ECONOMIC EVALUATION APPROACH TO A SECONDARY RECOVERY PROJECTION MODEL

by

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ABSTRACT

The objective of this research is the creation of a systematic approach to evaluating producing oil properties for possible profitable implementation of a secondary recovery system.

The procedure begins with the application of an equation which solves for the recoverable secondary reserves and, in the process, defines the workable range of values for the reservoir primary variables. The second chapter converts the reserve prediction into a physical rate relation characteristic of waterflooding for the evaluation methods applied in the fourth chapter to the resulting cash flow.

Completion of the evaluation cycle produces a value range of the primary variables for feasibly successful flooding in the subject and analogous reservoirs which can be used to refine the original values chosen.

The alternative investment decisions for this work are evaluated by comparing the Discounted Cash Flow Rate of Return and Net Present Value of the Cash Flow at a specific discount rate for the most probable reserve production. For ranking this project against other investment alternatives the Present Value Ratio was calculated. Uncertainty was gauged by comparing the range and values for the lowest possible reserve case to the highest probable reserve case.

The Zenith Heath Reservoir, subject reservoir of this research, produced an after-tax DCFROR of 29 percent and an NPV at 20 percent of $724,000 for the most probable recovery case.

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CHAPTER 1

INTRODUCTION

This thesis describes a procedure for producing an economic evaluation and an index for ranking and comparing reservoirs of interest for secondary recovery of oil by water injection.

Waterflooding is dominant among fluid injection techniques and is unquestionably responsible for the current high level of production and reserves within North America. Its popularity is accounted for by: (1) the general availability of water; (2) the relative ease with which water is injected owing to the hydraulic head it possesses in the injection well; (3) the ability of water to spread through an oil-bearing formation; and (4) water's efficiency in displacing oil.

The earliest water floods were accidental, resulting from shallow casing leaks and improperly plugged wells. The documented benefits of these accidental floods led the operators to inject water intentionally. At the time it was felt that the main function of water injection was to maintain reservoir pressure, allowing wells to have a longer productive life than by the normal pressure depletion.

In the earliest method of waterflooding water was injected first at a single well. As the water-invaded zone increased and adjacent wells were watered out, these wells were used as injectors to extend the area of water invasion. This was known as "circle flooding" (1). Under these circumstances, the evaluation of waterflood prospects was strictly a matter of analogy and application of "rules of thumb." If a successful water flood was conducted in a specific formation in a basin, operators presumed that nearby fields producing from the same zone could be flooded with similar results.

The exclusive use of analogy and rules of thumb had obvious limitations, apparent from the rather frequent unsuccessful waterflood attempts. Reliance on these methods is still frequently justified for flooding even today. Modern reservoir engineering permits us to delineate the range of reservoir conditions which will result in favorable physical response to waterflood efforts, and also to outline the range of conditions under which waterflooding will be of questionable success. By relating the various reservoir parameters involved to the results obtained from waterfloods a more determinate set of experience factors can be acquired, and the uncertainties involved in such a secondary recovery project are significantly reduced.

The vehicle of illustration for the manner in which various reservoir factors operate and their relative importance is an investigation of a specific reservoir with its conditions and a study of the effect of varying one or two of the engineering factors independently. The section relating to variable control in this thesis describes the different applicable methods and ranges for all uncontrolled input variables. Discussion of these acceptable characterization methods should indicate the use of this approach, within limits, on sandstone reservoirs inclusive of gas caps and exclusive of water encroachment.

The term "waterflood recovery" as used here refers to the increase in recovery above that which would be obtained by producing a field to its economic limit by primary means. In the case where flooding is initiated before all the primary oil has been produced, the recovery from the date of inception of a flood is the sum of the remaining primary recovery plus the "waterflood recovery" as defined.

Reserves and production projection accuracy depends on the quality and quantity of data available. The amount of information gathered through state agency monitoring and data collection for well service necessarily accumulates during the life of a property, and the reserve estimates become correspondingly more accurate.

The assemblage of information for the project begins with the state agency that records and collects characteristics and quantities of oil and gas production by lease, operator, well, unit, and formation. The State Geologic Survey collects and copies all well logs, formation cores, and well test results. Complementing these agencies are organizations that publish for distribution, such as the American Association of Petroleum Geologists (AAPG), American Petroleum Institute (API), Society of Petroleum Engineers (SPE), and such commercial information processors as Petroleum Information Corporation (PI).

Chapter Two presents the equation used in the waterflood reserve evaluation. With this equation, the degree of tolerance in each variable in the recovery factor range is evaluated. The primary recovery and sweep efficiency variables prove to be the most important provided the water saturation variable creates a workable situation. The final result of the second chapter is an applicable range of waterflood recoverable reserves from the subject reservoir.

Chapter Three illustrates a method for calculating the timing and production schedule to match the flood reserve figures. The resulting data is illustrated as an oil rate versus time curve. Another method is introduced in this chapter, for use in construing the results of this type of curve for other analogous reservoirs within the basin. The result of this chapter is a set of production figures on the subject of reservoir sequencing the production volumes with the timing of the injection project.

In Chapter Four, the economic evaluation used the discounted cash flow rate of return (DCFROR) and net present value at 20 percent as indicators of profitability. For ranking the investment opportunities a Present Value Ratio (PVR) was calculated. The DCFROR range for the lower and higher cases was 22 to 41 percent, and the NPV at 20 percent figures for the same cases ranged from $64,000 to $1,401,000. The PVR calculation from the most probable case was 0.36.

The material in Appendix A is a description and discussion of the research data accumulated on the subject reservoir, Zenith Heath. This reservoir is the physical vehicle for which the thesis calculations were carried out, to exhibit the evaluation method created here.

Appendix B contains the cost considerations in evaluating a petroleum project and the inputs used in the cash flow analysis. The cash flow calculations were done using a slightly modified version of the CSM Mineral Economics library program: DCF1. From the results of this case and the evaluation sequence used here, the conclusions and recommendations may be drawn for this type of an approach for investigating the investment decision pertaining to secondary recovery. The investment decision analysis may be done for a figure on allowable capital cost at a specific return rate or provide a net present value (NPV) figure for the project. The NPV approach could be applied to rank these development projects along with exploration programs, both of which compete for the available investment dollars in an industry where future returns must increasingly be generated from areas of known production as the areas available for discovering new production diminish.

CHAPTER 2

WATERFLOOD RESERVOIR EVALUATION

The solution to many technical problems is derived from interrelationships among an assortment of quantities, variables, or parameters. There may be only a few variables or several hundred; interrelationships among parameters may be explicit or implicit, well established or only approximate. The variables which depend, fully or partially, on the magnitude of other variables are called dependent.

Input variables for most practical problems are not known precisely; the degree of uncertainty can vary in the same problem from one variable to another. Variables that are known accurately are determinates; for instance, the gravity of crude oil obtained from a particular pool is usually precisely known. The degree of precision with which a quantity can be determined increases as data describing the pool are accumulated with the development of the field and the producing life of the pool (2).

The uncertainty of a parameter may result from difficulty in obtaining a direct and accurate measurement. This is particularly true of the physical reservoir parameters, which can only be sampled at certain points, and which are subject to errors caused by the presence of the borehole and borehole fluid, or by changes that occur during the transfer of rock and its fluids to laboratory temperature and pressure conditions. Uncertainty also results from the need to predict future parameter values. This type of uncertainty is particularly evident in investment analysis involving future costs, prices, and sales volumes. Uncertainty in the solution to investment problems is often called risk, and its study is risk analysis. (3)

The uncertainty in the value of a variable may be indicated by expressing the quantity as a probability distribution. Many recognized probability distributions can be used to describe physical quantities. Recent studies have used a variety of distributions to describe core analysis data. (4, 5) However, for the examples in this paper, the uniform and triangular distributions are believed to reasonably approximate the data used. (6)

In the uniform distribution, the variable may lie anywhere between two limits with equal probability. This distribution is used when no one range of values for a variable is more probable than any other, but information or intuitive reasoning indicates the variable will lie somewhere between the chosen limits.

The triangular (three-value) distribution is used for a variable when more data are available to indicate a central tendency of distribution. This allows postulating a "most likely" value to the distribution and an upper and lower limit. In this case, as for the uniform disbribution, the variable is not expected to assume a value less than the lower limit or greater than the upper limit. However, with improved quality of data it can be postulated that the variable will tend to assume a value close to the most likely value, and that there will be a decreasing probability for values away from the most likely value.

The area under either of these probability distributions is equal to unity since it is assumed that there is a 100 percent probability that the variable will lie somewhere under the curve. If an ordinate is erected at any particular value of the variable x within the designated interval the area to the left of x represents the probability that the value of the variable will be less than x, and the area to the right is the probability that it will be greater than x.

The triangular distribution is unsymmetrical if the most likely value is not chosen half-way between the upper and lower limits; sometimes such a supposition is warranted and desirable. It should be clear that with unsymmetrical distributions the most likely value will be different from the average value.

The problem may be defined generally as follows:

Given a set of input variables, their estimated probability distributions, and the interrelationships between these variables, determine the most probable solution and the degree of uncertainty for the solution. If the solution consists of more than one output parameter, the uncertainty must be determined for each one.

The objective of the method is to simultaneously obtain a valid solution of a problem and determine the degree of uncertainty associated with the solution. The range distribution for the solution describes the uncertainty of the project; the narrower the distribution, the greater the certainty of the solution and the more nearly it approaches a determinate quantity. On the other hand, a flat distribution with considerable spread between the upper and lower limits indicates a greater uncertainty in the solution.

2.1. Calculations for Recoverable Reserves Range

Using the equation for evaluating recovery efficiency as Callaway (7), the degree of tolerance in each variable may be calculated for the recovery factors against a specific economic situation, where recovery factors under waterflooding, where

B_o = initial oil formation volume factor

B_f = reservoir volume factor during the flood operations

S_{or} = residual oil saturation after waterflood (percent)

S_w = interstitial water water saturation (percent)

R = primary recovery efficiency (percent)

E = overall sweep efficiency (percent reservoir volumes)

N_{wf} = fraction of original oil in place (OOIP) which can be recovered by waterflooding.

This equation is:

$$N_{wf} = (1 - R - \frac{B_o}{B_f}) \left[1 - E\,(1 - \frac{S_{or}}{1 - S_w})\right]$$

The engineering factors involved in evaluating potential waterflood recovery will fall into two sets. The first set, the primary variables, are utilized in a direct mathematical relation for calculating recoverable reserves. Certain of the primary variables are not independent factors but depend on the secondary variables, which affect the estimate of recoverable oil indirectly through the primary variables. The primary variables are:

1. Primary recovery efficiency	R
2. Connate water saturation	S_w
3. Sweep efficiency	E
4. Residual oil saturation	S_{or}
5. Crude shrinkage (oil formation volume factor)	B_o/B_f

The secondary variables are listed below with the numbers in parenthesis indicating the primary variables which they affect:

1. Structural considerations (1, 3)
2. Oil viscosity (1, 3, 4)
3. Permeability (1, 3, 4)
4. Uniformity of reservoir rock (3)
5. Type of flood and pattern (3, 4)
6. Reservoir pressure at time of flooding (5)
7. Mobility ratio (1, 3, 4)
8. Economic factors (1, 3, 4).

The secondary variables are evaluated or derived directly from historical data and physical properties of the subject and analogous reservoirs. The figures used in this variable description section and the following section of projected flood performance figures are from the

Zenith Heath Reservoir, the subject reservoir (see Appendix A and Table 2.1 for description).

The calculations presented here are all based on the assumption that the portion of the reservoir which is not waterflooded (i.e., the unswept portion) is left, at the time of abandonment of the flood, completely saturated with oil and connate water. Under this assumption, which is known as the resaturation concept, the unswept portions of the reservoir act as "thief" areas which must be refilled with oil displaced from the conformable or swept portions of the reservoir. This treatment of the unswept areas assumes that they are in pressure communication with the swept portion of the reservoir but are bypassed by the invading water due to permeability variations or to physical considerations dictated by the geometry of the pay section and the waterflood pattern. The calculations also assume that the pressure during the flood process is increased sufficiently to force any free gas in the pore spaces back into solution in the oil. This treatment imposes a more severe limitation on the sweep efficiency required for a successful waterflood than does the widely used assumption of a "conformance" factor, wherein the unconformable portions are considered to be completely unaffected by the waterflood operations. This limitation is necessary in order to

TABLE 2.1.

ZENITH FIELD: SUMMARY OF FIELD AND RESERVOIR DATA

Date of Discovery	October, 1968
Type of Trap	Stratigraphic and structural
Producing Formation	Heath Sand, Tyler Formation
Producing Mechanism	Solution Gas Drive
Productive Area	1,710 acres
Unit Area	2,240 acres
<u>Reservoir Characteristics</u>	
Av. Depth to Top of Pay	8,000 feet
Av. Productive Thickness	6.12 feet
Acre-feet of Oil Pay	10,465
Av. Porosity	14.9
Av. Air Permeability	208 md
Av. Initial Water Saturation	23.5
<u>Fluid Characteristics</u>	
Gravity of Oil, Degrees API	38
Original BHP @-5,300 Datum, psig	3,564
12-1980 BHP @-5,300 Datum, psig	253
Reservoir Temperature, Degrees F	196
Bubble Point Pressure, psig	2,058
Original Solution GOR, CFPB	219

TABLE 2.1. (continued)

FVF at Bubble Point	1.12
FVF at Original Pressure	1.09
Viscosity of Crude at 196°F and BHP	2.66cp lab sample
Reserves, Present Operations	
Original Oil in Place	8,769,000 STB
Ult. Primary Recovery	1,674,500 STB
Primary Recovery, % of OOIP	19.1
Cumulative Production (6-80)	1,565,686
Well Status	
Development Pattern, Acres	160 and 320
No. of Producing Wells (8-80)	4
Maximum Producing Rate, 12-67	1,078 BOPD - 6 wells
Present Producing Rate, 12-80	121 BOPD

explain the complete failure which is occasionally observed in waterflood projects. (7)

The fundamental equation for evaluating the recovery efficiency by waterflooding, in terms of the five primary variables set forth previously, is: Waterflood recovery equals original oil in place minus primary recovery minus residual oil (after flood).

$$\text{Original oil in place} = 7758\ \phi\ \frac{1-S_w}{B_o}$$

$$\text{Primary Recovery} = R\left[7758\ \phi\ \frac{1-S_w}{B_o}\right]$$

$$\text{Residual oil (conformable section)} = 7758\ \phi\ E\ \frac{S_{or}}{B_f}$$

$$\text{Residual oil (non-conformable section)} = 7758\ \phi\ (1-E)\ \frac{1-S_w}{B_f}$$

Waterflood recovery

$$= 7758\ \phi\ \frac{1}{B_f}\left[E\ S_{or} + (1-E)(1-S_w)\right]$$

$$= \left[7758\ \phi\ \frac{1-S_w}{B_o}\right]\frac{B_o}{B_f}\left[E\ \frac{S_{or}}{1-S_w} + (1-E)\right]$$

$$= \left[7758\ \phi\ \frac{1-S_w}{B_o}\right]\frac{B_o}{B_f}\left[1-E\ \left(1-\frac{S_{or}}{1-S_w}\right)\right]$$

$$= \left[\left(7758\ \phi\ \frac{1-S_w}{B_o}\right)\right] - R\left(7758\ \phi\ \frac{1-S_w}{B_o}\right) - \left(7758\ \phi\ \frac{1-S_w}{B_o}\right)\frac{B_o}{B_f}\left[1-E\ \left(1-\frac{S_{or}}{1-S_w}\right)\right]$$

$$= \left(7758\ \phi\ \frac{1-S_w}{B_o}\right)\left(1 - R - \frac{B_o}{B_f}\left[1 - E\ \left(1 - \frac{S_{or}}{1-S_w}\right)\right]\right)$$

where $B_{\breve{o}}$ = original reservoir volume factor of crude

B_f = Reservoir volume factor of crude during flood operations

S_{or} = Residual oil saturation after waterflood (percent)

S_w = Connate water saturation (percent)

ϕ = Porosity (percent)

R = Primary recovery efficiency (percent original oil in place)

E = Over-all sweep efficiency (percent reservoir volumes)

This is the derived equation form of Callaway's equation solving for the barrels per reservoir acre foot recoverable by waterflood.

2.2. Primary Variable Analysis

The descriptions and following Figures 2.1 through 2.7 investigate the effect of each of the primary variables on the waterflood recovery efficiency when the individual factor is varied over the applicable range with all other factors held constant at their most probable or average range. These Zenith Heath Reservoir values were derived from the data evaluation collected on Zenith and analogous reservoirs.

2.2.1. Sweep Efficiency

The overall sweep efficiency or conformance factor E is comprised of two components, areal (or pattern) sweep efficiency and vertical sweep efficiency. The overall sweep efficiency as used here represents the product of the areal and vertical sweep efficiencies.

Experimental work conducted in the past has definitely established that areal sweep efficiency in a reasonably balanced pattern flood is very high under most circumstances and will approach 100 percent if the flood is continued to a fairly high producing water-oil ratio. (8,9) Applying this information, the overall sweep efficiency is considered to reflect primarily the vertical sweep efficiency. characterized by the permeability profile. (10)

For the Zenith case, a rectangular or uniform probability distribution is applied with a relatively large range, from 60 percent to 80 percent for sweep efficiency. The need to investigate this variation in probability is shown from the case investigation. A 60 percent effective sweep can be readily obtained with the mobility ratio and permeability profile described with the proposed modified line drive injection system. An 80 percent effective sweep would be obtainable by monitoring the flood, adjusting the injection rate, and adding additional wells for conformance, or with the addition of a polymer for vertical displacement control.

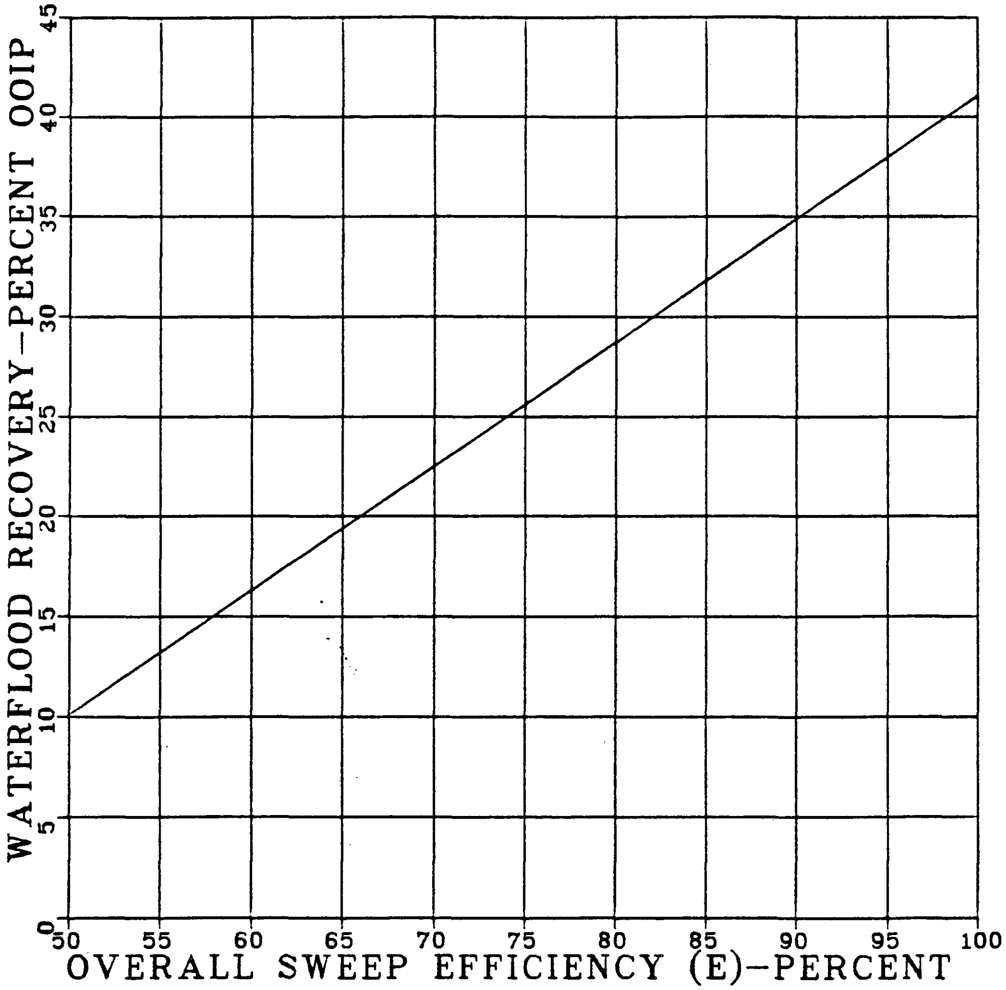
A wide range of sweep efficiencies is represented in the sensitivity analysis in order to illustrate the lowest acceptable value for an economic flood and the highest effective sweep justifiable with additional capital expenditures (see Figure 2.1).

The most probable value used in the base case calculations was 60 percent based on the uniformity and the relative pattern size of the reservoir. This produced figures on waterflood recovery of 16.3 percent OOIP or 157 bbl/acre ft, of the swept reservoir. An 80 percent effective sweep produced recoveries of 28.7 percent OOIP or 233 bbl/acre ft, respectively. Generating an affect on the solution range of 12.5 percent OOIP or 76 bbl/acre ft, which is nearly half of the lowest probable recovery

FIGURE 2.1

EFFECT OF SWEEP EFFICIENCY ON WATERFLOOD RECOVERY EFFICIENCY

(Zenith Field)



determined from the API equation (11) for upper limits, this makes the sweep efficiency variable among the most, if not the most, responsive variable in the secondary reserve equation.

2. 2. 2. Residual Oil Saturation

The residual oil saturation is the immobile oil saturation behind the flood front. The residual oil saturation ordinarily does not vary over extremely wide limits, although its value directly affects the calculations concerning recoverable oil and displaceable volume. The range of values applied can be drawn from three possible sources, and possibly compared. The first gives a most probable and occasionally a lower probable value in an equation summary based on core data by Kazemi.(12) The equation is:

$$S_{or} = S_o \, B_o \, E_b \, \frac{M}{1-v^2}\ , \text{ where}$$

S_{or} = Residual oil saturation after water displacement

S_o = Oil saturation from core analysis

B_o = FVF at the time of coring

E_b = Bleeding factor, proposed to be 1.1

M = Mobility ratio

V = Permeability variance

The second method for evaluating S_{or} was presented by Craze and Buckley (13), and is based on a correlation between oil viscosity and residual saturation, both under reservoir conditions.

Reservoir Oil Viscosity (in cp)	Residual Oil Saturation (percent of pore space)
0.2	30.0
0.5	32.0
1.0	34.5
2.0	37.0
5.0	40.5
10.0	43.5
20.0	46.5

The deviation of the individual data from this average showed the following trend against average permeability:

Average Reservoir Permeability (in md)	Deviation of Residual Oil Saturation from viscosity line (percent of pore space)
50	+12
100	+ 9
200	+ 6
500	+ 2
1,000	- 1
2,000	- 4.5
5,000	- 8.5

According to these statistical trends the residual oil saturation under reservoir conditions for a formation containing a 2-cp oil and having an average permeability of 200 md can be estimated at 37 + 6, or 43 percent of the pore space. But Craze and Buckley's data use total reservoir water drive recovery factors, so this percent figure needs to be multiplied by a sweep efficiency value, or 43 * .80 = 34.4 percent of the pore space. The last method accorded a value in this range would be derived from analogous reservoirs based on their recovery factors and displaced volumes.

This approach made the triangular probability distribution for the Zenith case range from a lower limit of 26.5 percent pore space volume, a most probable value of

30 percent, and an upper limit of 34.5 percent of the pore space, for the residual oil saturation value. An 8 percent pore volume probability range for the applicable S_{or} factor generated a 6.4 percent range in the percent of original oil in place for recoverable reserves or 58 bbl/acre ft (see Figure 2.2).

2.2.3. Water Saturation

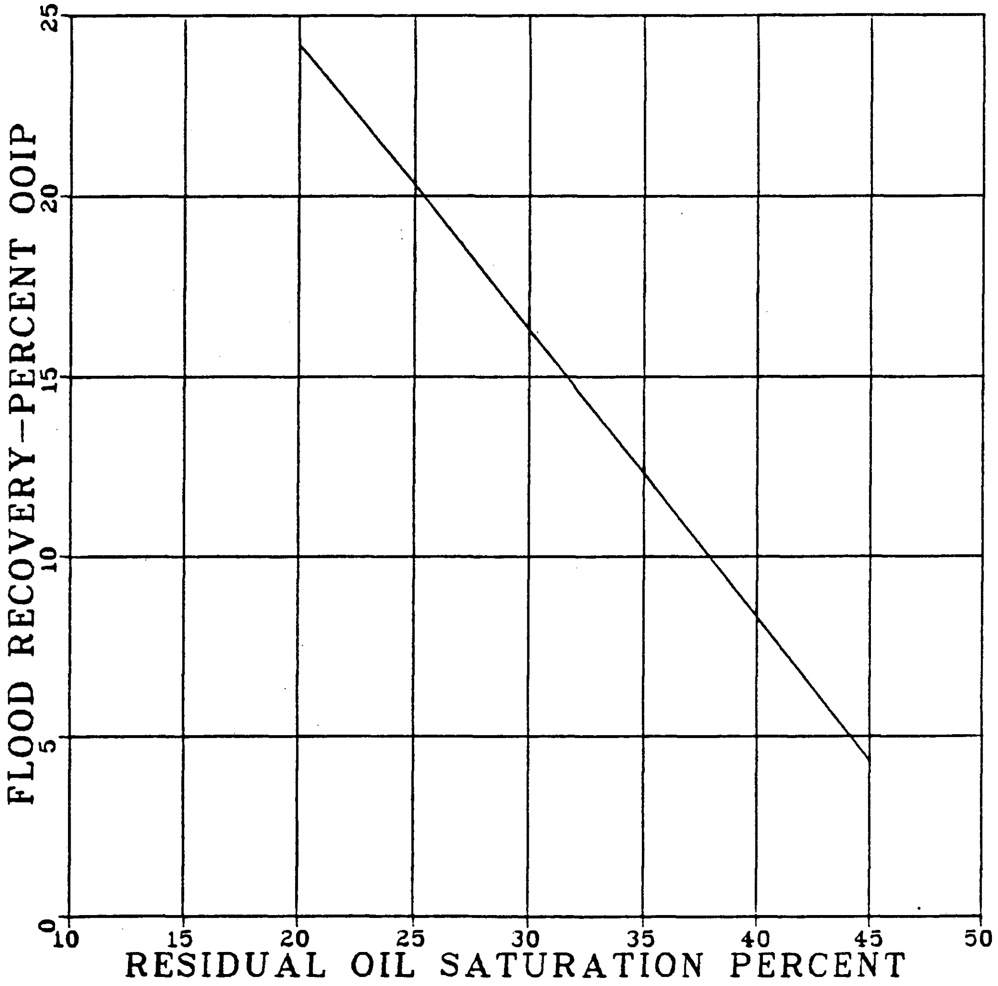
The Connate interstitial water (Fossil sear water) saturation term is ordinarily determined from core analysis and logs. (13) Core analysis and logs can produce a comparatively accurate measure of the magnitude of this trapped reservoir water with much of the same relatively small range of values as porosity.

The saturation normally varies somewhat in the producing section, and it is necessary to determine an average for the formation. Core analysis normally shows values for one-foot intervals, while the logging interval should be broken into several sections and each interpreted separately. Here the averaging was done by a thickness weighted and/or a volume weighted equation.

The initial water saturation for the applicable base case was determined to occupy 23.5 percent of the reservoir pore volume. For the sensitivity analysis the water saturation range was increased to illustrate its effect on the

FIGURE 2.2

EFFECT OF RESIDUAL OIL SATURATION ON WATERFLOOD RECOVERY EFFICIENCY (ZENITH FIELD)



solution values (Figure 2.3).

The probable range for the initial water saturation was 5 percent from a lowest probable of 21 percent to a highest probable of 26 percent. This applicable range had a milder 1.5 percent net effect on the recovery factor or 22 barrels per acre foot effect on the flood recovery volume. Increasing the range to a 10 percent range raises the flood effect to a 3.2 percent variance of recovery factor or 43 barrels per acre foot of reservoir in flood recovery. The higher water saturation could shorten the flood economic life, but not significantly in this case as will be shown later.

2.2.4. Primary Recovery

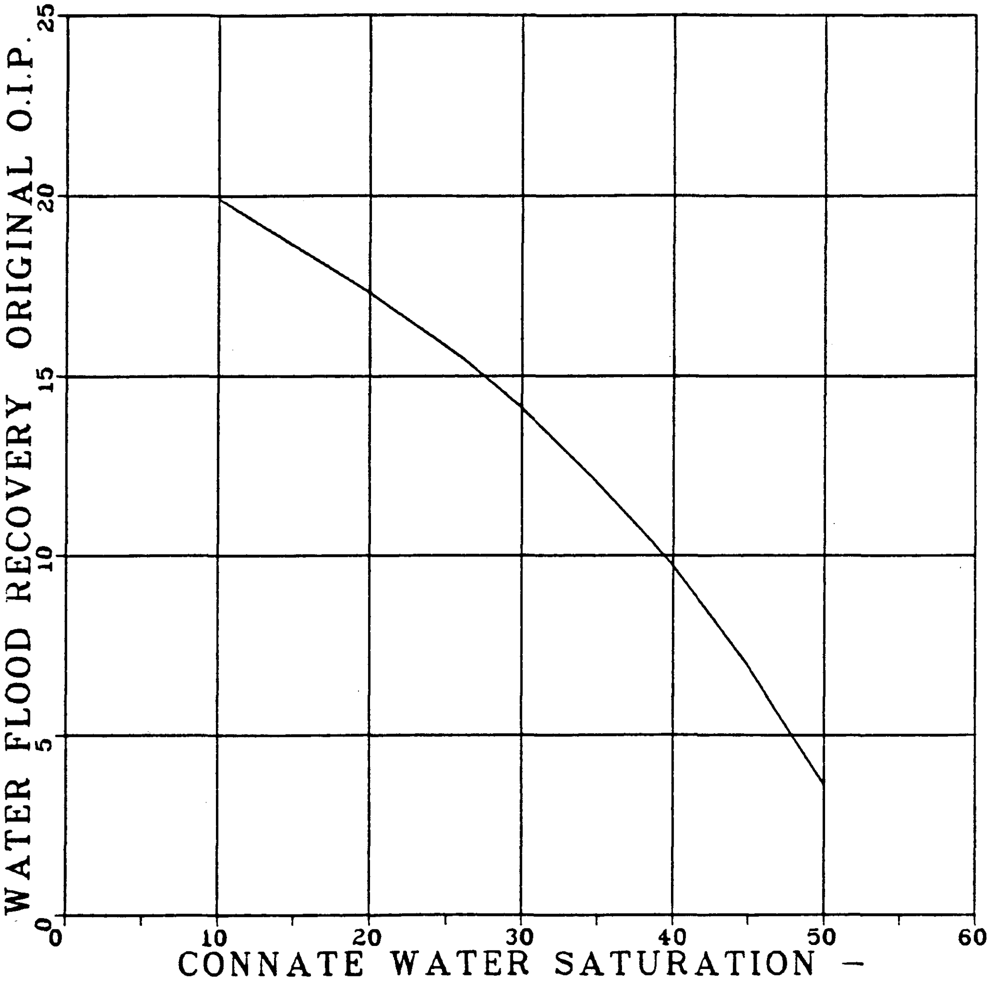
The sensitivity of the flood recovery volume to the primary recovery magnitude is direct, as the primary and secondary recovery are complements. Every barrel per acre foot of primary recovery is one less removable barrel produced when implementing the flood, accounting for the conformance. These figures vary directly with the timing and economics of any evaluation. The higher the primary recovery the greater is the necessity for a technically highly successful flood.

Waterflooding should be approached with caution in fields which have exhibited unusually high recovery

FIGURE 2.3

EFFECT OF CONNATE WATER SATURATION

ON WATERFLOOD RECOVERY EFFICIENCY



efficiencies. For any given set of reservoir conditions, the more oil obtained by primary the less, incrementally, will be available for recovery by flooding.

The primary recovery efficiency is one of the primary variables that can be determined within a narrow relative range of values. Dealing with a delineated reservoir with complementary production statistics permits an accurate valuation and check on its agreement with material balance calculations. Primary recovery is conveyed as a percentage of the original oil in place (OOIP) in the reservoir.

In the base case, the primary recovery efficiency was shown to equal 19 percent of the OOIP. An extended range is calculated here and illustrated in Figure 2.4 for use in the sensitivity analysis.

For the case where production data are not consulted, the primary recovery efficiency value would be assigned. A most probable value would be derived from the API empirical equation for primary recovery efficiency from solution-gas-drive reservoirs, plus the production expansion from above the bubble point. The API recovery equation is: (11)

$$R = (41.815) * \left[\frac{\phi\ (1-S_w)}{B_o}\right]^{+0.1611} * \left[\frac{k}{\mu_o}\right]^{+0.0979} * (S_w)^{+0.3722} * (P_b/P_a)^{+0.1741}$$

where R = recovery efficiency in percent of stock-tank oil in place at bubble point

$\emptyset$ = effective porosity; a fraction of bulk rock volume

Sw = interstitial water content; fraction of total pore space

Bo = oil formation volume factor; a dimensionless factor representing the volume of oil under reservoir conditions per unit volume of stock-tank oil

k = arithmetic average of absolute permeability (darcys)

μ_o = viscosity of reservoir oil (centipoises)

P = pressure (psig)

Subscripts

i = initial conditions

a = abandonment conditions

b = bubble point conditions

o = oil

w = water

g = gas

r = residual at abandonment conditions

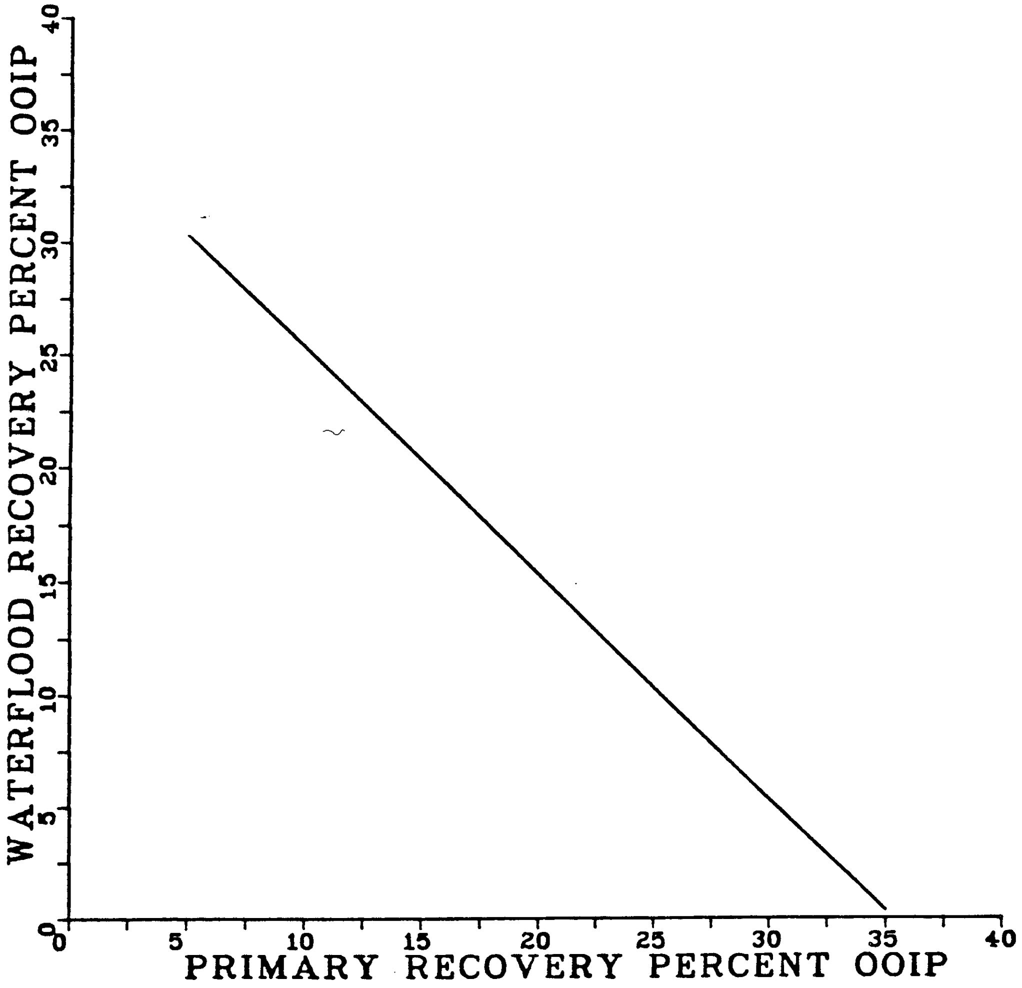
The probability range for primary recovery was from 17 percent of the OOIP to 22 percent OOIP. Historical production and decline curve reserves calculate 19 percent OOIP as the most probable value. Volumetric reserve calculations with historical production generally produce the lowest probable value for primary recovery, and the API empirical equation will provide the highest probable value. A 5 percent range for primary recovery creates a 5 percent change in the magnitude of waterflood recovery factor (see Figure 2.4).

2.2.5. Crude Shrinkage - Formation Volume Factor

The formation volume factor, symbol B_o and abbreviation FVF, at any pressure is defined as the volume in barrels that one stock tank barrel occupies in the formation (reservoir), i.e., at reservoir temperature and with the solution gas which can be held in the oil at the pressure. Because both the temperature and the solution gas increase the volume of the stock tank oil, the factor will always be greater than one. When all of the gas present is in solution in the oil, i.e., at the bubble-point pressure, a further increase in pressure decreases the volume at a rate which depends upon the compressibility of the liquid. The implication of the formation volume factor is that for every 1.21 barrels of reservoir liquid in the Zenith reservoir

FIGURE 2.4

EFFECT OF PRIMARY RECOVERY EFFICIENCY ON WATERFLOOD RECOVERY EFFICIENCY (ZENITH FIELD)



only 1.00 barrels, or 82.6 percent, can reach the stock tank. This figure 82.6 percent, or 0.826, is the shrinkage factor of the liquid at the bubble point. B_f denotes the formation volume factor effective at the time and pressure at flood startup. The reservoir fluid property may be visualized from Figure 2.5.

The representative format for crude shrinkage is B_o/B_f, which is relatively more applicable for comparison and use. The B_o/B_f represents the magnitude of crude shrinkage that has taken place between the initial production of the reservoir and the initiation of the flood system. This then serves as a basis for the value for volume correction and the amount of gas resaturation taking place. Since crude shrinkage can be correlated closely with theoretical calculations, the probable range is narrowed considerably. Figure 2.6 shows a common graphical solution to an empirical relation with four fluid physical properties relating to the formation volume factor, as expressed in a reservoir engineering text. (14) For the Zenith case, the range was less than 5 percent of the assigned value and produced a variation in flood results of less than 3 percent. This changes the recovery volume by about 16 barrels per acre foot of reservoir volume. A change in the values of a 10 percent magnitude produced a change in the recovery

FIGURE 2.5

FORMATION VOLUME FACTOR OF SANDY FIELD RESERVOIR OIL (14)

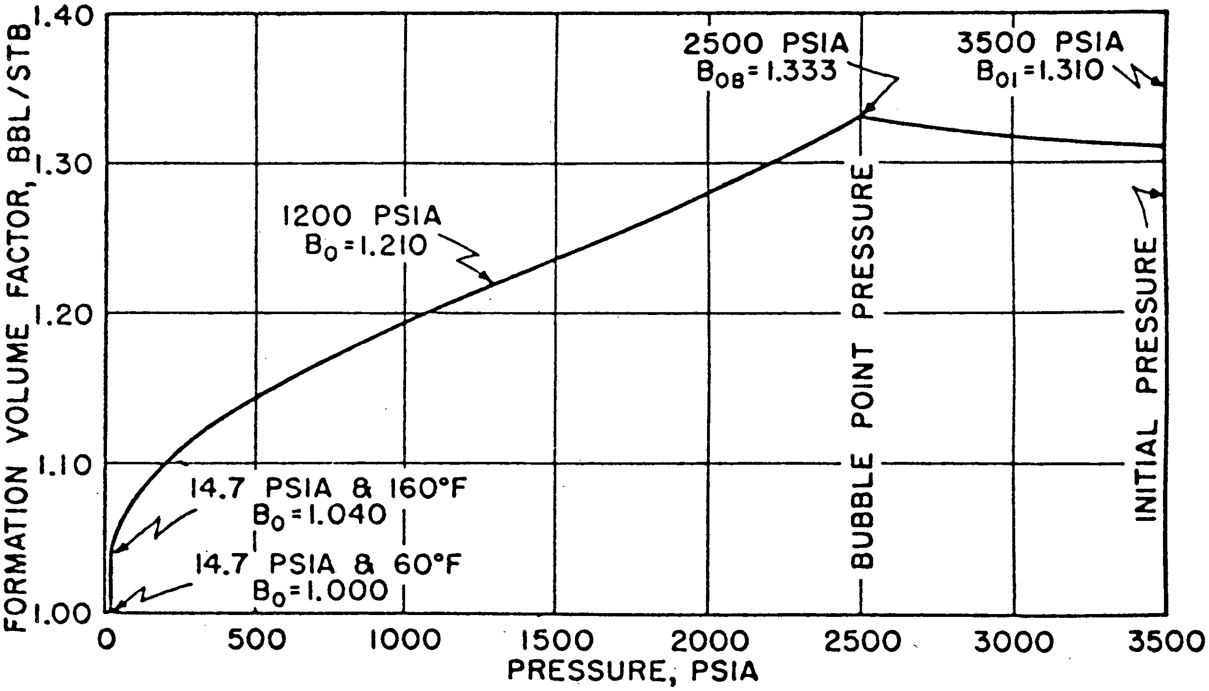
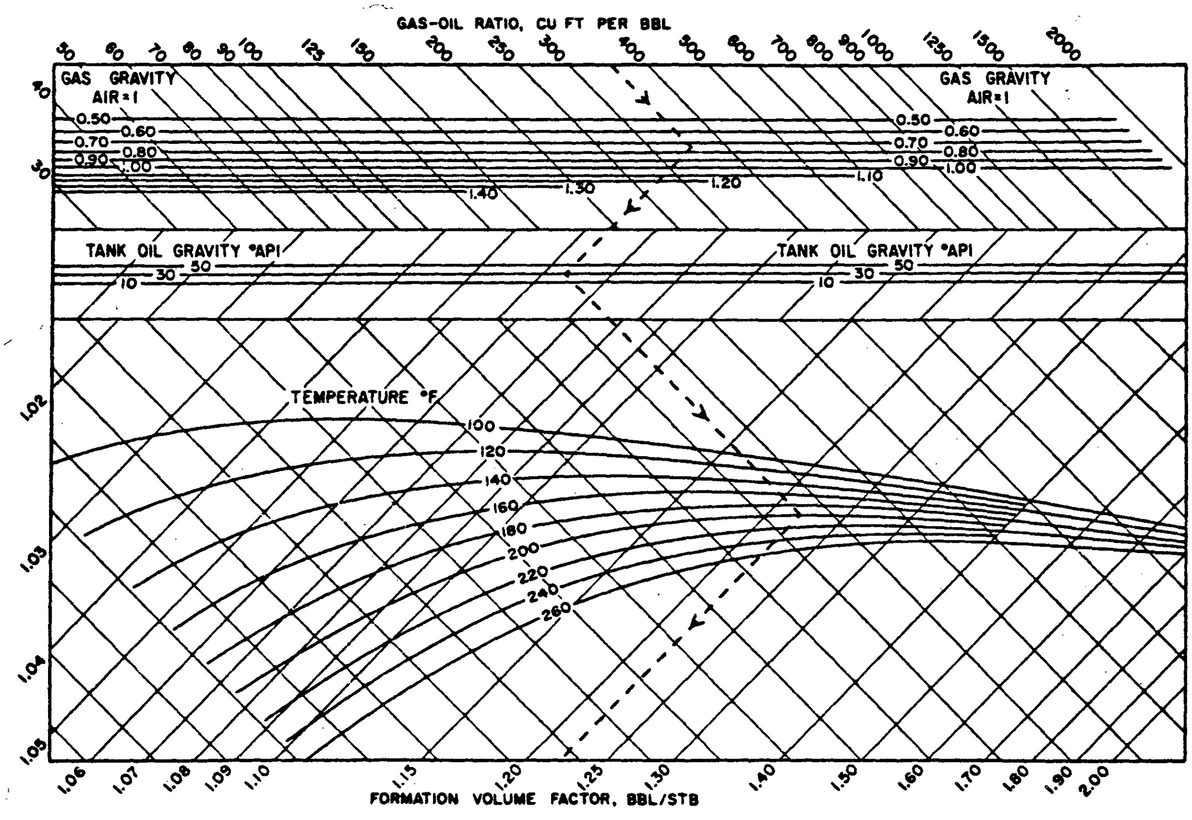


FIGURE 2.6

FORMATION VOLUME FACTOR OF BUBBLE POINT LIQUIDS (15)

(after Standing)



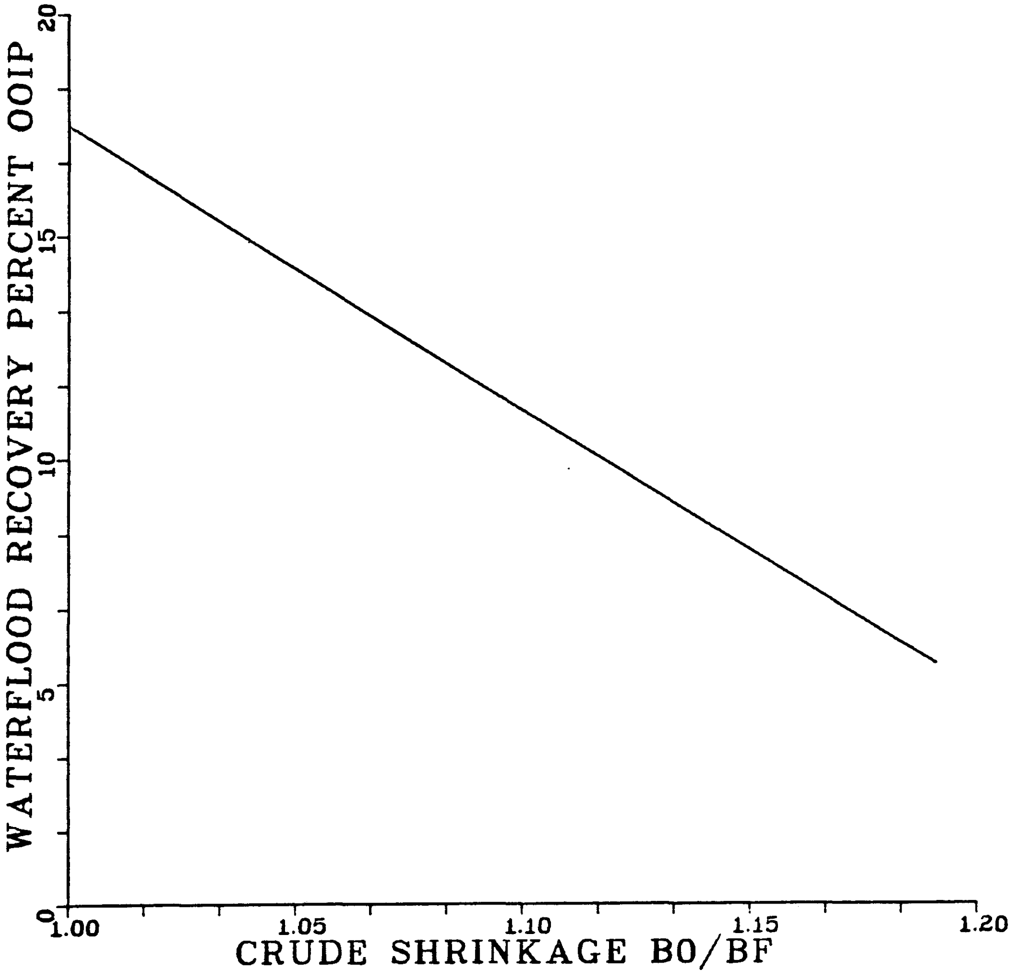
factor of less than 5 percent, or about 28 barrels per acre foot in recovery difference. The effect becomes more profound for high shrinkage crudes, especially when the reservoir pressure has been depleted, shrinking the crude correspondingly (Figure 2.7 for B_o/B_f analysis).

The optimum time for initiating a waterflood is generally early in the life of the field, before appreciable shrinkage of the crude occurs. The losses incurred by delay in initiating a flood are consistent even for relatively good waterflood prospects. They become poorer quality prospects, especially where the crude is of high shrinkage and where the overall sweep efficiency may be relatively low. One obvious exception to this conclusion exists when the wells may be draining large amounts of primary oil from undeveloped portions of the reservoir. Under these circumstances, an early waterflood will obviously serve to "shut off" the beneficial migration of oil, which may more than offset the benefits achieved in the developed area which can be flooded.

FIGURE 2.7

EFFECT OF CRUDE SHRINKAGE ON WATERFLOOD RECOVERY EFFICIENCY

(Zenith Field)



2.3. Secondary Variable Discussion

2.3.1. Permeability

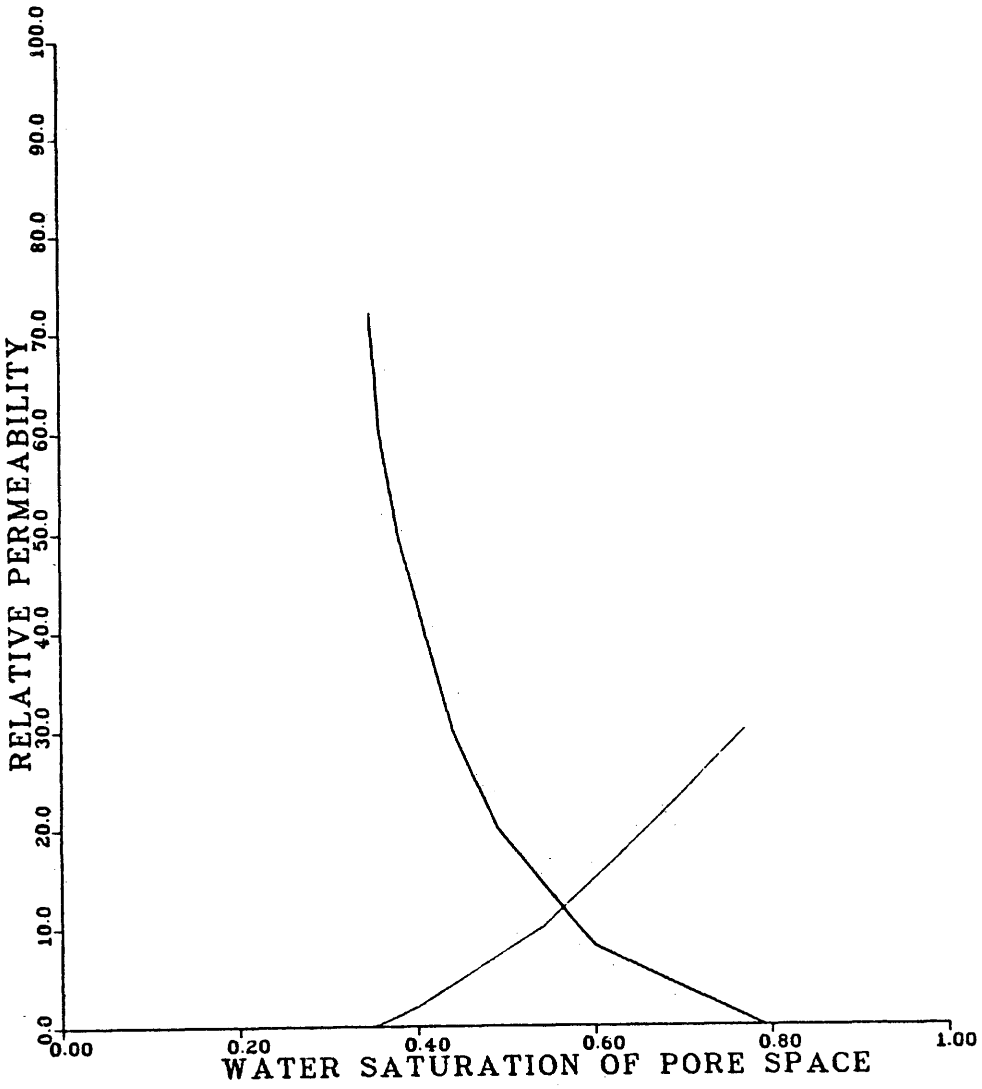
Permeability is determined in two basic ways - from laboratory tests on cores and from the analysis of well tests. Intercorrelation of the data between cores and drill stem test produces an equitable relationship. In Darcy's equation k, permeability, is effective to a single flowing fluid in a single phase system. It reflects a proportionality constant of resisting forces that differentiate between reservoir rocks. The symbols K_w and K_o denote the relative permeability of water and oil, which is the effective permeability of one fluid at a given saturation level.(see Fig. 2.8).

The variation of permeability is treated as an input variable in this analysis. Permeability variation was determined by arranging the permeabilities in decending order and calculating the percent of the permeability values exceeding each entry (cumulative relative frequency).

The permeabilities are plotted on the log scale and the permeability percentages on the probability scale of log-probability graph paper. (17) The best straight line is drawn through the points and permeability at the 84.1 cumulative percent value is read from this line and subtracted from the median permeability. The ratio is the permeability variation factor, V, a fraction.

FIGURE 2.8

PERMEABILITY AS A FUNCTION OF WATER SATURATION FROM CORE ANALYSIS ZENITH FIELD



2.3.2. Mobility Ratio

The mobility ratio relates the fluid viscosity and pressure gradient, expressed as the ratio of permeability to viscosity, k/λ . Where two fluids are flowing simultaneously, as the case of oil and water, it is the ratio of the mobility of the water to that of the oil which determines their individual flow rates, and therefore the water-oil-ratio (WOR). The mobility ratio (M) affects the displacement efficiency of oil by water, and the notation should be expressed as mobility of the displacing fluid to that of the displaced fluid.

Calculations for differences in the permeability variation (V) and mobility ratio (M) corrections are made with the theoretical calculations, e.g., a modification of the Dykstra-Parsons method. (18,19) Calculations are made for the various M and V factors that apply to the cases under study, and the ratio of the results is then applied as an adjustment factor to the analogy method data.

2.4. Method for Calculating Upper Limit of Secondary Recovery

The API method should be used for estimating the approximate upper limit of total recovery at the end of an efficient water injection project. The API Subcommittee on Recovery Efficiency compiled recovery data from more than 70 sandstone reservoirs operating under a natural water drive mechanism, where invading bottom or edge water was the dominant displacing medium. (11) From this data, an empirical equation was developed that correlates oil recovery with various reservoir parameters. This equation designates the upper limit of total oil recovery (primary plus secondary) which can be expected at the end of an efficient waterflood or pressure maintenance operation.

The empirical equation developed for water drive in sandstone reservoirs is as follows:

$$\text{Total Recovery (BAF)} = 4259 * \left[\frac{\phi\ (1-Sw)}{Boi}\right]^{1.0422} * \left[\frac{K_{Air}\ \mu_w}{1000\ \mu_o}\right]^{0.0770} * (Sw)^{-0.1903} * (P/Pa)^{-0.2159}$$

where:

K_{air} = Arithmetic average of absolute permeability (millidarcies, md)

S_w = Initial water saturation (fraction)

P_i = Initial pressure (psi)

P_a = Abandonment pressure (psi)

B_{oi} = Oil formation volume factor (RB/STB) at initial reservoir conditions

BAF = Stock tank (barrels per acre foot)

μ_w = Viscosity of water (cp)

μ_o = Viscosity of oil (cp)

(1) Set $P_i = P_a$: this accounts for formation representation.

(2) Apply a shrinkage correction for the change in the oil formation volume factor from pressure at flood start to steady-state pressure.

Set BAF equal to total recovery as calculated by previous equation.

BAF_s = Total recovery corrected for shrinkage

N_1 = Oil initially-in-place per acre foot.

Substituting:

$$N_1 = 77580\ (1-S_w)/B_{oi}$$

$$BAF_s = N_1 - (N_1 - BAF)$$

where:

B_{of} = Oil formation volume factor at start of flood (reservoir bbls/stock tank bbls, RB/STB).

Wayhan et al (20) investigated the application of the API equation for waterflood performance prediction on

27 successful floods in the Denver-Julesburg Basin.

With the Zenith reservoir values applied, the API equation produces a figure of 398 stock tank barrels per acre foot of total recovery (primary and secondary), after water displacement: this amount(s) of 49.1 percent of the original oil in place.

Using for comparison the figure with the highest probable value from the thesis analysis, the upper limit on the total recovery for Zenith would be 2,623,900 STBO or almost 30 percent of the OOIP. With favorable values for response time and peak oil rate, the Zenith analysis shows this to have an approximate 25-year life with production declining in the fifth year at an annual rate of 18 percent. The final water cut would be near 96 percent as the produced water volume would have the magnitude of the injected volume.

2.5. Solution Description

By applying the applicable value range illustrated below for the primary variables, calculations using the Calloway equation produced lowest probable, highest probable and most probable waterflood recoverable reserve figures.

Variable	Applied Range	Effect on Recovery Factor
Sweep Efficiency	60-80%	12.5%
Connate Water Saturation	21-26%	3.2%
Residual Oil Saturation	26.5-34.5%	6.4%
Primary Recovery	17-22%	5 %
Crude Shrinkage B_o/B_f	1.095-1.143	3 %

Combining the unfavorable values from the primary variable range gives the lowest probable reserve figure of 1,070,000 STBO. The calculation using the most favorable value from the primary variables range resulted in a highest probable reserve figure of 2,667,600 STBO; this was higher than the 2,623,900 STBO figure from the API equation. For this figure the lower of the two values needs to be used, so 2,623,900 STBO is the highest probable reserve figure. The most probable producable reserve figure for the Zenith Heath Reservoir was 1,429,000 STBO. A most probable reserve figure was calculated using the most probable or range average value as for the crude shrinkage variable. The most probable figure of 1,439,000 STBO corresponds to a total recovery of 35.4 percent OOIP, a 16.3 percent increase over the 19.1 percent of OOIP produced by primary means. These figures compare favorably with historical analogous floods which have produced nearly equal volumes from secondary and primary production. Total recovery factors for the lowest probable and highest probable cases were 31.3 percent and 49.1 percent OOIP, respectively.

CHAPTER 3

PRODUCTION SCHEDULING ANALYSIS

3.1. Introduction

With the calculation of secondary oil reserves completed using an application of the Calloway equation, the procedure for ascertaining the production performance to match the reserve figures is illustrated here.

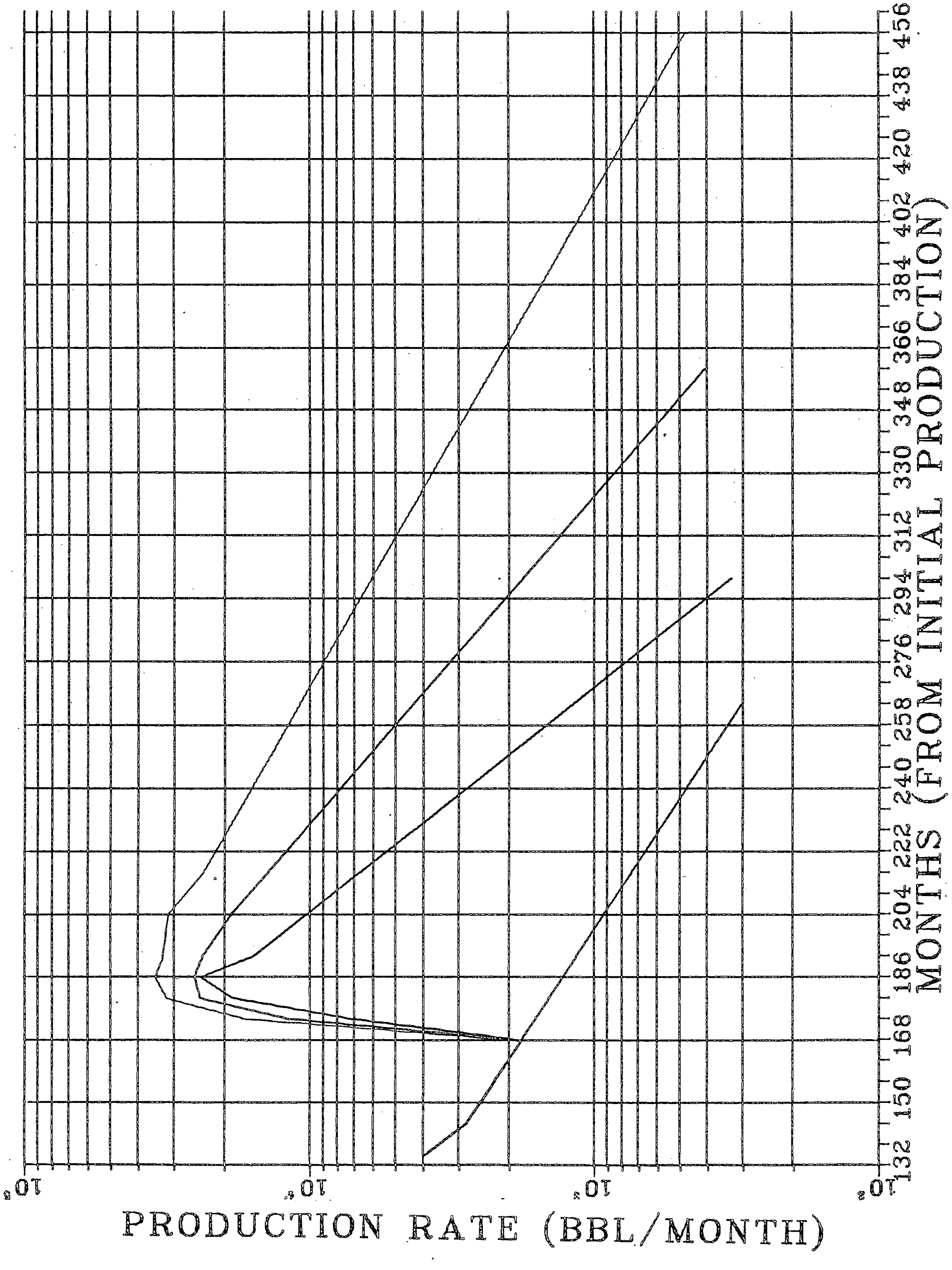
The Earlougher and Guerrero (21) empirical method was used in conjunction with calculations for the author's modified Slider analogy method, (22) to produce the performance figures on the flood. The performance figures are utilized to plot an oil-rate-versus-time curve for the flood. Once a normalized curve has been constructed, it can be applied to a new flood in an analogous reservoir. The curve also presents a descriptive format in the economic program in reading the line as producing oil volume and the area under the line as produced reserves with time.

The method procedure in this section matches the physical performance properties the subject reservoir would produce to attain a specific produced-reserve volume. These methods provide the production rates and timing information that initiate the scheduling for the economic evaluation.

The calculation results on the Zenith Heath reservoir are illustrated in an oil-rate-versus-time-type curve depicting the production for each of the three recoverable reserve cases (see Figure 3.1).

FIGURE 3.1

ZENITH HEATH RESERVOIR PRODUCTION CURVE



3.2. Assumptions and Definitions

All calculation procedures must make the following assumptions:

(1) The individual layers or zones of permeable sands within the reservoir and their fluid contents are laterally uniform.

(2) The performance of the reservoir as a whole corresponds to the summation of the performance of all its individual layers.

(3) No gravity segregation of fluids occurs.

(4) The displacement action is piston-like.

(5) No interlayer flow occurs.

The Earlougher and Guerrero empirical method (21) is based on experience gained from studies of data from core analyses and flood-pot tests for several thousand wells.

The term "geologically analogous" implies that the reservoirs are of the same geologic age and that they were deposited in a similar geologic environment and subjected to similar post-depositional changes. It follows from this premise that the micro and macro features of the reservoirs should be similar. These features include lithology, clay content, pore size distribution, geologic structure, continuity or lack of continuity of the pay zone or zones, and relationship to adjoining aquifers, if any.

An assumption used in the analogy method is that the oil-water relative permeability characteristics are the same in analogous reservoirs. This is a reasonable assumption, as indicated by data shown in a recent statistical review of relative permeability data. (23) Another such assumption is that net effective pay is defined in the same manner in the reservoir of interest as was done in the reservoir that is used as an analog. (22, 24)

Calculations are based on the concept that total (primary plus secondary) recovery from a given unit of pore space is the same in geologically analogous reservoirs. In the application of this method, it is assumed that primary oil is recovered from the entire reservoir volume. Secondary oil recovery, though, is considered to come only from the part of the reservoir that is affected by the injection well pattern. Any reasonable and consistent procedure for delineating the secondary drainage area gives acceptable results because the same procedure is used for both the new and the analog reservoir.

3.3. Injection Rate Calculations

The injection volume and number of injection wells needed to provide a specific production volume is evaluated by the injection rate calculations illustrated. The first equation is the general five-spot equation which can be modified for use in flood patterns, other than a five-spot:

$$i = \frac{0.00354\, k_w h\, (P_{wi} - P_{wp})}{\ln\, (d/r_w) - 0.619}$$

where

i = injection rate (bbls per day)

P_{wi} = sand face pressure in injection well (psi)

P_{wp} = sand face pressure in producing well (psi)

d = distance from injection well to production well (ft)

r_w = well bore radius (ft)

It should be emphasized that this equation as written applies to wells which have not experienced damage or stimulation. In such a case, a skin factor value or an effective well bore radius r_w value is added to the denominator inside the square brackets. Methods for evaluating the skin factor and/or the r_w term have been described in the literature. (25)

The injection pressure is given by the following equation:

$$p_{wi} = 0.433\rho_w D + P_s - P_f$$

where

ρ_w = specific gravity of water (dimensionless)

D = depth (ft)

P_s = surface pressure at the wellhead (psi)

P_f = friction loss in tubing (psi)

There is an upper limit for P_{wi} in water injection projects, and when this limit is exceeded fracturing or pressure parting results. The upper limit of P_{wi} can be evaluated with the aid of step-rate injectivity tests (26) or taken from the subject field service records. The Zenith Heath reservoir records showed breakdown on fluid treatments above 6200 psi.

Calculations for the Zenith Heath reservoir predicted injection rates between 700 and 900 bbls per day over an injection interval of 7 to 10 feet in the injection pattern (refer to Appendix A).

Because of the tacit assumption that relative permeability relationships are the same in geologically analogous reservoirs, it follows that the analogy method uses a proportionality equation:

$$\frac{i_{new}}{i_{old}} = \frac{(k_{air} * h/\mu)\ new}{(k_{air} * h/\mu)\ old} * \frac{(P_{wi} - P_{wp})\ new}{(P_{wi} - P_{wp})\ old} * \frac{\ln |(d/r_w) - 0.619|\ old}{\ln |(d/r_w) - 0.619|\ new}$$

"New" refers to the flood for which a prediction is desired, and "old" refers to the flood for which waterflood performance data are available. In viscous oil reservoirs, μ is an average of μ_w and μ_o . In other reservoirs, μ is simply μ_w . Note that the equation is capable of predicting injection rates by compensating for differences in well spacing, well bore radii, pressure, viscosity, permeability, and net effective pay thickness. The equation can also be modified for use in flood patterns other than a five-spot.

Both methods use the concept of injection efficiency, IE. This term accounts for losses of injection water to an aquifer of other zones. It is evaluated for conditions after fill-up as follows:

$$IE = (q_o + q_w)/i$$

where

q_o = production rate of oil (bbls per day)

q_w = production rate of water (bbls per day).

The effective injection rate is designated i_{eff}, which equals i * IE, and the cumulative injection volume is designated as $W_{i_{eff}}$ which equals W_i * IE.

3.4. Production Rate Calculations

The procedure depends chiefly on equalling the predicted secondary oil reserves by fitting values predicted from the following:

1. The first oil kick in a waterflood occurs at 0.6 to 0.8 of fill-up. The higher fraction applies to the more uniform sand. Fill up volume = Pore volume (PV) * Gas Saturation (S_g).

$$S_g = (1-S_w) \; (1 - (1 - \frac{N_p}{N}) \; \frac{B_{of}}{B_{ob}}$$

where

N_p = Primary production below bubble point pressure (STB)

N = Oil initially in place minus old oil that may have been produced above the reservoir bubble point pressure.

B_{ob} = Oil formation volume factor a bubble point pressure (reservoir bbl/STB).

If sufficient data are lacking to calculate fill-up volume, assume that the fill-up volume for most depleted sands amounts to 20 to 25 percent of the pore volume.

2. The steady-state injection rate is calculated by applicable equations, utilizing core analysis

and/or log data to evaluate k_w and h. This term permeability capacity, $k_w h$ (mdft) may be evaluated from results of a pressure fall-off test run prior to fill-up. Other approaches would be to evaluate $k_o h$ from a pressure build-up test or a productivity index test taken on a producing well before the flood implementation. (27) If the tests are not performed or until such a date the values can be taken from k_w/k_o ratios in the "k_w/k_o Digest". (28)

3. Peak oil rate usually occurs at fill-up. The ratio of injection rate divided by peak oil rate is usually between 2 and 12. Exceptional floods have ratios of 2 or lower. For normal floods, 4 to 6 is average. The ratios nearing 12 apply when there is either basal water sand, overlying gas sands, relatively low oil saturations (below 30 percent), or extensive natural fractures.
4. Time oil production rate remains at peak generally ranges from 4 to 10 months for an injection rate of approximately 1 bbl/day/acre-ft of sand. This actually depends on

additional factors concerning well spacing, amount of mobile oil, and time required to place entire project under flood.

5. The cumulative water injected at economic limit, W_{ia}, ranges from 1.25 to 1.7 pore volumes with an average of 1.5. Another way for estimating this value is to consider the probable (W_{ia}/secondary oil reserves) ratio. Riley (29) reported that this ratio normally ranged from 5 to 15 with a median of 9.
6. The total flood life, t_f, is figured as follows:

   $$t_f = W_{ia}/365 * i.$$

   The i used here (the steady-state rate calculated for conditions after fill-up) and t_f would be expressed in years.
7. The oil rate versus time curve is drawn in such a manner that it fits the values determined above. The area under the oil rate versus time curve must equal the secondary oil reserve evaluated in Chapter 2. The average production decline after peak oil-rate was between 25 and 70 percent per year, depending principally on injection rate, stage of depletion, and uniformity of the formation.

The oil-rate-versus-time curve, Figure 3.2, and the Table 3.1 data correspond to the subject reservoir, Zenith. The curve exhibits the historical monthly production rate with the projected monthly production rates after the flood initiation. The three lines projecting production rates are the lowest probable recoverable reserve case red, the most probable produced reserve case black, and the highest probable waterflood reserve case blue. Table 3.1 contains the monthly production and cumulative production figures for the Zenith Heath reservoir flood. These figures will represent the project sales volumes after a royalty adjustment for the cash flow analysis.

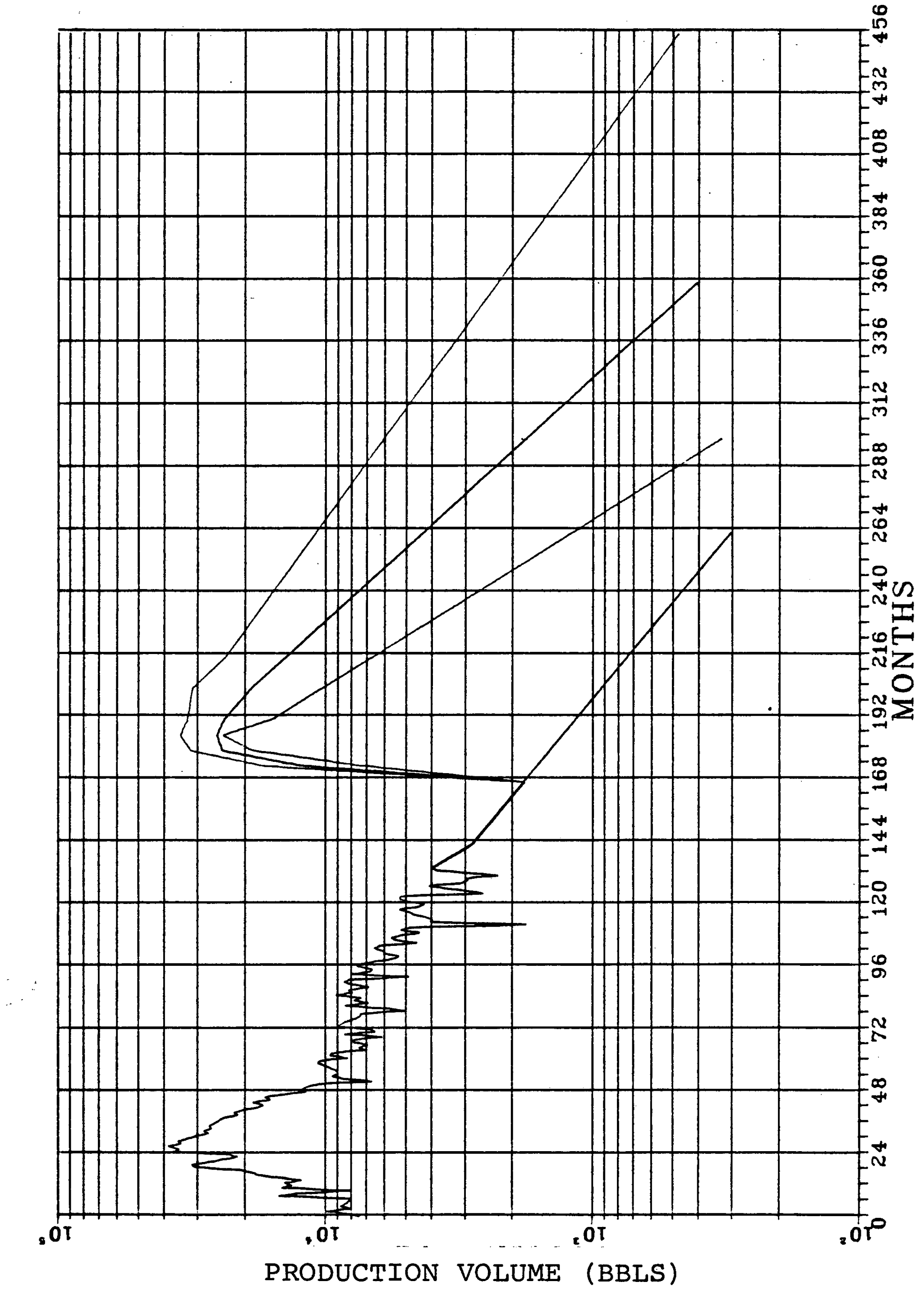
TABLE 3.1

MONTHLY FIELD PRODUCTION RATE (bbls)

Flood life in months	Lowest Probable	Most Probable	Highest Probable
0	3959	3959	3959
6	2810	2810	2810
18	2248	2248	2248
24	1798	1798	1798
30	7100	11800	16720
36	18720	24300	32000
42	24300	25300	34960
48	15808	23700	32700
60	10275	18840	31500
72	6688	14017	23663
84	4347	10429	19468
96	2827	7758	16014
108	1836	5773	13175
120	1192	4295	10841
132	775	2377	8919
144	504	2377	7335
156	328	1769	6037
168	-	1316	4964
180	-	979	4086
192	-	730	3362
204	-	541	2766
216	-	404	2274
228	-	-	1873
240	-	-	1538
252	-	-	1268
264	-	-	1043
276	-	-	857
288	-	-	705
300	-	-	581
312	-	-	477

FIGURE 3.2

OIL RATE VERSUS TIME CURVE (ZENITH PROJECT PROJECTION)



3.5. Discussion of Results

The low value for flood recovery for the Zenith Heath Reservoir case comes from applying the lowest probable values from the sensitivity analysis. Using these figures and their corresponding results on response and oil recovery rates from the previously outlined approach, calculations show a lowest probable recovery value of slightly more than 12.2 percent (31.3-19.1 = 12.2) of the OOIP, or 1,064,200 STBO. Fitting this value to the response curve, Figure 3.1, and rate relations, the total flood life on this lowest probable recovery is approximately 12 years. The annual production decline after the peak oil rate was nearly 40 percent starting at the end of year four. The peak oil rate in this case averaged nearly 500 STBO daily for nearly six months.

For the highest probable reserve recovery, the peak oil rate was nearly 1100 STBO in a day; the average over the 12-month peak rate range was near 950 STBO daily. The annual decline rate after peak production was approximately 20 percent; this described a total flood project life of 25 years. In order to normalize this case the injection volumes required were ascertained much more easily with an additional injection well, and later with an additional producing well added to the base case problem description of Appendix A. These additional wells are accounted for in the economic evaluation for the highest probable recovery case. The total contribution of the highest probable case in waterflood reserves was 2,623,900 STBO or 30 percent of the original oil in place.

Entering the calculations described with the established most probable values for the Zenith reservoir case results in a flood recovery factor of 16.3 percent of the original oil in place, about 3 percent less than the primary recovery factor. This 16.3 percent is a recovery volume of 1,429,000 stock tank barrels of oil, well below the median of the probability range. The agreement between the flood life and response equations for the recovery value produces a flood life of 17 years. The first three years declined at the present field decline rate. Beginning with the fourth year, the production rises in response to the water injected. All three scenarios are similar to this point. From here on, the magnitude of the peak oil rate and its duration varied with the recovery values which can be figured or shown from the type curve representing the subject reservoir, Figure 3.1. The peak oil rates varied from nearly 500 barrels of oil per day (BOPD) to 1150 BOPD. A peak rate of over 800 BOPD occured in the most probable case and was figured to be sustained for over 10 months. In the 12 years following the peak oil rate, the annual production decline was approximately 27 percent for the most probable values. All the production declines were carried to a common economic limit addressed in the monthly production costs (Appendix B).

CHAPTER 4

ECONOMIC EVALUATION

4.1. Introduction

In this age of increasingly complex investment situations, to be successful over the long run it is important that a primary economic evaluation criterion be selected and applied to compare alternative investment choices. Economic evaluation of investment alternatives relates to systematically evaluating the relative profit potential and to quantify the economic effects of the project factors. The well known prerequisite of successful engineering ventures is economic feasibility. The economic evaluation means used to analyze and rank this project were Discounted Cash Flow Rate of Return (DCFROR), Net Present Value (NPV), and Present Value Ratio (PVR) as defined and applied according to F.J. Stermole. (30)

DCFROR and NPV are probably the most widely used methods for computing the profitability. They are meaningful tools for evaluating an investment because they take into account the time value of money, the annual flow of income and expenses, and provide a common unit of measurement. The definition of DCFROR can be described simply as the discount rate which makes the present value of the after-tax income from an operation equal to the present value of investment. The tax and depletion treatment for this mineral evaluation case coincides directly with Stermole's method. The cash flow structure and assumptions as for the present worth calculations are illustrated in Appendix B.

4.2. Evaluation Methods

There is a need to divide the evaluation process for income-producing projects such as the waterflood program into two sub-classifications. The first method used in analysis comparison of projects competing for dollars in a limited budget where more than one project can be funded is a ranking process of non-mutually exclusive alternatives. The second method is a comparison of mutually exclusive alternatives, an analysis of options to provide one choice such as selecting the best primary variable options to improve waterflood operations or to optimize the development system in production operations.

The application of either evaluation process is based on a net value analysis of the projects or project product involved. Net value relates to the difference between revenues and costs at a specific point in time; here the term "revenue" refers to inflows of money and the term value is analogous to worth. The representative format used in this evaluation is Net Present Value (NPV) which denotes the annual project net worth with time value of money calculations made at some minimum rate of return, i^*. (A positive net present value indicates a successful investment.)

The basis of the net value analysis in evaluating mutually exclusive alternatives consisting of two factors is, producing the alternative with the largest positive net value for the level of investment. A choice between injection patterns or fluids should always incorporate the design that maximizes NPV. In the most probable case for the Zenith Heath reservoir, the waterflood design and parameters for the project produced an NPV at 20 percent of $724,000 from a present worth investment of $2,024,000.

Non-mutually exclusive alternatives are exploration or development projects where more than one choice can be selected depending on the available capital. As in mutually exclusive analysis, the goal of non-mutually exclusive project evaluations is to maximize the cumulative profitability generated from the investment dollars.

Instead of using growth rate of return (see Stermole, p. 238) or a comparitive analysis of cummulative net worth the judgement criterion applied in this thesis to rank non-mutually exclusive alternatives is the present value ratio (PVR).

The PVR technique ranks projects on the value of the ratio of NPV to present worth investment (PWI) costs with calculations using the minimum rate of return. The resultant NPV dollar per investment dollar ratio, PVR, appropriately ranks projects to maximize cummulative NPV with the investment magnitude - the largest PVR project is first, the second largest is ranked second, etc. If the project cost magnitude does not allow successively PVR ranked project initiation, a mutually exclusive analysis will dictate order changes for budget constraints.

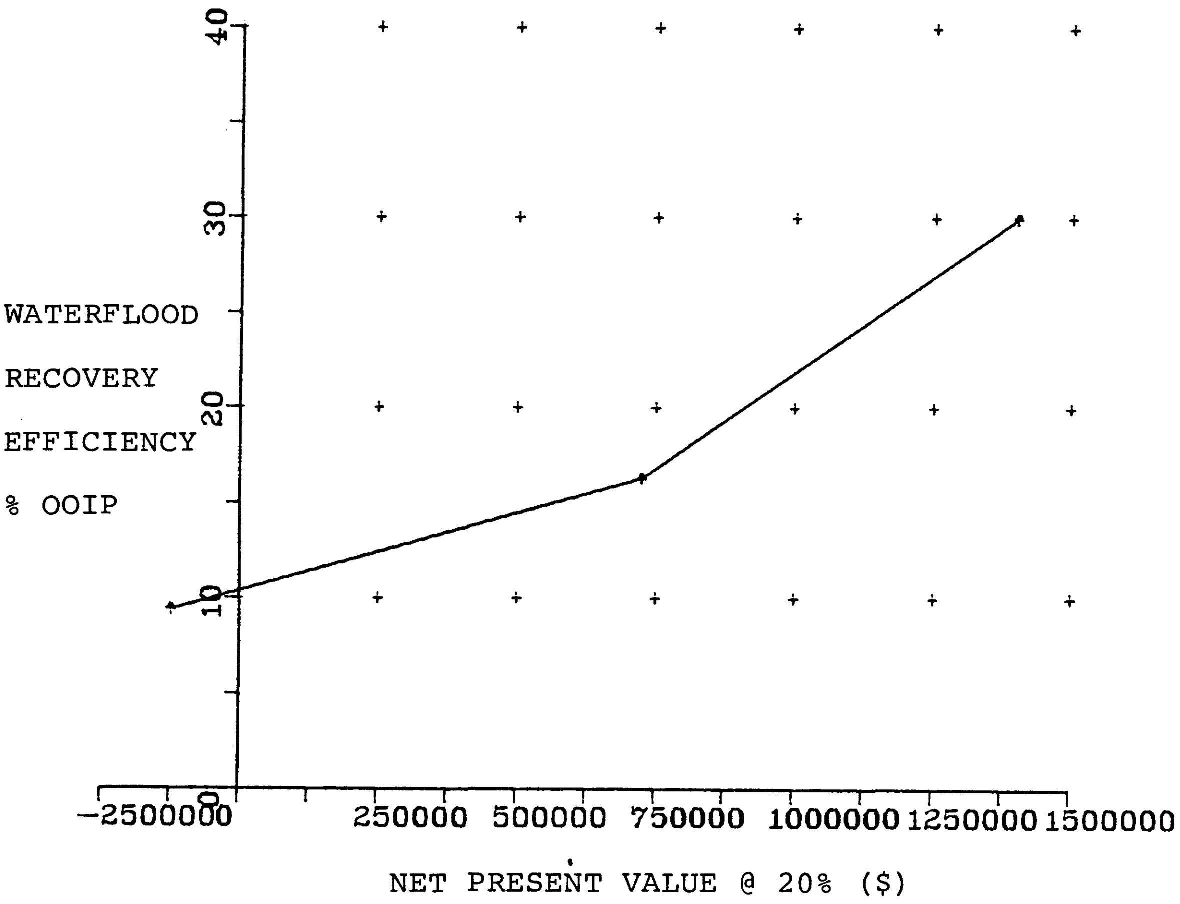
For the Zenith reservoir waterflood project the PVR ratio used to rank this project for the most probable case is 0.36 from an NPV at 20 percent of $724,000 from a PWI of $2,024,000. The PVR ranged from 0.03 to 0.63 for the lowest and highest probable cases related to the Zenith.

4.3. Sensitivity Analysis

The sensitivity analysis used in this evaluation has probabilities of occurences associated with the values of each primary variable. The sensitivity analysis becomes a probabilistic analysis for incorporating risk. In applying this probabilistic analysis, individual primary parameters are varied and their effect on the economic evaluation results are denoted by NPV change computed from the NPV waterflood recovery efficiency relationship illustrated in Figure 4.1. A short-coming of sensitivity analysis techniques in project evaluation stems from the inability to combine information from a number of sources into a determinate profitability indicator. In this analysis the probability is used to evaluate the effects of uncertainty; here a range of values is used to describe the primary variables since they cannot be adequately quantified by single value estimates. The determination of the lowest, highest, and most probable values of the primary variables will more accurately quantify the variable than will an average value, when calculating the profitability effects of a dynamic variable. The majority of the primary variables in the evaluation had an intermediate range of parameter values approximately 5 percent. A small range for all parameters,

FIGURE 4.1

ASSOCIATED NET PRESENT VALUE TO WATERFLOOD RECOVERY EFFICIENCY



such as the Crude Shrinkage range < 3 percent, is ideal. In application, a combination of small, intermediate, and large ranges (at water saturation at 20 percent) of parameter value variation for different parameters is obtained.

4.4. Inflation and Escalation

Since economic analyses deal with future events and the projections of the costs, revenues and salvage values associated with these events including effects of inflation and escalation, it seems that the effects of inflation and escalation on project costs and revenues have a very significant effect on economic analysis results and the uncertainty associated with the results. Consequently, it is critical to use a method of analysis which can distinguish between rises brought about by changes in intrinsic value and inflation with its resultant loss of purchasing power. (35)

Escalation is indicated by the progressive increases in the amounts paid for the things required to operate a business or maintain a household. Although escalation seems to result from a continuing series of individual actions, in times of high inflation (> 6 percent) the escalation rate applied to the project costs and revenues will reflect a magnitude based mostly on the inflation rate.

Opinions on how to handle escalation differ. They center around two approaches as follows: (1) constant dollar method. In this approach the projections of various components of cash flow are expressed as dollars of the year in which the evaluation is made. This assumes that prices and costs will escalate at the rate and thus offset each other, approximately. (2) component escalation method. In this method the escalation rate of each cost or price component in the cash flow stream is forecast independently. Using this method, one applies the knowledge to each component of the cash flow stream. Thus, wellhead prices for oil and gas, drilling costs, development expense, lease and well costs can be forecast based on recent experience or reasonable future expectations. Since the objective of the economic analysis is to maximize the future profit accumulated from the investment of capital, both methods will select the same alternative to maximize future profit. For proper analysis and consistent, correct economic evaluation conclusions, one must recognize that escalated dollar analysis and constant dollar analysis cannot be mixed and that the minimum ROR must be expressed in relation to the escalated dollar opportunities as a bank interest rate or attainable bond interest rates for escalated dollar analysis.

4.5. Cash Flow

The cash flow analysis is the end result of matching the inflow and outflow of all related funds over the investment life. The operating cost and income tax expenditures represent the outflows; the tax deductions, depreciation and depletion are deferred non-cash cost deductions for tax purposes. The inflow is our sales revenue and salvage values. On an after-tax analysis basis, the cash flow is analogous to the loan payment money available to pay off investment dollar principal and some after-tax rate of return on the unamortized investment each year.

To begin the evaluation estimate the project costs and revenues in today's dollar prices. This depicts the project costs and revenues as if the project occurred today. Since the project begins its life today, one must escalate today's prices for both costs and revenues to project the actual or escalated values that will be realized. The present worth calculation can wash inflation out of the escalated dollar analysis projections and leave the other monetary influences visible in the forecast dollar values. "Note that unless supply/demand and other considerations are nil, which means the escalation rate and inflation rate are equal, today's dollar value estimates for costs and revenues are not the same as the constant dollars." (36) For forecasting escalation rates for different commodities or segments of the industry, the U.S. Bureau of Labor Statistics publishes approximately 70 prices indexes of wage rates and an index of engineering costs which can be obtained to give past trends. Chemical Engineering presents the Marshall and Swift equipment cost index on a bimonthly basis.

Considering the Zenith waterflood project, the evaluation is based upon 100 percent cash investment. The company spent $24,000 to acquire mineral rights to non-producing property and the acquisition cost of producing property was treated as a sunk cost, since the transaction is based on primary reserves which are produced irrelevant to the waterflood project. The company spends $785,600 in drilling and intangible costs and $1,174,900 for injection equipment and other tangible well completion costs effective at the end of year one. The ensuing tangible and intangible costs are scheduled in Table 4.1. The tangible costs depreciated with DDB switching to straight line for a 10 year life assuming a zero salvage value. The production in barrels of oil follows the oil-production rate with time curve Figure 3.1 or the values from Table 3.1. A 12½ percent royalty per year must be paid. Operating costs started at $1,500 per well per

TABLE 4.1

WATERFLOOD DEVELOPMENT AND INSTALLATION COST

(Zenith Project)

WATERFLOOD INSTALLATION COSTS

Year	Injection Plant	Injection Distribution System	Produced Fluid Gathering System	Injection Well Conversions	Emergency Water Dis-posal Pit	D&E Water Supply Wells	Produced Water System	D&E Producing Well	Data Telemetry System	Total
1981										
Tangible	264,500	38,500	180,000	170,000	14,000	161,000	100,000	246,900		1,174,900
Intangible	8,000	850	4,500	750		302,000		469,500		785,600
1982										
Tangible									71,000	71,000
Intangible									3,000	3,000
1983										
Tangible										
Intangible										
1984										
Tangible				224,800						24,800
Intangible				1,300						1,300
1985										
Tangible										
Intangible										
1986										
Tangible										
Intangible										
1987										
Tangible								183,000		183,000
Intangible								629,900		620,900
									TOTAL	2,990,500

month escalating by 15 percent per year until the oil price escalation reaches its ceiling price at which time the operating costs are projected to be offset by escalation of revenues giving a washout of the two effects. Oil selling price was $16.20 per barrel in the evaluation year 1980 and was escalated 15 percent per year until a ceiling price of $65 per barrel was reached in 1990. The effective income tax rate is 52 percent. The end of project salvage value was $180,000. For the most probable case the recoverable crude reserves would be 1,424,950 barrels from a 14 year project life. This produces a $724,000 NPV for a minimum DCFROR of 20 percent, as illustrated in Table 4.2, cash flow calculations.

By applying a Stermole cash flow analysis and resulting NPV values, an economic determinate range and set of primary variables can be fabricated from the sensitivity analysis and reservoir engineering calculations.

Initially, a plot projecting discounted NPV figure values versus waterflood recovery factor or flood reserve values is constructed. A best fit line for the data points (Figure 4.1) generated by the lowest probable, most probable, and highest probable cases, is plotted through the zero NPV axis. The recovery factor or reserve figure at this point then designates the operational

TABLE 4.2

ZENITH HEATH SECONDARY RECOVERY

DEPRECIATION AND BORROWED MONEY SUMMARY

PROJ YEAR	DEPREC ITEM (ORIG COST)	TYPE DEPREC	ASSET LIFE	TOTAL ANNUAL DEPRECIATION	BOOK VALUE	SALVAGE VALU (INCL OTHER)	GAIN/LOSS (ASSET SALE)	INVESTMENT TAX CREDIT	ORIGINAL LOAN	PRINCIPAL PAYMENT	INTEREST PAYMENT
0	0.	---	0	0.	0.	0.	0.	0.	0.	0.	0.
1	1058700.	DDBSL	10	0.	1058700.	0.	0.	0.	0.	0.	0.
2	71000.	DDBSL	10	211740.	917960.	0.	0.	0.	0.	0.	0.
3	0.	---	0	183592.	734368.	0.	0.	0.	0.	0.	0.
4	224800.	DDBSL	8	146874.	812294.	0.	0.	0.	0.	0.	0.
5	0.	---	0	173699.	638596.	0.	0.	0.	0.	0.	0.
6	0.	---	0	136149.	502446.	0.	0.	0.	0.	0.	0.
7	183000.	DDBSL	6	106812.	578635.	0.	0.	0.	0.	0.	0.
8	0.	---	0	158745.	419889.	0.	0.	0.	0.	0.	0.
9	0.	---	0	132485.	287405.	0.	0.	0.	0.	0.	0.
10	0.	---	0	118929.	168475.	0.	0.	0.	0.	0.	0.
11	0.	---	0	109892.	58583.	0.	0.	0.	0.	0.	0.
12	0.	---	0	40509.	18074.	0.	0.	0.	0.	0.	0.
13	0.	---	0	18074.	-0.	0.	0.	0.	0.	0.	0.
14	0.	---	0	0.	0.	180000.	0.	0.	0.	0.	0.

SUMMARY OF MISCELLANEOUS COSTS

PROJ YEAR	NONDEPREC INVESTMENT	WKG CAP RETURN	WRITE-OFFS BEFORETAX	WRITE-OFFS AFTERTAX	AMORTIZATION COST	AMORTIZATION LIFE	AMORTIZATION DEDN	GROSS SALES	ROYALTY PAYMENT	GROSS REVENUE	OTHER INCOME	OTHER EXPENSES	OTHER TAXES
0	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.
1	684750.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.
2	3000.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.
3	0.	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.
4	1300.	0.	0.	0.	0.	0	0.	2173441.	271680.	1901761.	0.	0.	0.
5	0.	0.	0.	0.	0.	0	0.	4518698.	564837.	3953861.	0.	0.	0.
6	0.	0.	0.	0.	0.	0	0.	4503557.	562945.	3940612.	0.	0.	0.
7	620900.	0.	0.	0.	0.	0	0.	3754056.	469257.	3284799.	0.	0.	0.
8	0.	0.	0.	0.	0.	0	0.	312503.	39063.	273440.	0.	0.	0.
9	0.	0.	0.	0.	0.	0	0.	2601573.	325197.	2276376.	0.	0.	0.
10	0.	0.	0.	0.	0.	0	0.	1609891.	201236.	1408655.	0.	0.	0.
11	0.	0.	0.	0.	0.	0	0.	1197752.	149719.	1048033.	0.	0.	0.
12	0.	0.	0.	0.	0.	0	0.	891123.	111390.	779733.	0.	0.	0.
13	0.	0.	0.	0.	0.	0	0.	662992.	82874.	580118.	0.	0.	0.
14	0.	0.	0.	0.	0.	0	0.	211075.	26384.	184691.	0.	0.	0.

TABLE 4.2 (continued)

```
          ZENITH HEATH SECONDARY RECOVERY
          BASIC COST DATA REPRINT SECTION
          -------------------------------

      PROJECT LIFE = 14 YEARS      MINIMUM ROR = 20.0%

      INCOME TAX RATE = 52.0%

      THE (CONSTANT) ROYALTY RATE IS 12.5%

      INFLATION FACTORS, WHETHER ARITHMETIC OR GEOMETRIC,
      WERE NOT APPLIED TO REVENUES OR OPERATING EXPENSES.
      INSTEAD, BOTH ARE ASSUMED TO BE AFFECTED EQUALLY,
      SO A "WASHOUT" SITUATION EXISTS.

      CAPITAL COSTS ARE STATED IN "CURRENT" DOLLARS
      FOR THE YEAR IN WHICH SPENT.

                                                  DEPLETION SUMMARY
                                                  -----------------

PROJ   COST DEPL    NO. OF UNITS    TOTAL UNITS    UNITS REMOVED ADJUSTED  ALLOWABLE    PERCENT   50% TAXABLE   ACTUAL NET
YEAR  EXPENDITURE     ACQUIRED     (BEGIN YEAR)     THIS YEAR    CD BASIS  COST DEPL   DEPLETION   INC LIMIT    DEPLETION

  0          0.            0.             0.             0.          0.         0.          0.          0.          0.
  1      24000.      1424950.       1424950.             0.      24000.         0.          0.          0.          0.
  2          0.            0.       1424950.             0.      24000.         0.          0.          0.          0.
  3          0.            0.       1424950.             0.      24000.         0.          0.          0.          0.
  4          0.            0.       1424950.        156588.      24000.      2637.          0.     795316.       2637.
  5          0.            0.       1268362.        295920.      21363.      4984.          0.    1779893.       4984.
  6          0.            0.        972442.        263212.      16379.      4433.          0.    1775516.       4433.
  7          0.            0.        709230.        195830.      11945.      3298.          0.    1422454.       3298.
  8          0.            0.        513400.        145697.       8647.      2454.          0.          0.       2454.
  9          0.            0.        367703.        108399.       6193.      1826.          0.     851696.       1826.
 10          0.            0.        259304.         80649.       4367.      1358.          0.     391575.       1358.
 11          0.            0.        178655.         60003.       3009.      1011.          0.     215783.       1011.
 12          0.            0.        118652.         44642.       1998.       752.          0.     116324.        752.
 13          0.            0.         74010.         33214.       1247.       559.          0.      27734.        559.
 14          0.            0.         40796.         18385.        687.       310.          0.          0.        310.
```

TABLE 4.2 (continued)

```
                              ZENITH HEATH SECONDARY RECOVERY

                              OVERALL PROJECT COST AND CASH FLOW SUMMARY
                              ------------------------------------------

PROJECT    GROSS    OPERATING    AGGREGATE    NET INCOME      NET      NET TAXABLE   INCOME       NET        CASH
  YEAR    REVENUE     COSTS    DEPRECIATION  BEFORE DEPL  DEPLETION     INCOME        TAX       PROFIT       FLOW

    0          0.          0.          0.          0.         0.           0.          0.          0.          0.
    1          0.     108000.          0.    -108000.         0.     -108000.     -56160.     -51840.   -1819299.
    2          0.     124200.     211740.    -335940.         0.     -335940.    -174689.    -161251.     -23511.
    3          0.     142830.     183592.    -326422.         0.     -326422.    -169739.    -156683.      26909.
    4    1901761.     164255.     146874.    1590632.      2637.     1587995.     825757.     762238.     685649.
    5    3953861.     220375.     173699.    3559787.      4984.     3554803.    1848497.    1706305.    1884988.
    6    3940612.     253431.     136149.    3551032.      4433.     3546599.    1844232.    1702368.    1842950.
    7    3284799.     333080.     106812.    2844907.      3298.     2841609.    1477637.    1363972.     670182.
    8     273440.     383043.     158745.    -268348.      2454.     -270802.    -140817.    -129985.      31214.
    9    2276376.     440500.     132485.    1703392.      1826.     1701566.     884814.     816752.     951052.
   10    1408655.     506575.     118929.     783150.      1358.      781792.     406532.     375260.     495546.
   11    1048033.     506575.     109892.     431566.      1011.      430555.     223889.     206667.     317569.
   12     779733.     506575.      40509.     232648.       752.      231897.     120586.     111310.     152571.
   13     580118.     506575.      18074.      55469.       559.       54910.      28553.      26357.      44990.
   14     184691.     211073.          0.     -26362.       310.      -26692.     -13880.     -12912.     167497.
     THE DISCOUNTED CASH FLOW RATE OF RETURN
     FOR THIS PROJECT IS
                         ***     29.87    ***  PERCENT.

     THE NET PRESENT VALUE IS $ . 724315.680
     (USING A MINIMUM ROR OF 20.0%)

     THE PAYBACK PERIOD FOR THIS PROJECT IS 4.60 YEARS.

                    ROR/NPV SUMMARY
                    ---------------

MIN ROR (%)        NPV        MIN ROR (%)       NPV
      0         5428330.           40        -386492.
      2         4546188.           45        -504225.
      4         3805193.           50        -590448.
      6         3179464.           55        -653323.
      8         2648480.           60        -698715.
     10         2195849.           65        -730900.
     12         1808393.           70        -753034.
     14         1475444.           75        -767474.
     16         1188316.           80        -775997.
     18          939894.           85        -779956.
     20          724316.           90        -780387.
     25          299178.           95        -778094.
     30           -5286.          100        -773697.
     35         -225714.          110        -760439.
```

feasibility limit that a waterflood project must obtain through its primary variables.

Taking the recovery factor that represents the limit as economically viable projects into the sensitivity analysis graphs in Chapter Two a determinate set of primary variables is generated. This set of primary variables describes the limit and interactive region for results to produce feasible projects.

With this economic description of the factors it is now plausible to solve graphically, or with the Callaway equation, the economic range of interaction between two variables as a function of the recovery factor or NPV figures.

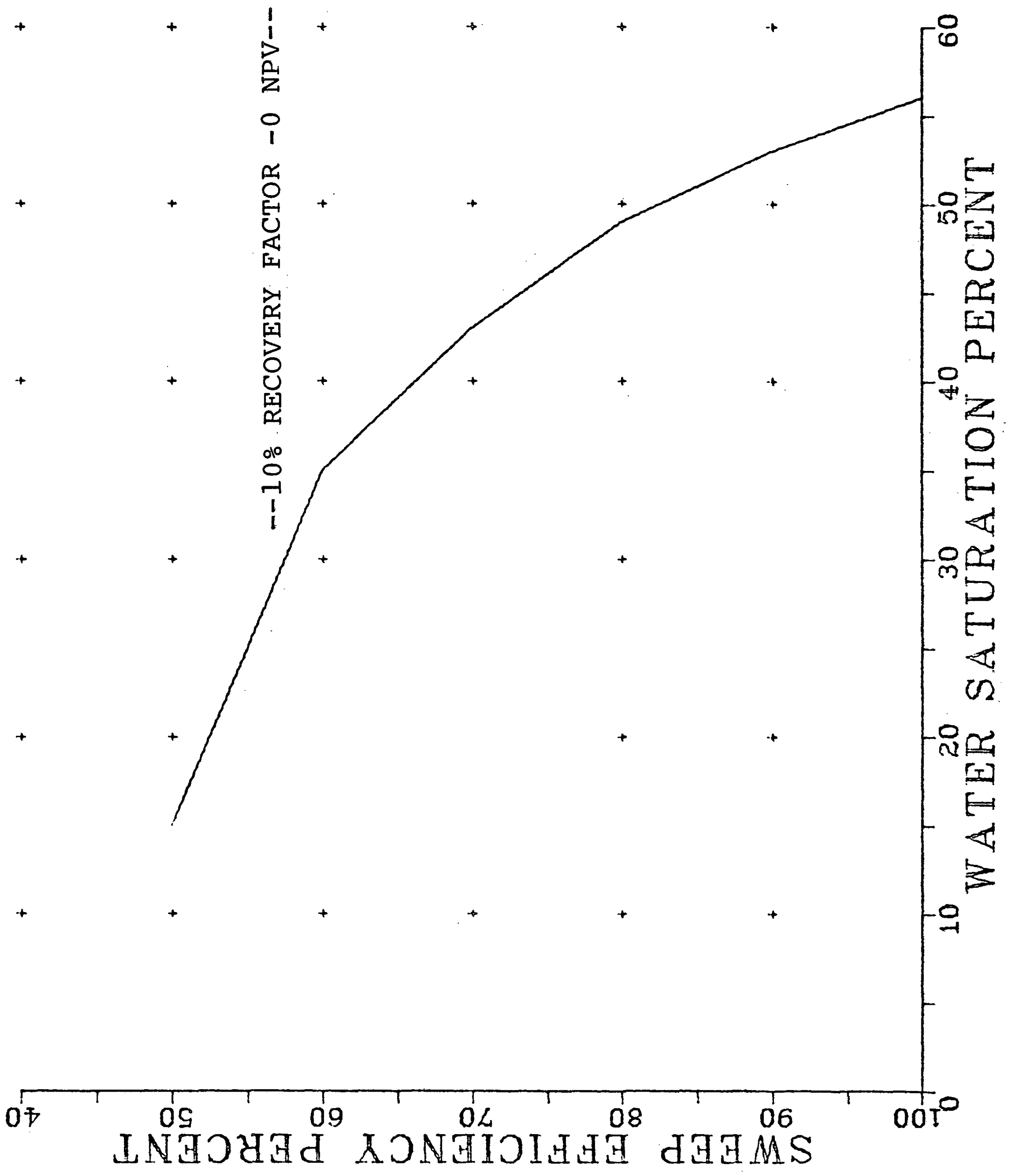
To illustrate the yield of these results reference the subject reservoir, the figures from the lowest probable; most probable, and highest probable case are shown in Figure 4.1. This graph can be used to forecast an 11 percent OOIP value for the recovery factor produced a zero NPV at 20 percent for this project. Using that recovery factor value to enter the graphical sensitivity analysis for the primary variables, Figure 2.1-4, 2.7, the following constraints are generated for profitable flooding:

Sweep Efficiency	$E \geq 52$ percent
Primary Recovery	$R \leq 23$ percent
Water Saturation	$S_w \leq 38$ percent
Residual Oil Saturation	$S_{or} \leq 37$ percent
Crude Shrinkage	$B_o/B_f \leq 1.09$

With these limits now described in economic terms, the problem of designing the injection pattern, the injection fluids, or fluid volumes is not judged on technical magnitude, but can be coordinated as a function of the recovery factor or a specific NPV figure.

In the subject reservoir, there is the option to expand the injection pattern to increase the sweep efficiency or inject a polymer slug to lower residual oil saturation behind the flood. Using the possible investment decision to increase the injection system size, this evaluation could estimate the magnitude of the sweep efficiency variable necessary to make the probable range of water saturations encountered result in a profitable or specific NPV project. As illustrated in Figure 4.2, the region below the 11 percent recovery factor line represents the workable range for sweep efficiency and water saturation to produce profitable results; on this graph other lines

FIGURE 4.2


--10% RECOVERY FACTOR -0 NPV--
WATER SATURATION PERCENT
0
10
20
30
40
50
60
SWEEP EFFICIENCY PERCENT
40
50
60
70
80
90
100

could be drawn to represent the NPV magnitude in the profitable region. The 11 percent line here represents the zero NPV limit.

The investment present value needed to initiate the Zenith Heath Reservoir waterflood project amounted to $2,024,000 assuming the primary production revenue stream was dedicated to property payment or sunk cost values. This produces a range in the discounted investment from about $2.25 per barrel of incremental recovery for the lowest probable case to about $1.00 per barrel for the highest probable case. These figures are in agreement with the incremental costs of waterflooding in the continental United States, which averages approximately $2.00 per barrel on incremental recovery. From this investment, the most probable case production produces a cash flow with an NPV of $1,332,000 and $724,000 at 15 percent and 20 percent, respectively, or a 29 percent DCFROR. This is for a project life of 14 years. The range of economic factors for the lowest probable case to the highest probable case was 19 percent in DCFROR (22 percent - 41 percent) and approximately $1,340,000 NPV discounted at 20 percent.

The research here would conclude that the Zenith Heath Field is a viable candidate for waterflooding. The

NPV associated with the analysis suggests nearly a million dollars of discounted investment could be used after response to improve flood recovery by additional wells improving pattern sweep efficiency and/or a slug polymer injection improving vertical sweep efficiency and mobility ratio.

APPENDIX A

A.1. Introduction

The Williston Basin, one of the largest structural and sedimentary basins in North America is a prolific hydrocarbon providence. An elliptical depression centered in North Dakota, the basin has been estimated to encompass between 240,000 and 325,000 square miles.

It is divided into two regions by the International Boundary with the northern Williston Basin of Canada encompassing southeastern Saskatchewan and southwestern Manitoba. The southern region, occupying roughly 111,000 square miles, underlies two-thirds of North Dakota, eastern Montana and northwestern South Dakota. Approximately 22,000 square miles of northwestern North Dakota and northeastern Montana represent the deepest part of the basin.

The limits of this sprawling basin are defined by distinct geologic features. The east and northeast are bounded by the acient Precambrian rocks of the Canadian Shield, while the Black Hills and the Sioux Uplift abut its southern edge in South Dakota. To the west, the United States portion is bordered by the Miles City Arch and the Central Montana Uplift, while the Sweetgrass Arch and North Battleford Arch form the western flank in Canada.

Composed of sediments deposited and lithified under shallow marine conditions, rocks of the basin slope gently towards its structural center in McKenzie County, western North Dakota. Here Precambrian rocks are overlain with up to 16,000 feet of predominantly Paleozoic sedimentary strata. Westward sloping sediments of North Dakota average 60 feet per mile.

A.1.1. Geologic History of the Williston Basin

The Williston Basin is the largest of a long trend of intracratonic basins formed over a period of more than 600 million years as shallow seas intermittently advanced and retreated over the shelf area of the North American craton. Development of the Williston Basin, which contains sedimentary deposits of every geologic period from Cambrian through Tertiary, may have been initiated as early as late Precambrian or early Cambrian. However, it did not become a distinct geological feature until mid-Ordovican when crustal subsidence created a wide, shallow depression on the cratonic shelf.

A.2. Discussion on Geology of the Zenith Field

The Zenith Field is located in T139N-R98W of Stark County, North Dakota on the south flank of the Williston Basin. It produces from the Tyler Formation, Heath Sands of Lower Pennsylvanian Age.

Production is from a multi-storied sequence of 4 to 12 feet (1.2 to 3.7m) thick quartzose sandstones deposited as a barrier island along regressive shorelines. A typically developed sequence consists, in ascending order, of the following:

1. 1-6 feet of black to greenish-gray sparsely fossiliferous shale. Thin interbeds of fossiliferous lime mudstone.
2. 1-4 feet of very fine-to fine grained sandstone containing small, burrow structures. Stratification is finely laminated to ripple cross-stratified. Thin interbeds of siltstone and shale ore are common which indicates lower shoreface environment.
3. 3-12 feet of fine to medium grained, well-sorted sandstone which commonly exhibits medium to low angle sets of cross-stratification. These genetic

units are the principal environment.

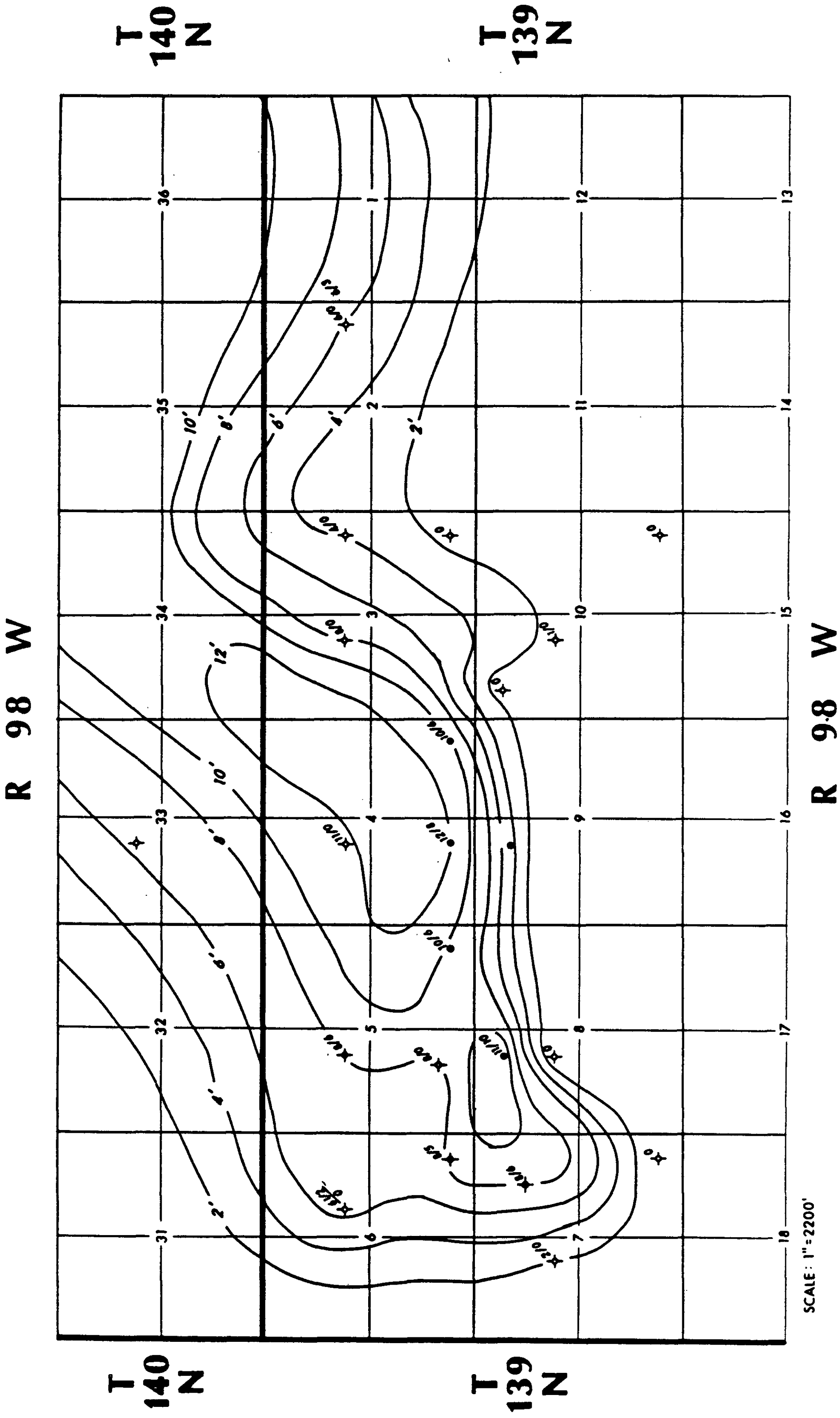
4. 1 foot fine to medium-grained sorted sandstone appears massive. The upper few inches are clayey and mottled with root structures. (foreshore environment) Lower 1/2 to 3 inches of coal (marsh environment).

In the landward direction (south) the shoreline sandstones interfinger with thin fossiliferous limestone, black shales, and oxidized mudstones which are interpreted to be lagoon, marsh and mudflat deposits. (29)

Throughout the subject area porosity and permeability in the sandstone have been greatly reduced or completely destroyed by caliche paleosol development. In the western part the caliche consists of gray to brown limestone nodules or nodular layers of limestone in the sandstones and contains syrite. In the eastern part the caliche has been strongly oxidized and nodular to brecciated limestone in the sandstones is associated with reddish-brown to white clay, heavy iron oxide cement and occasional anhydrite nodules.

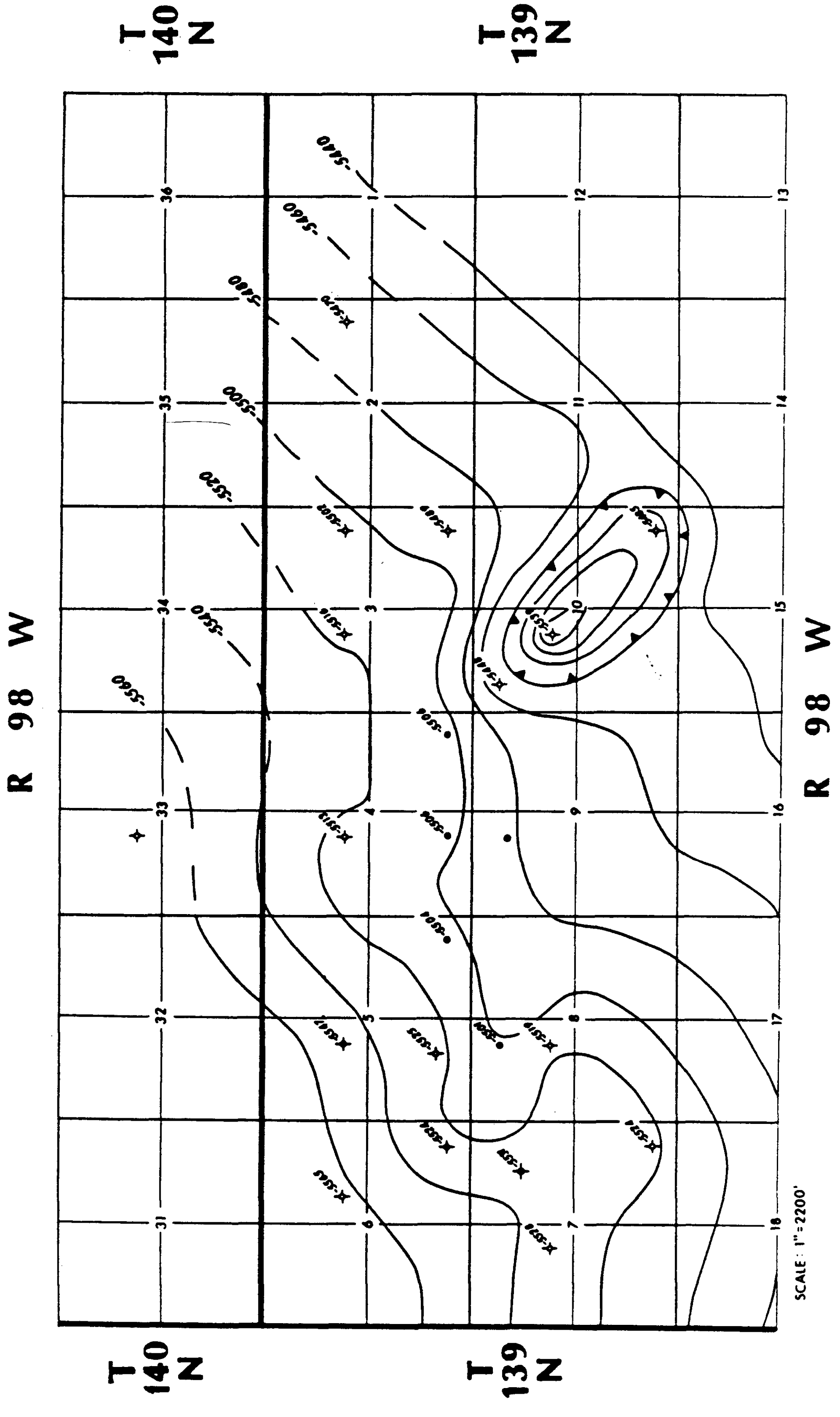
It is estimated that the caliche destroys as much as 50 percent of the potential reservoir rock in the area and is an essential factor in the stratigraphic entrapment of the petroleum reservoir by providing a south eastern (updip) barrier to migration. The structural aspect denotes the oil water contact on the North (see Figure A.1 and A.2). (31)

FIGURE A.1



ISOPACH: TYLER GROSS SAND C.I.= 2'

FIGURE A.2



STRUCTURE: TYLER "B" SAND C.I.= 20'

A.3. Development History

The Zenith Field was discovered in October 1968 with the completion of the Northern Pacific Railroad (N.P.R.R.) 16-5, (SE/4 SE/4 Sec. 5T139N-R98W). The 24 hour potential test on this well pumped 285 barrels of oil per day (BOPD) with 10/44" strokes per minute (SPM) and a gas oil ratio (GOR) of 219 standard cubic feet of gas per barrel of oil. The initial shut-in pressure was 3564 psi.

In December of the same year the #1 Wagner reached total depth (TD). It was located on the north side of the oil-water contact. It tested 6820' salt water with a slight show of oil and the initial shut-in pressure was 3573 psi. This well is located in SE/4 NW/4 Sec. 4 T139N-R98W.

In the next year, May of 1969, the N.P.R.R. 6-5A, (SE/4 NW/4 Sec. 5 T139N-R98W) was completed. On a 7½ hour preliminary potential test, it tested 730 barrels per day with 2 percent basic sediments and water (BS & W). The drill stem test recovered 7296' of oil, with an initial shut-in pressure of 3195 psi.

The Zarak Oyhus 16-6 (SE/4 Se/4 Sec. 6 T139N-R98W) was completed in November 1969 and had an initial potential pumping (IPP) of 270 BOPD, 38° API oil and 1 percent BS & W. Initial shut-in pressure was 2546 psi with 3760' of total fluid recovered from -5524 sub sea feet.

The Zarak #1 (C-NE/4 NW/4 Sec. 8 T139N-R98W) completed in April, 1970 had an initial potential pumping (IPP) of 498 barrels of 39.5° API oil, GOR: 200/1 scf/bbl; producing no water, at 8 strokes per minute (SPM), with 192" strokes. The Zarak #1 recovered 7220' fluid from the drill stem test with an intial shut-in pressure of 2234 psi.

In November 1970 the Tuhy #1 was completed. (SE/4 SW/4 Sec. 9 T139N-R98W). The initial potential test produced 332 barrels of 37.9° API oil/day, 2/10th percent water, with an estimated 400 SCF/BBL GOR and 10 SPM/144' strokes. The initial shut-in pressure was 3570 psi, recovering 4234' fluid on the drill stem test.

The Burlington Northern #1 (C-NE/4 Sec. 7 T139N-R98W) was completed in October 1970. The initial test produced 482 barrels of oil/day, no water with an estimated 750 SCF/BBL GOR at 10/120" SPM 6355' of fluid was recovered from an initial shut-in pressure of 1834 psi. The increase in the GOR noted here at 1834 psi pressure indicates the presence of free gas around this well bore by its pressure falling below the bubble point.

In January 1971, the Jablosky #1 (SE/4 SE/4 Sec. 4 T139N-R98W) was completed. Initial tests produced 304 barrels of 38° API oil, 4 percent water, with 10/144" SPM. The Jablonsky #1 recovered 5500' fluid on the drill stem test, and had an initial shut-in pressure of 2663 psi.

In March 1968, the North Dakota State Industrial Commission established a 320 acre spacing order. Subsequently the Zenith Field was developed on 320 acre spacings. The Zenith Field has had 8 developed wells, 2 are now plugged and abandoned, 2 are shut-in and there are 4 producing.

A.4. Primary Production

As of July 1, 1980 cumulative production had reached 1,565,686 Stock Tank Barrels of Oil (STBO). The North Dakota Geological Survey, the North Dakota Production Schedule and the Oil Production Report as well as production data furnished by the operators have been the sources of production information. Primary reserves as of July 1, 1980 were estimated at 198,700 STBO. The resulting ultimate primary recovery is 1,674,500 STBO, or 19.1 percent of the original oil in place. Based on the reservoir data tabulated on Table 1, the original oil in place was calculated to be 8,769,000 STBO. A tabulation of cumulative oil produced, primary reserves and ultimate primary production are shown by well in Table A.1 and located on Figure A.3.

Primary reserves were estimated by extrapolation of the individual well performance curves to the economic limit of 4 BOPD. Extrapolation of these curves is based on the stabilized production portions of the well performance curves taking well production history into consideration. Both the initial rate and the rate of economic limit are in barrels of oil per day. The initial rate for the remaining primary reserves figures in this case uses the June 1980 rate and applies this to the

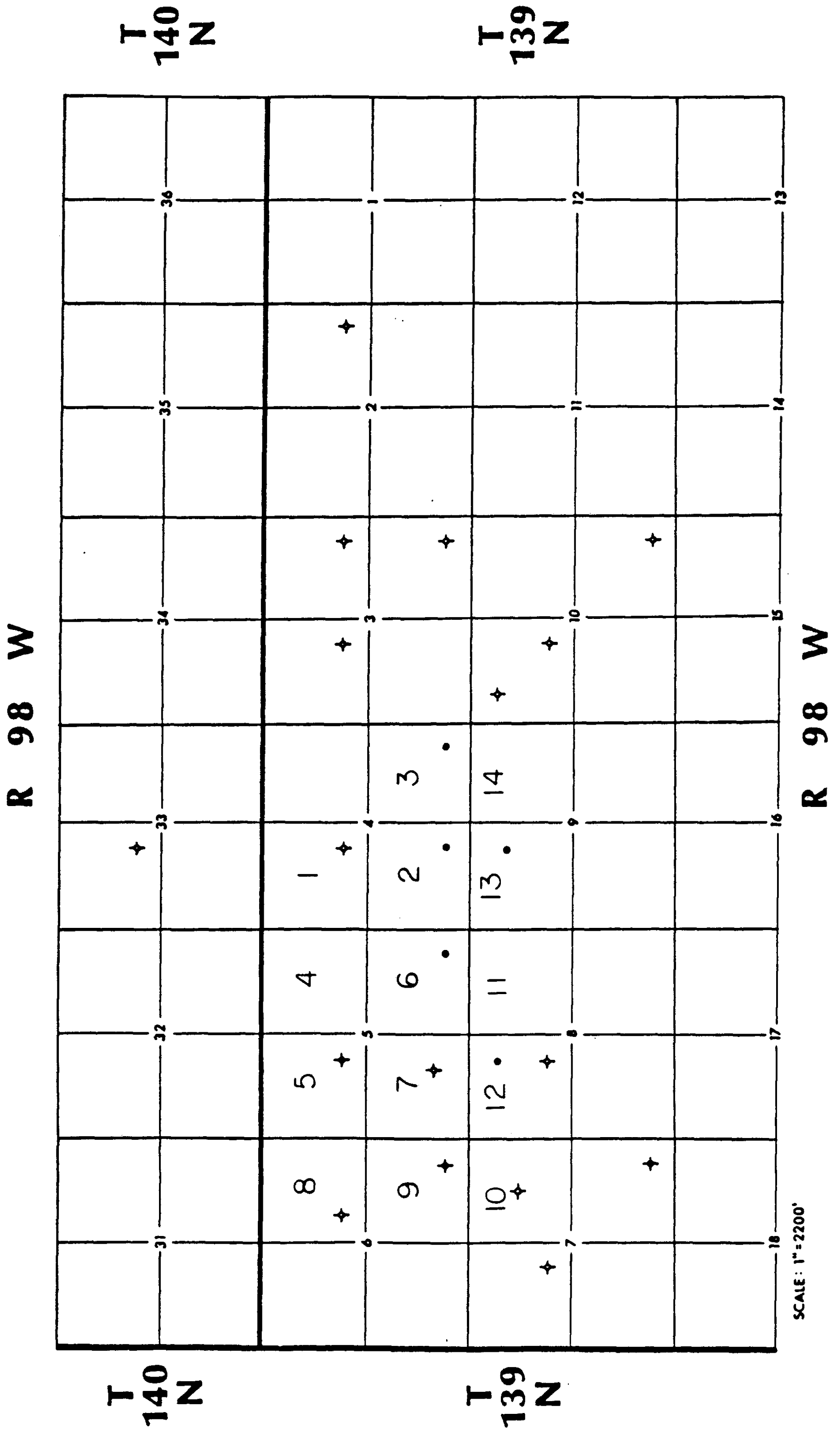
TABLE A.1

Tract #	Qtr.	Sec.	Surface Acres No.	%	Usable Wells No.	%	Primary Reserves Bbls.	%	Cumulative Production Bbls.	%	Ultimate Primary Bbls.	%
1.	NW	4	160	7.14			66,561					
2.	SW	4	160	7.14	1	25.00		33.49	206,714	13.20	273,275	15.49
3.	SE	4	160	7.14	TA				89,647	5.73	89,647	5.08
4.	NE	5	160	7.14								
5.	NW	5	160	7.14	TA				104,063	6.65	104,063	5.90
6.	SE	5	160	7.14	1	25.00	48,697	24.51	306,716	19.59	355,413	20.14
7.	SW	5	160	7.14								
8.	NE	6	160	7.14								
9.	SE	6	160	7.14	P&A				58,105	3.71	58,105	3.29
10.	NE	7	160	7.14	P&A				183,654	11.73	183,654	10.41
11.	NE	8	160	7.14								
12.	NW	8	160	7.14	1	25.00	54,381	27.36	424,677	27.12	479,058	27.15
13.	NW	9	160	7.14	1	25.00	29,093	14.64	192,110	12.27	221,203	12.54
14.	NE	9	160	7.14								
			2,240	100.00	4	100.00	198.732	100.00	1,565,686	100.00	1,764,418	100.00

TA - Temporarily abandoned

P&A - Plugged and abandoned

FIGURE A.3


T 140 N
T 139 N
R 98 W
R 98 W
36
35
34
33
32
31
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SCALE: 1"=2200'
T 140 N
T 139 N

decline curve equation calculations.

These are as follows:

-b slope of decline curve logrithmic

$q/q_o = \exp(-b)$

d = percent decline

$q = q_o e^{-bt}$

t = time

$Q - Q_o = \frac{q_o - q}{b}$

Q = cumulative production

Q_o = reserves

The calculation of the initial rate was done by production in 1980, divided by actual days produced, weighted by the decline factor to the economic limit. Calculations are in Table A-2. See Figure A.4 and A.5 for historical production decline.

The high operating costs result primarily from the high pour point of the Heath Crude. The crude tends to build a paraffin-like substance in the tubing and flow lines which incurs a consistent amount of maintenance. Heat systems are required with each tank battery and all production equipment is powered and heated by electricity. The crude is also trucked to a marketing point.

The producing mechanisms in the reservoir were fluid

TABLE A.2 ZENITH FIELD

Economic Limit of Production

(Monthly Cost)

$ 400	Pumping unit and lift equipment
30	Well treatment schedule
300	Workover remedial schedule
100	Chemicals
190	Contract labor
700	Power
1700	Monthly cost of production 1980

$1700 ÷ $16.5/bbl = 103

103 bbls/mo ÷ 30.4 days/mo = 3.4 bbls/day

4 BOPD Economic Limit

FIGURE A.4

PRODUCTION RATE WITH TIME (ZENITH FIELD)

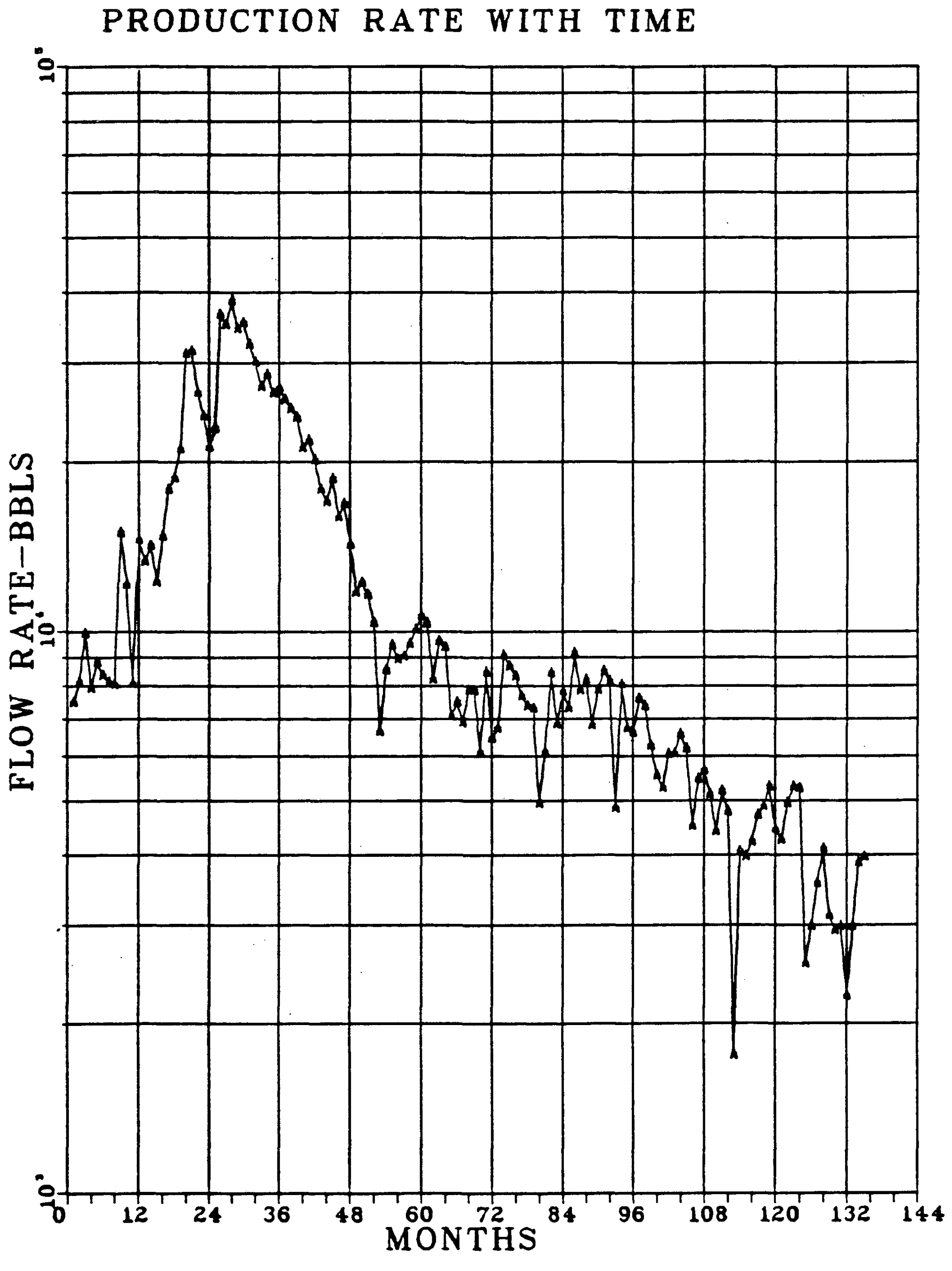
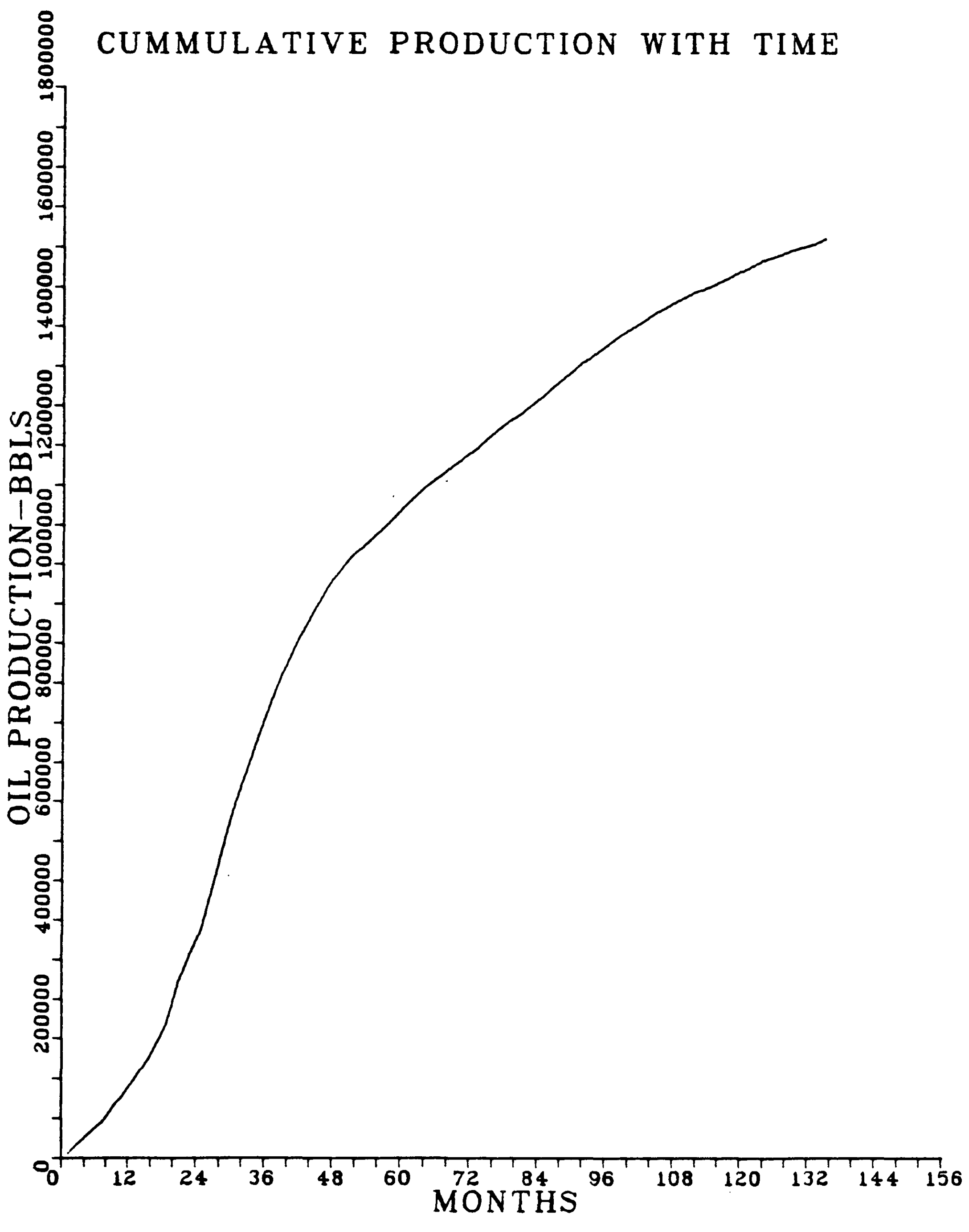


FIGURE A.5

CUMMULATIVE PRODUCTION WITH TIME (ZENITH FIELD)



expansion above the saturation pressure of 2058 psi and solution gas drive thereafter. There is no apparent water drive. Based on a December 12, 1980 pressure survey, the average reservoir pressure was approximately 250 psi. The gas phase occupying .129 pour volumes does not seem to be continuous as yet.

A.5. Reservoir Data

The production of the Heath Sand covers 1710 acres of 2 feet net oil sand and contains 10,465 acre feet of net oil sand.

A.5.1. Determining the Net Pay for Individual Wells

Procedures are summarized as follows:

1. Wells for which core analysis is available through the pay zone must have 10 percent plus porosity and 1 plus millidarcy permeability at a 10 percent plus oil saturation.
2. Wells with logs only must have a sonic measure porosity of 10 percent plus based on 19,500 Vm and 5,550 Vf (matrix velocity and fluid velocity). These values correspond with 65 msec at 10 percent porosity; also the gamma ray value must be less than 48 API units.

Qualifications:

1. Core analysis will be given preference when wells have both core analysis and logs.

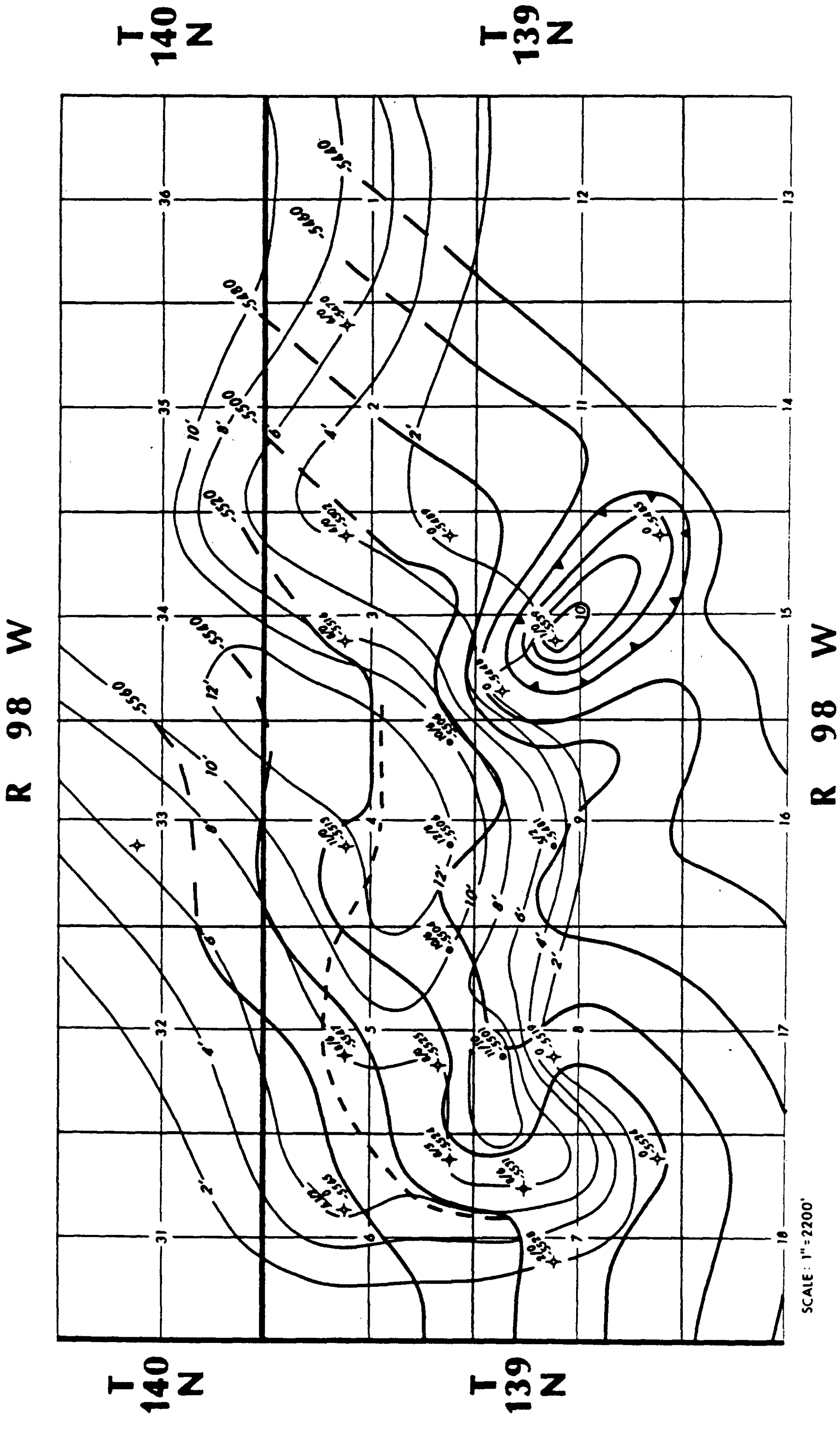
In the Burlington Northern well, only the gamma ray neutron logs are available. A semi-log plot of porosity versus API neutron units was made for each well to determine the neutron unit value corresponding to 10 percent porosity. A shale section and tight zone were assumed to have porosities of 38 units and 2 units respectively. These two points were used to establish the curves. Individual well net pay thicknesses were summarized on Figure A.2. To calculate porosity from the formation density log, a grain density and fluid density of 2.68 grams per cc and 1.0 grams per cc, respectively, were used.

The reservoir oil/water contact is difficult to delineate in the Heath Sand because productive limits are controlled more by permeability pinch-out than by water level. At the edge of the reservoir, some wells have recovered water on drill stem tests at various subsea depths. However, because of the oil/water transition zones in these lower quality sands (10 to 11 percent porosity) and less, the relative contact is projected by isopach slope (see Figure A.6).

Figure A.6 is a structure map on top of the Heath Sand and a net sand isopach on the Tyler Sand.

The original reservoir pressure of 3564 psi was obtained from the NPRR #16-5 (SE/4 SE/4 Sec. 5, T139N-R98W) in October of 1968. The pressure based on a datum of -5510 feet subsea was measured during the initial drill stem test.

FIGURE A.6



ISOPACH: TYLER GROSS SAND C.I.= 2'
STRUCTURE: TYLER SHALE MARKER BED C.I.= 20'

Analysis of samples collected later established a saturation pressure of 2058 psi. Use of a bottom hole pressure bomb for a PVT analysis would be called for in the initial stages of unitization to construct a map prepared for pressure data based on an average reservoir pressure weighted by psi per acre foot. The gas saturation at this time should be approximately 13 percent, resulting in a gas voidage of 1,536,400 barrels, as shown below:

1 pore volume = 7,758 x 0.51 x 10465 AF = 12,178,120 barrels.

Gas Void = 1,565,686 (12,178,120 - 288,000) = 12.9 percent.

Total field injection for the first year is expected to average 1400 BWPD. However, in order to get a more realistic indication of the flood response water requirements, it was assumed that 15 percent of the total water injected would be lost to other formations as well as to areas of the Heath Sand Reservoir not presently defined. It is also estimated that during the first year of injection there will be an average reservoir voidage due to production of 98 barrels per day. The above results in a net average injection for the first year of 1,200 barrels of water per day. When approximately 3/4 of this gas voidage is filled, we should start to see some tangible evidence of response and total field production from the closest pattern corresponding producing well. Based on an injection rate of 1,400 of water/day this should occur in 1,118 days or approximately 3 years after the start of injection. The most probable peak production rate should be from 700-800 barrels of oil per day. The maximum primary producing rate was in December 1967, at 1,078 barrels of oil per day from six wells.

The model runs indicated total injection requirements would be approximately 16,425 million barrels or 1.55 pour volumes. In terms of displaceable pour volumes (DPV) this injection requirement amounts to 1.35 DPV's and in the swept area 2.0 DPV's.

As is characteristic after fillup and injection development, the field injection rates would decline throughout the later life of the waterflood. After fillup there is essentially a steady state system and injection varies as a direct proportion to the producing capacity, which gradually declines as a result of shutting in of water producing wells. Total field water production also varies considerably as a result of shutting in high water cut wells.

A.6. Injectivity Calculations

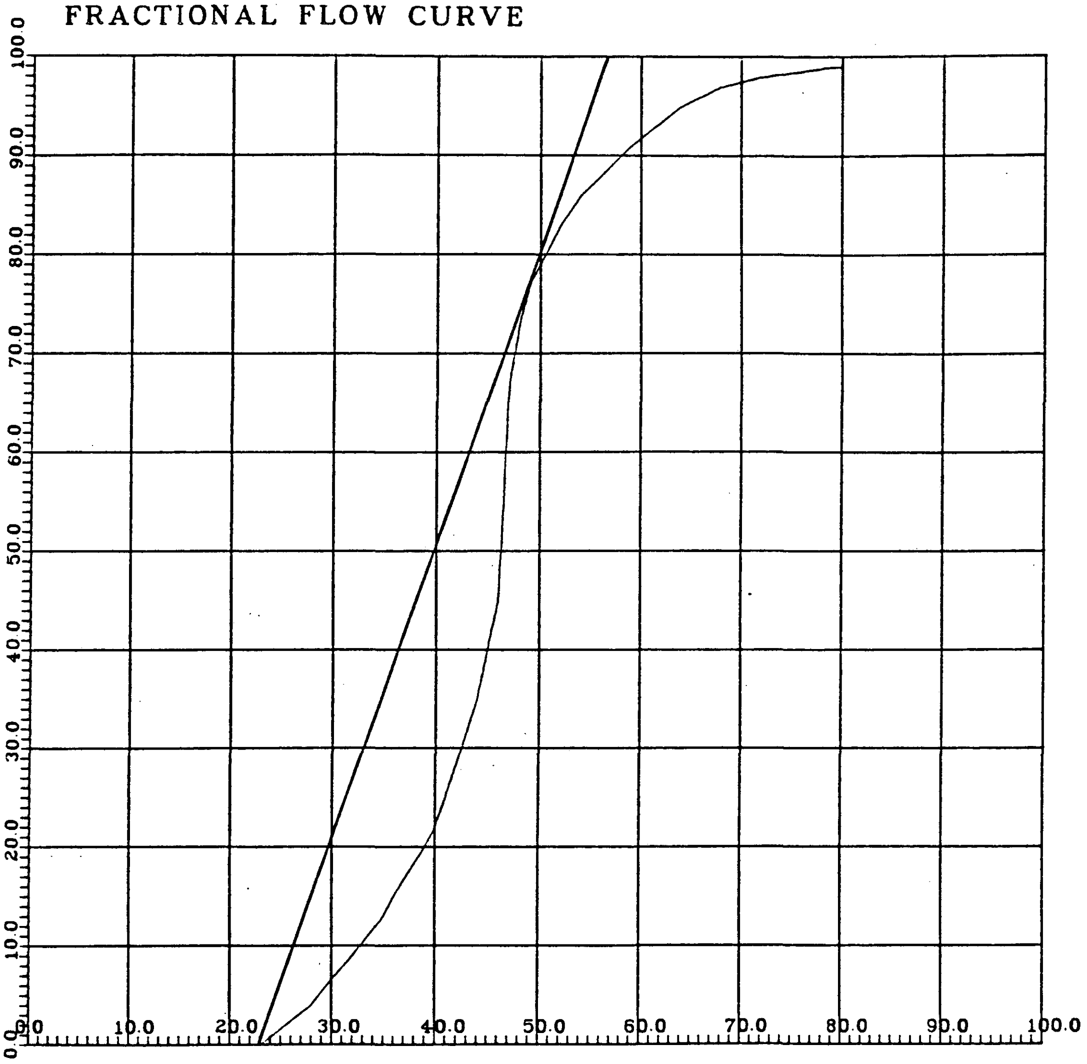
Stabilized (after fill-up) injection rates were calculated by first computing the specific injectivity index, and then applying that index to the permeability-thickness product (kh) for the selected injection wells.

The specific injectivity was calculated from the regular five spot steady state equation. However, since it was not known whether the patterned equation would give reliable results for the proposed linear pattern, the injectivity was checked using an unsteady state image well model with a typical segment of a peripherial flood pattern. The injectivity indicated by the image well model was in very close agreement with the computed five spot pattern equation. The relative permeability data utilized in the injectivity calculations were from the NPRR #16-6, NPRR #6-5a and the Zarak #1. This information is illustrated in Figure A.7 and 2.B. Also shown below is the mobility ratio (M) based on oil viscosity of 2.66 cp and water viscosity of 0.4 cp.

The relative flow permeabilities were picked from the Krw curves, at the average water saturation behind the flood front at breakthrough, i.e., the intersection of the tangent to the fractural flow curves at the fw-100%, Figure A.7. The relative oil permeabilities were taken

FIGURE A.7

FRACTIONAL FLOW CURVE (CORE NP16-5 ZENITH)



from the Kro curves at the minimum water saturation points.

From the five spots steady state equation:

$$\text{Injectivity, } i_w = \frac{.00354(k_{rw}/\mu_w\ k_a\ h\ \Delta P}{\ln d/r_w - 0.619} \quad \text{BPD}$$

Specific Injectivity, Is,

$$= \frac{.00354\ k_{rw}/\mu_w}{\ln d/r_w - 0.619\ k_a\ h\ \Delta P} \qquad \frac{\text{BPD}}{\text{md - ft - psi}}$$

krw = 0.111

μ_w = 0.4 centipoise

h = 10

Injection well surface pressure = 2,500 psi

Water specific gravity = 1.016

Producing well pressure = 250 psi

Well depth = 8,000 ft.

$P = 2500 + 8000 \text{ X } (.433 \times 1.016) - 250 = 5769$ psi

d = 3733' (distance from injector to producer)

r_w = 0.5' = injection well radius

As previously mentioned, 15 percent loss in injection volume has been assumed and, therefore, the effective injection rate used in the waterflood is 85 percent of the total water injected.

As previously noted, an r_w of 0.5' was used in calculating the well injectivity. Since most of the wells in the field have been fracture treated, the calculated well injection rate should be on the conservative side.

Some fracture treatment records for the field were examined and a formation fracture pressure greater than 6,000 psi was determined. The well head injection pressure will be kept below fracture pressure if sufficient injectivity can be obtained.

The average ratio for the Heath Sand prior to breakthrough was calculated to be 1.365, or slightly unfavorable as shown below:

$$M = \frac{K_{rw}}{K_{ro}} * \frac{\mu_o}{\mu_w} = \frac{0.111}{0.573} * \frac{2.66}{0.4} = 1.29 \text{ Mobility ratio}$$

A.7. Water Supply

Injection water will be obtained from the 100' thick Dakota sandstone which is found at an average depth of 5,500'. A drill stem test of the Dakota recovered 68 barrels of water in 17 minutes against an average head or back pressure of 2,035 psi. Drawn down calculations indicate that 18,000 barrels of water per day can be produced at a pump depth of 1950'. It is therefore planned to complete one supply well with a submersible pump capable of lifting 2,400 barrels of water per day.

A water analysis of the Dakota drill stem test sample indicates NaCl content of 25,000 ppm and no other objectionable qualities.

An alternate water supply sources was investigated. Water from the Minnelusa Formation found at a depth of 7,200', NaCl exceeds 330,000 ppm which would lead to a salt precipitation problem.

APPENDIX B

B.1. Costs

B.1.1. Development Expenditures

Exploratory expenditures are those costs of finding or discovering new oil and gas reserves. Development expenditures are those costs associated by the drilling of exploratory wells. The difference between the two types of drilling ventures is essentially the degree of uncertainty or risk involved and the generally higher cost of exploratory wells.

Of the three principal cost elements pertaining to the petroleum producing industry, exploration, development, and production, this study is concerned with the latter two only.

The objective of this study, to determine profitability of producing oil, is not a simple one, since the major cost factors that must be considered are variables. Therefore, the concept of cost estimates and profitability analysis forces the decision to select the effective variables and set ranges that are realistic to allow calculations that are considered representative.

B.1.2. Factors Affecting Costs

Geological and stratigraphic variations between areas can cause large differences in the cost of drilling and completing oil wells. For example, drilling time required for the same depth well, completion techniques and formation evaluations are different, thereby resulting in different total costs. Well depth will materially affect the cost of developing and operating an oil producing lease. Depth dictates size of drilling equipment used, amount and type of casing and producing equipment to be installed, and the annual operating expenses. There are two references (32, 33) that break down drilling and completion costs on a regional, state and national average by depth and type of completion. These API publications are invaluable in preparing cost figures for an area before research in an area.

The number of wells is a function of the current well density and the pattern of injection deemed appropriate, which is discussed in reference (34).

B.1.3. Costs of Drilling, Completing and Equipping Oil Wells

The costs of drilling, completing, and equipping oil wells can be classified as: (1) intangible drilling and development expenditures. For the purpose of estimating cost of the numerous jobs to be performed in developing a lease, the work can be broken into five categories: (a) site preparation, (b) drilling and completion, (c) producing equipment, (d) gathering system and (e) lease equipment. Costs for contingencies (engineering and administrative) can also be estimated.

Site Preparation. In the development of a lease, the first task is preparing the well site. The cost of site preparation includes such items as surveying for well location, clearing and leveling, preparing mud pits, dirt work building roads, and damages paid to the surface tenant. All of these items except for the cost of road building are considered to be intangible drilling and development costs. Road building is a major cost in site preparation and can vary considerably between areas. The cost of building a road is affected by well spacing, but terrain and environmental conditions will have the greatest impact upon road costs.

Drilling and Completion. Most of the cost of developing an oil lease is attributable to the expense of drilling, completing or recompleting the wells. Expenditures for all items in this category except for the cost of casing are classified as intangible drilling and development costs.

The major intangible drilling and development costs are as follows: (1) contract costs of the drilling rig, (2) cement, (3) evaluation and completion services, and (4) drilling fluid. Estimating the contract cost of drilling rigs for drilling wells to various depths can be based upon the number of days required for nondrilling and drilling operations. Nondrilling operations include rig moving time, rig up and tear down time, and time for other operations such as cementing, evaluation and completion services. Drilling operations charges are for the number of days required to actually drill the well. These times can be obtained from drilling records, bit records, and mud records for wells drilled in the area. The cost of day rates for appropriate size drilling rigs can be obtained from contractors in the area. The API references (32, 33) give a good overview of cost within a productive region.

Producing Equipment. For the Zenith Field, the producing wells are equipped with rod pumps and pumping units. This is an agreeable situation as the rod pumps have interchangable barrel diameters and can be sized to the production of a specific well for benefit of the flood. The pumping units all jack type and operate on electricity, providing a means to intermit or time production.

Gathering System. From the wellhead to the lease production equipment the oil would be carried by three inch electric line pipe of the Skin Effect Current Tracing, SECT type. The cost of heat controlled pipe in North Dakota is reflected in the installation cost summary, Table B.1.

Lease Equipment. The type of lease equipment installed on a lease is dependent on numerous factors. However, in this study it is assumed that the equipment consists of 2 heater-treaters, a test separator, 6 storage tanks, and the water injection system. The injection system center is the pump house where the tri-plex pump and system monitoring equipment is located. In addition to this are the pump's water storage treatment tank, high pressure lines to the injectors, and the water supply well. The costs on this are easily obtained, from bid turn key proposals on fabricating and installing the injection system from the water supply to the injection wellhead. For Zenith, two company bids were used, Falcon Pump, Casper, Wyoming and Fluor Supply, Cushing, Oklahoma, for a complete equipment list and price survey. The attendant meters (gas, oil and water), circulating pumps, valves, pressure regulators, scrubbers, and other equipment necessary for measuring, regulating and moving fluids in the battery area were included where necessary.

B.1.4. Annual Operating Cost Per Well

The operator's annual operating cost per well is the total amount of money expended each year for production of oil, divided by the total operating wells during the year. This cost corresponds to the annual operating expenses, for the injection system, production facilities, and lease maintenance.

B.2. Taxes

State and Federal Income Tax Assumptions. A combined Federal and State income tax rate of 52 percent is applied in the overall cost and cash flow summary. This assumes a corporate tax rate of 46 percent combined with the North Dakota state tax of 11 percent on natural resource sales.

State and County Production Taxes. The amount and type of these taxes vary from state to state. In some states only one tax may be levied, whereas in other states there may be several types of taxes. For example, the state of Texas has an oil and gas production or severance tax and a pipeline tax on oil. Most Texas counties will have an ad valorum tax and a school tax. North Dakota is considering a state resource tax but has not yet enacted one.

B.3. Depreciation

Depreciation represents the deterioration of equipment caused by wear and tear over the useful life of the asset. Costs applicable to tangible equipment or capitalized equipment are usually recoverable through depreciation for income tax purposes. The depreciation method applied was a double declining balance switching before the half life year to straight line. The schedules had a ten year life and used a zero salvage value.

B.4. Depletion

Lease costs and seismic surveying costs are depleted. The percentage depletion rates applied to the "gross income from the project or well head price for oil and gas actually decline from 20 percent in 1981, 18 percent in 1982, 16 percent in 1983, to 15 percent after 1983. As the income stream here begins in 1984 a 15 percent depletion rate was used in calculations relating the recapture depletion capital expenditures.

Cost depletion was computed using annual production divided by recoverable reserves and multiplying by the adjusted basis.

The higher of the two methods is used, unless the percentage depletion is limited by the 50 percent net value figure.

B.5. Price of Oil

The value of price of a barrel of oil depends, in general, upon the quality, degree American Petroleum Institute (API) gravity, and location of the field. The price of oil at the project is based on the December, 1980 price of $16.10 per barrel. Crude prices were escalated at 12 percent a year to a ceiling price of $165 per barrel in year 8. At this point a washout assumption of the escalation effects on crude price and operating costs capping their respective value levels.

The Windfall Profits Tax was escalated in accordance with its schedule at a rate of 10 percent per year through 1985, then escalated at a rate of 8.2 percent per year. The WPT was applied throughout the project life to the crude prices.

This type of project has a Tier I classification for WPT of 30 percent for independent producers (producing less than 1000 bbl/day oil or 6.0 million cu. ft./day gas) and a 70 percent WPT on major companies. The WPT is applied to the value of the crude between the base price and market price. The base price was set at $17.10 in January, 1980, escalating at the above delineated rates.

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