1$ to 15

An exponential function is used because finding rates of oil and gas typically follow a declining exponential curve, or more oil and gas

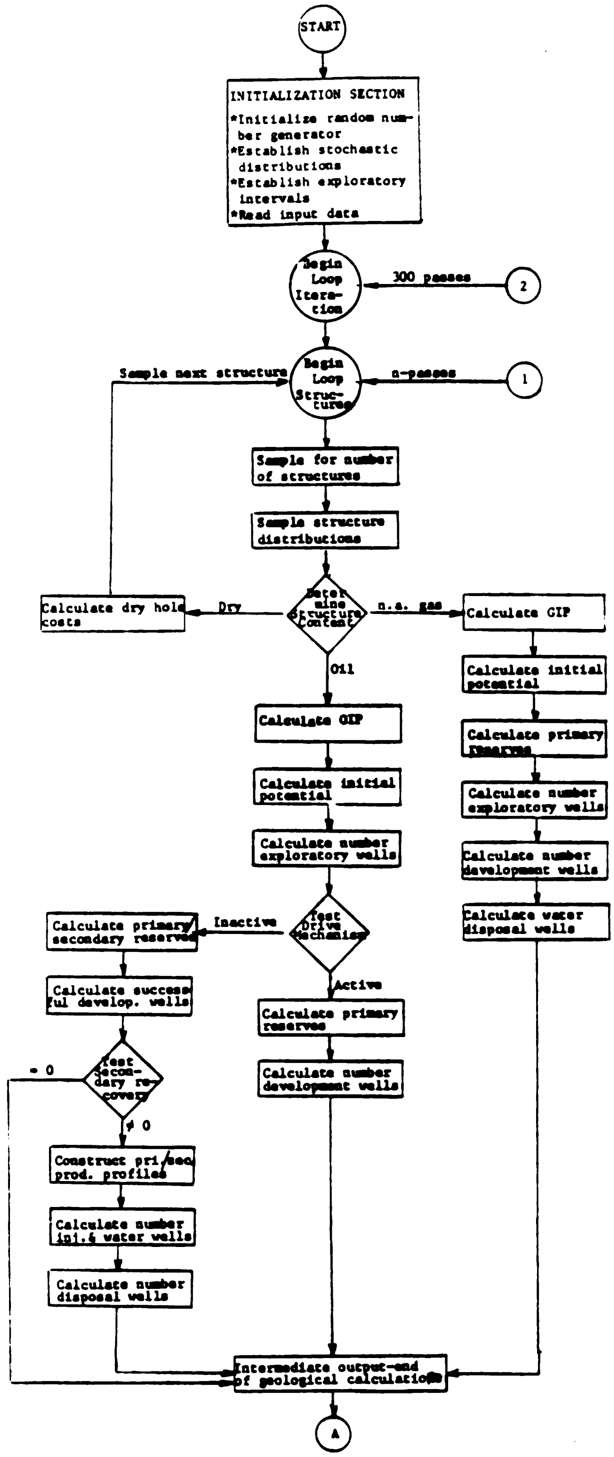

Figure 17. Flowchart of the resource description submodel.

reserves are discovered per foot of exploration drilling in the early stages of the discovery process than in the later stages. Therefore, the potential oil and gas reserves are categorized according to a function of exponentially increasing units of exploratory effort. This implies that as the exploratory footage increases, less potential oil or gas reserves are discovered per increment of exploratory footage. The last step in initializing the model is reading the input data and calculating any constants needed for execution of the program. Some of the constants calculated are the present value factors, combined federal and state income tax factors, and energy conversion factors.

Once the initialization phase is completed, the simulation begins. The model execution is controlled by two counters. The first counter keeps track of the number of iterations (i.e., passes) the model has executed. The PSM model has 300 iterations. The second counter keeps track of the number of geological structures sampled per iteration. An iteration is completed once all of the sampled structures within that iteration are analyzed in terms of the potential petroleum reserves and the economics of recovering the oil and gas. The information from the sampling of the structures is stored in a complex matrix array and the simulation continues until all 300 iterations have been completed.

The simulation is begun by first sampling from the number of structures distribution. Using simple random sampling, a value from the number of structures distribution is selected. The sampled value represents the number of structures that are analyzed for a particular iteration. For each structure all the geological variable distributions are sampled to define the characteristics of the structure. This information is used to determine whether the structure contains petroleum and to calculate the potential petroleum reserves, if the structure is found to contain petroleum.

If the structure is dry, the costs for drilling one exploratory well are tabulated and the simulation continues by sampling the next structure. The underlying assumption is that only a single well is necessary to identify a dry structure. The costs of a single exploratory well are assumed to include the drilling costs to basement depth,[12] plus any geological/geophysical costs.

If the structure contains either oil or natural gas a series of calculations are made to determine the total oil and gas in-place resources, the initial flow rate for development wells, the number of exploratory and development wells, and the potential oil or gas reserves. In the case where the structure contains oil, the first calculation determines the discovered oil in-place (OIP) resources using the following equation. The same relationship is used for determining discovered gas in-place (GIP) resources in the case when the structure contains gas. The calculations for total in-place oil and gas resources are used for determining potential reserves.

$$\text{OIP or GIP} = [\text{AREA (K)} * \text{NET PAY (K)} * \text{FILL (K)}]$$

Where: OIP or GIP = Discovered oil or gas in-place resources measured in barrels or cubic feet, respectively.
Area (K) = Area of structure measured in acres.
Net Pay (K) = Thickness of structure measured in feet.
Fill (K) = Volume of petroleum of the structure measured in barrels or thousand cubic feet per acre-foot.

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[12] The depth to a complex of undifferentiated rocks underlying the oldest identifiable sedimentary rocks in an area.

The next calculation made is the determination of the initial flow rate per development well, expressed in barrels of oil per unit of calendar time, and is used to calculate the number of development wells per structure. The initial flow rate for oil and gas reservoirs is determined using the following relationships which were determined empirically from worldwide studies (USDE 1979b).

OIL

$$IP = \frac{212 * \left[\frac{K * H}{V * 1000}\right]^{0.835}}{DHF}$$

GAS

$$IP = \frac{1785 * (K * H)^{0.22}}{DHF}$$

Where: IP = Initial flow rate per well measured in barrels (thousand cubic feet) per unit of time.

K = Permeability measures the fluid conductivity of the reservoir rock in terms of millidarcies.

H = Net pay measured in feet.

V = Viscosity measures the thickness of oil (i.e., how easy it pours) in terms of centpoises.

DHF = Depth horizon factor.

The number of exploratory wells is determined by dividing the structure acreage by the exploratory well spacing per acre. This value is bounded by a minimum of one well, and a maximum specified by the model user. If the calculated number of exploratory wells falls outside of either the minimum or maximum bound, the total number of exploratory wells is equal to the closest of these bounds. The number of development or producing wells is determined by dividing the peak flow rate of the structure, specified by the model user, by the average flow rate per well, calculated from the above IP equations. The number of exploratory and development wells is necessary for determining the drilling costs in the basin exploration and evaluation submodel.

The primary oil and gas reserves are determined by multiplying the discovered oil and gas in-place resources by the primary recovery factors. Secondary gas reserves are not represented in the model. Secondary oil recovery is considered for only those structures with inactive drive mechanisms,[13] since primary recovery for these structures is usually low and, therefore, secondary recovery is assumed to be a prudent investment. Secondary oil reserves are calculated by multiplying the discovered oil in-place resources by the secondary recovery factor which is a function of the primary recovery factor.

Basin Exploration and Evaluation Submodel

The basin exploration and evaluation submodel has two objectives. The first objective is to economically evaluate each structure on the basis of commercially producing oil or gas, which is accomplished by using a discounted cash flow analysis linked to a development plan or production profile. The second objective is to simulate the exploration process by ordering the structures identified and described in the previous submodel into a sequence which they might be tested in an exploration search process. Once these objectives are completed, the potential oil and gas reserves for each structure are categorized into a set of output tables, by total exploratory footage and a minimum

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[13] Inactive drive mechanisms include dissolved-gas drive reservoirs, whereas active drive mechanisms include gas-cap drive, water drive, or some combination.

acceptable supply price. The reserve output tables are the final output from the resource model segment discussed in the next chapter.

The general flow chart of the submodel (Figure 18) can be divided into (1) economic calculations necessary to determine the minimum acceptable supply price, (2) ordering of structures, and (3) categorization of the oil and gas reserves for all structures into output tables. Most of the data manipulations in this submodel consist of the economic calculations necessary to determine the minimum acceptable supply prices for each structure. The economic calculations determine the present value of expenditures for exploring, developing, and producing oil and gas and the present value equivalent of the production quantities expressed in either thousands of barrels of oil equivalent or thousand cubic feet of gas.

The various cost expenditure calculations made in terms of present value can be grouped into three major categories: investment expenditures (capitalized or expensed), operating expenditures (cash or non-cash), and tax shield. Capitalized investment expenditures are those deducted from income over the years of useful life of an asset. These expenditures include geological/geophysical expenses for exploration, the tangible fraction of successful exploratory and development well costs,[14] the surface equipment costs, and lease bonus expenses. Expensed investment expenditures are those deducted from income in the year the expenditure occurred. These expenditures include

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[14] Tangible well costs usually have salvage value (e.g., tools, pipe, engines) and are capitalized. Intangible well costs do not have salvage value (e.g., wages, fuel, repairs) and are expensed. (Megill 1979)

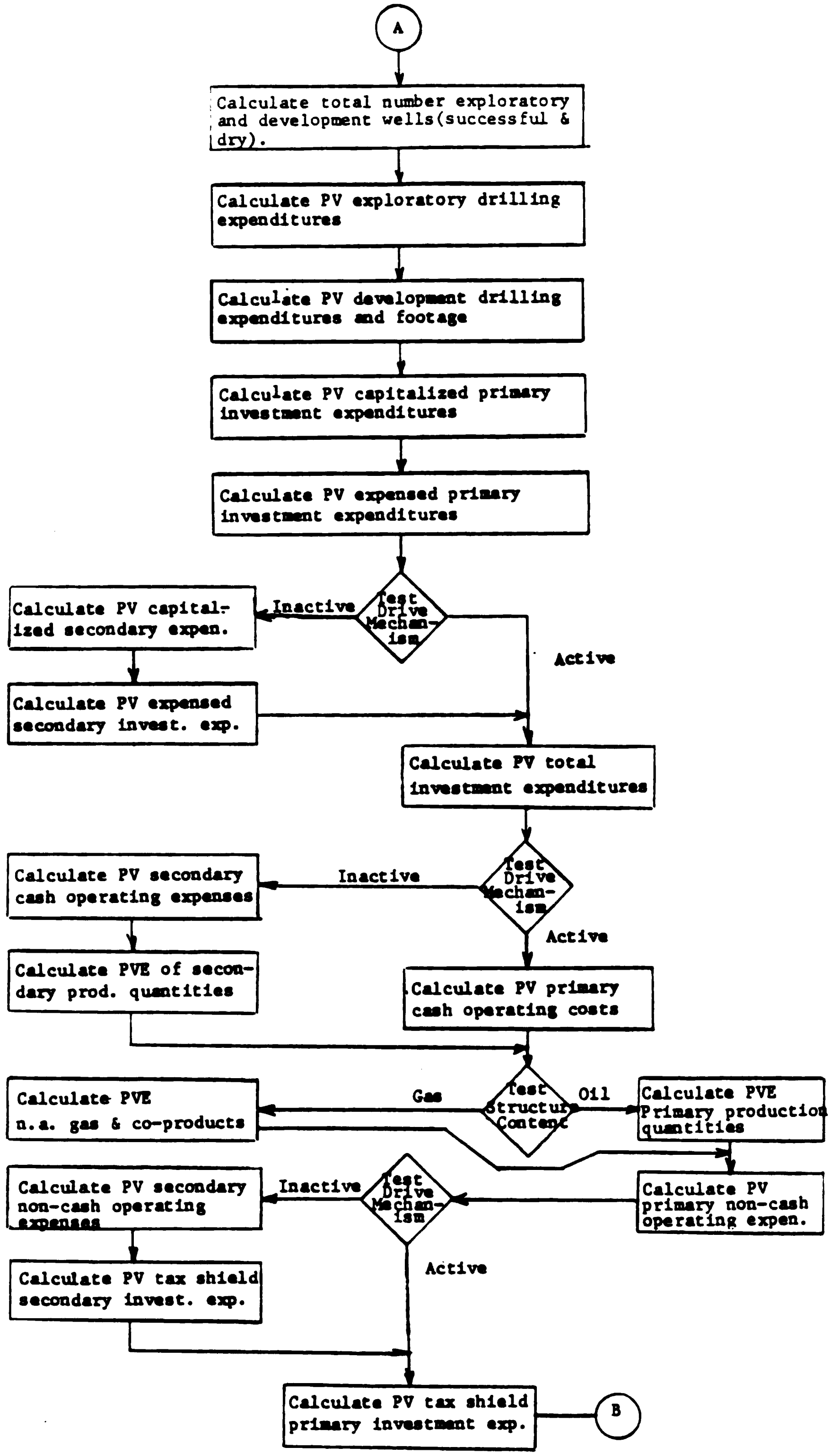

Figure 18. Flowchart of the basin exploration and evaluation submodel.

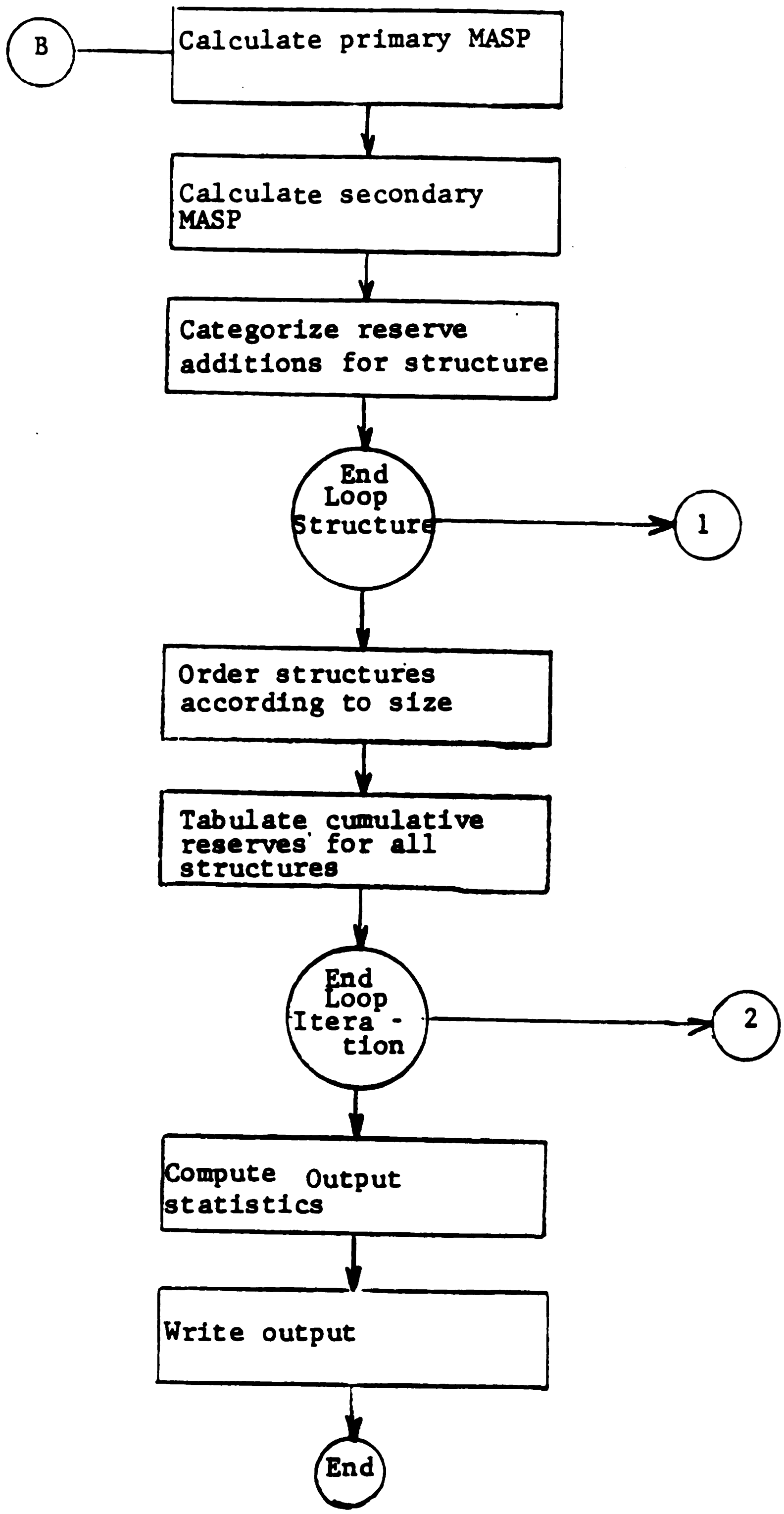

Figure 18. (cont'd.).

geological/geophysical expenses for the portion of exploration attributed to unsuccessful oil and gas drilling projects, drilling costs for unsuccessful exploratory and development wells, intangible fraction of successful exploratory and development well costs,[14] general and administrative expenses, lease rental payments, and well workover expenses. All of these expenditures are separately calculated on the basis of primary and secondary production (Figure 18).

A second group of expenditures are the cash and non-cash operating costs. Cash costs are those "out-of-pocket" expenditures made during the year such as field labor costs, variable costs of production (e.g., oil lifting/treatment costs, gas conditioning and compression costs), and general administrative costs (i.e., direct overhead). The non-cash operating costs refer to depreciation and percentage depletion.[15] Depreciation is an annual reduction of income reflecting the loss in the useful value of capitalized investments by reason of "wear and tear." The PSM uses the unit-of-production method to depreciate lease and well equipment, which has a life controlled by the physical depletion of reserves. The amount deducted each year can be expressed as the depreciable balance (cost of equipment less the accumulated depreciation) multiplied by the depreciable rate (annual production divided by the remaining reserves) and by an accelerated depreciation

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[15] Percentage depletion is a reduction in income reflecting the exhaustion of a mineral deposit. As a result of the Tax Reduction Act of 1975, percentage depletion for large companies has been eliminated for new discoveries and sharply restricts its application on existing gas sales. Therefore, percentage depletion is not accounted for in the PSM. (Megill 1979)

factor (ADF). The ADF is used to accelerate the rate at which the fixed assets are depreciated on a unit-of-production method. (Megill 1979)

The last group of economic calculations are the tax shields from primary and secondary expenditures. A tax shield protects an amount of income from taxation. The purpose of these calculations are to determine the total after-tax expenditures. The before-tax expenditures less the tax shield equals the after-tax expenditures. The total tax shield is composed of the tax shield from expensed investment and operating expenditures (i.e., the complement of the combined federal and state income tax rates multiplied by these expenditures) plus the tax shield on capitalized investment expenditures (i.e., sum of the investment tax credit multiplied by the total capitalized investment expenditures plus depreciation multiplied by the combined federal and state income tax rate).

The present value equivalent (PVE) for oil and gas production is the other component necessary for determining the minimum acceptable supply price. The present value equivalent is the discounted value of the production quantities. The PVE is the product of the gross oil and gas production quantities and the present value factor and the overall tax factor. The overall tax factor is the complement of all taxes applicable to oil and gas production such as federal and state income taxes, severance taxes and royalty payments. Costs related to revenue (i.e., taxes and royalties) are represented as a reduction in the quantities of oil or gas left for sale by producers. These costs cannot be directly determined because the resource model segment does not determine total revenue from production (i.e., wellhead price times production quantity) since wellhead prices are not represented in the resource model segment.

The minimum acceptable supply prices (MASP) for oil and gas reserves are determined by dividing the present value of total after-tax expenditures by the PVE of production. The MASP is defined as the marginal costs associated with finding, developing, and producing a given quantity of reserves.[16] If the MASP is less than or equal to the market price expected in the future, the specific oil or gas reservoir would be economical to produce. If the MASP is greater than the market price, the reservoir would be uneconomical to produce. A MASP is calculated for each structure and each structure is categorized into a specific MASP category.

After all structures within an iteration of the model have been described and evaluated, the next step is to order the structures to represent the exploration search process. A sorting algorithm is used to sort the structures from the largest to the smallest in terms of acreage. The underlying assumption is that explorationists test structures with the largest acreages first. Once the structures are ordered, the reserves are categorized into an output table by exploratory footage and by the MASP. Arranging the structures in a descending order by acreage insures that the largest structures with the greatest volume of oil and gas reserves are explored first.

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[16] Minimum acceptable supply prices do not include costs for undertaking an unsuccessful exploration project (i.e., dry hole). As a result, in areas like the Western Overthrust Belt where such projects are sizeable, a substantial difference may exist between the average costs of supplying resources to a particular destination and the MASP (USDE 1979a).

After the oil and gas reserves have been tabulated into an output table, one iteration of the model has been completed. After 300 iterations the results consist of 300 different reserves output tables. The reserves in each table represent expected values which tend to stabilize after a large number of iterations. The model aggregates these tables into a single table, representing the mean or expected values for oil and gas reserves categorized by exploratory footage and by the MASP. Estimates of the standard deviation for oil and gas reserves are not provided in the present model framework.

Assumptions of the Resource Model Segment

The assumptions of this model segment are categorized according to the activity phases of the oil and gas supply process and include those concerning the model design and input data base (USDE 1979a; 1979b).

Pre-exploration and Exploration

(1) The model assumes that prior to exploratory drilling, explorationists can identify the structure area through seismic testing.

(2) Explorationists do not have any prior knowledge about structure fill, thickness or any of the mechanical properties of the structure.

(3) Explorationists test structures with the largest areas first.

(4) The model assumes no directionality in the search for either oil or gas. This means that explorationists begin the search for oil and gas without a specific objective to find either oil or gas.

(5) The first exploratory well is drilled to basement depth.

(6) If the first well indicates the structure is dry, the entire structure is assumed to be dry.

Development

(7) There is no secondary recovery for non-associated natural gas.

(8) The model does not consider tertiary recovery.

(9) The number of salt water disposal wells is a function of the number of development wells.

(10) Primary and secondary recovery projects are initiated simultaneously for oil structures with dissolved-gas drive mechanisms. Secondary recovery is not considered a prudent investment for gas-cap and water drive mechanisms.

(11) The injection rate for secondary oil recovery is a function of the net pay of the structure and assumed to vary between one and three times the initial flow rate.

(12) Source water wells are drilled to one-half the depth of development wells. The drilling costs are assumed to be the same as development drilling costs with some additional costs per well for pumping equipment.

Production

(13) The production profile assumes that secondary oil production replaces lost primary oil production, but total production will still be maintained at the peak production rate. Total production over time conforms to a single profile with or without secondary recovery.

(14) Once total oil production begins to decline, the decline rates for total and primary oil production are assumed to be equal.

(15) Secondary production cannot be undertaken before primary production.

(16) The technological trends of exploring, developing, and producing oil and gas are assumed to prevail in the future as in the past prior to 1980. If a radical improvement in technology occurs then estimates of recoverable resources would be affected accordingly.

How inflation is treated in the model is a final assumption to be discussed. Whitney and Whitney (1979) suggests four ways of treating inflation for purposes of cash flow analysis.

(1) All costs and revenues can be estimated in dollar values as at the date of the study.

(2) All variables can be inflated to the value expected at the start of production or any year and, thereafter, use constant dollar values as of that date.

(3) Inflate each variable at some assumed constant rate of inflation.

(4) For each variable assume an explicit inflation rate for each year in the project life. Inflate the cash flow components through the life of the mine, and then deflate the annual net cash flows at an average inflation rate. The deflated cash flows can be used for the DCF analysis.

For this study, the first method was chosen as the most appropriate for treating inflation in the PSM. The implied assumption is that future costs and revenues inflate at the same rate. The impacts of using this assumption in the cash flow analysis are that capital costs are less than what is actually required, and taxes are underestimated, since it ignores the decline in the worth of depreciation (Whitney and Whitney 1979). Because of the manner in which the PSM is designed, there is no way of inflating each cost variable by a specific inflation rate and entering the result into the discounted cash flow analysis. Revenues are not considered in the resource model segment. If revenues were considered, this method probably would not be acceptable since petroleum prices have been increasing at a higher rate than the cost of exploration and production.

Preparation of the Input Data

The resource model segment is designed to estimate undiscovered oil and gas resources and reserves. This section discusses how the supply region is defined and the required geological and economic data for this model segment. A variety of data sources were used and, where data was limiting, subjective judgment was used to specify the variables.

Supply Region Definition/Classification

The first task in developing the input data base is defining the supply regions where petroleum may be potentially produced and classifying each region as to whether it is an explored area of proven hydrocarbons or an unexplored "frontier" province. The purpose of classifying supply regions is important because each type of area requires different modeling techniques and resource data inputs. The Lewis and Clark National Forest, the pilot test area for the model, is classified as an unexplored area with some geological information. Because the study area is small, there is only one supply region.

Some important criteria to use in defining supply regions are listed below. These criteria are important for defining supply regions because the uniformity of characteristics within a supply region (i.e., geology, topography, geography, mapping) provides for a more effective and efficient geologic and economic analysis.

(1) Supply regions should be geographically distinct, though not necessarily contiguous.

(2) Supply regions should be kept as large as possible to maintain fidelity of the input data and resource model outputs.

(3) Supply regions should have uniform styles of geology (i.e., areas overthrusted should not be included with areas that are not overthrusted) and, wherever possible, should be compatible with the U.S. Geological Survey's geological subprovince boundaries as defined in the U.S. Geological Survey's Circular 860 (Dolton et al. 1981).

(4) Supply regions should have uniform levels of mapping, since the degree of geologic mapping can greatly influence how certain geological variables are specified. For instance, as an area becomes more thoroughly mapped, the structural character is better known and understood. The increased knowledge gained may alter the number of structures modeled and, hence, oil and gas volumes of a defined supply region.

Geologic Input Data

The evaluation of undiscovered oil and gas resources and reserves required the specification of 16 geological variables and several geological relationships. Some of the geological variables, specified in terms of probability distributions, could only be estimated using worldwide statistics, whereas others could be specified using national and Canadian statistics. Because geological knowledge is often lacking, the specification of many of these distributions was based on the data from other geologically, similar explored areas. In other words, explored areas provided a historical basis for analogy with unexplored areas. A possible limitation of this assumption is that explored areas may have different conditions for petroleum accumulation than the unexplored areas.

For a few distributions, only local geological data specific to the supply region could be used. The data used to specify the distribution parameters were based on the structural geometry (i.e., folds and faults) of the supply region. The disadvantage of using such data is that other geological variables such as age of rocks, thermal history, and presence of potential stratigraphic traps do not receive localized representation. These factors can influence both the amount of petroleum and the ratio of oil to gas that can be expected. Another drawback is that structural traits are interpreted on the basis of existing mapping, or the amount of mapping available, rather than the geology. In the case of the Lewis and Clark National Forest, sufficient mapping exists to support a structurally derived evaluation. However, local data regarding potential stratigraphic and strati-structural traps is insufficient to warrant inclusion into the evaluation (Marshall 1981b). The primary sources for specifying most of the variables were the U.S. Department of Energy (1979b) and Van Poollen (1978). Specification of the local geologic variables was based on geological maps of the local area.

Table 2 summarizes the geological variables and relationships in terms of distribution type and data specificity. These variables are

Table 2. A summary of the geologic variables and specificity of the data.

Variable	Distribution Type	Data Specificity			
		World-wide	National	Canadian	Local Geology
Probabilistic					
Structure Fill	Log normal	X			
Oil Viscosity	Log normal		X		
Permeability	Log normal		X		
Drive Mechanism	Discrete		X		
Recovery	Triangular		X		
Number of Structures	Triangular				X
Structure Area	Log normal				X
Structure Thickness	Log normal				X
Structure Depth	Discrete			X	X
Hydrocarbon Occurrence	Discrete		X		
Relationships					
Secondary/Primary Recovery Relationship			X		
Gas-Oil Ratio/Viscosity Relationship			X		
Gas-Liquids Ratio/ Depth Relationship			X		
Other					
Basement Depth					X

used in the model for determining oil and gas occurrences, volume estimates, recovery potential, and well flow rate performance. For determining whether oil and gas occurs in a structure the model uses the data from the structure depth and hydrocarbon occurrence distributions. Unlike most distributions in the model, these two distributions are conditional upon each other rather than independent.

Estimates of the oil and gas in-place resources were based on the data from several distributions including the number of structures, structure area, structure thickness (net pay), and structure fill. In addition to these variables the gas-oil ratio/viscosity relationship[17] and the gas-liquids ratio/depth relationship[18] were used for determining the co-products production (i.e., associated natural gas and natural gas liquids from crude oil and non-associated natural gas). Oil and gas recovery is based on data from the structure drive mechanism and the recovery factor distributions. These are also conditional distributions in that recovery of oil and gas is dependent upon the drive mechanism of the structure. The secondary/primary recovery relationship is used for determining oil and gas recovery from secondary production. Finally, data from the structure thickness (net pay), permeability and oil viscosity distributions are used for determining the initial flow rate per well for each structure.

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[17] Gas-oil ratio is the number of cubic feet of gas produced per barrel of oil and there exists an inverse relationship between viscosity and the gas-oil ratio.

[18] Gas-liquids ratio is the number of barrels of natural gas liquids produced per cubic foot of gas and the ratio increases with depth.

Economic Input Data

Most national forest lands of the Northern Region are in western Montana and northern Idaho where oil and gas activities are either nonexistent or very limited. In the collection of the economic input data, most costs for oil and gas activities on national forest lands were assumed to approximate costs for other explored areas of eastern Montana and Wyoming. Drilling costs were adjusted for climatic, topographical, and geological conditions. Because field expenditures are incurred over several stages of petroleum exploitation, these costs are discussed according to these stages. The rule determined costs (i.e., accounting and tax rules) are discussed last.

The pre-exploration costs considered in the model are the geological-geophysical (G&G) fraction, the G&G capitalized fraction, lease bonus, and lease payment. Expenditures for G&G work depend on both the area and difficulty of the terrain as well as the degree of fineness of the survey data required. The PSM represents the G&G costs as a fraction of the exploratory drilling costs rather than using an entire set of variables. This makes the data collection process easier, keeps computer computations to a minimum, and still provides sufficient accuracy for this phase of activities. The G&G fraction is a logical way of representing these activities during this phase, since the results of G&G work influence exploratory drilling costs. The fraction was calculated by dividing the onshore national G&G expenditures by the national exploratory drilling expenditures for the lower 48 states. The G&G capitalized fraction defines the portion of all G&G work that is capitalized. Because the acquisition of leases on the Lewis and Clark

National Forest is on a noncompetitive basis, the lease bonus is zero, and the lease payment is equal to the annual federal lease fee.

The PSM represented the costs for exploration using the drilling costs for successful and unsuccessful exploratory and development wells by depth, the spacing of exploratory wells, and the success ratios for exploratory and development wells. The latter two variables are used for estimating the total number of exploratory and development wells.

The drilling costs are the most significant expense for this phase of oil and gas activities. Exploratory drilling is different from developmental drilling in that the former is done in an unexplored area for the purpose of searching for oil or gas, whereas the latter is done in an already explored area for the purpose of developing an oil field for production. The major costs for exploratory drilling include the hiring of a drilling crew, the rental or purchase of a drilling rig, movement of the rig and crew to the drill site, the preparation of a drill site pad (i.e., roads, grading, and gravel), the provision of support facilities for drill crew and equipment, general operating expenses and finance charges. The costs of exploratory drilling are a function of several factors listed below.

(1) Climatic conditions. The weather affects the amount of drilling time required, the productivity of the labor crew, and the operation of the equipment.

(2) Geology and soil conditions. The geology influences the drilling effectiveness while the soil conditions influence the road and site construction.

(3) Remoteness, terrain, and topography. These factors can influence the transportation costs of moving the crew and rig to a new drill site whether it is nearby or far away.

(4) Federal environmental leasing stipulations. These factors can influence the drilling costs on federal lands by imposing occupancy and activity timing constraints on the lease tracts. Since there has been a very limited amount of drilling on the Lewis and Clark National Forest, these were not possible to determine.

(5) Drilling depth. The drilling depth influences the type of equipment required and necessary parts.

Although development drilling is usually not associated with the exploration phase, these costs are now discussed for purposes of succinctness. The developmental drilling costs include the same set of expenses as exploratory drilling but the factors influencing these costs are not as great. The major expense is the construction of permanent drilling pads. The major factors influencing costs are drilling depth and difficulty of drilling. Generally as drilling experience increases (providing more geological information), the length of the drilling time becomes more predictable and efficient. In addition, there are reduced costs of transportation between well sites.

Because secondary data sources were inadequate for estimating the drilling costs on the Lewis and Clark National Forest, several drilling companies operating in western Montana were contacted. After talking with the different individual companies, several assumptions were made to estimate drilling costs.

(1) A dry and successful exploratory well were assumed to cost approximately the same. The individual companies stated this is a safe assumption.

(2) Because the different individual drilling companies found it difficult to estimate developmental drilling costs, a general "rule-of-thumb" was used to estimate these costs. The rule is that development costs are roughly 50 to 75 percent greater than exploratory drilling costs. Most drilling operators felt comfortable using this assumption. The dry developmental drilling costs were assumed to be the same as the dry exploratory drilling costs.

(3) Contacting drilling operators in western Montana for these costs was assumed to be the best way of accounting for climatic, topographical and geological factors influencing drilling costs.

(4) The exploratory drilling costs for oil and gas wells were assumed to be the same.

The primary variables used to represent the development phase of the oil and gas supply process include the surface equipment cost for oil and gas production, the reference capacity for the surface equipment, and a scaling factor used to adjust surface equipment costs. Surface equipment for oil fields, including those with associated gas production, and non-associated gas fields consists of flow lines, equipment needed to separate and process crude petroleum from water and other byproducts, equipment to power the pumps and support field operations, equipment for gas conditioning and compression, and reinjection of gas and water for secondary recovery. The type and scale of surface equipment is a function of the producing characteristics of the oil and gas field, such as the volume of produced oil and gas. Although these costs are a function of a complex set of factors, the PSM simplifies the task by basing the costs for surface equipment on a particular size of explored and developed oil and gas field (reference scale) with an associated production level (reference capacity). These costs are thus based on a production system capable of producing a certain quantity of oil plus water and/or gas per unit of time.

The following relationship is used in estimating surface equipment costs. The surface equipment costs are scaled in proportion to the equipment costs associated with a reference capacity to account for potential economies of scale (USDE 1979a).

$$\frac{C_1}{C_2} = \left[\frac{Q_1}{Q_2}\right]^X$$

Where:

C_1 = Equipment costs for given structure

C_2 = Equipment costs for a reference structure

Q_1 = Equipment capacity for a given structure

Q_2 = Equipment capacity for a reference structure

X = Scaling factor

The use of the scaling factor "x" allows for the estimation of equipment costs for different levels of production. This simplifies the cost estimation in that surface equipment costs are a function of production rates. If the data is insufficient, "x" may be assigned a value between 0.60 and 0.70 (Kalter et al. 1975). The surface equipment costs were partially estimated based on the U.S. Department of Energy publication, "Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations" (USDE 1981). Those instances where cost data were lacking, individual operating companies were contacted in Montana to specify the reference costs and capacities.

The economic cost data, representing the production phase of the oil and gas supply process, can be divided into operating and maintenance costs, and timing of production and investment outlays. The operating and maintenance costs include expenditures for permanent field labor, well workovers, support of in-field labor, fuel consumption, replacement parts for equipment, and variable costs for running surface equipment. The operating and maintenance cost variables used in the model are listed below.

(1) Labor field costs related to primary and secondary production.

(2) Well workover costs.

(3) General administrative expense factor.

(4) Primary and secondary oil lifting/treatment variable costs.

(5) Primary associated natural gas conditioning and compression variable costs.

(6) Primary non-associated natural gas lifting/conditioning variable costs.

The operating cost variables were specified using an U.S. Department of Energy publication on oil and gas field equipment (USDE 1981) and the Bureau of Census Oil and Gas Current Industrial Reports (USDC 1976, 1977, 1978, 1979).

The timing of production outlays consist of many variables represented as fractions, constants, or years, and include the reserves production fractions per year over the life of the oil and gas reservoir, the initial year of decline in total oil production, the decline rate for total oil production, the number of years the peak rate of production is sustained, and the time in years between the initiation of exploration and production and between the initiation of production and peak production. These variables defined the shape of the production profile as depicted in Figure 14. The lack of secondary data sources required this profile to be specified subjectively. This was accomplished by talking with several different companies in eastern and central Montana and several petroleum geologists.

The timing of investment outlays consist of several variables, measured in fractions, representing the percent of the investment spent annually over the life of the oil and gas reservoir. The variables include investments for exploratory and development wells, primary and secondary surface equipment and lease rental payments. The investment fractions were specified subjectively, in the same manner as the timing of production fractions.

The rule determined variables include tax rates and accounting rules. The tax rates are established by federal and state tax laws and include federal and state income tax rates, the Montana oil and gas ad-valorem and severance tax rates, and federal oil and gas royalties. The accounting rules include the investment tax credit percent, depreciation acceleration factor, tangible fraction of exploratory and development well costs, and the discount rate. The latter two probably deserve some further discussion.

The tangible fraction of exploratory and development well costs represents the percentage of such costs that are capitalized. Tangible well costs (e.g., tools, pipe, well casing, and tubing) usually have salvage value and average about 30 percent of total well costs (Megill 1979). Those well costs that do not have salvage value (e.g., wages, fuel, repairs, supplies) are considered the intangible well costs and can be expensed.

The discount (interest) rate represents a charge or fee for the use of monies, or is that rate which causes some people to forego expenditure today to have more to spend in the future. The discount rate is a critical parameter when evaluating the profitability of an investment project, whether in the private sector or public (government) sector. A project yielding a positive rate of return at a 4 percent interest rate may not be an acceptable project to invest corporate funds into if the discount rate used is 7 percent. The choice of the discount rate may mean the difference between the acceptance or the rejection of an investment project. Despite the critical nature of this parameter, the selected figure is often used arbitrarily and sometimes justified on the basis that similar values have been used in the past.

The appropriate discount rate is that number which indicates correctly when resources should be shifted from one project to another more profitable project, whether it is within the private market sector or the public sector. For example, resources should not be taken out of use where they can earn a 10 percent return on investment in order to utilize them in a use yielding only a 5 percent return. Economists refer to such a criteria as an opportunity cost. Opportunity costs are those costs attributable to doing one thing rather than another which stem from the foregone opportunities that have to be sacrificed in doing this one thing. The proper criterion to judge the desirability of a project is the value of the opportunities foregone by investing in the project. The appropriate discount rate for a project is the rate of return that the resources utilized would otherwise earn in the next best opportunity which can be thought of as the opportunity rate of return on investment. (Baumol 1977)

For a specific petroleum exploration/development project to be considered profitable to a firm, the net present value must be positive using a discount rate at least as high as the cost of capital. Funds (capital) necessary to finance corporate investment are raised by issuing stocks and bonds, borrowing from banks, selling assets, and retaining earnings from operations. These capital resources for financing the exploration/development projects, however, are not without a cost. The various investors and/or lenders require an appropriate rate of return for the use of their money, otherwise investors would be unwilling to provide any funds to a corporation and may choose to put their money in government bonds. Therefore, corporations can engage in only those projects which yield sufficient revenues to pay a return on the investment that is acceptable to the investors. The discount rate corporations use should be that rate which is equated to the cost of capital established by investors.

Since the PSM simulates investments by the petroleum industry in oil and gas reservoirs, the appropriate discount rate to use in the model should be equated to the cost of capital in this industry. Since corporate capital is derived from different sources, the discount rate can be established by calculating the weighted average cost of capital. Marshall (1981a) determined that the after-tax weighted average cost of capital (i.e., common equity, preferred stock, retained earnings, long-term debt) of 42 integrated, domestic and international petroleum corporations was equal to 12.6 percent in 1980. Although the discount rate used in discounted cash flow analysis is set by top management, and for various reasons may be higher than 12.6 percent, after considering several factors (e.g., cost of capital, corporate growth objectives, and future investment opportunities), the 12.6 percent rate represents a minimum value that should be used.

Description of the Model Output

The output from the resource model segment consists of five different sets of statistics. The first set of statistics include the expected incremental oil and gas reserves categorized by exploratory footage and minimum acceptable supply prices. The reserve quantities are reported on a cumulative basis by exploratory footage and on an incremental basis by minimum acceptable supply price.

The second set of statistics are the gas-oil and gas-liquids ratios. These are interpreted as the thousand cubic feet of associated natural gas per barrel of oil and the barrels of gas liquids per billion cubic feet of non-associated natural gas, respectively. These statistics are useful in the integrating model segment for determining the amount of co-product production for each unit of oil and gas reserves.

The third set of statistics reported are the average development drilling footages per unit of reserves by minimum acceptable supply price category. These numbers are interpreted as the average drilling footage, in thousands, per million barrels of oil or billion cubic feet of natural gas reserves. These statistics are reported for accounting purposes only, but can be used in the integrating model segment to constrain development drilling. Development drilling might be constrained to account for the unavailability of rigs or to meet one or more environmental objectives.

The total exploration costs for each interval of exploratory drilling are the fourth set of reported statistics. The last set of statistics are the undiscovered oil and gas in-place resources distributions. These distributions are reported in terms of a histogram with a specified mean and standard deviation. These statistics are useful for describing the extent of the total resource base relative to that portion that is recoverable, namely the reserves. The output statistics from the resource model segment are input data for the integrating model segment discussed in the next chapter.

CHAPTER IV

PETROLEUM SIMULATION MODEL: PART II

Introduction

The second part of the Petroleum Simulation Model is the integrating model segment. The objective of this segment is to forecast the timing and extent of petroleum production and transportation development. Linear programming is the solution technique. The purpose of this chapter is to introduce the basic concepts and assumptions of linear programming and the linear programming problem, matrix structure, assumptions, and outputs of the integrating model segment.

Basic Concepts and Assumptions of Linear Programming

Linear programming generally deals with problems of allocating limited resources among competing activities in the most optimal way and can be applied in a variety of ways as in the allocation of production facilities to products, the allocation of national resources to domestic needs, or the distribution of a commodity from one destination to another (Hillier 1974). Linear programming techniques are mathematical using a system of linear equations solved simultaneously to determine a best solution according to some criterion. Today the technique is widely used throughout the forest products industry as well as in government. The Forest Service uses linear programming in the FORPLAN model for national forest planning. FORPLAN fulfills three basic functions in the national forest process: information synthesis, allocation of resources, and alternative plan analysis (Kent 1980).

A standard form of the mathematical model describing a linear programming problem consists of maximizing or minimizing some objective function, subject to a set of constraints as shown below.

$$\text{MAXIMIZE } Z = C_1X_1 + \ldots + C_nX_n \quad \text{(OBJECTIVE FUNCTION)}$$

SUBJECT TO:

$$a_{11}X_1 + \ldots + a_{1n}X_n \leq b_1 \quad \text{(FUNCTIONAL CONSTRAINTS)}$$

$$a_{M1}X_1 + \ldots + a_{MN}X_n \leq b_n$$

$$X_1 \geq 0 \ldots X_n \geq 0 \quad \text{(NON-NEGATIVITY CONSTRAINTS)}$$

The data and mathematical equations used to define the problem are arranged into a matrix format, represented in symbolic notation in Figure 19. The objective function, $C_1X_1 + \ldots + C_nX_n$, is an expression measuring the effectiveness of the system as a function of the decision variables. Constraints (restrictions), $a_{11}X_1 + \ldots + a_{1n}X_n$, represent the total usage of the resources and limit the values that the decision variables can assume. The parameters, a_{ij}, b_i, and C_i, are inputs into the system which may not be known with certainty. Finally, the decision variables, X_i, are those the analyst must solve for to optimize the system.

The model described above, however, does not necessarily fit all linear programming problems. Some problems may minimize the objective function and/or have functional constraints in equality form or greater-than-or-equal-to inequality form. In some cases, the decision

Activity Resource	Decision Variables Resource Usage Per Unit X_1	. . . .	X_n	Type Sign	Constraint Quantity of Resource Available
1	a_{11}	. . . .	a_{1n}	$\leq$	b_1
2	a_{21}	. . . .	a_{zn}	.	.
.	.		.	.	.
.	.		.	.	.
.	.		.	.	.
m	a_m	. . . .	a_{mn}	$\leq$	b_m
C_{1j}	C_1X_1	. . . .	C_nX_n	=	Z (MAXIMIZE)

Figure 19. Standard linear programming model matrix.

variables may not have a non-negativity constraint but can be unrestricted in sign for some values. Any problem that mixes some or all of these forms is still considered a linear programming problem.

The utility of linear programming cannot be understood until the assumptions implicit in the model are highlighted. An understanding of these assumptions provides a basis for evaluating how well linear programming applies to a given situation. The four chief assumptions implicit in any linear program are proportionality, additivity, divisibility, and deterministic (Hillier 1974). The assumption of proportionality means that if inputs are doubled, outputs will also double. A term often used to describe this phenomenon is constant returns to scale. If this assumption cannot be satisfied within acceptable bounds, the analyst is in the realm of separable convex programming. Separable convex programming is useful for incorporating nonlinear functions into a linear programming problem through piecewise linear functions, which are a sequence of line segments used to approximate a nonlinear function.

If the objective function or constraints have cross-product terms which would change the total measure of effectiveness or total usage of some resource, then the additivity assumption is violated. If product A requires 6 units of input with a profit of 10 and product B requires 3 units of input with a profit of 5, then together 9 units of input would be required for a profit of 13. If this does not hold because of some interaction effect between products (variables), the analyst is faced with a nonlinear programming problem. This type of problem is concerned with modeling systems of nonlinear functions.

The divisibility assumption is concerned with whether activity units can be divided into fractional values so that non-integer values for the decision variables are permissible. If the solution of a linear programming problem is not integer but can be satisfactorily rounded to the nearest integer, the standard linear programming technique is still applicable. However if this is not permissible, integer or mixed integer linear programming is used. These specialized linear programming techniques restrict all or some of the decision variables to integer values.

The last assumption, deterministic, assumes that the parameters used in linear programming are known constants. Although this assumption is seldom satisfied, sensitivity testing is often used to identify the more sensitive parameters and to estimate them more accurately. In some cases, however, the uncertainty inherent in the parameters is so large, it is necessary to treat such parameters as random variables. When this situation occurs, the analyst enters the world of stochastic linear programming where some form of probability analysis is used in the problem formulation.

Understanding the technique of linear programming and the implicit assumptions is necessary for setting up the linear programming problem. The first step in setting up a linear programming problem is to define the decision variables, resources, and objective function. Once this step is completed and a check has been made that the linear programming assumptions have not been violated, the problem must be translated into mathematical terms (i.e., defining the set of linear equations) and displayed in the form of a matrix. Because of the numerous arithmetical calculations required to solve a linear programming problem, specialized algorithmns are used on a computer. After the problem is set up, the analyst must interpret the output and determine what information is needed and what further analysis must be done. Sensitivity tests can be conducted to better understand how the solution varies with changes in the input data.

Description and Assumptions of the Linear Programming Model

Introduction

The objective of the time-staged linear program[19] is to choose the timing (i.e., start dates) and extent (i.e., quantities) of exploration, development, and transportation activities while simultaneously considering other factors which depend upon time (e.g., prices of oil and gas, state of pipeline network, and drilling constraints) to maximize the net present value of the cash flow. Figure 20 is a schematic diagram of the linear programming matrix. The discussion will center around this figure by explaining the objective function and each of the resources (i.e., rows) and the decision variables (i.e., columns). Much of this discussion is based on the two documents describing this model published by the U.S. Department of Energy (USDE 1979a; 1979b).

Terminology

Some of the terms used for defining the linear program include three different types of regions, three kinds of time periods,

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[19] The linear program consists of several different time periods to represent the key variables of exploration, development, production, transportation, and sales.

COLUMNS j / ROWS i (a_{ij})	Exploratory Drilling	Development Drilling	Demand Activity	Transportation Over Links	Transportation Over Spurs	Network Expansion	Injection	Resource Inventory	Type Sign	RHS Contraint: Value	RHS Contraint: Units
	Decision variables(activities)										
Resources: Drilling Accounting (Exploration)	Million of Drilling Feet								Non-Constra.	Sum Expl. Drill	Feet
(Development)		Million Drilling Feet							Non-Constra.	Sum Devl. Drill	Feet
Material Balance (1)		Production Flows(-)					Transfer Gas $T_1 \rightarrow T_n$		MAX. ≤		Flows in
(2)			Products Consumed(+)						MAX. ≤		=
(3)				Consume (+) Produc Produce (-) Produc	Consume (+) Produc Produce (-) Produc				MAX. ≤		Flows out
Transprotation Link Capacity				Consumes Link Capacity +1		Produces Capacity for Set of Links (-)			MAX. ≤	Exist Cap. Link (Ø)	MBB/D BCF/D
Supply Convexity	Fraction of Exploratory Drilling 1 or Ø								MAX. ≤	1	None
Resource Inventory	Reserves Discovered BBL or TCF (-)	Reserves Consumed (+)						Transfers Reserves $T_1 \rightarrow T_n$ (+) or (-)	MAX. ≤	Ø	None
Network Expansion Convexity						Fraction of Project Constructed (≤ 1)			MAX. ≤	1	None
Objective Function (minimize) c_{ij}	PV million $/Day COST	PV of Profile million $/Day COST	PV of Oil & Gas Price REVENUE	Ø COST	$/mile for spurs capacity COST	PV of Project Cost COST			Non-Constra.	Z	$ COST

(+) entry=consumption (-) entry=production

Figure 20. The linear programming model matrix for the Petroleum Simulation Model.

development cost categories, exploratory increments, and transportation pipeline links and spurs. The three types of regions recognized in the model are supply regions (i.e., where oil and gas exploration and development occur), demand regions (i.e., where oil and gas sales occur), and transshipment regions (i.e., points where major pipelines meet). The three types of time periods include material balance (i.e., periods in which production and transportation flows occur), drilling start (i.e., period when exploratory and development drilling begin), and network expansion start (i.e., time when major pipeline capacity becomes available). A development cost category is synonymous with a minimum acceptable supply price category or the aggregation of one or more price categories. An exploratory increment is a unit of drilling effort expressed in feet. Finally, a transportation link or spur is a pipeline directed between two points, an origin and a destination.

All flow rates and capacities are expressed in terms of a single day while time periods are in terms of years. The produced quantities of oil and gas are expressed in millions of barrels of oil and billion cubic feet of gas, whereas reserves are expressed in billions of barrels of oil and trillion cubic feet of gas. Drilling footage is expressed in millions of feet. Costs and revenues are measured in millions of dollars.

Matrix Structure

The objective function is the minimization of the present value of total costs (i.e., exploration drilling costs, development costs, and transportation costs) less revenues. In contrast to the resource model segment the integrating model segment considers revenues from the sale of petroleum products. Because this function was converted from a minimization problem to a maximization problem, the objective function value is expressed as a negative number. Thus the optimal solution would provide the largest negative number.

The matrix rows, defining the resources of the model, are of six types. The first type are the drilling accounting rows. These rows sum the exploratory and developmental drilling by region, by drilling start period, and by product. Presently, the rows are used only for accounting purposes, but they may be used for constraining either exploratory or developmental drilling in simulating the unavailability of rigs or in slowing drilling to meet a specific environmental or social/economic objective.

The material balance rows insure that the sum of the flows into a region equal the sum of the flows out for each time period and product. Flows in arise from production and transportation in, whereas flows out arise from sales and transportation out. The reserves inventory rows can also be considered material balance rows. The purpose of these rows is to insure that reserves developed by development drilling do not exceed reserves discovered from exploratory drilling. In addition, the transportation link capacity rows also serve as material balance rows in that the flows through a pipeline link cannot exceed the capacity of the link for each material balance time period.

The last type of rows are supply convexity rows. The exploration convexity rows insure that the sum of the fractions of exploratory drilling does not exceed one for each increment in each supply region. The network expansion convexity rows prevent the various transportation projects from being carried out more than once.

The matrix columns, representing the decision variables or activities, consist of eight different columns. The first six columns define the investment activities for exploration, development, transportation, and sales. The first column represents exploratory drilling which serves to produce reserves for several development cost categories and uses exploration convexity. The objective function value is the present value, in millions of dollars, of exploratory drilling costs. Development drilling, the second column, converts the reserves discovered from exploration into production for a particular development cost category and time period. The objective function entry is the present value, in millions of dollars, of the production profile where each unit of production is assumed to cost an amount specified by the development cost category. The third column represents the demand activities which consume oil and gas products at the demand region in each material balance time period. The objective function entry is the present value of the forecasted market prices for oil and gas. The transportation activities consume oil and gas products at a source (i.e., demand region). The difference between transportation over pipeline links (fourth column) as opposed to pipeline spurs (fifth column) is that capacity is consumed in the former due to a capacity size limitation. The network expansion activities in the sixth column serve to provide pipeline link capacity for each of the material balance periods. These activities also use network expansion convexity and have an objective function entry equal to the present value of total daily pipeline costs over the life of the pipeline.

The last two columns, injection and resource inventory, serve as linking variables which affect more than one material balance or drilling start time period. Injection refers to the transfer of gas from one material balance period to the next at zero costs. Injection is used in the model for those cases where oil production is desirable, but the production of associated gas is not desirable until a later date. Different from injection, reserves inventory transfers unused (uncommitted) reserves from one drilling start period to the next.

Assumptions

As in the resource model segment, some important assumptions with respect to the model design (i.e., linear program) of the integrating model segment should be highlighted.

(1) The linear program optimization is carried out over the expected values of the reserves from the resource model segment, rather than optimizing the transportation network.

(2) Usually explorationists use information from past drilling to help make future drilling decisions. However, because this requires a sophisticated statistical decision process this was not incorporated into the resource model or integrating model segment.

(3) The model assumes a dynamic competitive equilibrium which implies a competitive market structure with perfect knowledge and foresight of model parameters (i.e., the basic cost/price trajectories). This assumption may be questionable for pipeline operation which is complicated with regulations.

(4) The model assumes that all the petroleum resources supplied can be sold in the market place (i.e., potential refineries).

Usually the linear program is run in a continuous mode (i.e., all variables being non-integer). However the model can be formulated in terms of a mixed integer mode where the network expansion variables can be restricted to zero-one integers. The integer restrictions prevent pipelines from being built in awkward and unrealistic pieces over time. This violates the assumption of divisibility to some extent, but since a rounding-off of pipeline capacity sizes is acceptable using the continuous mode and since the transportation network is of secondary importance, such a violation is permissible for purposes of this study.

Most of the parameters used in the linear program are assumed to be known with some degree of certainty and, therefore, the deterministic assumption is not violated. The mean reserve estimates used from the resource model segment have been risked (i.e., probability has been incorporated) and the linear programming model can assume the estimates known with certainty. The market price forecasts are probably the most uncertain and, to account for such uncertainty, three different price scenarios are used.

All of the equations used in the model are linear and, thus, the additivity assumption is not violated. However since the discovery of oil and gas does not follow constant returns to scale, the assumption of proportionality is violated. This assumption was satisfied in the resource model segment by tabulating the reserve additions as a function of exponentially increasing units of exploratory effort across an increasing set of minimum acceptable supply prices. Thus the discovery of oil or gas which is assumed to follow a declining exponential curve is incorporated into the linear program through the specification of many points along this curve connected by line segments.

Operating Procedures

The model operates in four sequential stages. The preprocessing stage re-formats the reserves output tables from the resource model segment. Matrix generation is the next stage in which the linear programming matrix, depicted in Figure 20, is constructed. Once the matrix is set up, the process of solving for an optimal solution can begin. The solution is reached through the use of a mathematical programming system for solving linear programming models. After the optimal solution is reached for the linear programming problem, the final stage is preparing the output tables. A report writer is a set of instructions used to aggregate and compile various sets of output data into summary tables.

Preparation of the Input Data

The data for the integrating model segment used to construct the linear programming matrix is entered as processed output from the resource model segment and as manual entries into various lists and tables. The preprocessor is a FORTRAN computer program used in rearranging the data from the reserves output tables produced by the resource model segment for use in the linear programming matrix. The primary purpose of the preprocessor is to provide the analyst with an opportunity to aggregate MASP categories (development cost categories). The advantage of aggregating these categories is to reduce the size of the linear program and costs of running the program. In addition to aggregating reserve additions across development cost categories, the preprocessor re-expresses cumulative reserve additions as incremental reserve additions and re-formats the data.

The chief data inputs regarding the timing of production include the material balance, drilling start, and network expansion start time periods. The material balance time periods refer to the calendar dates in which production and transportation flows occur. The convention used is that the calendar dates refer to the first year of a material balance period. The drilling start periods are actually start dates referring to the year exploratory and development drilling begin. The assumption is that exploratory drilling is completed within a year and any reserves discovered are available for development in the same year. Development drilling, however, occurs over a 4 to 6 year period. The drilling start periods are chosen with the production lead times in mind so that production begins at the start of a material balance period. Finally, network expansion time periods are also start dates and refer to the time when new major pipeline capacity becomes available for use.

The oil and gas market price forecasts are probably the single most important set of data in the linear program since these prices drive all activities. The prices are forecast for each material balance period and reflect the selling prices less windfall profit tax (WFPT) at each of the demand regions. The crude oil price forecasts reflect the domestic refinery acquisition costs for 1981 in terms of 1980 dollars. The gas prices reflect the average delivered price (i.e., arithmetic average of residential, industrial and commercial natural gas).

The price forecasts were obtained from the U.S. Department of Energy (USDE 1982). Because of the uncertainty in the price forecasts, three different price scenarios were used (i.e., high, low, and moderate). These price forecasts are based on many assumptions about the world oil price, economic growth (i.e., gross national product, inflation, disposable per capita income, and manufacturing production), and federal energy programs (i.e., Natural Gas Policy Act, Windfall Profits Tax, and various energy conservation programs). It should be noted that the price forecasts do not include the effects of future disruptions of oil supplies. The price forecasts are conditional statements about what could happen, and any significant changes in these assumptions would render such forecasts inaccurate.

Because the linear program does not account for the effect of the WFPT on oil production, the price forecasts were reduced by an amount equal to the tax. This tax is determined by deducting the adjusted base price[20] plus an adjustment for state severance taxes from the removal (sales) price. The difference is equal to the windfall profit which is multiplied by the windfall profit tax rate to arrive at the total windfall profit tax on a barrel of oil (Crumbley 1982).

The production profiles used in the resource model segment for estimating potential reserves provide the critical linkage between the resource model segment and the integrating model segment. These profiles are the production fractions for oil and gas reserves over a span of years and can be represented as daily or annual production fractions.

The early and late start dates for all exploratory and development drilling activities are another important data element. The late start dates are unconstraining and are usually the last year represented in the model. The early dates for exploration can be specified for each

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[20] The base price is that average price of uncontrolled domestic crude in December 1979. The adjusted base price accounts for the inflation occurring after the base price determination.

supply region or for each exploratory increment. The developmental start dates are usually specified for the supply region in total.

The last data inputs to consider in the linear program are those relating to the transportation system. The development of a transportation network is necessary so the transportation activities of the oil and gas supply process can be represented. Although a detailed transportation network would be useful for the purpose of this study, the transportation network was kept simplified. The network is only as detailed and comprehensive as to realistically represent the transportation alternatives.

The objective is to design an oil and gas transportation system, composed of potential new links and spurs or expansion of pre-existing pipelines, and estimate the total costs. Development of the transportation system data consists of defining the expected physical properties and characteristics of the crude oil and natural gas of the supply region, estimating the desired pipeline capacity, designing the transportation network system, and estimating the total costs of the system. The characteristics of crude oil and natural gas (e.g., specific gravity, viscosity, and flowing temperature) are important since they influence the mode (e.g., above or below ground) and size of pipelines connecting producing fields with an oil refinery or a gas utility plant. The next step is to define the desired pipeline capacity in million barrels of oil per day or billion cubic feet of gas per day from a supply region area, which is based on the potential oil and gas reserves (output from the resource model segment).

Because of the many uncertainties with respect to the length of pipeline routes, terrain to be traversed, and volume of oil and gas transported, the transportation network system is only hypothetical. The geographical placement (layout) of the oil and gas pipeline system is made on the basis of expected oil and gas field occurrence and many regional influences (e.g., climate, terrain, past and future land use patterns, public agency management plans, other existing transportation systems, and remoteness). After the system is designed and displayed on a map, the information is organized into a table which describes each pipeline segment (i.e., in terms of source and destination) and length in miles.

The last step is estimating the total pipeline costs of the transportation system. The pipeline costs for oil and gas links include pipeline construction costs, pump station costs, and operating expenditures. The construction capital costs influenced by the pipeline route, mode of laying, climate, and soil conditions include road and facilities construction, material acquisition and fabrication, and pipeline installation. The pump station capital costs are based on the required horsepower and include site preparation, construction of fuel units, and pumping stations. Finally, the operating costs consist of a fixed component (i.e., labor, support, and replacement parts) and a variable component (i.e., fuel charges or losses). The fixed component is estimated using a constant annual fraction of pipeline capital costs. The variable component is the amount of oil or gas used from the pipeline to run the pumping stations and other facilities. Because electricity or diesel engines are assumed to be used for this study, the variable component was not estimated.

Once all of this data is collected, it is organized into a table. The costs of the transportation system are categorized according to projects which may involve one or more pipeline links. For each project, the pipeline capacity, total capital costs, and operating expenditures are specified. The information in this table is used to calculate the total costs for each project. The oil pipeline engineering design and cost calculations were prepared by the U.S. Forest Service, Northern Region Engineering staff. The gas pipeline costs were based on the cost analyses in the final environmental impact statements for the Trailblazer, Rocky Mountain, and Trans-Anadarko Pipeline Projects (FERC 1980; FERC and USDI 1981; FERC 1982). These are similar sized pipeline projects.

Description of the Output

The output from the integrating model segment consists of many tables summarizing the exploration, development, and transportation activities and production quantities of the supply region. The first output report displays the simulated oil and gas forecasts in million barrels and billion cubic feet per day, respectively. The quantities are the average daily production flows within the time period. The transportation report lists the year, size (i.e., maximum capacity), location, and costs for all pipeline construction. The exploration and development drilling reports summarize the total drilling footage for each product and for each drilling start time period. These estimates represent drilling footage for successful and unsuccessful oil and gas wells. Finally, the development activity reports summarize the developed oil and gas reserves by time period and development costs.

CHAPTER V

THE LEWIS AND CLARK NATIONAL FOREST AS A PILOT TEST

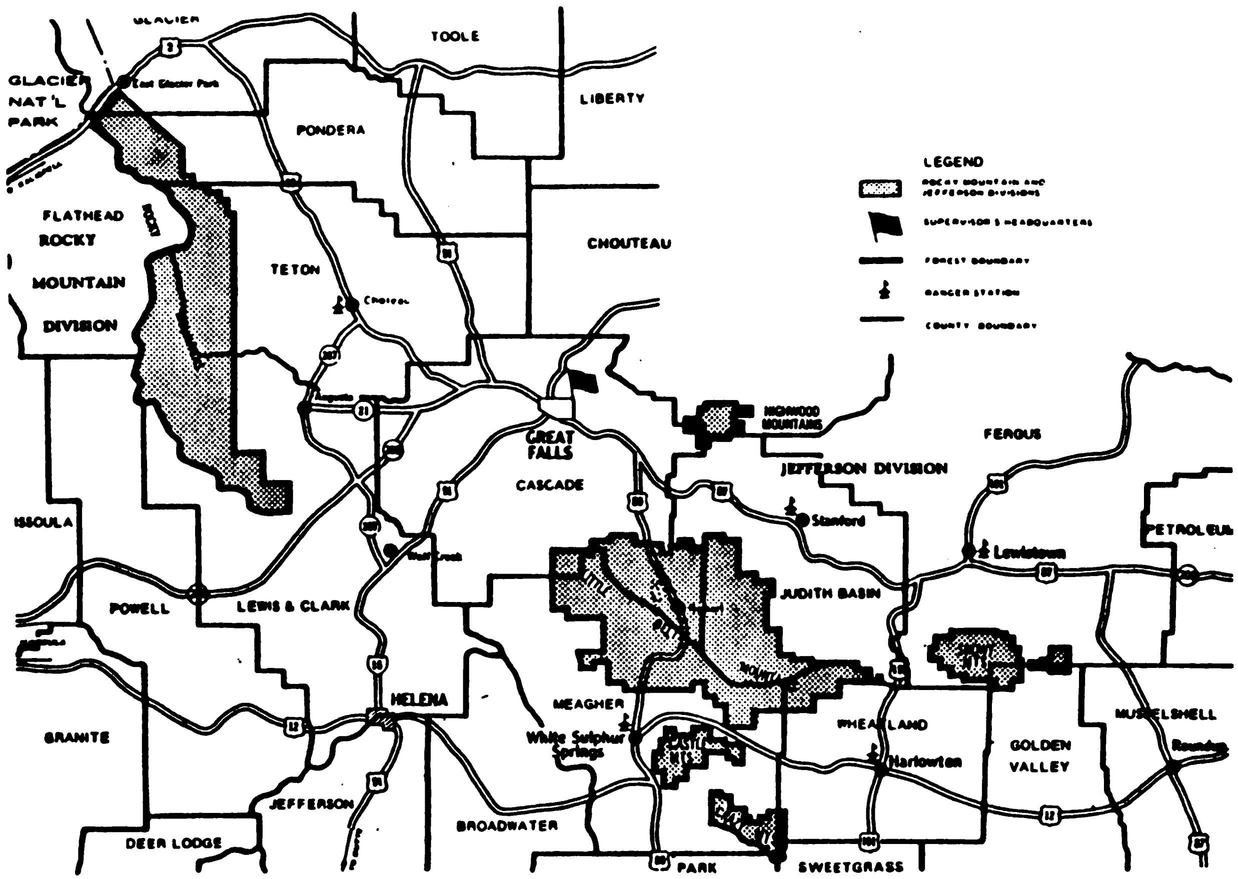
Introduction

The Lewis and Clark National Forest was used as a pilot test for the Petroleum Simulation Model (PSM) to evaluate the model and the quality of output to provide information about oil and gas resources that could be integrated into the national forest planning process. This chapter describes the study area and discusses the results from running the model. Some additional discussions include validating the model outputs, model logic, and assumptions.

The Lewis and Clark National Forest

General Description

The Lewis and Clark National Forest is situated in north-central Montana within the upper Missouri River system (Figure 21). The Forest, encompassing over 1.8 million acres, has been traditionally divided into two major divisions, the Rocky Mountain Division and the Jefferson Division. The Rocky Mountain Division contains the Rocky Mountain Ranger District and extends from Glacier National Park south to the Dearborn River and east of the Continental Divide. The Jefferson Division contains the Judith, Musselshell, and Kings Hill Ranger Districts and lies east and south of Great Falls. The division has six



SOURCE: USDA Forest Service 1982b. Proposed Lewis and Clark National Forest Plan. Lewis and Clark National Forest, Great Falls, Montana. 263 pp.

Figure 21. A vicinity map of the Lewis and Clark National Forest.

distinct mountain ranges: Little Belt Mountains, Highwood Mountains, Big Snowy and Little Snowy Mountains, Castle Mountains, and the northern Crazy Mountains. (USDA 1982b)

The topography of the Forest is quite variable, ranging from steep and rugged mountain slopes to more gently rolling terrain. The Rocky Mountain Division consists of a folded mountain structure, resulting from extensive overthrust faulting of sedimentary rock, and has very steep ridges and narrow valleys from glaciation. The area has some spectacular peaks with the highest elevation being 9,392 feet. The mountain ranges of the Jefferson Division are more dome-like structures with smooth rounded tops and deeply carved valleys. The division is more diverse geologically in that a portion of the area is overthrusted (i.e., folded and faulted), while other areas consist of large igneous rock bodies, limestone beds, and volcanic rocks. (USDA 1982c)

Approximately 85 percent of the land area is forested with the remaining area containing meadows, rocky ridges, and peaks. The production of forage continues to be the major revenue producing resource on the Forest, even though the growing season is limited by the lack of moisture on the low elevation lands and cold temperatures at the higher elevations. (USDA 1982c)

The study area provides a wide variety of recreational opportunities. Hunting is the most popular but other forms of dispersed recreation include fishing, cross country skiing, hiking, and snowmobiling. Because of poor access to most areas, large portions of the study area receive little recreational use. In addition, the Forest provides habitat for numerous species of wildlife and fish. Elk is the most popular big game species and other species include mountain goat, bighorn sheep, moose, mule deer, white-tailed deer, black bear, and mountain lion. Grizzly bears are found throughout the Rocky Mountain Division. Cold water fish species are present in all large streams. (USDA 1981c; 1982c)

The local area of influence for both divisions of the Lewis and Clark National Forest consists of 13 counties. The five counties surrounding the Rocky Mountain Division include Lewis and Clark, Toole, Teton, Pondera, and Glacier. The population of these counties was 72,448 in 1980, an increase of nearly 16 percent from 1970. The 1979 per capita income was 5,115 dollars compared to 4,525 dollars in 1970 (1972 dollars), representing an average annual growth rate of 1.23 percent compared to 1.91 percent statewide. The economic structure is primarily farming and ranching for Toole, Teton and Pondera. Service industries and state and local government provide the primary economic base for Glacier and Lewis and Clark counties. (USDC 1981) The unemployment rate has averaged 5.4 percent in the last five years, compared to 6.1 percent statewide (State of Montana 1982).

The local area of influence for the Jefferson Division consists of eight counties including Cascade, Choteau, Judith Basin, Fergus, Golden Valley, Wheatland, Meagher, and Musselshell. The population of these counties was 112,477 in 1980, an increase of only one percent from 1970. The area includes Great Falls, one of the largest metropolitan areas in Montana. Per capita income in 1979 was 4,117 dollars compared to 4,163 dollars in 1970 (1972 dollars), representing an average annual growth rate of -0.11 percent compared to 1.91 percent statewide. Again, the economic base for most counties consists of farming and ranching except for Cascade County which is primarily dependent upon Malmstrom Air Force

Base. (USDC 1981) The unemployment rate has averaged 4.8 percent in the last five years, compared to 6.1. percent statewide (State of Montana 1982).

The Lewis and Clark National Forest has a diverse set of natural resources which have supported the surrounding local communities, both economically and socially, for the last several decades and should continue to help provide for the future growth of these communities.

Petroleum Potential and Activities

The geology of the Lewis and Clark National Forest is varied. The Jefferson Division has the most diverse geology of the Forest, with an area in the western Montana Overthrust Belt (i.e., Castle and Crazy Mountains) and other areas of volcanic and igneous rocks. The Rocky Mountain Division has the complex geology characteristic of the Western Overthrust Belt. The entire Forest is considered a frontier area in that little is known about the petroleum potential and only a limited amount of exploration activity has occurred.

No quantitative oil and gas estimates have been made specifically for the Lewis and Clark National Forest, but some quantitative estimates have been made for several Western Overthrust Belt provinces. These estimates are summarized in Table 3 and, compared to the entire United States, provide some perspective as to the relative petroleum potential of the three Overthrust Belt provinces. The Rocky Mountain Division and a portion of the Jefferson Division are a part of the Montana Overthrust Belt.

Estimates of oil and gas potential have been made on a qualitative ranking of high, moderate, or low potential by Rice (1977), Mudge and

Table 3. Estimates of undiscovered recoverable oil and gas resources of the three Western Overthrust Belt provinces.

Area	Crude Oil (billion barrels)			Natural Gas3/ (trillion cubic feet)		
	Low1/	High2/	Mean	Low	High	Mean
Montana Overthrust Belt	0	2.0	0.6	1.8	25.0	9.3
Wyoming-Utah-Idaho Overthrust Belt	2.7	13.3	6.7	22.3	118.5	58.4
Total United States	64.3	105.1	82.6	474.6	739.3	593.8
Canadian Foothills Overthrust Belt				1.3	14.5	6.5

1/ 95 percent probability of more than that amount being present.
2/ 5 percent probability of more than that amount being present.
3/ Includes associated and non-associated natural gas.

Source: Dolton et al. (1981) and Powers (1981).

others (1977), Earhart and others (1977) and Mudge and others (1978). For purposes of the Lewis and Clark National Forest Plan, a hydrocarbon assessment was conducted. The assessment indicated that the highest potential areas included the Rocky Mountain Division and portions of the Jefferson Division (i.e., Crazy Mountains, and areas adjacent to the Castle Mountains). The east and south flanks of the Little Belt Mountains and the Highwood Mountains have a more moderate potential. The remaining portions are considered to have a low potential (Figures 22 and 23).

The occurrence of oil and gas in the vicinity surrounding the Lewis and Clark National Forest has been known since 1892. In that year, crude oil seeps were found on the north shore of Kintla Lake in the extreme northwestern corner of what is now Glacier National Park. Later in 1901, a more promising oil seep was found by a prospector digging a tunnel into the side of a mountain, north of St. Mary Lake in the eastern part of Glacier National Park. After exploration of this oil seep, the Swift Current oil field was discovered in 1903. By 1904, 12 wells were in operation, establishing the first crude oil production in Montana. The operation of these wells lasted only a few years and by 1910 production had ceased. (Douma 1953)

Other than the discovery of oil in Swift Current Valley, interest in this area waned until the late 1960's. During this time approximately 75 leases covering 185,000 acres of the Rocky Mountain Division were issued; seismic activity increased and 3 to 5 exploratory wells were drilled on the Forest. Some natural gas was discovered, but, because of the low prices, remoteness of the area, and complex geology, the exploration was discontinued and the leases relinquished. (USDA 1982c)

Interest in this area was resumed in the early seventies, primarily as a result of higher oil prices and the large discoveries of oil and gas in the Utah-Wyoming portion of the Western Overthrust Belt. Leasing activity increased markedly during this period. Several environmental assessments were completed in 1979 and 1980 to make lease recommendations on over 360,000 acres. Currently the oil and gas lease applications in all wilderness and proposed wilderness areas (Figures 22 and 23) of the Forest are pending issuance until the U.S. Congress decides on how to deal with this land management problem.

Presently (i.e., August 1982) a total of 209 oil and gas leases are either issued or pending reissuance covering 443,921 acres on the Lewis and Clark National Forest.[21] Many of these leases have stipulations which usually constrain surface occupancy by location, timing, or operations. Another 221 oil and gas lease applications, covering 708,407 acres, are awaiting issuance with a large portion of these in wilderness or proposed wilderness areas.[21] Except for the wilderness and proposed wilderness areas of the Rocky Mountain Division, all remaining lands have issued oil and gas leases. The Highwood Mountains, Big Snowy Mountains, Castle Mountains, Crazy Mountains, and a portion of the Little Belt Mountains of the Jefferson Division all have issued oil and gas leases or have pending lease applications. Approximately 690,000 acres of the Jefferson Division have not been leased or are

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[21] Monthly Minerals Leasing Report compiled by the U.S. Department of Agriculture, Forest Service, Northern Region Minerals and Geology Staff Unit.

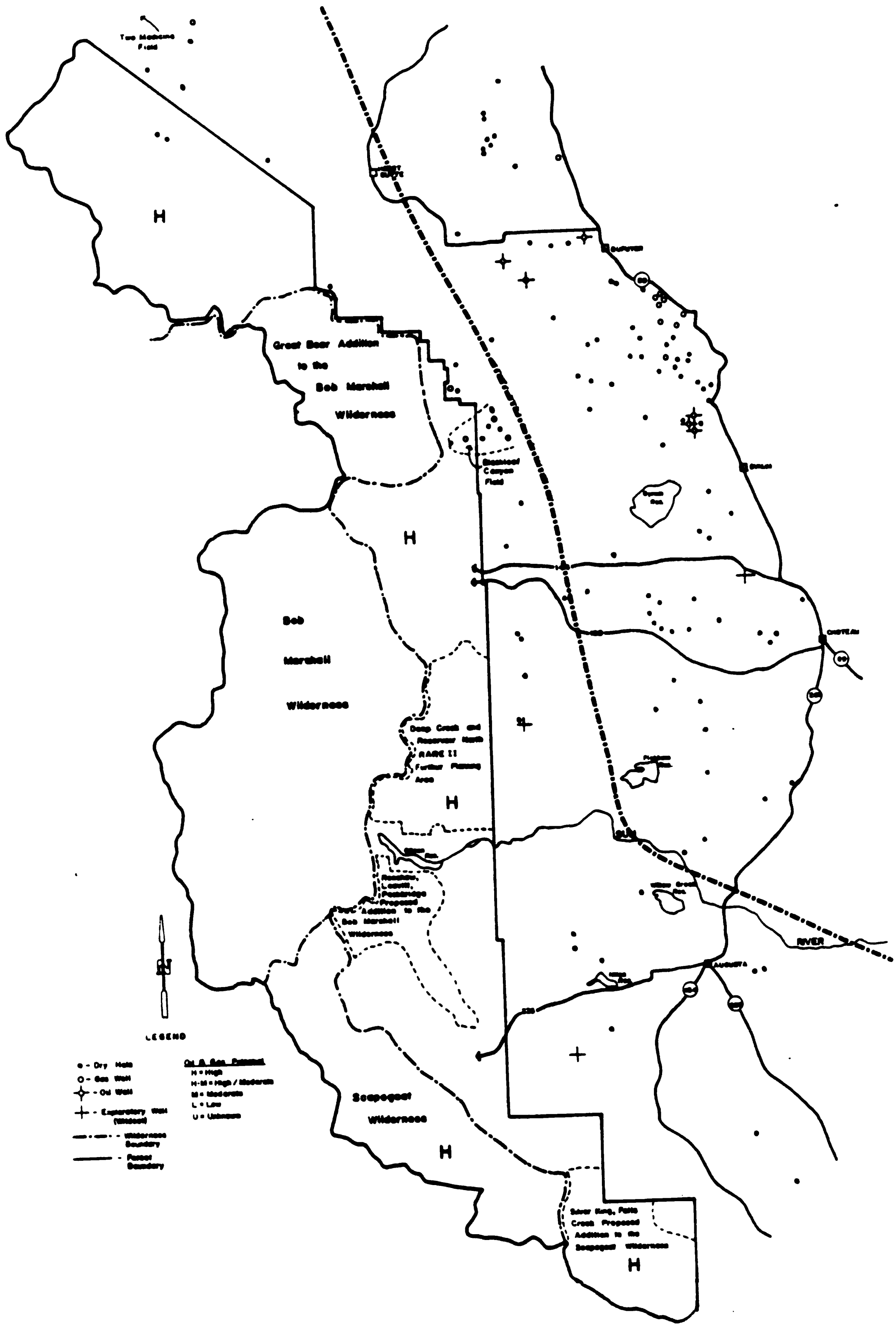

Figure 22. The Rocky Mountain Division of the Lewis and Clark National Forest.

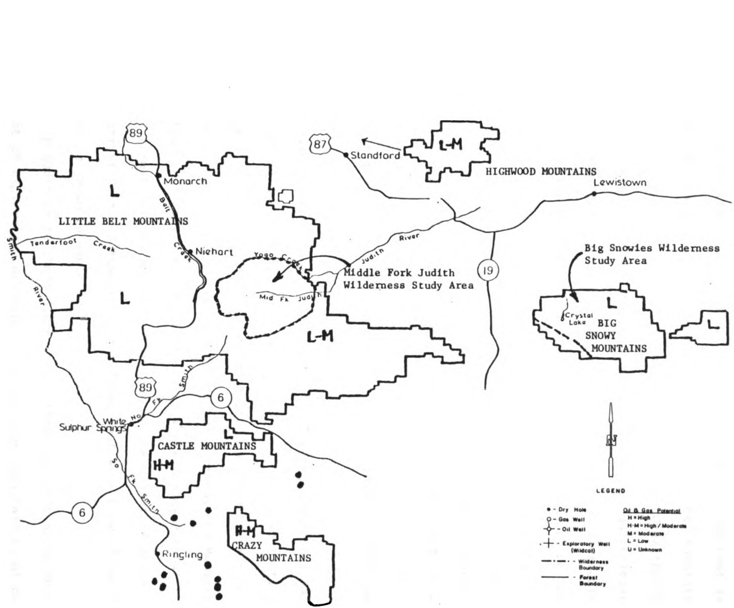

Figure 23. The Jefferson Division of the Lewis and Clark National Forest.

without any lease applications, representing 37 percent of the forest acreage.

Oil and gas activity is expected to increase in the next several years. Most activity would probably occur on the Rocky Mountain Division because of the high oil and gas potential. Over the next several years, companies will probably continue to acquire leases and consolidate lease holdings. Seismic activity has been increasing rapidly in the past several years as seen from Table 4. The Lewis and Clark National Forest has had only one application for permit to drill. The permit was issued with the intention of re-entering a shut-in gas well. The re-entry of the well was completed and found capable of production as soon as a pipeline is constructed. This well is within the Blackleaf Canyon area (Figure 22), recognized as one of the first areas in the Montana Overthrust Belt to commercially produce gas. (USDA 1982b)

All adjacent federal lands, except for Glacier National Park, are open to oil and gas leasing. Oil and gas exploration activities are now underway on the Blackfeet Indian Reservation and nearby private lands. In 1980, two new oil and gas fields were discovered, Two Medicine Field and Blackleaf Canyon Field (Figure 22). These fields established the first commercial oil and gas production in the western Montana Overthrust Belt. A summary of the first test well flows from these fields is shown in Table 5.

In addition to these discoveries, there has been an extensive amount of exploratory drilling along the Rocky Mountain Front between the Forest boundary and highways 89 and 287 (Figure 22). The oil and gas production, however, lies within the Sweetgrass Arch geological

Table 4. A summary of seismic activity on the Rocky Mountain Division of the Lewis and Clark National Forest.

Year	Number of Miles of Seismic Line Surveyed
1977	5
1978	12
1979	18
1980	25
1981	205

SOURCE: Background notes (unpublished) on oil and gas exploration of the Rocky Mountain Division, Lewis and Clark National Forest.

Table 5. A summary of oil and gas production of the Montana Overthrust Belt.

Field Name	Producing Formation	Depth	Oil B/Day	Gas MCF/Day	Condensate B/Day
Two Medicine	Sun River 1/	7,000	145	3,800	
	Blackleaf			50	90
Blackleaf Canyon	Sun River 2/	5,400		7,400	

1/ This field was discovered previously in 1954 and 1961 but was unable to economically produce oil and gas at that time.

2/ This field was known from earlier drilling, but the recent new wells have extended this field.

Source: Montana Oil Journal 1981b. 60(48):8

province east of the heavy-dashed line shown on Figure 22. Activities on the Jefferson Division have been more modest, but a few firms have done exploratory drilling on the north end of the Crazy Mountains (Figure 23). Although oil and gas exploration in and around the Forest is modest relative to portions of the Utah-Wyoming Overthrust Belt and Williston Basin, it is expected that continued activity will occur. If a significant discovery is made in this area, the Lewis and Clark National Forest may experience a dramatic increase in exploration and development activities.

Because of the lack of information about the size, extent, and location of oil and gas resources on the Lewis and Clark National Forest, the integration of these resources into current land use management has been difficult. From the environmental analyses and the draft Forest Plan some of the issues identified with oil and gas resources are:

(1) How much mineral exploration and development should be allowed?

(2) How should conflicts between exploration for and the development of mineral resources and surface resource values be resolved?

(3) What controls would be necessary to protect surface resources during exploration for and development of mineral resources?

(4) What social and economic effects on local communities will mineral exploration and development have and are they acceptable? and

(5) What surface value or uses should be withdrawn from mineral entry?

Additionally the agency is concerned about what levels of oil and gas activity will occur in the future and how much manpower and dollars would be necessary to manage the oil and gas program. The purpose of this study is to help provide information about oil and gas resources to the Forest to address the above issues and to better integrate oil and gas resources into the forest planning process.

Estimating the Petroleum Potential on the Lewis and Clark National Forest

This section discusses the output results of the PSM on the Lewis and Clark National Forest. The supply region for the Forest consisted of the Rocky Mountain Division and a portion of the Flathead National Forest (Figure 22).[22] The most recent geological data were used but because current economic cost data were not available, actual 1980 cost data were used.

Output Results from the Resource Model Segment

The output results are presented in a series of tables and figures and consist of the total undiscovered oil and gas in-place resources, the mean expected oil and gas reserves categorized by exploratory footage and minimum acceptable supply price (MASP), the mean gas-oil and gas-liquids ratios for each unit of reserves and price category, the mean developmental drilling footage for each unit of reserves and price category, and the total oil and gas exploration costs for each exploratory interval. The first set of statistics are the total undiscovered oil and gas in-place resources. These statistics are displayed graphically in Figures 24 and 25 in terms of a frequency distribution (histogram) and a cumulative distribution. The

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[22] Because of differences in the characteristics of structures between the Jefferson Division and Rocky Mountain Division, the structures of the Jefferson Division were not considered.

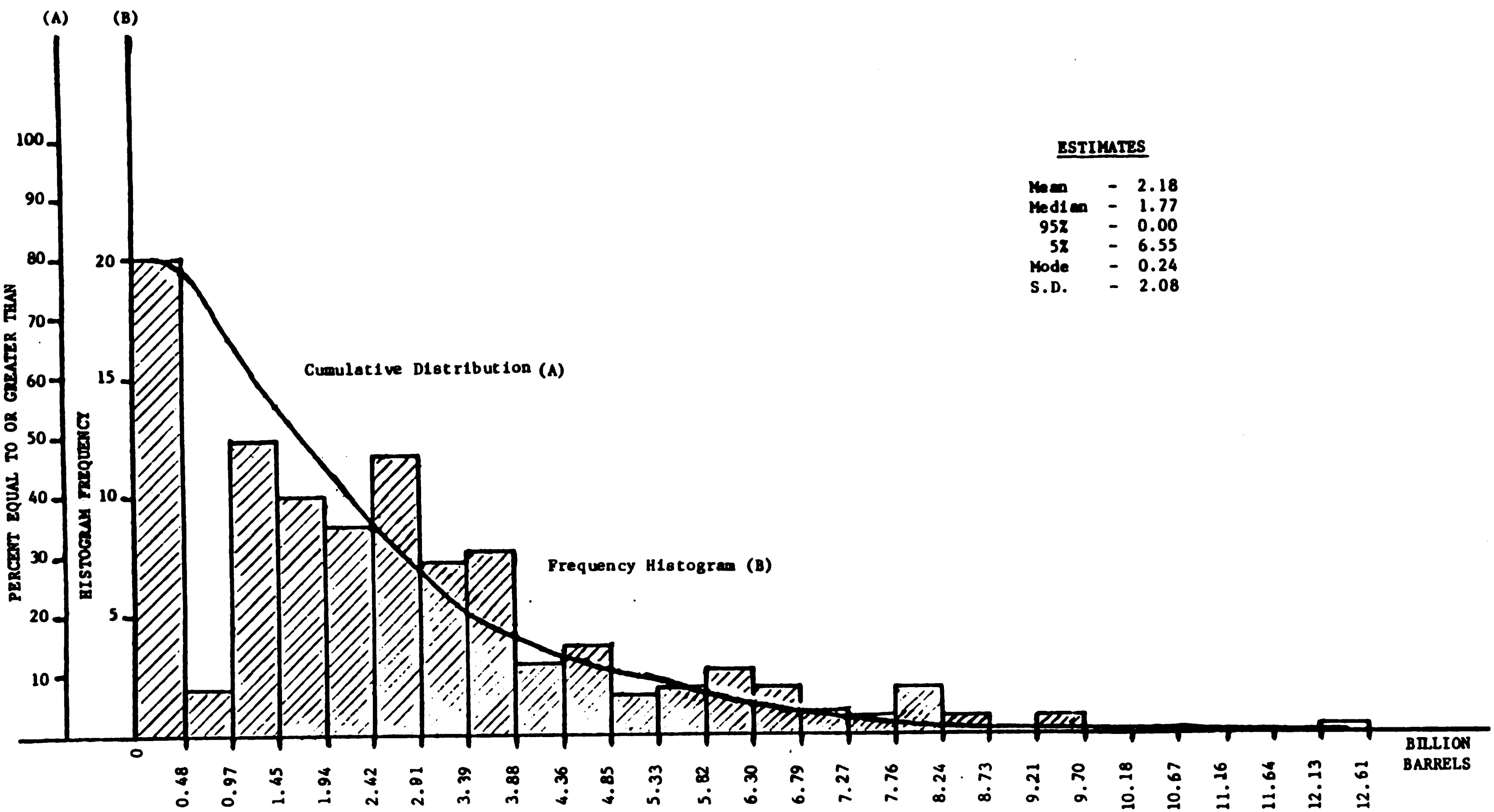


Figure 24. Frequency histogram and cumulative distribution of oil in-place for the Lewis and Clark National Forest.

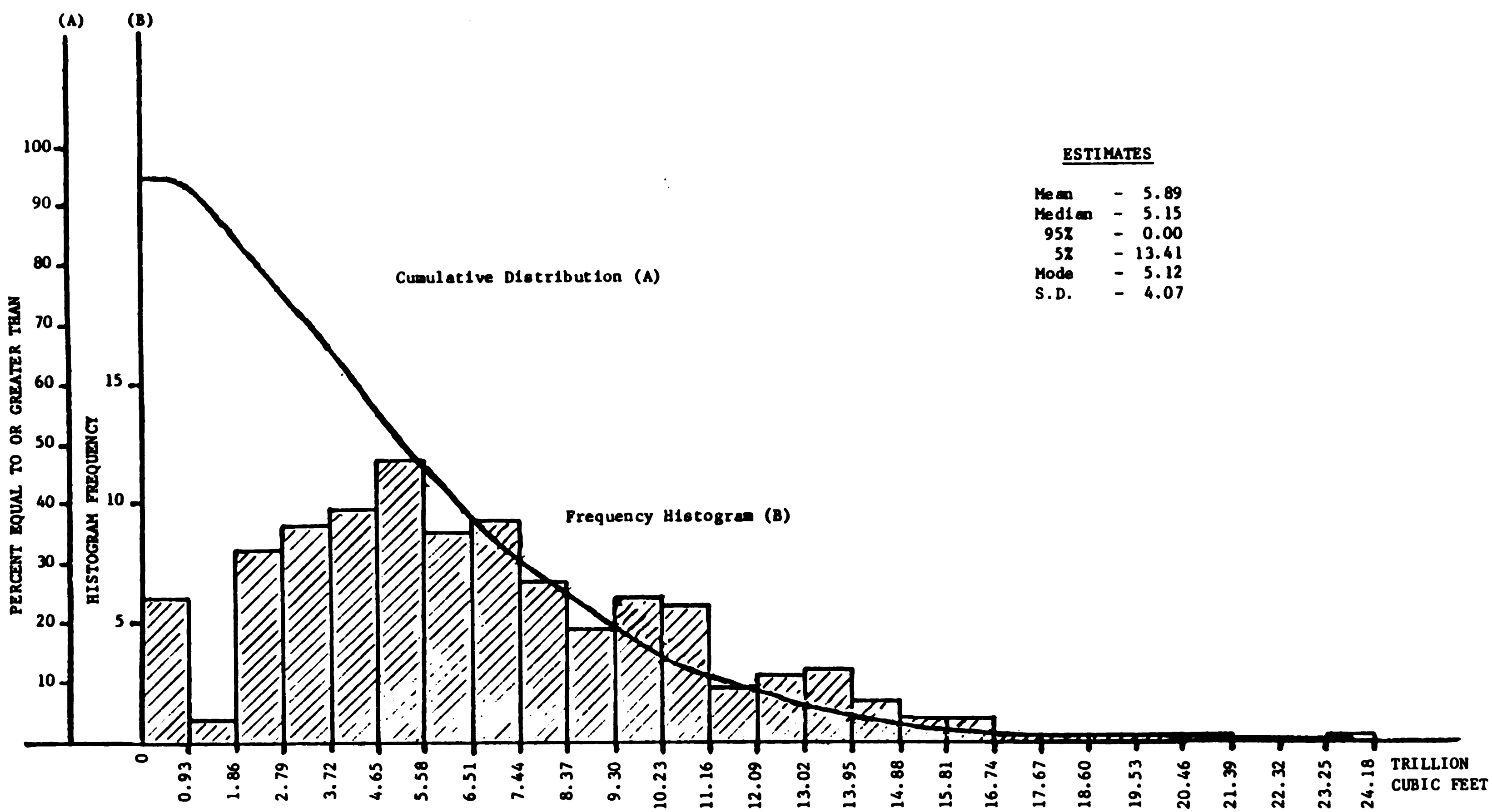


Figure 25. Frequency histogram and cumulative distribution of gas in-place for the Lewis and Clark National Forest.

distributions can be summarized by defining the 95th and 5th percentiles on the cumulative distributions. Table 6 compares these distribution values to the distribution mean.

The second set of outputs are the mean expected oil and gas reserves which are presented in Tables 7 and 8, respectively. The reserves are categorized on a cumulative basis by exploratory footage and on an incremental basis by price category. Table 7 shows that after 135,914 feet of exploratory drilling on all geological structures and summing across all price categories, the mean expected undiscovered reserves are estimated to be 955 million barrels. The reserve estimates vary depending upon the amount of exploratory footage and the MASP. If only the first increment of exploratory drilling was completed, oil reserves would equal 698 million barrels; the first two increments of exploratory drilling would have a reserve estimate of 816 million barrels, and so on. Only those reserves which could be developed for less than the market price of oil would be considered recoverable. At today's prices the reserves, with a development cost (i.e., MASP) of greater than 32.00 dollars per barrel, would not be recoverable. Whether a firm would develop the reserves in the price categories of 19.00 to 31.00 dollars per barrel is questionable since these reserves are marginal. Thus a more likely range for the oil reserves to fall within might be from 574 to 800 million barrels or 0.00 to 16.00 dollars per barrel as shown in Table 7.

The undiscovered gas reserves, as shown in Table 8, are interpreted similarly. The table shows that after 202,760 feet of exploratory drilling on all geological structures and after summing across all price categories, the mean expected gas reserves are estimated at 3.8 trillion

Table 6. Estimates of undiscovered oil and gas resources of the Lewis and Clark National Forest.

Commodity	F_{95} 3/	F_5 3/	Mean
Oil 1/	0.00	6.55	2.18
Gas 2/	0.00	13.41	5.89

1/ Billion barrels
2/ Trillion cubic feet
3/ Denotes the 95th fractile or the probability of more than the amount F_{95} is 95 percent; F_5 is interpreted similarly.

Table 7. Undiscovered oil reserves for the Lewis and Clark National Forest (million barrels).

Cumulative Exploratory Footage	Minimum Acceptable Supply Price1/																			
	2.00	4.00	6.00	8.00	10.00	13.00	16.00	19.00	22.00	25.00	28.00	31.00	34.00	37.00	40.00	45.00	50.00	60.00	70.00	90.00	Total
61070.	131.	186.	96.	49.	33.	48.	31 574	35.	15.	8.	5.	4.	4.	4.	1.	0.	10.	12.	1.	25.	698
74591.	169.	212.	112.	52.	36.	54.	38	40.	17.	9.	7.	6.	5.	4.	1.	0.	11.	12.	2.	29.	816
91106.	187.	243.	132.	59.	39.	57.	39	40.	18.	11.	8.	6.	5.	4.	2.	0.	11.	12.	2.	30.	905
111277.	188.	256.	138.	68.	40.	62.	39	40.	19.	11.	8.	6.	5.	5.	2.	0.	11.	13.	2.	30.	943
135914.	188.	264.	139.	68.	40.	62.	39 800	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	955
166006.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
202760.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
247651.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
302482.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
369452.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
451251.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
551159.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
673187.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
822232.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
1004276.	188.	264.	139.	68.	40.	62.	39.	40.	19.	11.	8.	6.	5.	5.	2.	2.	11.	13.	2.	31.	
	0.717	0.657	0.794	0.460	0.538	0.436	0.368	0.641	0.395	0.226	0.154	0.249	0.245	0.286	0.360	0.655	0.289	0.236	0.281	0.293	2/
	0.993	3.104	5.001	6.969	7.308	11.301	16.070	13.165	17.484	18.701	16.197	17.832	13.396	24.756	24.406	22.367	46.678	56.750	18.784	69.765	4/

Table 8. Undiscovered non-associated natural gas reserves for the Lewis and Clark National Forest (billion cubic feet).

Cumulative Exploratory Footage	Minimum Acceptable Supply Price 1/ 0.10	0.20	0.30	0.40	0.50	0.60	0.70	0.80	0.90	1.00	1.25	1.50	1.75	2.00	2.50	3.00	3.50	4.00	10.00	400.00	Total
61070.	0.	0.	0.	0.	0.	11.	1122.	654.	179.	71.	59.	13.	0.	0.	0.	0.	0.	0.	0.	0.	2109
74591.	0.	0.	0.	0.	0.	12.	1434.	807.	196.	89.	78.	19.	0.	0.	0.	0.	0.	0.	0.	0.	2635
91106.	0.	0.	0.	0.	0.	12.	1686.	926.	217.	108.	118.	20.	0.	0.	0.	0.	0.	0.	0.	0.	3087
111277.	0.	0.	0.	0.	0.	12.	1909.	1058.	236.	123.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	3494
135914.	0.	0.	0.	0.	0.	12.	2058.	1168.	277.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	3802
166006.	0.	0.	0.	0.	0.	12.	2096.	1181.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	3871
202760.	0.	0.	0.	0.	0.	12.	2098.	1186.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	3878
247651.	0.	0.	0.	0.	0.	12.	2098.	1186.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	
302482.	0.	0.	0.	0.	0.	12.	2098.	1186.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	
369452.	0.	0.	0.	0.	0.	12.	2098.	1186.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	
451251.	0.	0.	0.	0.	0.	12.	2098.	1186.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	
551159.	0.	0.	0.	0.	0.	12.	2098.	1186.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	
673187.	0.	0.	0.	0.	0.	12.	2098.	1186.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	
822232.	0.	0.	0.	0.	0.	12.	2098.	1186.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	
1004276.	0.	0.	0.	0.	0.	12.	2098.	1186.	295.	131.	136.	20.	0.	0.	0.	0.	0.	0.	0.	0.	
	0.0	0.0	0.0	0.0	0.0	0.0	0.119	0.674	1.245	1.731	2.000	2.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0 3/	
	0.0	0.0	0.0	0.0	0.0	0.144	0.255	0.378	0.461	0.463	0.499	0.675	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0 4/	

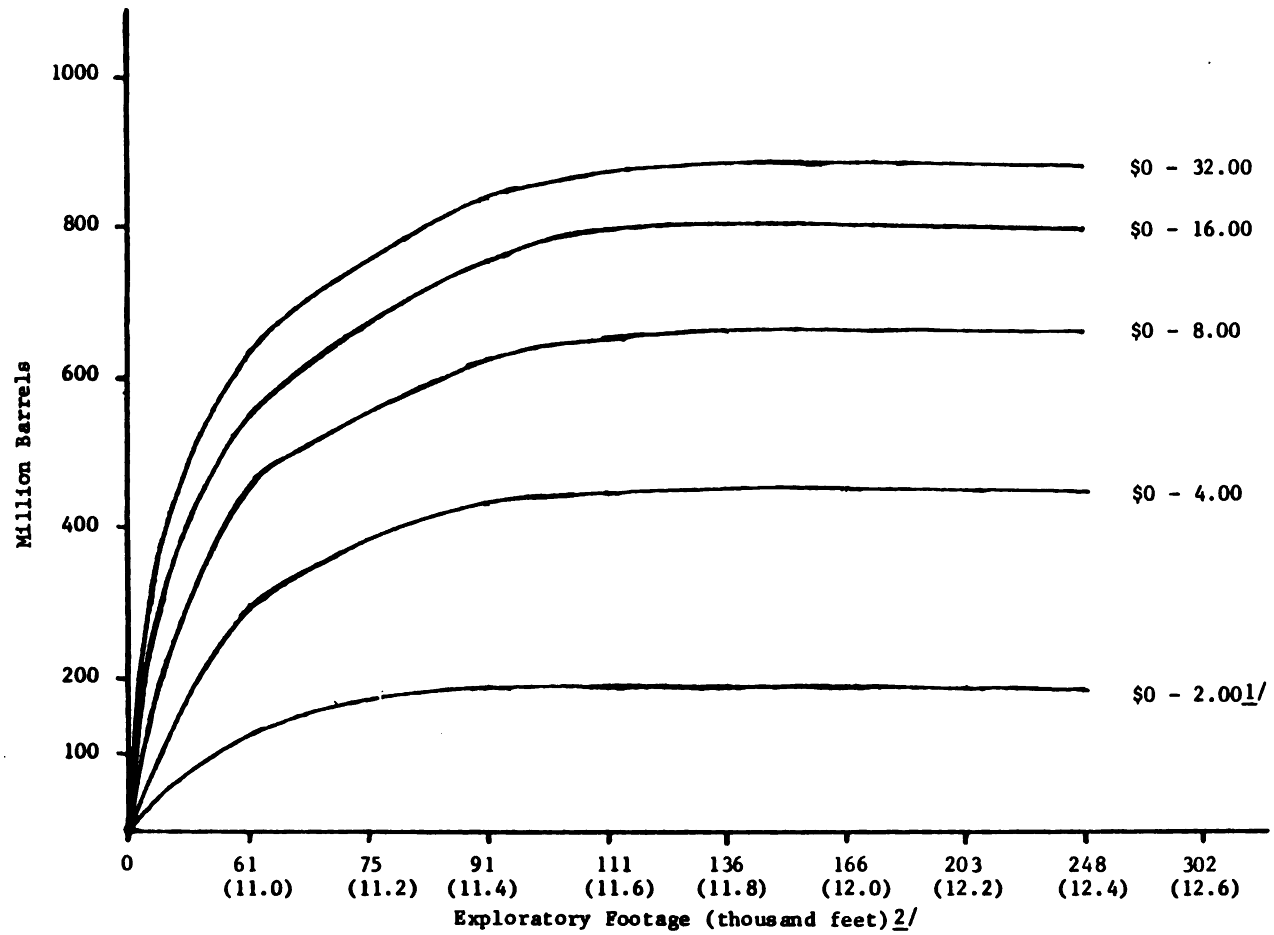
1/ Reserves are tabulated on a cumulative basis by exploratory footage interval and on an incremental basis by price category.
2/ Mean a.d. gas/oil ratio (MCF/barrel).
3/ Mean gas/liquids ratio (Barrels/MMCF).
4/ Mean developmental drilling footage (thousand feet/million barrels).

cubic feet. In contrast with the oil reserves, all of the gas reserves can be developed under today's market price conditions and, therefore, can all be considered recoverable.

An important relationship, seen in Tables 7 and 8, is that oil and gas reserves increase at a decreasing rate with either an increase in exploratory drilling or in price. This relationship can be more readily seen in Figures 26 and 27 which are alternative ways of expressing the same output information and may be more useful for planning purposes.

The third set of statistics include the mean gas-oil and gas-liquids ratios for each unit of reserves and price category. These statistics appear in the first row following the oil and gas reserves tables. The gas-oil ratios are expressed in terms of the average thousand cubic feet of associated natural gas per barrel of crude oil reserves in each price category. In Table 7, the first price category has an average of 0.717 MCF or 717 cubic feet of associated gas per barrel of oil. The gas-liquids ratios are expressed in terms of barrels of gas liquids per million cubic feet of natural gas reserves; the seventh price category in Table 8 has an average of 0.119 barrels per million cubic feet of gas reserves or 119 barrels per billion cubic feet of gas reserves. These statistics are used later in the integrating model for determining co-product production. The model treats associated natural gas and gas liquids as co-products and the production of these resources are combined with non-associated natural gas and crude oil in the integrating model, respectively.

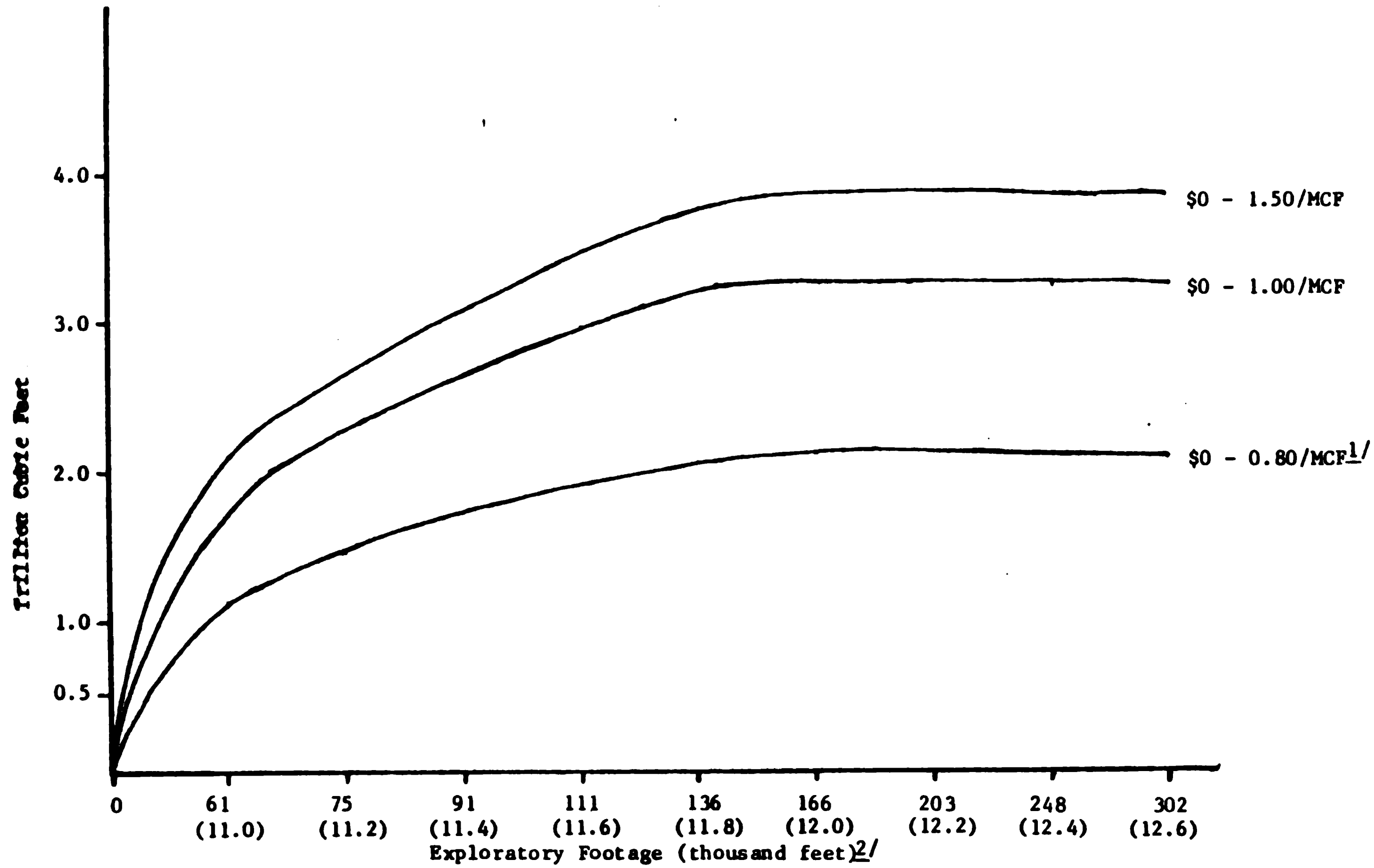
A fourth set of output statistics, appearing in the second row immediately following the oil and gas reserves tables, are estimates of the mean developmental drilling footage for each unit of reserves and



1/ Numbers represent the minimum acceptable supply price (MASP) or developmental cost per unit.

2/ Numbers in ( ) represent the natural logarithm (ln_x) of the exploratory footage.

Figure 26. Cumulative oil reserve curves for the Lewis and Clark National Forest.



1/ Numbers represent the minimum acceptable supply price (MASP) or developmental cost per unit.

2/ Numbers in ( ) represent the natural logarithm (ln_x) of the exploratory footage.

Figure 27. Cumulative non-associated natural gas reserve curves for the Lewis and Clark National Forest.

price category. These statistics are expressed in thousands of drilling footage per million barrels of oil or billion cubic feet of non-associated natural gas. For example, in Table 7 the average drilling footage in the first price category is equivalent to 993 feet of development drilling per million barrels of oil reserves. Similarly, in Table 8 the seventh price category has an average of 144 feet of development drilling per billion cubic feet of non-associated natural gas reserves. These statistics are used later in the integrating model segment for estimating developmental drilling footage.

The fifth set of reported statistics are the total oil and gas exploration costs for each exploratory interval. These statistics are summarized in Table 9 and represent the total fixed costs for drilling dry structures as well as structures with petroleum contents insufficient for economically viable development. These costs are non-discretionary, or that amount spent in the preliminary search process, and are those the firm must cover in addition to the development costs (i.e., MASP). Thus the resource model segment provides estimates of the total oil and gas resources and reserves which are used in the integrating model segment for generating production forecasts.

Output Results from the Integrating Model Segment

The purpose of the integrating model segment is to forecast oil and gas production flows, drilling activity, and transportation development with respect to calendar time. The primary outputs are the production forecasts as shown in Table 10. These quantities represent average

Table 9. Total incremental oil and gas exploration costs by exploratory footage interval in thousands of dollars for the Lewis and Clark National Forest.

Cumulative Exploratory Footage	Incremental Exploratory Footage	Crude Oil	Natural Gas	Total Combined
61070	61070	$12,311	$12,855	$25,166
74591	13524	3,670	5,347	9,017
91106	16515	2,551	5,428	7,979
111277	20171	1,301	4,205	5,506
135914	24637	391	2,522	2,913
166006	30152	43	798	841
202760	36754	4	81	85
TOTAL		20,271	31,236	51,507

Table 10. Oil and gas production forecasts for the Lewis and Clark National Forest.

Product 1/	Units	1982-1986	1987-1989	1990-1991	1992-1993	1994-1996	1997-2001	2002-2006	2007-2011	2012+
Crude Oil	Thousand BBLS/Day	0	57	134	134	134	131	96	30	5
Natural Gas	Million CF/Day	0	270	600	600	596	540	521	252	63

1/ Includes co-products.

daily[23] product flows for each time period in thousands of barrels or million cubic feet. For instance, an average of 57,000 barrels of crude oil and an average of 270 million cubic feet of natural gas are produced during the second time period, 1987 through 1989. The forecast extends over a 30 year time horizon and is graphically displayed in Figure 28. The crude oil production includes reserves from both primary and secondary recovery.

This segment of the model also provides an exploratory and development drilling forecast for oil and gas as shown in Table 11. The drilling footage estimates represent the total drilling within the time period, expressed in millions of feet. The table indicates that the total amount of exploratory and developmental drilling footage across all time periods is 338,000 feet and 6,708,000 feet, respectively. The development drilling includes production wells, source water wells, and injection wells for secondary recovery. Related to the exploratory drilling estimates are the oil and gas reserves discovered from this drilling effort over time as displayed in Table 12. An important relationship seen in this table is that generally as more exploratory drilling effort is expended, less oil and gas reserves are discovered per foot of exploratory drilling. Because of the exploration assumptions used in the model (Chapter 3), this relationship is expected. Tables 13 and 14 provide similar information in terms of the quantity of crude oil, associated and non-associated natural gas, and natural gas liquids developed or made ready for production over time.

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[23] Annual flows could be used as an alternative.

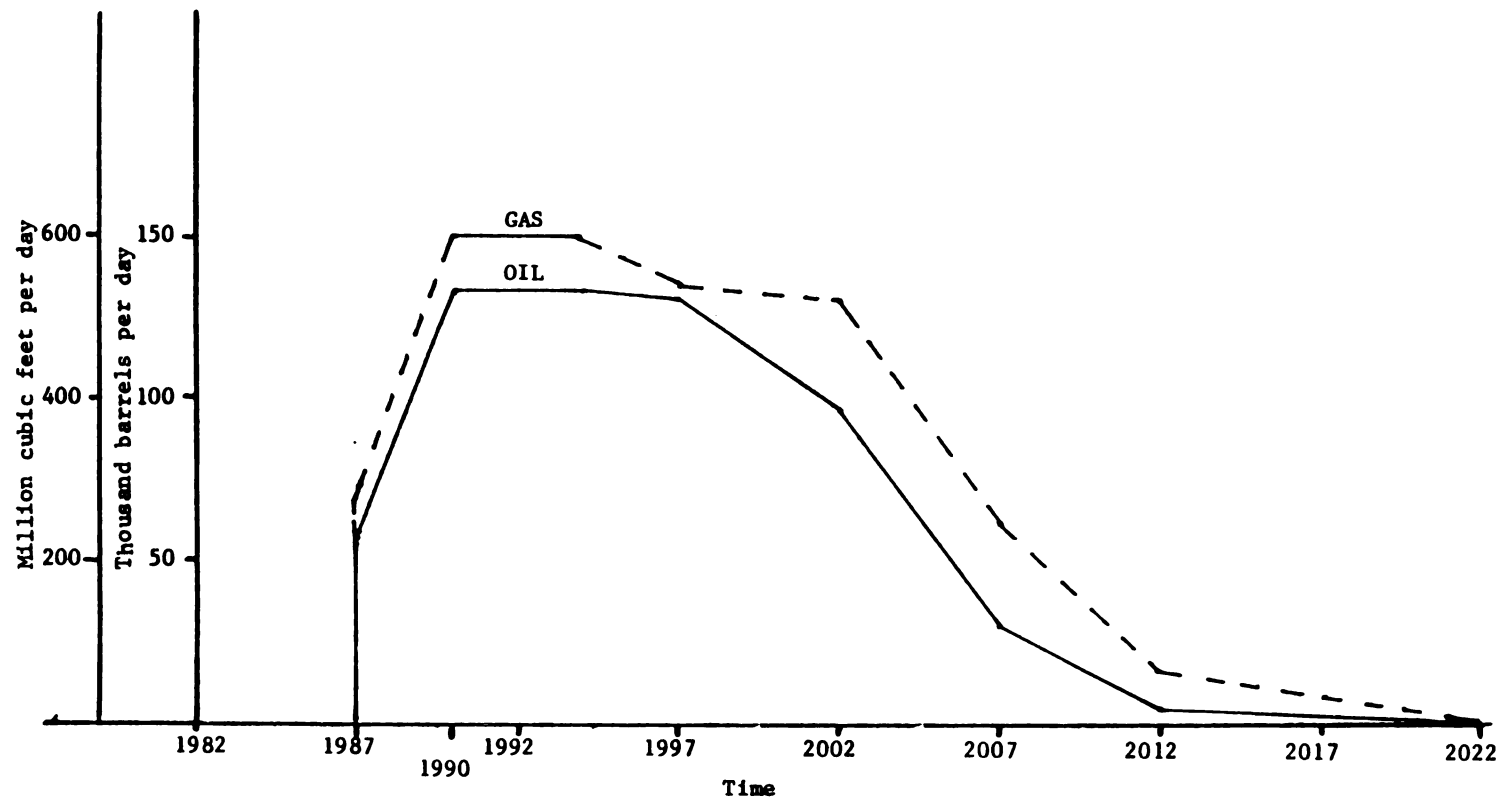


Figure 28. Oil and gas production profile for the Lewis and Clark National Forest.

Table 11. Estimated exploratory and development drilling in millions of feet for the Lewis and Clark National Forest.

Product	Exploratory Drilling				Development Drilling			
	1982-1986	1987-1991	1992-1996	1997+	1982-1986	1987-1991	1992-1996	1997+
Oil	.061	-	.050	.025	1.401	1.927	2.087	0.030
Gas	.061	-	.050	.091	0.689	-	0.447	0.127
Total	.122	-	.100	.116	2.090	1.927	2.534	0.157

Table 12. Discovered oil and gas reserves for each exploratory increment by time period for the Lewis and Clark National Forest.

Cumulative Exploratory Footage	Incremental Exploratory Footage	Crude Oil (Billion barrels)1/ 1982-1986	1987-1991	1992-1996	1997+	Non-associated Natural Gas (Trillion Cubic feet)1/ 1982-1986	1987-1991	1992-1996	1997+
61070	61070	0.698				2.109			
74591	13521			0.118				0.526	
91106	16515			0.089				0.452	
111277	20171			0.038				0.407	
135914	24637				0.12				0.308
166006	30152								0.069
202760	36754								0.007
	Total	0.698		0.245	0.012	2.109		1.385	0.384

1/ Does not include co-products.

Table 13. Crude oil and natural gas reserves developed by time period for the Lewis and Clark National Forest.

Average total cost per unit of product 1/	Crude Oil (Billion barrels)				Associated Natural Gas (Trillion Cubic Feet)			
	1982-1986	1987-1991	1992-1996	1997+	1982-1986	1987-1991	1992-1996	1997+
$ 2.00	.131		.057		.094		.041	
$ 4.00	.186		.070	.008	.122		.046	.005
$ 6.00	.096		.042	.001	.076		.038	.001
$ 8.00	.030	.018	.019		.014	.008	.008	
$13.00		.112	.029			.050	.013	
$23.00		.031	.047			.011	.016	
$35.50			.018				.005	
Total	.443	.161	.282	.009	.306	.069	.167	.006

1/ Represents the total development costs for both crude oil and associated natural gas. The associated natural gas is assumed to be transported with the non-associated natural gas.

Table 14. Non-associated natural gas and gas liquids reserves developed by time period for the Lewis and Clark National Forest.

Average total cost per unit of product 1/	Non-associated Natural Gas (Trillion cubic feet)				Non-associated Natural Gas Liquids (Billion barrels)			
	1982-1986	1987-1991	1992-1996	1997+	1982-1986	1987-1991	1992-1996	1997+
$0.60	.011		.001					
$0.70	1.123		0.788	0.189				
$0.80	0.655		0.405	0.128	.001	.001		
$0.90	0.179		0.057	0.059				
$1.00	0.071		0.052	0.008				
$1.25	0.059		0.077					
$1.50	0.013		0.007					
Total	2.111		1.387	0.384	.001	.001		

1/ Represents the total costs for both non-associated natural gas and gas liquids. The gas liquids are assumed to be transported with the crude oil.

Finally, some information on the oil and gas pipeline projects is also provided (Figure 29). Two pipeline projects were specified for this model segment. The first project was an oil pipeline stretching 148 miles from Heart Butte to Great Falls, Montana, with a maximum capacity of 134,000 barrels per day. The total fixed capital costs for this project were estimated at 30 million dollars in terms of 1980 dollars. The integrating model selected the start date and how this pipeline would be constructed. The output indicated the pipeline would initially be completed in 1987 with a capacity of 57,000 barrels per day. In 1990, the pipeline capacity would be expanded an additional 77,000 barrels.

The second project was a gas pipeline stretching 251 miles from Wolf Creek to a point in Canada with a maximum capacity of 600 million cubic feet per day. The total fixed capital costs were estimated at 220 million dollars in terms of 1980 dollars. The output results indicated that the pipeline would initially be completed in 1987 with a capacity of 270 million cubic feet per day. The pipeline capacity would be expanded an additional 330 million cubic feet per day in 1990 bringing the peak capacity to 600 million cubic feet.

Because the linear program did not restrict the network expansion variables to integer values, the model could expand pipeline capacity in any manner which most minimized the cost. The integer restrictions prevent pipelines from being built in awkward or unrealistic pieces over time. Although these restrictions were not invoked, the base run pipeline expansion does not appear unrealistic.

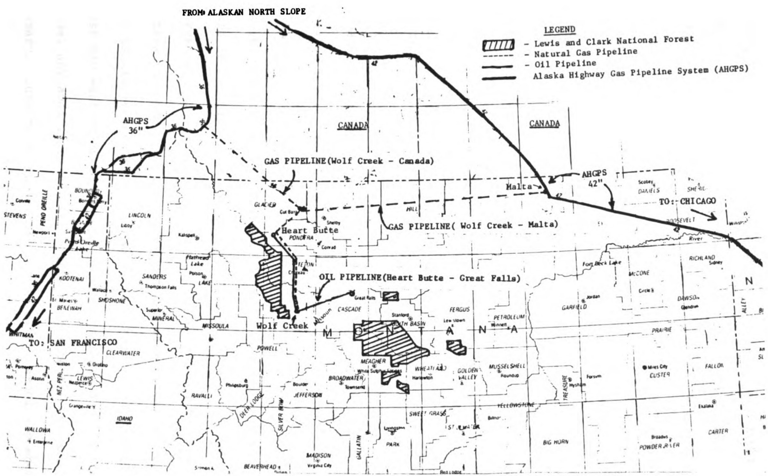


Figure 29. Petroleum transportation systems.

Validating the Simulator

Once all of the input data has been collected and the model has been run, the analyst is faced with the problem of model validity. Shechter and Lucas (1978) have outlined a series of validation tests and procedures that can be used by analysts studying simulation models. These tests involve the validity testing of the input data, the output, and the model design.

Validating the Input Data Set

Validating the input data base is useful for establishing the credibility of the model, which is dependent upon the confidence of the data set and the manipulations of the data in the modeling process. A first step in validating the input data set is making it available to the public for verification. Kaufman (1980) states that if this is not possible the utility of the assessments can be weakened. Thus, the input data set used in this study is provided in the appendix for interested readers to review and evaluate.

Another technique to validate the input data base are sensitivity tests which test the sensitivity of certain output variables with changes in certain input variables. Because some variables are subject to large variations, the analyst might be interested to know how sensitive the model outputs are to changes in such variables. If the output is highly sensitive to changes in a specific variable, the analyst may want to obtain a more precise estimate and, if the contrary is true, any additional effort in obtaining a better estimate may not be necessary. Such tests could also be useful for examining whether the model behaves in an expected and reasonable manner, given changes in key input variables.

Although many tests were made, only those found to have the greatest effects on outputs are discussed. The following geological variables were identified as having the most significant effects on output: number of structures, structure area, structure thickness, structure fill, permeability, and oil viscosity. The economic variables showing the most sensitivity to output with changes in the input values were drilling costs, operating variable costs, the discount rate, and the price trajectories in the integrating model segment.

The first sensitivity test centered around the variability of the number of structures specified in terms of a probability distribution. The variable serves as a basis for determining the number of potential petroleum traps that are sampled from the distribution for each iteration of the simulation. The exact value of this variable was not known with certainty. For the base run, this variable was specified as a triangular distribution with three parameters. The parameters defining the minimum and the maximum number of structures have a zero probability of being less than or more than the specified number of structures. The parameter defining the most likely number of structures represents the value with the greatest probability of occurrence. The parameter values were specified as 8, 32 and 28, respectively, as shown in Figure 30.

Because the model placed a constraint on the sample value of the distribution, the sensitivity tests involved changing the distribution parameters when the sample distribution value was constrained and when it was not constrained. The purpose of the constraint is to limit the

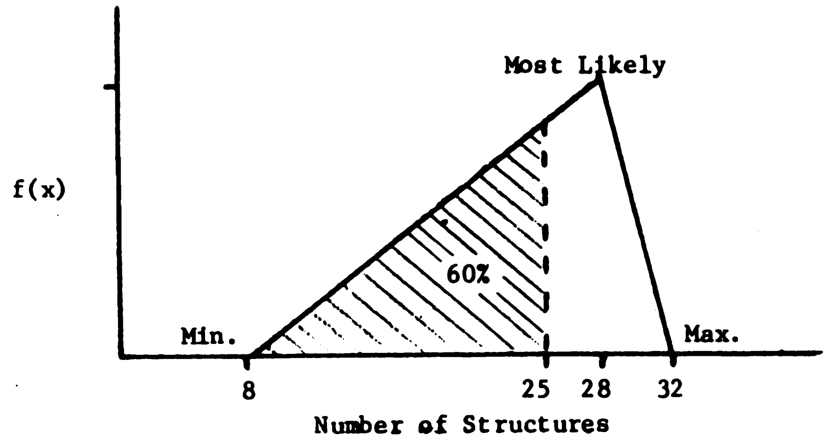


Figure 30. The number of structures distribution for the Lewis and Clark National Forest.

number of structures sampled in any iteration of the simulation to between 25 and 1,500 to insure computational feasibility.

For the base run, the median of the number of structures distribution (8-28-82) equalled 23. However, since 60 percent of the number of structures distribution area had fewer than 25 structures (Figure 30), and the constraints were invoked, the sampled values from the area with less than 25 structures were set equal to 25, raising the distribution median to approximately 30. When changing the distribution parameters, the greatest changes occurred when the maximum value was increased by 100 percent to 64 causing the median of the distribution to increase by nearly 20 percent. As a result oil and gas outputs increased by 27 percent. This is contrasted with a 100 percent decrease in the minimum value which created only a 3 percent change in the distribution median. As a result, the oil and gas resource estimates were influenced very little, a reduction of 4 and 1 percent, respectively. The most likely value was reduced by 50 percent which resulted in a 3 percent decrease in the median and a 2 percent decrease in resource outputs.

Figure 31 shows the results of changing the distribution parameters when the constraints on the number of structures distribution are relaxed. The relaxing of the constraints caused the distribution median to be more sensitive to changes in distribution parameters. Curve 1 is the cumulative distribution of the number of structures as shown in Figure 30. When the maximum value was increased 100 percent, the median of the distribution increased 39 percent and, as a result, oil and gas resources increased 35 and 46 percent, respectively. This change produced a greater amount of variance in the cumulative distribution as

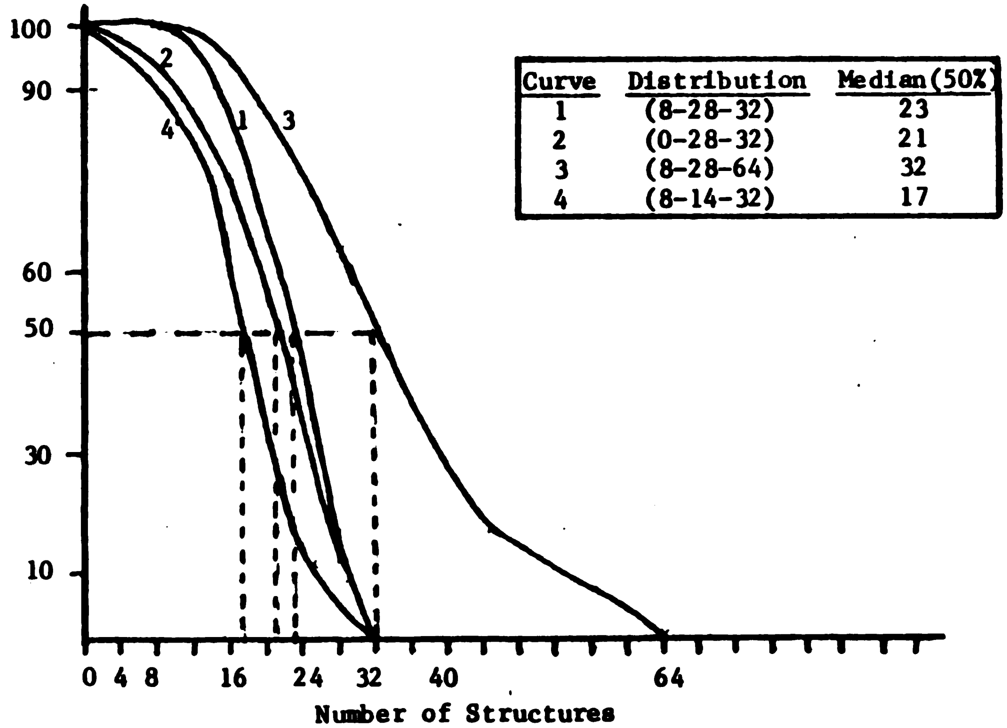


Figure 31. Cumulative frequency curves for the number of structures distribution (constraints relaxed).

well as raising the median (Curve 3). Curve 2 represents a 100 percent decrease in the minimum value which caused a 9 percent reduction in the distribution median and the oil and gas resources 9 and 17 percent, respectively. Decreasing the most likely value 50 percent, decreased the median 26 percent and oil and gas resources 19 and 24 percent, respectively, as shown in Curve 4.

In summary, the analyst should understand that in the base run, the maximum and most likely parameter values had the greater effects on output with the minimum value having the least. For distributions of different sizes and shapes, this may not hold true, since the extremes often exercise the greater control over the cumulative frequency curve and, hence, produce greater effects on outputs (Megill 1977). Because the constraints on the number of structures distributions were invoked, causing the distribution median to be higher, the oil and gas estimates are overstated by nearly 28 and 12 percent, respectively. In order to prevent the constraint from influencing the distribution, larger geographical supply region areas with a greater number of structures are necessary to accurately represent the size of the resource base.

A series of sensitivity tests were conducted on the geological variables structure fill, structure thickness, and structure area. The purpose of these variables are to determine the undiscovered oil or gas in-place for each structure sampled which is the product of these variables. Because these variables are not known with certainty, they are represented in the model as random variables specified in terms of cumulative lognormal distributions. Several tests were conducted to better understand the sensitivity of these variables.

For the base run, each of these variables was specified as a cumulative lognormal distribution and defined in terms of the 0.50 fractile and the 0.99 fractile. Figure 32 shows the cumulative distributions for each of these variables and the values used in the base run. Because structure fill, structure thickness, and structure area were specified in terms of cumulative distributions, the sensitivity tests were conducted by changing the parameter values. The results of the tests are shown in Figure 33. The sensitivity tests for each of the three variables were made separately while holding the parameter values of the other variables constant. The tests showed that each of the variables are equally sensitive, which is expected since the oil or gas in-place equation is a linear relationship.

The results also indicated that percentage changes in the 0.50 fractile created approximately the same percentage changes in the oil or gas in-place estimates, whereas the .99 fractile created percentage changes that were somewhat less. This is explained by the fact that the cumulative distribution curves have a steeper slope between zero and the 0.5 fractile which indicates a higher degree of occurrence or certainty. Therefore, changes in the 0.5 fractile created greater output changes. The slope of the cumulative distribution is much less steep between the 0.5 and the 0.99 fractile, representing more uncertainty with a lower frequency of occurrence and, therefore, changes in the 0.99 fractile have less impact. Thus, the analyst should be more careful and confident about specifying the 0.5 fractile than the 0.99 fractile for each of these distributions.

Permeability and oil viscosity were the last two geological variables tested and are discussed together since both are used for

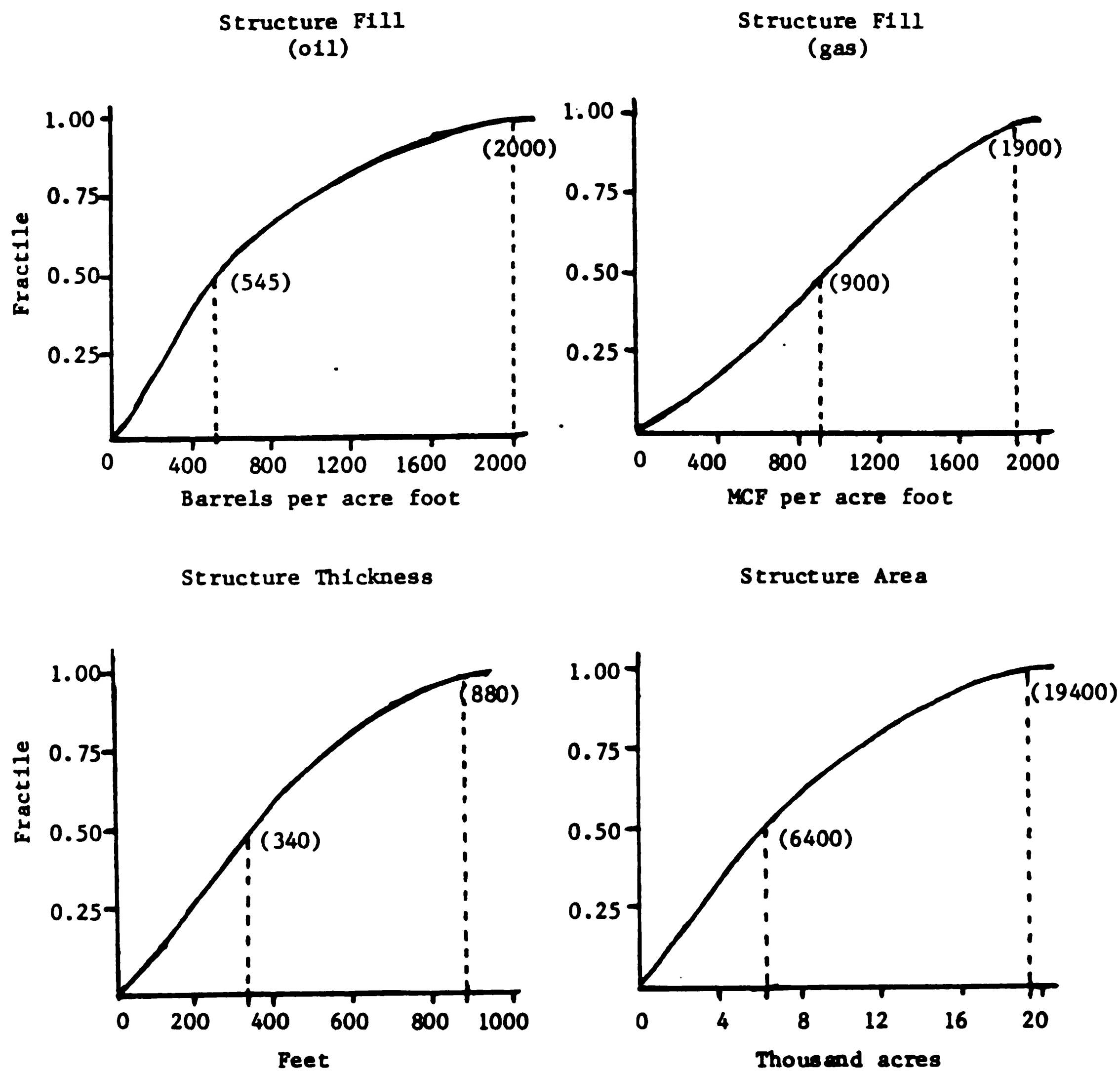


Figure 32. Cumulative distributions for structure fill, structure thickness and structure area.

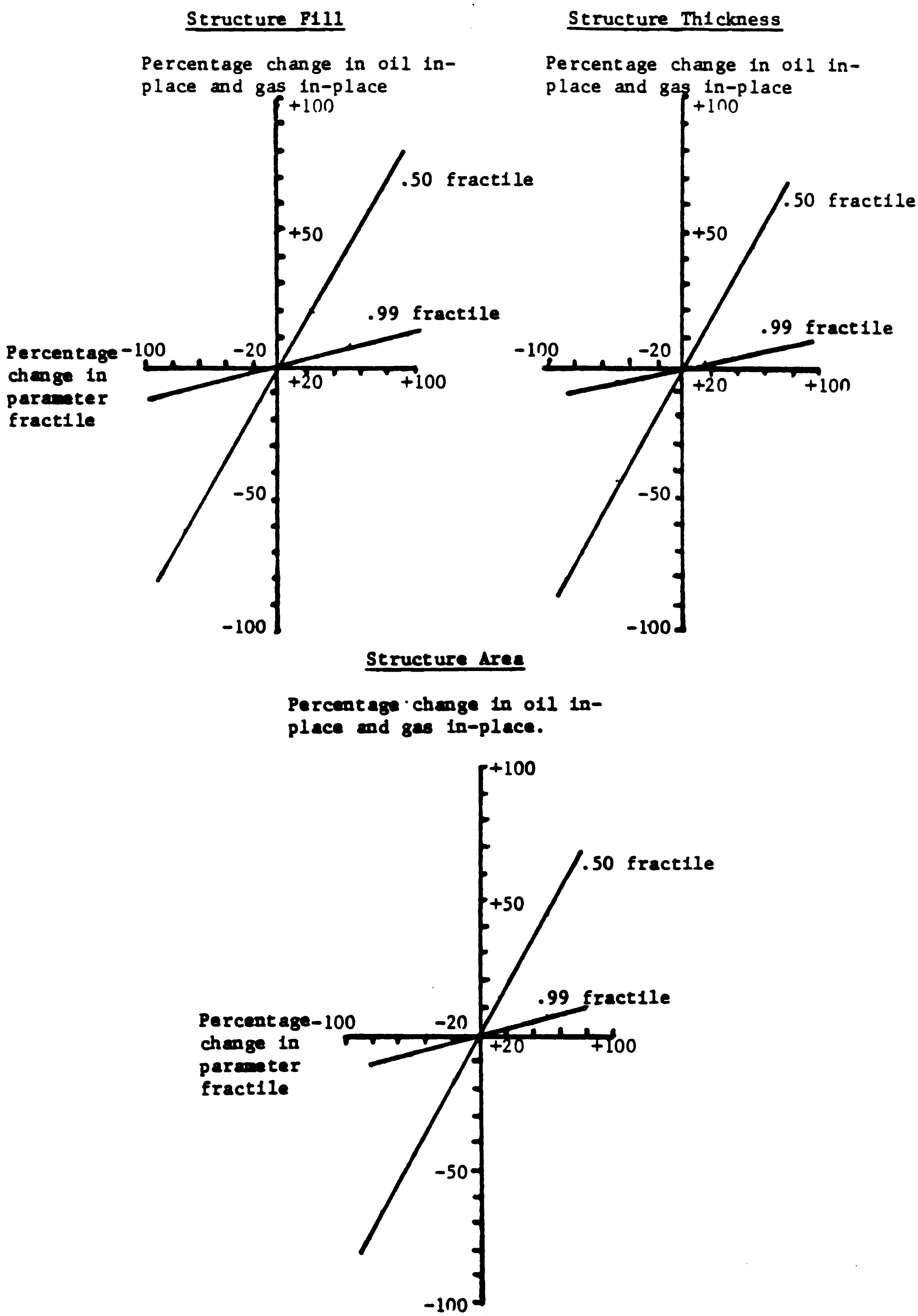


Figure 33. Sensitivity test results for structure fill, structure thickness and structure area.

determining the initial flow rate per well for each sampled structure as explained in Chapter 3. Permeability measures the fluid conductivity of the reservoir rock (i.e., ability of the fluid to move within the reservoir) and has a direct relationship with the initial flow rate. If permeability increases, then initial flow rate per well also increases. Oil viscosity measures the internal resistance of oil to flow. An inverse relationship exists between oil viscosity and initial flow rate per well. Again these variables are not known with certainty and thus some sensitivity testing seemed warranted. These variables were assumed to follow a lognormal distribution and were specified in terms of a cumulative distribution with the 0.5 and the 0.99 fractiles as the parameter values. The distributions and parameter values of the base run are displayed in Figure 34.

The tests were conducted for each variable by changing the parameter values of each distribution while holding other distribution values constant. The IP equation, which measures the initial flow rate per well, influences the number of development wells required per structure and the total costs of development. The sensitivity tests for these variables are relative to the average developmental drilling footage and the distribution of reserves across all development cost categories. The results of the sensitivity tests are presented in Figure 35.

The results indicate that a non-linear inverse relationship exists between permeability and developmental drilling footage. As expected, an increase in permeability increases the initial flow rate per well which in turn means that less development drilling footage is required as shown in Figure 35. The reduction in development drilling causes

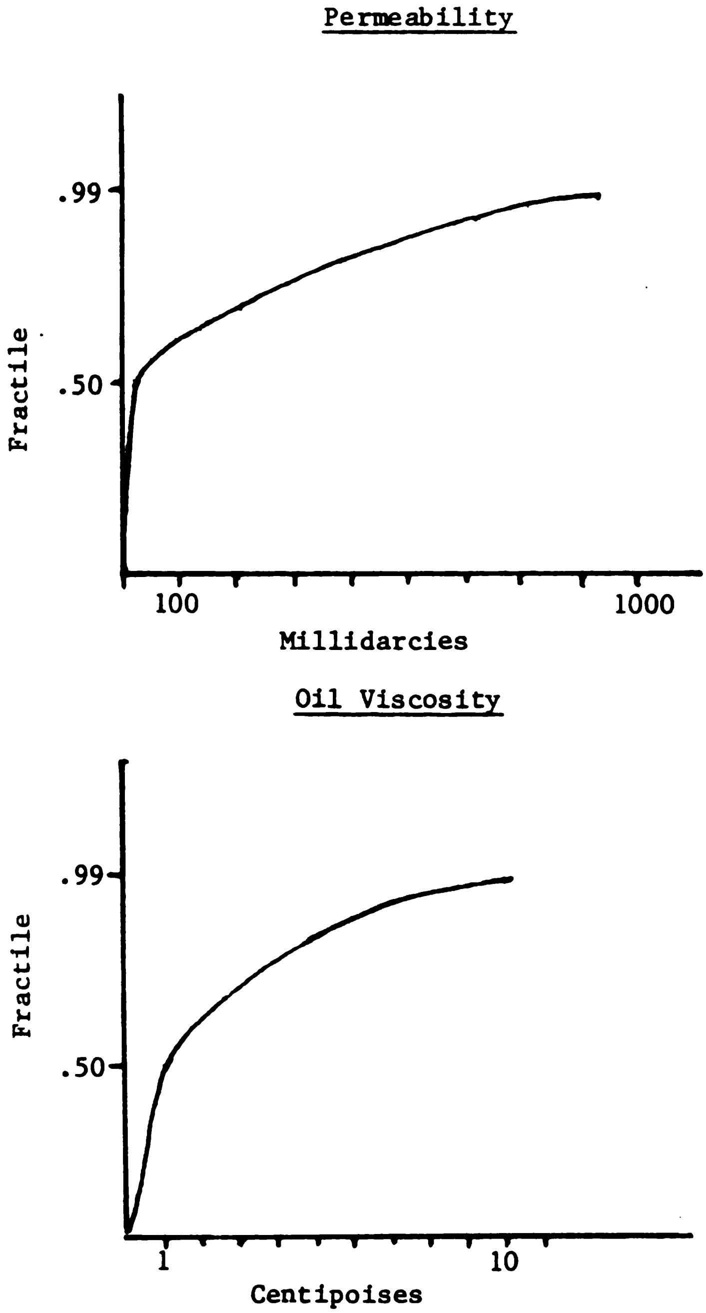
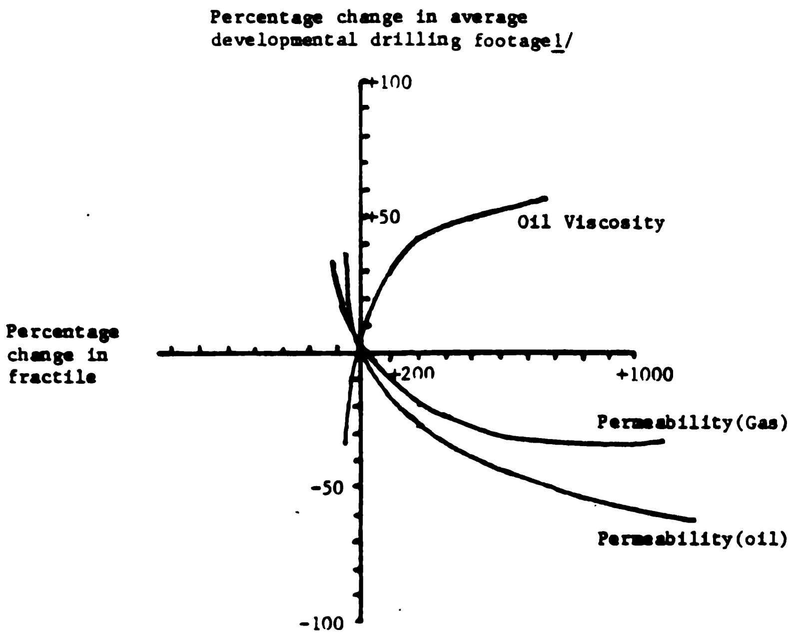
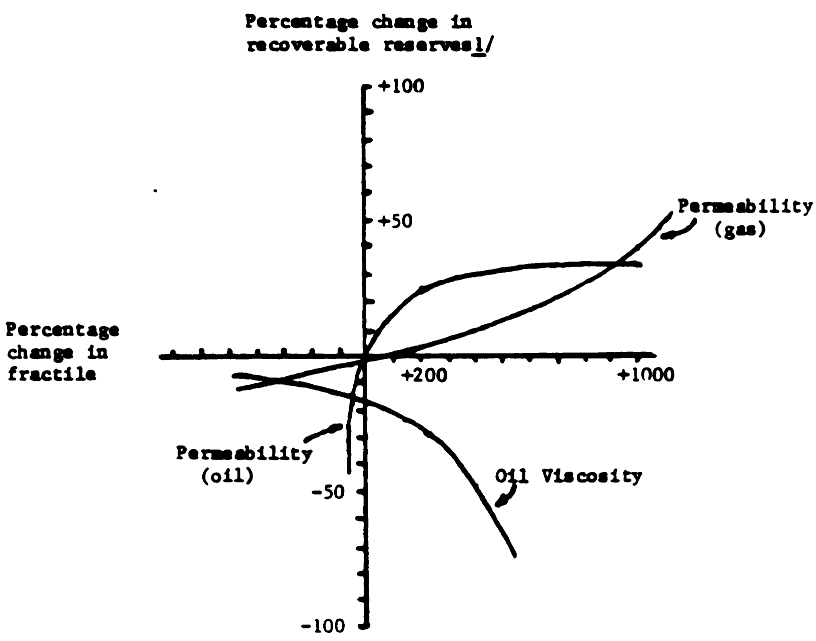


Figure 34. Cumulative distributions for permeability and oil viscosity.





1/ The relative changes are with respect to the first five cost categories and the 0.5 fractile.

Figure 35. Sensitivity test results for permeability and oil viscosity.

developmental costs to be reduced and increases the potential oil and gas reserves. However the percentage change in development drilling increases at first from an increase in the parameter value, but then diminishes as the change in the parameter becomes greater. This relationship is not as well defined with respect to changes in petroleum reserves. Again the 0.5 fractile was found to be more sensitive to changes in output than the 0.99 fractile.

The test results for oil viscosity indicates a non-linear but direct relationship between oil viscosity and developmental drilling footage. Again this is expected since an increase in oil viscosity causes the initial flow rate per well to decrease which in turn requires more development drilling footage (Figure 35). The additional drilling creates higher development cost and thus reduces the amount of oil reserves available. Again, percentage changes in development drilling increases at first, from an increase in the parameter value, but diminishes as the change in the parameter becomes greater. Except for oil permeability, both gas permeability and oil viscosity are more sensitive to changes in development drilling footage than reserves with changes in the parameter values.

The exploratory and development drilling costs are the largest expenditure of funds in any oil and gas project. In contrast to the geological variables, these cost variables are not represented in terms of probability distributions but as deterministic values which imply certainty. However, in frontier areas (e.g., Alaska, Western Overthrust Belt), drilling costs can be highly uncertain. A summary of the exploratory and development drilling cost estimates used in the base run are provided in the appendix. Until more drilling is conducted on the

Lewis and Clark National Forest or in other similar areas, it is difficult to estimate these costs with any level of certainty. Because of this variance, several sensitivity tests were conducted. The average cost estimates for both exploratory and development drilling were increased (decreased) 10, 25, and 50 percent, respectively, and the results are shown in Figure 36.

The various drilling cost sensitivity tests were studied relative to changes in total exploration costs, development drilling footage, and petroleum reserves. Figure 36 indicates that a direct linear relationship exists between drilling cost and total exploration costs, or percentage changes in drilling costs create equal percentage changes in total exploration costs. An inverse relationship exists between drilling costs and average development drilling footage. An important characteristic of this relationship is that the average developmental drilling footage is more sensitive to a decrease in drilling costs than to an increase in drilling costs and oil seems more sensitive than gas. If the costs are actually less than those specified, the effect on output is greater than if the costs were actually higher. Thus, the analyst should be more concerned about underestimating drilling costs.

The relationship between drilling costs and reserves (Figure 36), is important because if drilling costs rise, development drilling footage is reduced and less reserves are available at the lower price categories. Higher drilling costs cause reserves to become more expensive and, therefore, shift them to higher cost categories. The relationship is similar to development drilling footage in that reserves are also more sensitive to a decrease in drilling costs than to an increase, and oil is again more sensitive than gas. The reserves are

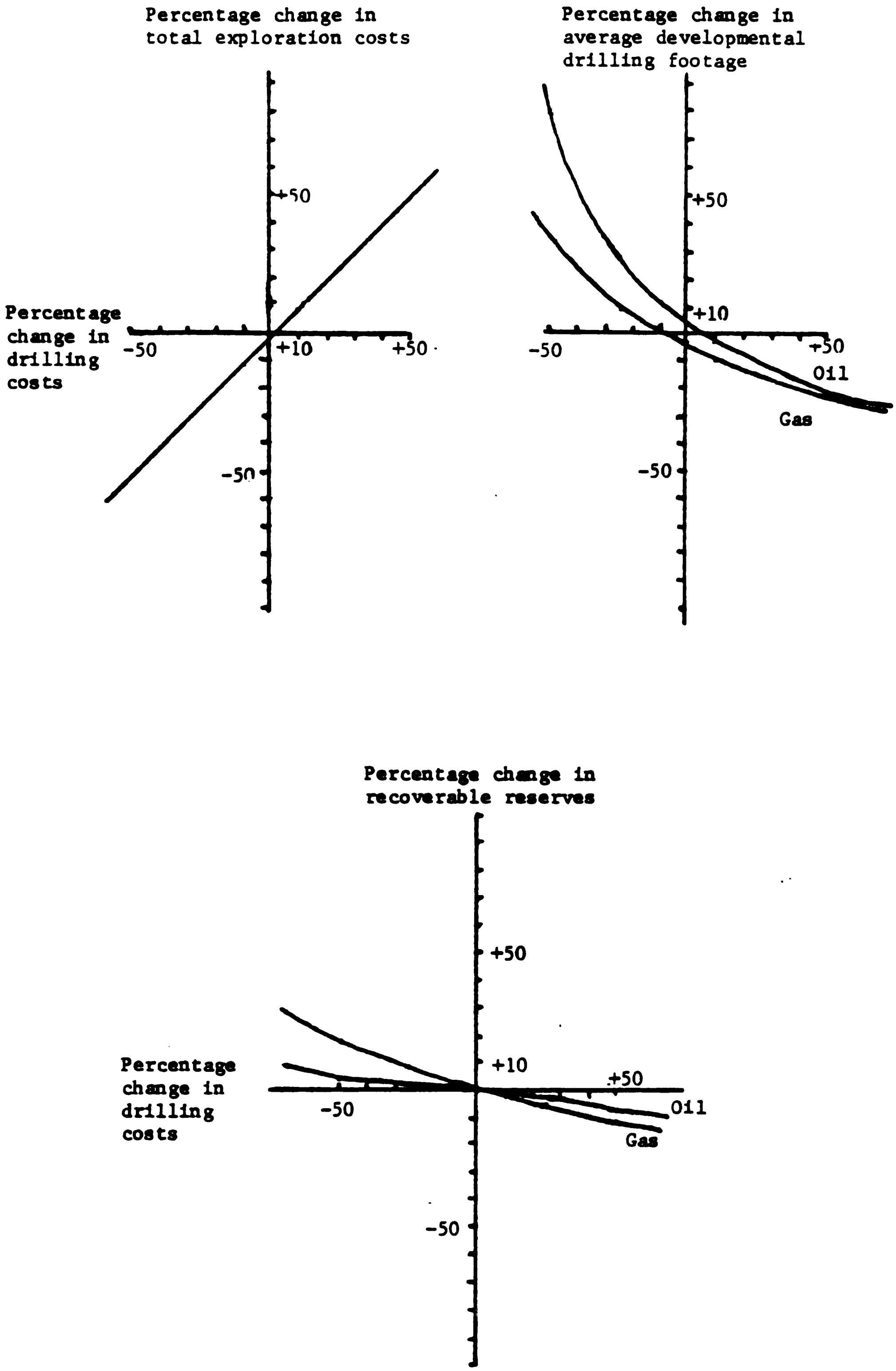


Figure 36. Sensitivity tests for drilling costs.

less sensitive to changes in drilling costs than average development drilling footage. Therefore, inaccurate drilling cost estimates cause a greater discrepancy in estimating development drilling footage than in reserves.

The operating variable costs included gas compression and conditioning and primary and secondary oil lifting and treatment costs. Because these costs were difficult to specify, the sensitivity tests helped to provide insight into the effects of output changes given some percentage change in costs. The results of these tests are presented in Table 15.

Relative to the base run, increases or decreases in the operating variable costs did not significantly influence the distribution of oil reserves across the development cost categories, unless the changes in costs exceeded 50 percent. However, gas reserves were sensitive to changes in costs of only 10 percent or more, resulting in large shifts of gas reserves across the development cost categories. Thus, changes in the variable operating costs shift the distribution of reserves across the development cost categories rather than changing the total amount of oil or gas.

The last economic variable tested was the discount rate. The discount rate of 12.6 percent used in the model was the after-tax weighted average cost of capital experienced by 42 petroleum firms in 1980. Although the determination of the discount rate was less subjective than the specification of some of the other economic variables, for purposes of interest, several sensitivity tests were conducted to determine the effect on output. The results are similar to those of the operating costs; changes in the discount rate alters the

Table 15. The relationship between percentage changes in operating variable costs and percentage changes in oil and gas reserves distribution.

Test	Oil Price Category					
Description	$0-2.00	$2-4.00	$4-6.00	$6-8.00	$8-10.000	Total Percent
Decrease 100%	29	23	11	7	4	74
Decrease 50%	25	26	12	7	4	74
Decrease 10%	21	27	14	7	4	73
BASE CASE	20	28	15	7	4	74
Increase 10%	19	27	15	7	4	72
Increase 50%	17	28	16	9	4	74
Increase 100%	11	30	17	10	4	72

Test	Gas Price Category						
Decription	$0-.50	$0.60	$0.70	$0.80	$0.90	1.00	Total Percent
Decrease 100%	96	2	1	1	0	0	100
Decrease 50%	74	15	5	3	1	1	98
Decrease 10%	0	18	54	17	5	3	97
BASE CASE	0	1	54	31	8	3	97
Increase 10%	0	0	24	51	15	5	95
Increase 50%	0	0	0	0	19	54	73
Increase 100%	0	0	0	0	0	0	0

distribution of the reserves among the different cost categories (Table 16). These effects are expected; if the discount rate increases (decreases) the cost of capital rises (falls) which means oil and gas reserves shift to higher (lower) cost categories since they become more expensive (inexpensive). In summary, if the analyst is uncertain about the discount rate, the potential error from mis-specification is the inaccurate representation of the oil and gas reserves across all cost categories.

The oil and gas price trajectories used in the integrating model segment are probably the most uncertain and the most important set of model inputs, since prices drive all other activities. Therefore, some sensitivity tests seem appropriate to better identify how different price scenarios influence the model output. Three different price scenarios were considered in the model which are provided in the appendix. The moderate price scenario was used for the base run. In order to test the effect that prices have on output, the integrating model was run three separate times each using a different price scenario. The results are shown in Table 17.

Changes in the price scenario effects the output of the integrating model in terms of the net present value of revenues (Table 17). The results indicate that the model is internally valid; as prices decrease (increase) the net present value of revenues also decrease (increase). Because the price changes between scenarios were relatively small, there were no effects on production outputs except for some minor increases in the high price scenario. This is expected since the development costs of oil and gas are quite low compared to the market price and, therefore, a significant price increase or decrease would have to occur

Table 16. The relationship between percentage changes in the discount rate and percentage changes in oil and gas reserves distribution.

Discount Rate	Oil Price Category						
	$0-2.00	$2-4.00	$4-6.00	$6-8.00	$8-10.00	Total Percent	
0%	35	27	11	7	4	80	
4%	29	29	11	7	4	69	
8%	26	27	13	7	4	70	
12.6% Base Case	20	28	15	7	4	74	
17%	18	24	17	6	6	65	
25%	13	21	17	10	5	61	
	Gas Price Category						
Discount Rate	$0-.50	$0.60	$0.70	$0.80	$0.90	$1.00	Total Percent
0%	0	19	72	7	2	1	100
4%	0	9	73	12	4	2	100
8%	0	3	67	21	5	2	98
12.6% Base Case	0	1	54	31	8	3	97
17%	0	0	39	36	14	4	93
25%	0	0	15	44	20	9	88

Table 17. A summary of output effects from changes in price.

Price Scenario	Net Present Value of Total Revenues (billion dollars)
Low	8
Moderate (Base Case)	11
High	13

to effect the production outputs in any significant way. The analyst should not be overly concerned about using low or high price scenarios since the effects are minor. Although if the development costs are relatively high compared to the market price, then changes in the price scenario could have more significant effects on output.

Validating the Model Outputs

Face validity tests are concerned with validating the output of the simulation model. These tests can be conducted in two ways. The first is answering the question about how reasonable the output appears to be in light of the area being studied and the geological and economical conditions which the model represents. Often this is accomplished by asking experienced individuals directly involved with the actual process being modeled or familiar with the area being studied about the reasonableness of the output. Although this is an informal test, it is an important test for any simulation model.

A more rigorous test of face validity is the goodness-of-fit test. This test is an attempt to check the model against some historical observations. For example, given a set of geological and economical input data describing the situation in the Williston Basin, could the PSM estimate the total cumulative production of oil and gas, plus any measured, indicated, and inferred reserves for this basin within ±25 percent? The question this test attempts to answer is whether or not the model can replicate a set of historical observations. However, because the goodness-of-fit test is more difficult to conduct and requires much time and expense to design, the model output was validated using the first method which is based on the intuitive judgment of knowledgeable individuals. Most individuals who were asked to judge whether the total amount of oil and gas resources and reserves seemed reasonable indicated that the estimates were within a range that was both realistic and reasonable for the study area considered.

Validating the Model Design, Relationships and Assumptions

The PSM is a model which attempts to forecast oil and gas reserves and expected future production in light of all the uncertainties with the use of probability, statistics, and various mathematical relationships. The model is a tool used to estimate oil and gas resources of an uncertain world. The question that arises is whether the model constitutes a reasonable representation of the oil and gas supply process given the postulated set of relationships among variables as well as the reliability of the input data set.

A first step towards testing the internal validity or logic of the model, and another way for testing the reasonableness of the output, is by using verification tests. The verification tests are identical to the sensitivity tests, but the motivation is different. In this case, the analyst is examining whether the model behaves in an expected and reasonable manner given changes in some key input variables. Before making these tests, the analyst hypothesizes about the qualitative direction and possibly the magnitude of the change in the model's output. Often knowledge from experience and previous observations of the real system provide the analyst with insight into how the model should perform with changes in certain key input variables. Several of these tests were conducted for the simulator and were previously discussed under validating the input data set. From the discussions of each of these tests, the model was found to be internally valid; when these key variables were changed in both directions, the model responded in the right direction and to some extent with the right magnitudes. Thus it can be inferred that the model is internally valid and the output changes seemed reasonable and expected.

The ultimate test of a model is the model's ability to predict (Shechter and Lucas 1978). For example, if the PSM predicts 100 million barrels of potential oil reserves on the Lewis and Clark National Forest today and ten years later exploratory drilling indicates there exists 105 million barrels of oil, the model can be assumed both reliable and an accurate predictor. Although an important test, much time will have to pass before the test can be completed and the model truly validated.

Other experiments could be conducted but the present set illustrate the sensitivity of the geological and economic cost variables. These variables are specified as accurately as possible with the given level of knowledge and the results provide a base for understanding which should be monitored through time to account for changing levels of knowledge. If all the information necessary for complete validation were available, the model would probably not have been constructed or needed. Knowing that the various sensitivity tests provide evidence that the model is internally valid and that the outputs can be quite sensitive to changes in certain key geological and economical variables, the next chapter discusses the utility of these outputs for planning and decision making.

CHAPTER VI

POTENTIAL OF THE SIMULATOR AS A MANAGEMENT TOOL

Introduction

Information provided by the simulator can be integrated into the land management planning and decision making process. The various applications of the model include land use planning, administrative planning, environmental assessment, and the development of management scenarios. The PSM may also be useful as an educational tool.

The PSM as a Land Use Planning Tool

The major goals of the forest plans now being prepared are to allocate lands to different uses (e.g., timber, range, minerals, recreation, wildlife) and to determine the most efficient mix of outputs to produce over the time horizon of the plan. The preparation of a forest plan requires an adequate resource data base and an understanding of the many production relationships between resources. The data base for most surface resources and uses can be improved and the production relationships better understood, but, relative to subsurface mineral resources, the data base is well developed. Because the demand for energy minerals (i.e., oil and gas) is expected to rise steadily in the future, the planning data base must be improved and the production relationships with other surface resources understood if these resources are to be adequately integrated into the forest planning process.

Information about the quantity, economic value, and location of various minerals is essential if the task of integrating energy minerals into the forest planning process is to be accomplished. Information about when or if these resources would be developed and produced would also be useful. The PSM does not provide all of this information, but it can provide the majority of data about oil and gas resources for a particular area of interest.

Quantity of Petroleum Resources

In order to prepare a national forest plan, a land manager or planner must have some knowledge about the quantity of the resources that exist on a forest or in a particular area. A planner needs to consider, if the resource occurs in significant quantities to consider in a plan and if the resource is not considered or is ignored in the forest plan, what the costs would be. Because estimates of potential oil and gas resources are difficult to make, such resources have not been adequately integrated into forest plans and as a result cannot influence land use allocations.

The outputs from the PSM can provide the planner with estimates of the quantity of oil and gas that may occur in a particular area. The quantities are expressed as the total resource endowment (i.e., oil or gas in-place), as the portion of the endowment that is economically recoverable (i.e., reserves), and as the amount that could be supplied to the market (i.e., production forecast). Each of these numbers, as presented and discussed in the previous chapter, provides the land manager or planner with some insight about the potential resource quantities that may exist on a forest. Although the estimates of potential quantities of oil and gas are not specific to a particular land management planning unit (i.e., analysis area or land capability unit), the estimates provide a broad land use planning target for describing or quantifying the overall resource potential.

Economic Value of Petroleum Resources

For purposes of comparison with other resources, petroleum resource quantities need to be expressed in terms of some economic value. Land managers are sometimes faced with the concern from the public or other resource specialists about what the resource quantities mean in terms of dollars. In situations where a high oil and gas potential exists, greater benefits per dollar of input may be accrued by primarily managing a block of land for oil and gas than for wildlife or primitive recreation. Although an area may not always produce oil and gas, keeping the management options open for such a land use opportunity is important from an economic viewpoint.

The PSM can assist the land manager or planner by providing these economic values. These values can be measured in terms of the net national economic benefit and in terms of the economic revenues returned to the federal, state, and local governments. The first measure, net national economic benefit, is the difference between total benefits and total costs of petroleum development. The second measure are those revenues returned to the appropriate levels of government by federal and state income taxes, windfall profit taxes, severance taxes, ad-valorem taxes, and royalties.

The integrating model segment provides the net present value (NPV) or present value of benefits less costs from oil and gas development

(Table 17, Chapter 5). For the base run, the NPV is equivalent to 10.5 billion dollars (1980 dollars) when discounted at 12.6 percent. Because environmental protection and damage costs were not incorporated into the model simulation, the net present value would only be an approximate estimate of the net national benefit from petroleum development. Environmental costs include those costs incurred to protect the environment and those that are uncompensated for and unexpected. An example of an environmental cost would be a lease stipulation not allowing exploration or development activities to occur within grizzly bear spring range in order to prevent the disruption of feeding. Petroleum development activities are delayed as a result. These costs were not incorporated into this simulation because of the difficulty of specifying them and the uncertainty of how much these costs would be. If these costs could be calculated, they can be readily incorporated into the simulation. The effect would be to explicitly incorporate the costs of developing petroleum resources to society under some environmental constraints.

Although most petroleum operations comply with any environmental restrictions imposed upon them, there is always a possibility of a major accident causing severe environmental damage. An example might be an oil well blowout with several thousand barrels of oil entering a nearby pristine stream, eliminating most life forms and significantly reducing the water quality. Again, these costs are not incorporated into the simulation and estimating them would probably be quite difficult. Thus, it might be best for the decision maker to keep these kinds of costs in mind when making land use planning decisions involving oil and gas resources.

Another measure of economic value are the returns to the public from oil and gas development which include state and federal income taxes, state severance taxes, royalties, and lease rental payments. Unfortunately, the PSM in the present framework does not directly provide estimates of these potential future revenues. However with some time and money, a skilled computer programmer could easily modify the resource model segment of the PSM to provide such statistics in addition to other annual investment expenditures (USDE 1979a).

Lease rental payments, windfall profit taxes, and royalties are of interest to a federal land management agency like the Forest Service. These are the measurable returns from producing petroleum products and serve as a basis for determining the efficiency of producing such outputs when compared with the administration costs, or budgeted dollars spent. Because royalties are relatively simple to calculate and the PSM provides the basic data from the integrating model segment, they can be estimated separately.

Royalties are based on the total gross revenues from the sale of oil and gas. Total royalties are equal to the total gross revenues multiplied by the royalty value. Discounting the royalties to the present by using an appropriate discount rate provides an estimate of the net present value of royalties. Thus, these values would provide a basis for determining the economic efficiency of an oil and gas program managed by a federal agency.

The economic valuation of oil and gas provides the land manager or planner with an estimate of how much society values such resources relative to other competing resources and uses for the same land. Should a situation arise in which it is more economically efficient to manage an area for oil and gas rather than primitive recreation but is politically unacceptable, the oil and gas values provide an estimate of the opportunity costs for not managing the area for oil and gas. The opposite may also be true.

The Distribution of Oil and Gas Resources

Knowing the spatial distribution of oil and gas resources is useful to the land manager because it provides the necessary information to help identify future land use conflicts. If a particular roadless area is managed for primitive recreation and wildlife protection and is overlying a large petroleum deposit which is not considered in the planning process, a conflict situation could exist if a firm wants to explore, develop, or produce the petroleum resources. In these situations, data about the distribution of oil and gas resources could provide the land manager with some information as to where land use conflicts could arise, and thus help prevent or minimize such disputes through better planning.

Unfortunately, the PSM does not provide any information about where the oil and gas deposits could occur or which deposits would produce. Until the exploratory drilling is completed, the spatial distribution of these resources remains unknown. If a simulation model could provide this information, the petroleum exploration phase would probably not exist. However, it may be possible for the forest geologists to use the qualitative minerals rating system developed for the Lewis and Clark National Forest as a guide for determining how the oil and gas reserves estimated by the PSM might be distributed. Land managers should expect the frequency of land use conflicts to be greater in areas of high potential and should concentrate on reducing such disputes through minerals resource planning. Because oil and gas is often so unevenly distributed, any estimate about the distribution could only be used as a rough planning guide.

Even though the usefulness of such an assessment is limited, it may provide land managers with additional insight into determining the accessibility of these resources. If most of the petroleum resources were expected to occur in the more rugged terrain where roads could not be constructed within the guidelines and standards established by a particular forest or regional office, then such resources may not be available to exploit. Or if these resources occurred beneath any sensitive and critical wildlife habitat, the timing restrictions imposed on oil and gas activities to protect the wildlife could be too severe to warrant any resources development and production. In both of these situations, directional drilling may be possible to exploit the petroleum deposit. This type of an analysis provides the land manager or planner with some knowledge about the accessibility of the petroleum resources and the potential for developing such resources.

The Timing of Resource Development

Given $\underline{A}$ units of a resource worth $\underline{X}$ number of dollars and distributed over $\underline{Y}$ number of acres, the final concern of the land manager or planner is to determine whether the resources will be developed by industry and, if so, how the resources are expected to be scheduled or produced by industry over time. In the case of timber, the Forest Service has more control over resource output scheduling; timber production forecasts can be determined easily and with more certainty.

However in the case of oil and gas resources, the Forest Service does not have as much control over the development timing and the production schedules are much more difficult to determine with much less certainty.[24] Because of these problems petroleum production forecasts can only be made using a simulation model in conjunction with a scenario, or set of data and assumptions which seems most likely for a particular area.

A production forecast of resource outputs and activities is useful to the land manager because it provides an estimated time frame over which the outputs could be expected to be produced, it provides some insight as to when the environmental, social, and economic impacts would occur, and it provides an estimate of how the production of a resource would influence land use allocation decisions over time. For these reasons, the oil and gas production forecast provided by the PSM for the Lewis and Clark National Forest as shown in Table 28 (Chapter 5) could be useful to land managers. Although such a forecast may be used by planners as though it was exact, the planners should recognize the many uncertainties with regard to both the geological resource data and economic cost data. The forecast is only as good as the input data and working assumptions of the scenario. For any given set of input data and assumptions a different forecast could be generated. Thus, the planner must use that forecast which seems most realistic for the given situation.

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[24] The Forest Service has some control with respect to the timing of lease issuance (i.e., until the lease is issued, no exploratory activity can occur).

Like any forecast, the most important factor influencing its usefulness is the accuracy. Because the conditions under which the exploitation of oil and gas deposits change continuously, the projections become less meaningful with time. As shown in Figure 28 most of the production and associated activities occur within the first two decades of the entire supply process which makes the forecast more reliable. Probably the most critical assumption behind these forecasts is the estimated time between the initiation of exploration and the start of production. For the forecast shown in Figure 28 the time span was assumed to be 5 years. If the time span was actually 3 years or 10 years, the timing of the oil and gas production and activities would dramatically change.

Assuming that 5 years is accurate, most of the environmental, social, and economic impacts occur in the beginning (i.e., first and second decades) of the production forecast. To the land manager or planner this means that if oil and gas is produced, the impacts on other resources, people, and current land use patterns would occur within the first two decades of the forest plan. If oil and gas is expected to occur on a forest and is not adequately integrated into the forest plan, then any attempt of industry to exploit such deposits may create a conflict with the present land use patterns and could create a need to revise the forest plan. Forest planners should not only develop a set of land use prescriptions for the present time, but attempt to show how the land use prescriptions would change if subsurface energy resources were developed.

In summary, the PSM can provide invaluable information to the land manager about oil and gas which can be used to improve the quality of petroleum resources planning. Specifically, the model can provide the necessary data to better define the dimensions of the oil and gas resources with respect to the quantity, value, and timing of development.

The PSM as an Administrative Planning Tool

Another aspect of the overall planning task is predicting future personnel needs and budgeting fund requirements resulting from increased oil and gas activities. These activities may include increases in the number of seismic permits and applications for permit to drill or requests for special use permits for development of an oil and gas production site. Whether such activities are expected or unexpected, they can effect a federal government agency by generating direct surface impacts and by causing the demand for other forest resources and uses to possibly change. These changes can alter the current forest workload and volume of business. The impacts usually cause a need for more personnel to administer the activities, more personnel training to provide the technical and management skills necessary to understand how to best administer such activities, and a larger budget to cover the additional expenses.

Although many uncertainties and difficulties exist in attempting to project future personnel and budgeting needs as they relate to increased mineral activities, the budget system requires that future personnel and budgeting needs be identified 3 to 4 years in advance and be incorporated into planned budgets. Thus, a federal agency must determine the impact that increased oil and gas activities may have on its ability to manage these activities and other resource responsibilities given budget and personnel constraints.

The PSM can provide some information to help solve this problem by using the exploratory and development drilling and transportation forecasts provided by the integrating model segment. The drilling forecasts were presented in Table 11 (Chapter 5). Provided the assumptions are accurate upon which these forecasts are based, oil and gas activity levels could be derived from these projections. For each time period, the total exploratory drilling can be divided by the average expected depth of an exploratory well as a means of estimating the number of exploration wells. Similarly, the development drilling forecasts for each time period can be divided by the average expected depth of a development well to estimate the number of potential development wells. The derived forecast of exploratory and development wells is presented in Table 18 and includes both successful and unsuccessful wells. A greater number of development wells for oil is shown because the total includes producing oil wells, source water wells, salt water disposal wells, and secondary recovery injection wells. The developmental gas wells include producing wells and some salt water disposal wells. These derived forecasts can be used for budget and personnel planning.

Several weaknesses of this method exist. Since some wells are drilled to basement depth, the first exploratory well, some to the specific structure depth, production wells, and some to one-half the structure depth, water source wells, using the above method would only provide an approximate estimate of the number of wells. Because the majority of the wells would be drilled to the average structure depth

Table 18. Derived forecast for the total number of expected exploratory and developmental wells.

	Exploratory Drilling 1/				Development Drilling 1/			
Product	1982-1986	1987-1991	1992-1996	1997+	1982-1986	1987-1991	1992-1996	1997+
Oil	8	-	6	3	175	241	261	4
Gas	8	-	6	11	86	-	56	16
Total	16	-	12	14	261	241	317	20

1/ All estimates derived by dividing the total footage as shown in Table 11 by the average expected well depth of 8,000 feet.

and a few would be drilled to a depth somewhat less than structure depth, the estimates would tend to be slightly underestimated. In contrast the development drilling could be slightly overestimated since the PSM does not account for the fact that some of the successful exploratory wells would be used as producing wells, and that some dry hole exploratory or development wells could be used as disposal or injection wells. Many other factors could also influence the level of drilling which are not accounted for in the PSM. These factors might include the availability of drilling rigs, climate, terrain and geology, various leasing stipulations which may place a constraint on the number of development wells in a particular area, the national economic situation and outlook, federal and state government incentives to encourage oil and gas activities, and the current supply and demand of oil and gas. The drilling estimates presented in Table 18 can be interpreted as the maximum which could occur given perfect non-constraining real world conditions.

A perfect non-constraining real world is an unrealistic situation and before such a forecast is used for assessing personnel and budgeting needs, adjustments need to be made to account for those factors not considered in the PSM which could influence the drilling activities. The number of development wells could be reduced slightly to account for those wells that would not be used for producing oil or gas, water source wells, disposal wells, and injection wells. A second adjustment would be to reduce the number of development wells to account for drilling rig availability, local and national economic conditions or lease stipulations that would constrain drilling activity.[25] Once the forecasts are calibrated, the future expected workload would equal the number of drilling permits expected to be filed with the Forest Service.

Converting the forecasted workload into administrative needs (i.e., personnel and budget funds) can be completed in two steps. The number of man-years required to administer the increased oil and gas activity can be estimated by multiplying the number of forecasted exploratory and development wells by a personnel/well ratio. Similarly, the number of dollars required can be estimated by multiplying the number of wells by a budgeted dollar per well ratio. The challenge of estimating such administrative needs, however, is in determining the personnel or budgeted dollar/well ratios.

The ratios depend upon the different kinds of tasks associated with issuing drilling permits, the general administration of oil and gas activities, and the amount of time required to complete each task. A detailed discussion of the tasks which the Forest Service is responsible for completing can be found in the Northern Region Oil and Gas Guide (USDA 1980d) but briefly they include:

(1) Participate in a predrill meeting or field review with the Bureau of Land Management and lease operator's representative to insure that the surface use plan prepared by the operator is in accordance with Forest Service lease stipulations and land management plans.

(2) Preparing an environmental analysis report or short Finding of No Significant Impact and Decision Notice to indicate impacts, alternatives, and mitigation measures for surface resources.

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[25] These adjustments could be made by changing some of the assumptions about the timing of oil and gas exploration and development in the PSM, and rerunning the model. This is discussed later in the chapter.

(3) Recommends to the Bureau of Land Management surface protection stipulations determined from the environmental analysis to cover activities occurring within the lease boundary.

(4) Issue special use permits for oil and gas activities occurring not on the lease.

(5) Once the drilling permit is approved and issued, the Forest Service holds a prework conference with the operator and the contractor to review surface construction specifications.

(6) Reviews and monitors activities on-lease and off-lease to insure the operator is in compliance with the lease and drilling permit stipulations, and contacts the Bureau of Land Management if problems of noncompliance arise.

(7) If the well is a dry hole, the Forest Service inspects the site to insure the operator·is in compliance with site rehabilitation instructions established by the Forest Service.

(8) If the well is a producer, the Forest Service continues monitoring for compliance with the surface use plan of the drilling permit.

Although these tasks are generally standardized for all Northern Region forests, the amount of time it takes to conduct each of these tasks may vary from forest to forest and from drill site to drill site. Some of the chief controlling factors include the type of terrain, management sensitivities of the site, and the existing forest staff in terms of size and range of skills. For example, if a site is sensitive with threatened and endangered wildlife species or is a scenic roadless area, the Forest Service may prepare an environmental impact statement rather than a standard environmental analysis. As another example, if the drill site is in the vicinity of imminent or intense oil and gas field development, the Forest Service may prepare an area development plan in cooperation with industry and the public to delineate the best transportation system and acceptable areas of surface occupancy for well pads, tank batteries, and other surface equipment facilities. The Custer National Forest has found that preparing area development plans has dramatically reduced the average processing time of drilling permits from 40 days to 5 days.[26] Because the amount of time to complete these tasks can vary greatly each, forest would have to define a most likely time frame for these tasks in order to estimate the required number of man-years and dollars. This estimate could then be bounded by a minimum and a maximum time frame with minimum and maximum estimates of man-years and dollars.

In addition to exploratory and developmental drilling, seismic activities and pipeline construction projects are also important aspects of oil and gas exploration, development, and production. The PSM does not provide any estimates of the expected level of seismic activities or miles of seismic lines, which might occur in a particular supply region. These estimates could possibly be inferred from the exploratory and development drilling forecasts. Transportation development forecasts are provided by the PSM, but such forecasts are only for the large transmission pipelines expected to be constructed. Because these larger pipelines are generally not constructed on national forest lands, such forecasts may not be useful to the Forest Service. However the Bureau of Land Management or state government may find such forecasts useful since they usually prepare the environmental impact statements for such projects. The PSM does not provide estimates of the construction activity involving oil and gas flowline or smaller gathering pipelines which would be constructed on national forest lands.

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[26] Letter dated March 5, 1982, concerning Supron Energy Corporation Meeting with Custer National Forest, from Jim Mann, Forest Supervisor, Custer National Forest.

This activity could possibly be inferred from the number of development wells and from the projected flow of oil and gas.

In summary, the PSM can also be used to provide information on projected levels of oil and gas exploratory and development drilling. These forecasts can then be used to project future personnel and budgeting requirements needed to manage the workload. Although these forecasts would only be a first approximation of future oil and gas activities, with further adjustments these projections could be made more realistic for a given situation. These estimates can be bounded by a minimum and a maximum estimate to account for the uncertainty in the projections.

The PSM as an Environmental Assessment Tool

Environmental effects can be categorized as physical, biological, economic, and social. The purpose of assessing these effects is to determine whether a particular project activity or program alternative will have beneficial or adverse effects on the surrounding physical, biological, and human environment. The information from such an analysis aids the decision maker in selecting a preferred course of action. The chief problem of assessing the environmental effects of future oil and gas activities has been the lack of information about the expected level and location of activities. By providing production forecasts and estimates of drilling and transportation development, the PSM can provide key data useful for conducting such analyses.

Because the PSM does not predict exactly where oil and gas accumulations would occur, the model outputs are not very useful for the assessment of physical and biological effects. The model outputs can, however, be a powerful aid in better assessing the social and economic effects of oil and gas activities. These impacts can be measured using input-output analysis.

The Forest Service uses a computer system known as IMPLAN to assist in the forest planning process involving economic impact assessment. IMPLAN is a system which enables forest planners to develop input-output models of a user defined impact area for the purpose of evaluating alternative management programs. Input-output models have been used in the past for evaluating forestry activities or policies on local economies (Elrod et. al. 1972; Schallau et al. 1969). Given the magnitude of the Forest Service planning task, the preparation of 124 forest plans and 9 regional plans, the construction of input-output models using IMPLAN is the only method to use for efficiently assessing social and economic impacts (Alward and Palmer 1982).

Input-output (I-O) models depict the economic structure of an economy at a particulr point in time. An I-O model represents the flow of commodities from each of the producing sectors to each consuming sector and is formulated in terms of a transactions table (Figure 37). Quadrant I represents the flow of goods and services which are produced and consumed in the economy. These flows are represented as technical coefficients or direct requirements. The coefficients are interpreted as the material requirements from each of the producing sectors, in order that each consuming sector can produce one dollar's worth of output. The technical coefficients in each column represent the many production functions, or the physical relation between inputs of resources and outputs of goods and services, of the regional economy. Quadrant II records the ultimate consumer's purchases (i.e., final

			Purchasing sectors: Intermediate demand — Agriculture, Mining, Manufacturing, Trade, Services, Finance	Final demand: Household consumption	Govt. expenditures	Gross domestic capital formation	Exports	Total gross output
			Quadrant I intermediate production & consumption	Quadrant II final outputs of producing sectors				
Producing sectors — Intermediate inputs	Agriculture	1	$x_{11} \cdots\cdots x_{1j} \cdots\cdots x_{1n}$	C_1	G_1	1_i	E_1	X_1
	Mining	.	. .	.	.	.	.	.
	Manufacturing	.	. .	.	.	.	.	.
	Trade	i	$x_{i1} \cdots\cdots x_{ij} \cdots\cdots x_{in}$	C_i	G_i	1_i	E_i	X_i
	Services	.	.	.	.	.	.	.
	Finance	n	$x_{n1} \cdots\cdots x_{nj} \cdots\cdots x_{nn}$	C_n	G_n	1_n	E_n	X_n
			Quadrant III primary inputs to production	Quadrant IV primary inputs to final demand				
Primary inputs	Payments to							
	Households		$H_1 \cdots\cdots H_j \cdots\cdots H_n$	H_C	H_G	H_1	H_E	H
	Government		$T_1 \cdots\cdots T_j \cdots\cdots T_n$	T_C	T_G	H_1	T_E	T
	Depreciation		$D_1 \cdots\cdots D_j \cdots\cdots T_n$	D_C	D_G	D_1	D_E	D
	Imports		$M_1 \cdots\cdots M_j \cdots\cdots M_n$	M_C	M_G	M_J	M_E	M
Total gross outlays			$X_1 \cdots\cdots X_j \cdots\cdots X_n$	C	G	1	E	X

SOURCE: USDA, Economics, Statistics and Cooperatives Service 1978. Regional development and plan evaluation: the use of input-output analysis. Agriculture Handbook No. 530. May. Table 2, p. 24.

Figure 37. Structure of an input-output transactions table.

demand) from the purchasing sectors, while quadrant III shows the primary inputs of production. Finally, quadrant IV represents primary inputs into final demand sectors such as government employees income and imports consumed by households.

Like any other analysis, I-O models must be used with caution. The first limitation of I-O models is that substitution is not allowed among inputs, fixed proportions exist in all production processes. Further, when output increases n times, all inputs are assumed to increase n times. This is referred to as constant returns to scale and is often not a realistic assumption among production processes. Finally, no sector can produce more than one output and an aggregated sector is assumed to produce the same product as when the model was developed. Although not totally defensible theoretically, the advantage of I-O models is that an entire economy can be represented in a single input-output table; without these assumptions this would not be possible.

Estimating the regional economic impacts of changes in final demand caused by various resource management actions is the most common use of I-O models by the Forest Service. The changes in final demand may arise from activities of timber harvesting, grazing, recreation, or oil and gas production. For example, using the oil and gas production forecasts in conjunction with IMPLAN, the economic and social impacts from such activities can be measured. The forecasted oil and gas production for the Lewis and Clark National Forest, expressed in monetary terms, can be represented in an I-O model as a change in final demand within the appropriate sectors. Using IMPLAN, the economic effects can be measured as changes in total gross output (output multiplier), changes in income

(income multiplier), changes in employment (employment multiplier), and changes in population. Figure 38 shows how each of these multipliers could be determined. The combination of output information from the PSM and I-O models can provide a more comprehensive and detailed account of potential regional economic impacts from oil and gas activities and would be useful to the social scientist in assessing social impacts.

Additionally, an assessment of the economic and social impacts from oil and gas exploration and development activities would be useful information to local communities. Often small local communities lack the money and expertise to plan for future events that may impact their communities, both economically and socially. On the Little Missouri National Grasslands, the rapid rise in oil and gas activities caught many of the local communities unprepared. The PSM in combination with IMPLAN provides a means for assessing economic and social impacts of future oil and gas activities.

The PSM as a Tool for Developing Management Scenarios

The model can also be used for evaluating the sensitivity of the petroleum forecasts to changes in assumptions. For example, alternative runs of the PSM might be made to evaluate the impact of uncertainty surrounding some of the key input variables, number of structures or drilling costs. Depending upon the different model and input data assumptions, the forecast can show significantly different patterns of resource and transportation development. Besides these uses, the PSM can be useful for addressing different public issues or management concerns surrounding petroleum resources development. Some of the chief issues or management concerns have revolved around land withdrawals,

RELATIONSHIP / MULTIPLIER	TYPE I $\left[\frac{\text{Direct* + Indirect** Effects}}{\text{Direct Effects}}\right]$	TYPE II $\left[\frac{\text{Direct + Indirect + Induced*** Effects}}{\text{Direct Effects}}\right]$
OUTPUT	Normally referred to as the output multiplier the purpose is to measure the change in output given a change in final demand for a particular industry.	Normally referred to as the Type II output multiplier.
INCOME	Normally referred to as the Type I income multiplier which measures the change in income (i.e., wages, salaries, rent, interest) given a particular change in final demand.	Normally referred to as the Type II income multiplier.
EMPLOYMENT	Normally referred to as the Type I employment multiplier which measures the change in employment given a particular change in final demand for a particular industry.	Normally referred to as the Type II employment multiplier.

* The direct physical requirements (i.e., effects) to produce a dollar of output of a given product.

** Indirect requirements are those needed to produce the direct requirements and so forth.

*** Induced effects are those created from new income being respent and its consumption further stimulating local income. These effects are calculated by moving the household sector into the first quadrant of the transactions table. The result is that Type II multipliers are larger.

Figure 38. Multipliers most often used and calculated from input-output models.

surface-use and resources constraints, the timing and rate of development, transportation development, and various government policies.

Alternative Land Use Designations

Since the 1976 National Forest Management Act was passed and the RARE II study was completed, land use designations of the national forest lands have become an important issue in the minds of many individuals and groups. The various forest land use plans now being prepared by the Forest Service serve as the basic "blueprint", once approved, of how the land is to be managed for each forest. The management alternative selected will influence the kind and amount of outputs produced which in turn will affect the livelihood of many individuals and organizations dependent upon the national forest lands. The search for that mix of outputs which serves the public interest in the most optimal way, although not necessarily the most efficient, is the challenge for the Forest Service planning teams.

Forest lands can be managed and used in numerous ways and each way would influence the physical, social, and economic environment differently. The Rocky Mountain Division of the Lewis and Clark National Forest could be managed as a wildlife preserve, as an energy reserve, as a watershed, as wilderness, or as some combination of these and, whichever land use pattern is implemented or selected, the production of surface and subsurface resources would be affected differently. Because petroleum resources are ignored or considered only to a limited extent in the forest planning process, the effects on these resources under different land use designations are not usually assessed.

Questions which often arise when considering the potential of oil and gas resources on the Lewis and Clark National Forest are: What is the effect on the petroleum potential when certain areas are designated as wilderness (assuming the lands are withdrawn from oil and gas leasing)? and What is the effect on the petroleum potential if in some areas the oil and gas leasing stipulations are so restrictive as to preclude oil and gas development? Haynes and Adams (1979) addressed similar questions relative to timber in a study to assess the impacts of the RARE II withdrawals on timber prices, consumption, and production. Using a market simulation model, the study concluded that withdrawing all RARE II roadless areas could raise U.S. lumber prices nearly 4 percent and reduce domestic lumber consumption by 3 percent by the year 2000. Additionally, domestic wood production would decline 17 percent in the Douglas-fir region, 28 percent in the Rocky Mountain region, and imports from Canada would increase 19 percent. A study of this type provides useful information to land managers for assessing the opportunity costs of withdrawals and would also be useful if done with oil and gas resources.

The oil and gas reserve estimates from the base run assumed all lands within the supply region were open and accessible to lease occupancy. From discussions with knowledgeable individuals about the leasing program on the Lewis and Clark National Forest, nearly 36 percent of the issued oil and gas leases have surface occupancy restrictions so stringent as to preclude occupancy and, hence, development. The effect is similar to a land withdrawal.

The impact on the oil and gas potential of such a withdrawal would depend upon the number of structures occurring within this area. Occupancy restrictions on nearly 40 percent of the surface could significantly reduce the oil and gas potential and future activities if 60 percent of the geological structures occurred within this area. This effect, however, would be much less if only 10 percent of the structures occurred in this area. These impacts could be measured using the PSM by respecifying the number of structures distribution and rerunning the model. The effect would be that the most likely number of structures would be reduced causing the estimated amount of oil and gas to decrease. Thus, such a measurement would provide land management planners with an estimate of the amount of oil and gas that would be foregone in the name of protecting other surface resources.

Because the supply region used for the base run has few structures, measuring the effects of land withdrawals from oil and gas development in the study area is not feasible. The reason is that the sample value from the number of structures distribution is constrained to a minimum sample of 25 structures to control the standard deviation of the mean oil and gas in-place resources distributions. If the effects of land withdrawals on the oil and gas potential are to be measured then larger supply region areas would have to be used so that the model constraint on the number of structures is not violated.

Timing and Rate of Development

Other concerns addressed by different public groups and land managers are the questions of how much oil and gas development would occur, when it would be initiated, and how rapidly would it be developed. The question of when oil and gas exploration and development would be initiated is difficult to answer since there are so many influencing variables beyond the control of the Forest Service. Generally, the timing is influenced by industry's preferred rate of development. The base run for the PSM assumed that a minimum of 5 years would be needed to explore and to develop the Rocky Mountain Division of the Lewis and Clark National Forest before production could begin. This was a subjective judgement made by several geologists knowledgeable about this area. Because of the uncertainty about the timing of exploration, development, and production, the analyst may want to know what the effect on production as well as economic benefits would be if this period took 10 years, the normal oil and gas lease tenure provision.

In order to determine the effects of using 10 years as the length of time before production begins, a separate run of the PSM was made. Assuming that exploration could begin in 1982 when all oil and gas leases would be issued, the effects were such that oil and gas production was pushed further into the future causing the net present value of revenues to decrease 35 percent to 7 billion dollars. The change in the production forecast is shown in Table 19 and Figure 39, as contrasted with Table 10 and Figure 28 (Chapter 5). The impact of this change in timing would mean that oil and gas production would not begin until 1992. This would spread the social, economic, and environmental impacts over a longer time period, reducing the intensity and possibly making them more manageable. However, the favorability of this impact

Table 19. Oil and gas production forecast for the Lewis and Clark National Forest: ten year lead time.

Product[1/]	Units	1982-1986	1987-1989	1990-1991	1992-1993	1994-1996	1997-2001	2002-2006	2007-2011	2012+
Crude Oil	Thousand BBLS/Day	0	0	0	25	134	134	128	98	15
Natural Gas	Million CF/Day	0	0	0	104	600	599	538	521	131

1/ Includes co-products and all units expressed in average daily quantities.

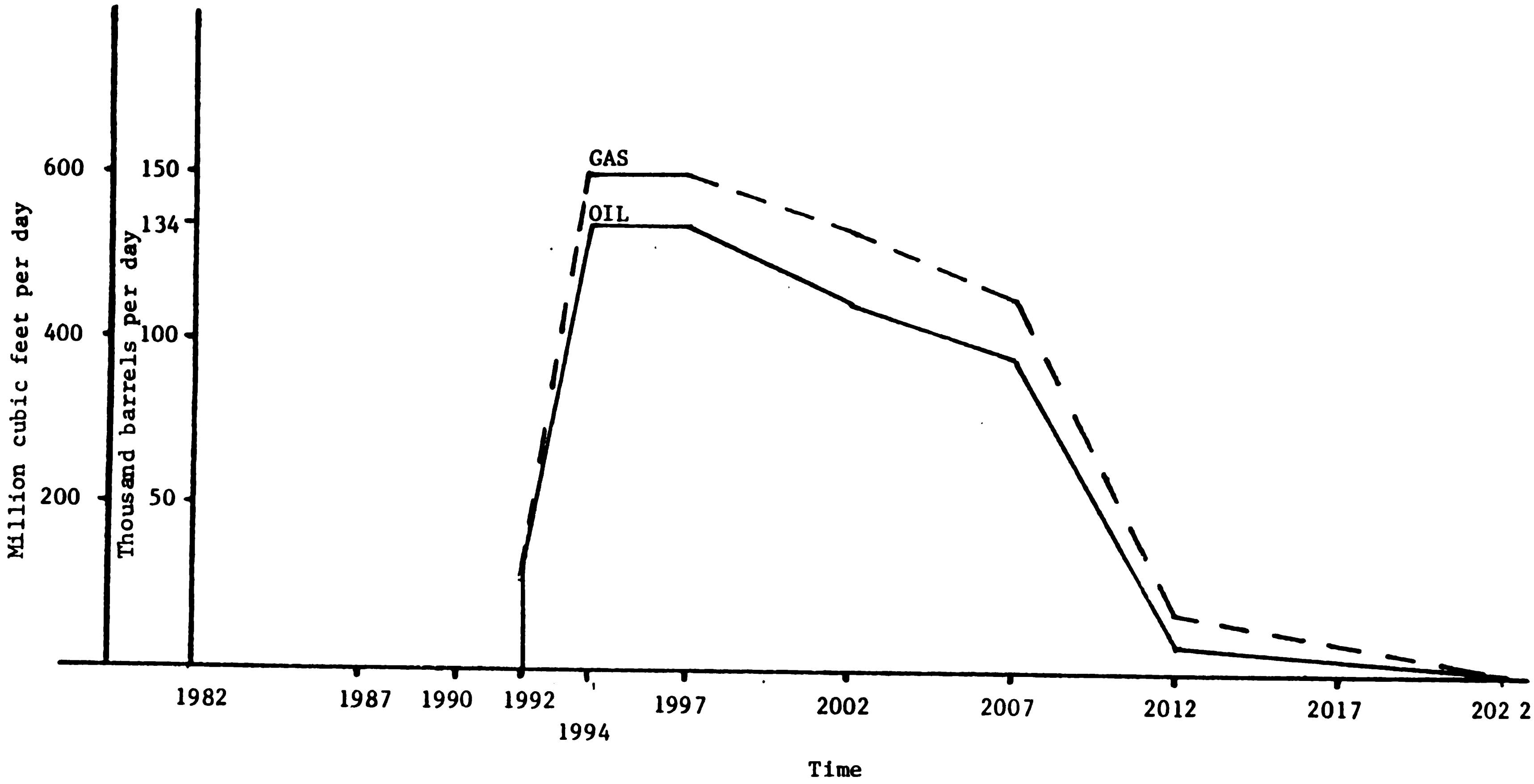

Figure 39. Oil and gas production forecast for the Lewis and Clark National Forest: ten year lead time.

is at a great expense in terms of the net present value of oil and gas revenues.

Similar experiments could be completed if the lead time was only 3 years. The importance of having such a capability is that the economic costs of delaying or speeding up oil and gas development can be measured using the PSM. The important point to remember is that the longer oil and gas activities are delayed, the greater the costs of oil and gas development. For example, the issuance of a drilling permit in 10 days would create much greater benefits to oil and gas development than if issued in 4 months. Sometimes when lease restrictions allow site occupancy for only 6 months out of the year a serious delay in the issuance of a drilling permit could preclude any exploration and development activities until the next year.[27] The PSM can thus be a useful tool for measuring the economic costs of delays in oil and gas exploration and development.

Since oil and gas leases have been issued for 100 percent of the nonwilderness lands on the Rocky Mountain Division of the Lewis and Clark National Forest, leasing delays are no longer a problem. Such delays still exist for those lands classified as wilderness or are proposed for wilderness classification. Because a decision to lease these lands must be made by December 31, 1983 these delays should not persist.

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[27] This is the expected behavior in situations where the activity is initiated in an area for the first time, however, once the activity becomes more commonplace it may be reasonable and efficient to waive some of the stipulations (i.e., seasonal occupancy restrictions in wildlife habitat; operating restrictions on slope). This would, of course, depend upon the situation and sensitivity of the site.

The PSM can accommodate leasing delays if the problem exists through the specification of early start dates for exploration in the integrating model segment. The early start dates can be specified for an entire supply region or for individual exploratory increments. The early start dates for exploration can be based on the leasing schedule for an area; due to leasing delays some areas would experience exploration before others. The effect of specifying the exploration start dates based on a leasing schedule spreads the exploratory drilling over time. In the base run, the early start dates for exploration were spread out over a 15 year period to account for the extensive wilderness acreage not yet leased[28] and for the accessibility problems that would be encountered due to the remoteness of the supply region. As a result the exploration and development activity was spread over a 15 to 20 year period.

A different set of assumptions could cause the exploration and development activities to be spread over a shorter or longer period of time. In order to determine the effects of such a change, a separate run of the PSM was made spreading these start dates over a 7 year period. This assumes the wilderness lands would be explored at a much more rapid rate than in the base run. The results of this run indicated that the exploration and development activity would be somewhat more intense and occur sooner than in the base run. Because the oil and gas resources are being developed sooner, production increases slightly.

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[28] For the base case it was assumed these lands would be available for oil and gas leasing after December 31, 1983.

Another concern is the rate at which oil and gas development should occur. The more rapidly an area is explored and developed, the higher the net present value of benefits to the nation. These benefits are offset by the fact that a more rapid development scenario would cause a greater influx of people, equipment, and dollars into a supply region area, in some cases a boom town situation, and may increase the difficulties of managing the environmental and socioeconomic impacts of development. The rate of oil and gas development on the Little Missouri National Grasslands in western North Dakota has dramatically increased since 1978. The towns in this area, although not boom towns, have experienced rapid population growth accompanied by many social and economic costs and benefits. As a result, the necessity of such rapid development is being questioned by many people. Why could there not be more gradual development to facilitate long-term prosperity and economic stability?[29] Is the collective effect of such large-scale development more harmful to the environment than gradual development? Is the nation conserving enough energy to help reduce the pressure on developing new sources? (Wenner 1980)

Depending upon the rate of oil and gas development, there are also effects on the physical and biological resources. A key issue in most environmental assessments concerned with oil and gas activities is the effect such operations would have on wildlife. The impacts are different depending upon the species, since some are more sensitive to the encroachment of such activities in and around their natural habitat. Some of the more sensitive species may be permanently displaced or

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[29] Grow at an acceptable rate of change.

reduced in numbers if any oil and gas operations occur in their natural habitat or critical portions of it, whereas other, more adaptable, species may only be temporarily displaced. Unlike the social and economic impacts on local communities, the means of mitigating the wildlife impacts can be more readily accomplished through protective stipulations on leases and drilling permits. The effects of these stipulations on oil and gas development, however, are often not considered and, in some instances, can preclude development. Thus, in both situations of maintaining local community lifestyles and economic stability or protecting other biological resources such as wildlife, the concern is over the rate of oil and gas development and whether it should or should not take place.

The PSM is a useful tool for assessing effects which constrain oil and gas exploration development. The rate of development could be controlled in the PSM by placing a constraint on exploratory or developmental drilling or by changing the length of the time period over which development would occur. Depending upon the management scenario, such changes could be made and the model rerun. The information from such experiments could be useful for developing more acceptable constraints on development and for determining the economic opportunity costs of such constraints.

Constraints were not placed on oil and gas development for the base run. In order to address the concern over the rate of development, two separate runs were made. The first run assumed that the local communities of Browning, Choteau, and Augusta would welcome oil and gas activities, but would not want growth to occur at such a rapid rate that it would severely disrupt local economic conditions and traditional lifestyles. Because the percentage growth rate of oil and gas activities that is acceptable to these local communities is unknown, an arbitrary rate of 10 percent per year was chosen. This constraint, however, was placed only on exploratory drilling activity because if less exploratory drilling occurs in a particular time period, there will be less oil and gas reserves discovered causing a reduction in the amount of reserves available for development and production. The results of this run are summarized in Table 20.

In comparing Table 20 with Table 11 (Chapter 5), the effect on drilling activity can be seen from imposing the constraint. A 27 percent decrease occurred in total exploratory drilling, with a greater percentage decrease in gas drilling than oil. The results are similar for development drilling, except that the magnitude of change is much less. Even though less exploratory drilling occurs, the results are reasonable because the majority of the reserves have still been discovered. Production levels essentially stay the same for oil, but are less for gas due to the larger decreases in drilling activity. Because overall investment activities are pushed further into the future and less gas is produced, the net present value of revenues drops from 10.5 billion dollars to 10 billion dollars (1980 dollars). The tradeoff has thus been quantified. Decision makers or land managers must decide whether the loss in the net present value of 0.5 billion dollars is worth the benefits obtained from a slower rate of development.

Another way of controlling the growth of oil and gas development is by changing the shape of the production profile. This is done by either lengthening the time period between the start of exploration and the

Table 20. Estimated exploratory and development drilling in millions of feet from imposing a 10 percent growth constraint on exploratory drilling.

Product	Exploratory Drilling				Development Drilling			
	1982-1986	1987-1991	1992-1996	1997+	1982-1986	1987-1991	1992-1996	1997+
Oil	.047	.014	.030	.020	2.184	1.144	1.847	0.240
Gas	.045	.016	.018	.057	0.510	0.179	0.207	0.343
Total	.092	.030	.048	.077	2.694	1.323	2.054	0.583

initiation of production or the time period between initiation of production and peak production. The profiles used for the base run are provided in the appendix (Figure A1). For purposes of an example only, an assumption can be made that because of the wildlife lease stipulations on many leases in the Rocky Mountain Division of the Lewis and Clark National Forest, the time period between the initiation of production and peak production should be extended to 4 years. The profile was altered and the model rerun to measure the effects on production, drilling activity, and revenues from such a change.

The results show that production is pushed into future time periods and peak production is not attained until 1992 (Figure 40). This figure can be compared with the base run result in Figure 28. Exploratory drilling remains the same, but development drilling is shifted slightly into future time periods. Since production has been pushed into future time periods, the net present value of revenues decreases from 10.5 billion dollars to 9 billion dollars. The tradeoff has been quantified and, again, the decision needs to be made about whether the loss in the net present value of 1.5 billion dollars is worth the cost of the wildlife lease stipulations which could decrease the rate of oil and gas development.

Although the rate of growth in the development of oil and gas resources on the Lewis and Clark National Forest is ultimately determined by the petroleum industry's preferred rate of exploration in this area, the Forest Service has the means of indirectly controlling the growth rate by its responsibility as a surface resource management agency. The chief means of control is their authority to recommend lease stipulations for the protection of surface resources and uses.

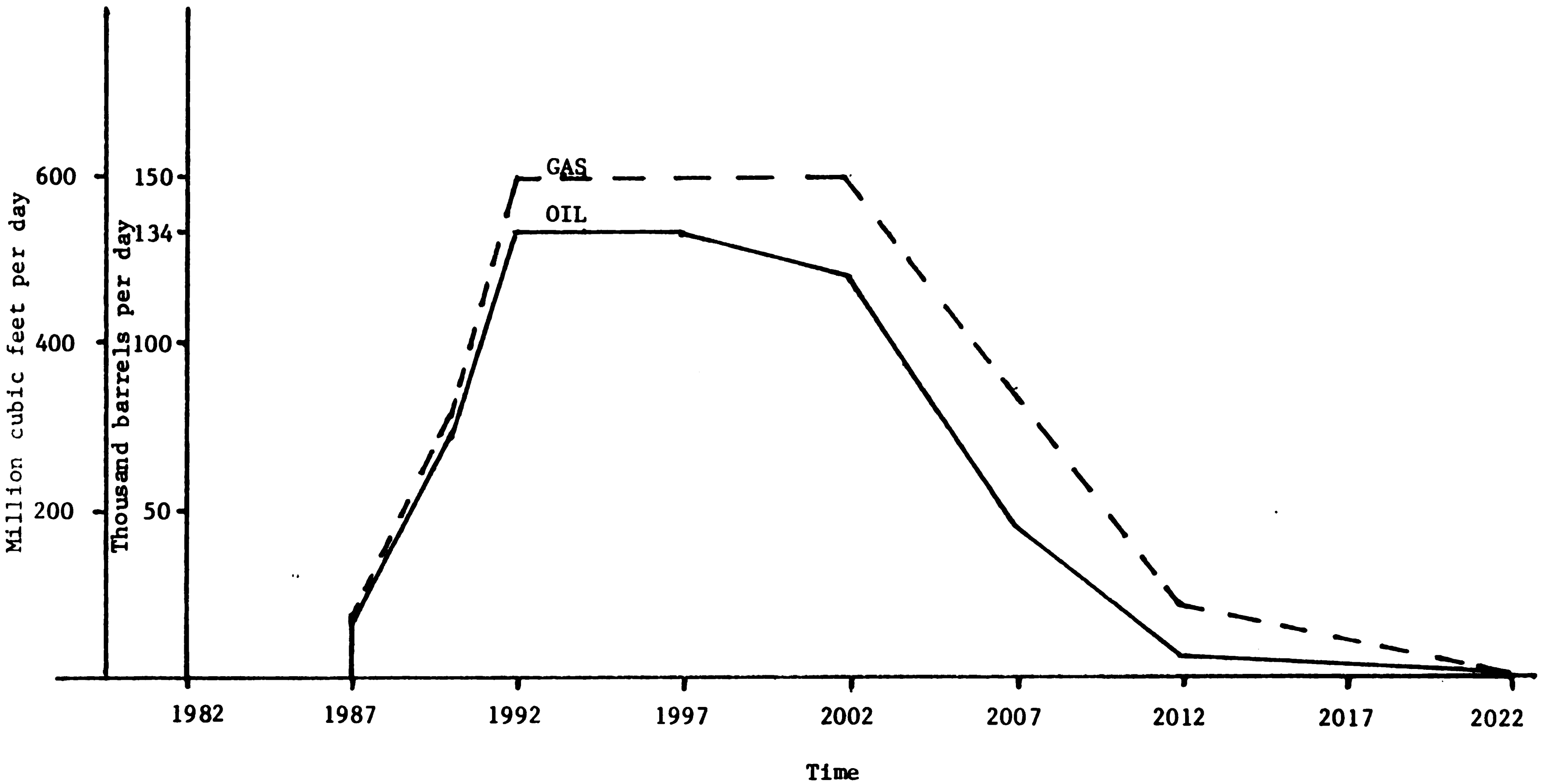

Figure 40. Oil and gas production forecast for the Lewis and Clark National Forest: four year development plan.

Presently under the current set of federal regulations, the Forest Service is unable to control growth to prevent boom towns. Nevertheless, the PSM could be a useful tool for assessing the economic impacts of lease stipulations or for assessing economic impacts of controlling growth. This information could be useful to the land manager for determining resource tradeoffs and for improving the land manager's understanding about how expensive it may be to constrain the rate of oil and gas development.

Other Issues or Concerns

The PSM may also be useful for analyzing the impacts of different rates of oil and gas production. The oil and gas production profiles used for the base run were developed based on collected data and subjective judgements from knowledgeable individuals and are assumed to be the profiles that would be most likely on the Lewis and Clark National Forest. Given the existing uncertainty surrounding these profiles, the land manager may want to know how alternative production profiles could impact surface resources and uses. In most instances, additional development expenditures (i.e., greater number of production wells; additional capacity for processing equipment) tend to shorten the lead times between exploration and maximum production, increase the maximum production rate, and create a steeper decline in production during the later years of production. The impact of more rapid development implies a greater disturbance of surface resources and uses. Another reason to vary the production profile is to determine if a greater return on investment is possible.

In order to show how the PSM can be used for addressing concerns of different production rates, two alternative sets of oil and gas profiles were developed as shown in Figure 41. The PSM was rerun separately for each set with the results summarized in Figures 42 and 43 and Tables 21 and 22.

The first alternative, profile A, assumed a more rapid rate of production for oil and gas. Figure 42 indicates that the maximum peak production is maintained for a longer period with a steeper decline in production for both oil and gas. Generally, the production forecast does not significantly change from the base run when compared with Figure 28. Comparing Table 21 with Table 11, a 53 percent increase can be seen in development drilling over the base run. The net present value of revenues declined only slightly since the additional revenues from earlier sales of oil and gas were offset by the additional investment in development wells and surface equipment.[30] The impact of changing the production profile would probably mean greater surface impacts from the additional development drilling and equipment.

The second alternative, profile B, assumed a much slower rate of production. Figure 43 indicates that the time period between the start of production and peak production is longer for both oil and gas, but the period of maximum peak production declines for gas and is lower for oil. A comparison of Table 22 with Table 11 shows a 62 percent reduction in development drilling which is attributed to the decline in production and a 31 percent drop in the NPV of revenues. Although the

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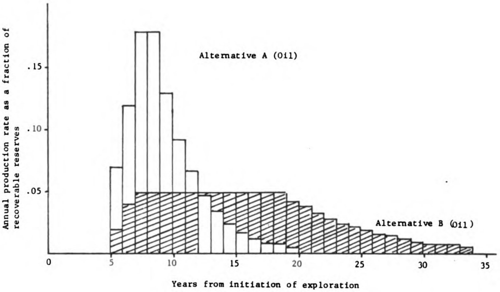
[30] If a larger pipeline was available, the maximum production rate would increase rather than be extended and cause the net present value of revenues to be larger than the base run.



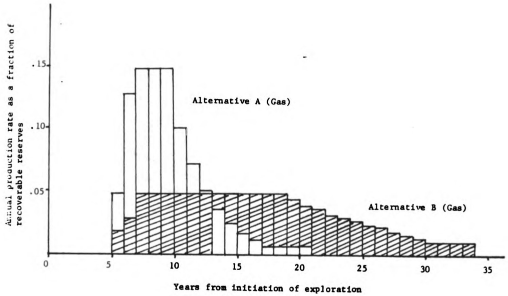


Figure 41. Alternative production profiles.

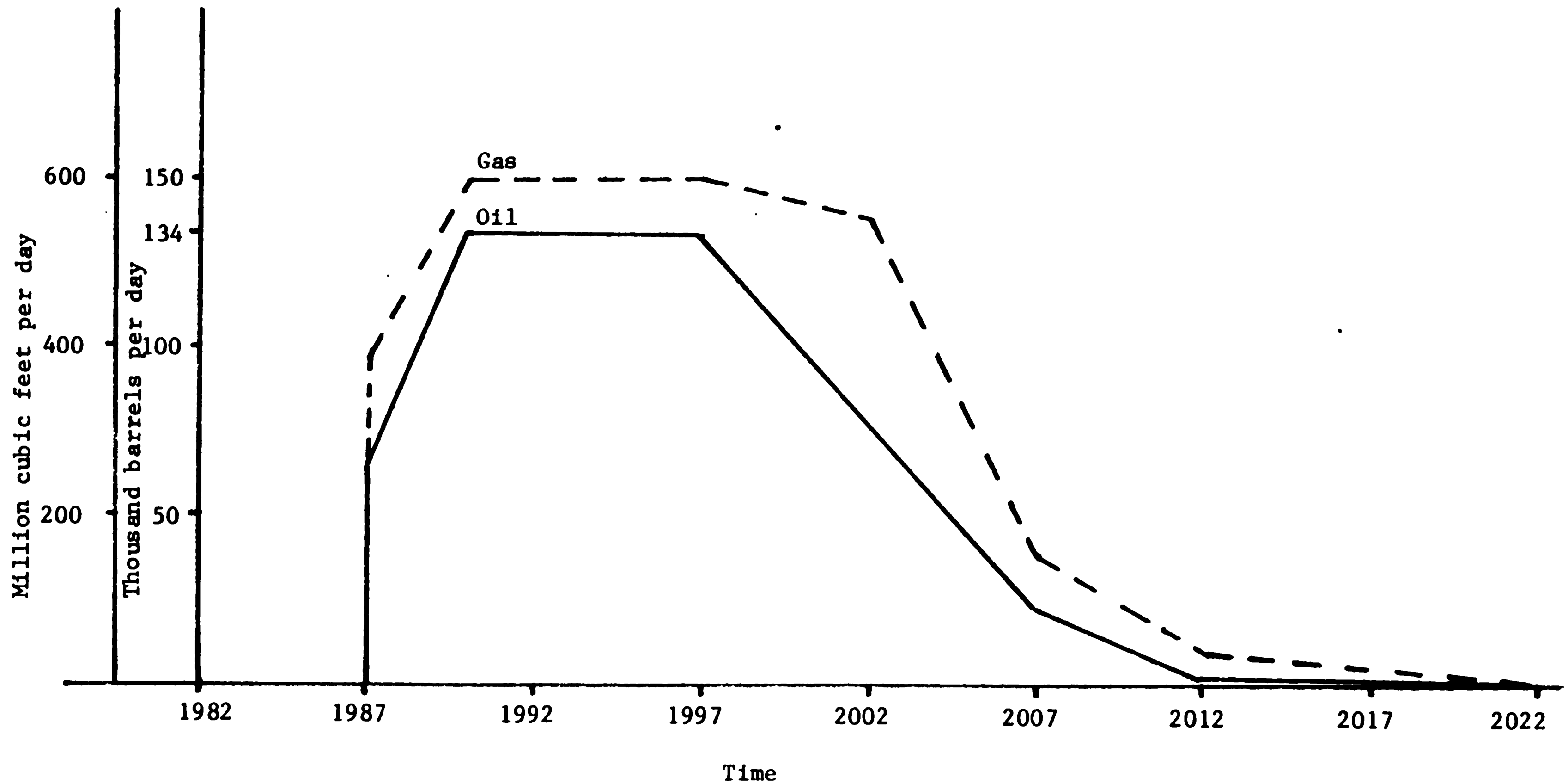


Figure 42. Oil and gas production forecast for the Lewis and Clark National Forest: alternative A.

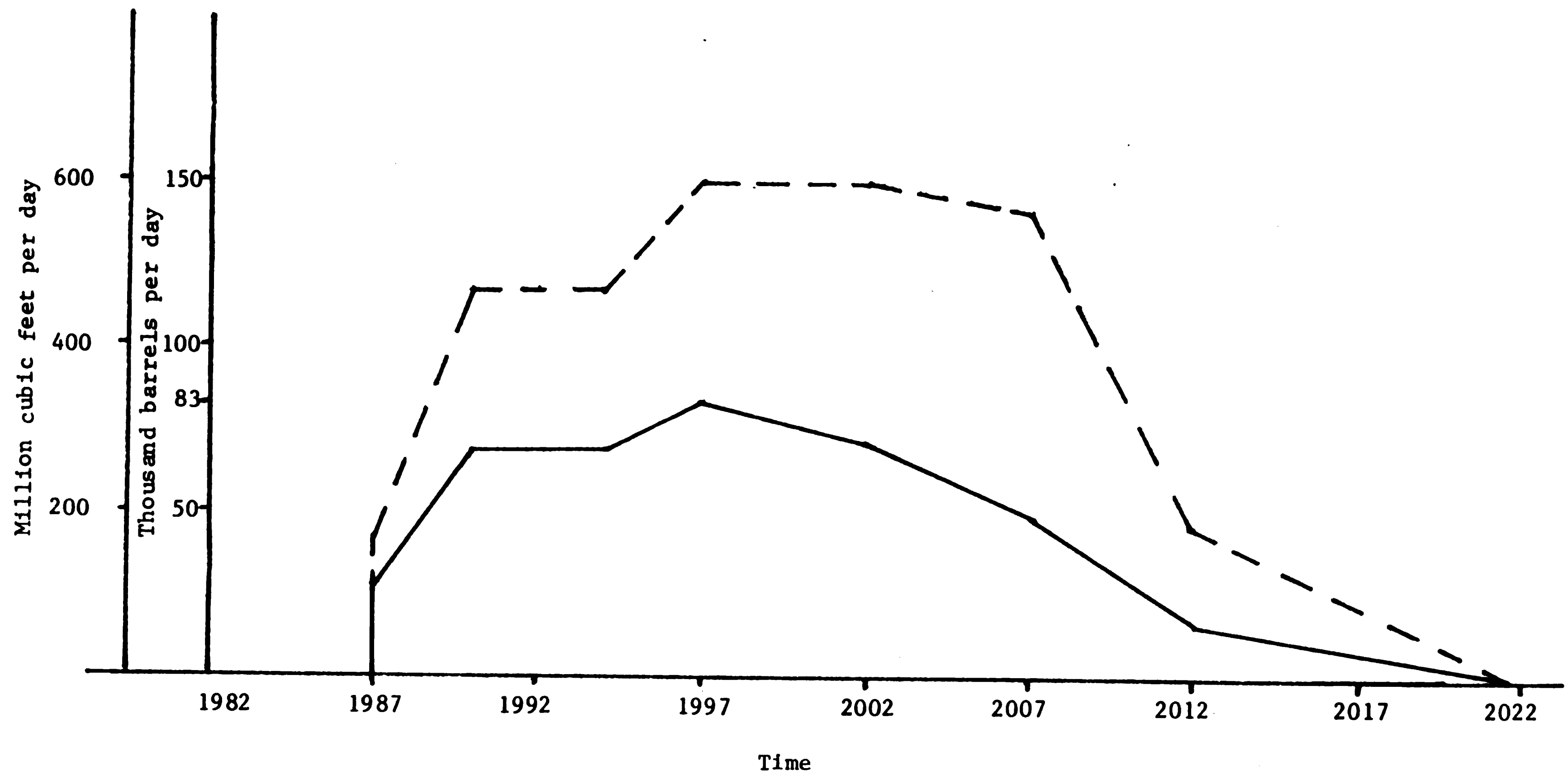


Figure 43. Oil and gas production forecast for the Lewis and Clark National Forest: alternative B.

Table 21. Estimated exploratory and development drilling in millions of feet for alternative production profile A.

Product	Exploratory Drilling				Development Drilling			
	1982-1986	1987-1991	1992-1996	1997+	1982-1986	1987-1991	1992-1996	1997+
Oil	.061	-	.050	.025	1.711	2.869	2.792	0.991
Gas	.061	-	.050	.091	1.038	-	0.681	0.192
Total	.122	-	.100	.116	2.749	2.869	3.473	1.183

Table 22. Estimated exploratory and development drilling in millions of feet for alternative production profile B.

Product	Exploratory Drilling				Development Drilling			
	1982-1986	1987-1991	1992-1996	1997+	1982-1986	1987-1991	1992-1996	1997+
Oil	.061	-	.050	.055	1.607	-	0.296	0.023
Gas	.061	-	.050	.091	0.336	-	0.223	0.062
Total	.122	-	.100	.146	1.943	-	0.519	0.085

surface impacts would probably be reduced as a result of less development drilling, this is offset by a decrease in oil and gas revenues.

The analyst may also find that the PSM is useful for analyzing the economic impact of alternative transportation systems. Marketing oil and gas in remote regions often requires extensive pipeline systems to transport the products economically. The designation of the pipeline corridors can often be controversial and selecting the route that appears most economical may not be politically acceptable. Many factors can influence the location of a pipeline corridor such as soil stability, climate, terrain, and land use patterns. For most supply region areas, there may exist a number of alternative transportation systems.

The transportation system considered in the base run is hypothetical, but assumed to be the most feasible and least costly without conducting an extensive study. It may be that there are concerns not being considered which would make such a transportation network infeasible. For instance, the gas pipeline originating in Wolf Creek, Montana, and connecting with the Alaskan Highway Gas Pipeline System (AHGPS), which would allow the gas to be marketed in San Francisco, may not be feasible. An alternative route for the gas pipeline might be from Wolf Creek to Malta, Montana. The pipeline would still connect with the AHGPS, but the gas would instead be marketed in Chicago (Figure 29, Chapter 5). The PSM could thus be used to test the effect on gas production and revenues if this were a more acceptable alternative.

Such a test was made and the results indicated that gas production was not affected. However, because the alternative gas pipeline is 107 miles longer the transportation costs increased causing the net present value of revenues to decline modestly. The difference in revenues between these two alternative gas transportation systems would be a measure of the opportunity costs for selecting a different transportation route.

Finally, the PSM may also have some use for analyzing the impacts of changing federal and state tax policies on oil and gas. The State of Montana increased the severence tax on oil from 2.65 percent to 5.0 percent in 1981. This increase and the fact that the oil price decontrol caused Montana's oil production to increase from 28.5 million barrels to 30.8 million barrels in 1981 resulted in a doubling of the state's oil tax revenue over 1980. These additional state revenues helped create a revenue surplus, which is unusual during times of severe recession (Western Oil Reporter 1982).

Generally speaking, an increase in severence taxes causes oil and gas production to decline, especially when such taxes cannot be passed on to the consumer. Whether the situation described in the above paragraph discourages future petroleum activities in Montana is difficult to analyze given the many factors influencing the situation.

The PSM as an Educational Tool

Thus far the potential of the PSM has been discussed as to its usefulness to the Forest Service for improving the management of petroleum resources. The PSM could also be useful as an educational tool. The simulator could serve as a valuable teaching and learning tool in the Forest Service annual 3 day oil and gas training workshop held for geologists, foresters, and other staff personnel interested in petroleum resources management. The model could be used to teach those attending the workshop about the dynamics of the oil and gas supply process. A series of exercises might demonstrate the significance of certain geological variables in resources estimation, the role of economics in reserve estimation, how uncertainty is incorporated in reserve estimation, and the effects of land withdrawals or changes in assumptions about the timing and rate of oil and gas development. It would allow those attending the workshop to learn about the major principles of the oil and gas supply process and to test their ideas about the management of these resources.

This chapter has described how the information on oil and gas resources from the PSM could be used to assist land use planning, administrative planning, environmental assessment, and for developing and testing management scenarios. The chief problem in the past has been that the type of information provided by the PSM has not been available to land management planners. As a result, energy values have not been adequately considered in the forest planning process which is a requirement established by the National Forest Management Act regulations (USDA 1982). A few forest plans in the Northern Region have reached draft stage and generally minerals are only being integrated to a limited extent. As a result, the mineral industry has been highly critical of these plans. It is expected that this problem will persist until energy minerals are more adequately considered in the forest plans.

CONCLUSIONS

Because of the National Forest Management Act regulations and the rising demand for minerals, especially energy minerals, a greater need exists for integrating minerals into the national forest land management plans. The objective of this study was to develop a method for assessing the future amount of oil and gas resources and activities in the Northern Region. The oil and gas resources information base generated can be used for improving land use management, assessing environmental impacts, and improving administrative management of federal government programs. A petroleum simulation model was used to estimate the potential of oil and gas resources and activities on a pilot test area, the Lewis and Clark National Forest. The model is intended to be used in those unexplored areas in the Northern Region where a mounting intensity of oil and gas activities is expected to occur.

In this paper the oil and gas supply process was described. Briefly the major concepts and terms relating to the origin and accumulation of petroleum, reservoir mechanics, and the complex management decisions involved in developing the reservoir to insure that the petroleum resources are efficiently recovered are outlined. The petroleum simulation model used in this study is designed to mimic the process so that estimates of potential petroleum resources can be made for a particular area.

Based on a review of past literature concerning petroleum resource appraisals, methods developed for estimating undiscovered oil and gas resources and reserves were summarized. Extensive variability of resource estimates exists due to the changing level of geologic knowledge, the changing technology of exploring for and recovery of petroleum, the changing economic and political environments and the different methods used. The resource estimates are not precise since many uncertainties are inherent in the estimates. The value of a resource assessment is that it provides a guide for quantifying the overall resource potential. Petroleum resource assessments are evolutionary and not revolutionary, changing with a steady influx of new technology, exploration of deeper depths, and addition of new lands to the process.

The Petroleum Simulation Model (PSM) is a mathematical programming model combining Monte Carlo simulation with linear programming to forecast petroleum reserves, production, and transportation development in unexplored areas. The model is a representation of the oil and gas supply process and is idealized because it incorporates only those geological, economical, and engineering factors and relationships of the supply process which are most significant in effecting petroleum supplies. The model structure is divided into two segments, a resource model segment and an integrating model segment.

The resource model segment is composed of a resource description submodel and a basin exploration and evaluation submodel. The first submodel uses a series of geological input variables specified in terms of probability distributions to describe the size, depth, and volume of petroleum contents for a particular supply region. The second submodel simulates the exploration and development process and evaluates the economics of commercially producing oil and gas using discounted cash flow analysis. The economic evaluation is accomplished using many different cost relationships to determine the cost of finding, developing, and producing oil and gas. The output from the resource model segment consists of several sets of statistics with the two most important sets being the oil and gas in-place resources distributions and the expected oil and gas reserves. The reserve quantities are reported on a cumulative basis by exploratory footage and on an incremental basis by minimum acceptable supply price. Other statistics provided are gas-oil and gas-liquids ratios, average developmental drilling footage, and total exploration costs for each interval of exploratory drilling. These statistics are key input data for the integrating model segment.

The objective of the integrating model segment is to forecast the timing and the extent of petroleum production and transportation development using a linear programming model. The linear programming matrix is constructed using a matrix generator in conjunction with processed output from the resource model segment, oil and gas market price forecasts, data relating to the timing of production, and transportation system costs. The outputs from this segment consist of an oil and gas production, drilling, and transportation forecasts.

The Lewis and Clark National Forest was used as a pilot test for the PSM. The input variables were based on the best set of collected geological and economic data for the study area, given the time and money available. The results indicated that substantial oil and gas resources could exist on the Forest with expected oil and gas reserves ranging from 500 to 800 million barrels and 2 to 4 trillion cubic feet, respectively. These reserve estimates were then translated into a possible oil and gas production and activity forecasts.

Following these results, a series of sensitivity tests were conducted to determine if changes in specific input variables affected outputs. These tests imply that larger supply regions with a greater number of structures should be used to prevent the outputs from being influenced by the constraint on the sample value from the number of structures distribution. Additionally, structure fill, structure thickness, and structure area were found to be sensitive in that percentage changes in the parameter values created equal percentage changes in output. Development drilling footage was found, at first, to be sensitive to changes in the permeability and oil viscosity parameters but the sensitivity diminished with greater percentage changes in the parameter values. Many sensitivity tests were made of the economic variables, but only drilling costs, operating variable costs, and the discount rate were found to be sensitive. The average developmental drilling footage and petroleum reserves were more sensitive to a decrease in drilling costs than to an increase. Operating variable costs and the discount rate were also found to be sensitive, with gas reserve outputs more sensitive to changes in these costs than oil reserves. Generally, changes in the economic cost variables caused oil and gas reserves to be redistributed across different cost categories (MASP) whereas changes in the geological variables caused the total amount of petroleum resources to increase or decrease.

The value of the PSM as a tool for improving oil and gas resources planning and management is directly related to how accurately it represents the actual oil and gas supply process. The sensitivity tests conducted indicated that the model was found to be internally valid; when the key variables were changed in both directions, the model responded as expected and to some extent with the expected magnitudes. In addition to these tests, the outputs from the PSM have been reviewed by knowledgeable individuals verifying that the oil and gas estimates are reasonable and realistic for the supply region area. A direct comparison of the model output with the actual process is difficult and costly. This test can only be made with time, as future petroleum exploration proceeds.

The various applications of the model outputs were also discussed. The model can provide information to help better define the dimensions of the oil and gas resources with respect to the quantity, value, and timing of development and improve land management planning. The exploratory and development drilling forecasts provided by the model are useful for better projecting future budgeting and personnel requirements necessary to manage future oil and gas activities. Using the IMPLAN model and the oil and gas production forecasts from the PSM, the economic and social impacts can also be estimated from any future oil and gas exploration and development. Finally, the PSM could be used for developing and testing different oil and gas management scenarios.

The PSM cannot provide all the required data to meet the National Forest Management Act requirements, but it can provide enough information about oil and gas resources to more adequately integrate them into the national forest planning process. Specifically, the PSM can:

(1) Provide information on the probable occurrence and quantity of oil and gas resources;

(2) Provide information about future oil and gas exploration and development;

(3) Provide information to determine the effects that current land resource prescriptions and management direction may have on oil and gas resources and visa versa; and

(4) Provide information to help determine what the social and economic effects on local communities would be from oil and gas development activities.

If this information were available to land managers, a land management alternative might be developed to emphasize energy resources exploration and development. Since most of the Rocky Mountain Division is managed for primitive recreation and wildlife, an energy alternative would be useful for showing how additional resource commodities could be developed while protecting other surface resources. The purpose of developing such an alternative would help better reflect the oil and gas resource use and development opportunities and offer another way of managing federal land resources on the Rocky Mountain Division to review and consider.

All of this discussion illustrates that the model is a developing tool and in its present form can be useful in aiding land management planning and decision making. Initially the model should be used on a regional or multi-forest level using larger supply region areas until a more specific data base is developed. The model does not make decisions or managerial policy or resource allocations, but provides the information useful for such decision making.

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APPENDIX

Table A1. Geological variables and relationships.

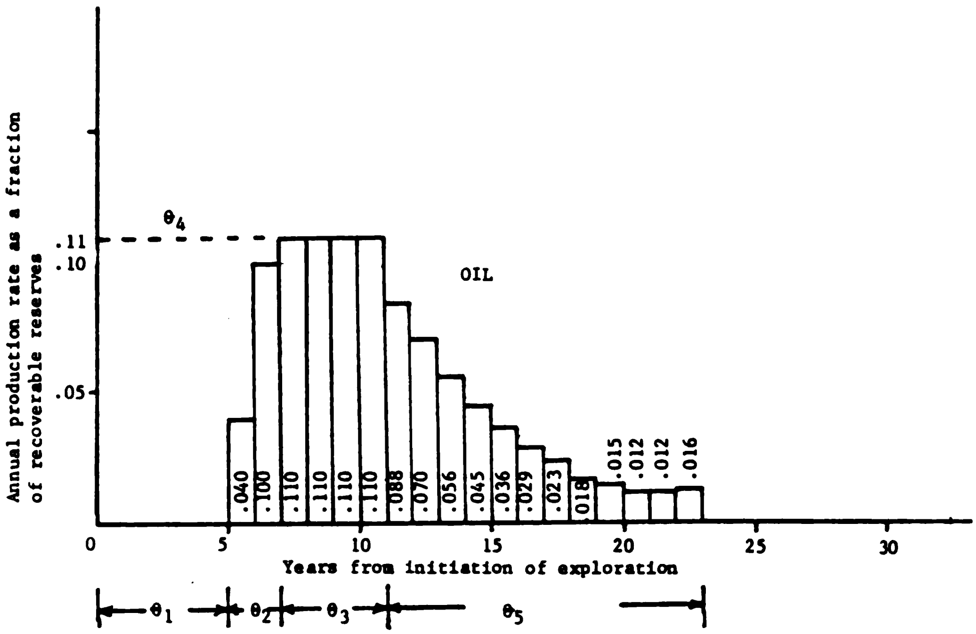
Geological Variables

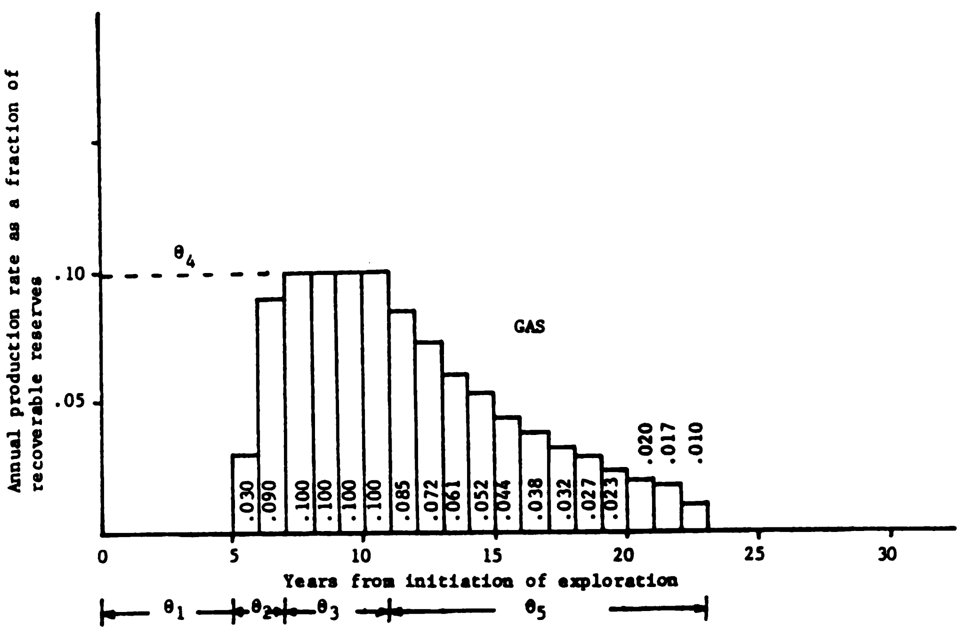
VARIABLE	TYPE OF DISTRIBUTION	DISTRIBUTION VALUE					
		DISCRETE	Cumulative Lognormal		Triangular		
			.50	.99	MINIMUM	MOST LIKELY	MAXIMUM
Structure Fill							
Oil	Lognormal		545.	2000.			
Gas	Lognormal		900.	1900.			
Oil Viscosity	Lognormal		1.	10.			
Permeability	Lognormal		30.	1000.			
Drive Mechanism							
Oil (Active)	Discrete	.40					
Gas (Active)	Discrete	.30					
Recovery Factors							
Oil (Active)	Triangular				.28	.51	.87
Oil (Inactive)	Triangular				.10	.21	.46
Gas (Active)	Triangular				.30	.50	.60
Gas (Inactive)	Triangular				.60	.75	.90
Number Structures	Triangular				8	28	32
Structure Area	Lognormal		6,400	19,400			
Structure Thickness	Lognormal		340	880			
Structure Depth							
0-5,000	Discrete	.50					
5-10,000	Discrete	.40					
10-15,000	Discrete	.10					
15-20,000	Discrete	0.					
20,000 +	Discrete	0.					
Hydrocarbon Occurrence							
0-5,000 Oil	Discrete	.03					
Gas	Discrete	.12					
Dry	Discrete	.85					
5-10,000 Oil	Discrete	.075					
Gas	Discrete	.075					
Dry	Discrete	.850					
10-15,000 Oil	Discrete	.075					
Gas	Discrete	.075					
Dry	Discrete	.850					
15-20,000 Oil	Discrete	.05					
Gas	Discrete	.10					
Dry	Discrete	.85					
20,000 + Oil	Discrete						
Gas	Discrete						
Dry	Discrete						

Geological Relationships	SPECIFIED VALUE	
	Viscosity	GOR
Gas-Oil Ratio/Viscosity Relationship	.1	4,000.
	.2	2,000.
	.5	800.
	1.0	400.
	4.0	110.
	10.0	50.
	Depth	GLR
Gas-Liquids Ratio/Depth Relationship	0-5,000	0.
	5-10,000	1.
	10-15,000	2.
	15-20,000	3.
	20,000 +	3.

Table A2. Economic variables.

Economic Variables		
Pre exploration Variables	**Estimated Value or Fraction**	**Units**
Geological-Geophysical Fraction of Total Exploratory Costs	0.124	
Geological-Geophysical Capitalized Fraction	0.42	
Lease Payment	2.00	$/Acre
Lease Bonus	0	
Exploration Variables		
Exploratory Drilling Cost		
0-5,000	100.00	$/Foot
5-10,000	130.00	$/Foot
10-15,000	250.00	$/Foot
15-20,000	450.00	$/Foot
20,000 +	650.00	$/Foot
Development Drilling Costs		
0-5,000	163.00	$/Foot
5-10,000	212.00	$/Foot
10-15,000	407.00	$/Foot
15-20,000	733.00	$/Foot
20,000 +	1,059.00	$/Foot
Exploratory Well Success Ratio	0.14	
Development Well Success Ratio	0.65	
Exploratory Well Spacing (Oil and Gas)	2,000.00	Acres
Maximum Success Exploratory Wells	10	Total Wells
Wells Per Pad by Depth	1	Wells/Pad
Development Variables		
Surface Costs (Primary Oil)	761,000	$
Surface Costs (Secondary Oil)	290,000	$
Surface Costs (Primary AD Gas)	820,000	$
Surface Costs (Primary NA Gas)	905,000	$
Reference Capacity (Primary Oil)	703,000	BBL/Yr.
Reference Capacity (Secondary Oil)	124,000	BBL/Yr.
Reference Capacity (Primary AD Gas)	3.65	BCF/Yr.
Reference Capacity (Primary NA Gas)	3.65	BCF/Yr.
Scaling Factor	.70	
Production Variables		
Labor Costs (Primary)	17,250	$/Well/Yr.
Labor Costs (Secondary)	18,600	$/Well/Yr.
General Administrative Expense	0.11	
Gas Conditioning Variable Costs	0.37	
Gas Compression Variable Costs	0.37	$/MCF
Primary Oil Lifting/Treatment Costs	0.06	$/BBL
Secondary Oil Lifting/Treatment Costs	0.09	$/BBL
N.A. Gas Lifting/Conditioning Costs	0.33	$/MCF
Cost for Well Workovers	45,000	$/Work-Over
Rule Determined Costs and Factors		
Income Tax Rate - Federal	0.46	
Income Tax Rate - State	0.0675	
Tax Credit Rate	0.10	
Advalorem Tax Rate - Oil	0.0295	
Advalorem Tax Rate - Gas	0.0295	
Severence Tax Rate - Oil	0.1860	
Severence Tax Rate - Gas	0.1715	
Royalty Rate - Oil		
< 110 (B/Day/Well)	.125	
111-130	.180	
131-150	.190	
151-200	.200	
201-250	.210	
251-300	.220	
301-350	.230	
351-400	.240	
> 400	.250	
Royalty Rate - Gas		
< 5 BCF/Day	.125	
> 5 BCF/Day	.167	
Depreciation Acceleration Factor	1.12	
Tangible Fraction Exploration Costs	0.30	
Tangible Fraction Development Costs	0.30	
Discount Rate	.126	





θ_1 Time period between initiation of exploration and the start of production.
θ_2 Time period between the start of production and peak production.
θ_3 The length of time peak production is maintained.
θ_4 The maximum peak production rate.
θ_5 The exponential decline rate of production: oil equals 20 percent and gas equals 15 percent.

Figure A1. Base run oil and gas production profiles.

Table A3. Petroleum prices.

	Crude Oil 1/			Natural Gas 2/		
Year	Low	Moderate	High	Low	Moderate	High
1982	28.00	28.00	28.00	3.50	3.50	3.50
1987	28.50	37.00	43.00	4.85	5.80	6.27
1990	33.00	45.00	54.00	5.83	7.00	7.58
1992	37.60	51.00	63.70	6.54	7.60	8.00
1994	42.50	57.00	73.20	7.25	8.20	8.42
1997	42.50	57.00	73.20	7.61	8.50	8.63
2002	42.50	57.00	73.20	7.61	8.50	8.63
2007	42.50	57.00	73.20	7.61	8.50	8.63
2012	42.50	57.00	73.20	7.61	8.50	8.63

1/ Crude oil prices reflect acquisition prices less windfall profit taxes.

2/ Natural gas prices reflect averaged delivered.