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THE GULF PROGRAM

AN APPLICATION OF COMPUTER SIMULATION TECHNIQUES TO OUTER CONTINENTAL SHELF LEASE BIDDING

By

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ABSTRACT

The oil industry is placing more emphasis on the use of risk analysis in Outer Continental Shelf lease bidding because of the uncertainty of finding commercial reserves and the high exploration and development costs. One form of risk analysis which is gaining support is Monte Carlo simulation. In the early 1970's, Conoco developed the Gulf Program, an offshore bidding computer model. The Monte Carlo simulation option had several limitations — cash bonus was the only bid variable, cost escalation was not performed, insufficient flexibility existed in development and production scheduling, and the results were not verifiable. To overcome these difficulties, the author developed the Exploration Simulation Program, utilizing the same basic program logic as in the Gulf Program. The new program requires less user time to run and provides more accurate and believable results.

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CHAPTER 1

INTRODUCTION

At the request of Mr. C. A. Norman, Director, Administrative Services and Offshore Bidding, Conoco Inc. (Conoco), a study was made of the Gulf Computer Program, an offshore U.S. economic evaluation model. The Gulf Program was designed to prepare deterministic and probabilistic evaluations of offshore prospects. Project timing, reserve, investment, and price data are inputs into the computer model. The deterministic evaluation option is performed to calculate the cash bonus which may be paid and still earn a specified rate of return. Monte Carlo simulation is another program option. Parameter ranges for timing, reserves, investment, and prices may be chosen according to specified distributions. A bonus probability distribution table is printed for the specified rate of return. Each bonus represents the acquisition price which can be paid to have a certain probability of earning the specified rate of return.

Numerous shortcomings were found in the program. The following list presents the major problems:

1. Cash bonus is the only bid variable which may be used.
2. Investment and operating costs have to be manually escalated before being loaded into the program.

3. Production decline is chosen based upon a program calculated life and the abandonment rate at the start of the project.
4. Project timing cannot be varied as required for many frontier projects.
5. Deterministic results cannot be easily verified.
6. Monte Carlo results cannot be checked. Some cases have been run which appear suspect.

The Exploration Simulation Program was developed to overcome the shortcomings of the Gulf Program. The new program is a comprehensive economics program which may be used in both onshore and offshore applications in the U.S. Because of the number of limitations, the program was completely redesigned. This thesis will be limited in scope to the Monte Carlo simulation option. A brief theoretical framework is presented along with a discussion on the role of simulation in the bidding for offshore oil and gas properties. The limitations of simulation will be emphasized.

The example is based upon real data as interpreted by the author and may or may not represent actual lease evaluation cases of Conoco.

In the following chapters oil industry risk, the Outer Continental Shelf Lands Act, Monte Carlo simulation, data constraints, and the economics of Outer Continental Shelf (OCS) lease bidding will be discussed.

CHAPTER 2

OIL AND GAS EXPLORATION - A RISKY BUSINESS

Petroleum exploration is one of the most risky business ventures. Unlike manufacturing operations, if exploratory efforts fail, a company is left with just a tax loss covering the write-off of leasehold and tangible investment. Little, if any, salvage remains. Yet, considering resource depletion, for a company to remain in business, continuous exploration must be maintained.

In the case of offshore exploration, the high costs make risk analysis essential. Industry officials acknowledge that platform costs can run from a low of $3 million (1982 dollars) for the shallow water areas in the Gulf of Mexico to hundreds of millions of dollars in deep waters or in hostile environments such as Alaska. Drilling costs per well range from around $4 million to over $20 million. Inflation compounds the problem because of the long time delays involved. Considering these high costs, management must have a method which will help evaluate both the economic potential of a prospect and its chance of success. This model must be capable of accounting for uncertainty in both geologic parameter estimation, as well as cost and price forecasting.

Most people who are unfamiliar with the petroleum industry fail to grasp the extent of exploration risk. Few other ventures require investment of tens of millions of dollars up front (excluding bonus) with roughly a 10 percent chance of finding a commercial deposit.

Table 1 presents a summary of the U.S. oil industry cash position for federal OCS lands as of December 31, 1979.

TABLE 1

Summary of Industry Cash Position
December 31, 1979

Value of Production	$ 50 Billion
Expenditures	
Bonus	27 Billion
Royalty and Rentals	8 Billion
Exploration and Development*	$ 24 Billion
Cash Position on December 31, 1979	($ 9 Billion)

*Estimated: Oil and Gas Journal (1979)

Source: U.S.G.S. OCS Statistics

Excluding federal income and windfall profits taxes, the government receipts amount to 66% of the value of production.

Even with the vast improvements in exploratory techniques, little change has occured in exploratory success because today's targets are much deeper and in more complex geologic regions.

Lohrenz (1978b) calculated an aggregate (after tax constant dollar) rate of return for all of the leases offered in the Gulf of Mexico between 1954 and 1969. Production data through 1976 was used and extrapolation was based upon decline. Three cases were calculated: decontrol, middle regulation, and strict price controls. His results indicated a range of from 11.6 percent under decontrol to 7.3 percent under strict price controls. Industry data indicates that this may be optimistic.

Only 135 out of the 1223 tracts leased in the Gulf of Mexico through 1976 earned a 15 percent rate of return. These values indicate the need for management science evaluation techniques. The only thing that has bailed out offshore oil and gas development was the partially unanticipated price increases in 1974 and 1979.

The offshore lease acquisition process involves three stages:

1. Prospect Generation
2. Reserve Valuation
3. Bid Determination.

The first lies within the realm of geology and geophysics. This paper will be limited in scope to the last two.

CHAPTER 3

THE OUTER CONTINENTAL SHELF LANDS ACT

In 1953, Congress initiated the process of leasing lands off the coasts of the United States with the Outer Continental Shelf Lands Act. The Secretary of the Department of Interior was granted the authority to issue leases on tracts of land not exceeding 5760 acres to the highest responsible qualifying bidder (29 U.S. Code, sec. 1337 a.b., 1953). Each tract is offered for a term of five years (in some cases, ten). Leases will be terminated after the primary lease period without approved drilling or production operations (29 U.S. Code, sec. 1337 b., 1953). Auctions are carried out through sealed bids, 20 percent of the bonus being included. Notice of sale and bid terms are published in the Federal Register at least thirty days prior to sale date. The Department of Interior selects tracts of land based upon industry recommendations.

Two forms of bidding were allowed under the 1953 act:

1. Cash Bonus.
2. Royalty Percent.

Bidding cash bonus[1] has been the most commonly used method. The Department of Interior specifies a fixed royalty (12.5 percent or greater) and requires that companies offer the amount of cash bonus they are willing to pay. The second form of bidding, royalty percent bidding, requires that firms pay a minimal cash bonus and bid upon the amount of royalty[2] (minimum 12.5 percent).

Selection of the highest bid is not automatic. The Department of Interior has a mandate to protect the national interest by receiving the "fair market" value for offshore acreage. Presale estimates of value (PSV) are prepared for a percentage of the tracts using simulation. A bid may be rejected if it does not adequately reflect fair value as estimated by the PSV and meet other criteria including competitiveness (Smiley, 1979, pp. 15-6). Rejection is rare if a high number of companies place bids. The Federal government is currently reviewing their policies.

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[1] A bonus is a payment to the owner of the mineral estate for the execution of an oil and gas lease (Hemingway, 1979, pg. 35).

[2] A royalty is a payment made in amount or value based upon the production saved, removed, or sold from a property (U.S. Code, Sec. 1337).

No drilling is allowed prior to the initial sale of a tract. Exploration is limited to geophysical techniques, primarily seismic. Industry-financed seismic programs are common. Information from surrounding leases is also used; industry makes recommendations for future sales based on this information.

In 1979, The Outer Continental Shelf Lands Act was amended to encourage further offshore development and foster competition through alternative bidding methods. The Department of Interior is required to use systems different from the cash bonus with fixed royalty method for at least 20 percent of future bids but not more than 60 percent. The following bidding methods were authorized by the Outer Continental Shelf Lands Act Amendments of 1978 (43 U.S. Code, Sec. 1337, 1979):

1. Cash bonus with fixed royalty.
2. Royalty percent with fixed bonus or work commitment.
3. Cash bonus or work commitment with fixed sliding scale royalty.
4. Cash bonus with fixed net profit share.
5. Net profit share with fixed cash bonus.
6. Cash bonus with fixed royalty and net profit share.
7. Work commitment with fixed cash bonus and royalty.

The Secretary of the Department of the Interior has the option of utilizing any or all of the above methods (Watt, 1981). Net profits share and work commitment may eventually be removed from consideration as bid variables (Federal Register, 1983).

Two new methods of payment were initiated by the 1978 amendments: net profit share and work commitment. Net profit share tax calculations require a new accounting system. Exploration, development, and operating costs are broken into four categories (Federal Register, 1980):

1. Allowance for Capital Recovery (ACR) and Overhead Qualifying
2. Allowance for Capital Recovery only Qualifying
3. Non Qualifying
4. Unallowable.

The reader is referred to the preceding reference for a cost classification schedule. The first three are treated as debits to the profit share capital account[3]. A capital recovery factor[4] is applied to the ACR and Overhead Qualifying costs, making it possible to deduct greater than 100 percent of these expenses up until the time that monthly revenues exceed monthly qualifying expenses, plus an additional 4 percent of the overhead qualifying expenses. The firm is then limited to a 10 percent allowance for the ACR and overhead qualifying costs. Net profit share taxes are paid after the net profit share capital account achieves payout (this tax is in addition to federal income taxes). These three cases are illustrated in Table 2.[5]

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[3]The net profit share capital account is charged with specific expenses incurred during exploration and development activity (Federal Register, 1980).

[4]The capital recovery factor is a mechanism to provide the lessee a return on the capital invested at risk in exploration and development (Federal Register, 1980, pg. 36787).

[5]A thirty percent capital recovery factor is used.

TABLE 2
Net Profit Share Calculations

Case 1 -- Capital Recovery Period

	Debits				Credits
	ACR and overhead Qualifying	ACR - only Qualifying	Non Qualifying	Total	Revenue
Direct and allowable joint costs:					
	$12,000	$5,000	$ 500	$ 17,500	
Overhead (4% x $12,000):					
		480		480	
Allowance for capital recovery (12,000 + 5000 + 480)x .30:					
			5,244	5,244	
Totals	$12,000	$5,480	$ 5,744	$ 23,224	
Balance forward				$ 23,224	

Case 2 — Closed Capital Account

	Debits				Credits
	ACR and overhead Qualifying	ACR - only Qualifying	Non Qualifying	Total	Revenue
Balance forward:				$ 23,224	
Direct and allowable joint costs:					
	$5,000		3,300[6]	8,300	10,000
Overhead (10% x $5,000):			500	500	
Totals	$5,000		$ 3,800	$ 32,024	$ 10,000
Balance forward				$ 22,024	

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[6]If the capital account was not closed in this month, a negative allowance for capital recovery would occur ($-510 = ($5000 + 3,000 + 300 - 10,000) x .30)). Since no capital recovery account will be used from this time on, ACR only qualifying costs are included with the non-qualifying costs.

Case 3 — Profit Share Period

	Debits				Credits
	ACR and overhead Qualifying	ACR - only Qualifying	Non Qualifying	Total	Revenue
Balance forward:				$ 22,024	
Direct and allowable joint costs:					
	$4,000		$ 2,500	6,500	$ 40,000
Overhead (10% x $4,000):					
			400	400	
Totals	$4,000		$ 2,900	$ 28,924	$ 40,000
Balance before profit share					11,076
Profit share					
U.S. Government + (50%)				5,538	
Lessee (50%)				5,538	
Totals				$ 11,076	$ 11,076
Balance forward					0

The last bid payment method, work commitment, was proposed to encourage exploration. Exploratory expenses are classified into two groups: allowable and unallowable expenditures (Federal Register, 1981a). Post-lease acquisitions, geological investigation costs (i.e., seismic surveys and exploratory drilling), are considered allowable expenses. These costs are deflated using the Oil Field Machinery and Tools, Commodity Code No. 1191 Producer Price Index. The federal government will reimburse 50 percent of constant dollar exploration costs up until the time property development begins or the entire amount of the bid has been refunded. The non-refunded portion of the bid is added to the leasehold account and either cost depleted or expensed at the time of surrender.

Under this act, over 6,729 tracts have been offered through 1975, 3,061 have received bids, and 2,705 were actually leased, for a high-bid total of almost $16 billion (Smiley, 1979, p. 7). The tracts averaged just over three bids each; most tracts received less than three bids. The largest bonuses appear to be correlated with the tracts receiving the most bids. Information, by tract, on the bids made by each company is maintained by the Bureau of Land Management (Statistical Summary of OCS Bidding).

The Gulf Program could only handle a variable bonus bid with a fixed royalty. Each of the bidding systems discussed in this chapter have been included in the Exploration Simulation Program. Bonus, royalty, net profits share, and work commitment may assume either a fixed value or may be calculated.

CHAPTER 4

SIMULATION - REAL WORLD APPLICATIONS

Monte Carlo Simulation is a useful means of estimating the net expected monetary value of an oil and gas property. This method considers the exploration risk and uncertainty involved in the estimation of reservoir and financial parameters (Kleijnen 1974; Newendorp, 1975). The Monte Carlo method involves the use of random or pseudorandom numbers in problem solving. A practical application of Monte Carlo simulation to oil and gas property valuation will be discussed in this chapter.

The Exploration Simulation Program model may be subdivided into three sections:

1. Reserve Calculation
2. Tract Development
3. Economic Evaluation.

Reserve Calculation

The first step in tract net monetary value calculation is to estimate recoverable reserves. The volumetric method of reserve calculation is the only one applicable in exploration decision making. Appendix A provides volumetric equations for three types of reservoirs: oil, associated gas, nonassociated gas.

In many instances, it may be beneficial to reduce the model to simply

$$\text{Recoverable Reserves} = \text{Net pay} \times \text{Reservoir Area} \times \text{Recovery.} \qquad (4.1)$$

Outer Continental Shelf data quality tends to be poor. Difficulties exist in quantifying distribution types and their parameters. Monte Carlo simulation may exacerbate geologic estimation error if too many parameters are used. Lack of parameter independence may also introduce error. Most importantly, management tends to use only results they understand, too many variables may cause confusion while adding little to the accuracy of the model.

Tract Development

Development investment (platforms, wells, and other producing facilities) has a significant impact on tract net monetary value. A computer simulation model must be capable of optimizing the number of completions, wells, and platforms. Development timing is an important consideration. Flexibility is essential at this stage; no one development method can be utilized in every situation.

The number of completions for a productive zone is a function of reserves, decline, and production life, using the following relation.

Number of Completions

= Reserves / Reserves per well (4.2)

= Reserves / f (decline, life, reserves)

Appendix B contains the equations for calculating the number of completions per zone using exponential and hyperbolic decline.

Tract development may proceed in several ways. A template may be set. Development drilling will proceed one well at a time until the platform can be installed. Once the platform is in place, the initial wells are commonly completed before drilling resumes. In other cases, the platform may be set before any drilling occurs. If several platforms are necessary, they may be drilled simultaneously, consecutively, or on a staggered basis depending upon the reserves, platform availability, corporate goals, and economics.

Optimal well and platform selection involves maximizing net monetary value subject to the following constraints:

1. Maximum number of completions.
2. Limits on which zones can be completed together.
3. Maximum number of wells per platform.
4. Maximum number of platforms.

With the exception of a net profit share bid, the problem can be simplified by developing the most prolific zones first and maximizing the number of completions per well. Net profit share economics dictates that each platform come on production at approximately the same time. This demonstrates that the net profits share system is a disincentive to efficient operation. Three principal tables must be considered in determining the most economic development scheme.

1. Platform Cost
2. Platform Construction Time
3. Development Drilling Time

Optimality may be determined by varying the number of platforms. Initially, the minimum number of platforms required to develop the tract is used. The number is increased until net monetary value decreases.

Platform costs vary only slightly with the number of slots. For example, an eighteen slot platform costs roughly ten percent more than an eight slot platform.

Economic Evaluation

The final step involves calculating the net monetary value of a tract using a given set of parameter values. An unrisked bid may be determined using the results. The following is a list of common economic calculations which should be considered in the order in which they would normally be performed (ref. Appendix C):

1. Leasehold Cost
2. Exploratory Well Costs
3. Template Investment
4. Initial Development Well Costs
5. Platform and Production Facility Investment
6. Final Development Well Costs
7. Annual Production
8. Revenue, Net Royalty and Severence Taxes
9. Operating Costs
10. Federal Income Tax
11. Net Profit Share
12. Work Commitment
13. Net Cash Flow
14. Net Present Value/Rate of Return

15. Condemnation Costs[1]
16. Bid Variable.

Exploration and development decisions must be considered separately. The Production Department, which oversees development, looks at investment decisions from a different perspective. Exploration costs are treated as sunk when tract development decisions are made. The following two rules should serve as guidelines for field development and abandonment:

1. Development may be postponed if discounted development costs exceed discounted operating gain (the minimum rate of return may vary between the exploration and production department).
2. Wells will usually be shut-in when operating gain approaches zero (net revenue less lifting costs).

It must be emphasized that escalated dollar monetary values should never be used in conjunction with constant dollar monetary values.

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[1] Condemnation costs are the costs associated with a non-productive tract. They are expensed in the year incurred with the exception of leasehold costs which are expensed when the lease is released.

Bid variable determination is the most crucial economic calculation. Cash bonus is currently the most common bid payment. The net monetary value of a tract will be paid out in the form of a bonus. Since bonus is amortized by cost depletion, an iterative process is required to calculate the maximum bonus. Net profits share is calculated using an iterative process as well. Once the time of initial tax payment is determined, the tax rate is varied to equate discounted cash flows to zero. Work commitment calculation is similar to that of bonus. An iterative process is required to drive the incremental depletion benefit to zero. Royalty affects property development economics and must be calculated iteratively.

Monte Carlo Simulation

Determining maximum bid value at specified rates of return is the desired result of all the economic calculations. More complete information may be gathered by varying the many parameters and recalculating values for the bid variable. Three hundred iterations provides sufficient information to qualify the probability of achieving a specific rate of return with any given bid.

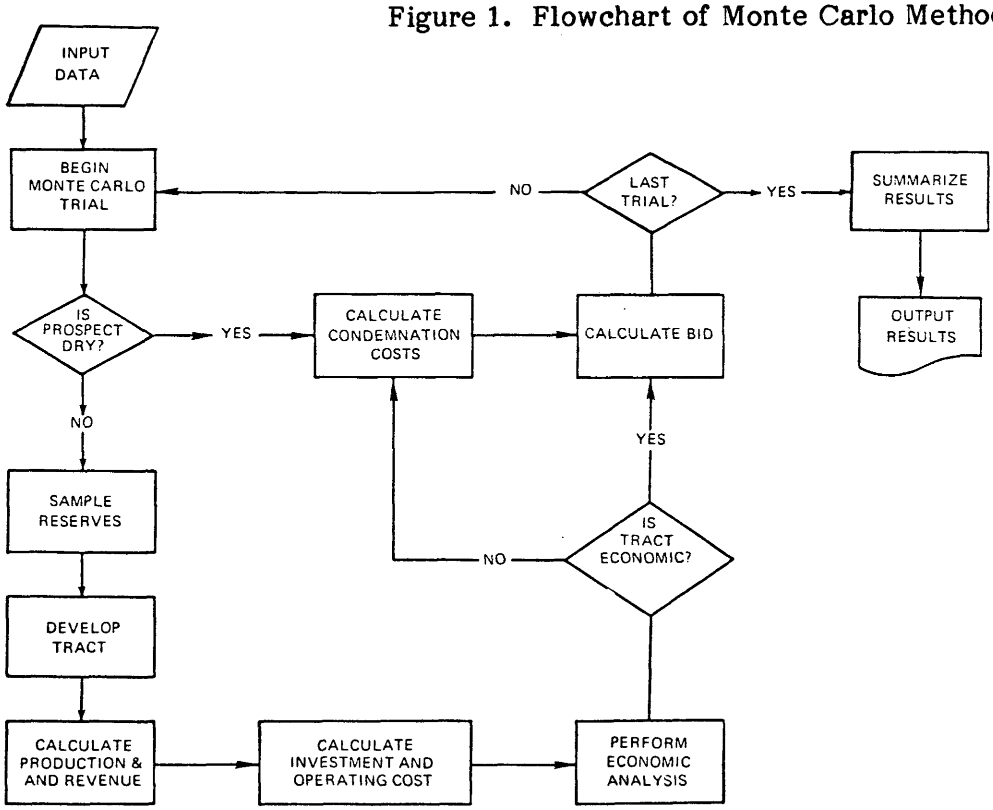
Monte Carlo simulation involves a process of repetitively sampling values for various economic parameters, calculating net monetary value using the specified model, and statistically summarizing the results. Variables may be assigned a specific probability distribution, be fixed, or be calculated.

Smith (1970, p. 545) outlines the Monte Carlo simulation process as follows:

1. A random number is generated on the interval 0 to 1 (Naylor et. al., 1966).
2. A value for one of the probabilistic variables is chosen.
3. Steps 1 and 2 are repeated until all probabilistic variables have been assigned values.
4. Mathematical calculations are performed.
5. Steps 1 through 4 are repeated a specific number of times.
6. Results are summarized using conventional statistical methods.

Appendix D presents probability distributions used in exploration simulation. The inverse transformation method of assigning values to a probabilistic variable is presented in Appendix E. A flow chart of the Monte Carlo method is presented in Figure 1.

Figure 1. Flowchart of Monte Carlo Method.



Bid Determination

Economic analysis is one of many tools used in bid determination. Management reviews the geologic, geophysical, and engineering data, assessing its quality. Experience is the primary tool used in bid selection. The successful management possesses the ability to estimate recoverable reserves and assess risk. This risk is based upon management's opinion of the quality of the scientific data. Another important consideration is the evaluation partners make on each tract. Economic analysis is primarily used for bid justification.

Sensitivity analysis indicates that reserves, initial investment, production rates, project timing, and prices are the primary determinants of risk adjusted bid values. Other parameters are insignificant if risk is assumed to be moderate to high. The long offshore development lead times (3 to 10 years) causes discounting to minimize the effects of other parameters. Management is, therefore, primarily concerned with the reserve, investment, and timing estimates.

After the data is reviewed by management, initial bid ranges are established. Potential partners may be brought into the discussion.

Security is extremely tight; the number of people involved in bid discussion is held to a minimum. Bid ranges are narrowed as the sale date approaches; the bid may not be decided upon until the day of the sale. Geologic data, economic data, availability of funds, and experience are all used to determine bid values.

Applicability

Three requirements must be met before Monte Carlo simulation will be accepted by management and used in decision making:

1. Flexibility
2. Simplicity
3. Comprehensibility.

Because of regional variation in data quality and the associated uncertainty, the economist must have the capability of varying parameter probability distributions. The 1978 amendments to the Outer Continental Shelf Lands Act mandates the use of alternative bidding methods; therefore flexibility must exist in the choice of bidding methods. The last two acceptance criteria are related. The number of parameters should be held to a minimum; a model with fewer variables is easier to understand. Results will not be believed, or used, if the model does not make sense. The model must be logical even to a non-technical person. Dependency relationships between variables can cause difficulties (Newendorp 1975, pp. 405-31). Model design should minimize the number of interrelated variables if the program is to receive wide application. Any model, no matter how accurate, will never be used if it is so complex that management cannot understand the results or if it is not easily adapted to handle a variety of corporate needs.

Input/Output Format

The input and output formats should receive the bulk of the attention. Simplicity is essential because the busy manager does not have time to wade through stacks of computer printout looking for a tract's net expected monetary value. It must be remembered that the manager in charge of bidding is deluged with information during the month preceding a sale. A decision maker will likely rely on the proverbial "seat-of-pants" method of property valuation if a concise summary is not presented. Graphical, in addition to tabular, data presentations are valuable. The following elements could be included in the output:

1. Model Description.
2. Distribution of Estimated Reserves.
3. Frequency Plot of Bid Value.
4. Tabular Distribution Summary.

Monte Carlo simulation, if presented properly, can provide better information and aid in the bidding process. Ranges are presented for net expected monetary value. Project ranking is facilitated by the additional information.

Data Quality

Geology is a science of uncertainty. Little information is available in wildcat areas and the data that does exist is subject to a high degree of uncertainty. Two primary data sources are at the disposal of the geologist: geophysics (primarily seismic) and well data. The experienced geologist uses this data to reconstruct a region's depositional history. Four factors are reviewed in the evaluation process: source rock, reservoir rock, reservoir trap and migration. As paleoenvironments are reconstructed, the geologist delineates prospects which he feels have greater hydrocarbon potential. It must be remembered that perfect information exists only in fairyland — never in the oil patch. The role of the geologist is analagous to that of a person whose job depends upon assembling and identifying a 1000-piece puzzle with less than 50 pieces; a great deal of subjectivity is involved.

Table 3 presents several geological tools and the reservoir parameters which may be estimated using them.

TABLE 3
Geological Tools and their Applications

Tool	Application
Seismic	Reservoir Extent Reservoir Thickness Structure
Logs	Porosity Reservoir Thickness Water Saturation Structure Lithology Oil/Gas Pay Zones
Core	Oil/Gas Permeability Porosity Water Saturation Source Rocks Depositional History Lithology
Drill Stem Test	Initial Potential Flow Rates Reservoir Pressure Data

All geologists interpret the data in a different manner; individual experience and bias are the primary factors influencing these interpretations. Quantifying the uncertainty is a goal of the experienced geologist. A 90 percent confidence interval would be desirable; however, this is a difficult task in rank wildcat areas.

The use of probability distributions instead of point estimates provides the best available information for management decision making.

Uncertainty can be best quantified if a range of possible parameter values is provided. Management can then evaluate both downside risk and upside potential when making an investment decision. Subjectivity should not be as great a problem as with the point estimate because more thought and study are required for distribution preparation. Simulation provides management a bid variable frequency distribution for a desired rate of return. The actual bid value depends upon management's view of the data quality, available funds, other prospects, risk, corporate strategy, and partners' evaluations. Economics provides management one more tool to help arrive at a bid decision.

CHAPTER 5

PROGRAM APPLICATIONS

The sample case in Appendix F was developed to demonstrate the differences between the Gulf Program and the Exploration Simulation Program in handling an unconventional case. Maximum bid values to earn a 10 percent rate of return are presented for both programs in Figure 2 and Table 4.

Table 4 presents the maximum bid which can be made to have the indicated probability of earning a ten percent rate of return (ROR) given the economic assumptions of the model. For example, if a 60 percent probability of earning a ten percent ROR is desired, a $65 million bid may be made. It can be seen that the approximations used in the Gulf Program result in an overbid of from 16 to 38 percent. The actual bid which Conoco makes may vary from the simulated results depending upon management's opinion of the data quality, available funds, corporate strategy, and partner's evaluations.

TABLE 4

Bonus For Ten Percent Rate of Return
(Million Dollars)

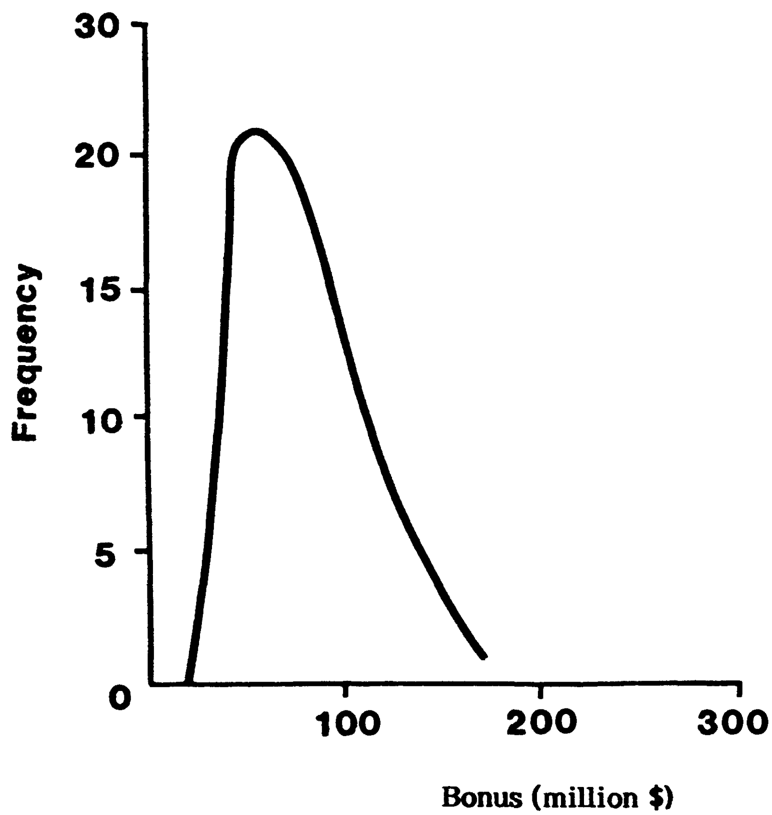
Probability of Earning ROR	Gulf Program	Exploration Simulation Program	Gulf Program Overbid (Percent)
+0	239	173	38
20	136	107	27
40	98	84	17
60	80	65	23
80	58	50	16
99	28	22	27

The following criteria served as the basis of comparison between the two programs:

1. Result Accuracy
2. Computer Cost
3. User Cost
4. Ease of Application
5. Solution Time.

BONUS FREQUENCY DISTRIBUTION-REVISED PROGRAM

(10 percent ROR)



NOTE: FIFTY PERCENT OF THE TIME THE TRACT WAS DRY

FIGURE 2.

Result Accuracy

Limitations of the Gulf Program result in less accurate results (Table 4) than the Exploration Simulation Program. Appendix G shows the percent error in the bid values calculated by the Exploration Simulation Program. Three hundred productive iterations are performed. The percent error for this number of iterations varies from 0.3 to 0.7 percent, which is insignificant.

Five deficiencies in the Gulf Program can be cited:

1. Inability to treat exploratory investment timing as a random variable.
2. Inability to treat development timing or investment costs as uniformly distributed variables. A triangular distribution is always assigned to these variables.
3. Difficulty using a lognormal distribution to approximate reserves.
4. Distributions are totally dependent upon a previously entered deterministic economic evaluation case.
5. Inability to handle alternative bid methods.

The following approximations were necessary to adapt the problem to the Gulf Program:

1. The initial exploratory timing was assigned the expected value (18 months) and treated as deterministic.
2. Platform construction delay had to be assigned a triangular distribution with the same minimum and maximum values instead of a uniform distribution.
3. The expected investment was escalated manually and loaded by year as supplemental investment for the deterministic low, middle, and high case reserve levels used in another program option (Table 5). Only dry hole cost was calculated by the program. Development dry holes were assumed to be drilled last and escalated using the 1988 inflation factor. The 1985 escalation factor was used for exploratory dry holes. It cannot be determined if investment was varied based upon the level of rserves simulated.
4. A fifty percent dry risk probability was assigned to each horizon instead of to the tract. The prospect was uneconomic 50.3 percent of the time instead of 50 percent at a ten percent rate of return.
5. A lognormal distribution was fit to the three deterministic reserve levels, 13.2, 21.1, and 33.0 million barrels, used in another option. The program assumed that there was a ninety-five percent probability of discovering 13.2 million barrels, a

fifty percent probability of discovering 21.1 million barrels, and a five percent probability of finding 33.0 million barrels.

6. The number of completions and the production schedule was optimized by the program using the total reserves, the initial flow rate, the recovery before decline, and the calculated 1983 abandonment rate. Production life or decline rate cannot be assigned.

7. The fixed net profits share was approximated using a variable royalty. The program was first run using the expected reserve level and zero royalty fraction. It was determined that the net profits share would be paid starting in 1991 (Case 1 prices were assumed). Table 6 presents the variable royalty interest used to approximate the net profits share. It was calculated using annual investment, operating costs, and revenue data from the initial run.

The Exploration Simulation Program was able to perform Monte Carlo simulation without making any adjustments.

It should be noted that the results of the two programs are not significantly different for cases in which the data does not require manipulation to be run on the Gulf Program.

TABLE 5

Supplemental Investment - Gulf Program

(Million Dollars)

	Oil Reserves (Million Barrels)					
	13.2		21.1		33.0	
Year	Tangible	Intangible	Tangible	Intangible	Tangible	Intangible
1985	25,735	6,204	25,735	6,204	25,735	6,204
1986	6,434	12,408	6,434	12,408	6,434	12,408
1987	26,328	38,918	27,738	38,716	40,388	38,682
1988	15,973	9,050	28,213	18,036	50,339	35,686

Note: Supplemental investment includes producing well, platform, production facility, and pipeline investment for the stated reserve levels inflated at 6 percent.

TABLE 6

Net Profits Share Approximation

Gulf Program

(Million Dollars)

Year	Revenue	Operating Costs	Dry Hole Cost	Investment	Royalty Fraction
1984			25,002	37,503	0.0000
1985			12,501	31,939	0.0000
1986				18,842	0.0000
1987				65,512	0.0000
1988	176,464	700		53,285	0.0000
1989	230,630	700			0.0000
1990	189,151	1,643			0.2942
1991	322,238	1,643			0.4972
1992	167,960	1,643			0.4946
1993	67,983	1,643			0.4867
1994	27,519	1,643			0.4672
1995	10,905	1,441			0.4273
1996	4,026	943			0.3712
1997-end of life	1,327	687			0.2153

Cost

A total cost breakdoen of both programs is presented in Table 7.

TABLE 7

Program Cost

	Gulf Program	Exploration Simulation Program
Computer Use Fee	$ 24	$ 37[1]
User Time, Hours	8	2
User Cost[2]	200	50
Total Cost	$ 224	$ 87

[1]If no iteration recap is requested, the cost is $20.

[2]Based upon a salary including fringe benefits of $25 per hour.

Even though the Gulf Program requires less computer time to run, more man-hours are needed to prepare the data, causing the program to be more expensive than the Exploration Simulation Program. When conventional cases are run, the total cost drops to around $100 for the Gulf Program and $30 for the Exploration Simulation Program.

Ease of Application

The inability to handle new bidding systems and the required approximations make the Gulf Program difficult to use. The Monte Carlo simulation routine was designed under different economic conditions. The new program, though requiring a greater degree of sophistication on the user's part, is easier to apply once mastered. All input is straight forward. The user has a greater degree of flexibility in economic modeling.

Solution Time

The increased flexibility and increased number of input parameters reduces the required user time. More projects can be run in the same amount of time. The user no longer has to try to adapt an economic model to the computer program. The new program was designed to handle all foreseen cases. This decreased user time results in an increased cost effectiveness.

The Exploration Simulation Program has been used to evaluate four federal and state offshore lease sales. Conoco acquired 69 leases for $130 million net to Conoco at these sales.

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APPENDIX A

VOLUMETRIC EQUATIONS BY RESERVOIR TYPE

Oil Reservoir:

$$STBO = \frac{7758 \cdot h \cdot A \cdot \phi \cdot (1-Sw) \cdot RFo}{B_{oi}} \quad (A1)$$

Associated Gas Reservoir:

$$SCFG = STBOP \cdot GOR \cdot RF_g \quad (A2)$$

Nonassociated Gas Reservoir:

$$SCFG = 43.56 \cdot h \cdot A \cdot \phi \cdot (1-S_W) \cdot \frac{P_R}{14.7} \cdot \frac{520}{T_R} \cdot \frac{1}{Z} \cdot RF_G \quad (A3)$$

Where:

7758	=	Barrels per acre foot
43.56	=	Cubic feet per acre foot
STBO	=	Recoverable stock tank barrels of oil
h	=	Net pay thickness, feet
A	=	Productive area, acres
ϕ	=	Porosity, as a decimal fraction
Sw	=	Connate water saturation, as a decimal fraction
RF_o	=	Recovery factor, oil (primary depletion)
Boi	=	Oil formation volume factor
SCFG	=	Recoverable standard cubic feet
STBOP	=	Stock gas tank barrels of oil in place
GOR	=	Gas-oil ratio, SCF per barrel
RF_G	=	Recovery factor, gas
P_R	=	Original bottom hole pressure, psia (psia = psig + 14.7)

T_R = Reservoir temperature, ^{o}Rankin (^{o}Rankin = ^{o}F + 460)

Z = Gas compressibility factor

APPENDIX B

ZONE COMPLETION CALCULATION BY DECLINE TYPE

$$\text{Number of Completions} = \frac{\text{Reserves}}{\int_0^a IP \cdot dt + \int_a^L q_t \cdot dt} \quad \text{(B1)}$$

$$= \frac{\text{Reserves}}{F^{-1}(q_t)}$$

where

IP = Initial production rate, MBO/yr or BCF/yr

q_t = Production in period t, in MBO or BSCF

L = Production life, years

$R_{\%}$ = Percent reserves produced prior to decline, as a decimal function

$F^{-1}(q_t)$ = Inverse transformation of production function

a = Production life prior to decline, years

$$a = \frac{F^{-1}(q_L)}{IP} \cdot R_{\%} \quad \text{(B2)}$$

Exponential Decline

$$F^{-1}(q_t) = IP \cdot t \qquad \text{for } t < a \quad \text{(B3)}$$

$$F^{-1}(q_t) = IP \cdot a + \frac{IP}{d}\left[1 - e^{-d(t-a)}\right] \qquad \text{for } t > a \quad \text{(B4)}$$

$$F^{-1}(q_L) = IP \cdot a + \frac{IP}{d}\left[1 - e^{-d(L-a)}\right] \quad \text{(B5)}$$

a is calculated iteratively using the equation:

$$a = \frac{e^{dL} - e^{da}}{d \cdot \frac{1-R\%}{R\%} \cdot e^{dL}} \tag{B6}$$

$$\text{Completions} = \frac{\text{Reserves}}{IP \cdot a + \frac{IP}{d}\left[1 - e^{-d(L-a)}\right]} \tag{B7}$$

Hyperbolic Decline

$$F^{-1}(q_t) = IP \cdot t \qquad \text{for } t \leq a \tag{B8}$$

$$F^{-1}(q_t) = IP \cdot a + \frac{IP}{di\,(n-1)}\left[\left[1 + ndi\,(t-a)\right]^{\frac{n-1}{n}} - 1\right] \qquad \text{for } t > a \tag{B9}$$

$$F^{-1}(q_L) = IP \cdot a + \frac{IP}{di\,(n-1)}\left[\left[1 + ndi\,(L-a)\right]^{\frac{n-1}{n}} - 1\right] \tag{B10}$$

a is calculated iteratively using the equation:

$$a = \frac{\left[\left[1 + ndi\,(L-a)\right]^{\frac{n-1}{n}} - 1\right]}{di\,(n-1)\left[\frac{1-R\%}{R\%}\right]} \tag{B11}$$

$$\text{Completions} = \frac{\text{Reserves}}{IP \cdot a + \dfrac{IP}{di\,(n-1)}\left[\left[1 + ndi\,(L - a)\right]^{\frac{(n-1)}{n}} - 1\right]} \tag{B12}$$

where Z = Decline, barrels per year

d = Annual decline rate, as a decimal fraction

di = Initial annual decline rate, as a decimal fraction

n = Exponent

Use a = ($R_{\%} \cdot$ Reserves) as an initialization value.

APPENDIX C

ECONOMIC CALCULATIONS

Leasehold costs	= $A_n + C$
Well cost	= $I_n + T_n$
Annual production	= f (decline, production limit during platform development, initial production rate)
Revenue, net	= $P \cdot Q_n$
Operating Cost, net	= Net cost interest · f (production, number of wells, number of platforms)
Federal Income tax	= FIT Rate $\cdot (R_n - DPR_n - DP_n - I_n - OC_n) - ITC_n$
Work commitment	= $.5 \cdot E_c$
Net Cash Flow	= $R_n - OC_n - I_n - T_n$ - FIT - NPST + WC

Where

A_n	=	Net lease acquisition price
C	=	Contra[1]
I_n	=	Net intangible investment
T_n	=	Net tangible investment
P	=	Net product price
Q_n	=	Net production
FIT	=	Federal income tax
R_n	=	Net revenue
DPR_n	=	Net depreciation
DP_n	=	Net depletion

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[1]Contra is the capitalized portion of geophysical (seismic) and administrative costs which can be assigned to the tract.

OC_n	=	Net operating costs
ITC_n	=	Net Investment tax credit
NPST	=	Net profit share tax
WC	=	Work commitment reimbursements
E_c	=	Qualifying exploratory cost

APPENDIX D

PROBABILITY DISTRIBUTIONS

The following continuous distributions are commonly used in oil and gas property evaluation:

1. Uniform
2. Triangular
3. Lognormal

This appendix is devoted to a mathematical presentation of the above distributions. The reader is referred to Newendorp (1975), Hogg and Tanis (1977), Parson (1974), and Naylor et al. (1966) for detailed presentations. Table 3 gives the probability density function (pdf) and cumulative probability distributions for these distributions.

The applications and limitations of each distribution are summarized in Table 4.

TABLE 8

PROBABILITY DENSITY FUNCTIONS AND CUMULATIVE PROBABILITY DISTRIBUTIONS, OF SELECTED PROBABILITY DISTRIBUTIONS

Distribution	Probability Density Function	Cumulative Probability Distribution
Uniform	$P(X) = \frac{1}{c-a}$ for $a \leq x \leq c$ $= 0$ for $x < a$ or $x > c$	$F(X) = \frac{x-a}{b-a}$
Triangular	$P(X) = \frac{2(x-a)}{(b-a)(c-a)}$ $x \leq b$ $= \frac{2(c-x)}{(c-b)(c-a)}$ $x > b$	$F(X) = \frac{(x-a)^2}{(c-a)(b-a)}$ for $x \leq b$ $= \frac{(c-x)^2}{(c-b)(c-a)}$ for $x > b$
Lognormal	$P(Y) = 2V(Y)^{-\frac{1}{2}} \exp\left[-\frac{1}{2}\frac{(y-E(Y))^2}{V(Y)}\right]$	$F(z) = \int_{-\infty}^{z} (2\pi)^{-\frac{1}{2}} e^{-w^2/2}\, dw$ or $F(X) = \int_{-\infty}^{\ln x} \left[2\pi V(Y)\right]^{-\frac{1}{2}} \exp\left[-\frac{1}{2}\frac{(y-E(Y))^2}{V(Y)}\right] dy$

Where x	=	random variable
a	=	minimum value of x
b	=	most likely value of x
c	=	maximum value of x
z	=	standard lognormal z statistic
w	=	lognormal z statistic for $X = x$

The lognormal transformation is $y = \ln x$, where X is lognormally distributed and Y is normally distributed. The standard lognormal variate z statistic is defined as

$$z = \frac{\ln x - E(Y)}{V(Y)^{\frac{1}{2}}} \quad \text{and } w = z$$

TABLE 9

APPLICATION AND ASSUMPTIONS

OF SEVERAL COMMONLY USED PROBABILITY DISTRIBUTIONS

Distribution	Application	Assumptions
Uniform	1. Verify randomness 2. Express uncertainty when only minimum and maximum values can be specified.	Each value of the random variable is equally likely to occur.
Triangular	Express uncertainty when minimum, most likely, and maximum values can be specified.	----------------------
Lognormal	Almost all geologic variables are distributed lognormally i.e., bed thickness, core permeability, oil recovery, and reserves per field in a sedimentary basin (Newendorp, 1975, p. 267).	The mean and variance of the distribution can be specified. These statistics may be calculated from a scatter diagram using lognormal probability paper.

APPENDIX E

VARIATE GENERATION FROM PROBABILITY DISTRIBUTIONS

The inverse transformation method (Naylor et al., 1966) will be used to assign values to probabilistic variables. A variable x can be sampled from its cumulative probability distribution F(x) by using the inverse function $F^{-1}(x)$ and a random number r. Kleijnen (1974) observes the following relationship:

$$x = F^{-1}(r). \tag{E1}$$

From this it follows that

$$r = F(X) = \int_{-\infty}^{X} f(x)\, dx. \tag{E2}$$

Furthermore,

$$p(x < X) = P\left[F^{-1}(r) < X\right] = P\left[r < F(x)\right] = F(X) \tag{E3}$$

Table 5 presents the inverse functions for the uniform, triangular, and lognormal distributions.

TABLE 10

INVERSE FUNCTIONS

UNIFORM, TRIANGULAR, AND LOGNORMAL DISTRIBUTIONS

Distribution	Inverse Function		
Uniform	$x = a + (b-a)\,r$	for $0 < r \leq 1$	(E4)
Triangular	$x = a + r\,(c-a)\,(b-a)^{\frac{1}{2}}$	for $r \leq \frac{2}{c-a}$	(E5)
	$x = c - (1-r)\,(c-b)\,(c-a)^{\frac{1}{2}}$	for $\frac{2}{c-a} < r \leq 1$	(E6)
Lognormal	$x = \exp\left[E(Y) + [V(Y)\,K/12]^{-\frac{1}{2}} \left[\sum_{i=1}^{k} r_i - \frac{K}{2}\right]\right]$		(E7)

The inverse function is developed using the Central Limit Theorem (Naylor et al., 1966, pp. 92-95, 101), where r is a uniformly distributed random variable on the interval [0,1] and K is usually assigned a value of 12.

APPENDIX F

SAMPLE CASE

(All Costs in 1982 Dollars)

Sale Location	Gulf of Mexico
Sale Date	1-1-83
Water Depth, Feet	800
Bid	Cash Bonus with Fixed Net Profits Share
Federal Tax Rate, Percent	50
Royalty	None
Net Profits Share, Percent	40
Capital Recovery Factor, Percent	100
First Exploratory Well[1]	Min: 1-1-84, Max 1-1-85
Platform Construction Delay, Months[1]	Min: 30, Max. 45
Product Sale Date	Upon Completion of Platform Development
Seismic Cost, M-$	100
Rental, $/acre/yr.	3
Operating Costs/compl, M-$[2]	Min: 54, Mode: 65, Max: 70
Cost Inflation, Annual Percent	6
Dry Risk, Percent	50

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[1] A uniform distribution is assumed.

[2] A triangular distribution is assumed.

PRICES

	Case 1	Case 2
Probability, Percent	50	50
Oil (Tier 3)		
1983 Price, $/barrel	33.00	33.00
Price Escalation, Percent	6	6 through 1988 8 after 1988
Windfall profits tax	kept	phased out
Gas (Section 102)		
1983 Price, $/MCF	3.00	3.00
Price Escalation, Percent	10 through 1985 Equilibrate to 85% oil price in 1986 7% after equilibration	10% through 1985 7% after 1985

RESERVE DATA

Zone	Probability	Thickness[3] (feet)	Area[4] (acres)	Oil[4] Recovery (STB/acre ft)	GOR[4] (SEF/BBL)
7,000 ft.	16%	20			
	50%	32			
	84%	49	660	500	800
11,450 ft.	16%	20			
	50%	33	660	500	800
	84%	50			

*Deterministic Variables

PRODUCTION DATA

Zone	Completion Type	IP[5] (BOP)	Recovery Before Decline (%)	Decline Rate (%)	Life (Years)
7,000 ft.	Single	Min: 800 Mode: 1,000 Max: 1,000	50	22	18
14,450 ft.	Single	Min: 800 Mode: 1,000 Max: 1,000	50	22	18

---

3 A lognormal distribution is assumed.

4 Deterministic variables.

5 A triangular distribution is assumed.

EXPLORATORY AND DEVELOPMENT DATA

	Low Reserve	High Reserve
Exploratory Wells	3	3
Exploratory (P&A)	3	3
Depth, feet	15,000	15,000
Maximum Platforms	2	2
Maximum Wells/Platforms	40	40
Development Dry Holes	1	1

INVESTMENT [6]

($MM)

	Tangible			Intangible		
	Min.	Mode	Max.	Min.	Mode	Max
Exploratory Well P&A (15,000 ft)	1.26	1.40	1.54	9.36	10.40	11.44
Development Well P&A (15,000 ft)	1.17	1.30	1.43	3.96	4.40	4.84
Development Well (7,000 ft)	1.17	1.30	1.43	2.70	3.00	3.30
Development Well (14,500 ft)	1.80	2.00	2.20	3.24	3.60	3.96
Platform (Investment made over a 2.5 year period)	25.77	28.63	31.49	33.13	36.81	40.49
Production Facilities	16.00	25.00	55.0	0.00	0.00	0.00
Pipeline	4.50	5.00	5.50	0.00	0.00	0.00

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6 Investment is assumed to follow a triangular distribution.

APPENDIX G

EXPLORATION SIMULATION PROGRAM ERROR

Table 11 presents the percent error for the sample case (Appendix F) on the Exploration Simulation Program for varying numbers of productive iterations. Twelve hundred iterations was chosen as the standard case against which all other cases were compared. Conoco decided three hundred productive iterations was adequate.

TABLE 11
Exploration Simulation Program Percent Error

Percent

Probability of Earning a 10% ROR	Exploration Simulation Program Bonus (MM$)	Number of Productive Iterations						
		200	300	400	600	800	1000	1200
+0	173	0.3	0.3	0.2	0.1	0.0	0.0	0.0
20	107	0.7	0.4	0.3	0.2	0.0	0.0	0.0
40	84	0.6	0.5	0.5	0.3	0.2	0.0	0.0
60	65	1.2	0.5	0.4	0.3	0.2	0.0	0.0
80	50	3.7	0.6	0.5	0.4	0.3	0.1	0.0
99	22	4.7	0.7	0.6	0.6	0.4	0.2	0.0