

ECONOMIC MODEL OF MOBILITY CONTROL METHODS FOR  
CARBON DIOXIDE FLOODING

A THESIS

BY

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## ABSTRACT

A levelized cost procedure is used to determine the profitability of mobility control for carbon dioxide flooding. Mobility control can be applied profitability to carbon dioxide floods. The profitability of the project is highly dependent on the price of oil, oil price escalation rate, and cost of mobility control agents. The cost of CO<sub>2</sub> plays a far less important role for the profitability of the CO<sub>2</sub> flood than the factors mentioned above.

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## INTRODUCTION AND SUMMARY

Economic considerations are important to determining whether or not enhanced oil recovery processes will be applied to petroleum reservoirs. The objective of this study is to provide a means by which to compare the costs of mobility control alternatives for carbon dioxide flooding. The mobility control alternatives investigated include use of conventional CO<sub>2</sub> flooding, and use of foams or polymers for mobility control.

A levelized cost procedure is used to evaluate the different mobility control alternatives under consideration. By definition, levelized costs are a stream of constant annual payments over the life of the investment, with the same discounted present value as the actual stream of payments. When capital as well as continuing yearly operation and maintenance costs are involved, the levelized cost is the sum of the appropriate fixed charge rate times the capital outlay plus the levelized stream of annual costs. The use of levelized costs provides a means of comparing different investment strategies - in this case a commitment to a particular mobility control alternative - with different capital outlays and annual cost streams.

In this study, a Fortran computer program with approximately 45 input variables is used to perform the engineering and economic analysis. These input parameters relate to:

- °Operating characteristics: Mobility ratio, amount of CO<sub>2</sub> injected, flood type - conventional, foam or polymer CO<sub>2</sub> flood.
- °Field characteristics
- °Financial parameters

The program incorporates subroutines to calculate the oil recovery which occurs as a function of time, capital investment costs, operation and maintenance costs and crude oil revenue over time. The windfall profits tax, royalties and state and local oil and gas severance taxes are accounted for. The program finally levelizes cost stream and provides levelized (annualized) profit which can be used to compare the different investment alternatives. The annualized profit does not account for overhead expenses or the corporate income tax.

The oil recovery model incorporated into the program is based on the work of Claridge [10]. We assume that the amount of CO<sub>2</sub> injected and the mobility ratio remain invariant with time.

The structure of the program is modular which allows for efficiently incorporating changes to the model. Future revisions to capital and operating and maintenance costs can easily be made. Differences in the results from use of other oil recovery models can be investigated.

A case study for a hypothetical oil field about the size of SACROC in West Texas showed that it is possible to make a profit by using mobility control.

Profits are particularly sensitive to the price of oil, oil price escalation rate, cost, escalation rates and concentrations of surfactants and polymers and the discount rate for discounting future cost streams. The cost and escalation rate for CO<sub>2</sub> and the operation and maintenance cost escalation rate plays a far less significant role to the profitability of a CO<sub>2</sub> flood.

The levelized cost concept used in this analysis may be applied towards evaluating other enhanced recovery processes.

## THE OIL FIELD\*

### Introduction, Screening Criteria

We must select a hypothetical oil field with given reservoir characteristics in order to perform the engineering and economic analysis. The characteristics of the reservoir must satisfy general CO<sub>2</sub> miscible flooding screening criteria. Such criteria are summarized in Table 1 [1] and include considerations for API gravity oil, oil viscosity, crude composition, formation type, reservoir depth, reservoir temperature, average permeability, oil saturation, pay zone thickness and minimum miscibility pressure.

### Field Characteristics

The field characteristics required for this analysis include:

- °Waterflood status of the field
- °Has the field been waterflooded?  
If yes, how many water injection wells exist in the field? How many of these water injection wells are being converted to CO<sub>2</sub> injection wells?
- °Number of new CO<sub>2</sub> injection wells to be installed in the field.
- °Reservoir depth
- °Production well spacing in acres
- °Net pay zone thickness
- °Reservoir porosity
- °Number of production wells in the field
- °Connate water saturation

---

\*Subroutine Field

TABLE 1  
CO<sub>2</sub> FLOOD SCREENING CRITERIA\*

EOR Process: CO<sub>2</sub> Flooding

Oil Properties

Suggested Value or Characteristic

°API Gravity <sup>(1)</sup>	> 26° ( 30° preferred)
Viscosity, cp <sup>(1)</sup>	< 15 ( 10 is preferred)
"Composition" <sup>(1)</sup>	High percentage of intermediate (C <sub>5</sub> -C <sub>30</sub> ), especially C <sub>5</sub> -C <sub>12</sub> hydrocarbon is desired

Reservoir Characteristics

Suggested Value or Characteristic

Type of Formation <sup>(2)</sup>	Sandstone or carbonate with minimum fractures and high-permeability streaks
Depth, ft. <sup>(1)</sup>	> 2,000 ft--deep enough to allow high enough pressure
Reservoir Temperature, °F	< 250°F (pressure required increases with temperature)
Average Permeability, md	Not critical (if sufficient injection rates can be maintained)
Oil Saturation	> 30% V <sub>p</sub>
Thickness of Pay Zone, ft.	Relatively thin unless formation is steeply dipping

Additional Considerations

- (1) Pressure required for optimum production (sometimes called minimum miscibility pressure) ranges from about 1200 psi for a "light" ( 30° API) crude oil at low temperatures to over 4500 psi for heavy crudes at higher temperatures. Therefore, a high percentage of light intermediates is desired.
- (2) A minimum of communication between layers is desired. A steeply dipping reservoir is also an advantage because it allows gravity to be utilized for stabilization of the displacement front.

---

\* Source: Dr. J. J. Taber, Director, New Mexico Petroleum Recovery Research Center, Socorro, New Mexico

The field characteristics of existing full-scale CO<sub>2</sub> injection projects were considered in establishing the field properties for this analysis as shown in Table 2 [2]. More emphasis was placed on the data for the established and more prominent projects which include Crossett (North Cross), Kelly Snyder (SACROC), South Gillock and the Twofreds fields.

Based on the data summarized in Table 2, the following parameters are established for our analysis:

- °Reservoir porosity: 25 percent
- °Net pay zone thickness: 20 feet
- °Reservoir depth: 7,000 feet
- °Temperature: 140 °F\*
- °Connate water saturation: 25 percent
- °Production well spacing: 40 acres
- °Number of existing production wells: 64

The field properties are assumed to be homogeneous throughout the reservoir.

### Waterflooding

Waterflooding has been used as a secondary petroleum recovery technique in many reservoirs which are candidates for CO<sub>2</sub> flooding. Therefore, we assume that the field has undergone waterflooding before CO<sub>2</sub> flooding commences. We assume that a five-spot waterflood has been performed on a 80 acre-spacing which is typical of many fields in the West Texas region. For our hypothetical field this establishes the number of water injection wells at 16.

---

\*Note that temperature is not an input parameter for the computer model

TABLE 2  
SUMMARY DATA FOR FULL SCALE CO<sub>2</sub> INJECTION FIELD PROJECTS

	Field: Location:	Crosset (North Cross) West Texas	Lick Creek Arkansas	Kelly Snyder (SACROC) West Texas	Ritchey Arkansas	South Gillock Texas Gulf Coast	Twofreds West Texas	Weeks Island Louisiana Gulf Coast
Porosity (%)		22	33	3.9	30.7	29.5	19.5	26
Permeability (md)		3-5	1,200	19.4	2,800	1,156	32	3,500
Initial Wat Satn. (%)		35	32	21.9	20	22.5	43.5	7
Av. Net Pay Thickness (ft)		96	12	139	9	39	25	250
Av. depth (ft)		5,300	2,500	6,700	2,600	9,000	4,820	12,700
Reservoir Temperature (°F)		106	118	130	126	214	104	225
API Gravity (°)		44	17	41.8	16	38	36	32
Field Size (Acres)		1,120	900	51,000	220	5,940	4,392	5
#Prod Wells		19	38	305	15	30	40	1
#Inj. Wells		9	16	659	1	6	22	1

The National Petroleum Council has published general guidelines on the proportion of wells they feel can be converted for enhanced recovery based on the number of years the field has been in operation. These guidelines are summarized in Table 3. For this analysis we assume a West Texas field which has been in operation between 16 to 25 years. Therefore, from Table 3, we see that 50 percent of the water injection wells may be converted to CO<sub>2</sub> injection wells. So far our analysis, 8 of the 16 water injection wells will be converted to CO<sub>2</sub> injection wells. The other water injection wells are to be salvaged (with no salvage value).

The number of new injection wells which have to be drilled for this field to complete a normal five-spot injection pattern is 41.

#### HCPV Calculation

Subroutine Field calculates the hydrocarbon pore volume of the field:

$$\text{HCPV} = 7759.5 * \text{wellsp} * h * \text{por} * (1 - \text{Sw}_c) * \text{nowell} \quad (\text{Equation 1})$$

where

HCPV is the hydrocarbon pore volume in bbl

7759.5 is the conversion factor from acre-feet to bbl

wellsp is the well spacing in acres

h is the pay zone thickness in feet

por is the porosity (fraction)

Sw<sub>c</sub> is the connate water saturation

nowell is the number of production wells in the field

#### Assumptions Summary

Table 4 summarizes the pertinent assumptions for our hypothetical field.

TABLE 3

PROPORTION OF WELLS REQUIRING CONVERSION FOR ENHANCED RECOVERY\*

Number of Years Field Has Been In Operation	Percentage of Wells
26 or More	150
16 to 25	50
6 to 15	25
1 to 5	0

\* Source: Reference [3]

TABLE 4  
HYPOTHETICAL FIELD ASSUMPTIONS  
Assumptions For Subroutine Field

---

- °Reservoir satisfies general CO<sub>2</sub> miscible flooding screening criteria (see Table 1)
  - °Homogeneous reservoir properties
  - °Reservoir porosity: 25 percent
  - °Net pay zone thickness: 20 feet
  - °Reservoir depth: 7,000 feet
  - °Temperature: 140 °F\*
  - °Connate water saturation: 25 percent
  - °Production well spacing: 40 acres
  - °Number of existing production wells: 64
  - °Field has been waterflooded
  - °Number of water injection wells in field: 16
  - °Number of water injection wells to be converted to CO<sub>2</sub> injection wells: 8
  - °Number of new CO<sub>2</sub> injection wells to be drilled: 41
- 

\*Note that temperature is not an input parameter for the computer model

## OIL RECOVERY MODEL\*

### Introduction

An oil recovery model must be used to derive a production schedule for the hypothetical CO<sub>2</sub> flood. The production schedule is essential for performing the economic analysis for the project. For this project, the basic objective of the model is to provide a production schedule as a function of mobility ratio and number of hydrocarbon pore volumes CO<sub>2</sub> injected into the reservoir. We assume that the injection rate (number of hydrocarbon pore volumes of CO<sub>2</sub> injected per day) does not vary over time and is constant throughout the life of the tertiary oil recovery project. The mobility ratio is also assumed to be invariant over the life of the project.

### Literature

The classical literature was consulted to identify methods of predicting oil recovery for carbon dioxide flooding projects. The methods identified include the following:

- °Mathematical frontal advance calculations
- °Potentiometric studies not recognizing viscous fingering in unstable displacements
- °Experimental studies on dispersion rates for linear displacements
- °Areal sweep efficiency studies
- °Computer simulation work

In addition, classical work that dealt with how mobility ratio influences oil recovery for miscible flooding operations were consulted.

---

\*Subroutine Moblty

This literature includes the work of:

°Haberman	[4]
°Dyes, Caudle and Erickson	[5]
°Caudle, Erickson and Slobod	[6]
°Blackwell, Rayne and Terry	[7]
°Aronofsky and Ramey	[8]
°Bradley, Heller and Odeh	[9]

### The Model

Claridge [10] has reviewed the above work and the work of others. On the basis of these works he has proposed a simplified oil recovery correlation which can be used to predict oil recovery as a function of mobility ratio and number of hydrocarbon pore volumes of gas injected for a five-spot well pattern. Figure 1 shows the result of his model:

°Oil recovery in miscible flooding is shown for a five-spot well pattern as a function of mobility ratio and HCPV gas injected

°M is the mobility ratio

°F<sub>i</sub> is the HCPV of gas injected

°N<sub>p</sub> is the HCPV of oil produced

The correlation shown in Figure 1 applies to a five-spot pattern.

We assume a homogeneous, isotropic, single layer reservoir.

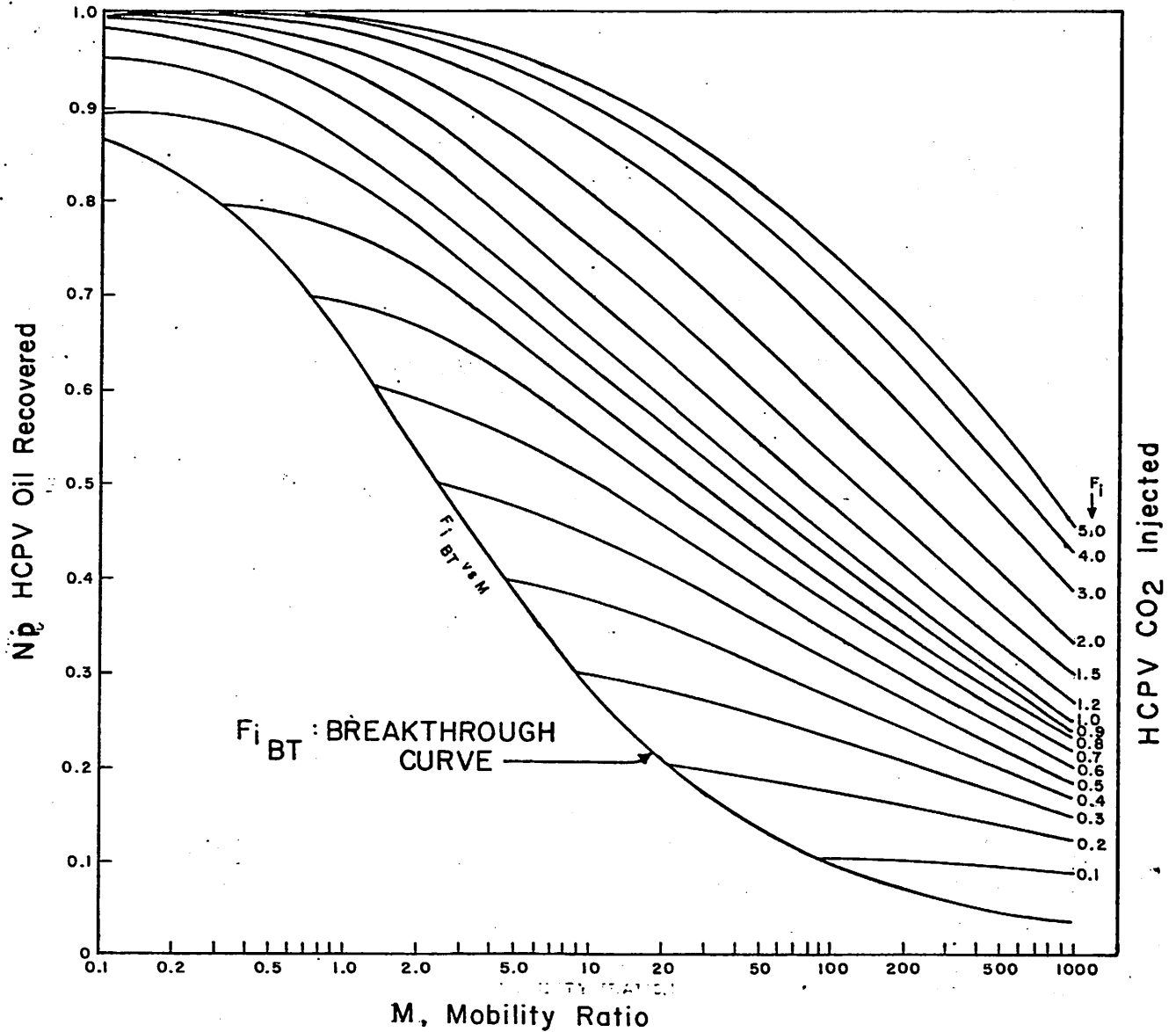
An algebraic set of equations may be used to describe oil production as a function of mobility ratio and HCPV gas injected.

The curves in Figure 1 correspond to the following equations [10]:

$$(F_i)_{BT} = [0.90/(M + 1.1)]^{0.50} \quad (\text{Equation 2})$$

FIGURE 1

OIL RECOVERY IN MISCIBLE FLOODING FOR FIVE-SPOT WELL PATTERNS



Source: Claridge, E.L., "Prediction of Recovery in Unstable Miscible Flooding", Society of Petroleum Engineers Journal, April, 1972, Figure 3, pp 143-155.

$$\frac{N_p - (F_i)_{BT}}{1.0 - N_p} = \left[ \frac{1.60}{(M_{ko})^{0.61}} \right] \left[ \frac{F_i - (F_i)_{BT}}{1.0 - (F_i)_{BT}} \right]^{1.28/M_{ko}^{0.26}} = C_1 \quad (\text{Equation 3})$$

$$\text{where, } M_{ko} = [0.78 + (0.22)(M^{0.25})]^{4.00} \quad (\text{Equation 4})$$

$M_{ko}$  is known as Koval's modified viscosity ratio.

$M$  is the mobility ratio  
(for displacing fluid/displaced fluid).

$F_i$  is the HCPV of solvent injected in an ideal five-spot well pattern of unit thickness which will produce an invaded area (containing fingers of solvent and intervening regions occupied by oil) whose outer envelop corresponds to the areal-sweep efficiency in the Caudle - Witte correlation corresponding to the number of HCPV solvent injected times the area of the five-spot.

$(F_i)_{BT}$  is the number of HCPV injected at breakthrough; the value of  $F_i$  at breakthrough.

$N_p$  is the HCPV of oil produced.

Multiplying the left hand side of Equation 3 by  $(1.0 - N_p)$  we get:

$$N_p - (F_i)_{BT} = (1.00 - N_p)(C_1) \quad (\text{Equation 5})$$

Multiplying through the left hand side of Equation 5 we get:

$$N_p - (F_i)_{BT} = C_1 - (N_p)(C_1) \quad (\text{Equation 6})$$

Combining like terms we get:

$$N_p + N_p C_1 = C_1 + (F_i)_{BT} \quad (\text{Equation 7})$$

Factoring  $N_p$  we get:

$$N_p (1 + C_1) = C_1 + (F_i)_{BT} \quad (\text{Equation 8})$$

We finally get  $N_p$  by dividing both sides of Equation 8 by  $1 + C_1$ :

$$N_p = [C_1 + (F_i)_{BT}] / 1 + C_1 \quad (\text{Equation 9})$$

where

$$C_1 = \left[ \frac{1.60}{(M_{ko})^{0.61}} \right] \left[ \frac{F_i - (F_i)_{BT}}{1.0 - (F_i)_{BT}} \right]^{1.28/M_{ko}^{0.26}} \quad (\text{Equation 3})$$

### Model Limitations

The author of this model was contacted [11] to learn of any further limitations it may have. It was indicated that the model may not be accurate for predicting oil recovery in the range of low mobility ratios (mobility ratio less than 1.0). Negative oil recoveries can result in this low range of mobility ratios. The equations are valid, however, for all mobility ratios greater than one.

In addition, it has been learned that the model does not give entirely accurate results in the breakthrough region. In this region higher oil recoveries are predicted than physically possible.\* Caution should be used when interpreting results in the breakthrough region [12].

### Assumptions Summary

Table 5 summaries the pertinent assumptions for Subroutine Moblty. This subroutine calculates the total oil recovery which will occur for a given mobility ratio and HCPV of  $CO_2$  injected. A year by year oil production schedule is generated.

\* $dN_p/dF_i > 1.0$  near breakthrough region

TABLE 5  
OIL RECOVERY MODEL ASSUMPTIONS  
Assumptions for Subroutine Moblty

---

- °Mobility ratio: Constant over time
  - °HCPV CO<sub>2</sub> injected: Constant over time
  - °Five-spot well pattern
  - °Homogeneous, isotropic single layer reservoir
  - °Viscous forces predominant over gravity force
-

## Oil Production At Low Mobility Ratios

At low mobility ratios ( $M = 1$ ) an oil bank will be formed and Claridge's model is modified since we do not have single phase flow [12]. There is to be no oil production until the oil bank breaks through. The amount of gas injected at oil bank breakthrough is [12].

$$(F_i)_{OBBT} = (F_i)_{BT}/1 + [S_{or}/(1 - S_{wc} - S_{or})] \quad (\text{Equation 10})$$

where:

$(F_i)_{OBBT}$  is the HCPV of gas injected at oil bank breakthrough

$(F_i)_{BT}$  is the HCPV of gas injected at oil breakthrough

$S_{or}$  is the residual oil saturation

$S_{wc}$  is the connate water saturation

After the oil bank breakthrough we have the oil production as [12]:

$$N_p = 1 - \frac{dN_p}{dF_i} (F_i) \quad (\text{Equation 11})$$

For  $(F_i)_{OBBT} < F_i < (F_i)_{BT}$

where:

$N_p$  is the oil production in HCPV

After ordinary breakthrough occurs we have the oil production

$$[12]: \quad N_p = \frac{dN_p}{dF_i} (F_i) - \frac{dN_p}{dF_i} [F_i - (F_i)_{OBBT} + (F_i)_{BT}] \quad (F$$

Appendix B should be consulted to determine the value of  $\frac{dN_p}{dF_i}$ .

Equations 11 and 12 are applied to use of surfactants for a mobility ratio of one. We assume that the connate water saturation and residual oil saturation are both 0.25.

## CAPITAL, OPERATING AND MAINTENANCE COSTS\*

### Introduction

It is only necessary to look at the differences in capital and operating costs when comparing different capital investment and operating alternatives under consideration. In such an analysis any costs which are the same for different alternatives (and possibly not known very well) may be omitted without any effect on the results. However, all capital and operating costs must be considered to determine the profitability of a particular alternative. In this analysis, we attempt to account for all capital and operating expenses attributable for a particular CO<sub>2</sub> flood so the profitability of the alternative can be ascertained. Different capital investment and operating alternatives can also be compared by use of the computer program.

The methods available for mobility control include:

- °Doing nothing (conventional CO<sub>2</sub> flood)
- °Use of WAG CO<sub>2</sub> injection
- °Use of foam (surfactants)
- °Use of polymers

Conventional flooding and use of foams are not included in this analysis. WAG is not considered since there are questions about this mobility control method which remain unanswered and cannot be easily modeled. These issues are knowning:

- °How much water and gas must be injected to retain a given mobility ratio?
- °How changing the mobility ratio changes the amount of water and gas to be injected.

Capability to add analysis for WAG exists in the computer program.

\*Subroutines Capital and ONM

Operating and maintenance costs are those attributable for the production of the tertiary oil after capital expenditures have been made. This includes costs such as labor, power, surface and subsurface equipment maintenance and repair etc. The capital and operating expenses presented in this analysis are estimates only and may not be identical to the expenses incurred for a particular field, during a particular year, or for a particular oil producer. These costs, however, can be representative of expenses which will be incurred over the life of the CO<sub>2</sub> flood project.

In our discussion below on capital and operating and maintenance costs we first discuss the costs which apply to all of the different operating alternatives modeled for mobility control: conventional flooding, and use of foam or polymers; then we discuss costs specific to each of the mobility control operating alternatives considered.

#### COSTS COMMON TO ALL MOBILITY CONTROL ALTERNATIVES CONSIDERED

##### Field Development Cost:

We first consider the capital costs associated with developing the field for carbon dioxide flooding. Field development costs could include costs for:

- °Drilling new CO<sub>2</sub> injector wells
- °Drilling new producer wells
- °Converting existing producing wells to CO<sub>2</sub> injection wells
- °Converting existing water injection wells to CO<sub>2</sub> injection wells

In our analysis we need to drill new CO<sub>2</sub> injection wells for the five-spot injection pattern and convert existing water injection wells to CO<sub>2</sub> injection wells.

For our analysis, no new production wells need to be drilled and existing production wells will not be converted to CO<sub>2</sub> injection wells.

The field development costs outlined above were formulated in mid 1976 dollars [13] and have been escalated to mid 1982 dollars by use of the GNP Implicit Price Deflator [14,15]\*. The field development costs are shown below in mid-year 1982 dollars:\*\*

°Drill new CO<sub>2</sub> injectors: Normal cost for drilling completing, and equipping injector\*\*\* + incremental cost of  $87,400 + (\$1.25) \times (\text{depth, ft})$

°Drill new producer: Normal cost for drilling, completing and equipping well\*\*\*

°Convert existing producer to CO<sub>2</sub> injection: Normal cost for conversion\*\*\* + incremental cost of  $\$87,400 + (\$1.25) \times (\text{depth, ft})$

°Convert existing water injector to CO<sub>2</sub> injection:  $\$87,400 + (\$1.25) \times (\text{depth, ft})$

An estimate of the normal cost of drilling, completing equipping wells and normal costs for converting wells are required in order to estimate the field development costs. These costs are discussed now.

#### Normal Cost of Drilling, Completing, and Equipping Wells

Estimates for the costs of drilling, completing and equipping wells can be made by consulting API field data [16]. This data summarizes by region and depth interval the cost of drilling, completing and equipping wells during 1980. The costs are again scaled to mid-1982 dollars by

\* GNP Implicit Price Deflator mid-year 1982: 203.66  
GNP Implicit Price Deflator mid-year 1976: 132.87  
Ratio =  $203.66/132.81 = 1.533$

\*\* All costs expressed in mid-year 1982 dollars

\*\*\* Described in later section

use of the GNP implicit price deflator\* [14]. The data is summarized region by region in Appendix A in tabular format. The costs are expressed in dollars per foot vs. depth. Table 6 shows the regions for which this data is available.

In this analysis, assuming a West Texas field at 7,000 feet, we use a mid year 1982 cost of drilling, completing and equipping a well at \$60.00 per foot.

#### Normal Cost for Converting Wells

Existing production wells may be reconditioned and utilized as injection wells in a carbon dioxide flood. The cost of using existing wells depends on region, age of the equipment and well depth. Table 7 [17] shows the estimated cost of converting an existing production well to an injection well. The major cost element for converting an existing production well to an EOR production well are workover costs. The costs are escalated by use of the GNP implicit price deflator and are expressed in mid-year 1982 dollars.

For our analysis assuming the equipment was installed between 1961-1970 and assuming a West Texas field at 7,000 feet we have the cost of converting an existing production well to a CO<sub>2</sub> injection well as \$57,000 per well.

---

\*GNP Implicit Price Deflator mid-year 1982: 203.66  
GNP Implicit Price Deflator mid-year 1980: 177.36  
Ratio 203.66/177.36 = 1.148

TABLE 6

REGIONS FOR WHICH COST OF DRILLING, COMPLETING AND EQUIPPING  
A WELL ARE AVAILABLE\*

---

°Alabama	°New Mexico - West
°Alaska - Onshore	°New Mexico - East
°Alaska - Offshore	°North Dakota
°Arkansas	°Oklahoma
°California - North	°Texas, District 1
°California - Central Coast	°Texas, District 2
°California - East Central	°Texas, District 3
°California - South	°Texas, District 4
°California - Offshore	°Texas, District 5
°Colorado	°Texas, District 6
°Florida	°Texas, District 7B
°Illinois	°Texas, District 7C
°Indiana	°Texas, District 8
°Kansas	°Texas, District 8A
°Kentucky	°Texas, District 9
°Louisiana - North	°Texas, District 10
°Louisiana - South	°Texas - Offshore
°Louisiana - Offshore	°Utah
°Michigan	°Wyoming
°Mississippi	°Appalachian
°Montana	°Offshore Federal Waters
°Nebraska	°Gulf of Mexico - Northern

---

\*See Appendix A for actual data and details

TABLE 7  
 COST OF CONVERTING EXISTING PRODUCTION WELL TO AN INJECTION WELL  
 (Mid-Year 1982 Dollars)

State	Depth	Equipment Installed Before 1950	Equipment Installed 1951-1960	Equipment Installed 1961-1970
West Texas	2,000	20,800	17,500	14,000
	4,000	33,000	25,600	22,200
	8,000	69,600	60,000	49,800
	12,000	191,500	158,700	125,900
South Louisiana	2,000	43,800	36,500	29,300
	4,000	82,800	97,700	55,600
	8,000	113,700	97,700	81,400
	12,000	208,300	172,800	137,100
California	2,000	25,300	21,200	17,000
	4,000	60,200	50,300	40,500
	8,000	125,100	107,500	89,500
	12,000	315,500	281,400	207,400

### Well Operating and Maintenance Costs

The incremental operating and maintenance costs for production wells attributable to tertiary recovery are set at \$11,315.00 per year (scaled to mid-year 1982 dollars) per production well [13]. On a per day basis this is \$31.00 per well.

The direct annual operating expense for injection wells is set at \$35,100 per well per year (scaled to mid-year 1982 dollars) [18]. This cost is expressed in mid year 1982 dollars. This is \$96.16 per well per day.

The well operating and maintenance costs are characteristic of a West Texas field at 7,000 foot depth.

### CO<sub>2</sub> Injection Equipment for Project

The cost of CO<sub>2</sub> injection equipment for the tertiary recovery project includes costs of all equipment necessary to install a CO<sub>2</sub> flood in a depleted field. The major items included in this estimate are CO<sub>2</sub> storage facilities, injection plant and accessories, injection lines and electrification. This cost is set at \$61,200 per injection well (scaled to mid year 1982 dollars) characteristic of a West Texas field at 7,000 foot depth.

## COST SPECIFIC TO EACH MOBILITY CONTROL METHOD

### Conventional CO<sub>2</sub> Flooding

For a conventional flood we assume that a CO<sub>2</sub> gas recycling plant will have to be installed. The capital cost for a recycling plant is set based on the volume of recycled gas to be processed in the plant [13]:

Capacity 25 million cubic feet per day or less:

\$6,120,000 (scaled to mid-year 1982 dollars)  
for 25 MCF per day capacity. Lesser capacity  
scaled directly.

Capacity greater than 25 million cubic feet per day:

\$6,120,000 (scaled to mid-year 1982 dollars) for 25 MCF.  
Additional capacity scaled by a 0.60 exponent.

The operating cost is set at \$0.153 (scaled to mid-year 1982 dollars) per thousand cubic feet of CO<sub>2</sub> recycled [13].

For this analysis we assume that gas recycling occurs after three years of operation. After this time, 50 percent of the CO<sub>2</sub> injected is recycled. This behavior was characteristic of the Lick Creek field in Arkansas [2].

#### CO<sub>2</sub> Flooding With Foam

Use of surfactants to generate foam will reduce the requirements for purchased CO<sub>2</sub> from a conventional CO<sub>2</sub> flood. This reduction can be quantified by the use of Table 8. (See Appendix B for details) [12]. Table 8 shows the values for how many MCF CO<sub>2</sub> is required per barrel of oil recovered as a function at mobility ratio when  $dN_p / dF_i$  is equal to 0.10 ( $N_p$  is the oil recovery in HCPV and  $F_i$  is the HCPV of CO<sub>2</sub> injected). In this analysis we also assume that 1 bbl of CO<sub>2</sub> is 2.5 MCF. Again, Appendix B should be consulted to obtain the full details for this analysis.

To calculate the percentage reduction in CO<sub>2</sub> requirements with the use of foam in the CO<sub>2</sub> flood we first select the base case conventional CO<sub>2</sub> flood mobility ratio and read the number of MCF CO<sub>2</sub> / bbl oil recovered from Table 8. Then we select the foam CO<sub>2</sub> flood mobility ratio and determine the reduction in CO<sub>2</sub> requirements over conventional flooding.

TABLE 8  
 MOBILITY RATIO VS MCF CO<sub>2</sub> / BBL OIL RECOVERED\*

Mobility Ratio, M	MSCF CO <sub>2</sub> / BBL Oil Recovered
1.0	3.65
2.0	4.17
3.0	4.53
4.0	4.83
5.0	5.05
6.0	5.24
7.0	5.40
8.0	5.55
9.0	5.68
10.0	5.79
11.0	5.91
12.0	6.02
13.0	6.12
14.0	6.20
15.0	6.28
16.0	6.35
17.0	6.42
18.0	6.50
19.0	6.57
20.0	6.61
30.0	7.11
40.0	7.46
50.0	7.75
60.0	8.01
70.0	8.22
80.0	8.44
90.0	8.61
100.0	8.78
200.00	10.10

---

\*When  $dN_p/dF_1 = 0.10$ , assume 2.5 MCF CO<sub>2</sub> / bbl oil recovered  
 See Appendix B for details

The use of foam will require additional capital expenditures for surfactant storage facilities, mixing and injection equipment. Downhole foam generation could be used to avoid corrosion problems when foam and CO<sub>2</sub> mix. However, downhole foam generation has not been practiced and its costs are not well understood.

An alternative to downhole foam generation is to generate the foam at the surface and make use of coatings and inhibitors to prevent corrosion.

In this analysis we assume that use of foam as a mobility control agent will incur a fixed cost of [19]:

$$\$57,000 + \$3.00 \times \text{depth (feet) per injection well}$$

The operating and maintenance per injection well are assumed to double over conventional flooding [19].

The operating and maintenance costs will also include the cost of the surfactant. The computer program will ask the user several questions related to use of the surfactant:

- °Cost of surfactant in dollars per bbl
- °Amount of surfactant required in bbl per Mcf CO<sub>2</sub> injected
- °Surfactant cost escalation rate
- °Percentage reduction in CO<sub>2</sub> requirements with foam use

#### CO<sub>2</sub> Flooding With Polymers

Like foam, use of polymers for mobility control in CO<sub>2</sub> flooding will reduce the requirements for purchased CO<sub>2</sub>. For this analysis we assume that the percentage reduction in CO<sub>2</sub> requirements which will occur with the use of polymers as a mobility control agent is the same as that which occurs with the use of foam (see Table 8).

The use of polymers will require additional capital expenditures for polymer storage facilities, mixing facilities and injection equipment.

In this analysis we assume that use of polymers as a mobility control agent will incur a fixed cost of [19].

\$22,000 + \$1.00 + depth (feet) per injection well

The operating and maintenance cost per injection well is assumed to increase 50 percent over conventional flooding [19].

The operating and maintenance costs will also include the cost of the polymer. The computer program will ask the user several questions related to use of polymers:

°Cost of polymer in dollars per bbl

°Amount of surfactant required in bbl per Mcf CO<sub>2</sub> injected

°Polymer cost escalation rate

°Percentage reduction in CO<sub>2</sub> requirements with polymer use

### Assumptions Summary

Tables 9 and 10 summarize the pertinent capital and operation and maintenance cost assumptions for this analysis, respectively.

TABLE 9  
CAPITAL COST ASSUMPTIONS FOR ANALYSIS  
Subroutine Capital

---

Costs Common To All Mobility Control Alternatives Considered:

Field Development Costs

°Drill new CO<sub>2</sub> injections: Normal cost for drilling, completing, and equipping injector + incremental cost of \$87,400 + (1.25) x (depth, ft)

°Drill new producer: Normal cost for drilling, completing and equipping well (see Appendix A)

°Convert existing producer to CO<sub>2</sub> injection: Normal cost for conversion + incremental cost of \$87,400 + (1.25) x (depth, ft)

°Convert existing water injector to CO<sub>2</sub> injection: \$87,400 + (1.25) x (depth, ft)

°Normal cost for drilling, completing and equipping wells: \$60.00 per foot

°Cost of converting existing production well to a CO<sub>2</sub> injection well: \$57,000 per well

°No new production wells to be drilled

°No existing production wells to be converted to CO<sub>2</sub> injection wells

°Cost of CO<sub>2</sub> equipment: \$61,200 per injection well

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TABLE 9 (con't)  
CAPITAL COST ASSUMPTIONS FOR ANALYSIS  
Subroutine Capital

---

Costs Specific To Each Mobility Control Method:

Conventional CO<sub>2</sub> Flood

°Capital cost for gas recycling plant:  
Capacity 25 million cubic feet per day  
or less. \$6,120,000 for 25 MCF. Lesser  
capacity scaled directly

°Capacity greater than 25 million cubic  
feet per day. \$6,120,000 for 25 MCF.  
Additional capacity scaled by a 0.60  
exponent

Foam CO<sub>2</sub> Flood:

°Capital: \$57,000 + \$3.00 x depth (ft)  
per injection well

Polymer CO<sub>2</sub> Flood:

°Capital: \$22,000 + \$1.00 + depth (ft)  
per injection well

---

TABLE 10  
OPERATION AND MAINTENANCE COST ASSUMPTIONS FOR ANALYSIS  
Subroutine ONM

---

Costs Common To All Mobility Control Alternatives Considered:

°Incremental operating and maintenance costs for production wells: \$11,315 per production well per year

°Operating and Maintenance costs of injection wells: \$35,100 per injection well per year

Costs Specific To Each Mobility Control Method:

Conventional Flood:

°Gas recycling plant O & M Cost: \$0.153 per thousand cubic feet of gas recycled

°Fifty percent CO<sub>2</sub> recycled after 3 years

Foam CO<sub>2</sub> Flood:

°Operating and maintenance cost per injection well double from conventional flooding

°Percentage reduction in CO<sub>2</sub> use same for polymer and foam CO<sub>2</sub> flood

Polymer CO<sub>2</sub> Flood:

°Operating and maintenance cost per injection well increase 50 percent over conventional flooding

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## CRUDE OIL REVENUE\*

### Introduction

The market price of crude oil is one important factor which will determine whether or not a profit will be realized from the CO<sub>2</sub> flood project. Crude oil prices determine the revenues that can be obtained from oil recovered by tertiary recovery and is a key factor in determining the rate of return possible for an EOR project.

In this analysis we consider several factors which influence the revenue which will be obtained from the CO<sub>2</sub> flood. These factors include:

- °Market price of crude oil
- °Oil price escalation rate
- °Royalties, severance and production taxes
- °Windfall profits tax

Before crude oil prices were deregulated, firms investing in EOR operations were not able to realize as great a return on their investment unless the crude oil recovered from the EOR operation was exempt from the price regulation. At this time domestic crude oil prices have been deregulated and producers are able to sell their production at the market price.

### Crude Oil Price, Oil Escalation Rate

We have seen over the last decade that the market price for crude oil is volatile. Military and political actions in major oil producing regions of the world can quickly contribute to supply disruptions.

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\*Subroutine Revenue

Major OPEC producing countries including Saudi Arabia have been pressing other OPEC members to peg crude oil prices to western inflation rates. This helps to keep the prices of OPEC's imports of goods and technology from western nations stable.

In this analysis we use a mid 1982 sweet crude oil price of \$32.50 per bbl [20]. The crude oil escalation rate is tied to the general long-term United States inflation rate and is set at 9 percent [14, 21].

#### Royalties, State and Local Oil and Gas Severance and Production Taxes

Royalties, state and local oil and gas severance and production taxes and the federal windfall profit tax will reduce the crude oil revenue that the producer will obtain. For this analysis, assuming a West Texas CO<sub>2</sub> flood, a royalty of 1/8 (12.5%) [22] and state and local oil and gas severance and production taxes of 4.6 percent [23] are used. Appendix C can be used to obtain information regarding state and local oil and gas severance and production taxes for all areas in the United States.

#### Windfall Profits Tax

The Crude Oil Windfall Profit Tax Act (WPTA) passed by Congress in 1980 affects tertiary oil recovery as follows:

°Under the WPTA incremental tertiary oil is taxed with newly discovered and heavy oil at a rate of 30 percent on net revenue over an average tax base price of \$16.55/bbl [24, 25, 26, 27].

The computer model accounts for this provision of the WPTA to tertiary oil recovery.

### Assumptions Summary

Table 11 summarizes the pertinent assumptions for Subroutine Revnue. This subroutine computes the oil revenue which will be obtained from the CO<sub>2</sub> flood. Royalties, state and local severance and production taxes and the windfall profit tax are all subtracted from the gross revenue in this subroutine.

TABLE 11  
ASSUMPTIONS FOR SUBROUTINE REVNUe

---

°Sweet Crude Oil Price: \$32.50/bbl

°Oil Price Escalation Rate: 9%/yr.

°Royalty: 1/8 (12.5%)

°State and Local Oil and Gas Severance and Production Taxes: 4.6%

°Windfall Profit Tax on Tertiary Recovery: 30% on net revenue  
over base crude price of \$16.55/bbl

---

## FINANCIAL PARAMETERS - LEVELIZED COST

### Introduction

In this section we discuss the financial parameters necessary for the analysis. These parameters include:

- °Discount rate for discounting future cost and revenue streams
- °Fixed charge rate for capital
- °Tax considerations - Debt interest, accelerated depreciation, Investment tax credits
- °Depreciation
- °Use of real vs. current costs
- °O & M and materials cost escalation rate
- °Cost of CO<sub>2</sub>
- °Number of years analysis covers

Levelized costs are also discussed. A levelized cost procedure can be used to evaluate different investment alternatives under consideration. By definition, levelized costs are a stream of constant annual payments over the life of the investment, with the same discounted present value as the actual stream of payments. When capital as well as continuing yearly operation and maintenance costs are involved, the total levelized cost is the sum of the appropriate fixed charge rate times the capital outlay, plus the levelized stream of annual costs. The use of levelized costs provides a means of comparing different investment strategies - in this case a commitment to a particular mobility control method - with different capital outlays and annual cost streams.

At this juncture we discuss and review the financial-mathematics concepts that are frequently used in investment and economic analysis. The concepts of discounting, capital recovery, levelization and depreciation are presented and described below. We begin with the concept of discounting.

### Discounting

Most problems in investment analysis involve determining what is most economical in the long run. In such problems it is necessary to recognize the time value of money; because of the existence of interest, a dollar today is worth more than a dollar next year. If the interest rate is  $i$ , then a dollar one year from today will be equivalent to  $1/(1 + i)$  of today's dollars. For example, at an interest rate of 10 percent one would be indifferent between 90.91¢ today and \$1 a year from now ( $90.91¢ \times 1.1 = \$1$ ). This assumes, of course, there is a guarantee of \$1 a year from now. This concept can be expanded to any time period  $n$  such that a dollar  $n$  years from now is equivalent to  $1/(1 + i)^n$  dollars today (where  $n$  is the number of years). The term  $1/(1 + i)^n$  is called the single payment present worth factor.

The process by which future dollars are expressed in today's dollar equivalent is referred to as discounting. When more than one year of future dollars must be discounted, a series of single-period discounting steps can be undertaken (as in the example above). Alternatively, uniform-series discounting can be performed when the stream of future dollars is composed of equal yearly amounts. At an interest rate of  $i$ , equal annual payments ( $P$ ) over  $n$  years are equivalent to  $P$  of today's dollars. For example, a stream of \$1 payments for 10 years

at 10 percent interest is equivalent to \$6.144 of today's dollars. In the formulation above, the term  $[(1 + i)^n - 1]/[i(1 + i)^n]$  is called the uniform series present worth factor.

The processes of discounting and its counterpart, compounding (expressing today's dollars in future equivalents), are used either explicitly or implicitly in all sophisticated methods of investment and economic evaluation involving time. Of course, in more sophisticated analyses, discounting or compounding may be done a quarterly, monthly, or even in some cases on a daily basis rather than on the yearly basis described above. The basic mathematical principles remain the same, however. Although these principles are simple, many issues surround the processes of discounting and compounding. The proper choice of  $i$ , the interest (or discount) rate, is one such issue. The question of whether to use real or nominal (inflated) dollars is another issue. These issues are presented and discussed in later sections of this report.

For our analysis we use a discount rate of 15 percent [28].

### Capital Recovery

The uniform series present worth exercise can be reversed with the objective of finding the uniform series of payments that is financially equivalent to a dollar today at a given interest rate over a given time span, rather than the other way around. This can be done by multiplying today's dollar by the capital recovery factor, which is the reciprocal of the uniform series present worth factor. Doing this for a sample case in which the interest rate is 10 percent and the number of years is 10, a dollar today is equivalent to  $\$1 \times \frac{0.10(1 + 0.10)^{10}}{(1 + 0.10)^{10} - 1}$ , or \$0.16275 each year for the next 10 years.

The concept of capital recovery is an important one particularly in situations where the objective is to place capital and operating costs on an equivalent annual basis. Application of the capital recovery factor to today's capital costs yields the annualized capital cost (in the absence of taxes and other complicating factors). For operating costs, a different procedure called levelization is used to provide annualized costs. This process is described below.

### Levelization

In levelization, a series of equivalent annual payments is derived that is equivalent in today's dollars (more correctly in present value) to a series of varying annual payments. Operating costs are a typical example of "payments" that can be expected to vary over time due to escalations in fuel, labor, and materials costs. When such costs for a particular investment alternative are expressed on an equivalent annual basis through the process of levelization, they can be added to the annualized capital costs of the alternative for comparison with the total annualized costs of other investment alternatives.

Mathematically, the process of levelization can be shown as follows. First, today's dollar equivalent (present value) of varying annual costs is represented as:

$$\frac{C_j(1 + P_j)}{1 + d} + \frac{C_j(1 + p_j)(1 + p_{j+1})}{(1 + d)^2} + \dots$$

$$+ \dots \frac{C_j(1 + p_j) \dots (1 + P_{j+N})}{(1 + d)^N} \quad \text{(Equation 13)}$$

where:

$C_j$  = Beginning-year cost of variable being evaluated in initial year  $j$

$P_j$  = Price escalation of that variable in year  $j$

$N$  = Number of years over which levelization is performed

$d$  = Average discount rate over time period considered

$PV_j$  = Present value of variable being evaluated in initial year  $j$

Once the present value has been obtained, the process of annualizing (levelizing)\* proceeds as before. That is, the present value is simply multiplied by the capital recovery factor to obtain the levelized cost.

Thus:

$$LC = (CRF) \times (PV_j) \quad (\text{Equation 14})$$

where:

LC is the Levelized cost

$$CRF \text{ is the Capital recovery factor} = \frac{i(1+i)^N}{(1+i)^N - 1}$$

An equivalent way to derive levelized cost is to calculate a levelization factor that, when multiplied by the cost in initial year  $j$ , will yield the levelized cost. This levelization factor is calculated by using the following formula:

$$\left[ \frac{d(1+d)^N}{(1+d)^N - 1} \right] \left[ \frac{1+p}{d-p} \right] \left[ 1 - \left( \frac{1+p}{1+d} \right)^N \right] \quad (\text{Equation 15})$$

where

LF is the levelization factor

$p$  is the annual price escalation rate for entire time period  $N$

\* The terms annualize and levelize may be used interchangeably. However, here we generally speak of levelized operating costs and annualized capital costs.

This last formula is applicable, however, only when p is a constant for the entire period of levelization. The equivalence in present value of the stream of unequal annual costs and the corresponding stream of equal levelized costs is shown in Table 12 and 13.

### The Fixed Charge Rate

The total annualized cost is composed of annualized capital costs (also called fixed capital charges) and annualized operating costs. Annualized operating costs are obtained by levelizing the stream of yearly operating costs associated with an investment alternative. The method of calculating annualized capital costs is somewhat more complex. This discussion concerns the calculation of annualized capital costs through the mechanism of the fixed charge rate. The fixed charge rate is the rate that, when multiplied by the total investment cost, yields the annualized capital cost associated with an investment alternative. Equations for the calculation of the fixed charge rate are presented.

The equations provided below to calculate the components of the fixed charge rate are similar to the ones provided in the EPRI\* Technical Assessment Guide [29].

The levelized annual fixed charge rate is defined as follows:

$$\begin{aligned} \text{Levelized Annual Fixed} &= \text{Return (weighted cost of capital) (Equation 16)} \\ \text{Charge Rate} &+ \text{Sinking fund depreciation} \\ &+ \text{Allowance for retirement dispersion} \\ &+ \text{Levelized annual income tax-tax} \\ &\quad \text{preference allowances} \\ &+ \text{Property taxes, insurance, etc.} \end{aligned}$$

---

\*Electric Power Research Institute, Palo Alto, California

TABLE 12  
CALCULATION OF PRESENT VALUE

Year	Initial Year Cost		Price Escalation Factor	=	Escalated Cost	Discount Factor	Present Value
	C	x	$(1 + p)^N$		$C_E$	$1/(1 + d)^N$	$PV = \frac{C_E}{(1 + d)^N}$
1	1		1.0700		1.0700	0.9091	0.9727
2	1		1.1449		1.1449	0.8264	0.9462
3	1		1.2250		1.2250	0.7513	0.9204
4	1		1.3108		1.3108	0.6830	0.8953
Total							3.7346*

P = annual price escalation rate (7 percent in this example)  
n = year number  
d = discount rate (10 percent in this example)

\*Present value is the same whether calculated by this long method or by the method of discounting levelized costs shown in Table 13

TABLE 13

CALCULATION OF PRESENT VALUE BY DISCOUNTING LEVELIZED COSTS

Year	Initial Year Cost		Levelization Factor		Levelized Cost	Discount Factor	Present Value
	C	x	L.F.	=	L.C.	$1/(1 + d)^N$	$PV = LC/(1 + d)^N$
1	1		1.1782		1.1782	0.9091	1.0110
2	1		1.1782		1.1782	0.8264	0.9737
3	1		1.1782		1.1782	0.7513	0.8852
4	1		1.1782		1.1782	0.6830	0.8047
Total							3.7346*

$$L_F = \left[ \frac{d(1 + d)^n}{(1 + d)^n - 1} \right] \left[ \frac{1 + p}{d - p} \right] \left[ 1 - \left( \frac{1 + p}{1 + d} \right)^n \right]$$

\*Present value is the same, whether calculated by this method or by the long method in Table 12.

Note also that  $LC = PV \times \frac{d(1 + d)^n}{(1 + d)^n - 1} = 3.7346 \times 0.3155 = 1.1782$

The components of the fixed charge rate have the following definitions:

$$\begin{aligned} \text{Weighted Cost of Capital} &= \text{Debt ratio} \times \text{debt cost} && \text{(Equation 17)} \\ &+ \text{Preferred stock ratio} \times \text{preferred} \\ &\quad \text{stock cost} \end{aligned}$$

$$+ \text{Common stock ratio} \times \text{common stock cost}$$

$$\text{Sinking Fund Depreciation} = \frac{r}{(1+r)^N - 1} \quad \text{(Equation 18)}$$

where:  $r$  is the discount rate (weighted cost of capital)

$N$  is the book life

$$\text{Allowance for Retirement Dispersion} = \left[ \sum_{n=1}^N v^n s_n \right]^{-1} - r - \text{sff} \quad \text{(Equation 19)}$$

where:  $N$  is the book life of the property

$v^n$  is the present worth factor at year  $n$  at rate  $r$

$s_n$  is the percent surviving in year  $n$  and is calculated by averaging the beginning and end of year  $n$  percents listed in the Iowa State University retirement dispersion curves.

$r$  is the discount rate

$\text{sff}$  is the sinking fund depreciation factor for discount rate  $r$  over  $N$  years

$$\begin{aligned} \text{Levelized Annual} &= \text{Capital recovery factor for } N \text{ years} + \\ \text{Income Tax} &\quad \text{allowance for retirement dispersion} - \text{straight line depreciation for } N \text{ years} && \text{(Equation 20)} \end{aligned}$$

$$\times \text{tax rate}/(1 - \text{tax rate})$$

$$- \text{Capital recovery factor for } N \text{ years} + \text{allowance for retirement dispersion} - \text{straight line depreciation for } N \text{ years}$$

$$\times \text{Debt ratio} \times \text{debt cost}/\text{weighted cost of capital}$$

$$\times \text{Tax rate}/(1 - \text{tax rate})$$

This concludes the listing of equations to calculate the fixed charge factor. Table 14 illustrates the application of these equations to the calculation of a fixed charge rate considered to be representative for oil companies [28].

TABLE 14  
 COMPONENTS OF THE FIXED CHARGE RATE FOR OIL COMPANIES  
 CALCULATED FOR A REPRESENTATIVE CASE\*  
 (For Application to Capital Cost)

Cost Component	Percent Fixed Charges
Total Return (Debt and Equity)	15.0
Book Depreciation (Sinking Fund)	0.40
Allowance for Retirement Dispersion	0.60
Levelized Income Tax	5.5
Levelized Annual Accelerated Depreciation	(1.7)
Levelized Annual Tax Credit	(2.8)
Property Tax	1.0
Insurance	<u>1.0</u>
Total Fixed Charge Rate	19.0

\*Source: Reference 28

## Tax Considerations

The corporate income tax system not only provides a substantial contribution to federal and state treasuries but also provides incentives to firms to invest in particular ways. Any analysis of investment alternatives is therefore incomplete without a full examination of the effects of income tax requirements on these alternatives. For many firms the tax consequences of large energy supply investments can be so substantial in relation to their total tax liability that the analysis of investment alternatives cannot be completed in isolation from the overall profit and tax picture of the firm. The key provisions of the three major investment incentives incorporated in the income tax laws are described below to help the reader properly understand for the effect of income taxes on the investment decision. Our analysis is a pre-tax analysis.

### Debt Interest

The first provision of the tax laws affecting investment decisions is that debt interest is considered by the Internal Revenue Service (IRS) to be a deductible expense for income tax purposes. Because debt interest is deductible, its cost to the firm is considerably less than preferred or common stock for which a return is paid and on which taxes are paid. Thus, those investment alternatives that can be more heavily financed by debt, everything else being equal, will tend to cost less than investment alternatives financed by other means. A firm may have other reasons why it cannot or will not issue more debt, but this does not destroy the incentive that income taxation provides for debt financing.

### Accelerated Depreciation

Perhaps the most significant way in which income tax laws affect investment is through the provision of accelerated depreciation. The straight-line, sum-of-the-years'-digits, and declining-balance methods of depreciation described below are allowed methods of depreciation by the IRS. The firm can use whichever of these methods works to its greatest tax advantage. Like interest, no taxes are paid on income earned in the amount equal to depreciation. However, unlike interest, depreciation is an accounting expense - it is not an operating expense that must be paid and then can be subtracted from gross income to calculate the net after-tax cash flow resulting from an investment. It should be noted, though, that all methods of investment analysis account for book depreciation. In one way or another every investment must not only earn a return over its lifetime but also must earn income to recover the initial-investment cash outlay. This is accomplished through depreciation.

Liberal tax depreciation policies evolved because Congress and the IRS recognized that the assets of firms were used up over time and that an incentive was needed to encourage firms to replace worn out physical capital. The depreciation tax incentive works in two ways. If straight-line depreciation over the physical life of an asset is viewed as the norm for investment recovery, faster methods of depreciation provide the first incentive. Shorter depreciation times provide the second incentive. IRS depreciation policy allows both of these incentives. For investment in new equipment, the sum-of-the-years'-digits method or the double-declining-balance method may be used, with switching to straight-line depreciation allowed whenever this becomes most advantageous to the taxpayer.

The allowance of these methods of calculating depreciation can increase by as much as 100 percent the present value of depreciation for tax purposes over that obtainable from straight-line depreciation. Typically, a tax life roughly two-thirds of economic life is allowed by the IRS. This provides additional value to firms. In some cases the IRS has allowed an even shorter write-off period.

In depreciating an investment, the firm must determine a value for the investment that meets IRS guidelines. This value, which is referred to as the investment basis, is equal to the sum of current dollar expenditures for the investment. It does not include interest during construction. Depreciation cannot be claimed when a facility is under construction - tax depreciation begins when a facility is placed in service.

Having described the concept of depreciation, it is appropriate to describe the methods of depreciation allowed by the IRS. For the simplest method, the straight-line method yearly depreciation is equal to:

$$D_t = \frac{1}{N} (B - L) \quad (\text{Equation 21})$$

where

$D_t$  is the depreciation in time period  $t$

$N$  is the depreciable asset life in years

$B$  is the investment basis

$L$  is the estimated salvage value of the investment after  $N$  years

In order to use the declining-balance method, the asset must be tangible property with a useful life of at least three years. All the other methods have in common the fact that they produce more cash than

the straight-line method early in the life of the asset. For this reason, they are generally more profitable than the straight-line method, everything else being equal.

The declining-balance method may be used on any tangible property having a useful life of at least three years. Depreciation for any one year is computed by multiplying the depreciation rate, which is constant throughout the life of the asset, by the current basis of the asset. The basis is then reduced by the amount of the depreciation taken during that year, and the procedure is repeated for the next year. This cycle continues until either the useful life of the asset is expended or the total depreciation taken is equal to the original basis minus the salvage value. Thus the current basis of the asset declines with time. The depreciation rate is larger than that used for the straight-line method. The maximum rate that can be used with the declining-balance method is twice that of the straight-line method, or  $2/N$ . This rate applies only if the property was acquired new by the taxpayer after December 31, 1953; otherwise, the maximum rate is  $1.5/N$ . The latter rate is used if the property was acquired used or acquired before January 1, 1954.

The formula for declining-balance depreciation in time period  $t$  is:

$$D_t = B \frac{a}{N} \left(1 - \frac{a}{N}\right)^{t-1} \quad (\text{Equation 22})$$

where:

$D_t$  is the depreciation in time period  $t$

-- is the depreciation rate for the declining balance method

$a$  is the 1.5 for used property

$a$  is equal 2 for new property

$N$  is the depreciable asset life in years

$B$  is the investment basis

The sum-of-the-years'-digits method may be used on personal property and, in general, on property used as a part of manufacturing, production, or extraction. With this method, the current year's depreciation deduction is calculated by subtracting the salvage value from the original basis of the property and multiplying this quantity by a fraction that differs from year to year. The fraction has a denominator that is constant with time and equal to the sum of the digits representing the number of years of useful life of the asset. For example, for  $N = 5$ , the denominator equals  $1 + 2 + 3 + 4 + 5 = 15$ . The numerator changes each year and is equal to the number of useful years of life left in the asset at the beginning of the current year. For example, if an asset originally had a useful life of five years, at the end of the second year it has three years useful life remaining so that the fraction for the third year would be  $3/15$ , or  $1/5$ . In general, for an asset with  $N$  years useful life, the denominator of the fraction is equal to  $N(N + 1)/2$  and the numerator of the fraction is equal to  $N - t + 1$ , so that the entire fraction is equal to  $2(N - t + 1)/N(N + 1)$ . Thus, the formula for sum-of-the-years' depreciation in any year  $t$  is

$$D_t = \frac{2(B - L)(N - t + 1)}{N(N + 1)} \quad (\text{Equation 23})$$

where, the notation is the same as that for Equations 21 and 22.

These are the three methods of depreciation that are specifically allowed by law. In addition, the Internal Revenue Code states that "any other consistent method productive of an annual allowance which when added to all allowances for the period commencing with the taxpayer's use of the property and including the taxable year, does not, during the first two-thirds of the useful life of the property, exceed the total of

such allowances which would have been used had such allowances been computed under the method described in paragraph (2)." The method described in the paragraph referenced is the declining-balance method. Thus, the declining-balance method produces as fast a write-off as is allowable during the early life of the asset. In this sense, it is a limiting method of depreciation.

#### Investment Tax Credits

The final tax incentive available to encourage investment is the so-called investment tax credit. The investment tax credit was originally instituted by the Revenue Act of 1962 in order to encourage investment in new plants and equipment. That act provided that a certain fraction of the amount of money invested by an individual or a firm in new capital assets is deductible as an investment credit from the taxpayer's income tax liability. Since its original enactment the investment tax credit has been repealed and reinstated several times, each time in a slightly different form. At present the basic rate is 10 percent of the value of a qualified investment. Qualified investment is essentially construction cost excluding land and structures. The investment tax credit may be claimed at the time of construction - a facility does not have to be operational in order to claim the credit. The investment basis upon which credit is claimed is the same basis upon which depreciation is claimed - that is, current dollar construction costs excluding interest during construction.

In addition to the basic 10 percent rate, another 1 percent credit is available to firms that offer their employees qualified employee

stock ownership plans and yet another 0.5 percent to firms where employees match employer contributions to such plans. Thus the maximum investment tax credit rate available to firms is 11.5 percent.

The amount of the credit is not always simply 10, 11, or 11.5 percent of the total invested by the taxpayers during the current year in new plant and equipment. The effective rate used for computing the credit varies with the useful life of the asset, as shown below.

<u>If the useful life (in years) is:</u>	<u>The applicable percentage of expenditures qualifying for the credit is:</u>
Less than 3	0
More than 3 but less than 5	33-1/3
More than 5 but less than 7	66-2/3
More than 7	100

Moreover, the maximum amount of investment credit that is allowable in a single year depends on the taxpayer's total tax liability during that year. The credit can be used to offset the first \$25,000 of tax liability and 90 percent of the tax liability above \$25,000. Credit earned in excess of these limits can be carried back three years to offset previous tax liabilities or carried over seven years to offset future tax liabilities. Thus, in practice the effective investment tax credit rate in any given tax year could be quite different from the rates specified in the tax code.

Congressional revisions to the investment tax credit in 1978 made the existing credit a permanent one. Existing law also makes the investment tax credit available under certain conditions to owners of leased property (lessors) and provides that the credit may be passed to the lessee if he is the original user.

This concludes the discussion of income taxes and income tax incentives to investment. The equations provided have been specified to handle most of the factors discussed above but because of the complexity of tax considerations the analyst is advised to proceed with caution and consult the tax code whenever an investment evaluation involves unusual tax considerations. Also, because the tax code is subject to continual revision, the analyst must give attention to updating tax-related input assumptions if his calculations are to be realistic. It should be recognized, on the other hand, that many tax incentives are temporary, lasting perhaps three to five years. Evaluations covering 5 to 20 year time frames should therefore not be made overly sensitive to the latest short-run tax incentives enacted by Congress.

#### Use of Real vs. Current Costs

Price changes are very important in investment analysis and must be properly accounted for by the analyst. To take price changes into account, it is useful to distinguish between two kinds of price changes. One is a "nominal" price change that results from changes in the purchasing power of the dollar, i.e., inflation or deflation. The amount of this nominal price change is indicated by the change in the general level of prices as measured by price indices.

The other type of price change that can occur is a change in "real" terms. This means that the price of a given good or service rises proportionately more or less than the change in the general purchasing power of the dollar such that its price changes over time relative to the prices of other goods and services. For example, given that the general price index rose over a five-year period from 1.00 to 1.30, the

price of a piece of equipment that also rose 30 percent over the same period would in effect remain constant in terms of its price relative to prices in general; i.e., its price would change in nominal terms but would remain constant in real terms. Costs are said to be expressed either in real (constant) or in current (inflated) dollars. Constant and current dollar costs are directly related by inflation according to the following formulation:

$$\text{Constant dollars} = \text{current dollars}/(1 + \text{inflation rate})^t$$

where:

t is the current dollar year minus constant dollar base year

In investment analysis the choice is sometimes made to use constant dollars to facilitate communication. The use of constant dollars is helpful because people generally think in terms of today's cost levels. Alternatives can thus be compared on a basis that has absolute as well as relative meaning to the analyst. Using this approach in its simplest form, all costs and revenues are assumed to inflate at the general inflation rate; therefore, they remain constant in real terms. With this assumption, renewal costs and other future expenses and benefits are evaluated at present prices. If there is reason to believe that certain items of cost or benefits will not inflate at the general rate of inflation, then their future values are adjusted only for the estimated real change, i.e., the effective change after taking into account the change in the general price level. If the future price of a good or service were fixed at current levels by lease arrangements (without a cost escalation clause), the price would decline in real terms in the face of inflation. It would be necessary to adjust the

future payments by a price index prior to discounting them to present value in order to express them in constant dollars. Employing this procedure, the appropriate discount rate is a real rate, that is, one from which the inflation factor has been removed. Assuming constant future prices can greatly simplify an analysis and in many applications will result in reasonably accurate results. However, the success of the approach rests not only on the assumption that future receipts and expenditures will respond fully and evenly to inflation, but also on the assumption that tax considerations and the source of investment funds do not importantly affect the outcome - two assumptions that are quite unrealistic for oil company related investments.

The real after-tax return to the firm may be substantially changed by inflation, even if pre-tax investment receipts and costs are assumed fully and equally responsive to inflation. Other things being equal, inflation will tend to have a detrimental effect on an investment financed principally by equity funds, i.e., nonborrowed funds. Among the reasons are the following:

- °tax deductions for depreciation are unresponsive to inflation
- °terminal value of equipment is responsive to inflation and will be reflected in the capital gains tax
- °tax deductions for interest on the borrowed portion of capital are unresponsive to inflation, such that the present value of the deductions diminishes over time
- °inflation in receipts tends to move a firm into higher tax brackets.\*

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\* At the same time, the move into higher tax brackets tends to increase the value of a given deduction from taxable income.

However, in the case of an investment funded by a large proportion of borrowed funds, it is possible, other things being equal, that the after-tax return to equity may be maintained or even improved in the face of inflation due to the following factor: The real value of the debt charges (amortized principal and interest) to finance the investment may decline because of the fixed nature of these payments. This gain to the borrower may equal or exceed his loss due to the fixed nature of depreciation and interest deductions.

From a practical standpoint, the proper treatment of tax effects in an inflationary economy can best be handled by calculating fixed capital charges and levelized operating costs on the basis of projected current dollar expenditures. Operating costs are calculated based on the levelization of the current dollar expenditures over the investment lifetime.

#### Cost Escalation Rates

For this analysis we assume that the base case cost of materials will escalate at the same rate as the long term inflation rate of 9 percent [13, 21]. These escalation parameters include those for:

- °Cost of CO<sub>2</sub>
- °Operation and maintenance costs
- °Cost of surfactants
- °Cost of polymers
- °Oil price

### Cost of CO<sub>2</sub>

For this analysis we assume a delivered, and compressed CO<sub>2</sub> cost of \$2.50 per MCF for the base case analysis [25]. This value is currently typical for a West Texas CO<sub>2</sub> flood. The cost assumes use of a CO<sub>2</sub> pipeline from a major CO<sub>2</sub> production area close to West Texas.

### Period of Analysis

We assume a project analysis period of 10 years for the base case. This timeframe is typical for investment evaluations of the type we are considering at oil companies.

### Profit

The annualized profit may be calculated as follows:

$$\begin{aligned} \text{Levelized Annual Profit} &= \text{Levelized Revenue} \\ &\quad - \text{Levelized Capital Cost} \\ &\quad - \text{Levelized O \& M Cost} \end{aligned}$$

The annualized profit is computed in subroutine profit.

TABLE 15  
FINANCIAL PARAMETERS ASSUMPTIONS SUMMARY

---

Discount Rate:	15 percent
Fixed Charge Rate For Capital Expenses:	19 percent
Long-Term Inflation Rate:	9 percent
Materials and O & M Escalation Rate:	Inflation rate (9 percent)
CO <sub>2</sub> Cost (delivered and compressed):	\$2.50/MCF
No. of years analysis covers:	15 years
Current dollars analysis	
Pre-tax Analysis	

---

## THE PROGRAM

### Summary:

A Fortran Program compatible with the computer system at New Mexico Tech incorporates the items discussed in the oil field, oil recovery model, capital and operating and maintenance costs, crude oil revenue, and financial parameters, cost levelization sections of this report. The program contains approximately forty-five input variables. A copy of the code appears in Appendix D.

The structure of the program is modular with subroutines performing given tasks so that changes in the oil recovery model, capital and operating and maintenance costs and other parameters may be made easily.

Table 16 describes the various subroutines used in the program and their functions. Figure 2 shows the flow chart for the main program.

Figures 4-9 contain the flow charts for Subroutines, Data, Field, Moblty, Captal, ONM, Revnue, and Profit, respectively.

The input variables are discussed in Table 17. Tables 18-23 contain the variable listings and variable descriptions for Subroutine Field, Moblty, Captal, ONM, Revnue and Profit, respectively.

FIGURE 2  
MAIN PROGRAM FLOWCHART

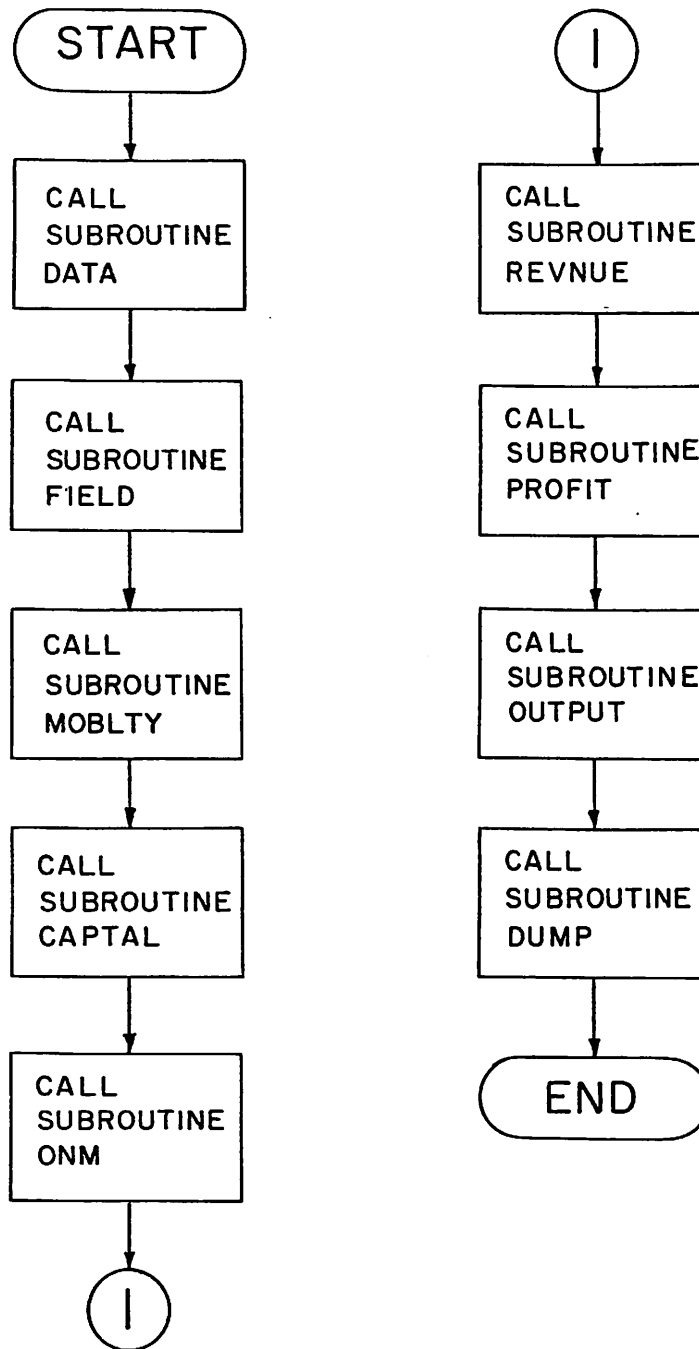


TABLE 16  
LIST OF SUBROUTINES

Subroutine Name	Subroutine Function
DATA	Enter data for economic and engineering analysis
FIELD	Calculate the total displaceable oil volume for the field. Calculate the HCPV.
MOBLTY	Calculate the total oil recovery which will occur for a given mobility ratio and HCPV gas injected. A five-spot pattern is assumed. An oil production schedule is generated.
CAPTAL	Compute the capital investment costs associated with the type of CO <sub>2</sub> flood which is being analyzed: conventional CO <sub>2</sub> flood, use of WAG, foams or polymers as mobility control agents. Levelize capital costs.
ONM	Compute the O & M Cost for the type of CO <sub>2</sub> flood being analyzed levelize O & M costs.
REVNUE	Compute the oil revenue which will be obtained from the CO <sub>2</sub> flood. Royalties, state and local severance and production taxes and the windfall profit tax on net revenue are all subtracted from the gross revenue. Levelize oil revenue.
PROFIT	Compute the gross profit which results from the CO <sub>2</sub> flood. Annual profit = Levelized revenue - Levelized capital cost - Levelized O & M cost.
OUTPUT	Output pertinent results from the engineering and economic analysis.
DUMP	Dump and print all input parameters, intermediate results and final results. Used to check model.
COMMA	Inserts commas for oil production and dollar values in output.

FIGURE 3  
SUBROUTINE DATA FLOWCHART

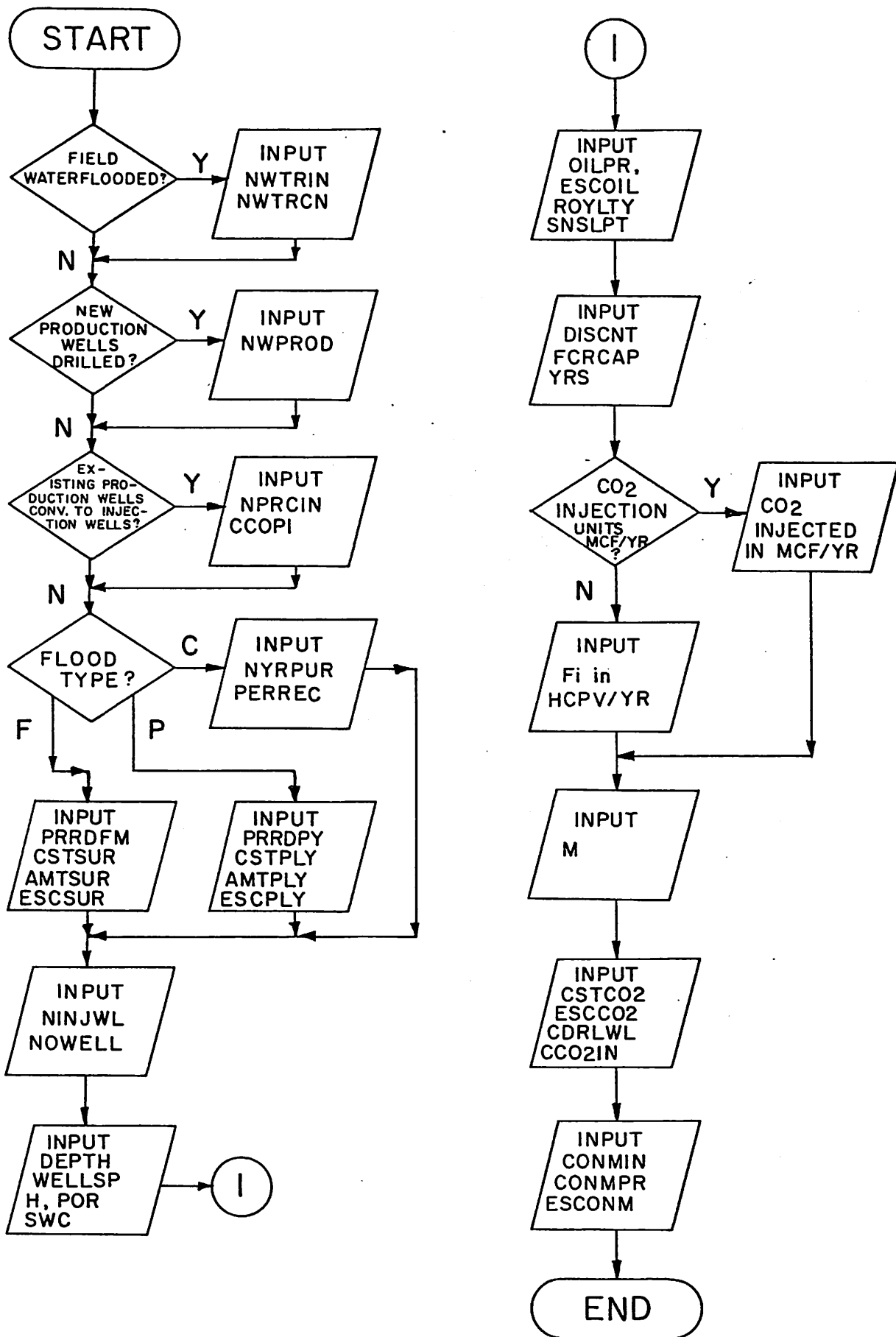


TABLE 17  
SUBROUTINE INPUT VARIABLE LISTING

Input Variable	Variable Description
Variables related to waterflooding	
NWTRIN	Number of water injection wells in field
NWTRCN	Number of water injection wells being converted to CO <sub>2</sub> injection wells
Variables related to whether or not new production wells have to be drilled	
NWPROD	Number of new production wells to be drilled
Variables related to converting existing production wells to CO <sub>2</sub> injection wells	
NPRCIN	Number of existing production wells to be converted to CO <sub>2</sub> injection wells
CCOPI	Cost of converting existing production wells to CO <sub>2</sub> injection wells in dollars per well
Project Type, Type	
C	Conventional CO <sub>2</sub> Flood
W	WAG CO <sub>2</sub> Flood
F	Foam CO <sub>2</sub> Flood
P	Polymer <sup>2</sup> CO <sub>2</sub> Flood
Conventional CO <sub>2</sub> Flood	
NYRPUR	Number of years entire CO <sub>2</sub> requirements purchased
PERREC	Percentage of CO <sub>2</sub> used which is recycled when CO <sub>2</sub> recycling occurs (as fraction)
Foam CO <sub>2</sub> Flood	
PRRDFM	Reduction in CO <sub>2</sub> requirements with foam CO <sub>2</sub> flood over conventional flood (as fraction)

TABLE 17 (continued)  
SUBROUTINE INPUT VARIABLE LISTING

Input Variable	Variable Description
CSTSUR	Cost of surfactant (in dollars/bbl)
AMTSUR	Amount of surfactant required (in bbl/Mcf CO <sub>2</sub> )
ESCSUR	Surfactant cost escalation rate (as fraction)
Polymer CO <sub>2</sub> flood	
PRRDY	Reduction in CO <sub>2</sub> requirements with polymer CO <sub>2</sub> flood over conventional flood (as fraction)
CSTPLY	Cost of polymer (in dollars/bbl)
AMTRY	Amount of polymer required (in bbl/Mcf CO <sub>2</sub> )
ESCPY	Polymer cost escalation rate (as fraction)
Injection and Production Wells	
NINJWL	Number of new injection wells to be installed
NOWELL	Number of production wells in field excluding production wells converted to CO <sub>2</sub> injection wells
Field Characteristics	
DEPTH	Reservoir depth (in feet)
WELLSP	Production well spacing (in acres)
H	Net pay thickness (in feet)
POR	Porosity (as fraction)
SWC	Connate water saturation (as fraction)

TABLE 17 (continued)  
SUBROUTINE INPUT VARIABLE LISTING

Input Variable	Variable Description
<b>Financial Parameters</b>	
OILPR	Current oil price (dollars/barrel)
ESCOIL	Oil price escalation rate (as fraction)
ROYLTY	Royalty (as fraction)
SNLSPT	State and local severance and production taxes (as fraction)
DISCNT	Discount rate for discounting future cost and revenue streams (as fraction)
FCRCAP	Fixed charge rate for capital expense (as fraction)
YRS	Number of years analysis covers
<b>Mobility Ratio and HCPV CO<sub>2</sub> Injected</b>	
FI	Amount of CO <sub>2</sub> injected in MCF/yr or HCPV/yr
M	Mobility Ratio
<b>CO<sub>2</sub> cost and escalation</b>	
CSTCO <sub>2</sub>	Cost of CO <sub>2</sub> compressed and delivered (in \$/MCF) <sup>2</sup>
ESCCO <sub>2</sub>	CO <sub>2</sub> cost escalation rate (as fraction)
<b>Capital Cost Data</b>	
CDRLWL	Cost of drilling, completing, and equipping well (in dollars/ft)
CCO2IN	Cost of CO <sub>2</sub> injection equipment (in dollars/injection well)

TABLE 17 (continued)  
SUBROUTINE INPUT VARIABLE LISTING

Input Variable	Variable Description
Operation and Maintenance Cost Data	
CONMIN	O & M Cost (dollars/injection well/year)
CONMPR	O & M Cost (dollars/production well/year)
ESCONM	O & M Cost escalation rate per year (as fraction)

FIGURE 4  
SUBROUTINE FIELD FLOWCHART

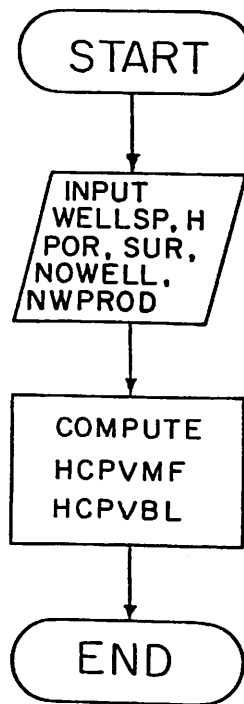


TABLE 18

## SUBROUTINE FIELD VARIABLE LISTING :

Input Variable	Variable Description
HCPVBL	HCPV in BBL
HCPVMF	HCPV in MMCF

FIGURE 5  
SUBROUTINE MOBLTY FLOWCHART

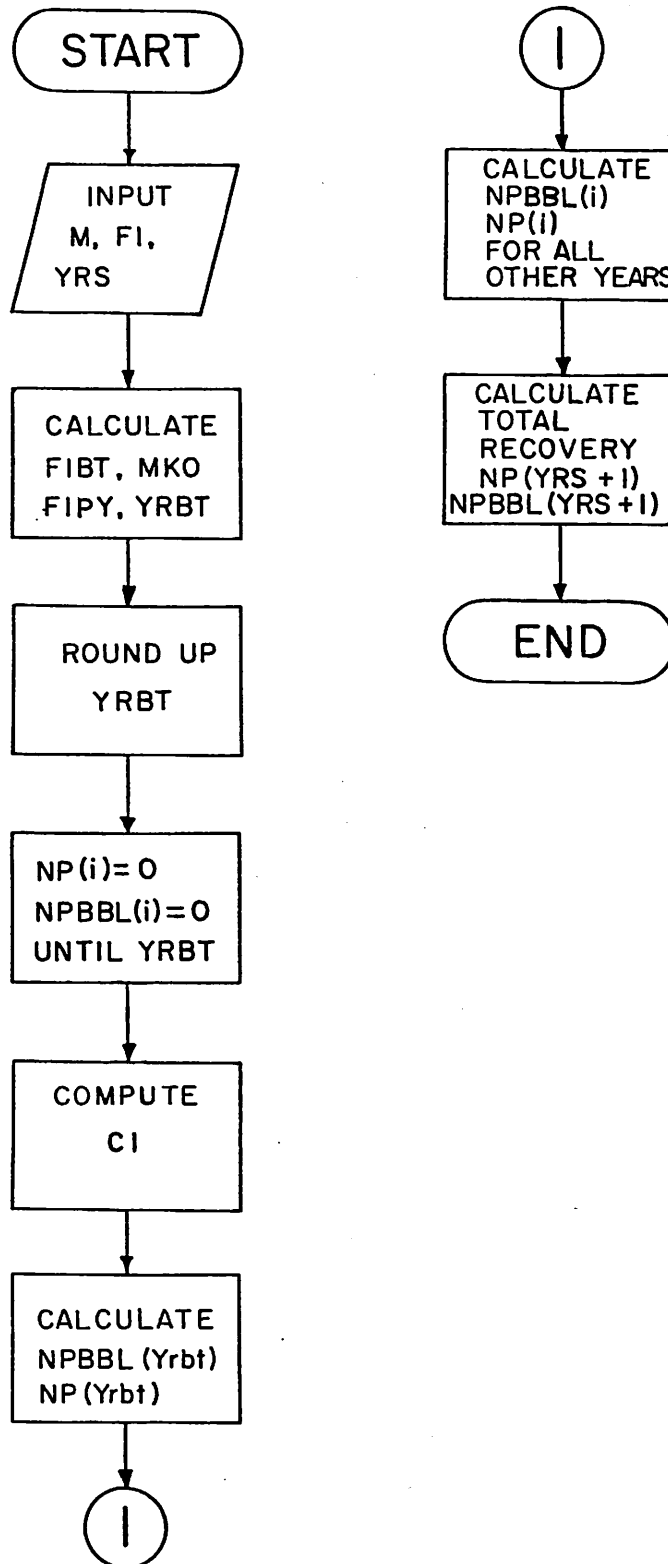


TABLE 19  
SUBROUTINE MOBLTY VARIABLE LISTING

Input Variable	Variable Description
M	Mobility Ratio
FI	Number of pore volumes gas injected
FIBT	Value of FI at breakthrough
NP	Oil production (percent HCPV)
FIPY	Number of pore volumes gas injected per year
YRBT	Year breakthrough occurs
MKO	Koval's modified viscosity ratio
NPBBL	Oil production in bbls
NP	Oil production in percent HCPV
C1	See thesis text on oil recovery model for details

FIGURE 6  
SUBROUTINE CAPITAL FLOWCHART

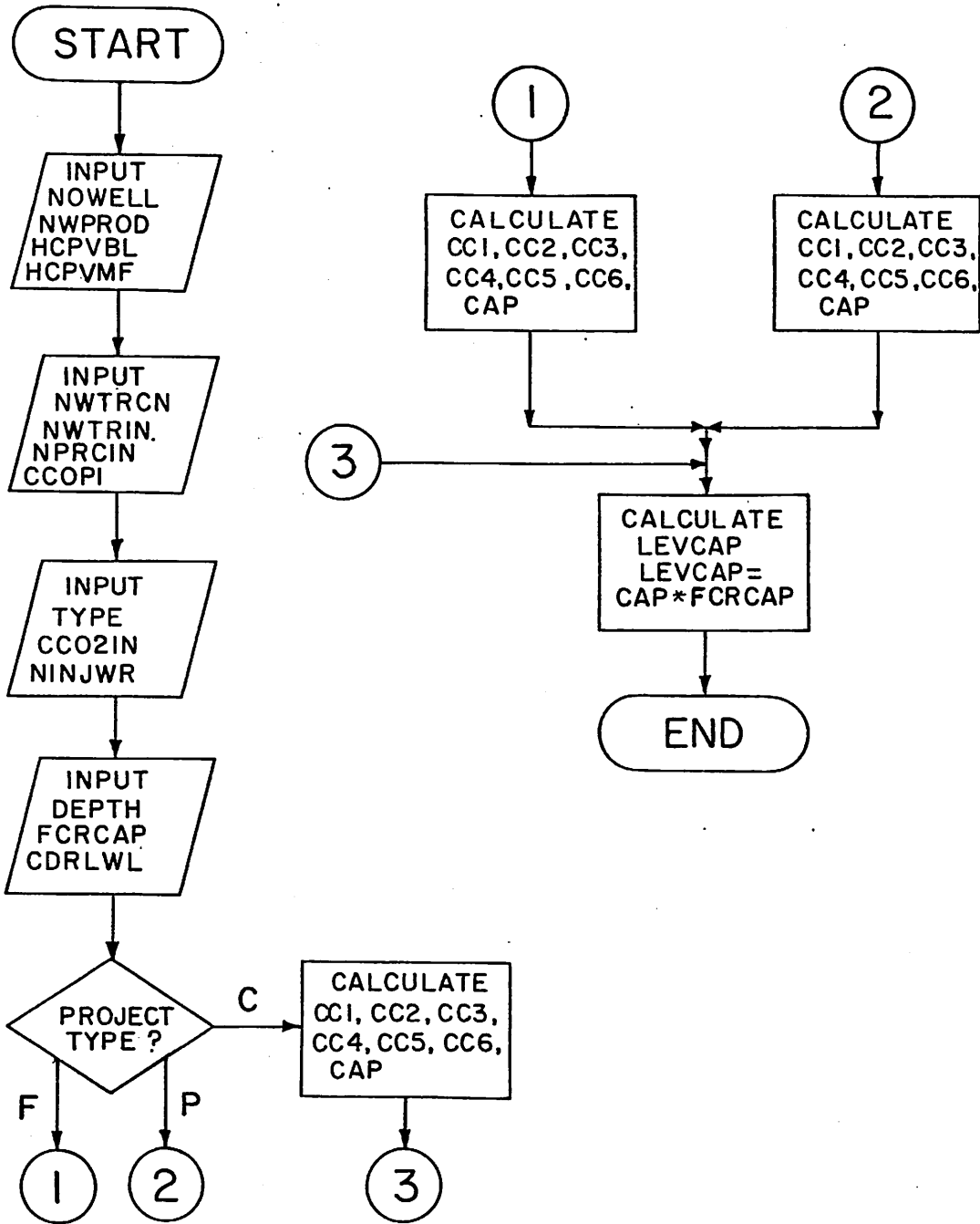


TABLE 20  
SUBROUTINE CAPITAL VARIABLE LISTING

Input Variable	Variable Description
CC1	Cost of drilling, completing and equipping new injectors
CC2	Cost of drilling, completing and equipping new producers
CC3	Cost of converting existing producers to CO <sub>2</sub> injectors
CC4	Cost of converting existing water injection wells to CO <sub>2</sub> injection wells
CC5	Cost of CO <sub>2</sub> injection equipment for CO <sub>2</sub> flood project
For conventional CO <sub>2</sub> flood	
CC6	Cost of separation CO <sub>2</sub> from produced gas
For foam CO <sub>2</sub> flood	
CC6	Other capital costs characteristic of using foam as a mobility control agent
For Polymer CO <sub>2</sub> flood	
CC6	Other capital costs characteristic of using polymer as a mobility control agent
CAP	Total capital cost CAP = CC1 + CC2 + CC3 + CC4 + CC5 + CC6
LEVCAP	Levelized Capital Cost

FIGURE 7  
SUBROUTINE ONM FLOWCHART

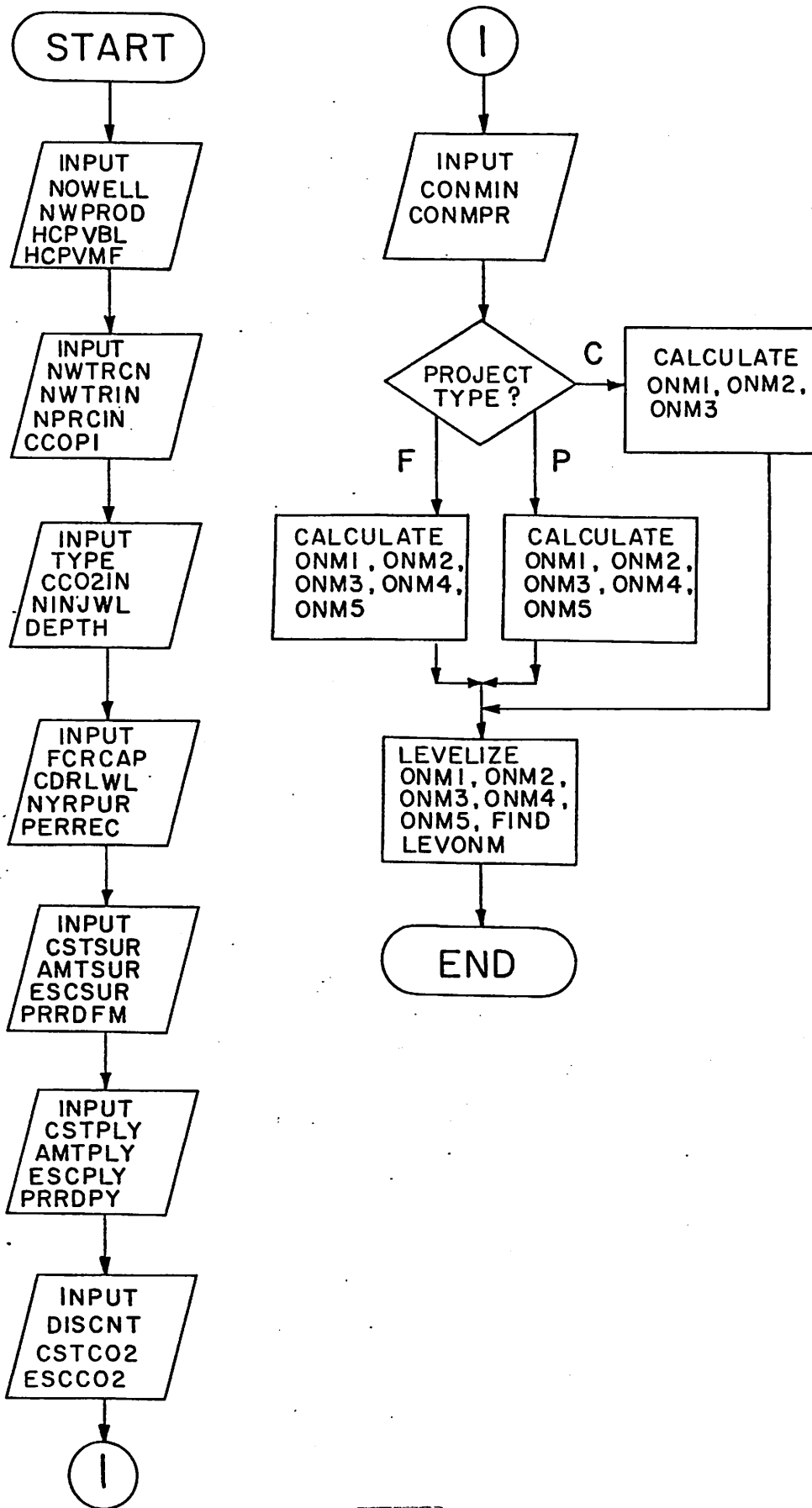


TABLE 21  
SUBROUTINE ONM VARIABLE LISTING

Input Variable	Variable Description
ONM1	Operation and maintenance cost for injection wells
ONM2	Operation and maintenance cost for production wells
ONM3	Cost of CO <sub>2</sub>
For Foam CO <sub>2</sub> flood	
ONM4	Cost of surfactant
ONM5	Operation and maintenance cost characteristic of using foam as a mobility control agent
For polymer CO <sub>2</sub> flood	
ONM4	Cost of polymer
ONMS	Operation and maintenance cost characteristic of using polymer as a mobility control agent
LEVONM	Levelized O & M Cost

FIGURE 8  
SUBROUTINE REVNUUE FLOWCHART

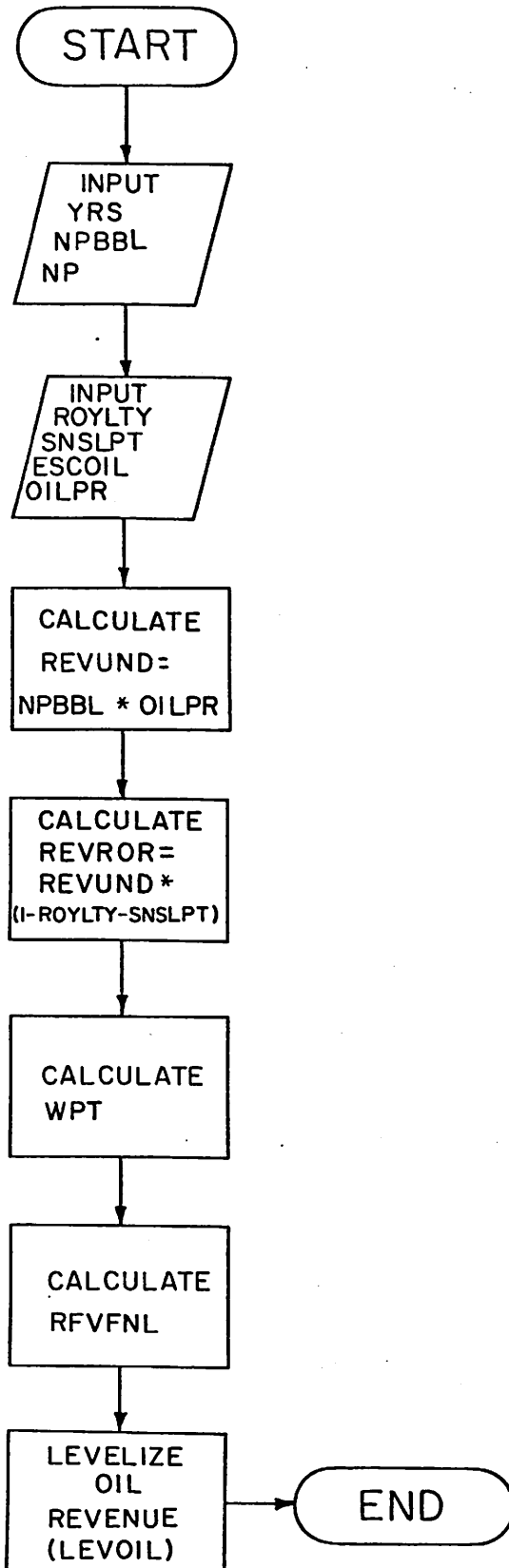


TABLE 22

## SUBROUTINE REVNUUE VARIABLE LISTING

<u>Input Variable</u>	<u>Variable Description</u>
REVUND	Undiscounted, escalated revenue
REVROR	Revenue after royalty, state and local severance and production taxes have been removed
WPT	Windfall profit tax
REVFNL	Total final revenue after all royalties, state and local severance and production taxes and windfall profits tax have been removed.
LEVOIL	Levelized oil revenue

FIGURE 9  
SUBROUTINE PROFIT FLOWCHART

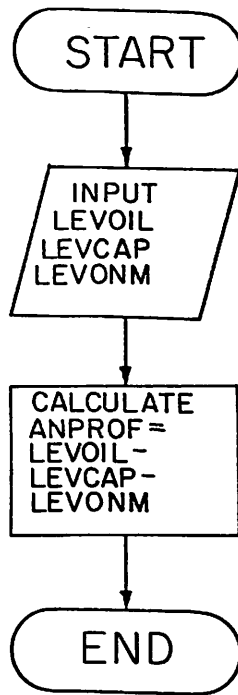


TABLE 23

## SUBROUTINE PROFIT VARIABLE LISTING

Input Variable	Variable Description
ANPROF	Annualized Profit (Dollars)
LEVOIL	Levelized Oil Revenue (Dollars)
LEVCAP	Levelized Capital Cost (Dollars)
LEVONM	Levelized O & M Cost (Dollars)

## RESULTS - CONCLUSIONS

### Introduction:

We have provided a description of the oil field, oil recovery model, capital and operating and maintenance costs, crude oil revenue, financial parameters - cost levelization, and program structure. In this section we apply what has been described in these previous sections and provide pertinent results from case runs of the model. We use these results to make conclusions regarding mobility control for carbon dioxide flooding.

First, let us review the objective of the model and lay out some guidelines which will help keep the results in perspective:

°The basic objective of this work is to provide a means by which different mobility control alternatives for an oil field can be compared. The use of levelized costs provides the means of comparing these different investment strategies with different capital outlays and annual cost streams.

°In this model we assume that when a particular mobility control method is applied under a particular set of operating conditions it will work with no problems. Whether or not this will actually happen, of course, is the subject of a detailed reservoir engineering study for the particular field in question. This point must be kept in mind when comparing different alternatives.

°The capital and operating and maintenance costs presented in this analysis are estimates only and may not be identical to the expenses for a particular field, during a particular year, or for a particular producer.

°The profits expressed in this analysis may not represent the actual profits obtained from the investment. First, the profit numbers are the outcome based on assumptions which are assumed to be valid over a five to twenty year timeframe. The chances that these assumptions will actually hold true over this time period are virtually nil. This analysis does not account for company overhead expenses and the effect of the corporate income tax.

°Our last point concerns a basic principle of this analysis. We are using profit as a guideline for choosing an alternative. This is acceptable in a capitalistic society. However, the methodology may not have any merit in other societies where profit is not a factor in choosing the alternative. The factors essential to choosing the best alternative could be maximizing production or extending production over a longer time period. Maximum profits do not always produce maximum production.

At this juncture, we describe the parameters for the base case analysis.

### Base Case Parameters For Conventional CO<sub>2</sub> Flood

It is useful to have a base case for describing and comparing the results from the computer model. Most of the base case parameters have already been specified in previous sections of this report. We summarize the important base case parameters for reference:

°Conventional CO<sub>2</sub> Flood

°Mobility ratio: 30

°CO<sub>2</sub> Injected: 0.2 HCPV/yr., 41.8 MMCF/yr.

°50 percent CO<sub>2</sub> recycled after 3 years

°Well data: 8 of 16 water injection wells converted to CO<sub>2</sub> injectors, 41 new injection wells, 64 production wells

°Reservoir properties: Depth of 7,000 feet, 40 acre spacing, net pay thickness of 20 feet, porosity of 25 percent, connate water saturation of 25 percent

°Oil price: \$32.50/bbl

°Oil price escalation rate: 9%/yr.

°Royalty: 1/8 th

°State and local severance and production taxes: 4.6 percent

°Discount rate: 15 percent

°Fixed charge rate for capital: 19 percent

°Analysis period: 10 years

°CO<sub>2</sub> cost: \$2.50/MCF

°CO<sub>2</sub> cost escalation rate: 9%/yr.

°Cost of drilling completing and equipping well: \$60/foot

°O & M cost escalation rate: 9 percent/yr.

We now look at pertinent results for this base case analysis.

### Base Case Results For Conventional CO<sub>2</sub> Flood

We are dealing with a field with approximately 75 million barrels of oil in place prior to the CO<sub>2</sub> flood. Approximately 70 percent of this oil is recovered over a ten-year period. Table 24 shows the oil recovery schedule, amount of CO<sub>2</sub> injected and final oil revenues on a year-to-year basis.

Capital costs are as follows:

°Cost of drilling, completing, and equipping new injectors: \$21,162,150

°Cost of converting existing water injectors to CO<sub>2</sub> injectors: \$769,200

°Cost of injector equipment for CO<sub>2</sub> flood: \$2,998,800

°Cost of CO<sub>2</sub> recycling equipment: \$280,546

The total capital cost is \$25,210,696.

Operation and maintenance costs total approximately 3.5 million dollars per year while CO<sub>2</sub> is not recycled. After CO<sub>2</sub> recycling commences the O & M costs is reduced to approximately 3 million dollars per year. O & M costs for injection and production wells total about 1.7 million and 0.7 million dollars per year respectively.

Levelized profit is approximately 188 million dollars per year.

The levelized cost components are as follows:

TABLE 24  
 BASE CASE CONVENTIONAL CO<sub>2</sub> FLOOD RESULTS

Year	Percent Recovered	Barrels Recovered	MMCF CO <sub>2</sub> Injected	Final Oil Revenue (\$)
1	19	14,644,562	418	324,486,884
2	13	10,095,836	418	239,320,028
3	9	7,043,567	418	178,846,096
4	7	5,248,075	418	142,903,962
5	5	4,073,933	418	119,095,798
6	4	3,259,184	418	102,396,369
7	3	2,669,122	418	90,212,438
8	2	2,227,403	418	81,063,133
9	2	1,887,817	418	74,044,211
10	<u>2</u>	<u>1,620,946</u>	<u>418</u>	<u>68,574,568</u>
Total	70	52,770,450	4,180	1,420,943,488

- °Levelized revenue: \$198,049,188
- °Levelized capital cost: \$4,790,032
- °Levelized O & M cost: \$5,029,322
- °Annualized profit: \$188,229,834

Having provided a description of the base case for a conventional CO<sub>2</sub> flood we show the effect of varying critical parameters on costs and profits. The parameters investigated include:

- °Mobility ratio
- °Amount of CO<sub>2</sub> injected
- °Oil price
- °Oil price escalation rate
- °Number of years analysis covers
- °Discount rate
- °Fixed charge rate for capital
- °Cost of CO<sub>2</sub>
- °CO<sub>2</sub> cost escalation rate
- °Number of years until CO<sub>2</sub> recycling commences
- °Amount of CO<sub>2</sub> recycled when recycling commences
- °O & M cost escalation rate

All values are maintained to those set at the base case except the variable being changed. We begin by considering mobility ratio.

Figure 10 shows the percentage oil recovered and annualized profit as function of mobility ratio. The annualized profit increases sharply with lower mobility ratios. The profit shown for a particular mobility ratio can only be realized if the mobility ratio indicated on the figure can be attained for a conventional CO<sub>2</sub> flood.

FIGURE 10  
MOBILITY RATIO vs ANNUALIZED PROFIT AND OIL RECOVERY FOR CONVENTIONAL CO<sub>2</sub> FLOOD\*

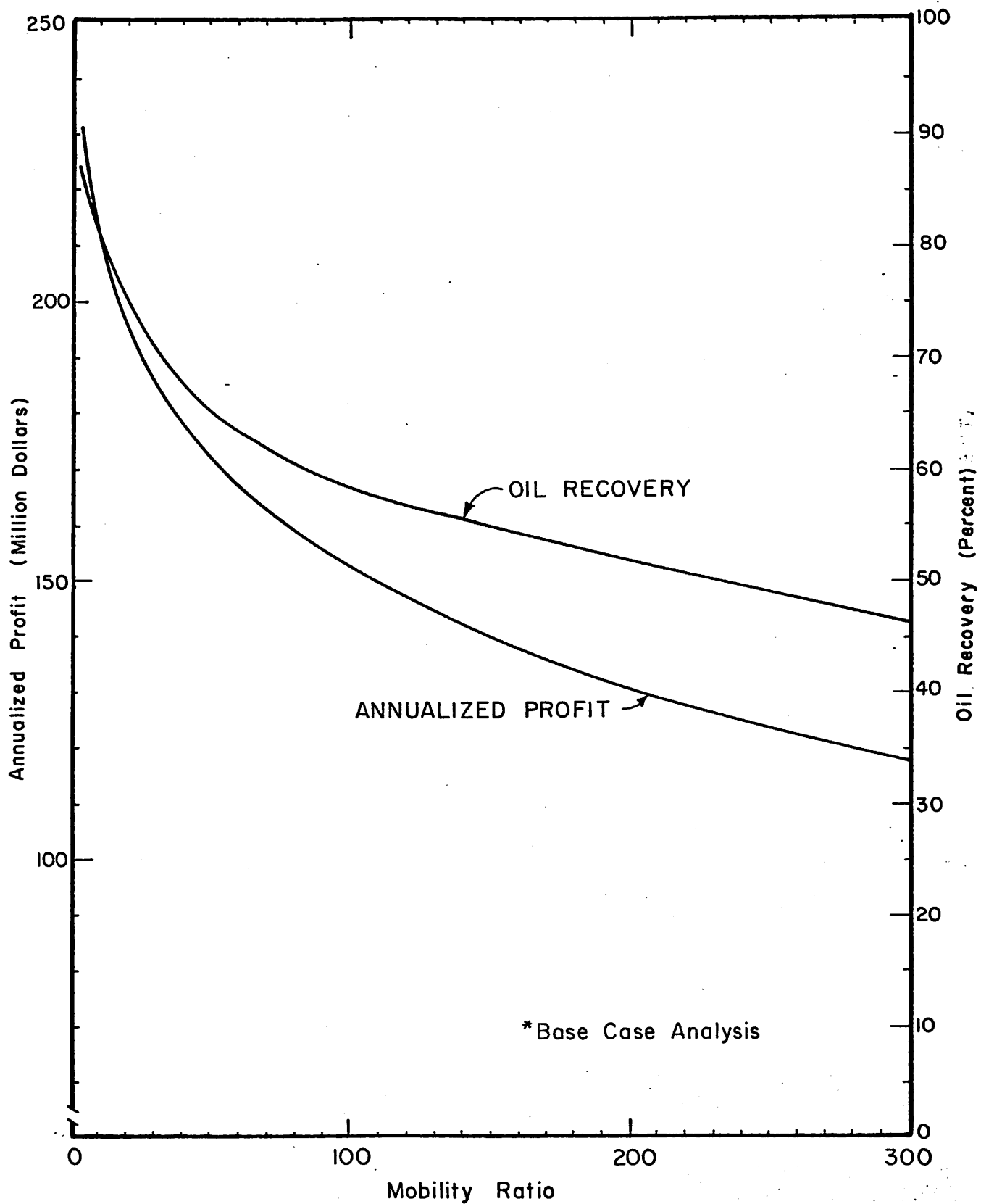


Figure 11 shows the effect of varying the amount of CO<sub>2</sub> injected on annualized profit. Greater profits are realized as more CO<sub>2</sub> is injected. The sharpest rise in annualized profit occurs until about 0.25 HCPV CO<sub>2</sub> is injected per year. The mobility ratio is maintained at 30.

Figure 12 shows the effect of crude oil price on levelized oil revenue. The levelized oil revenue is a direct function of crude oil price. Levelized oil revenues increase approximately 5 million dollars for every dollar per barrel increase in the oil price. A change in actual oil price over an assumed oil price in the economic analysis can affect revenues significantly.

Figure 13 shows the effect of crude oil price escalation rate on levelized oil revenue. This escalation rate is nearly a direct function of levelized oil revenue. In this base case analysis levelized oil revenue increases approximately 4 million dollars for each percentage point rise in the oil price escalation rate. Thus, a decrease in the price of oil and oil price escalation rate by 1 dollar per barrel and 1 percent respectively can decrease levelized oil revenues by about 9 million dollars.

Figure 14 shows how the number of years the analysis covers affects annualized profit. As the project life increases, more oil is recovered, but the rate at which oil is recovered declines. Annualized profits are much higher with a shorter project life since most of the oil is recovered after breakthrough which occurs during the second year for this base case analysis.

FIGURE II  
HCPV CO<sub>2</sub> INJECTED PER YEAR vs ANNUALIZED  
PROFIT FOR CONVENTIONAL CO<sub>2</sub> FLOOD \*

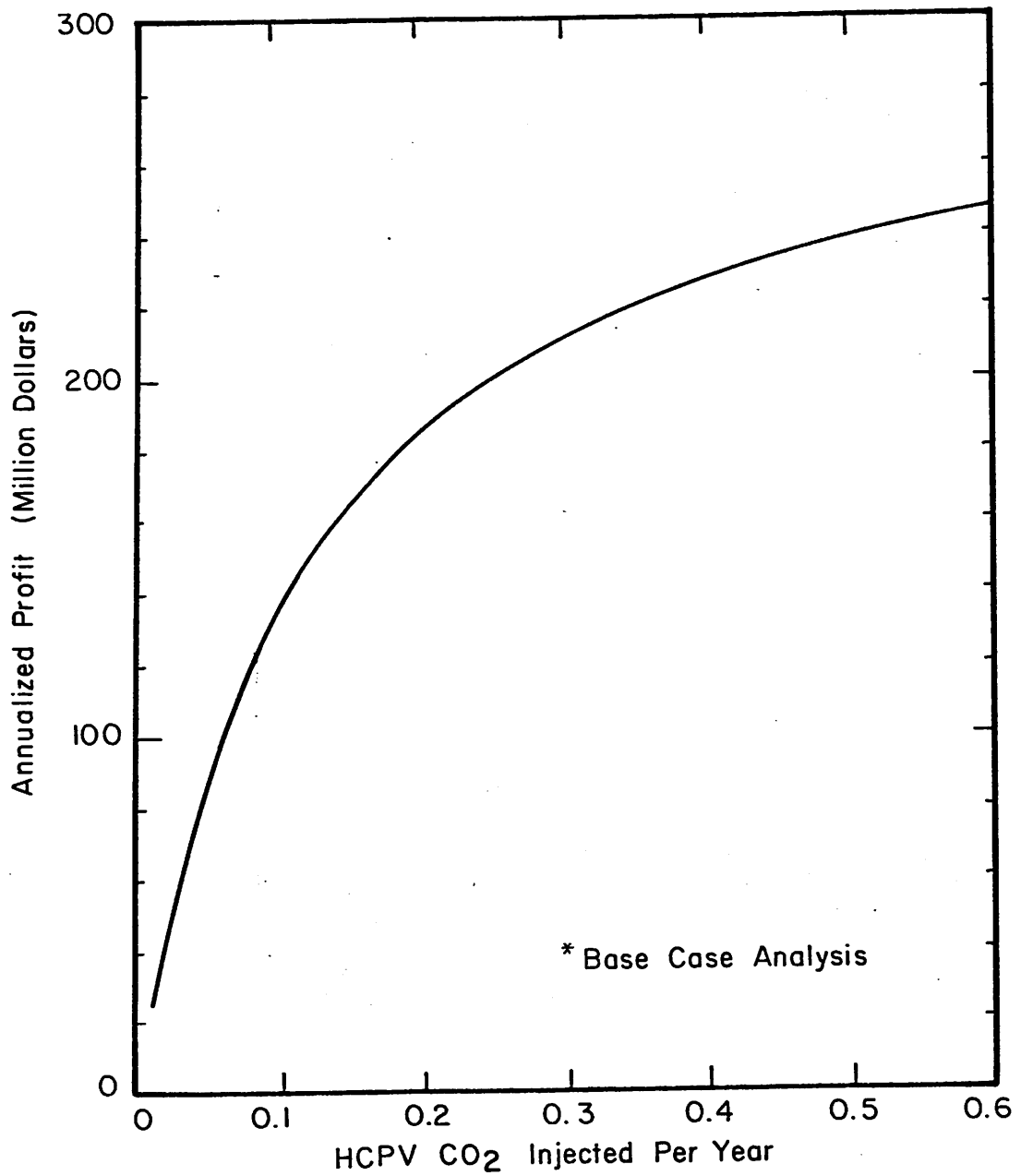


FIGURE 12  
OIL PRICE vs LEVELIZED OIL REVENUE FOR  
CONVENTIONAL CO<sub>2</sub> FLOOD \*

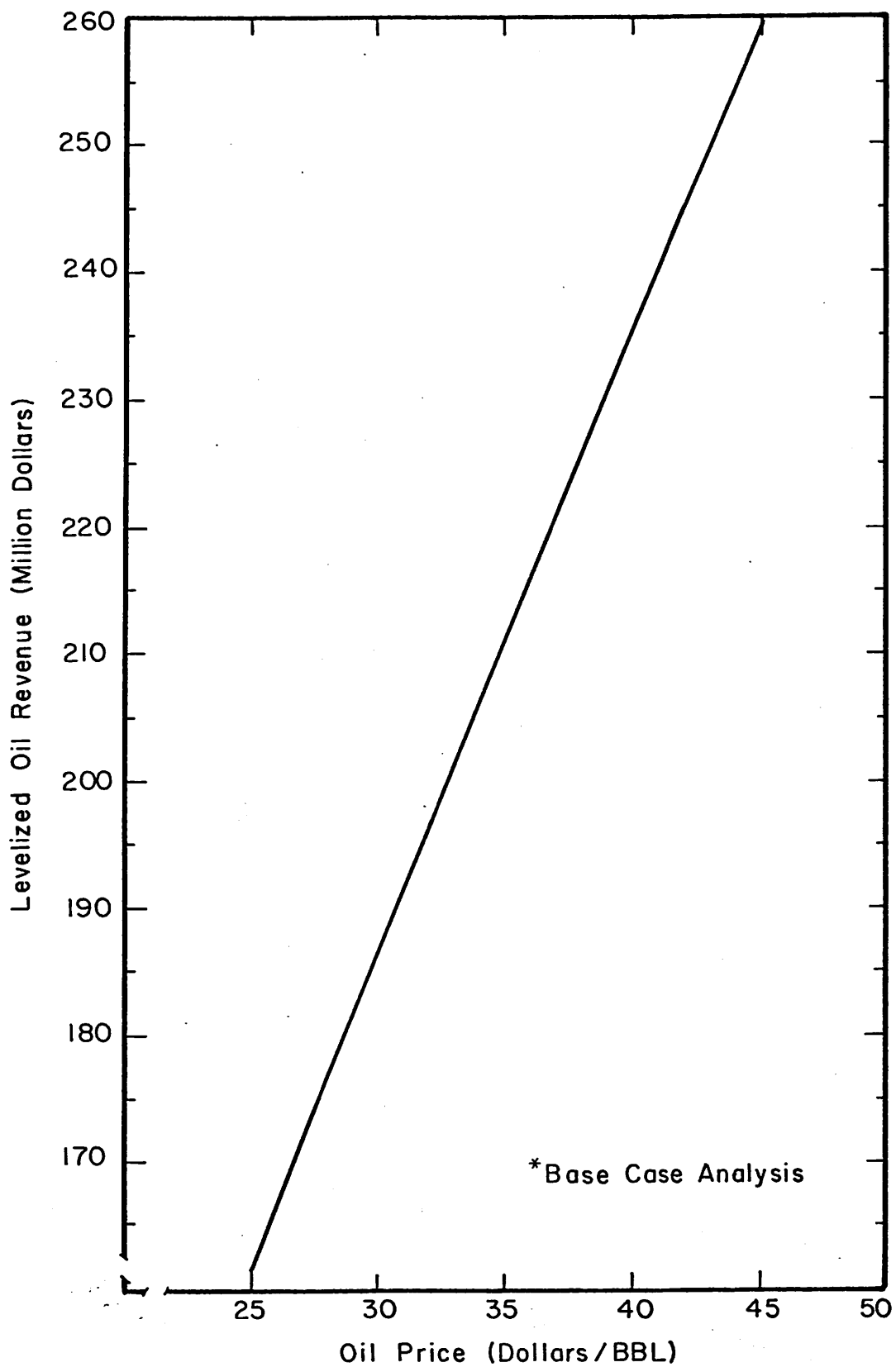


FIGURE 13  
OIL PRICE ESCALATION RATE vs LEVELIZED OIL REVENUE FOR CONVENTIONAL CO<sub>2</sub> FLOOD \*

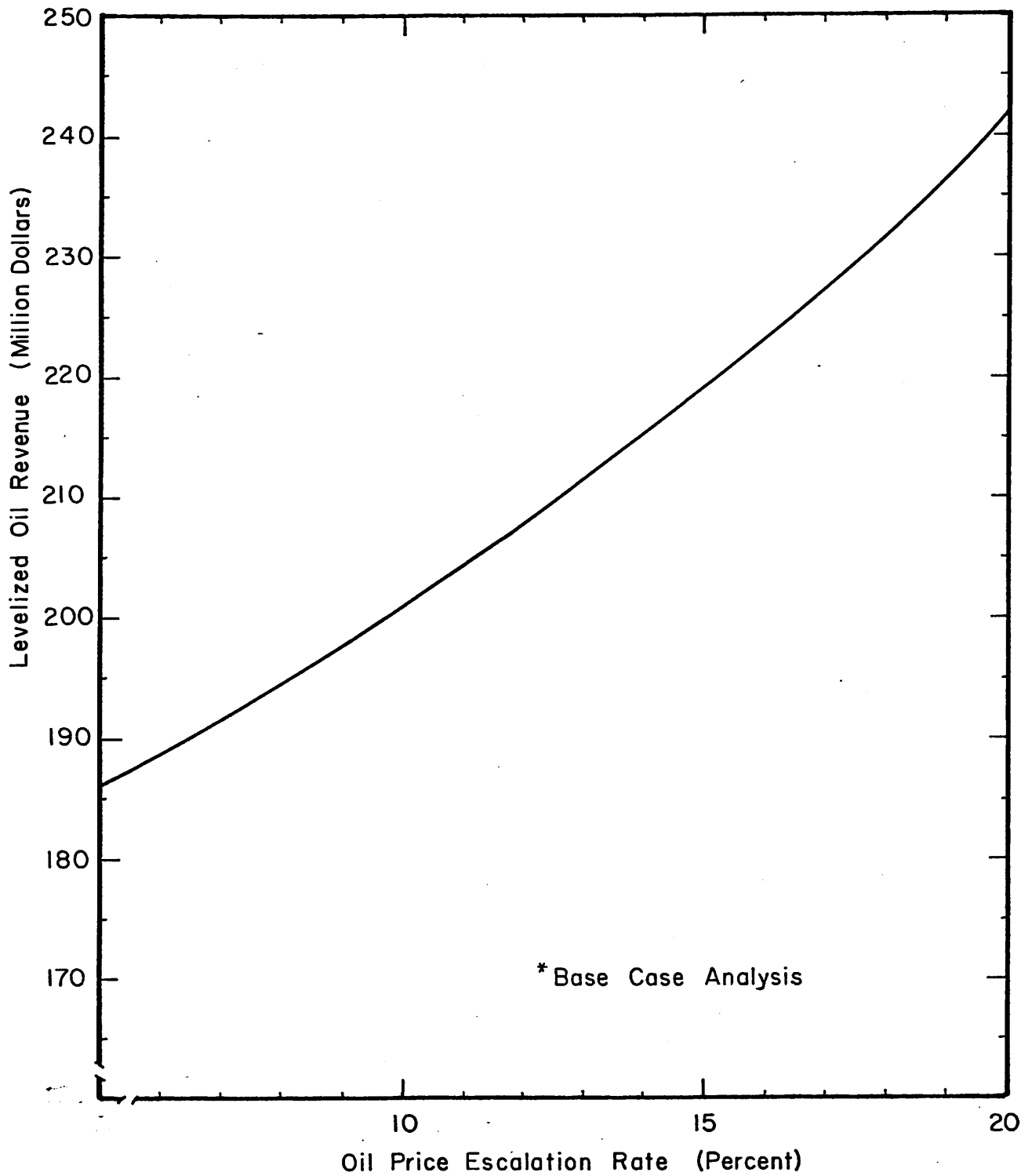


FIGURE 14  
NUMBER OF YEARS ANALYSIS COVERS vs ANNUALIZED  
PROFIT FOR CONVENTIONAL CO<sub>2</sub> FLOOD \*

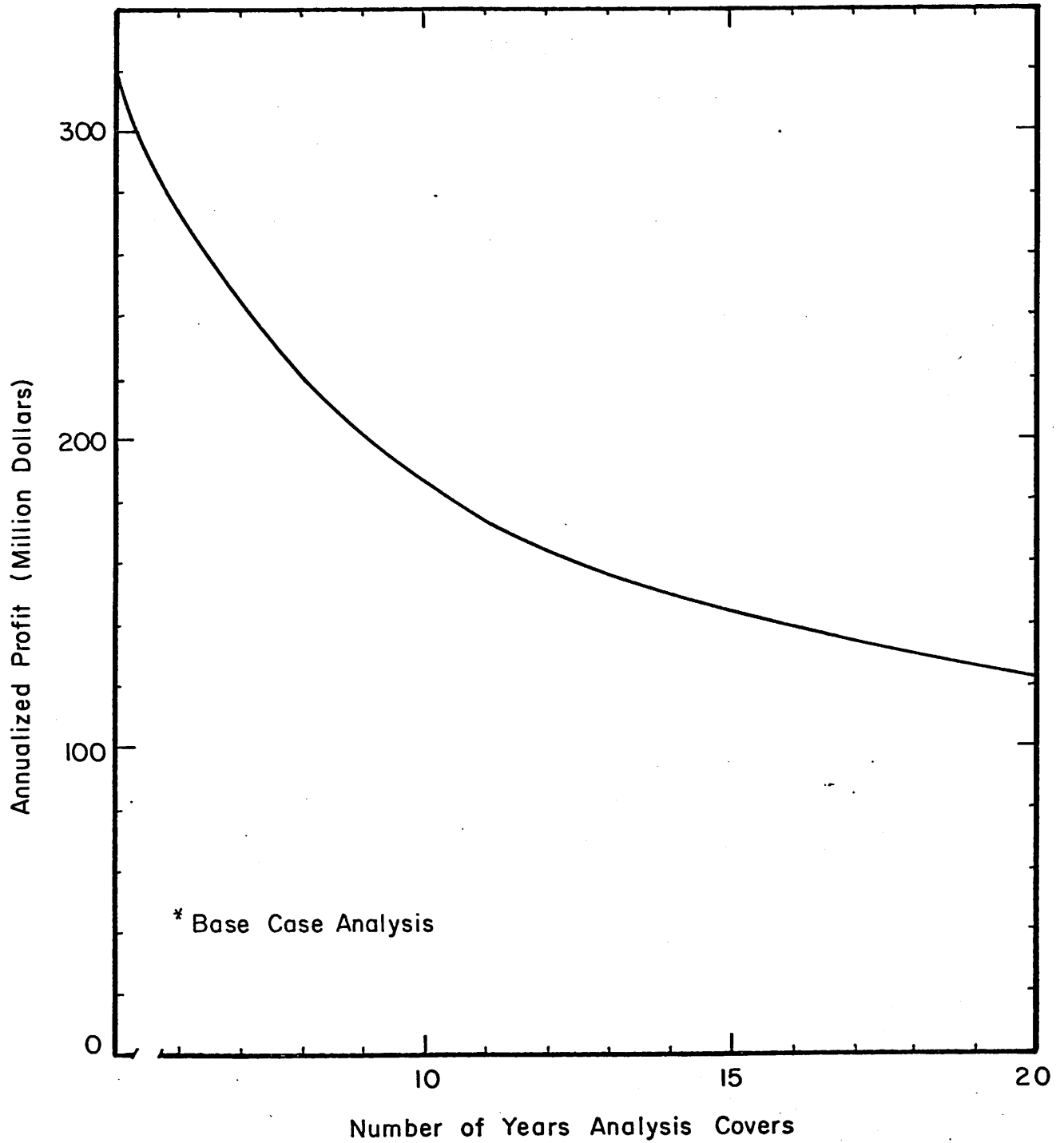


Figure 15 shows that the discount rate for discounting future costs and revenues directly affects annualized profit. An increase in the discount rate of 1 percent increases the annualized profit by nearly 4 million dollars.

Figure 16 shows that the fixed charge rate for capital directly affects the levelized capital cost. For our base case analysis, total capital expenditures were approximately 25.2 million dollars. The levelized capital cost is about 4.8 million dollars. The levelized capital cost increases approximately \$250,000 for each percentage point increase in the fixed charge rate.

Figure 17 shows that the cost of CO<sub>2</sub> is directly related to the levelized operation and maintenance cost. CO<sub>2</sub> represents from 19 percent of the total O & M cost when CO<sub>2</sub> is recycled to 30 percent of the total O & M cost when CO<sub>2</sub> is not recycled. The levelized operation and maintenance cost increases about \$450,000 for every one dollar per MCF increase in the cost of CO<sub>2</sub>.

Figure 18 shows that the CO<sub>2</sub> cost escalation rate almost directly affects levelized O & M costs. The levelized O & M cost increases approximately \$45,000 for every one percent increase in the CO<sub>2</sub> cost escalation rate.

Figures 19 and 20 show how CO<sub>2</sub> recycling affects the levelized operation and maintenance cost. Levelized O & M cost increases approximately \$85,000 for each year CO<sub>2</sub> recycling is delayed. Levelized O & M costs decrease approximately \$10,000 for each one percent of CO<sub>2</sub> which is recycled.

FIGURE 15  
DISCOUNT RATE vs ANNUALIZED PROFIT FOR  
CONVENTIONAL CO<sub>2</sub> FLOOD\*

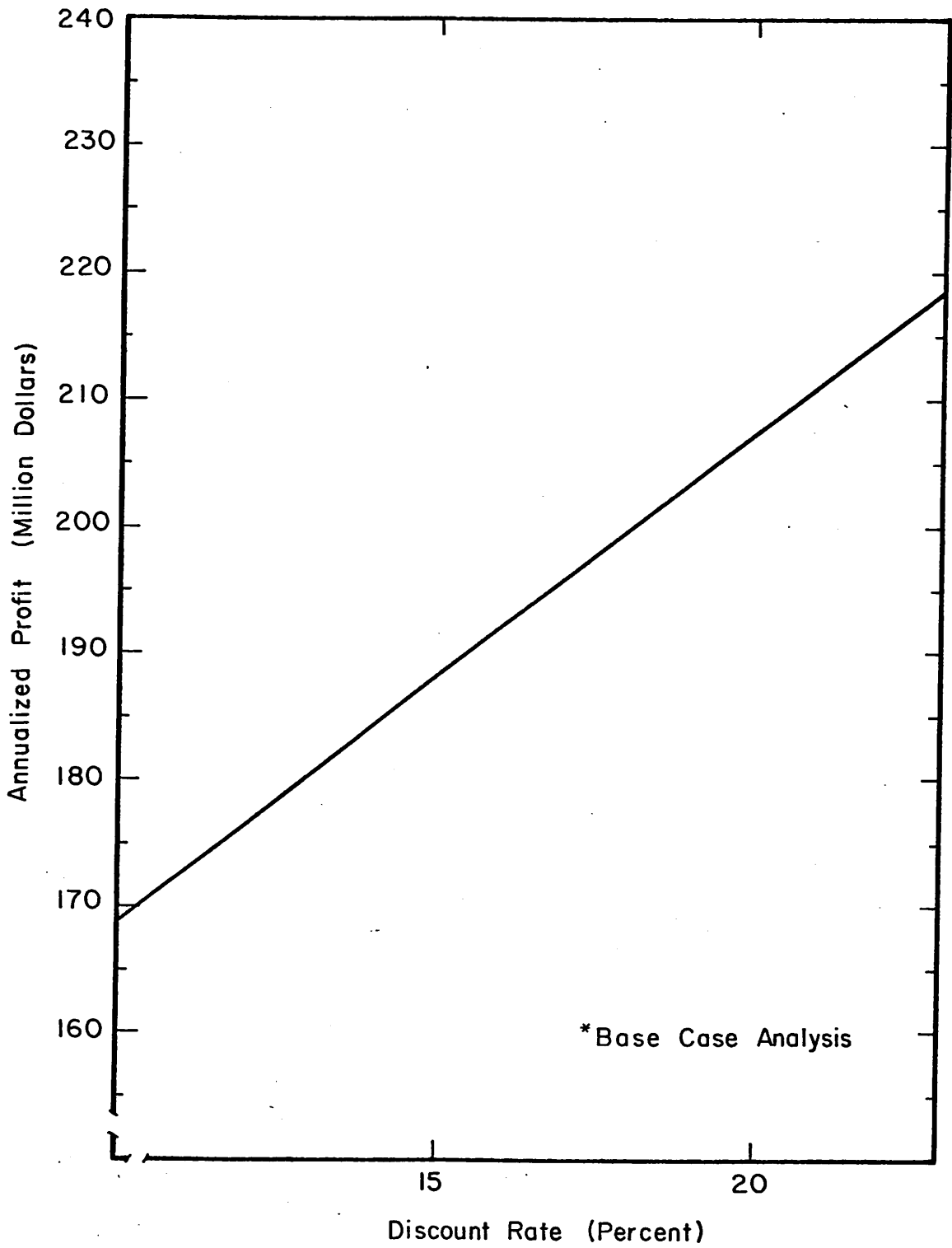


FIGURE 16  
FIXED CHARGE RATE FOR CAPITAL vs LEVELIZED CAPITAL  
COST FOR CONVENTIONAL CO<sub>2</sub> FLOOD\*

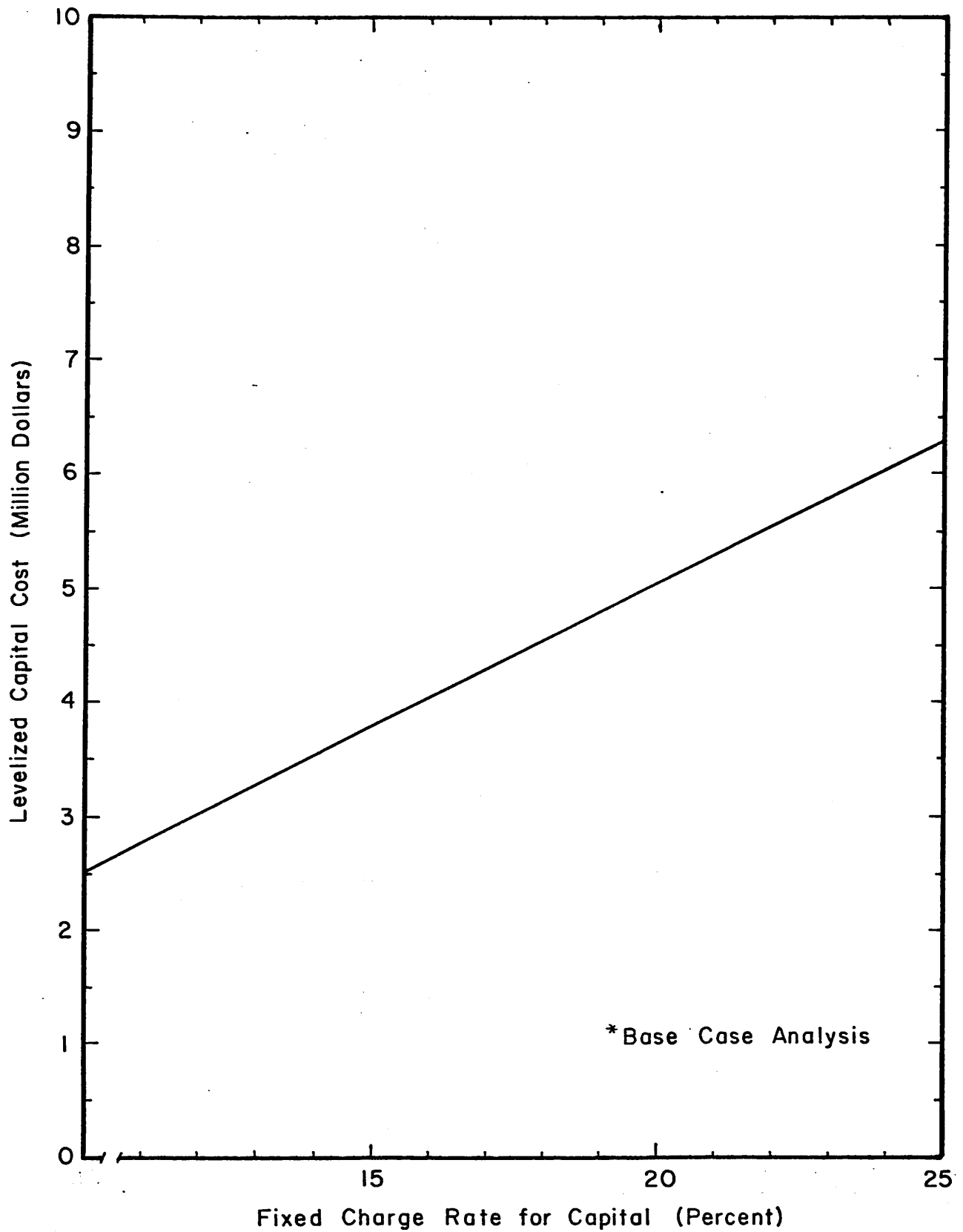


FIGURE 17  
COST OF CO<sub>2</sub> vs LEVELIZED OPERATION AND  
MAINTENANCE COST FOR CONVENTIONAL CO<sub>2</sub>  
FLOOD\*

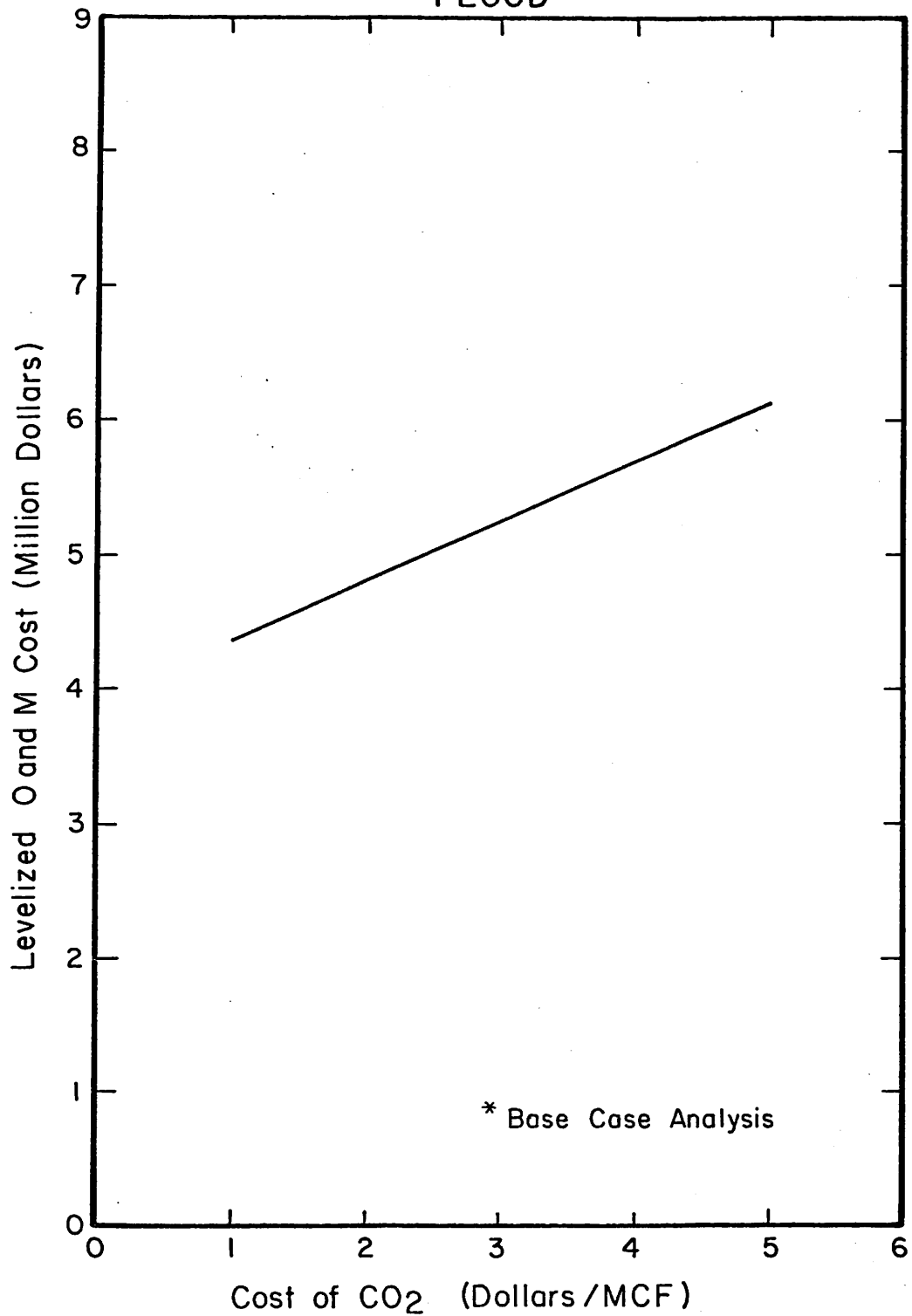


FIGURE 18  
CO<sub>2</sub> COST ESCALATION RATE vs LEVELIZED OPERATION  
AND MAINTENANCE COST FOR CONVENTIONAL CO<sub>2</sub> FLOOD\*

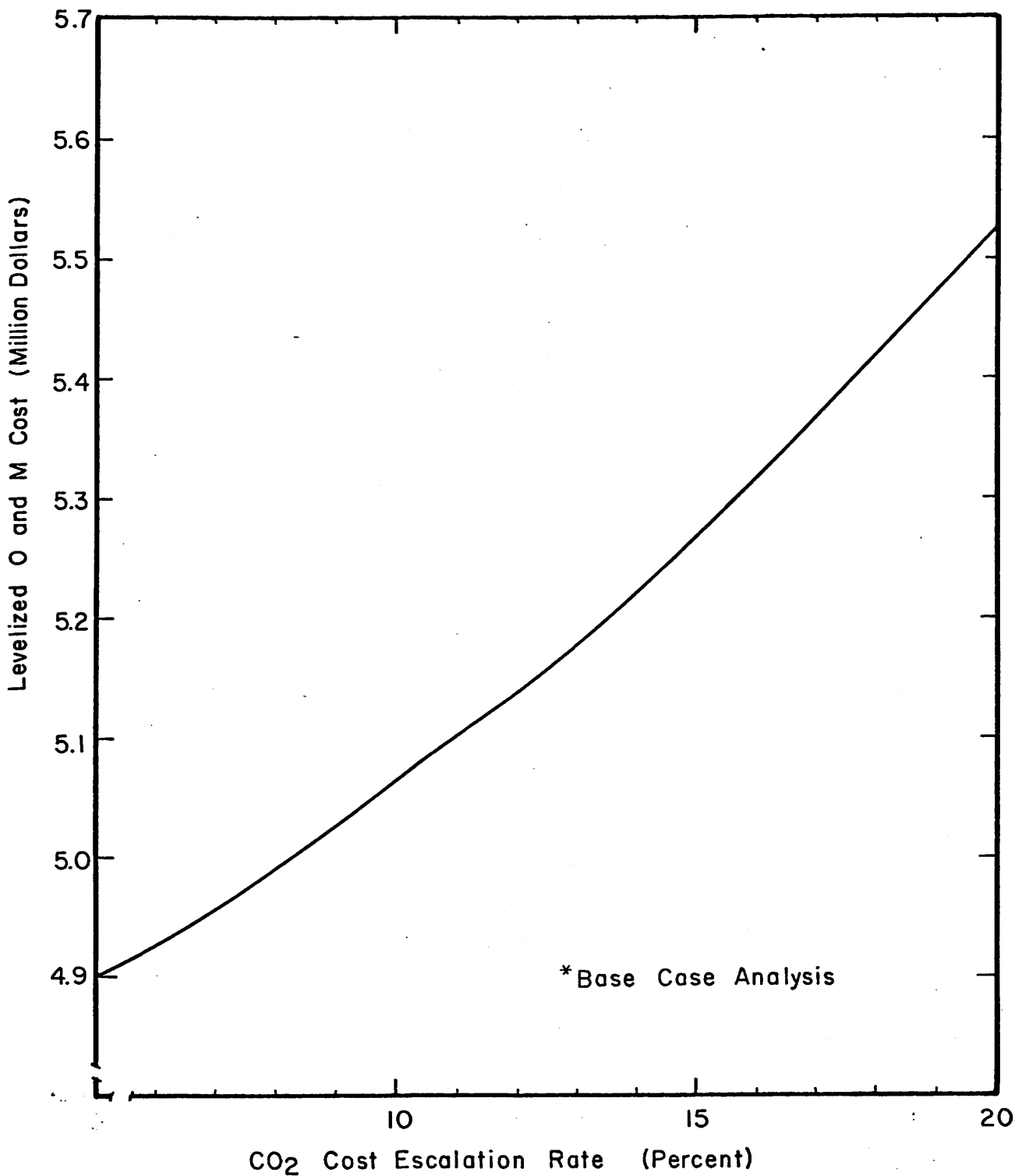


FIGURE 19  
NUMBER OF YEARS UNTIL CO<sub>2</sub> RECYCLING COMMENCES vs  
LEVELIZED OPERATION AND MAINTENANCE COST \*

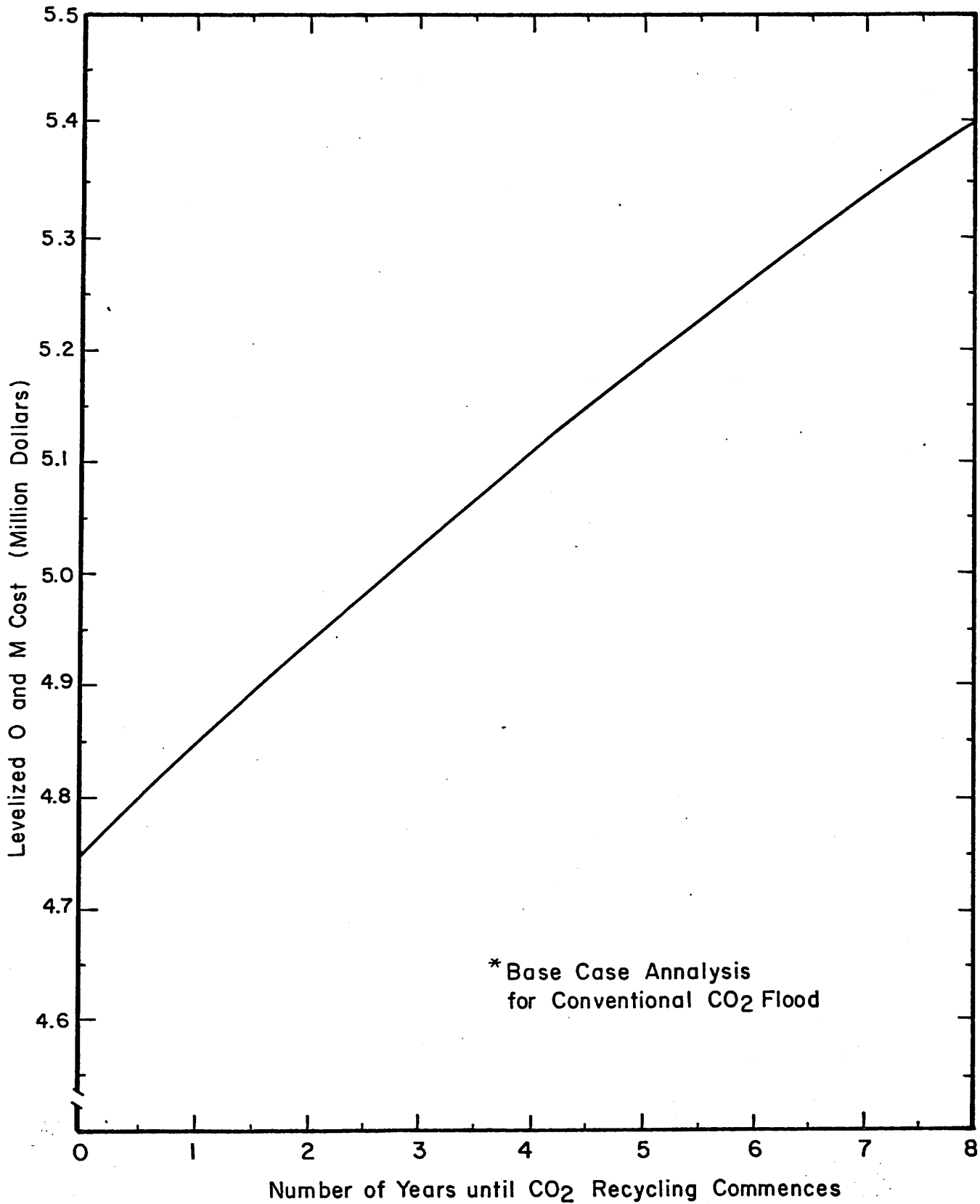


FIGURE 20  
AMOUNT OF CO<sub>2</sub> RECYCLED WHEN CO<sub>2</sub> RECYCLING  
COMMENCES vs LEVELIZED OPERATION AND MAINTEN-  
ANCE COST \*

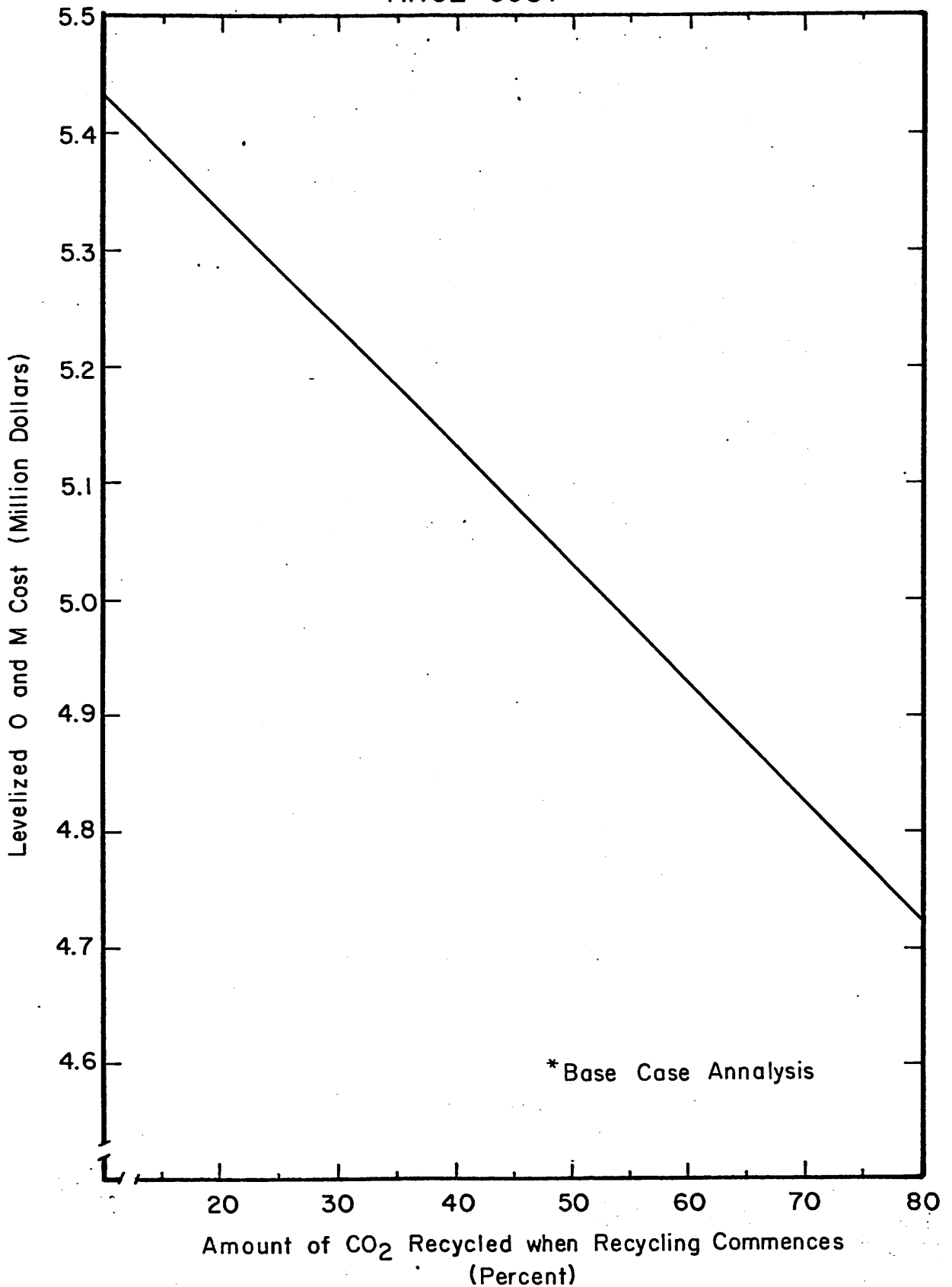


Figure 21 shows that the operation and maintenance cost escalation rate directly affects the levelized O & M cost. Levelized O & M costs increase approximately \$175,000 for each percentage rise in the O & M cost escalation rate.

#### Base Case Parameters For Foam and Polymer CO<sub>2</sub> Floods

The base case for a foam or polymer CO<sub>2</sub> flood parallels the base case conditions specified for the conventional CO<sub>2</sub> flood with the following important differences:

- °Mobility ratio: 5
- °Percentage reduction in CO<sub>2</sub> requirements over conventional flooding with the use of foam or polymers as a mobility control agent: 29%
- °Cost of surfactant: \$500/bbl
- °Surfactant concentration: 1% with foam having 20% water
- °Surfactant cost escalation rate: 9%/yr
- °Cost of polymer: \$75/bbl
- °Polymer concentration: 1%
- °Polymer cost escalation rate: 9%/yr

#### Base Case Results For Foam and Polymer CO<sub>2</sub> Flood

Again, as in the case of a conventional CO<sub>2</sub> flood we have a field size of about 75 million barrels prior to CO<sub>2</sub> injection. Table 25 shows the oil recovery schedule, amount of CO<sub>2</sub> injected and final oil revenue on a year-to-year basis for both the polymer and foam CO<sub>2</sub> flood. Total recovery is 87 percent when polymers or foams are used as mobility control agents since in this mobility controlled case a mobility ratio of 5 was used vs a mobility ratio of 30 for the conventional CO<sub>2</sub> flood. The conventional CO<sub>2</sub> flood yielded an oil recovery of 70 percent.

FIGURE 21  
OPERATION AND MAINTENANCE COST ESCALATION RATE  
vs LEVELIZED OPERATION AND MAINTENANCE COST  
FOR CONVENTIONAL CO<sub>2</sub> FLOOD\*

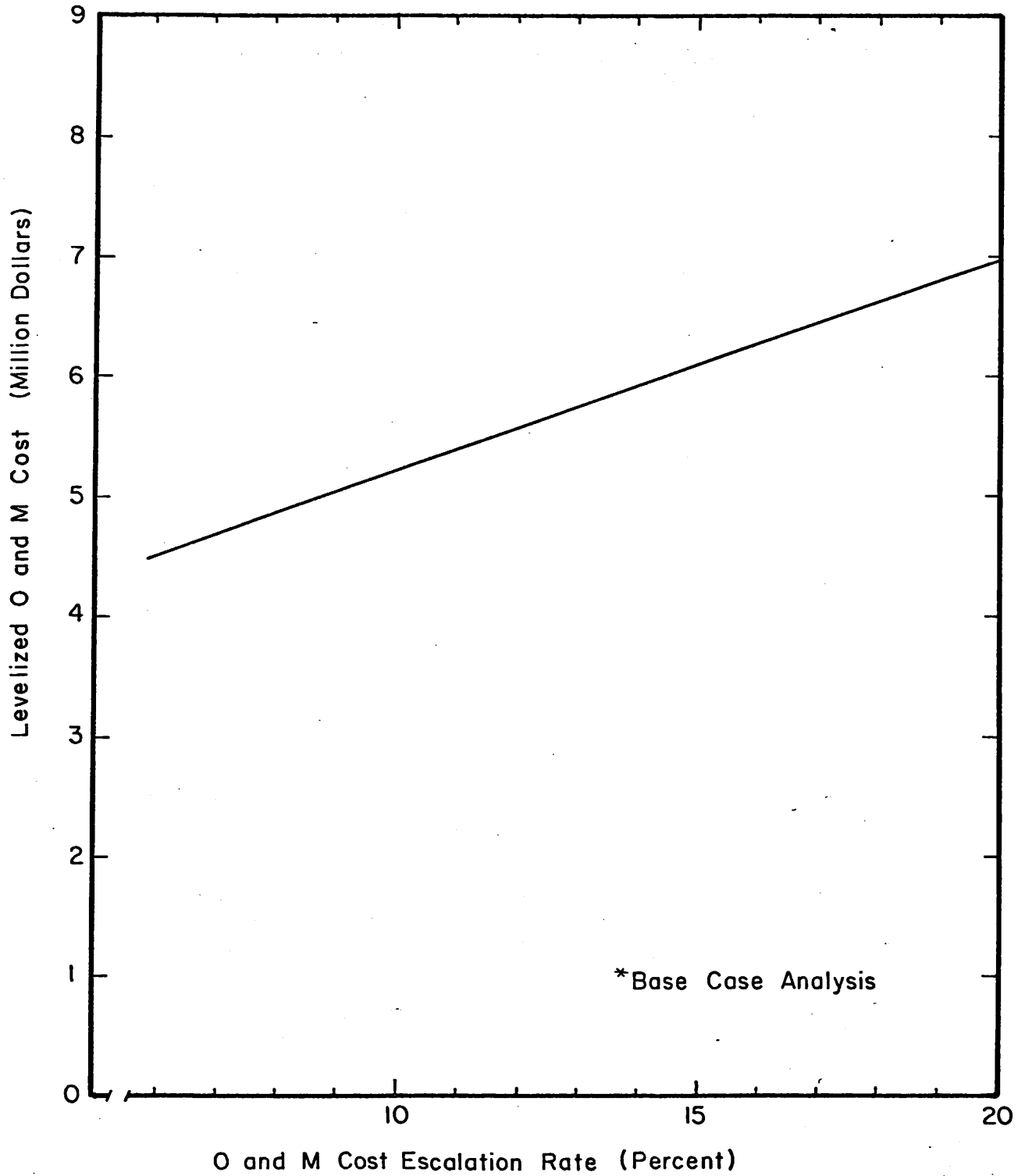


TABLE 25  
 BASE CASE FOAM AND POLYMER CO<sub>2</sub> FLOOD RESULTS

Year	Percent Recovered	Barrels Recovered	MMCF CO <sub>2</sub> Injected	Final Oil Revenue (\$)
1	0	0	297	0
2	39	29,449,126	297	698,086,384
3	15	11,616,707	297	294,964,568
4	10	7,817,726	297	212,875,008
5	6	5,154,627	297	150,688,392
6	4	3,570,296	297	112,170,819
7	3	2,589,107	297	87,508,047
8	2	1,949,887	297	70,963,336
9	2	1,514,245	297	59,391,920
10	<u>1</u>	<u>1,205,831</u>	<u>297</u>	<u>51,013,014</u>
Total	87	64,867,556	2,970	1,737,661,504

The total capital costs are approximately 28.1 million and 26.4 million dollars with the use of surfactant and polymer respectively. This is an increase of about 2.9 million and 1.2 million dollars with using surfactants and polymers respectively over the capital costs for the base case conventional CO<sub>2</sub> flood.

Operation and maintenance costs increase substantially when foams or polymers are used as mobility control agents. This is primarily due to the cost of the surfactant and polymers. The total annual O & M costs with use of foams or polymers total 20.3 million and 14.6 million dollars respectively. The surfactant and polymer cost are about 10.2 and 12.1 million dollars per year respectively.

The levelized profit is approximately 202 million dollars when foam and 212 million dollars when polymers are used for mobility control.

The levelized cost and revenue components for the foam CO<sub>2</sub> flood are:

- °Levelized revenue: \$241,172,218
- °Levelized capital cost: \$5,344,348
- °Levelized O & M cost: \$7,472,123
- °Annualized profit: \$202,448,664

For the polymer CO<sub>2</sub> flood the levelized cost components breaks down as follows:

- °Levelized revenue: \$241,172,218
- °Levelized capital cost: \$5,006,718
- °Levelized O & M cost: \$4,566,053
- °Annual profits: \$211,884,566

At this juncture, we investigate how changing surfactant or polymer cost, concentration and escalation rates affect the levelized O & M cost which will in turn directly affect the annualized profit. As in the case of conventional flooding, all variables are set at the base case values except the one being investigated.

Figures 22, 23, 25, and 26 shows that surfactant and polymer cost and concentration directly changes levelized operation and maintenance cost. The surfactant or polymer cost escalation rate nearly directly affects the levelized O & M costs as shown in Figures 24 and 27. The levelized O & M costs increase per unit increase in costs, concentration and escalation rate as summarized below:

Increase in levelized O & M cost with:

- °Surfactant cost increase of \$10/bbl: \$520,000
- °Surfactant concentration increase of 0.1%\*: 2,500,000
- °Surfactant cost escalation rate increase of 1%: \$1,000,000
- °Polymer cost increase of \$10/bbl: \$2,600,000
- °Polymer concentration increase of 0.1%: \$1,950,000
- °Polymer cost escalation at increase of 1%: 750,000

### Conclusions

The economic viability of a carbon dioxide flooding project with or without mobility control is highly dependent on the crude oil price which is expected to be obtained throughout the life of the project and the crude oil price escalation rate. The cost of CO<sub>2</sub> and, therefore, the CO<sub>2</sub> cost escalation rate do not affect the economics of the project

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\*Have 20% water in foam

FIGURE 22

SURFACTANT COST vs LEVELIZED OPERATION AND MAINTENANCE COST FOR FOAM CO<sub>2</sub> FLOOD\*

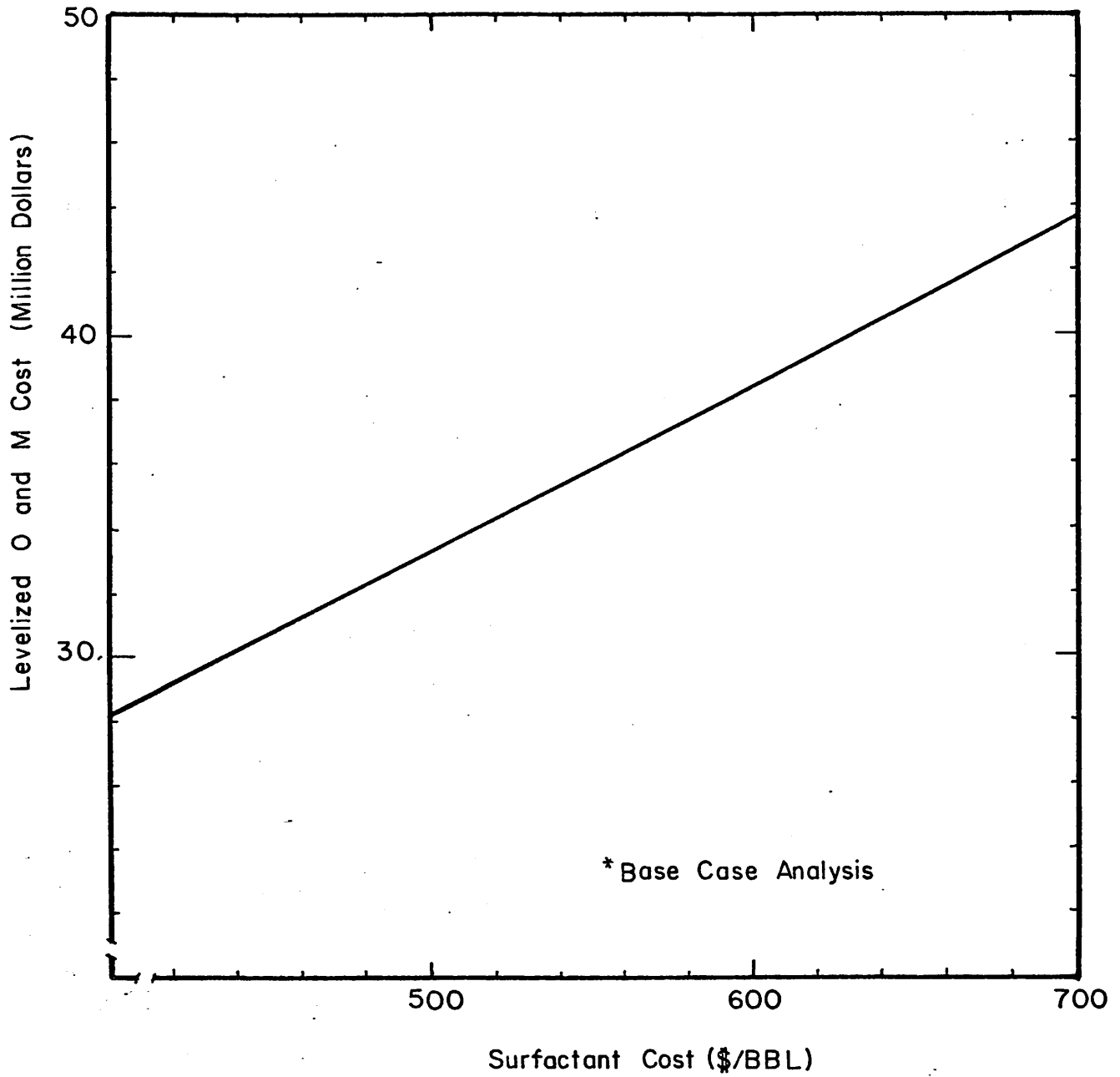


FIGURE 23

SURFACTANT CONCENTRATION vs LEVELIZED OPERATION AND MAINTENANCE COST FOR FOAM CO<sub>2</sub> FLOOD\*

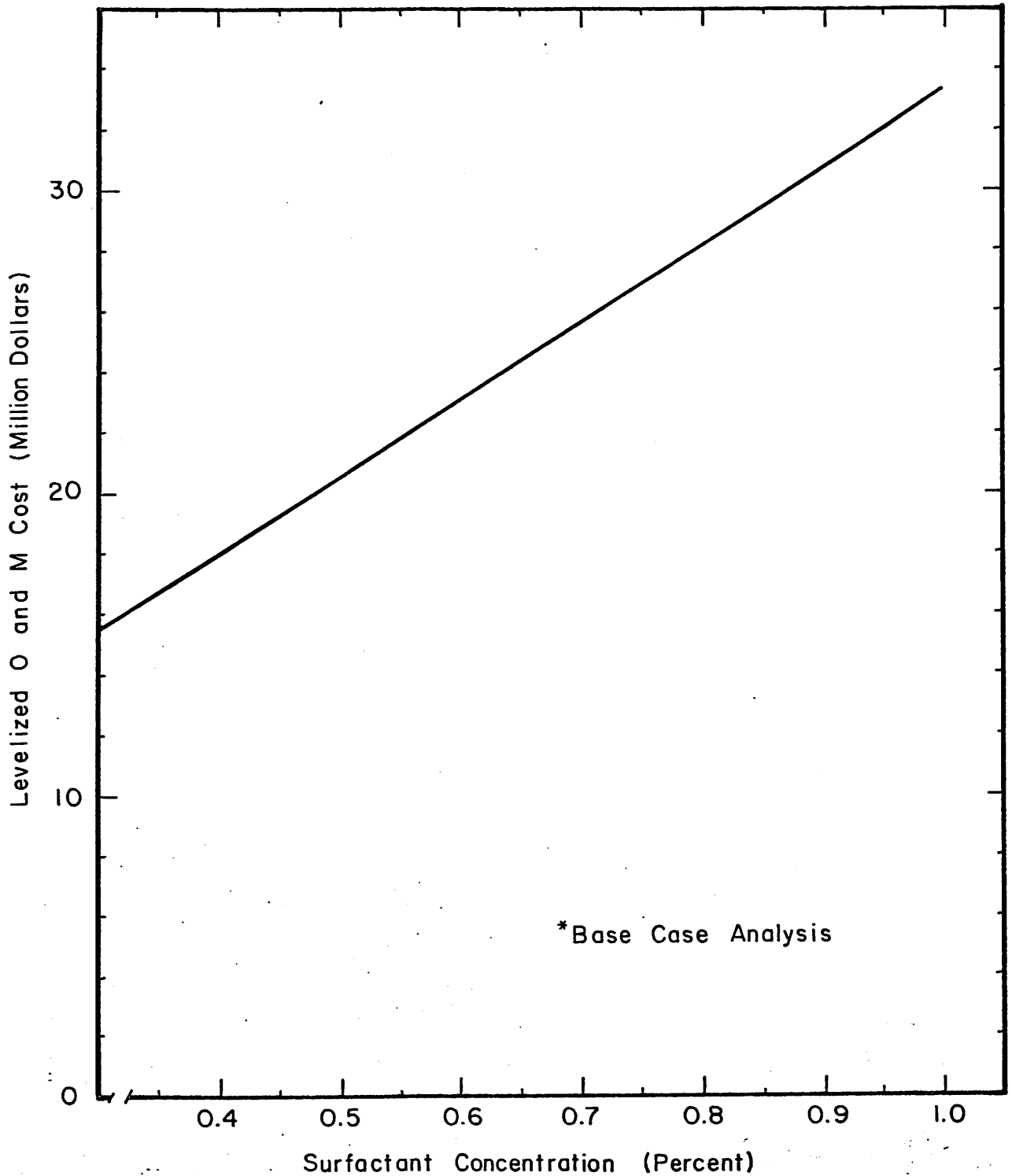


FIGURE 24  
SURFACTANT COST ESCALATION RATE vs LEVELIZED OP-  
ERATION AND MAINTENANCE COST FOR FOAM CO<sub>2</sub> FLOOD\*

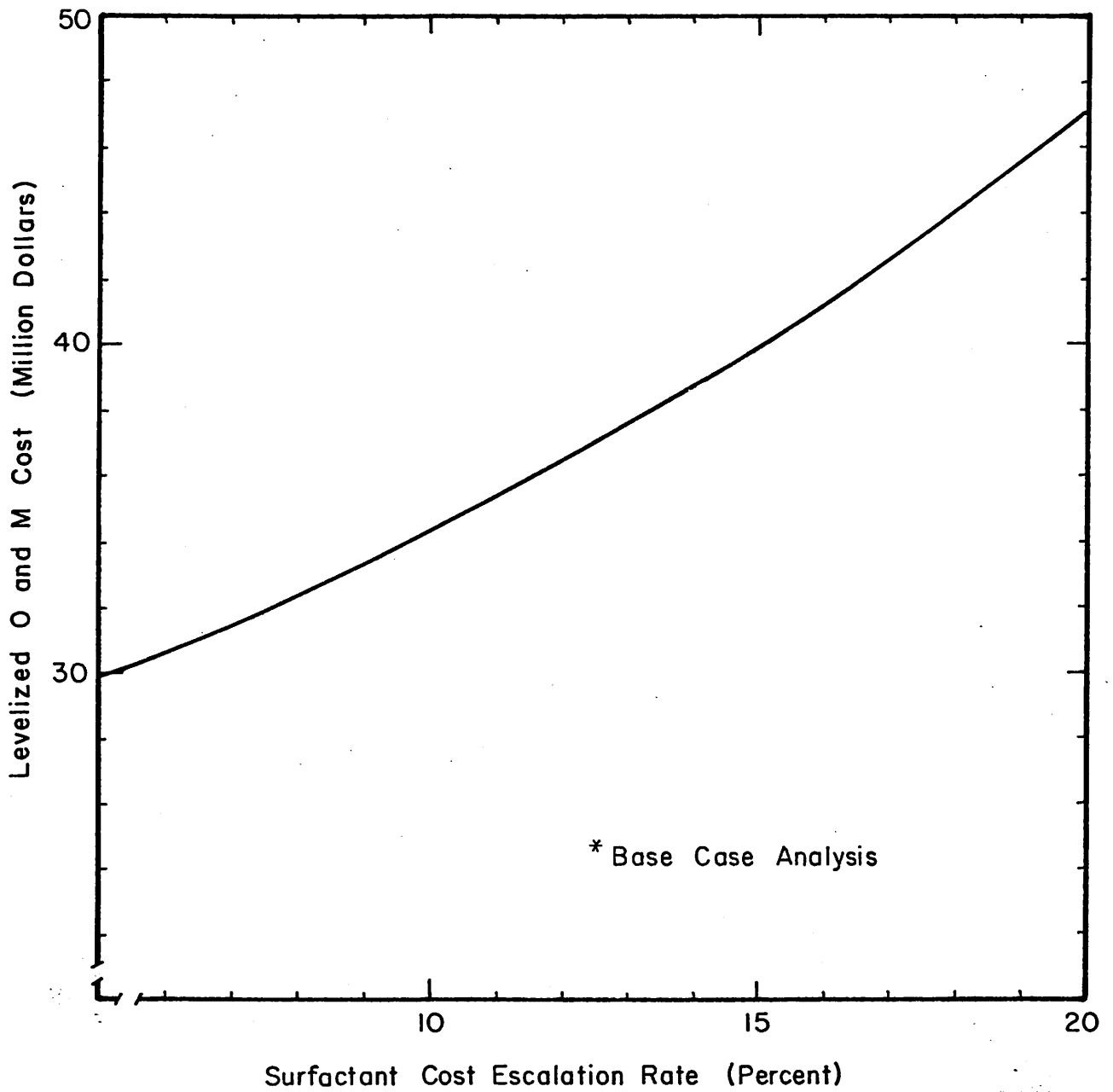


FIGURE 25  
POLYMER COST vs LEVELIZED OPERATION AND MAINTEN-  
ANCE COST FOR POLYMER CO<sub>2</sub> FLOOD\*

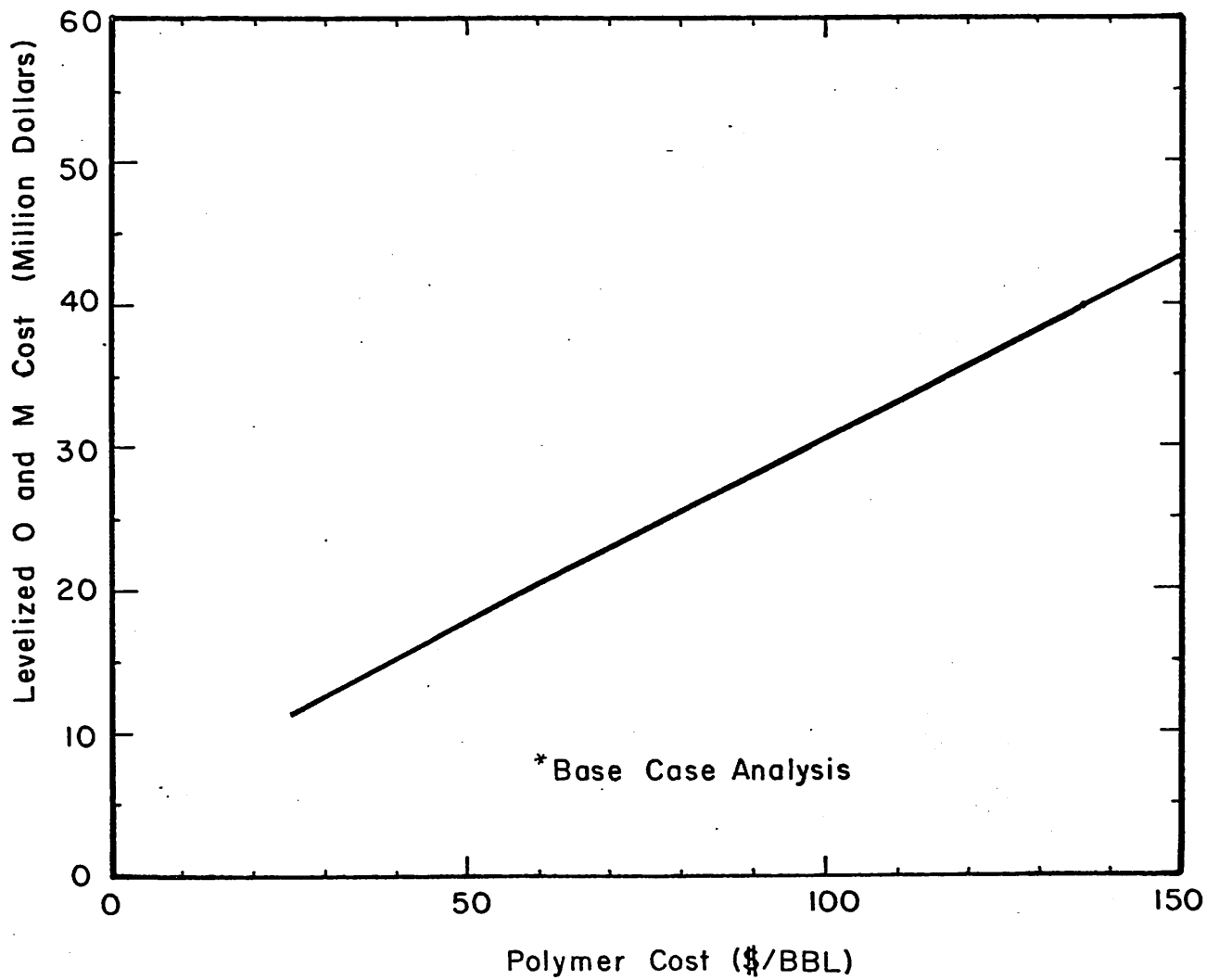


FIGURE 26

POLYMER CONCENTRATION vs LEVELIZED OPERATION AND MAINTENANCE COST FOR POLYMER CO<sub>2</sub> FLOOD\*

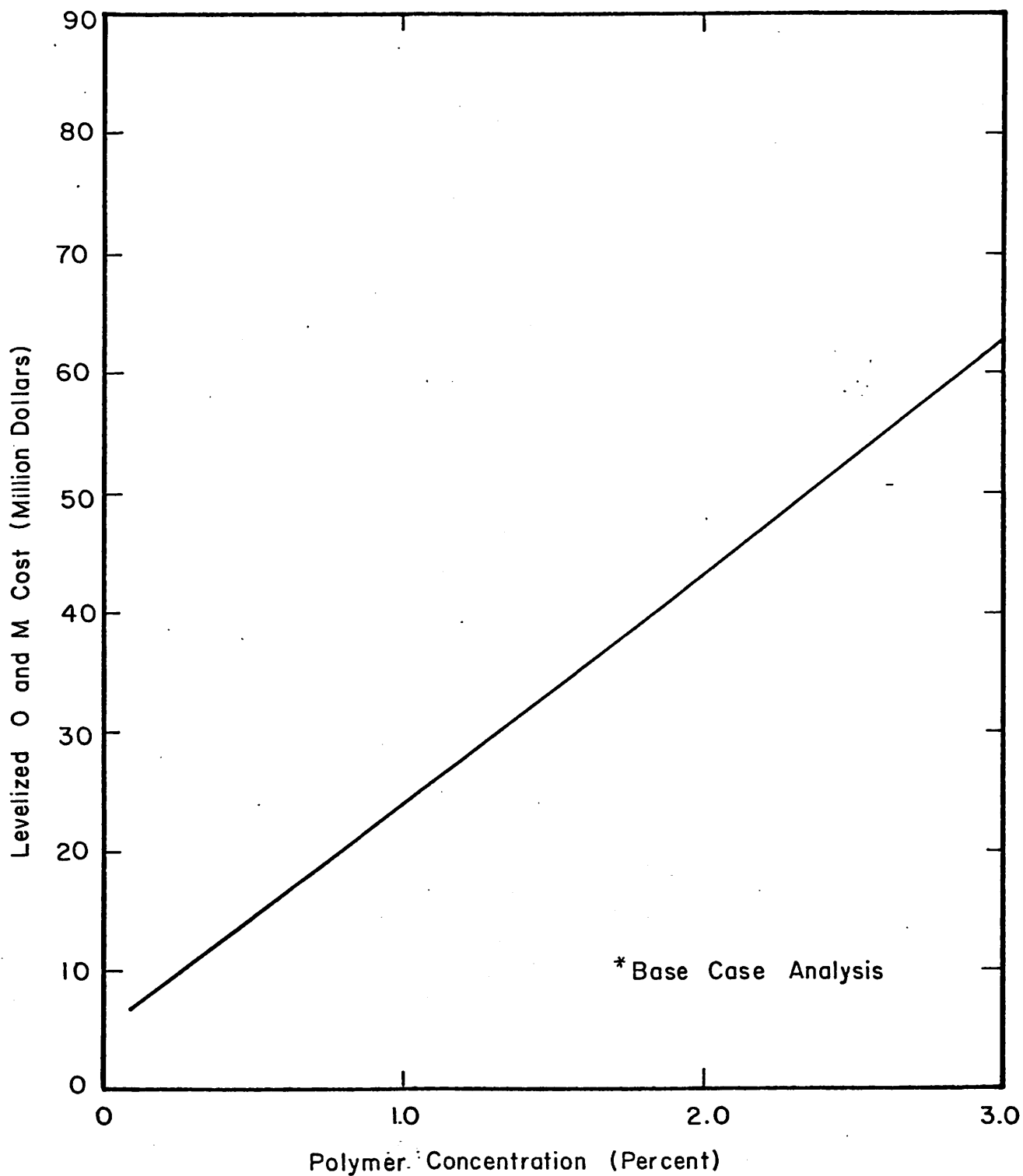
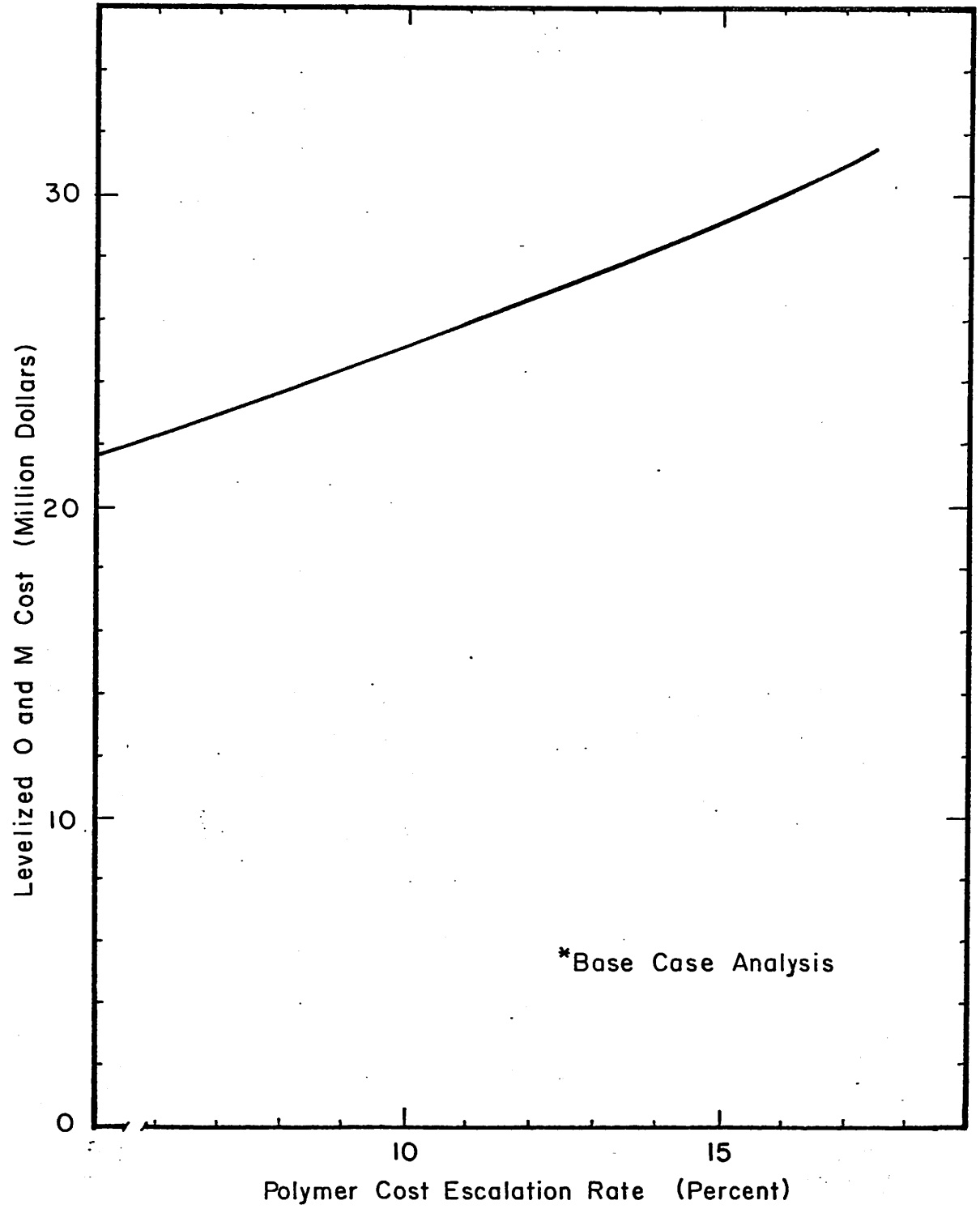


FIGURE 27

POLYMER COST ESCALATION RATE vs LEVELIZED OPERATION AND MAINTENANCE COST FOR POLYMER CO<sub>2</sub> FLOOD\*



as severely as the oil price and oil price escalation rate. To support this we summarize the following quantitative data from our base case conventional CO<sub>2</sub> flood:

°Levelized oil revenues increase approximately 5 million dollars for every dollar per barrel increase in the oil price. Levelized oil revenues increase approximately 4 million dollars for each percentage point rise in the oil price escalation rate.

°Levelized O & M costs increase approximately \$450,000 and \$45,000 for every one dollar per MCF increase in the cost of CO<sub>2</sub> and every one percent increase in the CO<sub>2</sub> cost escalation rate respectively.

Since the CO<sub>2</sub> cost and CO<sub>2</sub> cost escalation rate do not significantly influence the viability of the project it follows that the use of CO<sub>2</sub> recycling is not an important economic factor for CO<sub>2</sub> floods.

Other financial parameters (in order of importance) important to the viability of the CO<sub>2</sub> flood project include the discount rate, fixed charge rate for capital and operation and maintenance cost escalation rate. The discount rate is as important as the oil price and oil price escalation rate:

°Annualized profit increased by nearly 4 million dollars for each 1 percent increase in the discount rate in our base case CO<sub>2</sub> flood.

The importance of the fixed charge rate for capital and operation and maintenance cost escalation rate is about the same level as the cost of CO<sub>2</sub> and CO<sub>2</sub> cost escalation rate. In our base case conventional CO<sub>2</sub> flood:

°Levelized capital cost increased approximately \$250,000 for each percentage point increase in the fixed charge rate.

°Levelized O & M costs increased approximately \$45,000 for each one percent rise in the O & M cost escalation rate.

The costs, concentration and cost escalation rates of surfactants and polymers play an important role in the profitability of foam or polymer CO<sub>2</sub> floods. The level of sensitivity to profit parallels that of the oil price and oil price escalation rate.

Other things being equal, we saw that mobility control for CO<sub>2</sub> floods can be a profitable venture. In our base case foam and polymer CO<sub>2</sub> flood, a higher annualized profit was realized than that for the conventional CO<sub>2</sub> flood:

°Annualized profit of 202 and 212 million dollars for foam and polymer CO<sub>2</sub> flood respectively vs \$188 million for the conventional CO<sub>2</sub> flood.<sup>2</sup>

The levelized cost procedure used in this analysis can also be applied for evaluating the economics of other enhanced oil recovery processes.