Circular 166 1978

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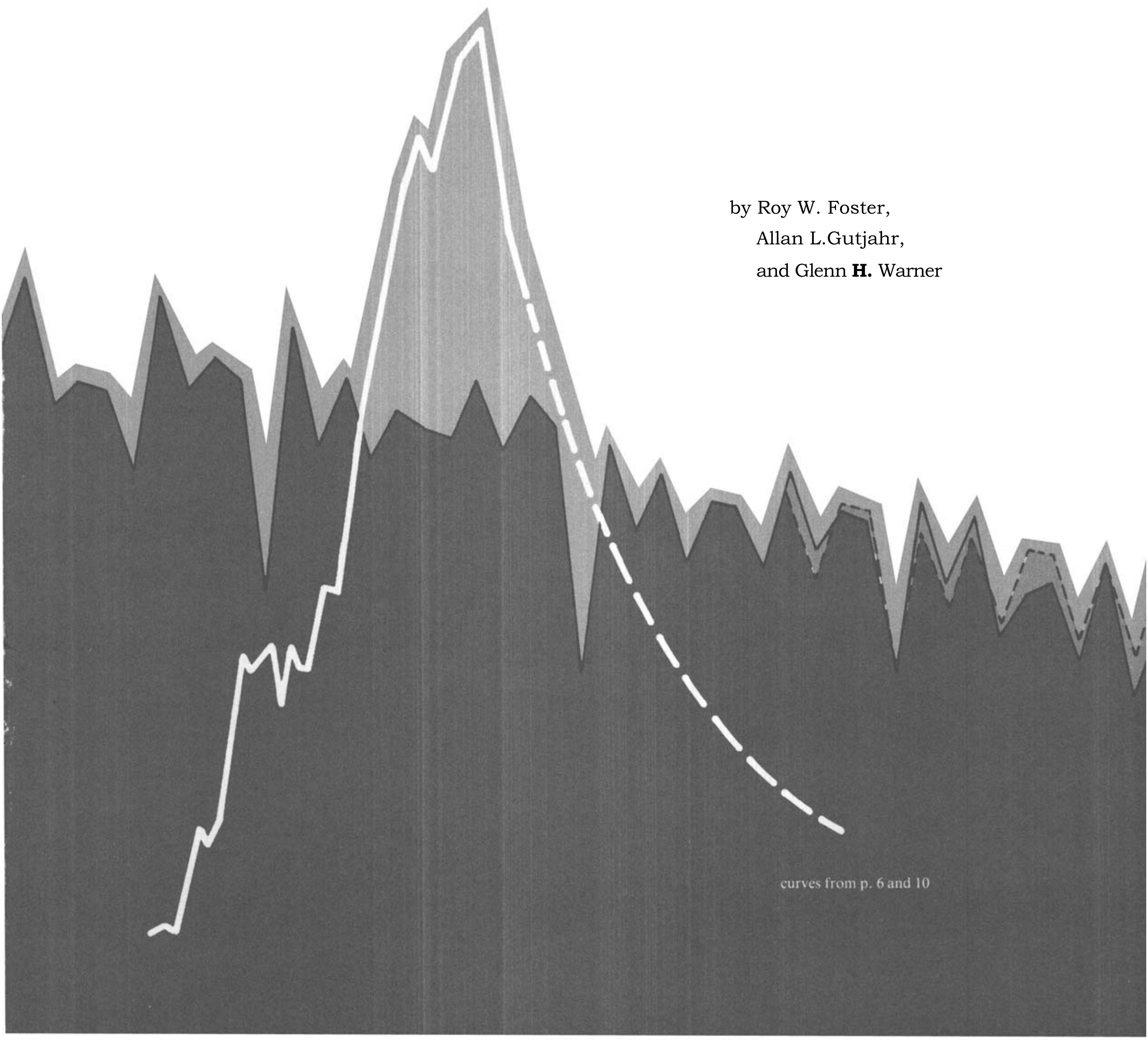
including reserves of the 50 largest pools

by Roy W. Foster,
Allan L.Gutjahr,
and Glenn **H.** Warner



Circular 166

New Mexico Bureau of Mines & Mineral Resources

A DIVISION OF
NEW MEXICO INSTITUTE OF MINING & TECHNOLOGY

Estimates of New Mexico's future oil production including reserves of the 50 largest pools

by R. W. Foster, A. L. Gutjahr, and G. H. Warner

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Preface

This report consists of two parts: 1) an estimate of future oil production for New Mexico, including estimates for the northwest and southeast areas, and 2) an analysis of reserves of the 50 largest oil pools in New Mexico. Graphs showing production and estimated reserves for these 50 pools are included in the appendix. Production estimates and data are limited to crude oil; condensate is not included.

Future production for the state and for most pools was predicted by using the current rate of decline computed from a multiple-regression routine. The data base consisted of the average daily production per month for 1975 and 1976. As nearly as possible, current production data were used to reflect current conditions. The base-period data include: level of exploration, development drilling of existing pools, expansion or initiation of enhanced recovery programs, abandonment of wells and pools, and rate of decline in production. The predictions assume that the level of development and rate of decline will remain the same as they were during the base period. Over the long term, conditions will change and the actual ultimate recovery will be greater or less than current estimates. Nevertheless, the predictions should be quite accurate for a term of one to two years. This method of estimating future production is not intended to replace conventional reservoir evaluation studies. However, as new production data become available, this rapid and inexpensive method provides a reasonably accurate way of updating predictions of future production, particularly for the short term.

All data used in predicting future production were obtained from public records, including the annual production reports of the Lea County Operators Committee (1940-1946), the New Mexico Oil Conservation Commission and Lea County Operators Committee (1947-1949), and the New Mexico Oil and Gas Engineering Committee (1950-1976).

At the time of this study, Warner was a student assistant at New Mexico Bureau of Mines and Mineral Resources.

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November 11, 1977

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Abstract

Using a multiple-regression computer program, projections were made of future oil production for the state and for the northwest and southeast producing areas. Projections were based on the rate of decline in average daily production during the years 1975-1976. The average rate of decline during this period was 3.5 percent per year overall but increased to a projected yearly rate of over 5 percent during 1976. Projections of future production indicate that approximately 2 billion barrels of oil will be produced until the year 2026, when the economic limit will be reached. Of this production, 1.9 billion barrels will come from the southeast area and slightly less than 14 million barrels will come from the northwest area. Similar projections were made for the 50 largest oil pools based on the amount of oil produced in 1975. The 50 pools accounted for 80 percent of the oil produced in New Mexico in 1975. At current rates of decline these pools contain an estimated 550 million barrels of recoverable oil.

Estimated future oil production

Estimates of future oil production for New Mexico and for the southeast and northwest producing areas were prepared using current rates of decline. The economic limit used to determine remaining production was based on the number of producing wells at the end of 1976 and a limit of 3 BOPD (barrels of oil per day) for each well. The limits used were 1.2 million bbls (barrels) per year for the northwest, and 14.0 million bbls per year for the southeast. These figures could be adjusted upward depending upon pipeline capacity and location, or downward depending upon economic conditions.

The estimated future production to the economic limit is 1.9 billion bbls for the southeast area and 13.6 million bbls for the northwest area, giving a total future production for the state of almost 2.0 billion bbls. The current rate of decline of production is 3.5 percent per year for the southeast area and 16.0 percent per year for the northwest area. Projections indicate that the economic limit will be reached in the year 2026 for the southeast and 1983 for the northwest.

According to API (American Petroleum Institute), proven oil reserves for New Mexico at the end of 1975 were 588 million bbls. This total is comprised of 25 million bbls in the northwest and 563 million bbls in the southeast. The greatest reserve figure published by API was 1.1 billion bbls at the end of 1961. Production from 1962 through 1975 totaled 1.5 billion bbls. Adding the remaining reserves of 588 million bbls obtains a grand total of 2.088 billion bbls. Thus, an additional 1.0 billion bbls were found by exploration, development, or revision of previous reserve estimates in the 14 years between 1962 and 1975, inclusive. The estimate of future production of approximately 2.0 billion bbls, based on the current rate of decline and using area predictions, suggests that an additional 1.4 billion bbls (beyond the proven reserves of API) need to be recovered in the 50-year period from 1976 to 2026.

Production estimates were made using a computer program involving multiple regression. Projections were based on the decline in average daily production for the 1975-1976 period. This period was used so that reserve estimates would reflect current conditions. The data can be easily updated at any time; new projections can be made rapidly and inexpensively. As an example, the data needed for production estimates were keypunched and proofed in about four hours. Computer costs for a total of 1,360 monthly predictions amounted to $11.02.

In September 1975, projections were made for the state based on average daily production of crude oil and condensate. This project was summarized in the 1976 Annual Report of the Office of the State Geologist (Arnold and others, 1977). The data used to establish the rate of decline were for the period April 1973 through September 1975. A comparison of the projection for the remainder of 1975 plus 1976 with actual production is shown in fig. 1. Predicted production of crude oil and condensate for the 15-month period was 183,020 bbls above actual production, for an error of slightly less than 0.2 percent. Predictions and actual monthly production agreed closely for the first nine months when the average monthly error amounted to 39,283 bbls below actual production. For the last six months, predictions were consistently higher than actual production; the average monthly error was 89,428 bbls.

Long-range predictions are subject to greater error. For short periods of one or two years the predictions should be quite accurate. Estimates of revenues, therefore, should be reliable enough for advance planning. Estimates can be updated monthly or annually and new projections made to increase short-term reliability. Modifications of the computer program are underway to place greater emphasis on the more current data and to simplify the use of the output.

Production of condensate fluctuates with the demand for natural gas; therefore, figures for condensate are not included in the crude oil projections in this report. Condensate production in 1976 amounted to five percent of the total crude oil produced.

Monthly projection 1977-1978

Monthly predictions of the production of crude oil for New Mexico are given for 1977 and 1978 (fig. 2 and table 1). Projections were made based on the average monthly production from February 1975 (a peak of 252,791 BOPD) to December 1976 (230,776 BOPD).

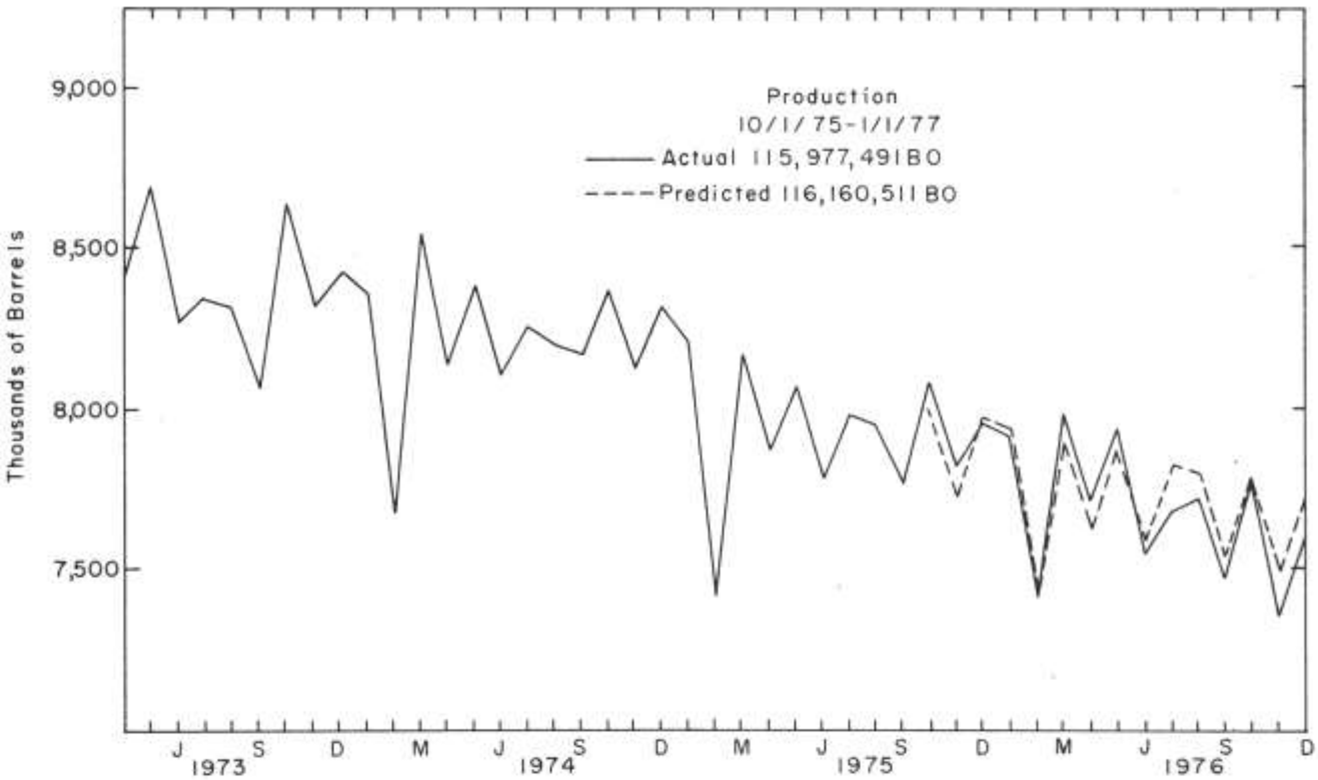

FIGURE 1—ACTUAL (4/1/73-1/1/77) AND PREDICTED (10/1/75-1/1/77) MONTHLY OIL PRODUCTION (BO—barrels of oil).

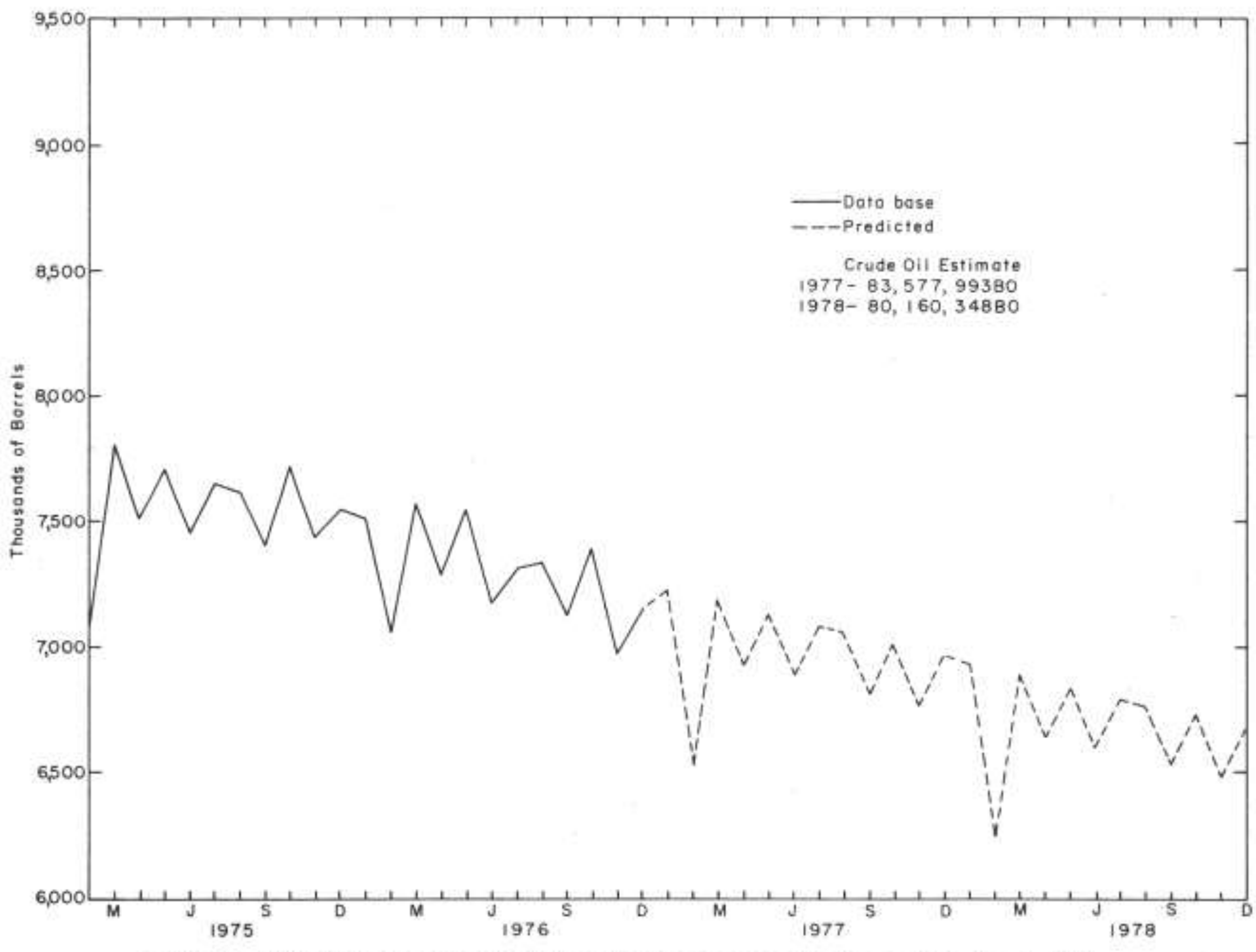

FIGURE 2—1977-1978 PREDICTION OF MONTHLY CRUDE OIL PRODUCTION FOR NEW MEXICO (BO—barrels of oil).

TABLE 1—MONTHLY PREDICTIONS OF CRUDE OIL PRODUCTION FOR NEW MEXICO 1977-1978 (in barrels).

	1977	1978
January	7,235,679	6,939,815
February	6,512,772	6,246,436
March	7,185,521	6,891,672
April	6,929,550	6,646,200
May	7,135,673	6,843,901
June	6,881,520	6,600,120
July	7,086,197	6,796,440
August	7,061,583	6,772,812
September	6,810,060	6,531,570
October	7,012,603	6,725,853
November	6,762,840	6,486,300
December	6,963,995	6,679,229
TOTAL	83,577,993	80,160,348

This is a decline of 22,000 BOPD for the 23-month period. The projected yearly rate of decline is almost four percent. Crude oil produced in 1975 totalled 90,753,522 bbls; in 1976 production declined to 87,436,859 bbls. The estimate for 1977 is 83,577,993 bbls and for 1978-80,160,348 bbls.

Totals given for 1977-1978 production in table 1 differ slightly from the predicted production given for these two years in table 2. This variation is the result of a slightly different rate of decline for the state when the data base used for projecting production is the total production for the state. In table 2 predicted statewide production was obtained by adding estimates for the northwest and southeast areas. The question as to whether statewide projections or area projections are more accurate is still being investigated. Statewide projections are used here for simplicity. In any case, the differences between the two short-term projections are small (less than 0.1 percent).

TABLE 2—PREDICTED YEARLY OIL PRODUCTION FOR NEW MEXICO 1977-1990 (in barrels).

Year	Statewide	Northwest area	Southeast area
1977	83,593,213	3,087,718	80,505,495
1978	80,250,725	2,592,595	77,658,130
1979	77,088,548	2,177,043	74,911,505
1980	74,293,059	1,832,928	72,460,131
1981	71,241,248	1,534,825	69,706,423
1982	68,530,028	1,288,815	67,241,213
1983	65,945,098	1,082,043	64,863,055
1984	62,740,452	Economic limit	62,740,452
1985	60,356,035		60,356,035
1986	58,221,515		58,221,515
1987	56,162,550		56,162,550
1988	54,324,465		54,324,465
1989	52,259,970		52,259,970
1990	50,411,793		50,411,793

Northwest area

Crude oil produced in northwestern New Mexico reached a peak of 14,210,632 bbls in 1961. With minor exceptions, production has declined steeply since then (fig. 3). The annual rate of decline for various periods since 1961 has been: 1961-1964, 19 percent; 1965-1970, 9 percent; and 1974-1976, 18 percent. The current rate of decline is 16 percent per year, based on the decline from a peak average production of 13,676 BOPD in February 1975 to 9,450 BOPD in December 1976.

From the number of producing wells at the end of 1976, the economic limit is 1.2 million bbls of oil per year. This limit at the current rate of decline would be reached in 1983. The estimate for remaining production is 13.6 million bbls from the end of 1976. This figure is 7.5 million bbls lower than estimates of proven reserves by API, including oil produced in 1976.

Because of the small amount of oil being produced, discoveries, development, and enhanced recovery programs can cause considerable fluctuation in total production figures. The average yearly rate of decline since 1961 has been six percent. When projected, this rate of decline would mean a future production of 46.5 million bbls. The present rate of decline in the larger fields and their development status would seem to preclude any major increase in production in northwestern New Mexico. Furthermore, waterflood programs have limited potential for adding significantly to reserves. New discoveries are the important factor in slowing or reversing the current rate of decline.

Southeast area

In 1969 maximum annual production of oil in the southeast area was reached at 117,722,236 bbls (fig. 4). Production dropped off slightly in 1970 to 117,181,123 bbls. Since then the decline has been much steeper. As indicated in fig. 4, the rate from 1970 to 1973 averaged eight percent per year. From 1973 to 1976 the rate was lower at 2.8 percent per year. The overall rate of decline for the 1970-76 period was 5.5 percent per year.

Average production for the 1975-1976 base period reached a peak of 239,408 BOPD in March 1975. By December 1976 production declined to a low of 221,326 BOPD. This decline represents a projected rate of 3.5 percent per year. The curve for average daily production (fig. 4) shows that the overall decline has increased from 1.8 percent in 1975 to 4.9 percent in 1976. The decline from the peak average daily production for 1976 has been higher with a projection of 5.5 percent per year.

At the current rate of decline the economic limit of 14.0 million bbls will be reached in the year 2026. Future oil production is estimated at 1.9 billion bbls, making the ultimate recovery for the southeast area just under 5 billion bbls. To maintain the present low rate of decline,

State
1977 Crude Oil Production

Month	Actual	Predicted
J	7,106,561	7,235,679
F	6,484,750	6,512,772
M	7,153,390	7,185,521
A	6,882,403	6,929,550
M	7,087,739	7,135,673
J	6,754,081	6,881,520
J	6,903,045	7,086,197
A	6,900,827	7,061,583
S	6,691,426	6,810,060
O	6,986,077	7,012,603
N	6,737,841	6,762,840
D	6,927,950	6,963,995
Totals	82,616,090	83,577,993

1.1% error

Ramey total oil ~~78~~,244,648
87

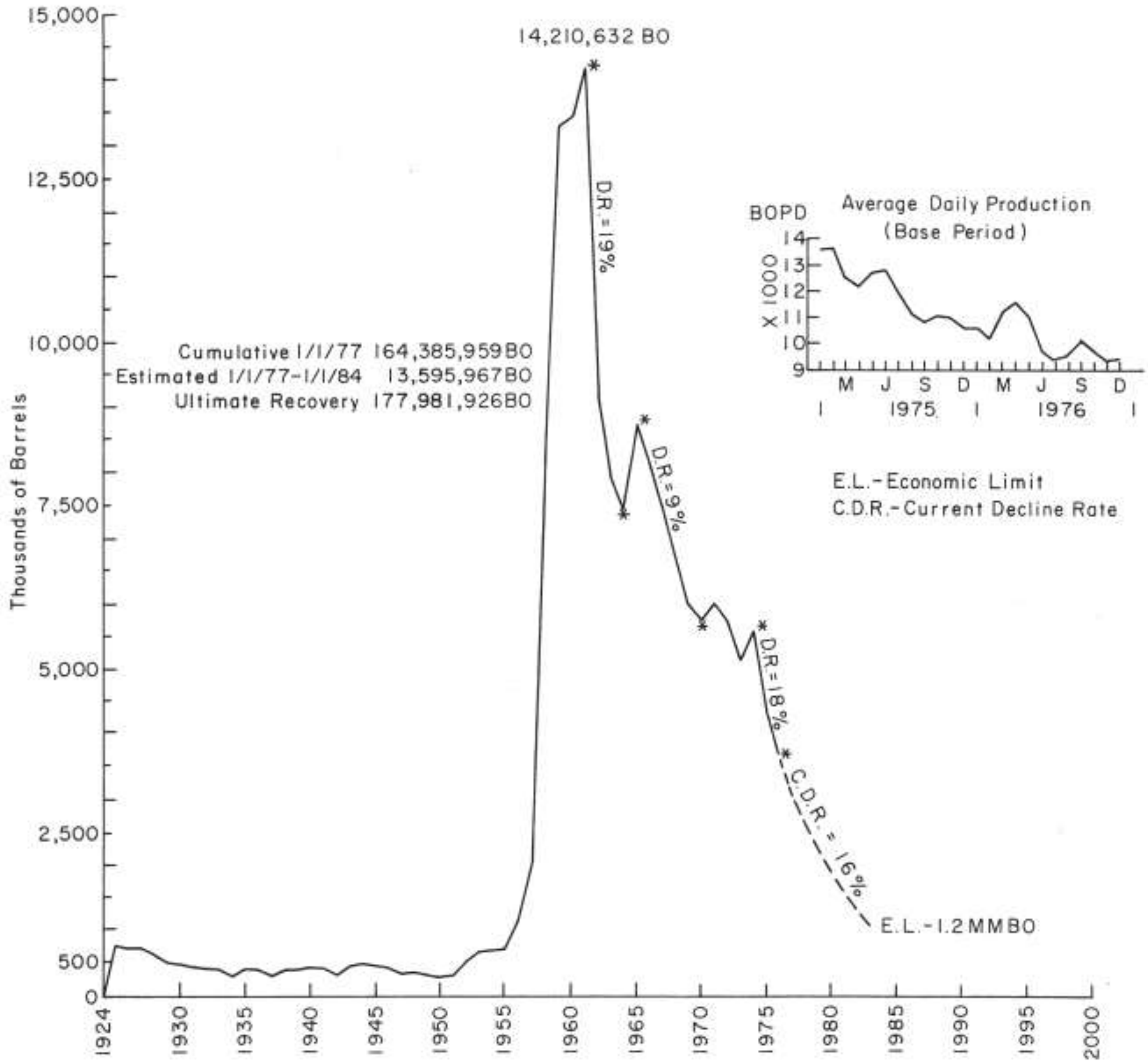

FIGURE 3—NORTHWEST NEW MEXICO: CRUDE OIL PRODUCTION AND ESTIMATED FUTURE PRODUCTION (BO—barrels of oil; MMBO—million barrels of oil; asterisks indicate years between which decline rates were calculated.)

considerable new oil must be added to the known reserves each year, with exploration and development drilling continuing at least at the current level. Expansion of existing waterflood projects and initiation of new projects also would be necessary. Other types of enhanced recovery projects cannot be relied upon at this time to add significant production. Over the short term, most of the additional oil will be found in established pools by testing pay zones of the relatively shallow Permian rocks at only slightly greater depths than those currently being exploited. Significant potential for the discovery of new oil exists in the deeper Permian Wolfcamp and various Pennsylvanian formations.

Statewide projection

As discussed previously, predicted production of crude oil for New Mexico is approximately 2.0 billion bbls at the current rate of decline. Decline rates since peak production of 123,735,473 bbls in 1969 are shown in fig. 5. From 1970-1973 the rate of decline was eight percent per year. From 1973-1976 the decline was three percent per year. Predicted crude oil production for the period from 1977-1990 for the southeast and northwest areas and the state are given in table 2.

In fig. 5 the projection of future production is based on total production for the state. This results in a

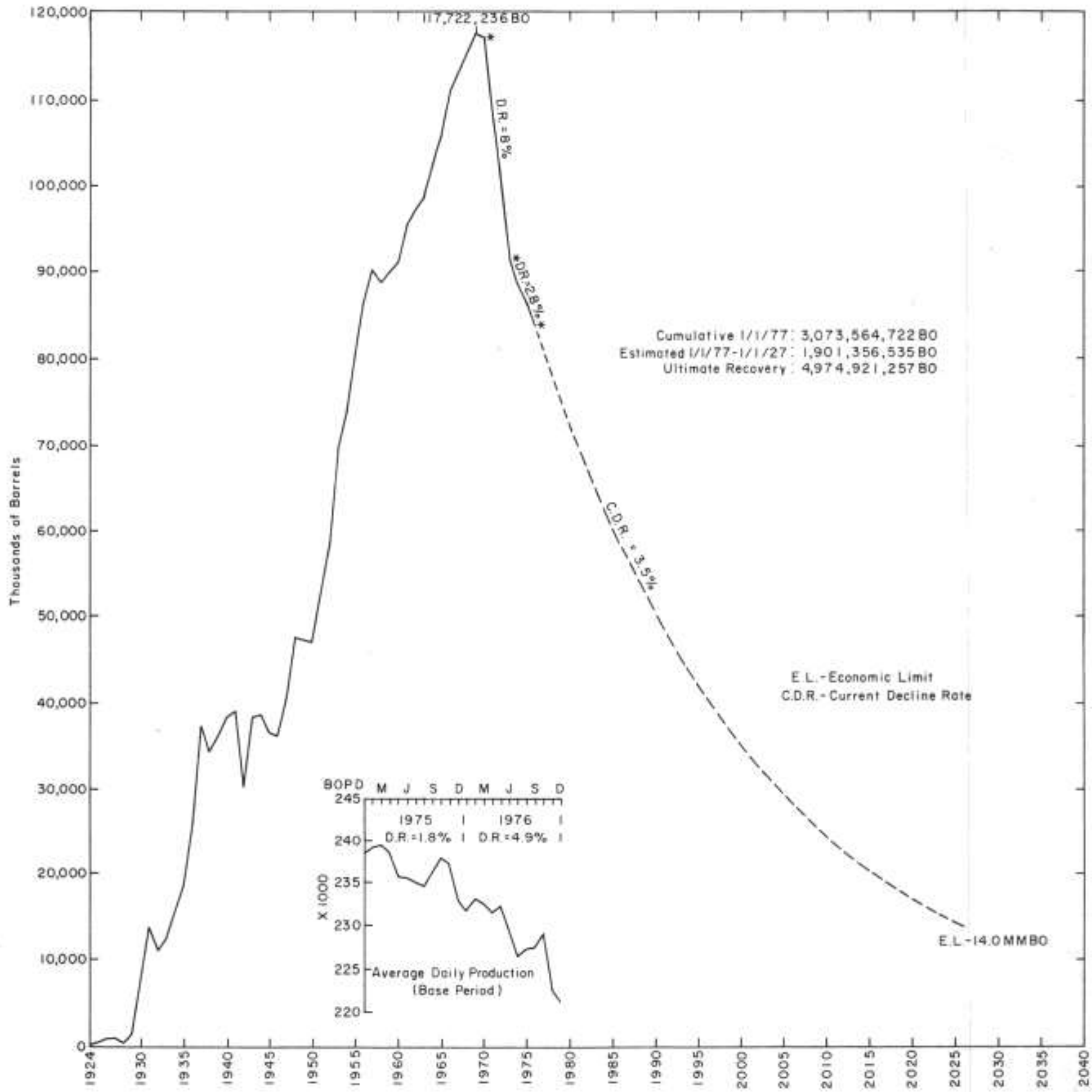

FIGURE 4—SOUTHEAST NEW MEXICO: CRUDE OIL PRODUCTION AND ESTIMATED FUTURE PRODUCTION (BO—barrels of oil; MMBO—million barrels of oil; asterisks indicate years between which decline rates were calculated.)

slightly higher rate of decline for the statewide prediction than for the southeast area. In 1976 only four percent of the crude oil produced came from the northwest area, but this area contained eight percent of the producing oil wells. The statewide economic limit is 15.3 million bbls based on a total of 13,580 producing wells at the end of 1976. These factors, along with the higher rate of decline for the northwest area, account for the lower predicted production and shorter economic life for the state than for the southeast area.

Studies of the 50 largest pools suggest reserves of 549.0 million bbls. The average current rate of decline for these pools, based on combined production, is 4.5 percent per year, slightly higher than the decline rate for the state. These pools currently account for 80 percent of the yearly oil production.

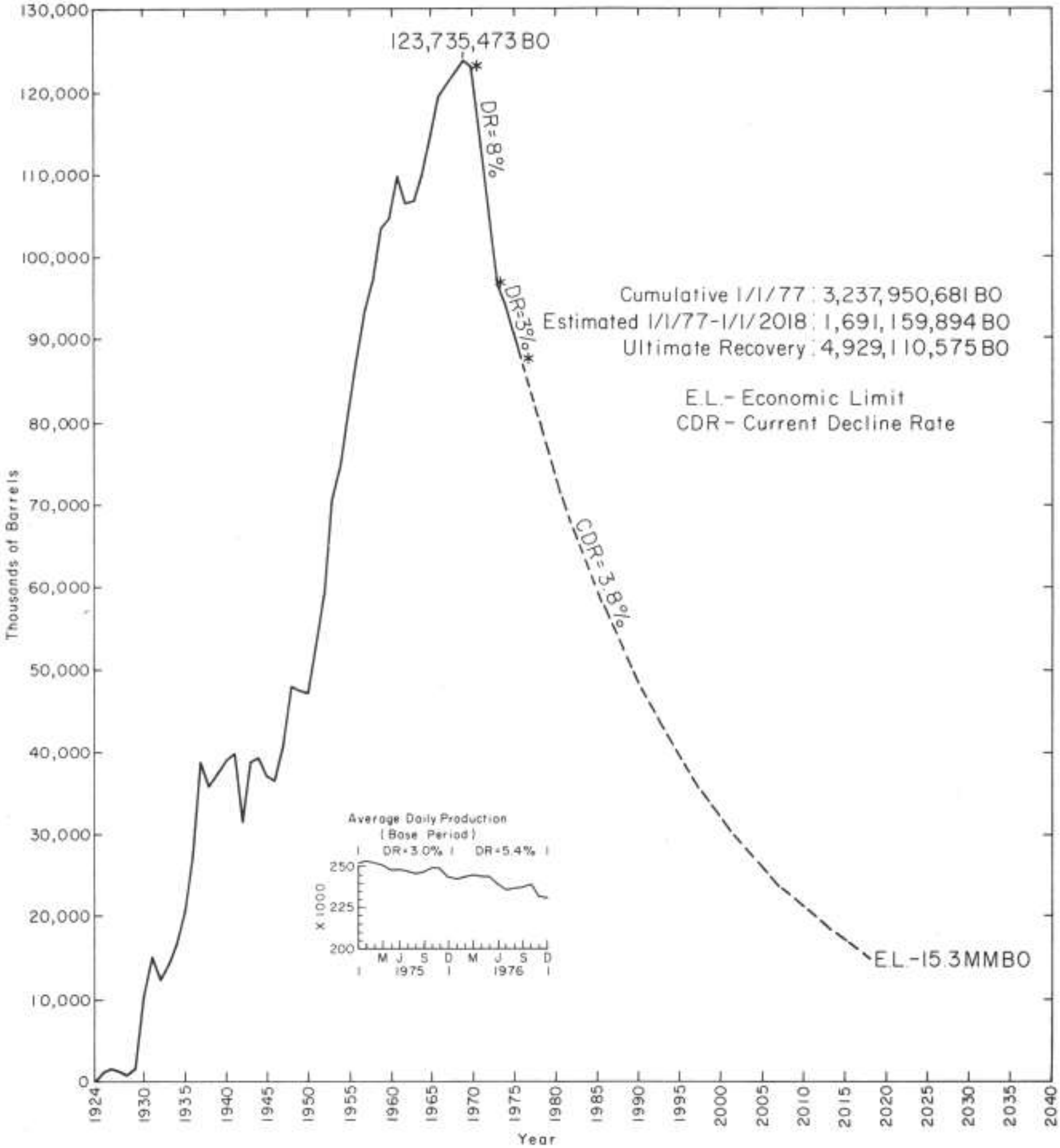

FIGURE 5—New Mexico: Crude oil production and estimated future production (BO—barrels of oil; MMBO—million barrels of oil; asterisks indicate years between which decline rates were calculated.)

Reserves of the 50 largest pools

Pools were selected on the basis of oil produced in 1975. In 49 pools, the method of calculating reserves was based on the rate of decline of oil produced. The only pool for which some variation of this method could not be used was Empire (Abo). In this case, estimates of reserves were from exhibits presented to the New Mexico Oil Conservation Commission.

Economic limits for each pool were determined by using 1) the number of producing wells at the end of 1975 and 2) a statistical analysis of average daily production per well for each pool based on depth and actual limits in production for 1975.

In 1975 production was reported from 505 designated oil pools containing 13,580 wells. Among these pools, 50 accounted for 80 percent of the total crude oil produced; the three largest—Empire (Abo), Vacuum (Grayburg-San Andres), and Maljamar (Grayburg-San Andres) —accounted for 29 percent. From 1922 to 1976, these 50 pools accounted for 68 percent of the cumulative oil produced in New Mexico, and estimated reserves as of January 1, 1976, totaled 549.0 million bbls. For the 1975-1976 base period, 42 of these pools were declining in production, 2 had increases in 1976 as a result of additional well completions, and 6 had increased as the result of waterflood or gas injection projects. A majority of the 50 pools have enhanced recovery projects, including 29 with waterflood programs, 3 with gas injection, and 1 with a combination waterflood and gas-injection program. Many of the pools with waterflood projects have lower decline rates as the result of initiation of new projects or expansion of preexisting programs. When these projects reach a maximum stage of development, the production decline will be much higher.

In any projection of recoverable reserves several assumptions are necessary. When using decline-curve methods, it is assumed that conditions will remain the same in the future as they were during the base period used for the projection. Obviously, in most cases, conditions will not remain the same (particularly over long periods of time). Where waterflood programs are involved, a typical curve would consist of a series of peaks and valleys repeated over a number of years. Multipay fields undergo a seemingly endless process of development. In pools with small numbers of wells, the addition of one or two wells will make significant changes in the amount of oil produced for short periods of time. During the process of converting producing wells to injection wells for waterflood programs, production usually drops sharply for at least a year. These factors, plus workovers, installation of higher capacity pumps, and reevaluation of producing zones (including gas-oilwater relationships), can result in large changes in recoverable reserves for some pools.

Methods

Three methods were used to estimate the amount of remaining recoverable oil in the 50 pools examined in this study:

1) reservoir evaluation for the Empire (Abo) Pool;

2) a multiple regression program (35 pools) and an equivalent exponential curve fit (6 pools) using current production data; and

3) historic decline rates taken from periods of stable pool conditions (8 pools).

Reservoir evaluation

Empire (Abo) was the only pool for which one of the decline-curve methods was not suitable. The evaluation was based on estimates of the original oil in place, the remaining oil, and the economic life.

Multiple regression

The computer program used in this study was a special version of a rather general multiple-regression routine. The multiple-regression routine relies heavily on subroutines that are in the IBM Scientific Subroutine Package (SSP). The program will be simplified in later work so that it can be used on other computers. The reason for using a rather general multiple-regression routine was that it permitted experimentation with several different prediction models.

The final model used was a simple regression of the logarithm of production versus time. In the final predictions, the conversion back to nonlogarithmic data was carried out, and an approximate 95-percent confidence interval was computed for each predicted value. This prediction interval gives some idea of the precision of the predicted value if the original model was correct.

Initially, the average daily production by month was punched on cards along with months numbered consecutively. The fitting process was carried out for periods of time where production was declining. If P_i is the actual production in month *i*, then our model used for predicting logarithms, Y_i, was $Y_i = a + bi$, where a and *bi* were constants determined by minimizing

$$\Sigma (\log_e P_i - a - bi)^2 *$$

For example, if we had values (24, P_{24}), (25, P_{25}) . . . (48, P_{48}), presuming the onset of decline before month 24, we would find *a* and *b* such that

$$\sum_{i=24}^{48} (\log_e P_i - a - bi)^2$$

is as small as possible. Then our predicted value for the logarithm of month 49 would be

$$Y_{49} = a + b\,(49),$$

and our actual predicted value would be

$$P_{49} = e^{Y_{49}} = e^a e^{b(49)}.$$

The regression program used calculates a, *b*, standard deviations of the predicted logarithms, and a correlation coefficient that indicates—among other things—how much of the variation is explained by the regression.

A description of the setup for the cards needed to run the program follows, along with the control cards needed for the present computer at New Mexico Insti-

*Log_e means logarithm to the base *e* (natural logarithm).

tute of Mining and Technology. In addition, the output obtained is described.

The first data card is a control card set up as follows:

Column 1 contains the number 2.

Columns 2, 3, and 4 contain the number of data points used in the regression, (right adjusted).

Column 6 contains a 1.

Columns 20-22 contain number of monthly predictions, (right adjusted).

Columns 31-41 contain the number of the initial month for which a prediction is to be made (with a decimal point).

The second card is a heading card and can contain any identifying information desired.

The next group of cards contain the data points. Each card has the number of the month in columns 1-5 (with a decimal) and the average daily production for that month in the next ten columns (also with a decimal).

The output lists the input data (along with the logarithm of the average daily production for each month), the means and standard deviation of the logarithmic data, the estimates a (intercept) and *b* (regression coefficient), the correlation between months and the logarithm of the production, an analysis-of-variance table, a table of residuals, the predicted values of the logarithm, and the associated standard deviation and predicted actual values with two standard deviation limits.

Table 3 shows the data keypunched for the input deck for the Crossroads (Silurian-Devonian) Pool and the appropriate control cards. Table 4 shows the associated output. The fitted line for the logarithm of the production is

$$Y_i = 9.75922 - .00411584i$$

and for the true production, $P_i = e^{Y_i}$, we get

$$P_i = e^{9.75922} e^{-.00411584i}.$$

The proportionate decline from month to month is $e^{-.00411584} \cong .99589$ and the annual proportional decline is $e^{-(.00411584)12} \cong .9518$.

The procedure used for the predictions here is not based on any underlying physical model. The assumption for each field is that all other factors remain similar to those under which past production occurred. A model incorporating the physics of fluid flow and the geological structure would certainly be more desirable. However, such models would be extremely complicated to use not only because of the equations needed but also because of the parameter values required.

The log-regression model was used to predict values, and then the predicted values were compared with actual values observed. For the short-run data used, this simple model was very successful. As the horizon of the prediction occurs farther in the future, the predictions may be more and more unreliable. For short periods of a few years (presuming a reasonable amount of decline data), such predictions should be quite good.

Some other possibly interesting and useful prediction models that could be explored are time-series models (autoregressive and moving averages, in particular). These models would be more adaptable to changes and possibly might be better tools in the long run.

TABLE 3—Input deck for Vacuum (Grayburg-San Andres) Pool.

Control cards

```
// PETRO JOB GUTJAHR, TIME = (2), LINES = 2000
// SYSAB2 ACCESS USERLIB (STATIS1L61)
EXEC REGLOG
```

Data Cards

```
2  12  1      6      22.
VACUUM-GB/SA
11.  16630
12.  16395
13.  16371
14.  16248
15.  16398
16.  16270
17.  16319
18.  16030
19.  15785
20.  15889
21.  15847
22.  15960
```

Control cards

```
/*
/&
```

One might investigate the governing flow equations to explain why a log regression is so good for predicting—in essence comparing a distributed system with this rather simple lumped system.

The logarithmic curve-fit procedure also can be done with a programmable pocket calculator. The HP-25C calculator, along with the program for exponential curve fitting from the Hewlett-Packard applications program manual, was used on six pools. The results are essentially the same as those obtained with the multiple-regression program; minor variations are due to round-off differences.

A comparison of projections obtained by multiple regression and exponential curve fit using the same data base is given in table 5. Also shown are estimates for future production using the constant-percentage-decline method. This method is commonly used by engineers when cumulative production and rate of production plotted on Cartesian paper results in a straight-line relationship. The example is the Hobbs (Blinebry) Pool; the data base is the average daily production for the period from September 1975 through October 1976. The estimated production for 1976 is not included in the reserve estimate in table 5 as it is on the graph for the Hobbs (Blinebry) Pool (fig. 42). The economic limit used was 4 BOPD per well.

Projected future production is almost identical, using either the multiple-regression or exponential curve-fit

TABLE 4—TYPESCRIPT OF OUTPUT PRINT-OUT, VACUUM (GRAYBURG-SAN ANDRES) POOL.

```
                              Multiple Regression Program

                                      Vacuum-GB/SA

                        The Number of Independent Variables is  1
                        The Number of Observations is  12

PRODUCTION DATA

     Date          Log-Data        Raw Data
     11.00000       9.71896         16630.
     12.00000       9.70473         16395.
     13.00000       9.70327         16371.
     14.00000       9.69573         16248.
     15.00000       9.70492         16398.
     16.00000       9.69708         16270.
     17.00000       9.70009         16319.
     18.00000       9.78222         16030.
     19.00000       9.66682         15785.
     20.00000       9.67338         15889.
     21.00000       9.67074         15847.
     22.00000       9.67784         15960.

Variable   Mean          Standard     Correlation   Sum of Deviations   Regression     Std Deviation of
 No.                     Deviation     X VS Y        from the Mean      Coefficient    Regression Coefficient
 1     0.165000E 02 0.360555E  01  -.896892E 00   0.143000E 03        -.411584F-02   0.64178E-03

DEPENDENT VARIABLE

       9.69131        0.01655

INTERCEPT    0.975922E 01

                      ANALYSIS OF VARIANCE FOR THE REGRESSION

SOURCE OF VARIANCE                 SUM OF SQUARES        D.F.         M.S.
ATTRIBUTABLE TO REGRESSION         0.242245E-02       .10000E 01   .24224E-02
DEVIATION FROM REGRESSION          0.58899E-03        .10000E 02   .58899E-04
TOTAL                              0.30114E-02

       F-VALUE=  41.12885

    MULTIPLE CORRELATION COEFFICIENT=   0.89689

              TABLE OF RESIDUALS

CASE NO.     Y VALUE      Y ESTIMATE      RESIDUAL

   1        .97190E 01   0.97139E 01    0.50201E-02
   2        .97047E 01   0.97098E 01   -0.50955E-02
   3        .97033E 01   0.97057E 01   -0.24452E-02
   4        .96957E 01   0.97016E 01   -0.58708E-02
   5        .97049E 01   0.96975E 01    0.74348E-02
   6        .96971E 01   0.96934E 01    0.37146E-02
   7        .97001E 01   0.96892E 01    0.10838E-01
   8        .96822E 01   0.96851E 01   -0.29154E-02
   9        .96668E 01   0.96810E 01   -0.14201E-01
  10        .96734E 01   0.96769E 01   -0.35181E-02
  11        .96707E 01   0.96728E 01   -0.20485E-02
  12        .96778E 01   0.96687E 01    0.91715E-02

              RANKING OF RESIDUALS

 SAMPLE NUMBER 1   NUMBER OF DATA POINTS  12
 VALUE OF X    %< OR = X
  -.140000E-01    0.083
  -.500000E-02    0.250
  -.300000E-02    0.333
  -.200000E-02    0.583
  0.300000E-02    0.667
  0.500000E-02    0.750
  0.700000E-02    0.( )
  0.900000E-02    0.917
  0.100000E-01    1.000

 ESTIMATED VALUES AND STANDARD DEVIATIONS FOLLOW

   INDEPENDENT VARIABLES:  .23000E 02

      PREDICTED  VALUE =  .96646E 01          STANDARD DEVIATION OF THE PREDICTION = .47234E-02
      PREDICTED ACTUAL VALUE =        15749.   TWO SIGMA PREDICTION INTERVAL =(      15601.,     15899.)

   INDEPENDENT VARIABLES:  .24000E 02

      PREDICTED VALUE =   .96604E 01          STANDARD DEVIATION OF THE PREDICTION = .52987E-02

      PREDICTED ACTUAL VALUE =        15685.   TWO SIGMA PREDICTION INTERVAL =(     15519.,     15852.)

   INDEPENDENT VARIABLES:  .25000E 02

      PREDICTED VALUE =   .96563E 01          STANDARD DEVIATION OF THE PREDICTION = .58878E-02

      PREDICTED ACTUAL VALUE =        15620.   TWO SIGMA PREDICTION INTERVAL =(     15437.,     15805.)

   INDEPENDENT VARIABLES:  .26000E 02

      PREDICTED VALUE =   .96522E 01          STANDARD DEVIATION OF THE PREDICTION = .64869E-02

      PREDICTED ACTUAL VALUE =        15556.   TWO SIGMA PREDICTION INTERVAL =(     15356.,     15759.)

   INDEPENDENT VARIABLES:  .27000E 02

      PREDICTED VALUE =   .96481E 01          STANDARD DEVIATION OF THE PREDICTION = .70935E-02

      PREDICTED ACTUAL VALUE =        15492.   TWO SIGMA PREDICTION INTERVAL =(     15274.,     15714.)

   INDEPENDENT VARIABLES:  .28000E 02

      PREDICTED VALUE =   .96440E 01          STANDARD DEVIATION OF THE PREDICTION = .77058E-02

      PREDICTED ACTUAL VALUE =        15429.   TWO SIGMA PREDICTION INTERVAL =(     15193.,     15668.)
```

TABLE 5-COMPARISON **OF DECLINE-CURVE METHODS FOR** HOBBS (BLINEBRY) POOL, given in barrels of oil; economic limit 39,420. Abbreviations: MR-multiple regression; ECF-exponential curve fit; CPD-constant-percentage decline.

Year	MR	ECF	CPD
1977	296,563	296,457	287,665
1978	245,463	245,503	223,635
1979	203,305	203,306	177,326
1980	168,909	168,824	140,605
1981	139,430	139,425	111,489
1982	115,523	115,461	88,403
1983	95,630	95,616	70,096
1984	79,422	79,399	55,581
1985	65,518	65,572	44,072
1986	54,385	54,302	34,945
1987	44,895	44,969	
1988	37,332	37,342	
Reserves	1,546,375	1,546,176	1,233,817
Decline rate	17%	17%	21%

method. These methods indicate an economic life of 12 years and recoverable reserves of 1.5 million bbls from January 1, 1977. From the constant-percentage-decline method, the economic life is 10 years and the reserves are 1.2 million bbls.

Hitoric decline rate

A historic decline rate was used to project production, where production of oil was increasing during the 1975-1976 base period or where the peak daily production occurred near the end of this period. The decline rate used was from a stable period during the history of the pool under either primary or secondary recovery. If waterflooding was not involved or was initiated near the end of the base period, a primary decline rate was used. If stable pool conditions were present following the start of waterflooding, a secondary decline rate was used. In both cases the percentage used was the average yearly decline for the stable period. Future production was calculated at this rate beginning with 1977 (using the estimated production for 1976 with data through October of that year).

Economic limits

At some stage in the life of an oil well, continued production of oil remaining in the reservoir is no longer economically feasible. This stage can occur rather abruptly where a natural water drive or a gas cap is the source of reservoir energy. In most cases, when the end of the life of a well approaches, the amount of oil produced will slowly decline to a point where the cost of lifting the oil to the surface exceeds the value of the oil produced. Factors involved in lift costs include depth, surface equipment, condition of casing, hole conditions, fuel, transportation, labor, and overhead. Other factors involved in operating costs are taxation, royalties, and working interest; all are weighted against the value of the oil produced to determine the economic limit for each well. This limit will vary from company to company. Studies to determine economic limits list barrels and fractions of barrels against depth. Another approach is to evaluate the point at which wells and pools are actually abandoned. For this report an analysis of each of the 505 active oil pools in New Mexico in 1975 was made to determine what the current economic limit is, based on the average daily production per well. Results of this study are summarized in table 6. The data indicate that depth can be used only in a general way. In this report only two classifications are used: 1) an economic limit of 2 BOPD at depths shallower than 5,000 ft and 2) an economic limit of 4 BOPD below 5,000 ft.

Depth of 0-5,000 ft

In 1975 the southeast area had 177 designated oil pools, with 8,304 wells having recorded production. The average production was 12.5 BOPD per well. In this depth range 134 pools involving 4,503 producing wells were in the stripper category (<10 BOPD). Even though these stripper wells averaged only 5.9 BOPD, their aggregate production amounted to 25 percent of the oil produced from this depth range. Within the stripper category, only eight percent of the wells produced less than 2 BOPD. Below this level abandonment is likely in most cases. As an example, 165 wells in 17 pools produced an average of less than 1 BOPD in 1975. The latest available reports for 1976 show that 57 of these wells (35 percent) have been shut in or abandoned. Most of the remaining wells were being produced intermittently. This intermittent production could continue for a number of years. However, excluding some unforeseen change in productive capacity, most will be abandoned in the near future.

In the San Juan Basin, 39 of the 63 pools and 657 of the 1027 producing wells were in the 0-5,000 ft depth range; 29 pools and 377 wells were in the stripper category with an average production per well of 6.8 BOPD. Of these pools, nine had an average per well production below 2 BOPD and five of these pools have since been shut in or abandoned.

Depth greater than 5,000 ft

At the end of 1975 southeast New Mexico had 20 pools wih 87 wells and an average production per well of less than 4 BOPD. The percentage of wells producing less than 4 BOPD does not follow a definite pattern when compared with depth brackets. From 5,000 to 6,000 ft only 2 percent of the stripper wells produced less than 4 BOPD; from 6,000-7,000 ft there was 7 percent; from 7,000-8,000 ft, 9 percent; from 8,000-9,000 ft, 25 percent; and from 9,000-10,000 ft, 10 percent. Of the 20 pools, four have since been shut in or abandoned; one consists of a single well producing gas; production from three now averages above 4 BOPD.

Northwest New Mexico has 12 pools containing 188 wells, with average production of less than 4 BOPD per well. These wells represent 83 percent of the stripper wells in this area. High gas:oil ratios in the San Juan

TABLE 6—1975 WELL PRODUCTION DATA AND CLASSIFICATION BY DEPTH.

Depth Range	> 10 BOPD						< 10 BOPD (Strippers)						All Pools				
	1975 Prod.	(%)	Pools	Wells	BOPY	BOPD	1975 Prod.	(%)	Pools	Wells	BOPY	BOPD	1975 Prod.	Pools	Wells	BOPY	BOPD
Southeast Area																	
0-5,000'	28,245,713	(75)	43	3,801	7,431	20.1	9,629,176	(25)	134	4,503	2,138	5.9	37,874,889	177	8,304	4,561	12.5
5,000-6,000'	5,806,930	(81)	21	612	9,488	26.0	1,402,680	(19)	11	636	2,205	6.0	7,209,610	32	1,248	5,777	15.8
6,000-7,000'	16,157,539	(90)	12	349	46,297	126.8	1,788,120	(10)	13	731	2,446	6.7	17,945,659	25	1,080	16,616	45.5
7,000-8,000'	1,335,592	(85)	20	156	8,561	23.5	234,587	(15)	11	85	2,760	7.6	1,570,179	31	241	6,515	17.9
8,000-9,000'	5,432,933	(99)	17	270	20,122	55.1	67,941	(1)	9	28	2,426	6.7	5,500,874	26	298	18,459	50.6
9,000-10,000'	8,186,685	(99)	41	858	9,542	26.1	73,572	(1)	10	30	2,452	6.7	8,260,257	51	888	9,302	25.5
10,000-11,000'	2,368,662	(95)	36	179	13,233	36.3	111,671	(5)	11	44	2,538	7.0	2,480,333	47	223	11,123	30.5
11,000-12,000'	2,767,422	(99)	22	161	17,189	47.1	17,018	(1)	10	10	1,702	4.7	2,784,440	32	171	16,283	44.6
12,000-13,000'	2,263,323	(>99)	15	83	27,269	74.7	532	(<1)	1	1	532	1.5	2,263,855	16	84	26,951	73.8
>13,000'	232,929	(99)	4	15	15,529	42.5	2,657	(1)	1	1	2,657	7.3	235,586	5	16	14,724	40.3
Subtotal >5,000'	44,552,015	(92)	188	2,683	16,605	45.5	3,698,778	(8)	77	1,566	2,362	6.5	48,250,793	265	4,249	11,356	31.1
All Pools	72,797,728	(85)	231	6,484	11,227	30.8	13,327,954	(15)	211	6,069	2,196	6.0	86,125,682	442	12,553	6,861	18.8
Northwest Area																	
0-5,000'	1,497,256	(62)	10	280	5,347	14.7	929,903	(38)	29	377	2,467	6.8	2,427,159	39	657	3,694	10.1
5,000-6,000'	449,687	(73)	7	92	4,888	13.4	168,778	(27)	7	136	1,241	3.4	618,465	14	228	2,713	7.4
>6,000'	1,105,172	(88)	1	51	21,670	59.4	152,134	(12)	9	91	1,672	4.6	1,257,306	10	142	8,854	24.3
Subtotal >5,000'	1,554,859	(83)	8	143	10,873	29.8	320,912	(17)	16	227	1,414	3.9	1,875,771	24	370	5,070	13.9
All Pools	3,052,115	(71)	18	423	7,215	19.8	1,250,815	(29)	45	604	2,071	5.7	4,302,930	63	1,027	4,190	11.5
State Totals																	
<5,000'	29,742,969	(74)	53	4,081	7,288	20.0	10,559,079	(26)	163	4,880	2,164	5.9	40,302,048	216	8,961	4,497	12.3
>5,000'	46,106,874	(92)	196	2,826	16,315	44.7	4,019,690	(8)	93	1,793	2,242	6.1	50,126,564	289	4,619	10,852	29.7
All Pools	75,849,843	(84)	249	6,907	10,982	30.1	14,578,769	(16)	256	6,673	2,185	6.0	90,428,612	505	13,580	6,659	18.2

Basin apparently are responsible for the ability to produce these wells at lower levels. The small number of wells and amount of oil produced do not seem to warrant a change in economic limits for this area now.

For the state overall, the 0-5,000 ft depth range includes 391 wells (four percent of the total) with production less than 2 BOPD. Below 5,000 ft, 275 wells (six percent) produced less than 4 BOPD, including wells to a depth of 13,000 ft.

Economic limits in barrels of oil per year for a specific pool can seem quite high. An example would be the Vacuum (Grayburg-San Andres) Pool. Based on 2 BOPD per producing well at the beginning of 1976, the economic limit would be 327,770 bbls. If this amount of oil were produced for 10 years after the economic limit was reached, the net change in the estimated ultimate recovery for this pool would only be one percent.

Projection analyses

The 50 largest pools in New Mexico (based on the amount of oil produced in 1975) are discussed according to their rank that year. This analysis includes methods used to estimate recoverable oil, predicted reserves, and problems encountered in decline-curve projections for each of the pools. Estimated reserves and ultimate recovery are summarized in table 7. Estimated reserves given in the table and on the figures for each pool include estimates of production for 1976 based on production data through October. Locations for each of the pools are given in figs. 6, 7, and 8. Figs. 9-58 are in the appendix.

Empire (Abo); rank 1, figs. 6 and 9, table 8.

This pool has led the state in the production of crude oil since 1962. In 1976, with 15,296,442 bbls produced, it accounted for 17 percent of New Mexico crude oil production. The pool is a solution-gas-drive reservoir with an element of gravity drainage and a possibly active water drive along the southeast edge. In June 1974 a gas-pressure maintenance program was initiated, resulting in the formation of a secondary gas cap, which is expected to increase the ultimate recovery from 45 percent to 53 percent of the original stock tank barrels in place. Under this program and transfer of allowables, average production has increased from 26,695 **BOPD** in 1973 to 36,659 BOPD in 1974 and 41,698 BOPD in 1975. Also, reservoir pressure has been stabilized.

The estimated ultimate recovery is 212.8 million bbls (New Mexico Oil Conservation Commission 1973, 1974a, b), representing 53 percent of the calculated 401.6 million stock tank barrels of oil originally in the reservoir. To January 1, 1976, production was 127,-776,576 bbls, leaving an estimated reserve of 85.0 million bbls.

Vacuum (Grayburg-San Andres); rank 2, figs. 7 and 10.

The Vacuum Pool was discovered in 1929. Development drilling during 1938-1939 resulted in a peak daily primary production of 16,300 bbls in December 1939.

TABLE 7—ESTIMATED RESERVES AND ULTIMATE RECOVERY OF 50 LARGEST POOLS.

Rank 1/1/76	Field	Discovery Year	Depth Factor M=1,000 ft	Approximate Decline Rate	Recovery (bbls) to 1/1/76	Estimated Reserves (bbls)	Ultimate Recovery (bbls)	Remaining %
1	Empire (Abo)[1]	1957	6M-7M*	--	127,776,576	85,023,424	212,800,000	40%
2	Vacuum (GB-SA)[2]	1929	0-5M	5%	159,307,712	113,186,510	272,494,222	42%
3	Maljamar (GB-SA)[2]	1926	0-5M	12%	106,266,703	32,815,518	139,082,221	24%
4	Hobbs (GB-SA)[2]	1928	0-5M	14%	226,978,885	22,326,892	249,305,777	9%
5	Eunice-Monument (GB-SA)[3]	1929	0-5M	6%	320,986,627	49,288,145	370,274,772	13%
6	Langlie-Mattix (Y-SR-Q)[2]	1929	0-5M	12%	91,866,446	21,270,748	113,137,194	19%
7	Vacuum (Abo Reef)[2]	1960	8M-9M	24%	67,671,100	11,643,839	79,314,939	15%
8	Vacuum (Glorieta)[2]	1963	5M-6M	8%	38,784,478	32,049,781	70,834,259	45%
9	Bagley, North (Penn)	1970	9M-10M	23%	37,819,611	8,490,139	46,309,750	18%
10	Grayburg Jackson (Q-GB-SA)[2]	1929	0-5M	10%	74,349,934	14,460,611	88,810,545	16%
11	Drinkard[2]	1944	6M-7M	19%	69,691,580	6,243,611	75,935,191	8%
12	Vacuum, North (Abo)[4]	1963	9M-10M	8%	12,521,096	22,844,764	35,365,860	65%
13	Crossroads (S-D)[2]	1948	12M-13M	33%	37,166,001	2,824,177	39,990,178	7%
14	Vada (Penn)[2]	1967	9M-10M	26%	46,398,811	4,313,770	50,712,581	9%
15	Tocito Dome (Penn "D")[2]	1964	6M-7M	54%	10,763,368	780,352	11,543,720	7%
16	Jalmat (T-Y-SR)[2]	1953	0-5M	12%	55,517,999	8,143,830	63,661,829	13%
17	Blinebry Oil and Gas[2]	1945	5M-6M	14%	34,883,919	3,181,451	38,065,370	8%
18	Justis (Blinebry)[2]	1958	5M-6M	25%	21,820,022	3,221,129	25,041,151	13%
19	Eumont (Y-SR-Q)[2]	1953	0-5M	12%	64,254,922	5,068,885	69,323,807	7%
20	Denton (D)[2]	1949	11M-12M	19%	90,150,236	3,704,554	93,854,790	4%
21	Shugart (Y-SR-Q-GB)[2]	1937	0-5M	9%	14,787,132	7,372,772	22,159,904	33%
22	Lovington (Abo)[2]	1952	8M-9M	9%	27,348,277	7,264,107	34,612,384	21%
23	Denton (WC)[2]	1950	9M-10M	16%	32,749,051	3,269,504	36,018,555	9%
24	Paduca (Del)[2]	1961	0-5M	11%	9,481,149	5,130,818	14,611,967	35%
25	Loco Hills (Q-GB-SA)[2]	1939	0-5M	37%	41,104,065	1,380,591	42,484,656	3%
26	Square Lake (GB-SA)[4]	1941	0-5M	7%	20,736,400	3,326,490	24,062,890	14%
27	Artesia (Q-GB-SA)[3]	1923	0-5M	14%	22,344,628	3,279,482	25,624,110	13%
28	Paddock[2]	1945	5M-6M	14%	21,902,480	2,838,741	24,741,221	11%
29	Chaveroo (SA)[4]	1965	0-5M	24%	17,426,456	1,737,183	19,163,639	9%
30	Wantz (GW)[4]	1963	7M-8M	15%	1,250,628	4,007,868	5,258,496	76%
31	Eunice, South (SR-Q)[4]	1930	0-5M	14%	23,088,739	4,691,510	27,780,249	17%
32	Horseshoe (Gallup)[4]	1956	0-5M	19%	34,613,623	2,018,992	36,632,615	6%
33	Corbin (Abo)[3]	1959	8M-9M	27%	11,754,684	1,544,907	13,299,591	12%
34	Hobbs (Blinebry)[2]	1968	5M-6M	17%	3,711,963	1,906,103	5,618,066	34%
35	Flying M (SA)[3]	1964	0-5M	10%	4,916,900	3,171,497	8,088,397	39%
36	Hospah, South (Lower Sand)[2]	1966	0-5M	10%	2,905,839	3,483,754	6,389,593	55%
37	Pearl (Queen)[2]	1956	0-5M	20%	17,661,300	1,469,988	19,131,288	8%
38	Bronco (S-D)[2]	1953	11M-12M	26%	13,093,519	1,155,322	14,248,841	8%
39	Bagley (S-D)[2]	1949	10M-11M	18%	24,967,415	1,496,389	26,463,804	6%
40	Dollarhide (D)[2]	1952	8M-9M	11%	5,437,079	2,764,944	8,202,023	34%
41	Dollarhide (Tubb-Drinkard)[3]	1951	6M-7M	20%	15,176,164	1,498,860	16,675,024	9%
42	Baum (Upper Penn)[2]	1955	9M-10M	5%	6,312,592	5,257,092	11,569,684	45%
43	Puerto Chiquito, West (Mancos)[2]	1966	0-5M	6%	5,456,384	4,979,324	10,435,708	48%
44	Moore (D)[3]	1952	10M-11M	17%	20,441,031	1,438,998	21,880,029	7%
45	Lovington (Paddock)[4]	1952	6M-7M	16%	11,474,369	1,538,467	13,012,836	12%
46	Penrose-Skelly (GB)[2]	1936	0-5M	21%	17,687,107	858,547	18,545,654	5%
47	Hospah, South (Upper Sand)[2]	1967	0-5M	25%	3,094,136	664,449	3,758,585	18%
48	Caprock (Q)[2]	1941	0-5M	16%	71,223,144	1,104,640	72,327,784	2%
49	Cato (SA)[4]	1966	0-5M	33%	13,339,347	635,506	13,974,853	5%
50	Sawyer, West (SA)[2]	1968	0-5M	14%	1,417,127	1,599,809	3,016,936	53%
	TOTALS				2,196,682,590	548,984,948	2,745,667,538	20%

[1]Projection from reservoir studies
[2]Average daily production—multiple regression
[3]Average daily production—exponential curve fit
[4]Historic decline rate

*Economic limit is considered to be 2 BOPD/well from 0-5,000 ft and 4 BOPD/well below 5,000 ft.

T — Tansill
Y — Yates
SR — Seven Rivers
Q — Queen
GB — Grayburg
SA — San Andres

Del — Delaware
WC — Wolfcamp
GW — Granite Wash
S-D — Silurian-Devonian
Penn — Pennsylvanian
D — Devonian

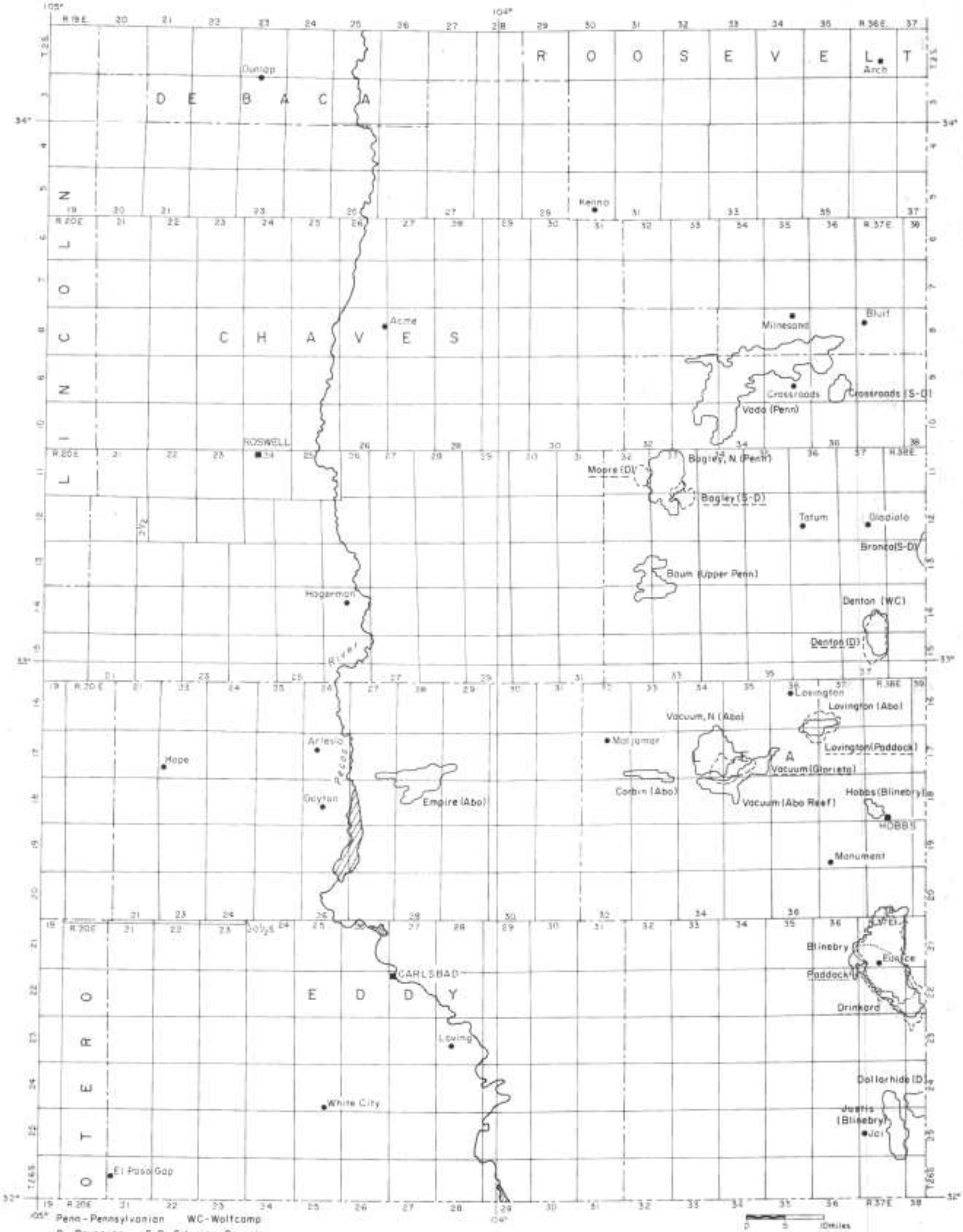

FIGURE 6—LOCATION MAP FOR SOUTHEAST AREA POOLS (Lower Permian to Silurian).

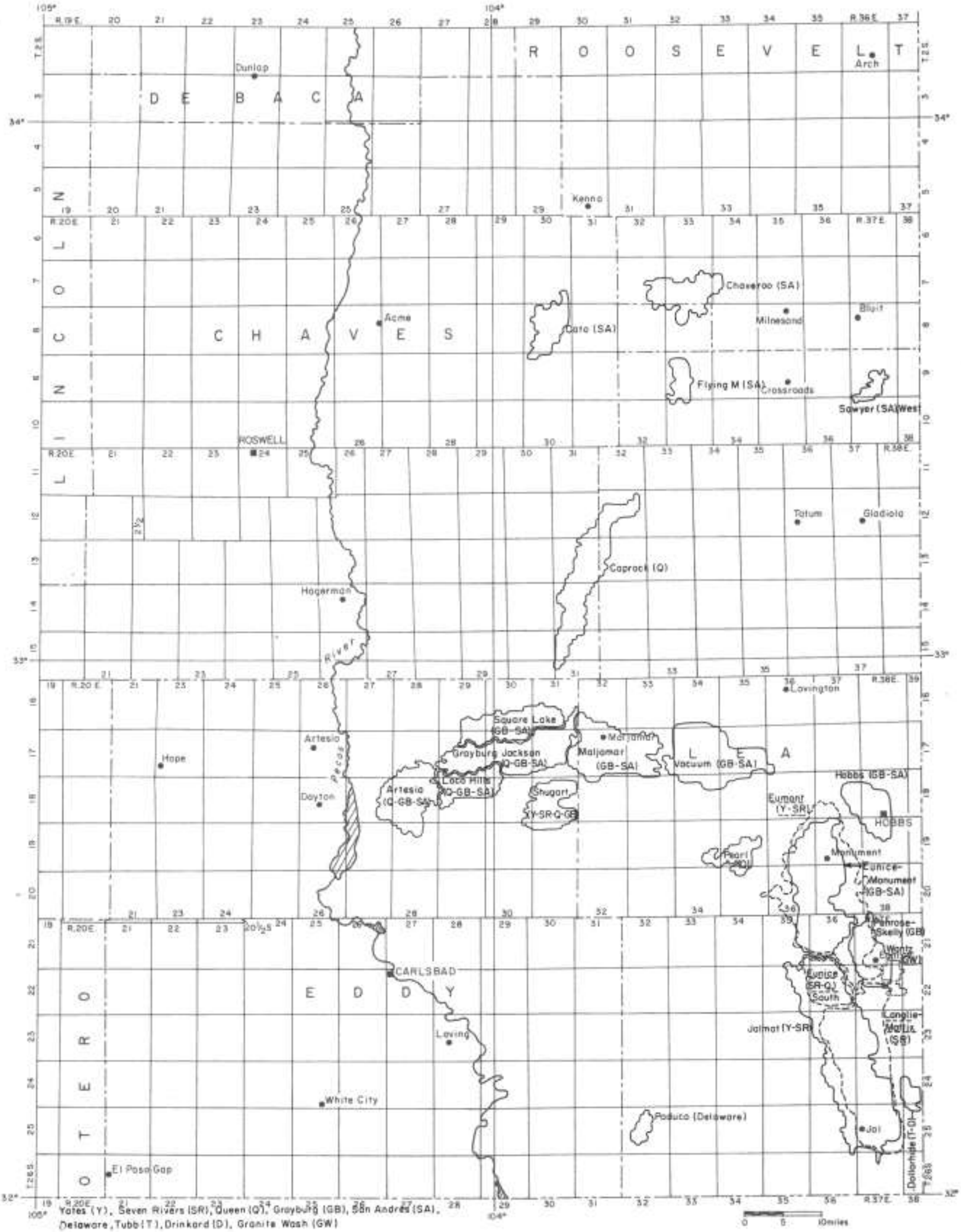

FIGURE 7—LOCATION MAP FOR SOUTHEAST AREA POOLS (Permian).

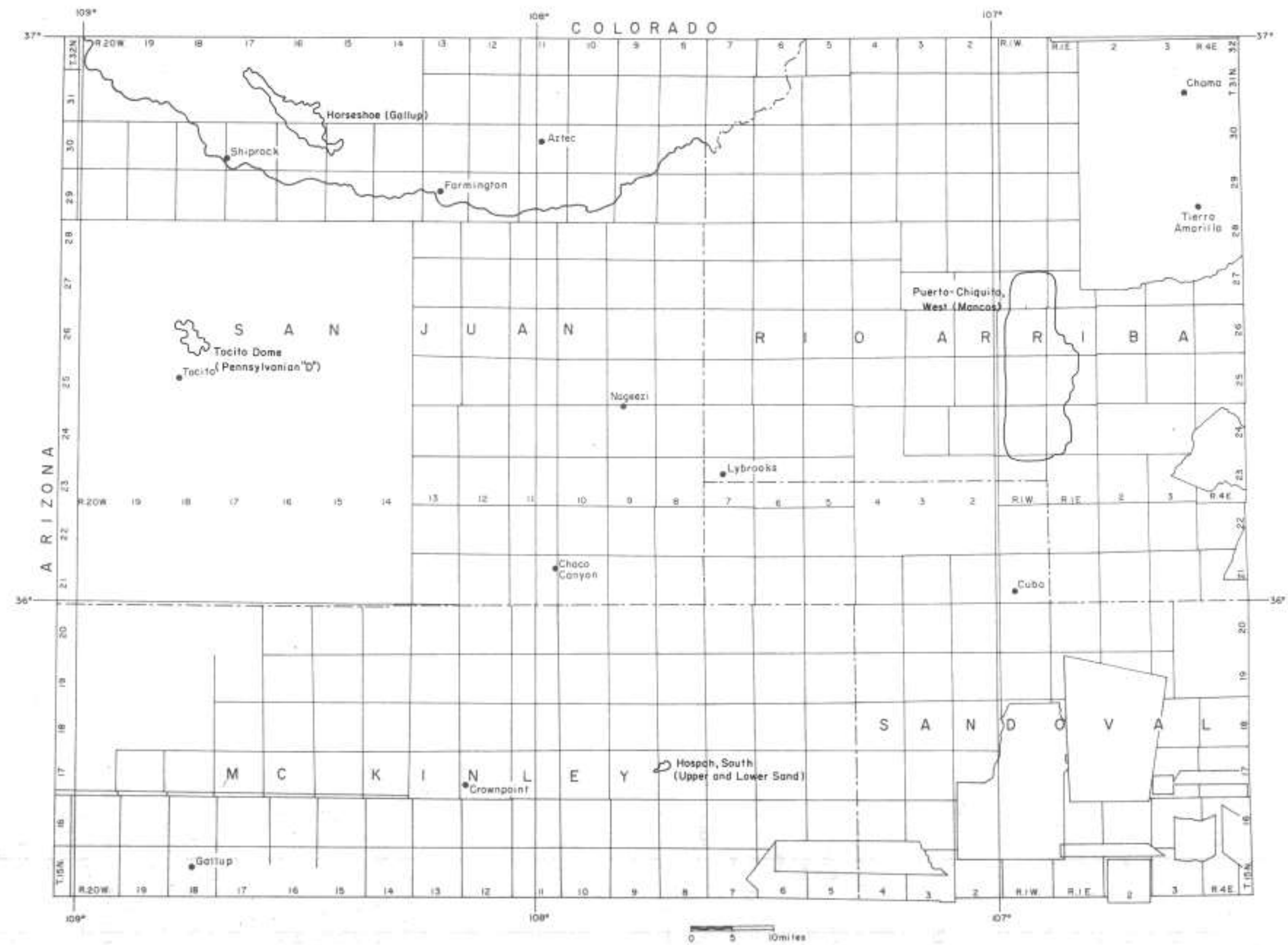

FIGURE 8—LOCATION MAP FOR NORTHWEST AREA POOLS.

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TABLE 8—EMPIRE (ABO) RESERVOIR DATA (From New Mexico Oil Conservation Commission Case Nos. 4954, 5135, 5177).

Original reservoir conditions	
Hydrocarbon datum	5600 ft
Pressure - 2264 ft	2359 psia
Pressure at bubble point - 2264 ft	2231 psia
Reservoir temperature	109°F
Gas-oil contact	-1750 ft
Water-oil contact	-2265 ft
Productive area	8990 ac
Stock tank oil in place	263 bbls/ac
Gas-oil ratio	1250 SCF/bbl
Formation volume factors: gas	0.00098 RVB/SCF
oil	1.606 RVB/STB
Current reservoir conditions (1975)	
Average pressure	1321 psia
Cumulative gas injected	29,254 MMCF
Unit gas injected (daily)	29,052 MCF
Outside gas injected (daily)	21,598 MCF
Gas-oil ratio	1262 SCF/bbl
Gas production (daily)	51,800 MCF
Cumulative water injected	1,051,007 bbls
Water production (daily)	1335 bbls
Voidage available for transfer (daily)	30,062 RVB

Abbreviations

SCF -- Standard cubic feet
RVB -- Reservoir barrels
psia -- Pounds per square inch absolute
MMCF -- Million cubic feet
MCF -- Thousand cubic feet
bbls -- Barrels
STB -- Stock tank barrels

The highest yearly primary recovery was 5,018,313 bbls in 1944. Yearly production of oil to 1962 reflects prorationing. Waterflooding began in 1958 and has been expanded with the addition of seven projects in the period from 1967 to 1973. In 1975 secondary oil accounted for 36 percent of the oil produced from the Vacuum Pool. Oil produced in 1974 amounted to 6,096,067 bbls for an average daily production of 16,700 bbls. Production declined slightly in 1975 to 6,073,009 bbls; the estimated production for 1976 is 5,874,277 bbls.

Additional waterflood projects could result in stabilization of production for several years. The projection of the remaining recoverable reserves is based on the current decline in average daily production from 16,630 bbls in November 1975 to 15,960 bbls in October 1976. The result is a projected decline of five percent per year, with reserves of 113.0 million bbls. Following maximum waterflood development, the rate of decline will be steeper than five percent; however, reserves may be as high as projected, depending upon the area remaining for additional waterflood projects.

Maljamar (Grayburg-San Andres); rank 3, figs. 7 and 11.

The Maljamar Pool was discovered in 1926; development expanded during World War II and production reached 2,142,282 bbls in 1946. The amount of oil produced remained fairly stable through 1950 as a result of excess capacity and additional wells. Extensive development drilling during 1955-1963, along with the beginning of waterflooding in 1958, increased the annual production to 2,927,469 bbls by 1961. Greatly expanded waterflooding from 1962 to 1967 resulted in peak production of 7,378,649 bbls in 1972. Production has since declined to 4,850,296 bbls in 1975 and to an estimated 4,288,378 bbls in 1976. Most of the oil produced in 1975 is credited to the waterflood program.

The current rate of decline for the base period from January 1975 through October 1976 is 12 percent per year, indicating reserves of 32.8 million bbls of oil and an ultimate recovery of 139 million bbls.

Hobbs (Grayburg-San Andres); rank 4, figs. 7 and 12.

Cumulative production from the Hobbs Pool since its discovery in 1928 amounts to 227 million bbls of oil. This pool ranks second to Eunice-Monument in the total amount of oil produced through 1975. The highest yearly production was 12.8 million bbls in 1931. Production since 1940 has been fairly uniform and reflects prorationing, workovers, and recompletion to other zones. Water flood projects initiated in 1971 and 1975 have not yet affected the rate of decline since 1970. On a yearly basis, this decline amounts to about five percent. The current rate of decline from July 1975 to October 1976 is 14 percent per year, possibly the result of converting some producing wells to injection wells during 1975. A somewhat less than 14-percent decline is anticipated even if the waterflood project is not entirely successful.

Based on the 14-percent decline, recoverable reserves are 22.3 million bbls with an ultimate recovery of 249 million bbls.

Eunice-Monument (Grayburg-San Andres); rank 5, figs. 7 and 13.

The Eunice and Monument Pools were combined in 1971. The cumulative combined production for both pools through 1975 has been 321 million bbls of oil. From the peak production of almost 14 million bbls in 1944, the average decline in production is four percent per year through 1975. Establishing a stable-field- condition rate of decline for the pool is difficult because some wells were shifted to other pools, and other wells were reclassified to oil or gas. Fairly uniform conditions prevailed from 1951 to 1954; the rate of decline for this period was nine percent per year. A small waterflood project initiated in 1968 accounts for only a small amount of the total yearly production.

Based on the current rate of decline from a peak average daily production in February 1975 through October 1976, estimated reserves are 49.3 million bbls with an ultimate recovery of 370.3 million bbls.

Langlie-Mattix (Yates-Seven Rivers-Queen); rank 6, figs. 7 and 14.

The Langlie-Mattix Pool, discovered in 1929, had a peak primary production of 3,278,329 bbls in 1940. Under stable pool conditions to 1948, oil production declined at 14 percent per year. Increased drilling began in 1948; additional wells were transferred from the Penrose-Skelly Pool in 1956. Waterflooding, begun in 1958, led to general increases in production through 1960. Conditions remained fairly uniform through 1965, with the exception of two additional waterflood projects initiated in 1963 and three projects in 1964. The rate of decline for this period again was 14 percent. Continued expansion of the waterflood programs resulted in a peak production for the pool of 3,449,971 bbls in 1974. In 1975 production declined slightly to 3,420,032 bbls, followed by a sharp drop in 1976 of 12 percent to the estimated 3,021,720 bbls.

Based on average daily production from June 1975 to October 1976, the decline rate is 12 percent with estimated recoverable reserves of 21.3 million bbls. Almost all the oil produced in 1975 is attributed to waterflooding.

Vacuum (Abo Reef); rank 7, figs. 6 and 15.

In 1968 production of oil reached a high of 6,032,391 bbls. The yearly decline through the estimate for 1976 has been 10 percent. Production in 1975 decreased to 3,097,463 bbls; the estimate for 1976 is 2,847,183 bbls. A gas-pressure maintenance program begun in 1970 appears to have had little effect on the rate of decline, although 56 percent of the oil produced in 1975 is considered to be the result of this program. Relatively small volumes of gas have been injected, and possibly the program can be expanded.

The current average daily production from April to October 1976 is declining at a rate of 24 percent per year, indicating remaining recoverable reserves of 11.6 million bbls. Possibly, the rate of decline will be somewhat less, but it probably will prove higher than the annual 10-percent decline since 1968.

Vacuum (Glorieta); rank 8, figs. 6 and 16.

From the average daily production from May to October 1976, the current rate of decline is eight percent per year, indicating reserves of 32.0 million bbls or 45 percent of the original recoverable oil in the reservoir. Discovered in 1963, the pool was essentially developed by the end of 1964. The amount of oil produced remained fairly stable through 1972. The decline rate for 1972-1976 is eight percent per year, the same as the current rate of decline for the base period.

Bagley, North (Pennsylvanian); rank 9, figs. 6 and 17.

Discovered in 1957, development and significant production did not begin until 1963. Peak production was 6,721,007 bbls in 1969. By 1975 oil production had declined to 2,174,303 bbls for an average rate of decline of 19 percent per year. During 1974-1976 the yearly decline was only four percent because of additional completions. However, during the April-October 1976 base period the rate of decline increased to a projected 23 percent per year. Reserves at this rate of decline are 8.5 million bbls with an estimated total recovery of 46.3 million bbls.

A pilot waterflood project was started in 1972. Results appear to have been negative, and the project was abandoned in 1975. Stable pool conditions prevailed during 1970-1974 and the rate of decline was 23 percent. Under stable conditions this rate is likely to continue.

Grayburg-Jackson (Queen-Grayburg-San Andres); rank 10, figs. 7 and 18.

Discovered in 1929, this old field continues to supply a significant amount of the oil produced in New Mexico. Production data include the Grayburg-Keely Pool abolished in 1959. Determining a stable rate of decline for pools of this type is difficult. Workovers, recompletions to other zones, development drilling, and prorationing have resulted in a complex development history. From 1951 to 1953 production declined at 13 percent per year, but this figure is considered only an approximation because of lower allowables being offset by additional wells. Waterflood projects begun in 1957 have resulted in increased production to a peak of 2.9 million bbls in 1972. Additional projects initiated in 1973, 1974, and 1975 may have slowed the current rate of decline. In 1975, 70 percent of the production was considered secondary. The rate of decline occurring after maximum development of waterflood projects should be steeper than the current 10 percent decline. The present decline, based on the average daily production from March to October 1976, indicates recoverable reserves of 14.5 million bbls with an ultimate recovery of 88.8 million bbls.

Drinkard; rank 11, figs. 6 and 19.

From its discovery in 1944, the pool was rapidly developed with peak production of 6,754,648 bbls in 1949. A fairly stable condition prevailed until 1961 when additional development resulted in a moderate increase in production to 1965. The rate of decline under fairly stable conditions was 13 percent from 1949-1961 and 10 percent from 1965-1972. The lower rate of decline for the latter period may have been the result of waterflood programs started in 1967 and 1969. However, waterflooding has accounted for only a small amount of the production. Increases in oil produced from 1972 through the projections for 1976 are the result of increased drilling and recompletions from other zones. If this activity continues in 1977, oil production could be increased or stabilized for at least another year. Average daily production of oil has declined since the peak of 5,347 BOPD in February 1976 to below 5,000 BOPD from July-October 1976. The projected rate of decline is 19 pecent per year with estimated reserves of 6.2 million bbls.

Vacuum, North (Abo); rank 12, figs. 6 and 20.

Discovered late in 1962, production increased from 452 bbls that year to 2,246,429 bbls from 142 wells in 1972. Conversion of producing wells to injection wells caused a decline in production in 1973-1974. Estimated production for 1976 is 2,011,012 bbls; anticipated production for 1977 will probably be higher. The only stable conditions during the history of the pool were from 1968-1969, when the rate of decline was eight percent. This rate is used to project the reserves of 22.8 million bbls. Based on a probable success for the water-flood project, production of oil could increase for the next several years, assuming continued expansion of the project. However, following maximum development, the stable rate of decline is expected to be greater than eight percent per year.

Crossroads (Silurian-Devonian); rank 13, figs. 6 and 21

Although discovered in 1948, peak production of 2.9

million bbls was not reached until 1973. Oil production increased beginning in 1972 as a result of additional drilling and a special increase in allowables for certain fields in September 1972. The current rate of decline of 33 percent per year is based on a projection of data from May 1975-October 1976. Reserves are estimated at 2.8 million bbls. Since 1973 the yearly decline rate has been 30 percent. During the same period, water production has increased at a rate of 22 percent per year from 11.9 million bbls to 19.7 million bbls.

Vada (Pennsylvanian); rank 14, figs. 6 and 22.

The decline curve for this pool is similar to Bagley, North (Pennsylvanian). Vada was discovered in 1956 and was originally named Lane (Pennsylvanian); in 1970 it yielded 12,058,211 bbls. By 1975 production had decreased to 1,418,492 bbls; the estimate for 1976 is 1,283,399 bbls. The average rate of decline for this period was 30 percent per year. During 1975 the rate of decline stabilized, but beginning in February 1976 production was declining at a projected rate of 26 percent per year. The number of producing wells has decreased from 267 in 1970 to 155 in 1975. A waterflood project was approved in 1971 but was abandoned the following year. Estimated reserves are 4.3 million bbls with an ultimate recovery of 50.7 million bbls.

Tocito Dome (Pennsylvanian "D"); rank 15, figs. 8 and 23.

Located in northwestern New Mexico, this pool was discovered in 1964. In 1966 production reached 1.1 million bbls, then by 1972 had declined to 0.7 million bbls. Development drilling beginning in 1972 resulted in a peak production of 1.9 million bbls in 1974. In 1975 production dropped to 1.1 million bbls; the estimate for 1976 is 0.4 million bbls. Under stable conditions from 1968-1970 the rate of decline was 19 percent per year. The current decline based on average daily production from October 1975-October 1976 is 54 percent per year with estimated reserves of 0.8 million bbls. A number of additional wells or an enhanced recovery program would be necessary to significantly change the high rate of decline for this pool.

Jalmat (Tansill-Yates-Seven Rivers); rank 16, figs. 7 and 24.

The Jalmat Pool, created by order of the Oil Conservation Commission in 1954, includes parts of the former Jalco, Langmat (gas), Jal, Cooper Jal, Eaves, and Falby Pools. The decline curve represents oil produced since creation of the pool. Cumulative production through 1975 includes oil produced from wells formerly assigned to other pools.

Under stable primary conditions from 1959 to 1962, the decline rate was 13 percent. Two water-injection projects, started in 1962, resulted in a moderate increase in production to 1965. Conversion of a number of producing wells to injection wells caused the sharp decline in production for 1966. The rate of decline continued at 12 percent per year until 1970. Initiation of additional waterflood projects and further expansion of earlier projects resulted in increased production to 1,101,230 bbls in 1975. The estimate for 1976 is slightly less at 1,081,378 bbls. Although somewhat erratic, the decline for the base period from October 1975-October 1976 indicates a projected decline rate of 12 percent per year. Secondary production in 1975 represents 55 percent of the total for the year. Further expansion of the waterflood program should result in increased production. Under the current rate of decline, reserves are 8.1 million bbls.

Blinebry Oil and Gas; rank 17, figs. 6 and 25.

Data include oil produced from the Terry (Blinebry) Pool from 1952-1971. The Blinebry Oil field and Blinebry Gas field were consolidated in 1974, substantially increasing the number of wells in the pool. Also production increased moderately from 904,404 bbls in 1973 to 1,013,800 bbls in 1975. Estimated production for 1976, with data available through November, should be approximately 988,000 bbls. Production declined fairly steeply from October 1975, when production averaged 3,058 BOPD, to July 1976, when production averaged 2,524 BOPD, reflecting in part adjustments for past production over allowables. Production remained steady in August and September and then increased to 2,720 BOPD in October. The projected rate of decline since October 1975 has been about 14 percent per year, indicating reserves of 3.2 million bbls at the economic limit of 4 BOPD per well. The majority of wells are currently flowing; the average producing rate of all wells is 6 BOPD. If the economic limit were lowered to 2 BOPD (because most wells are flowing), 1.7 million bbls of recoverable reserves would be added. However, these additional reserves would add only four percent to the estimated ultimate recovery.

Under stable pool conditions from 1957 to 1959, and again from 1965 to 1970, the rate of decline was 12 percent and 15 percent respectively.

Justis (Blinebry); rank 18, figs. 6 and 26.

Cumulative production includes oil produced from the North Justis (Blinebry) Pool for 1961-1963. Peak production was reached in 1966 at 1,968,848 bbls. With minor exceptions because of additional well completions in 1969 and 1974, production has declined to 964,853 bbls in 1975 and less than 800,000 bbls in 1976. Under stable conditions from 1970 to 1973 the rate of decline was 15 percent per year. For the base period 1975-1976 production had declined approximately 1,000 BOPD from January 1975 to October 1976. The projected decline from November 1975 is 25 percent per year; reserves are estimated to be 3.2 million bbls.

Eumont (Yates-Seven Rivers-Queen); rank 19, figs. 7 and 27.

This pool was created by the Oil Conservation Commission in 1953. Some of the acreage was once part of the Jalco and Langmat Pools (now Jalmat), and the pool includes the former Arrow and Hardy Pools. Also at the time of creation, vertical limits were restricted to the Yates, Seven Rivers, and Queen Formations, and an oil well was designated as having a gas:oil ratio of 100,000:1. The cumulative production is approximate.

The rate of decline under fairly stable conditions from 1958 to 1961 was 19 percent per year. At the current rate of 12 percent per year, from October 1975-October 1976 recoverable reserves are estimated to be 5.1 million bbls with an ultimate recovery of 69.3 million bbls. Waterflood projects first authorized in 1960 are considered to be responsible for 46 percent of the 1975 production of oil. Any possible expansion of these projects could result in increased production or a continuation of the current relatively low rate of decline for the pool.

Denton (Devonian); rank 20, figs. 6 and 28.

This pool was discovered in 1949. Cumulative production through 1975 was almost 90.2 million bbls. From the peak production of 7,983,995 bbls in 1955, the rate of decline has been a uniform 11 percent per year to 1974. In 1975 production increased slightly but the decline from October of that year through October 1976 has been at a 19 percent per year rate. When projected to the economic limit, reserves would total 3.7 million bbls. A return to the historic 11 percent decline results in reserves of 6.6 million bbls.

Shugart (Yates-Seven Rivers-Queen-Grayburg); rank 21, figs. 7 and 29.

Cumulative production includes data for the abolished Shugart (Queen-Grayburg) Pool. Although discovered in 1937, the pool consisted of only 29-37 producing wells through 1955. Beginning in 1956 the number of producing wells increased, reaching a high of 221 in 1964.

The first waterflood project was authorized in April 1952. Other projects were initiated between 1965 and 1973. These projects, along with extensive development drilling, have resulted in several production peaks typical of most waterflood operations. Under stable pool conditions from 1949 to 1951, the rate of decline was 22 percent per year. For the base period 1975-1976, average daily production reached a peak in May 1976. The rate of decline through October on a yearly basis is nine percent. Reserves estimated from this limited data base are 7.4 million bbls. Potential expansion of the waterflood programs could result in a nine percent or less rate of decline for several years. If conditions remain stable the rate should be significantly higher than nine percent.

Lovington (Abo); rank 22, figs. 6 and 30.

This pool was produced at allowable rates until 1963, when it began to decline. Under stable conditions from 1967-1970 the pool was depleted at a rate of 11 percent per year. The current rate of decline using data from September 1975 through October 1976 is at nine percent per year, indicating reserves of 7.3 million bbls with an ultimate recovery of 34.6 million bbls.

Denton (Wolfcamp); rank 23, figs. 6 and 31.

This pool was discovered in 1950 and reached peak production of 3,368,871 bbls from 95 wells in 1954. Under stable conditions production declined at a rate of 15 percent per year between 1955 and 1960. Additional completions and injection of water beginning in 1966 slowed this rate of decline. Based on average daily production from December 1975 through October 1976, the current rate of decline is 16 percent per year. When projected to the economic limit, reserves total 3.3 million bbls, with an ultimate recovery of 36.0 million bbls. Waterflooding was responsible for 45 percent of the oil produced in 1975; expansion of this project could result in increased production of oil.

Paduca (Delaware); rank 24, figs. 7 and 32.

Under stable primary conditions, recoverable oil was depleted at a rate of 13 percent per year from 1964 to 1967. The sharp decline in production in 1968 resulted from conversion of producing wells to water-injection wells. Waterflooding initiated in 1968 and expanded in 1969 resulted in peak production of 881,199 bbls in 1970. The current decline rate is 11 percent per year based on average daily production from December 1975-October 1976. At this rate of depletion, reserves are 5.1 million bbls with an ultimate recovery of 14.6 million bbls. Based on secondary oil produced in 1975, apparently the maximum waterflood development has been reached.

Loco Hills (Queen-Grayburg-San Andres); rank 25, figs. 7 and 33.

For the base period 1975-1976, peak production was 1,773 BOPD in January 1976. The projected yearly decline based on data through October is 37 percent per year, resulting in producible reserves of 1.4 million bbls with an ultimate recovery of 42.5 million bbls.

During primary production a relatively stable depletion period occurred from 1941 to 1953, with a yearly rate of decline of 12 percent. Under secondary recovery, establishing stable conditions for this pool is difficult because of new projects and expansion of existing projects. From 1967 to 1969 the rate of decline was 23 percent per year. Almost all of the oil produced at Loco Hills is considered secondary. If the 23 percent secondary decline represents stable conditions reserves would be about 2.0 million bbls.

Square Lake (Grayburg-San Andres); rank 26, figs. 7 and 34.

Under stable primary conditions from 1945 to 1950, production of oil declined at a rate of 21 percent per year. Additional completions, beginning in 1954, and the start of waterflooding in 1958 resulted in increased production with typical secondary peaks through 1970. From 1971 to 1973, under stable conditions, the rate of decline was 15 percent per year. Additional waterflood projects in 1973 and 1974 resulted in increased production to an estimated 621,228 bbls for 1976. Peak average daily production for the base period 1975-1976 was achieved in October 1976; the decline method used for most pools could not be applied in this case.

Secondary oil accounted for 87 percent of the 1975 production. Assuming that waterflooding has reached a maximum stage of development, the stable secondary decline rate of 15 percent was used to project reserves, suggesting 3.3 million bbls remaining for an ultimate recovery of 24.1 million bbls.

Artesia (Queen-Grayburg-San Andres); rank 27, figs. 7 and 35.

The Artesia Pool was discovered in 1923. Prior to 1941 cumulative production of oil was 4,477,955 bbls. The Nichols Pool was combined with Artesia in 1950 and is included in the earlier yearly production data. Extensive development drilling from 1945-1957 led to a considerable increase in the production of oil. Water injection was started in 1957; peak production for the pool of 1,078,115 bbls was reached in 1961. New water-flood projects and continued expansion of preexisting projects has resulted in an overall low rate of decline of five percent per year from 1961 to 1975. Secondary production peaks occurred in 1965, 1969, and possibly in 1976. Estimated production for 1976 is 656,204 bbls, about 100,000 bbls above 1975 production. For the base period 1975-1976 peak average daily production was 1,877 BOPD in May 1976, declining to 1,754 BOPD by October 1976. This decline suggests that increased secondary oil production peaked in 1976 and, under current conditions, will decline in 1977. Apparently stable secondary depletion occurred from 1961-1963. The rate of decline for this period was 15 percent per year. The current rate of decline from May-October 1976 is 14 percent per year. At this rate, reserves total 3.3 million bbls of oil with ultimate recovery of 25.6 million bbls.

Paddock; rank 28, figs. 6 and 36.

A stable primary depletion of 14 percent per year was established from 1949-1958. Development drilling, begun in 1960, led to increased production until 1963 and a low rate of decline through 1969. A small waterflood project started in 1969 apparently was partly responsible for the increase in production of oil to 604,160 bbls in 1973. Production has since declined to 542,903 bbls in 1975 and is estimated at 486,991 bbls for 1976. Based on average daily production from May 1975 to October 1976, the current rate of decline is 14 percent per year, indicating reserves of 2.8 million bbls.

In 1975 secondary oil accounted for only six percent of the oil produced at Paddock. Although the success of the current program has not been analyzed, expansion of this program to other parts of the pool could lead to increases in production in the future.

Chaveroo (San Andres); rank 29, figs. 7 and 37.

This pool was discovered in 1965. Peak production was reached two years later at 4,199,843 bbls from 345 wells. For the base period 1975-1976 the highest production was 1,717 BOPD in December 1976. Waterflooding initiated in 1968 involves only a small portion of the pool; in 1975 it accounted for just slightly over six percent of the production. The increase estimated for 1976 is the result of additional wells completed in the pool. In the absence of a current rate of decline, the decline of 24 percent per year for the stable period from 1967-1975 was used, indicating reserves of 1.7 million bbls.

Wantz (Granite Wash); rank 30, figs. 7 and 38.

This pool was discovered in 1963 with the completion of two wells. Additional drilling was not done until 1972 when two more wells were completed. In 1973 the East Brunson (Granite Wash) Pool was abolished and its three wells included in the Wantz Pool. Fifteen additional wells were drilled in 1973. Development drilling has continued at a rapid pace since 1973, and there were 49 producing wells at the end of 1975. Production in 1975 was 500,373 bbls; the estimated production for 1976 is 658,723 bbls. The recent development of the pool and the corresponding increase in production precludes the use of the methods applied in evaluating most of the other fields. Instead, the rate of decline for the two wells completed in the Wantz Pool in 1963 was used to project future production, assuming that 1976 represents the peak production. In November 1976, the pool had 56 producing wells compared with 49 at the end of 1975. The limits of the pool may not be defined; therefore, production could continue to increase. Recoverable reserves from the two-well decline rate of 15 percent are 4.0 million bbls with an ultimate recovery of 5.3 million bbls.

Eunice, South (Seven Rivers-Queen); rank 31, figs. 7 and 39.

The shifting of wells between South Eunice, Eumont, and Eunice-Monument and category changes in wells from oil to gas complicate discussion of this pool. Reported cumulative production does not correspond with yearly production figures.

Peak production was 1,433,431 bbls in 1958. A yearly decline followed until 1974 when production increased as a result of waterflood programs initiated in 1970. Production for 1973 declined to 161,568 bbls of oil from 167 wells. By 1975 production had increased to 500,137 bbls from 166 wells; the estimated production for 1976 is 747,271 bbls. In 1975 waterflooding accounted for 88 percent of the oil produced at South Eunice.

A good stable-condition rate of decline could not be established. From yearly declines for the period from 1958 to 1973, the pool was depleted at a rate of 14 percent per year. Using this rate and assuming a production peak in 1976, the recoverable reserves would be 4.7 million bbls, with an ultimate recovery of 27.8 million bbls. Potential additional waterflood programs or extensions of current programs could lead to further, although probably lower, peak periods of production. However, a stable-condition rate of decline probably would be closer to 20 percent per year.

Horseshoe (Gallup); rank 32, figs. 8 and 40.

Peak primary production was 4,464,269 bbls of oil in 1960. Waterflooding was started in this year, but production continued to decline until the program was expanded in 1963; and a secondary peak of 3,643,993 bbls was reached in 1965. By 1974 production had declined to 488,519 bbls. Additional wells completed in 1975 and 1976 stabilized production, and the highest amount of oil produced for the base period was 1,456 **BOPD** in September 1976. Using the historic decline rate of 19 percent per year from 1965-1974, reserves are estimated to be 2.0 million bbls.

Corbin (Abo); rank 33, figs. 6 and 41.

Based on the average daily production from a peak in November 1975 of 1,590 bbls of oil to 1,196 bbls in September 1976, the current rate of decline is 27 percent. The 838 BOPD for October 1976 was not used because it was not considered representative of well capacities. At the current rate of decline, reserves are 1.5 million bbls, with an ultimate recovery of 13.3 million bbls. The stable-condition rate of decline from 1966-1974 is 13 percent, indicating reserves of 3.1 million bbls and an ultimate recovery of **14.9** million bbls. From a low of 348,107 bbls in 1974, production has increased to 445,150 bbls in 1975 and an estimated 453,754 bbls in 1976. These increases resulted from additional well completions in 1975 and 1976.

Hobbs (Blinebry); rank 34, figs. 6 and 42.

This pool was discovered in 1968 and reached peak production of 695,064 bbls of oil from 31 wells in 1970. Oil produced in 1975 amounted to 431,011 bbls from 27 wells; the estimated production for 1976 is 359,728 bbls. The current yearly rate of decline for the base period 1975-1976 is 17 percent. Reserves at this rate of depletion are 1.9 million bbls and the ultimate recovery is 5.6 million bbls. Under apparently stable conditions from 1970-1975 the rate of decline was nine percent per year, indicating reserves of 3.7 million bbls. A nine percent decline is considered too low for a pool of this type; the rate will probably be closer to the current 17 percent decline.

Flying M (San Andres); rank 35, figs. 7 and 43.

Discovered in 1964, peak production of 524,809 bbls of oil was reached in 1965. A waterflood program, started in 1965, was considered to be responsible for 61 percent of the oil produced in 1975. Yearly fluctuations in production closely reflect the number of producing wells. Where conditions remain relatively stable, the decline averages 12 percent per year. The current decline of 10 percent per year is based on average daily production from January 1975 to October 1976, indicating reserves of 3.2 million bbls with an ultimate recovery of 8.1 million bbls.

Hospah, South (Lower Sand); rank 36, figs. 8 and 44.

Waterflooding was started in 1972 and expanded in 1974. Production of oil has been fairly stable since 1970; peak average daily production for the base period was 1,237 bbls in June 1975. The projected rate of decline since then has been 10 percent per year, indicating reserves of 3.5 million bbls.

Pearl (Queen); rank 37, figs. 7 and 45.

Maximum primary production was reached in 1961 at 1,069,198 bbls of oil. Production was only slightly less in 1962, with an additional 14 wells in the pool. Under stable conditions from 1962-1964 the primary depletion rate was 19 percent per year. Waterflooding was initiated in 1964 and production rapidly increased to a high of 2,290,100 bbls in 1967. From 1967 to 1974 the decline was uniform despite the start of additional waterflood projects in 1968 and 1969. The rate of depletion for this period was 22 percent per year. The current decline rate of 20 percent per year is based on average daily production from January-October 1976. At this rate of depletion reserves are 1.5 million bbls with an ultimate recovery of 19.1 million bbls.

Bronco (Silurian-Devonian); rank 38, figs. 6 and 46.

This pool was discovered in 1953. Peak production was reached in 1956 at 802,714 bbls of oil. Oil was produced at near-allowable levels until decline began in 1965. Based on average daily production from August 1975 to October 1976, the current rate of decline is 26 percent per year. At this rate of depletion, reserves would be 1.2 million bbls. From past history, this projection appears to be too low. The rates of decline under stable conditions from 1965 to 1970 and 1973 to 1976 were 11 percent and 14 percent respectively, resulting in reserves of 2.3 million bbls. The water:oil ratio has increased from 1.5:1 in 1973 to 3.0:1 in 1975; one well currently has a water:oil ratio of 25.8:1. It is likely that some of the remaining eight wells will be shut in in the near future, and the decline rate for the pool will be higher than the 11 percent or 14 percent but lower than the present rate.

Bagley (Silurian-Devonian); rank 39, figs. 6 and 47.

Although not undergoing as steep a production decline as the Bronco Pool, the Bagley Pool is similar in having a rapidly increasing water:oil ratio. At Bagley, from 1972-1975, the ratio has increased from 6.6:1 to 11.3:1. Oil production also increased during the same period, but was somewhat offset by an estimated 24 percent decline for 1976. The stable rate of decline from 1967-1972 was 21 percent per year. The current decline projection of 18 percent is from data for the 15-month period beginning August 1975, indicating reserves of **1.5** million bbls of oil.

Dollarhide (Devonian); rank 40, figs. 6 and 48.

The current rate of decline, based on average daily production from July 1975 to October 1976, is 11 percent per year. Peak production for the pool was 504,266 bbls of oil in 1973, declining to 345,801 bbls in 1975 and an estimated 323,612 bbls for 1976. The average yearly decline since 1973 has been 13 percent. Waterflooding initiated in 1962, increases in allowables beginning in 1965, and development drilling in 1972 are responsible for the increased production from the low of 1964. The stable-condition primary rate of decline from 1958-1962 was 30 percent per year. The current decline rate of 11 percent indicates reserves of 2.8 million bbls with an ultimate recovery of 8.2 million bbls. Waterflooding was credited with 90 percent of the 1975 production. The rate of secondary depletion is expected to increase if present conditions remain stable.

Dollarhide (Tubb-Drinkard); rank 41, figs. 7 and 49.

This pool was discovered in 1951 and reached peak production of 1,597,000 bbls of oil in 1956, with 77 producing wells. Additional drilling in 1956 resulted in a slow rate of decline through 1957. Under stable primary producing conditions through 1966, the rate of decline averaged 18 percent per year. Waterflooding was initiated in 1969 and production of oil was increased to 398,292 bbls in 1973.

For the base period 1975-1976 the highest average daily production was 1,055 bbls in January 1976. The projected rate of decline through October is 20 percent per year, indicating reserves of 1.5 million bbls with an ultimate recovery of 16.7 million bbls.

Baum (Upper Pennsylvanian); rank 42, figs. 6 and 50.

This pool was discovered in 1955 but consisted of either one or two wells until 1968, when 10 wells were completed and two others added from the abolished Baum (Wolfcamp) Pool. Development drilling resulted in 30 producing wells and a peak production of 1,505,159 bbls of oil in 1970. Oil production then declined at a rate of 29 percent per year to 322,439 bbls in 1975. Estimated production for 1976 is 309,098 bbls.

Peak production for the current base period 1975-1976 was in February 1975 at an average of 1,024 BOPD. The current decline through October 1976 is at a rate of five percent per year, indicating reserves of 5.3 million bbls and an ultimate recovery of **11.6** million bbls. Under stable pool conditions this low rate of decline probably cannot be maintained.

Puerto Chiquito, West (Mancos); rank 43, figs. 8 and 51

In 1966 the Puerto Chiquito (Mancos) Pools were separated into east and west areas. Gas injection started in West Puerto Chiquito in **1968.** Along with establishment of suitable locations for producing wells to take advantage of gravity drainage, the gas injection resulted in increased production to 777,573 bbls of oil in 1971. Production has since declined at a rate of 19 percent per year to 321,875 bbls in 1975. The rate of decline was much lower in 1976, with an estimated production of 309,621 bbls.

Average daily production was fairly uniform for the base period 1975-1976. The projected rate of decline is six percent per year, indicating producible reserves of almost 5.0 million bbls. If the rate of decline returns to 19 percent, projected reserves would be reduced to **1.4** million bbls.

Moore (Devonian); rank 44, figs. 6 and 52.

Discovered in 1952, the pool had a high of 19 producing wells completed by 1955. Peak production of 1,235,240 bbls of oil was reached the following year. The amount of oil produced from 1956-1967 reflects allowables. A stable primary rate of decline of 21 percent per year began in 1971 when 865,143 bbls were produced and continued to 1976 when an estimated 256,866 bbls were produced. Peak average daily production for the base period was 988 bbls in February 1975. The projected yearly rate of decline is 18 percent per year, indicating reserves of 1.4 million bbls and an ultimate recovery of 21.9 million bbls.

Lovington (Paddock); rank 45, figs. 6 and 53.

Discovered in 1952, rapid development led to a peak production of 1,281,121 bbls of oil from 84 wells in 1955. The decline that followed was temporarily offset by development drilling in 1964-1965. A waterflood program was started in 1966 and additional injection wells were added in 1968, 1971, 1973, and 1974. Secondary oil accounted for 78 percent of the production in 1975. If the program remains at the present level, production is expected to decline in 1977.

The average daily production for the base period 1975-1976 has been fairly uniform. The highest production was in February 1976, but the projected yearly decline (with data through October 1976) is only one percent. The projection of remaining reserves is based on the assumptions that decline will begin in 1977 at the stable primary rate of decline of 16 percent that occurred from 1955 to 1963. This indicates reserves of 1.5 million bbls and an ultimate recovery of 13.0 million bbls.

Penrose-Skelly (Grayburg); rank 46, figs. 7 and 54.

The Penrose and Skelly Pools were combined in 1945. In 1956 more than half the wells assigned to this pool were transferred to Langlie-Mattix. Peak production under pool conditions since 1956 has been 386,040 bbls of oil in 1972. Production has since declined to 305,234 bbls of oil in 1975 and an estimated 258,934 bbls of oil for 1976. Waterflooding under the present limits of the pool began in 1965; additional projects were initiated in 1973 and 1974. Secondary oil is credited with only nine percent of the 1975 production. The addition of a number of producing wells between 1969 and 1975 appears to be responsible for periods of increased production and the rather low rate of decline from 1972 to 1975. Estimated recoverable reserves are based on the average daily production from October 1975 to October 1976. When projected, these data give a rate of decline of 21 percent per year, indicating reserves of 0.9 million bbls.

Hospah, South (Upper Sand); rank 47, figs. 8 and 55.

With the introduction of waterflooding and with additional producing wells, production reached a peak of 498,878 bbls of oil in 1970. Additional completions through 1972 insured fairly uniform production. Stable pool conditions have resulted in a steep decline from 406,002 bbls in 1974 to an estimated 213,168 bbls in 1976. To calculate producible reserves at the current rate of decline, the average daily production from September 1975 to October 1976 was used. Peak production for the base period occurred in February 1975, but the rate of decline through June 1975 was steeper than the decline has been from September 1975. At a 25 percent rate of depletion, reserves are estimated at 0.7 million bbls or 18 percent of the calculated ultimate recovery for the pool.

Caprock (Queen); rank 48, figs. 7 and 56.

Various discovery dates have been assigned to Caprock, but the first recorded production from the presently defined limits of the pool was in 1941. Apparently, oil was not produced in 1942 and 1943. Development began in 1944 when six additional wells were completed. The number of producing wells increased to 128 in 1950 and remained approximately at this level through 1953. Under fairly stable pool conditions from 1949 to 1953, the primary decline rate was 29 percent per year. From 121 wells in 1953, the number of producing wells increased to 584 in 1956, partly as the result of extensive development drilling and partly through the inclusion into Caprock of the area of the North Caprock (Queen) and Drickey (Queen) Pools. The peak primary production was 5,108,791 bbls in 1956. Waterflood projects are shown for the year they were approved. Six of the total of 16 approved projects were still active at the end of 1975; these accounted for 90 percent of the oil produced in that year. As a result of the various waterflood projects, production remained fairly uniform through 1965 with a peak of 6,203,282 bbls in 1964. Projects approved in 1968 and 1972 are not currently active. Under stable pool conditions from 1965 to 1976, the secondary decline rate has been 26 percent per year.

The base period used to calculate the current decline of 16 percent per year was December 1975-October 1976. Production for this period has been erratic and needs to be checked against the final adjusted figures. Reserves are estimated at 1.1 million bbls, with an ultimate recovery of 72.3 million bbls.

Cato (San Andres); rank 49, figs. 7 and 57.

Maximum yearly production was 3,519,747 bbls of oil in 1968, two years after discovery of the pool. Waterflooding initiated in 1968 has been on a small scale and, from a pool standpoint, has not been reflected in the yearly production data. In 1975, 22 percent of the oil produced at Cato was considered secondary.

Peak production for the base period 1975-1976 was in September 1976. The slight increase in production for 1976 was the result of a number of new completions during the year. Under stable conditions from 1968 through 1975, the rate of decline was 33 percent per year. The new wells completed in 1976 can be expected to decline at approximately the same rate as the older wells. In projecting reserves, the historic decline rate of 33 percent per year was used, with the assumption that conditions will remain uniform. At this rate of depletion, reserves are 0.6 million bbls with an ultimate recovery of about 14.0 million bbls.

Sawyer, West (San Andres); rank 50, figs. 7 and 58.

The peak production of 294,816 bbls in 1974 was followed by a decline to 284,277 bbls in 1975, and an estimated 244,985 bbls for 1976. With minor fluctuations, the average daily production for the base period 1975-1976 has declined from 867 bbls in January 1975 to 681 bbls in October 1976. When projected, this data represents a yearly rate of decline of 14 percent and indicated reserves of 1.6 million bbls.

Since the discovery of West Sawyer in 1968, some development drilling has been done each year. The limits of the pool are not presently defined and additional drilling may perpetuate the present low rate of decline for several years. Once stable pool conditions are reached, the rate of depletion may be somewhat greater than the current 14 percent.

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6

Appendix

Graphs showing production and estimated reserves for the 50 largest oil pools in New Mexico

FIGURES 9-58 (symbols and abbreviations on next page)

EXPLANATION FOR FIGURES 9-58

Symbols and abbreviations

⊙	waterflood projects
☼	gas injection
⊠	air injection
E.L.	economic limit
C.D.R.	current decline rate
P.D.R.	primary decline rate
S.D.R.	secondary decline rate
H.D.R.	historic decline rate
BO	barrels of oil
GOR	gas:oil ratio

Notes

Asterisks on curves indicate years between which decline rates were calculated.

Inserts on figs. 9-58 indicate economic limit (where decline curve extends beyond original grid) and average daily production.

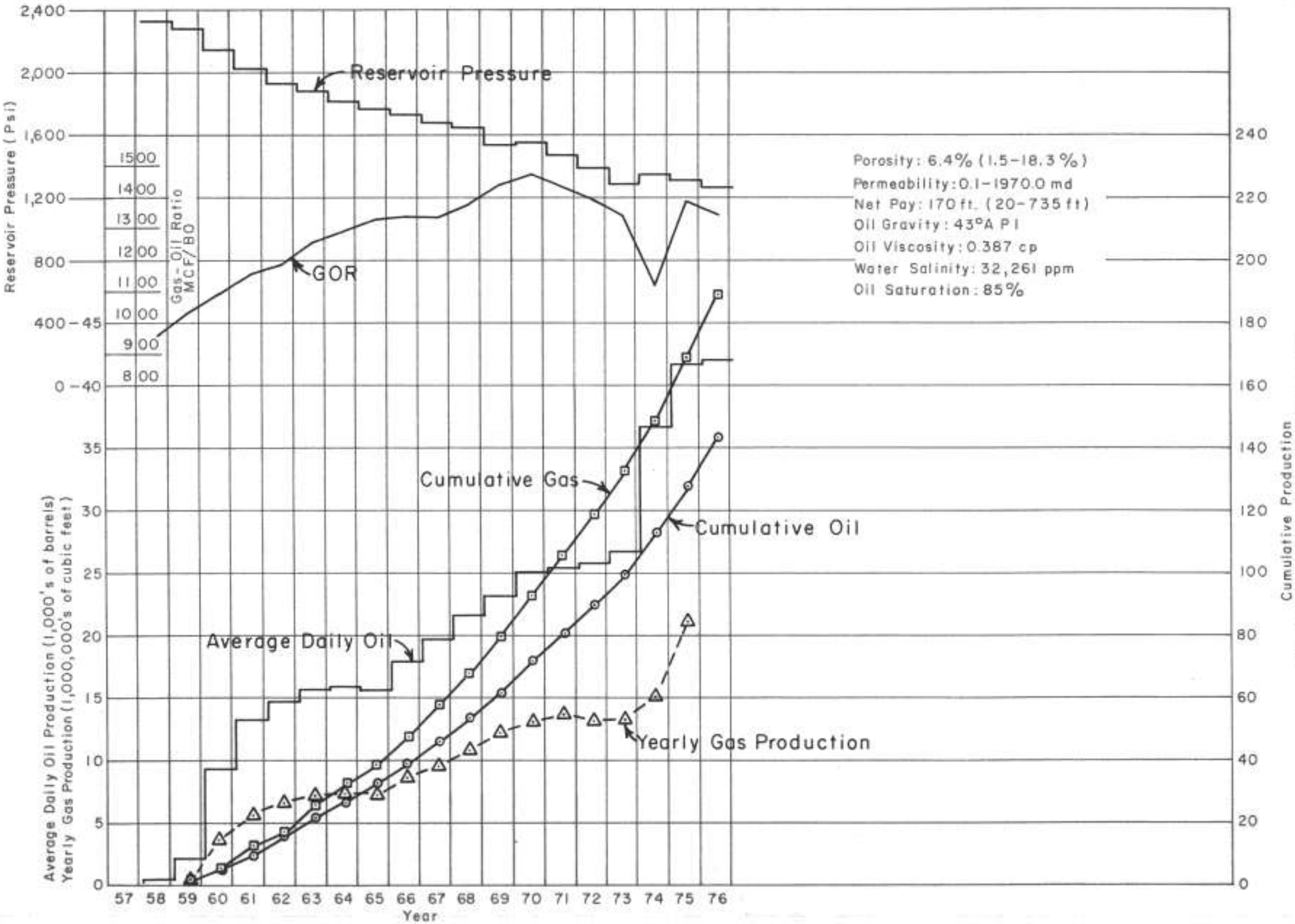

FIGURE 9—EMPIRE (ABO) POOL. (Abbreviations: md, millidarcies; cp, centipoise; ppm, parts per million; psi, pounds per square inch.)

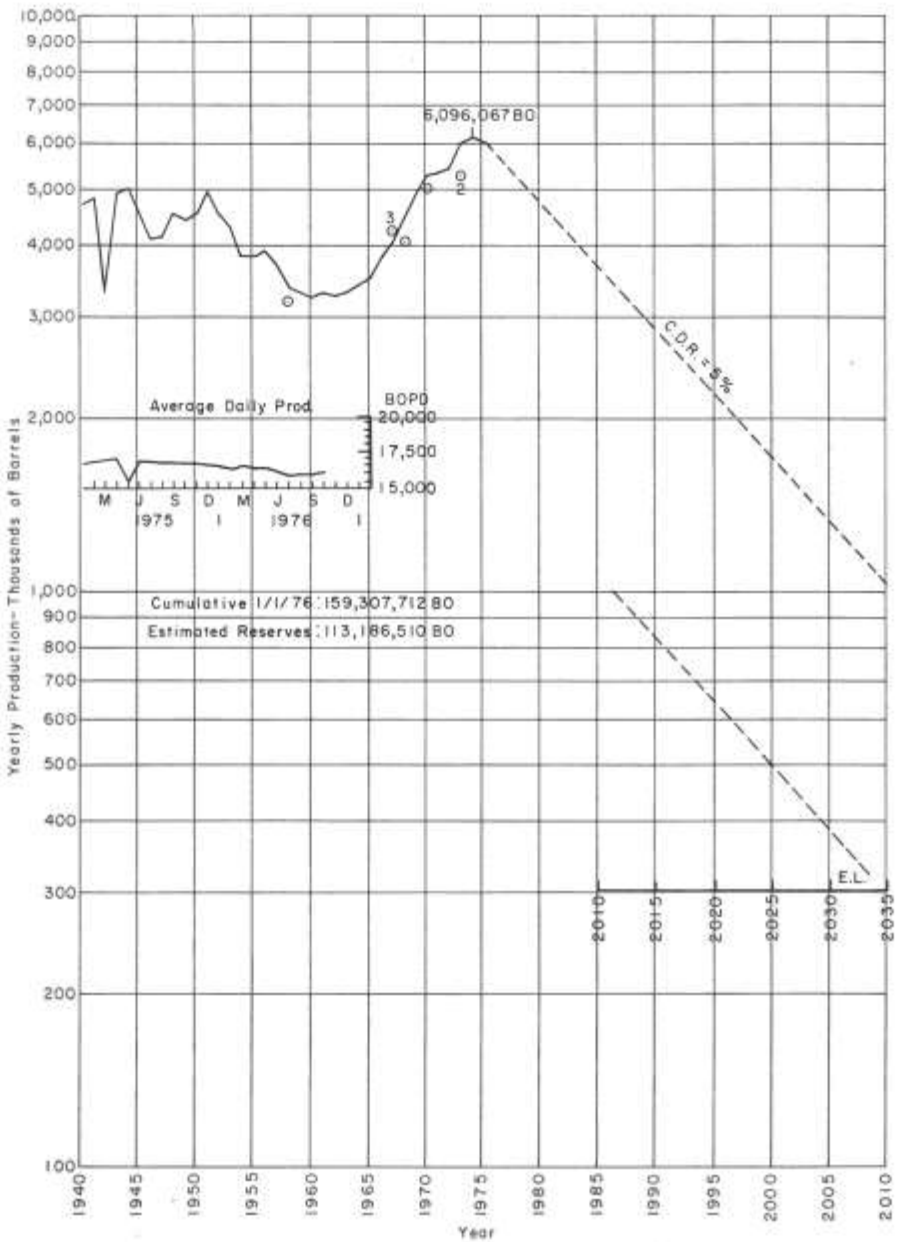

FIGURE 10—VACUUM (GRAYBURG-SAN ANDRES) POOL.

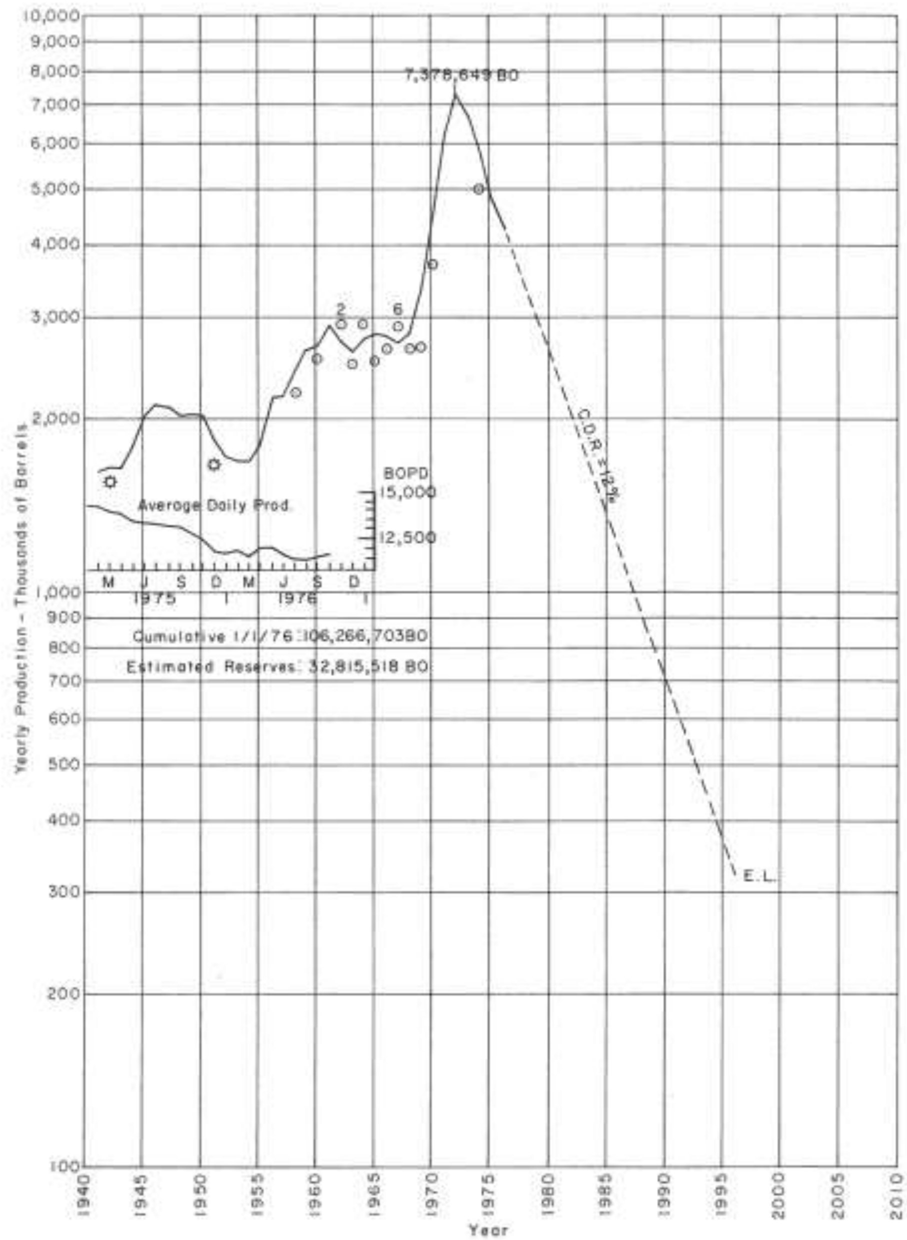

FIGURE 11—MALJAMAR (GRAYBURG-SAN ANDRES) POOL.

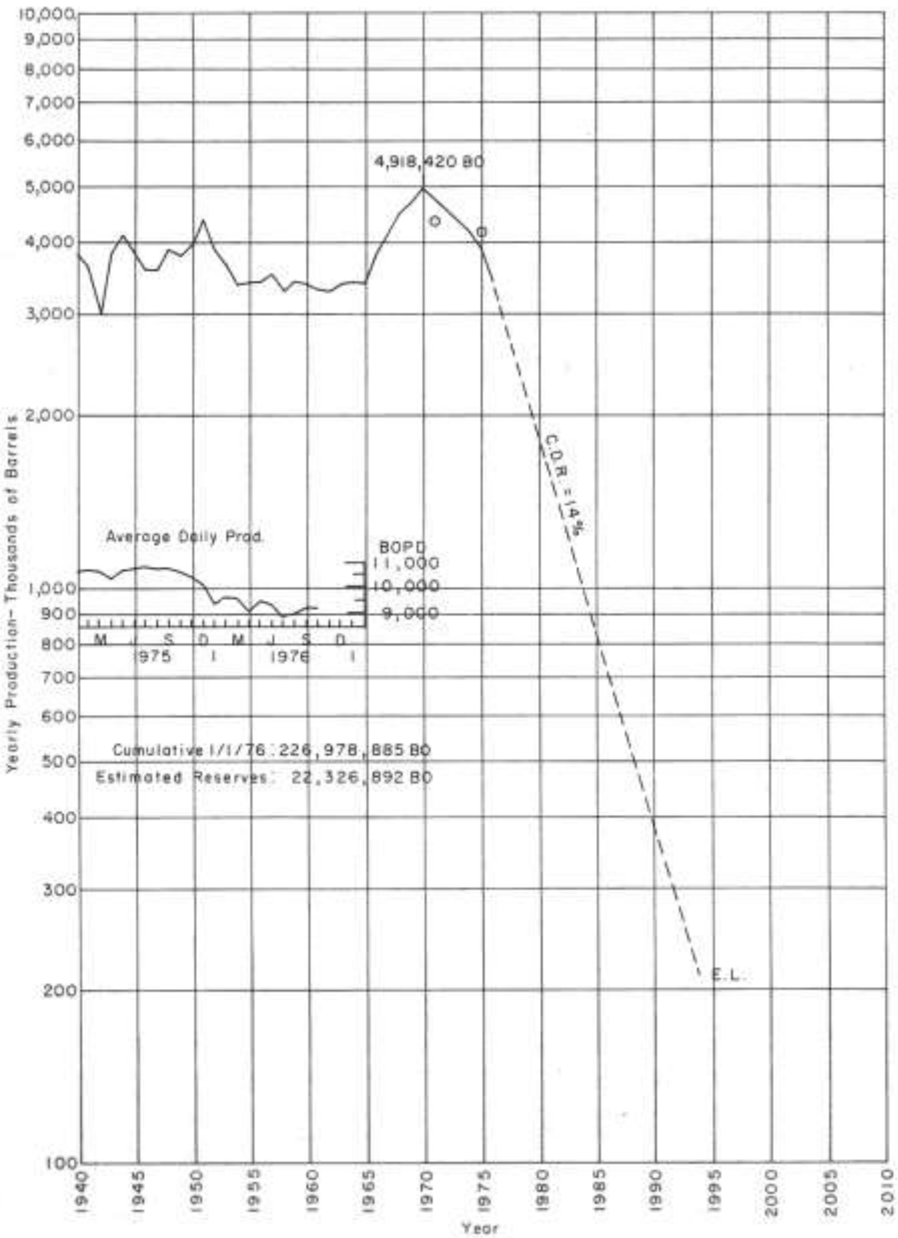

FIGURE 12—HOBBS (GRAYBURG-SAN ANDRES) POOL.

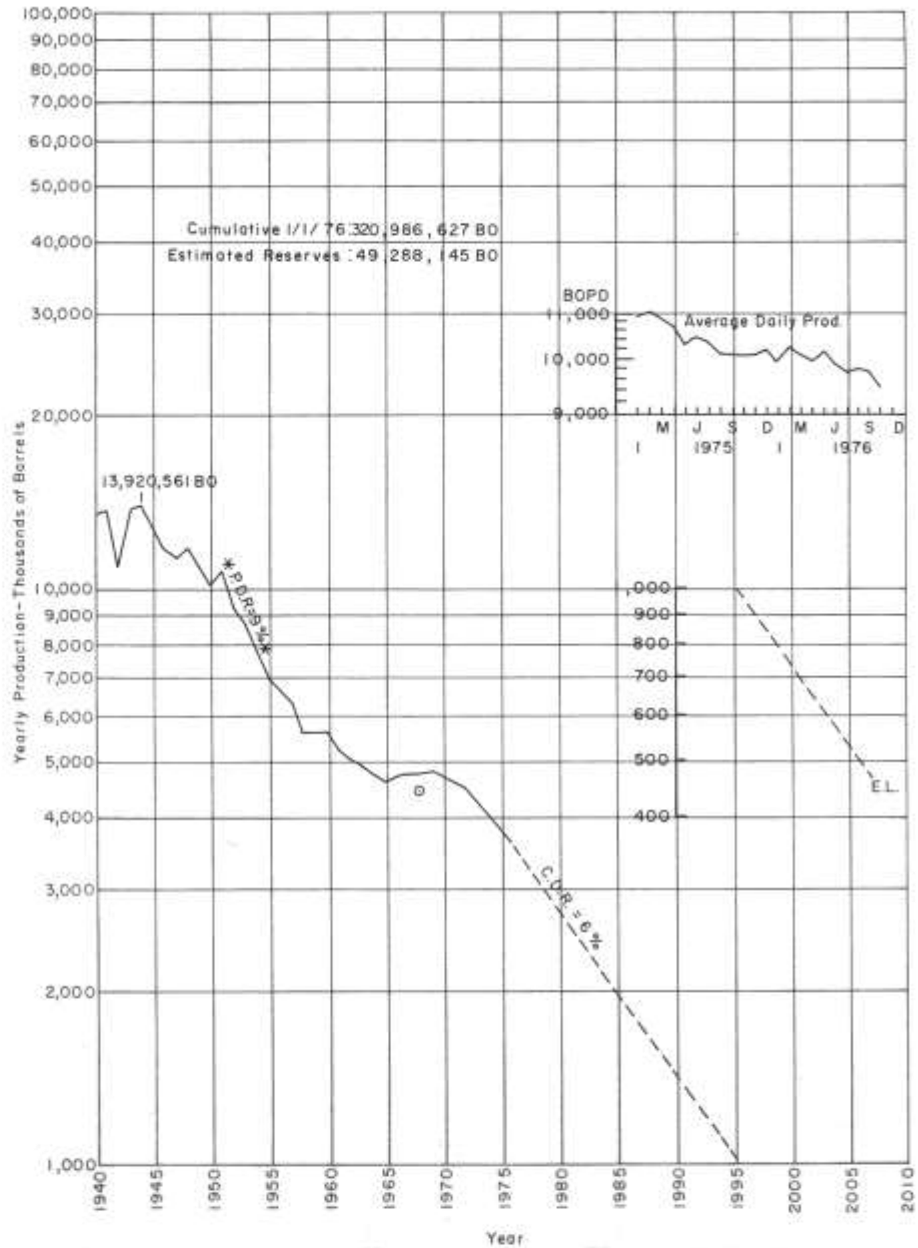

FIGURE 13—EUNICE-MONUMENT (GRAYBURG-SAN ANDRES) POOL.

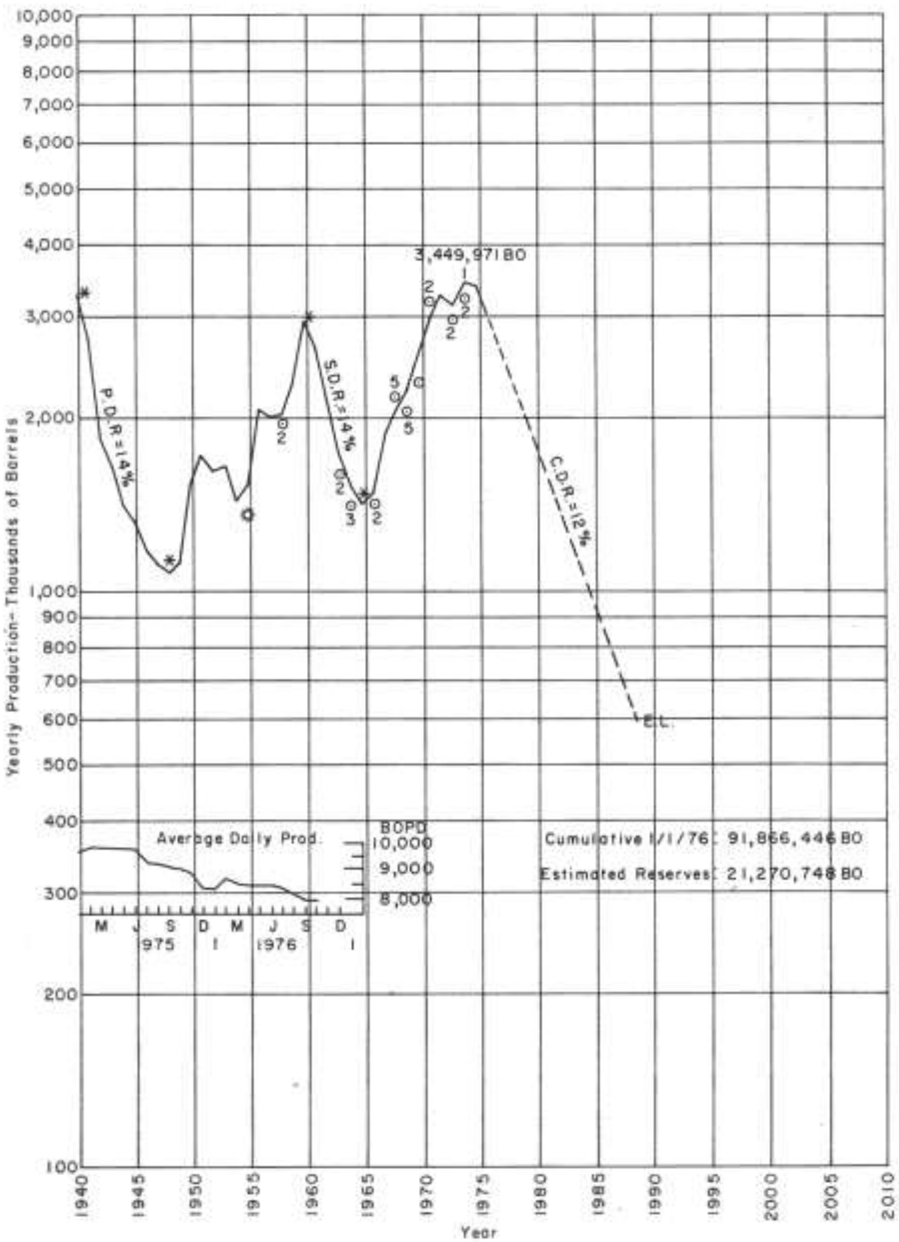

FIGURE 14—LANGLIE-MATTIX (YATES-SEVEN RIVERS-QUEEN) POOL.

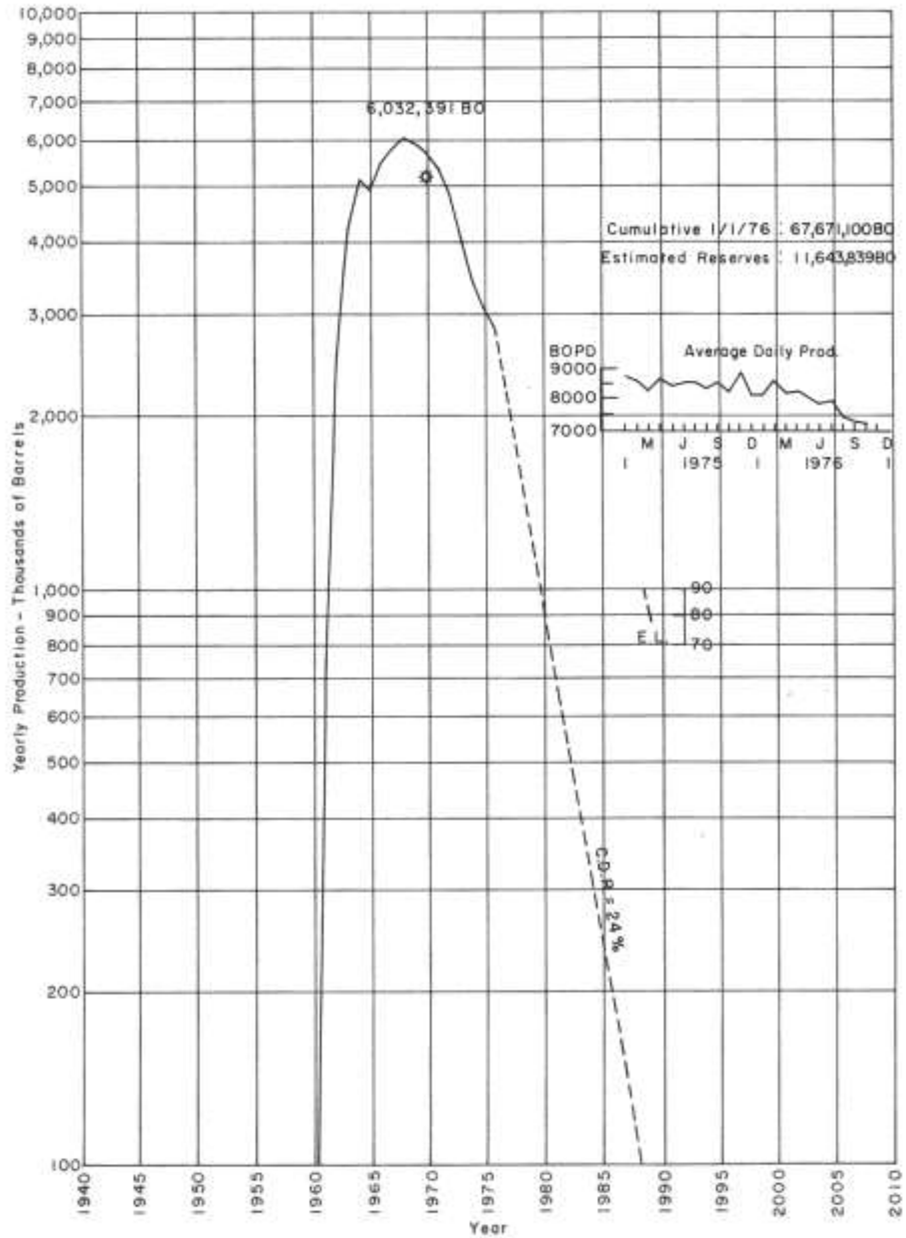

FIGURE 15—VACUUM (ABO REEF) POOL.

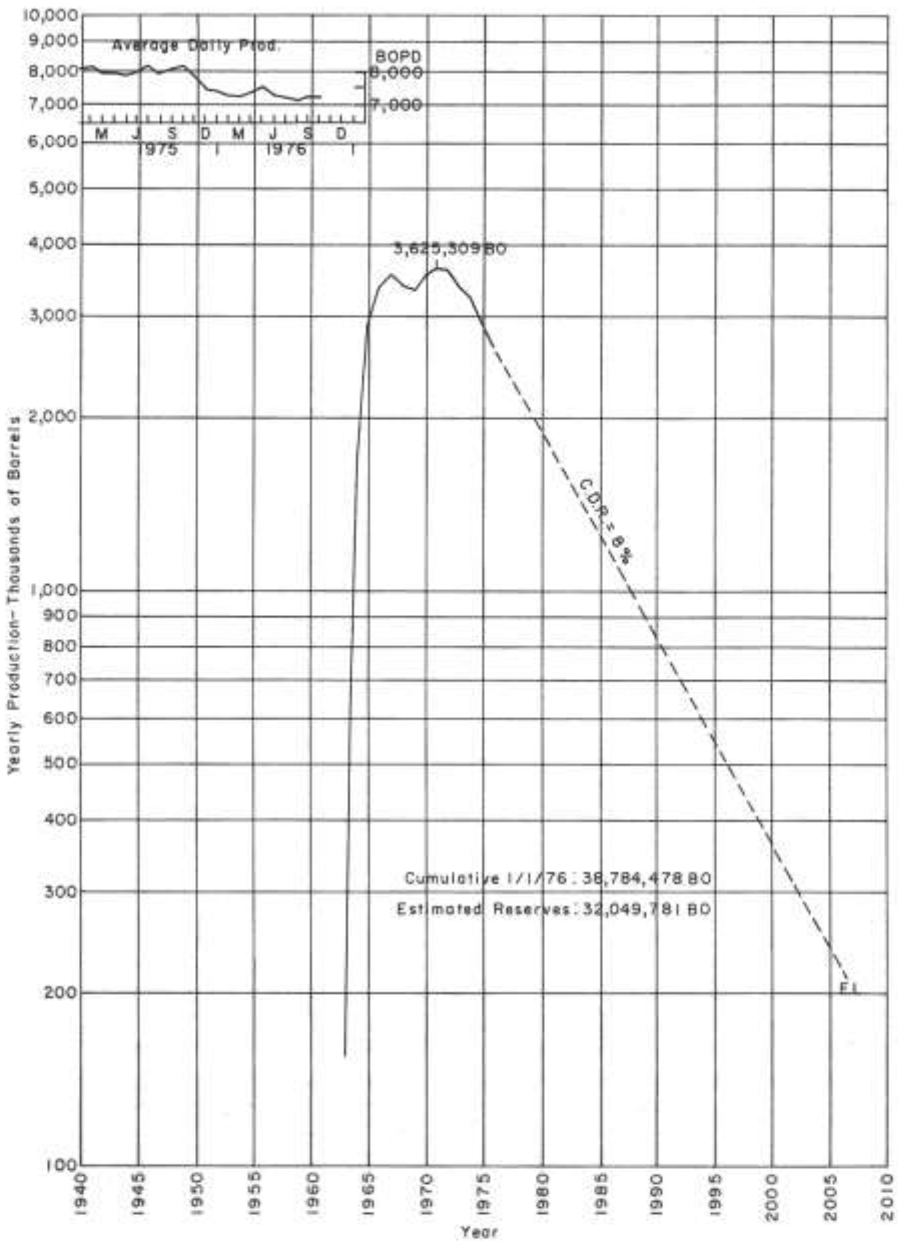

FIGURE 16—VACUUM (GLORIETA) POOL.

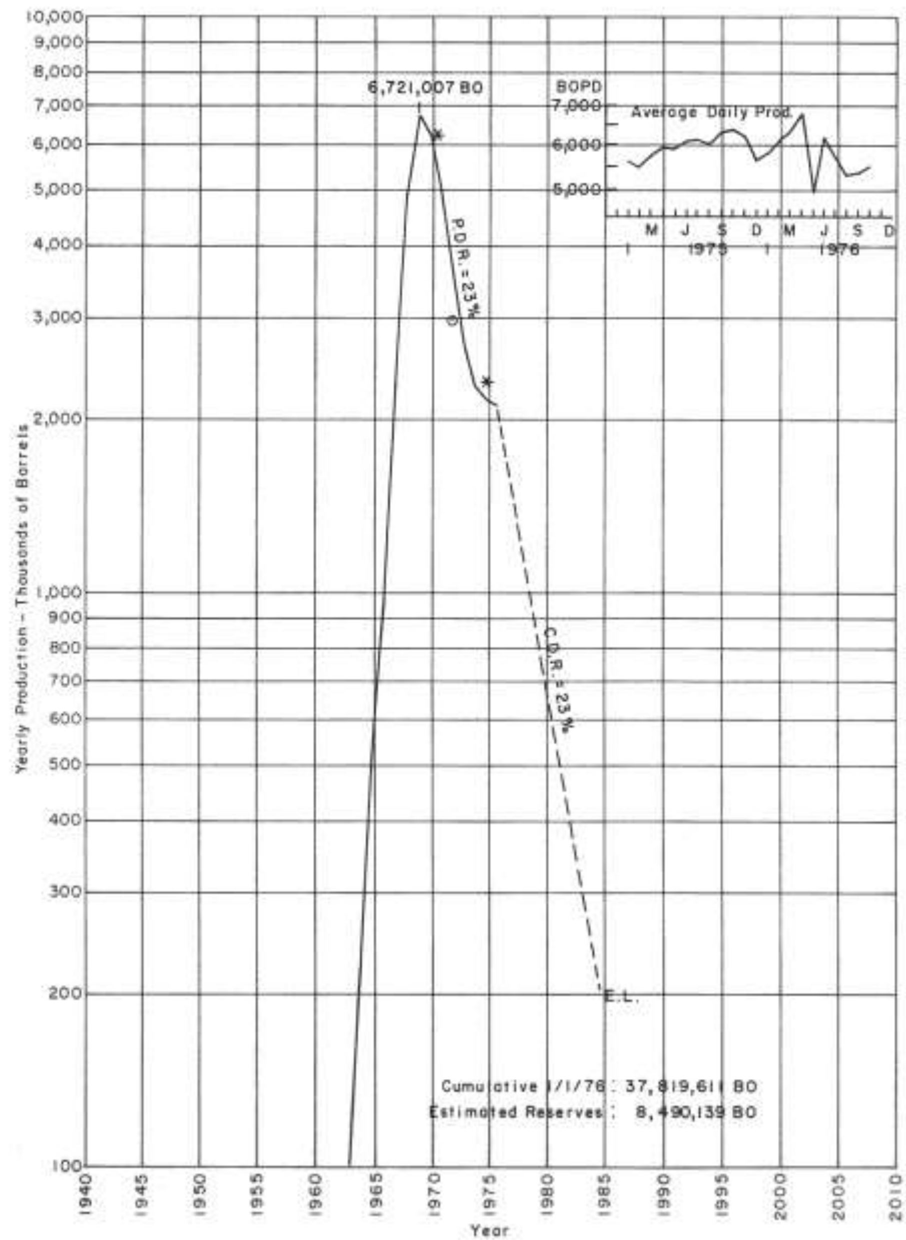

FIGURE 17—BAGLEY, NORTH (PENNSYLVANIAN) POOL.

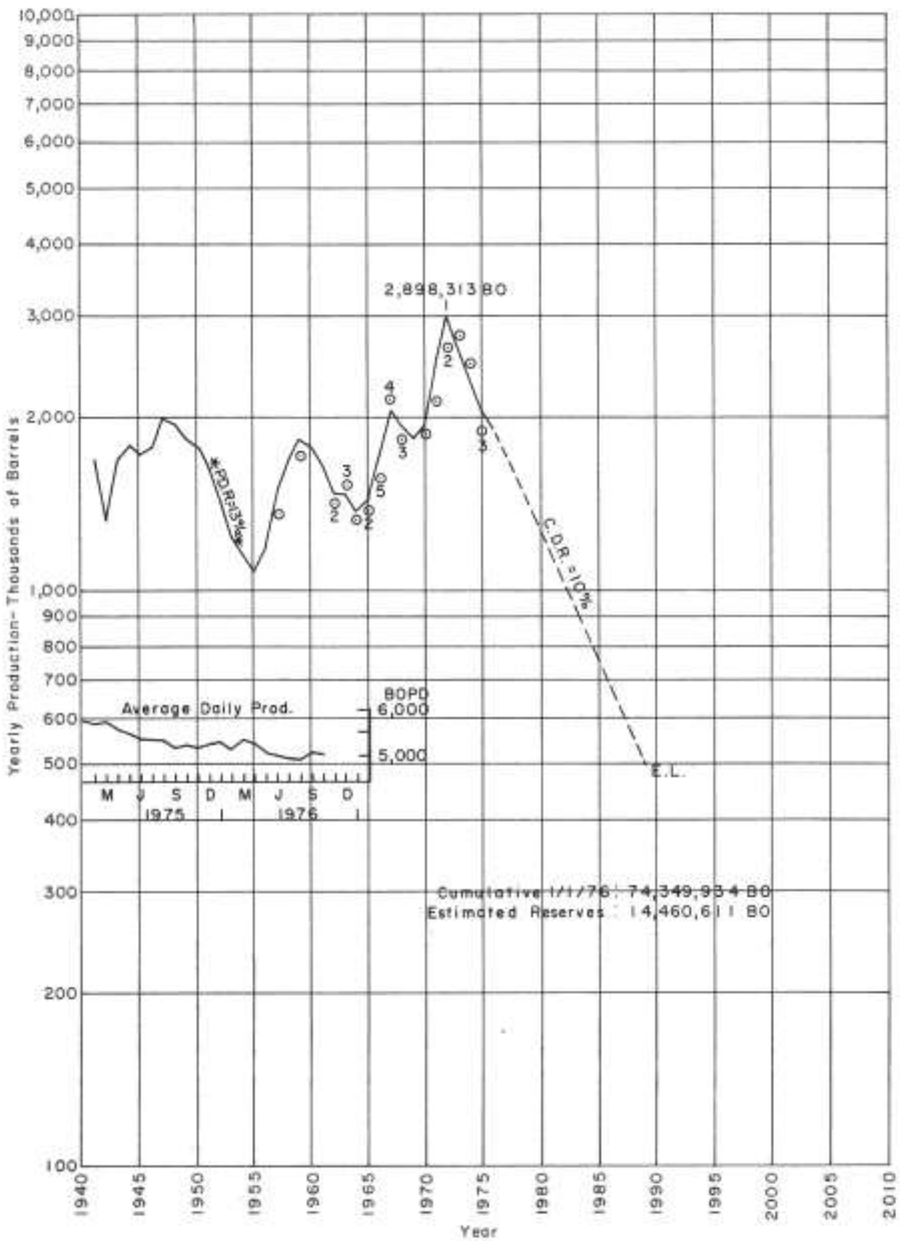

FIGURE 18—GRAYBURG-JACKSON (QUEEN-GRAYBURG-SAN ANDRES) POOL.

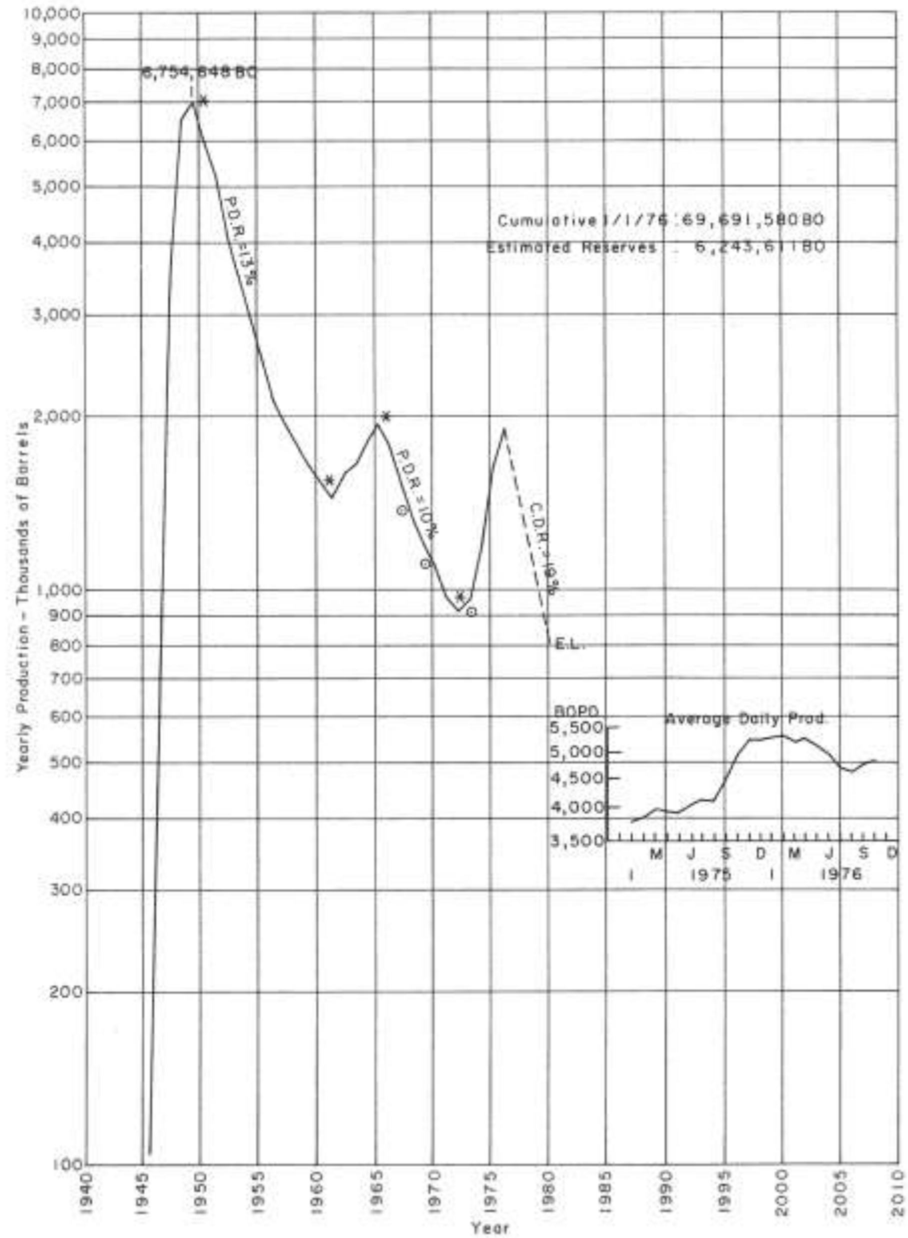

FIGURE 19—DRINKARD POOL.

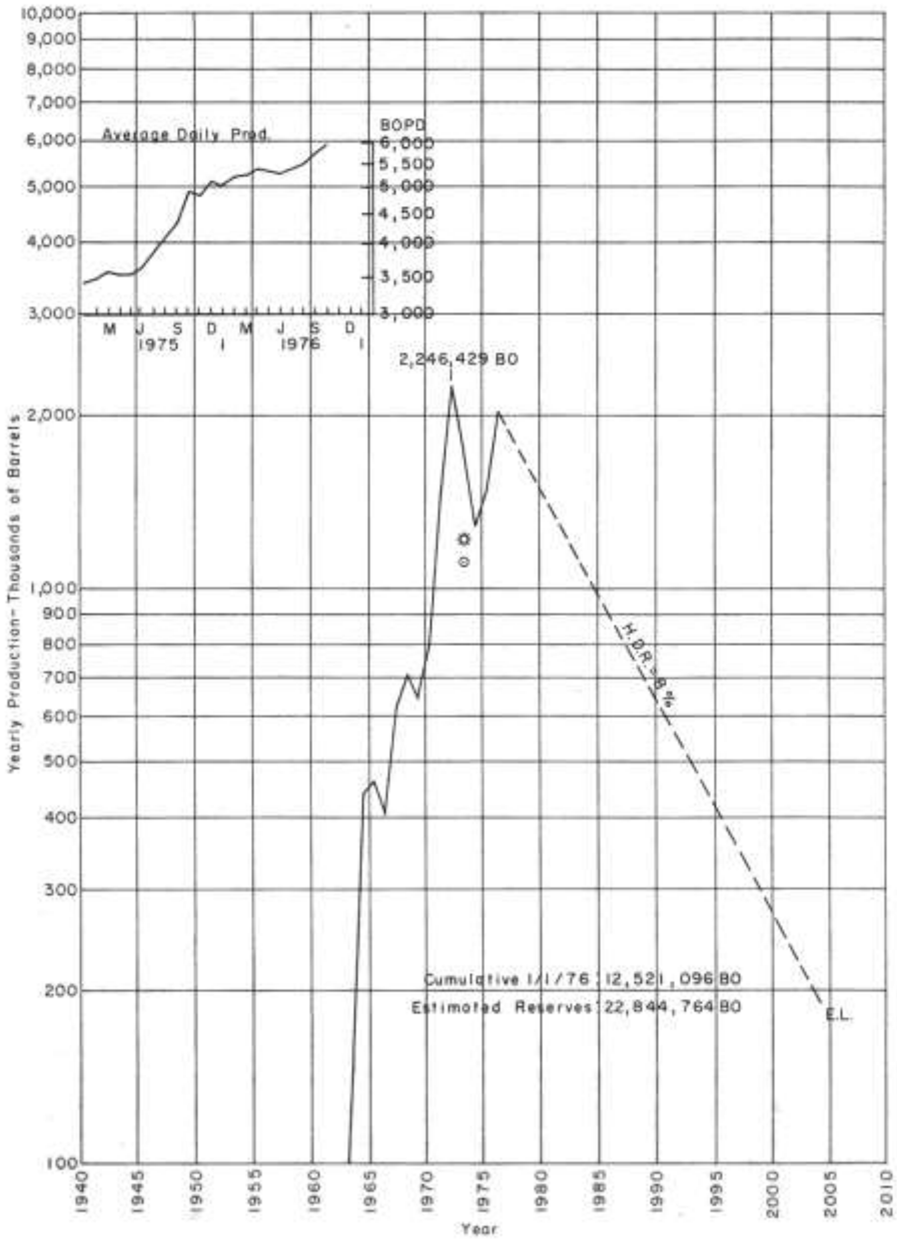

FIGURE 20—Vacuum, North (Abo) Pool.

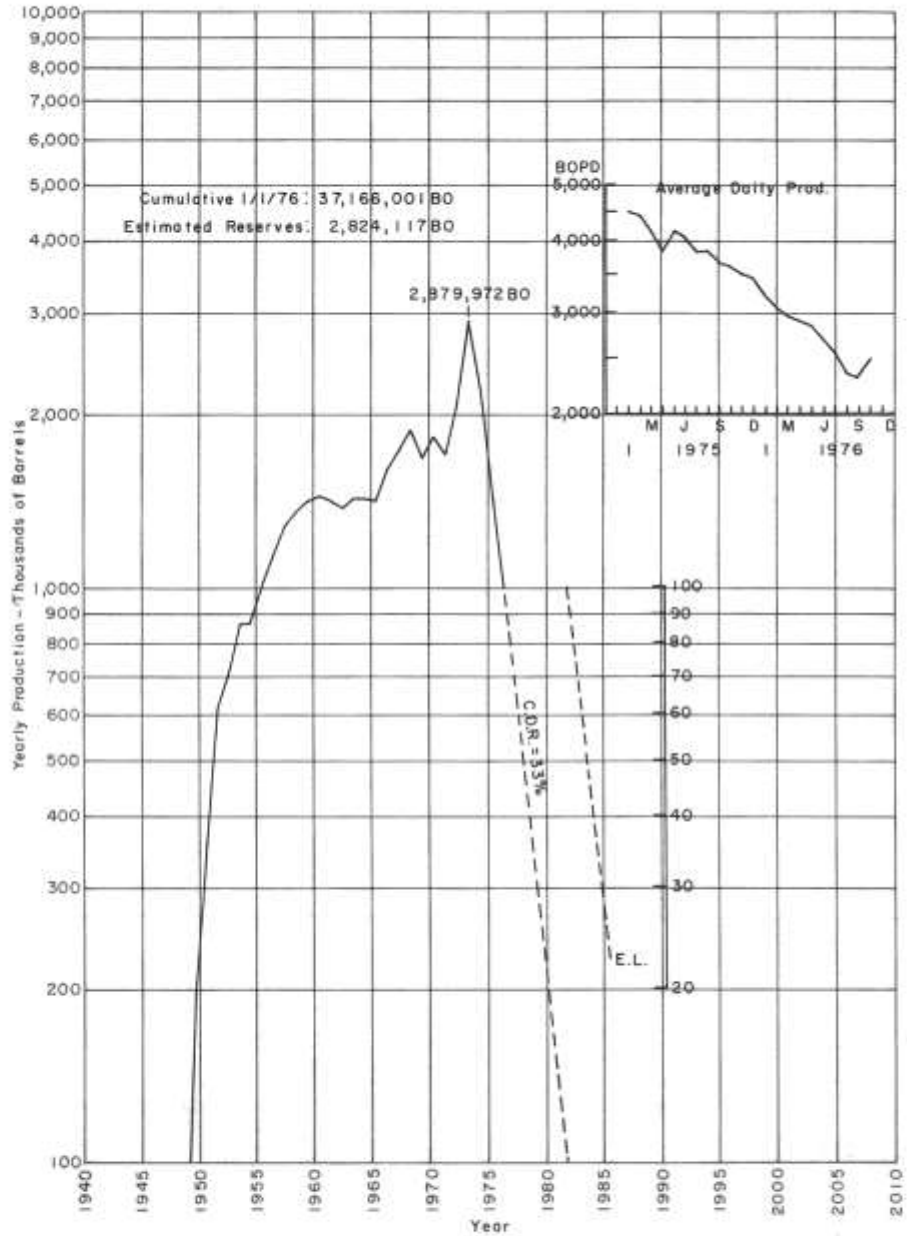

FIGURE 21—Crossroads (Silurian-Devonian) Pool.

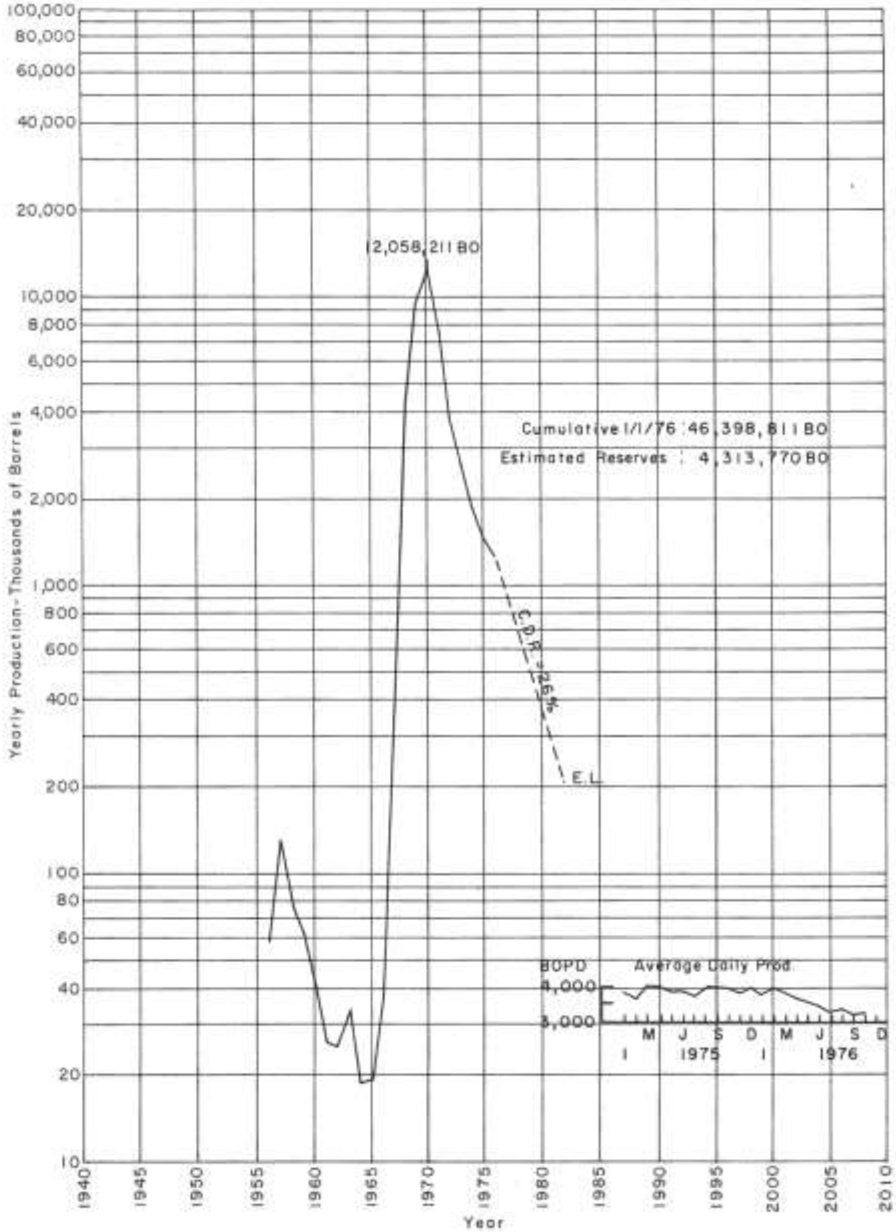

FIGURE 22—VADA (PENNSYLVANIAN) POOL.

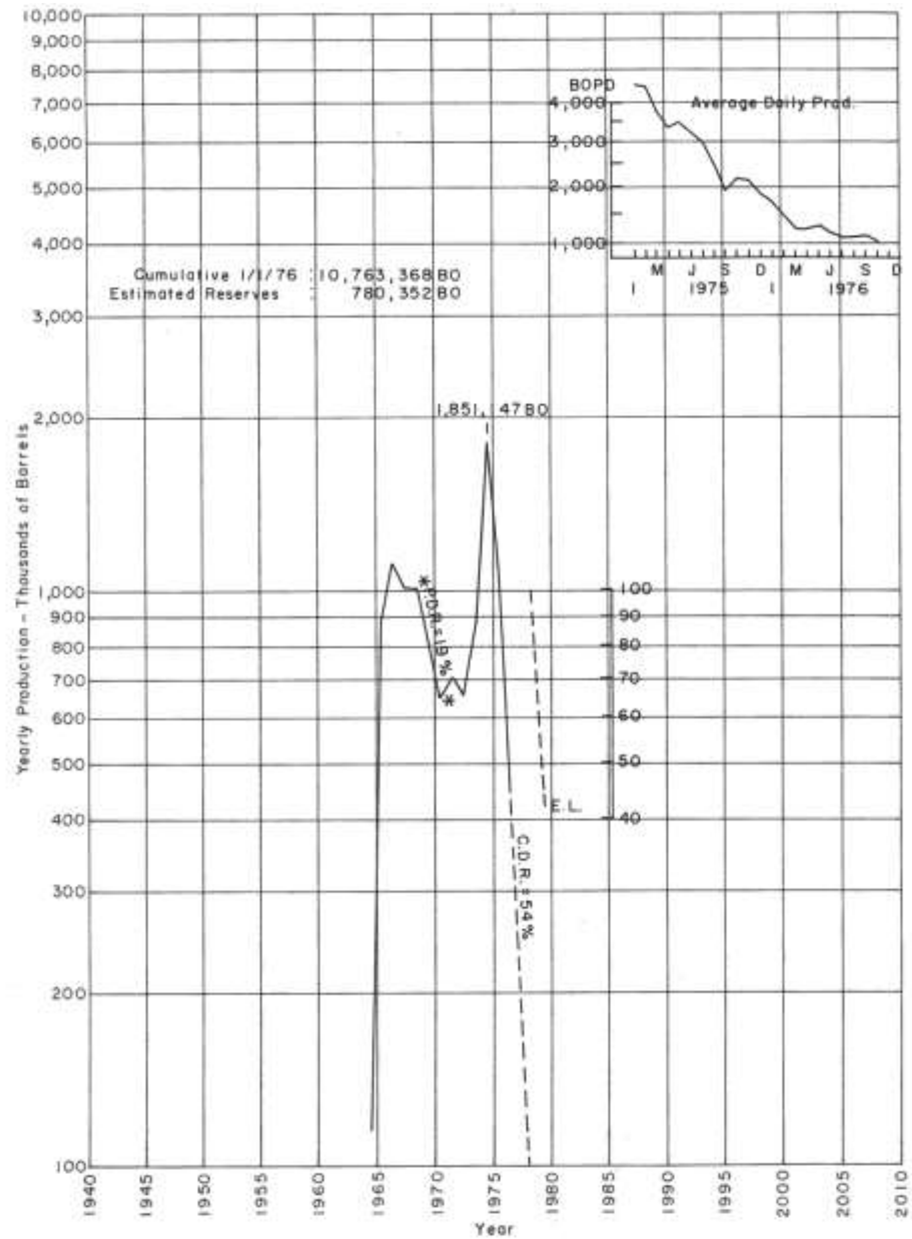

FIGURE 23—TOCITO DOME (PENNSYLVANIAN "D") POOL.

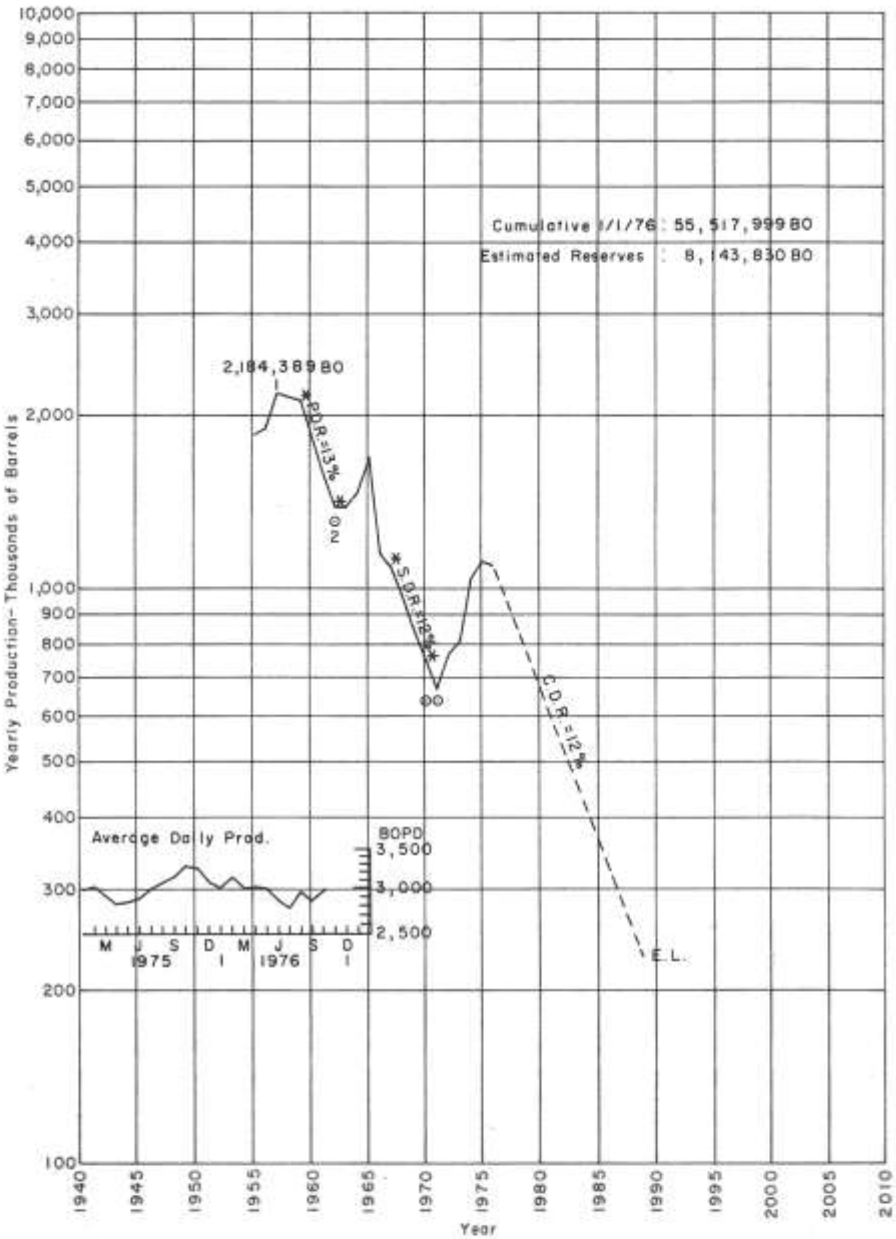

FIGURE 24—JALMAT (TANSILL-YATES-SEVEN RIVERS) POOL.

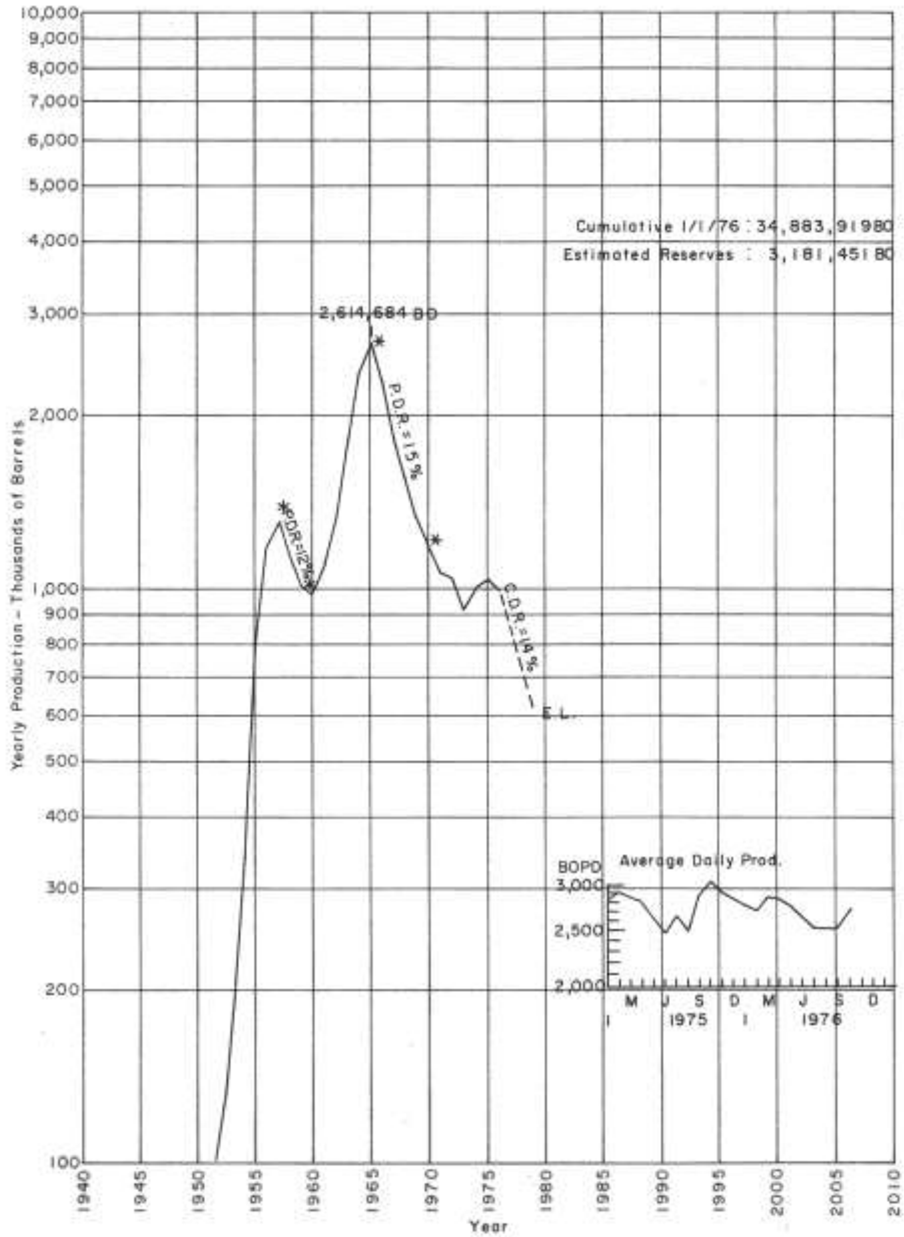

FIGURE 25—BLINEBRY OIL AND GAS POOL.

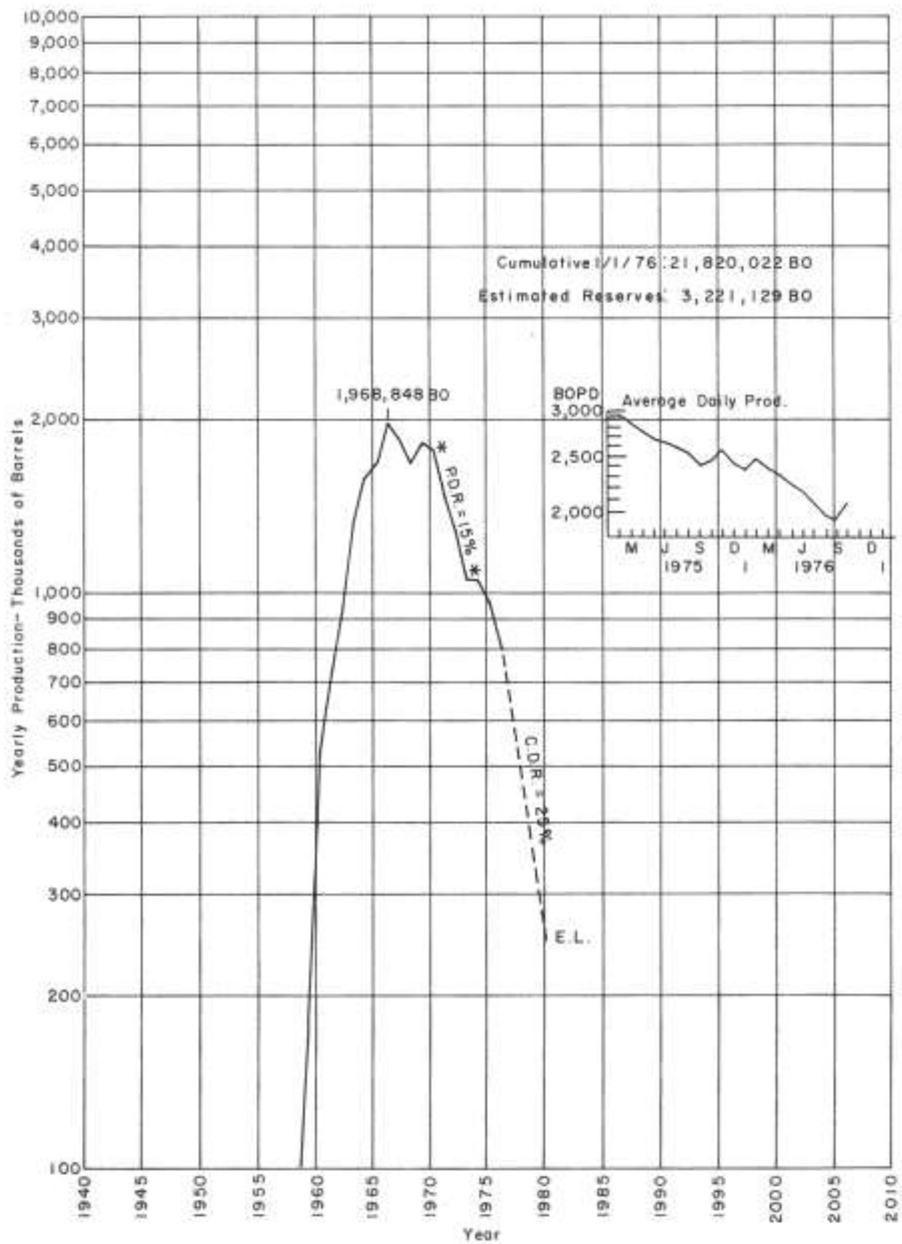

FIGURE 26—JUSTIS (BLINEBRY) POOL.

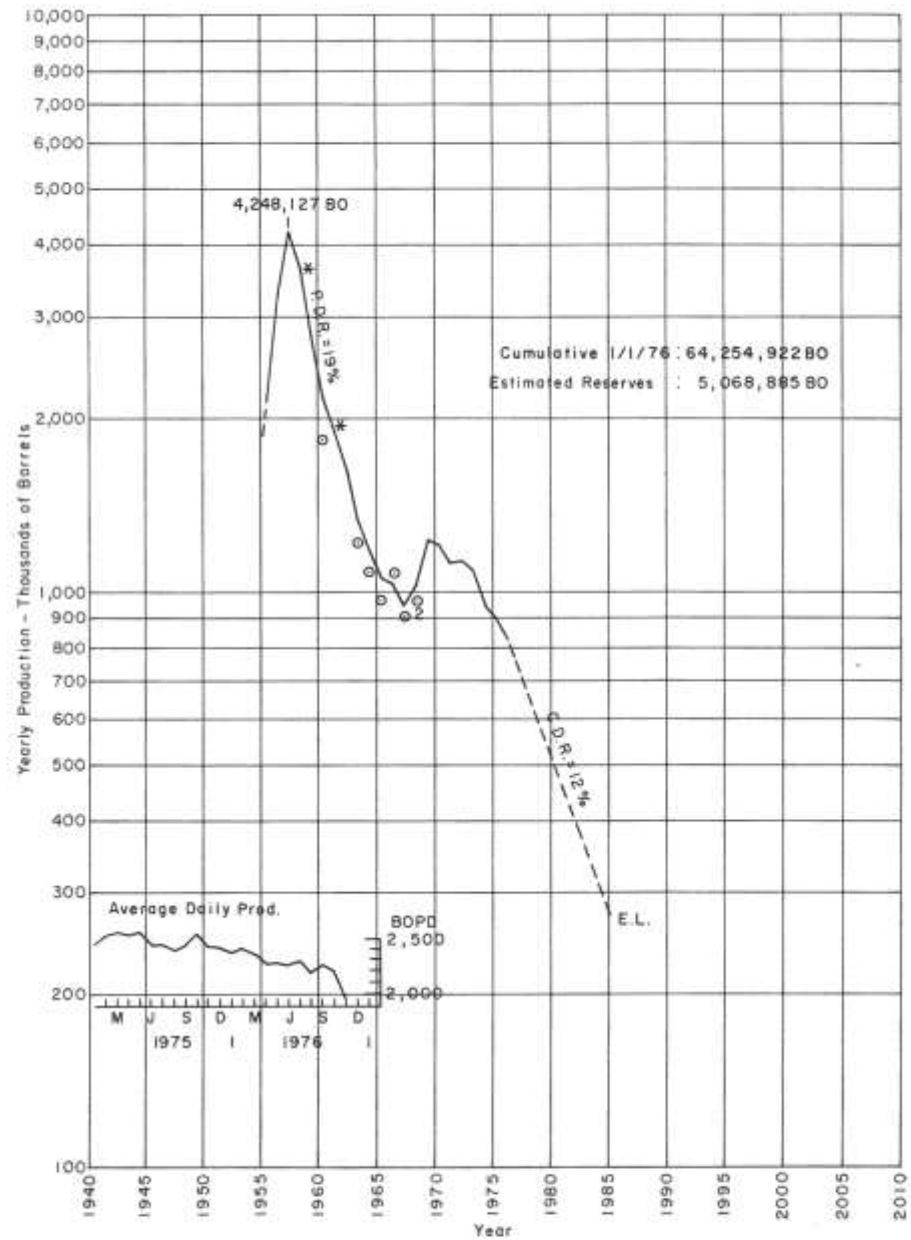

FIGURE 27—EUMONT (YATES-SEVEN RIVERS-QUEEN) POOL.

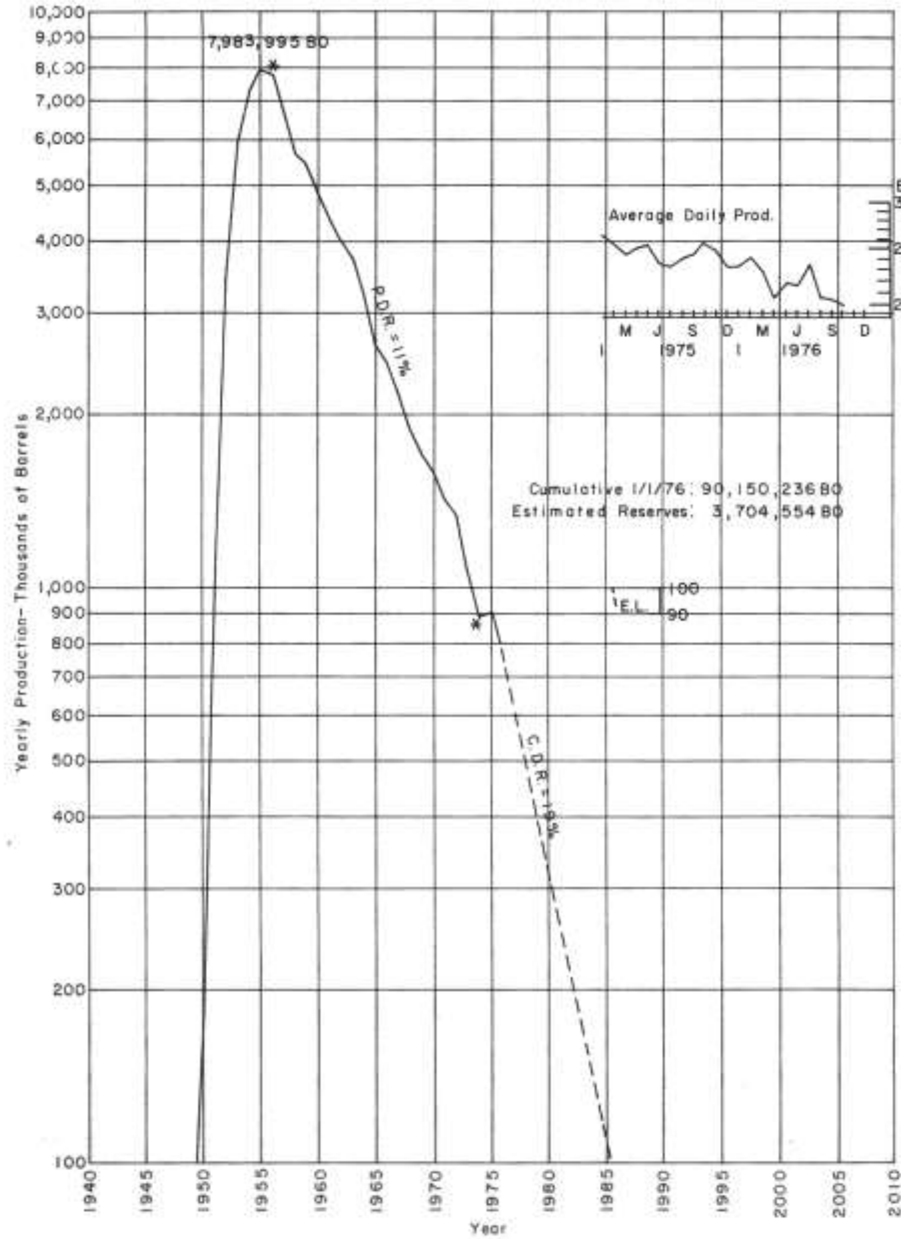

FIGURE 28—DENTON (DEVONIAN) POOL.

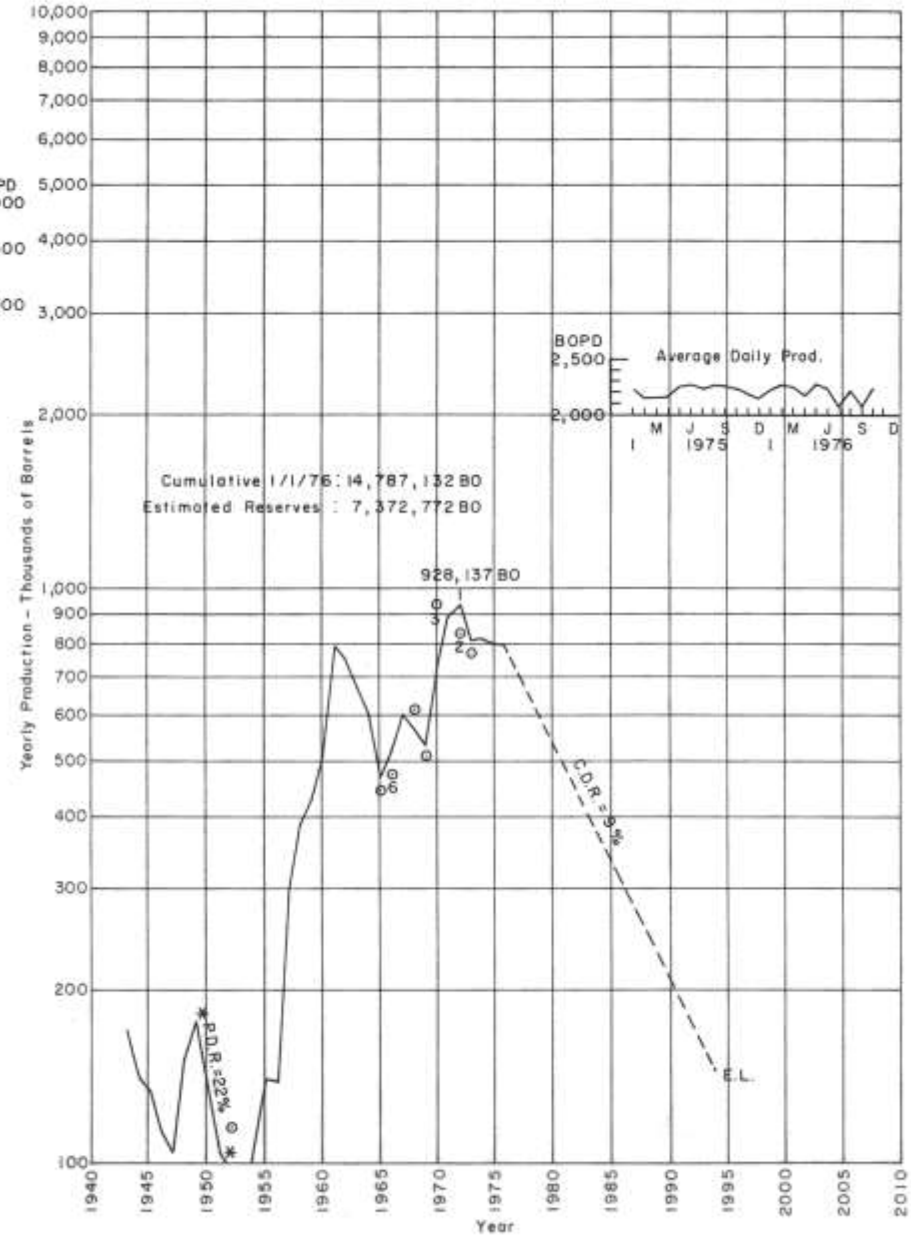

FIGURE 29—SHUGART (YATES-SEVEN RIVERS-QUEEN-GRAYBURG) POOL.

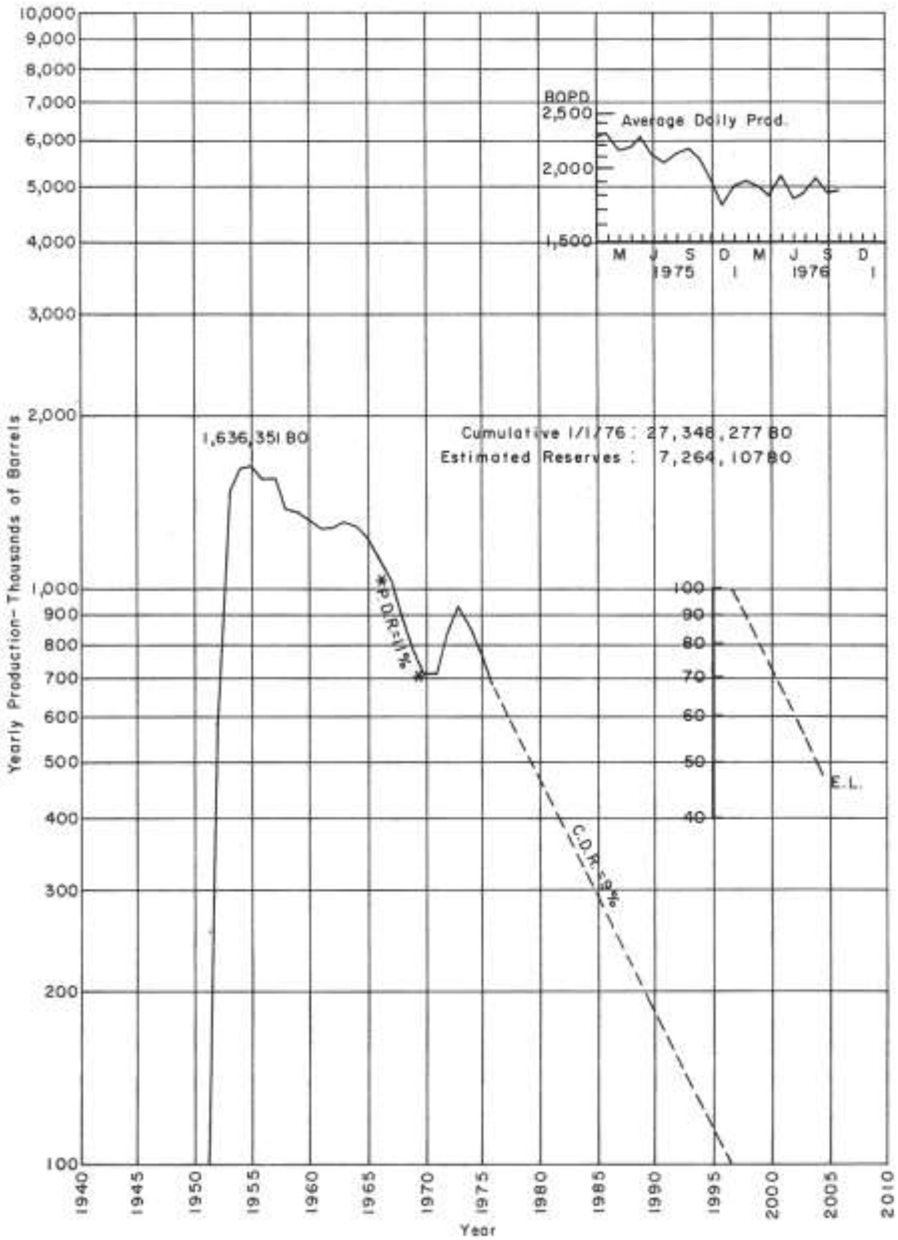

FIGURE 30—LOVINGTON (ABO) POOL.

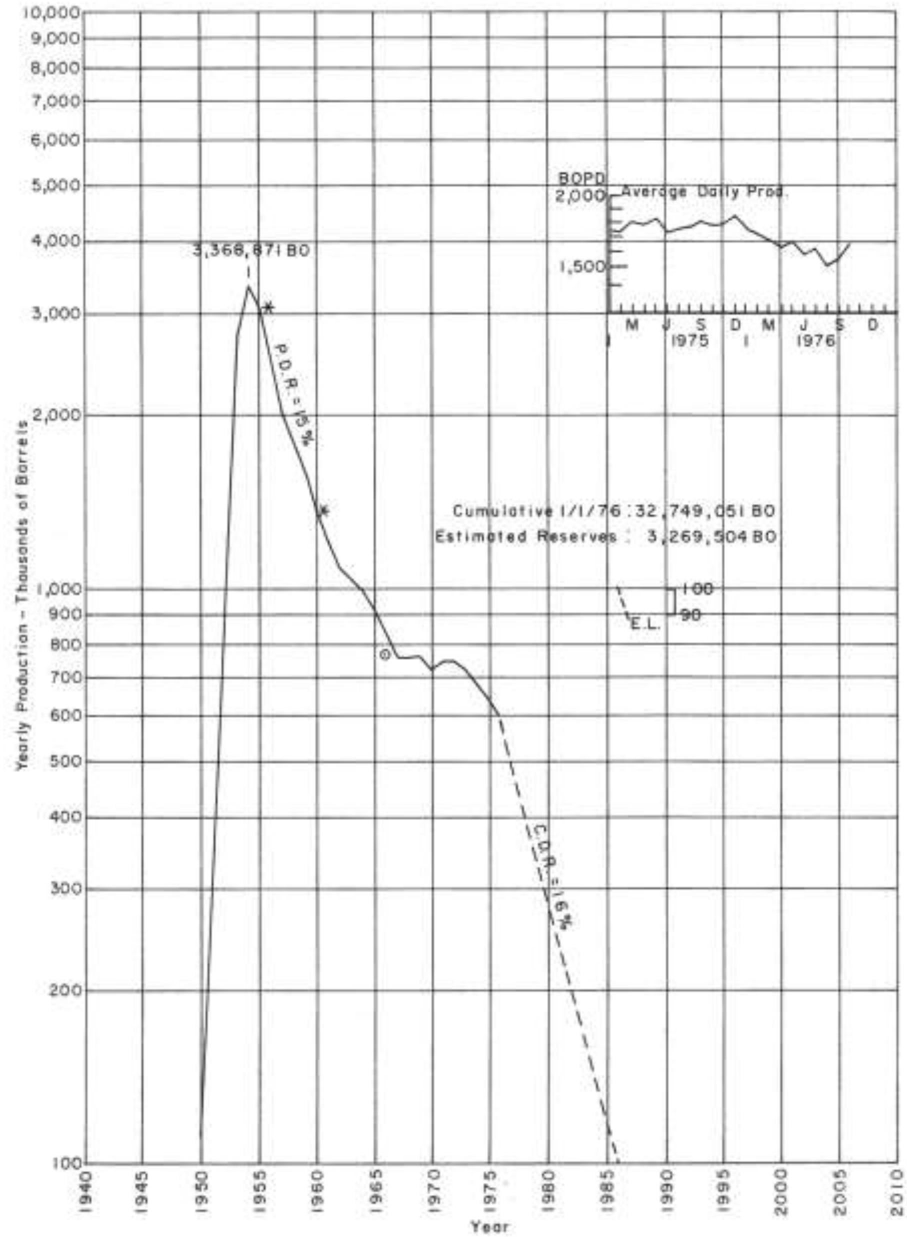

FIGURE 31—DENTON (WOLFCAMP) POOL.

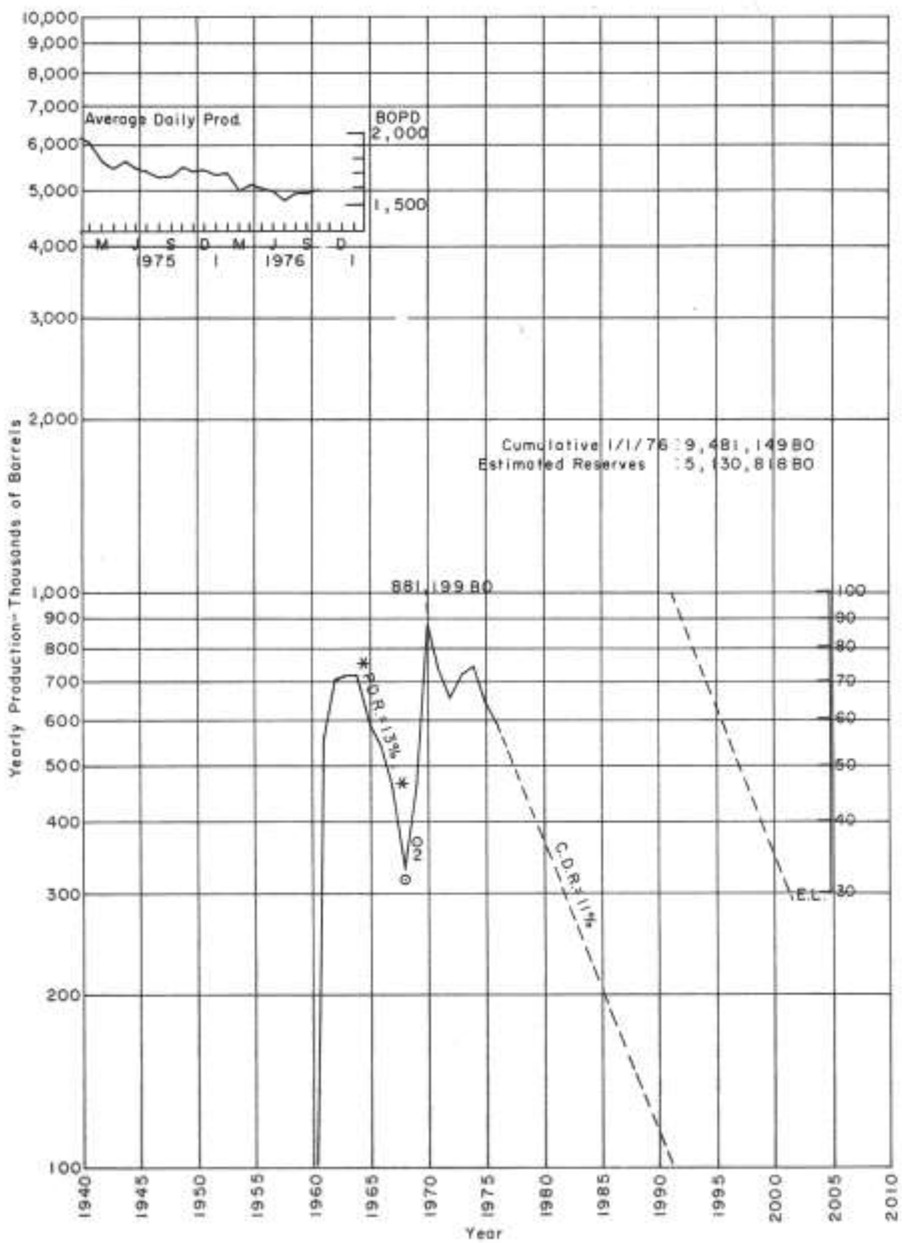

FIGURE 32—PADUCA (DELAWARE) POOL.

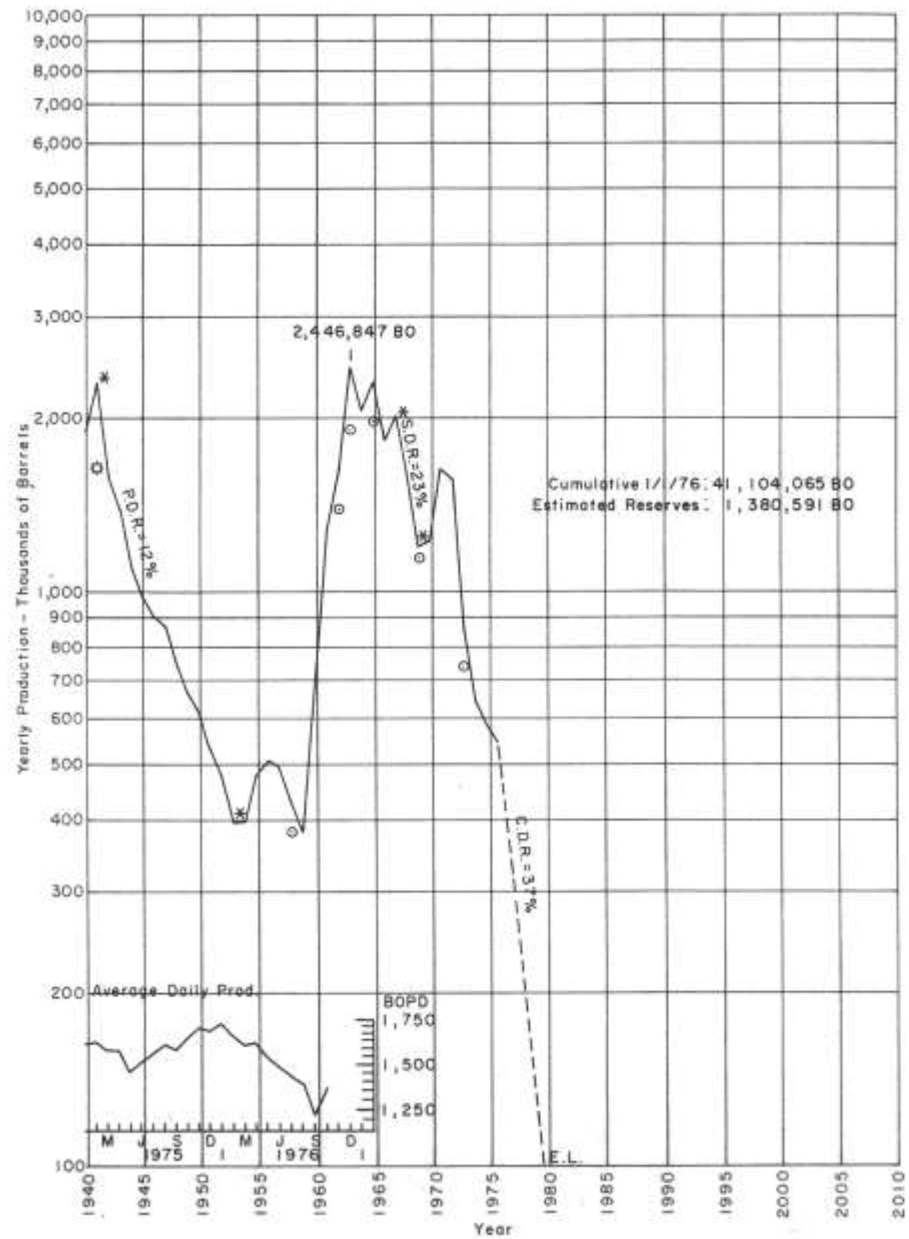

FIGURE 33—LOCO HILLS (QUEEN-GRAYBURG-SAN ANDRES) POOL.

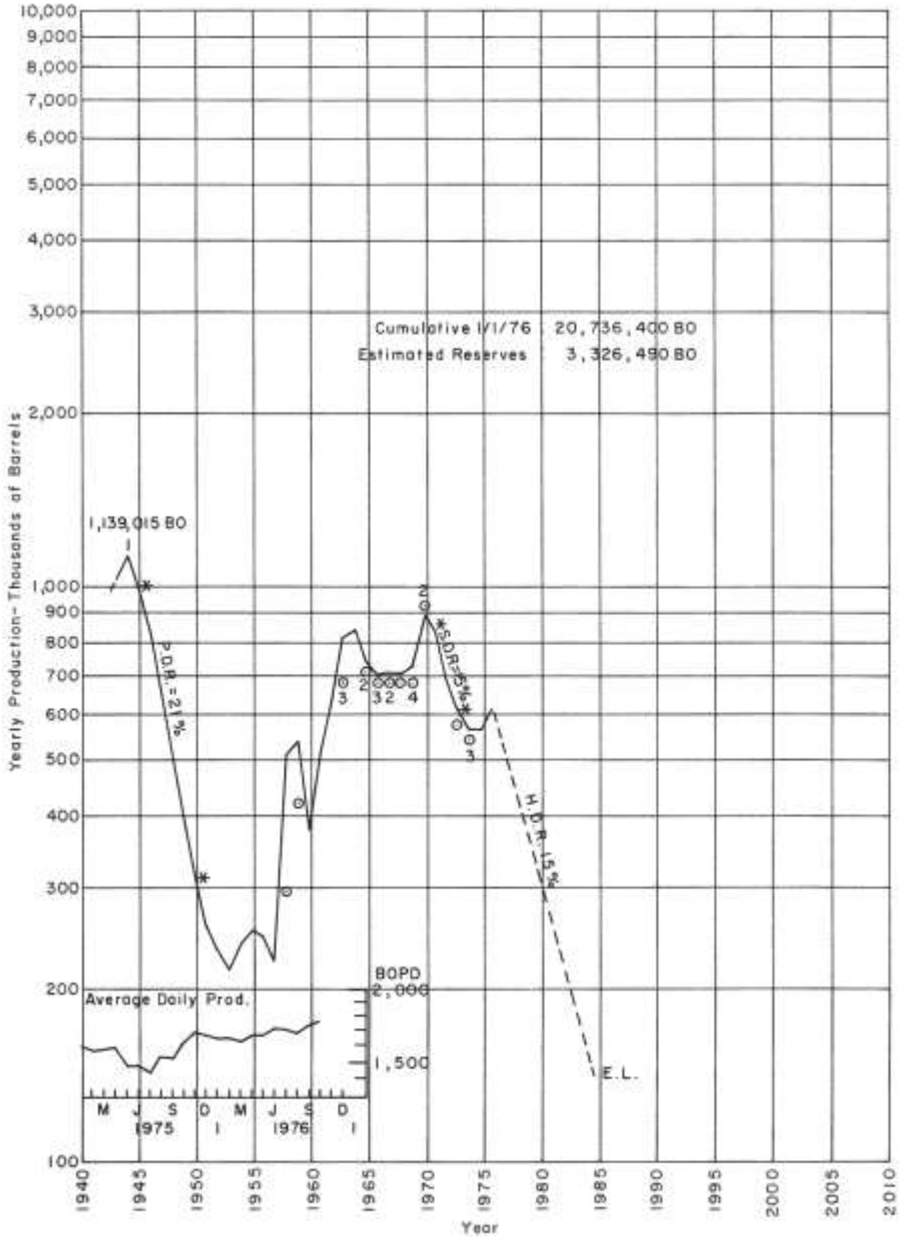

FIGURE 34—SQUARE LAKE (GRAYBURG-SAN ANDRES) POOL.

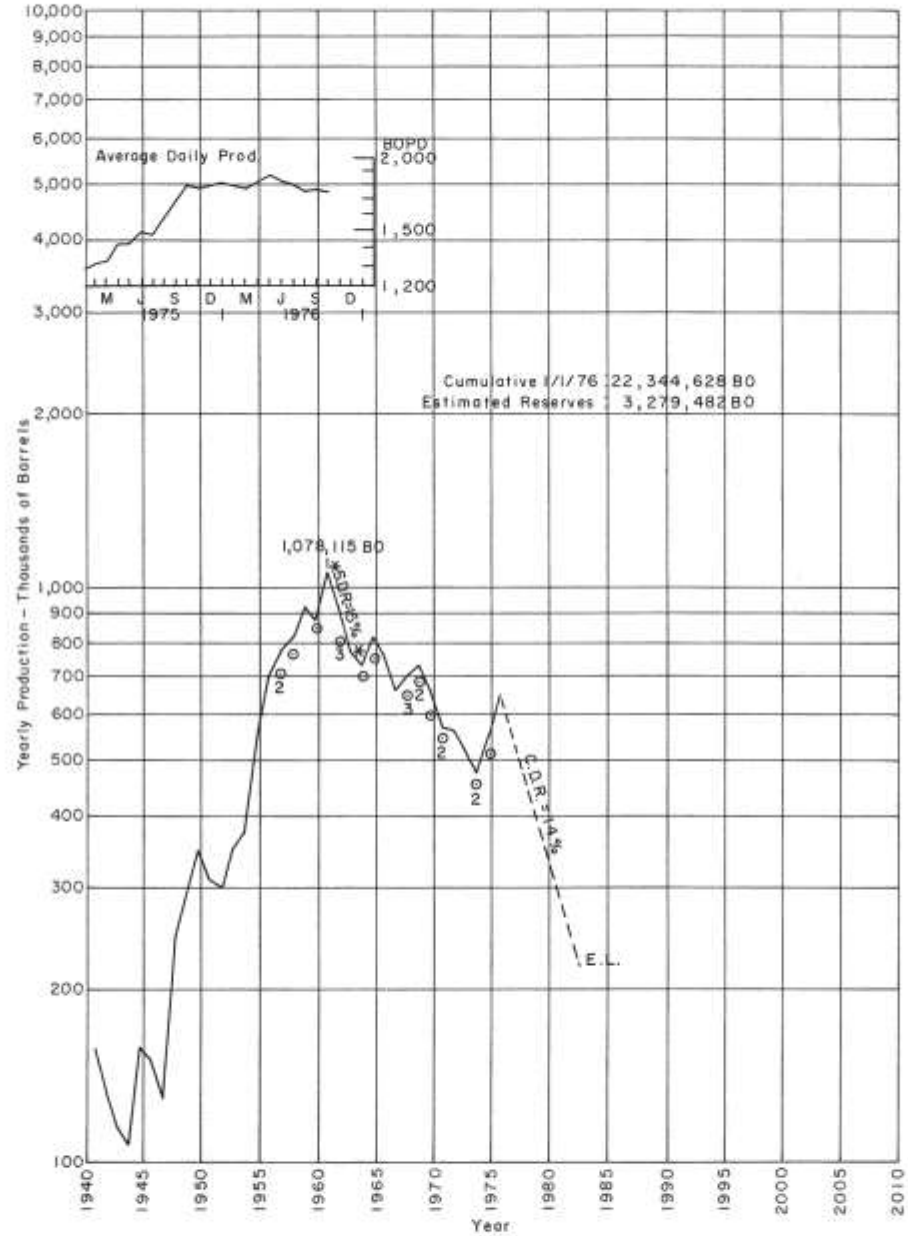

FIGURE 35—ARTESIA (QUEEN-GRAYBURG-SAN ANDRES) POOL.

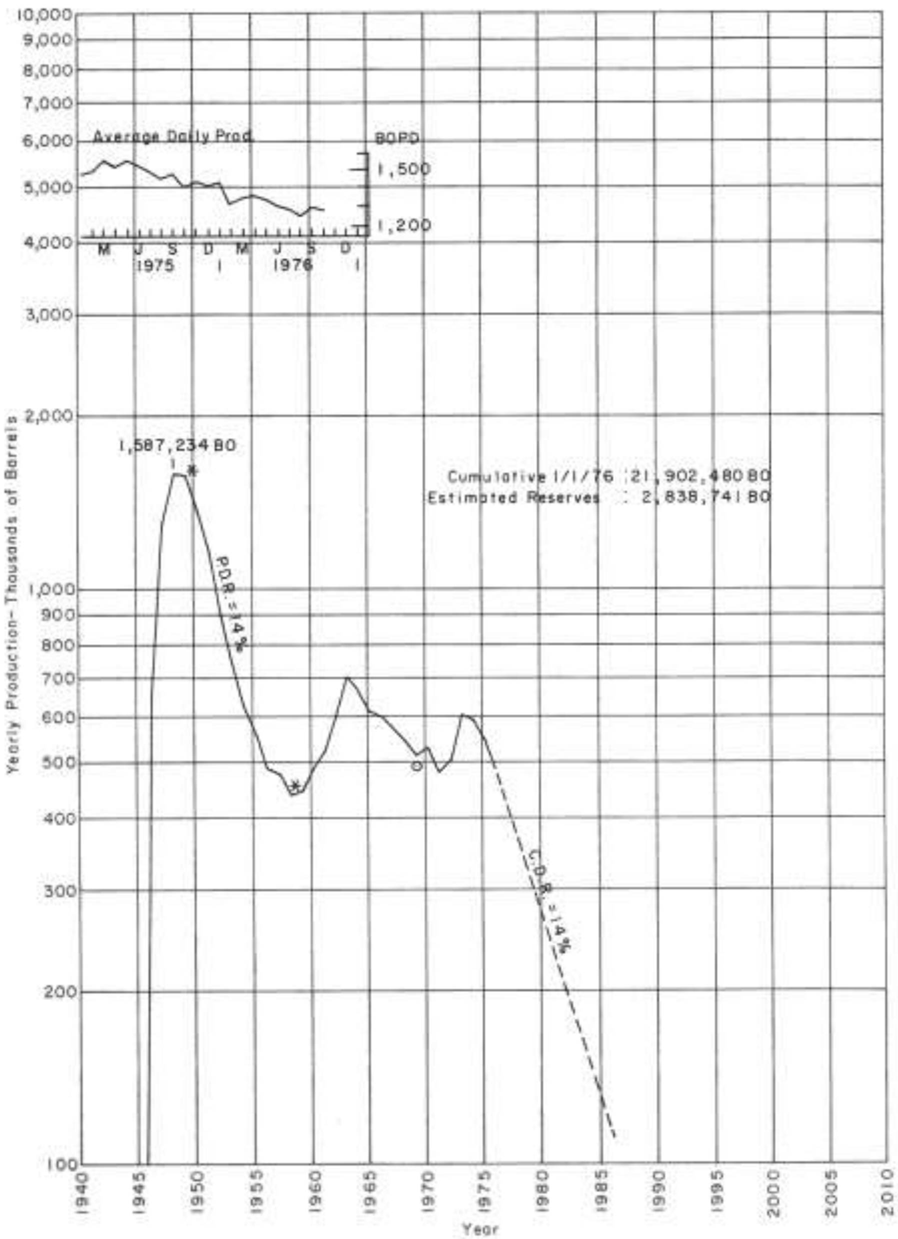

FIGURE 36—PADDOCK POOL.

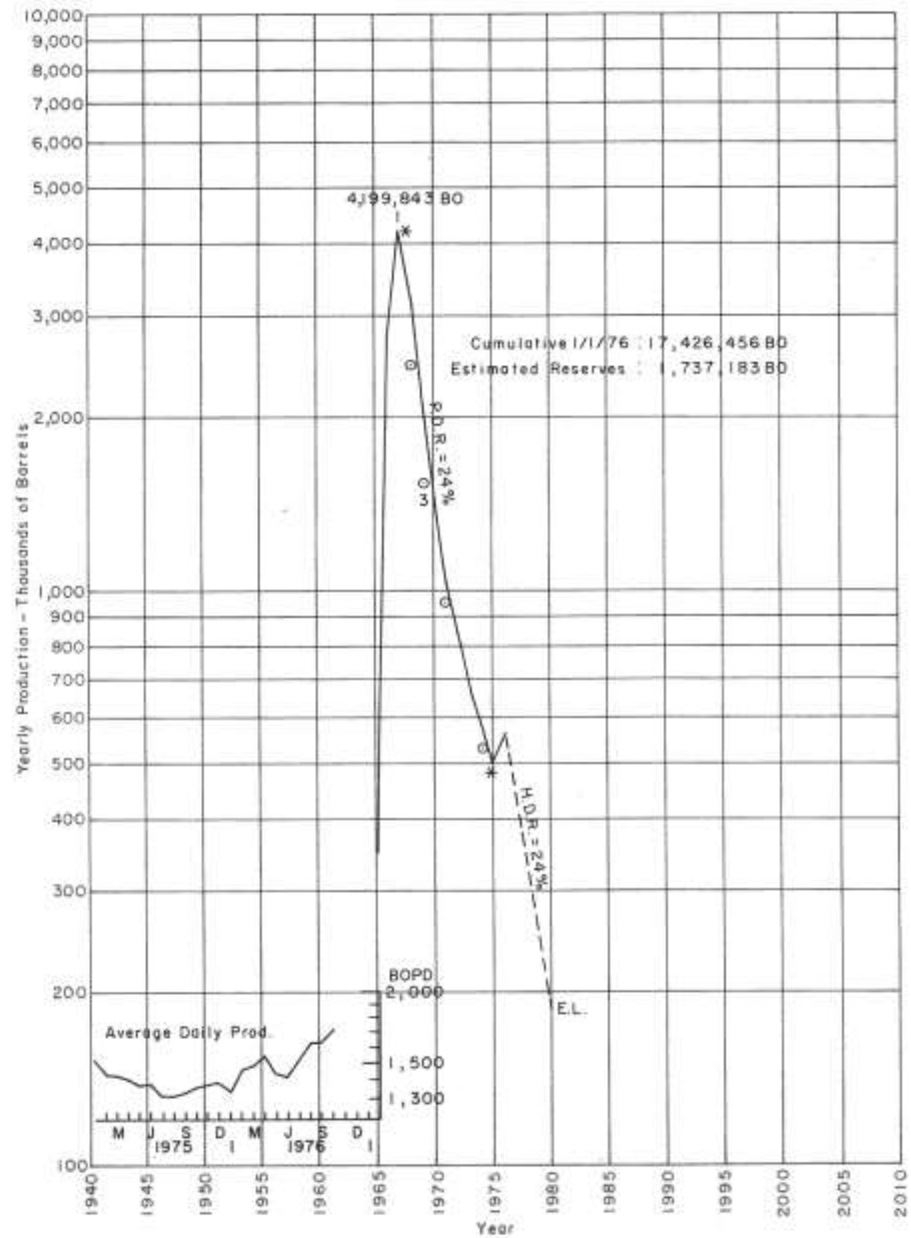

FIGURE 37—CHAVEROO (SAN ANDRES) POOL.

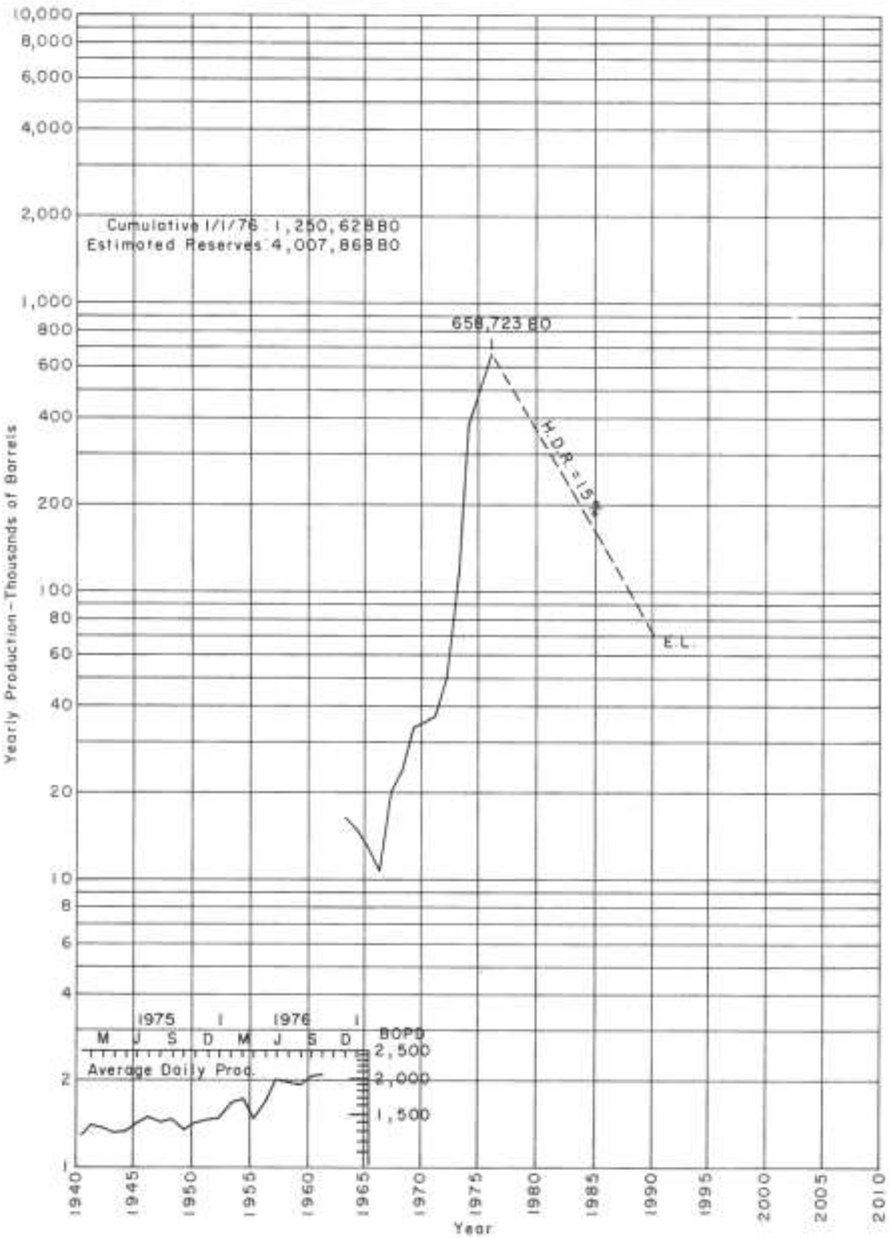

FIGURE 38—WANTZ (GRANITE WASH) POOL.

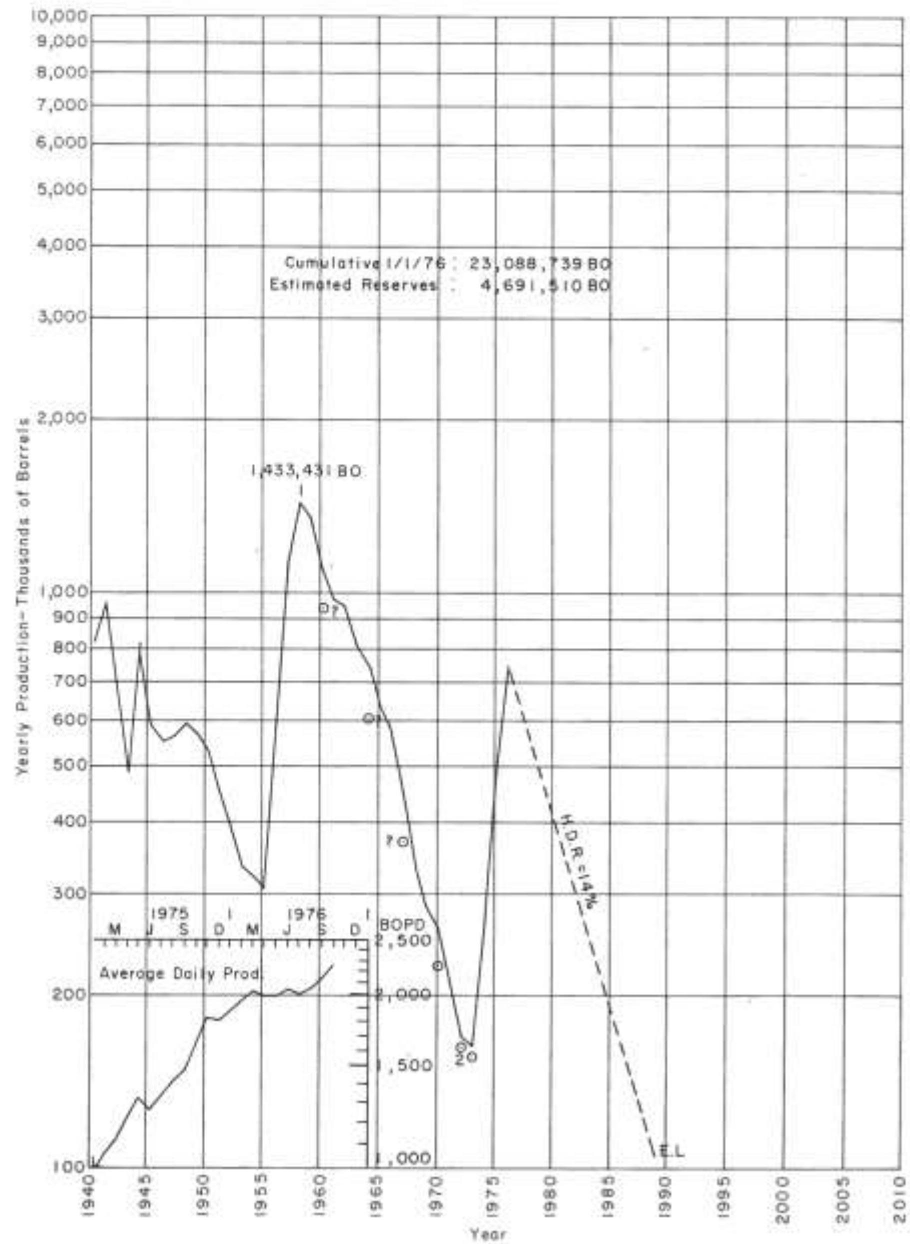

FIGURE 39—EUNICE, SOUTH (SEVEN RIVERS-QUEEN) POOL.

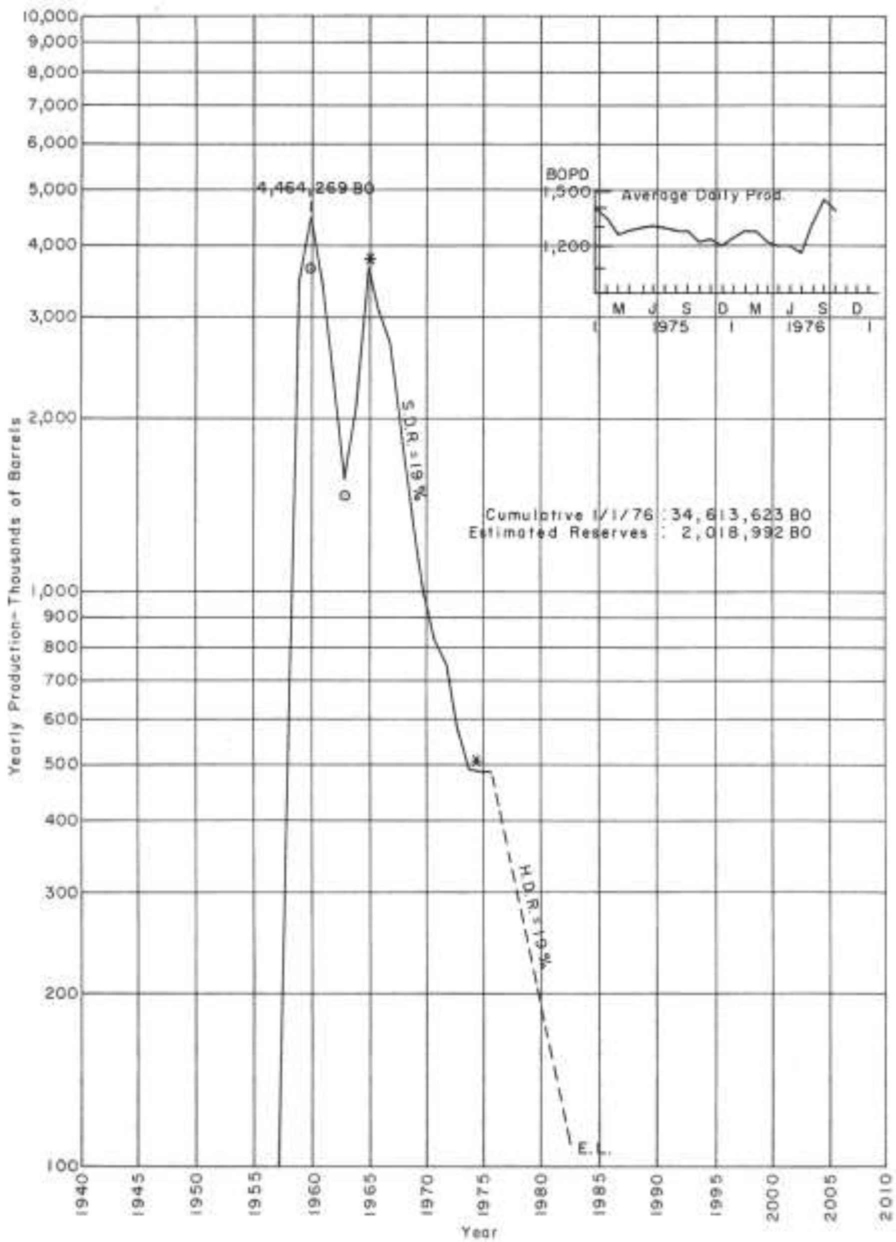

FIGURE 40—Horseshoe (Gallup) Pool.

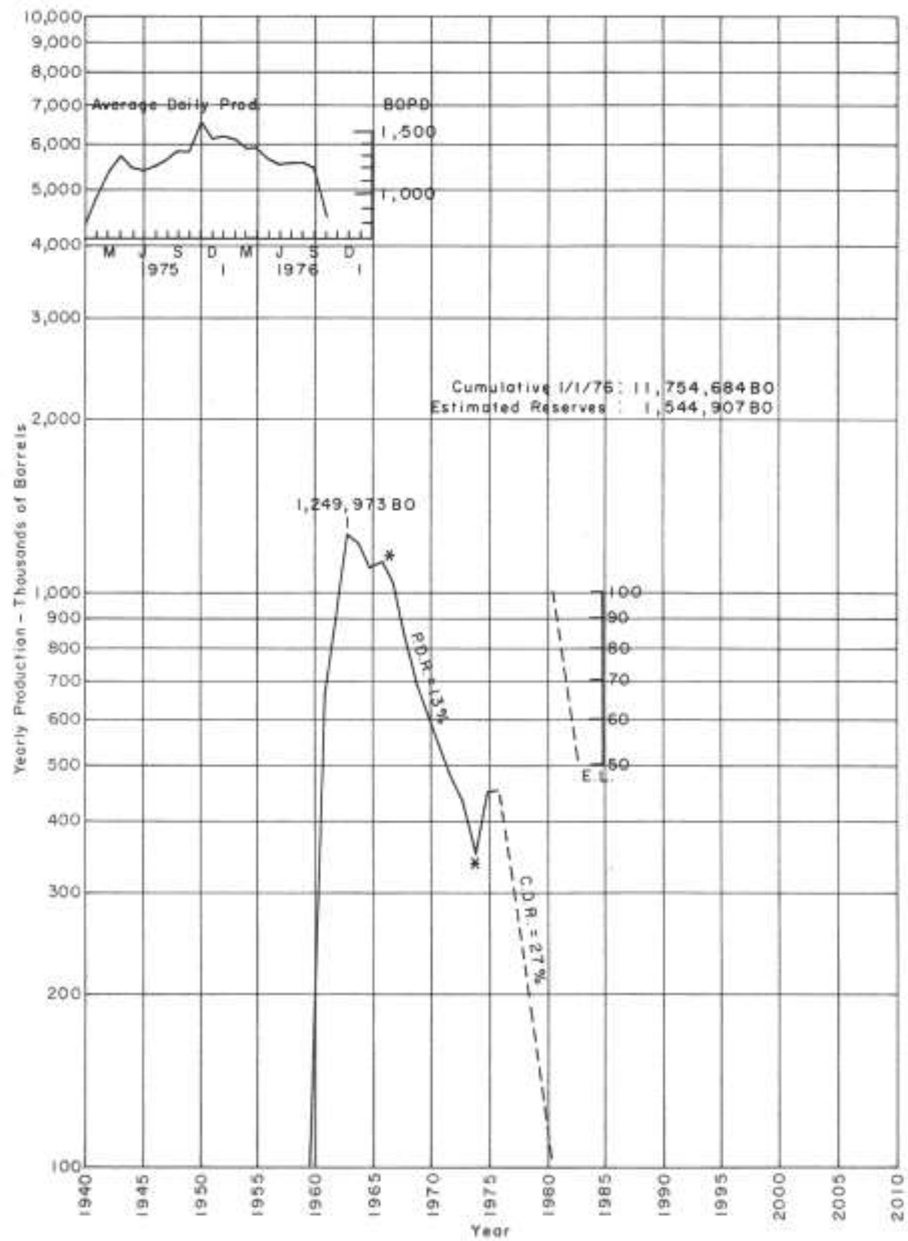

FIGURE 41—Corbin (Abo) Pool.

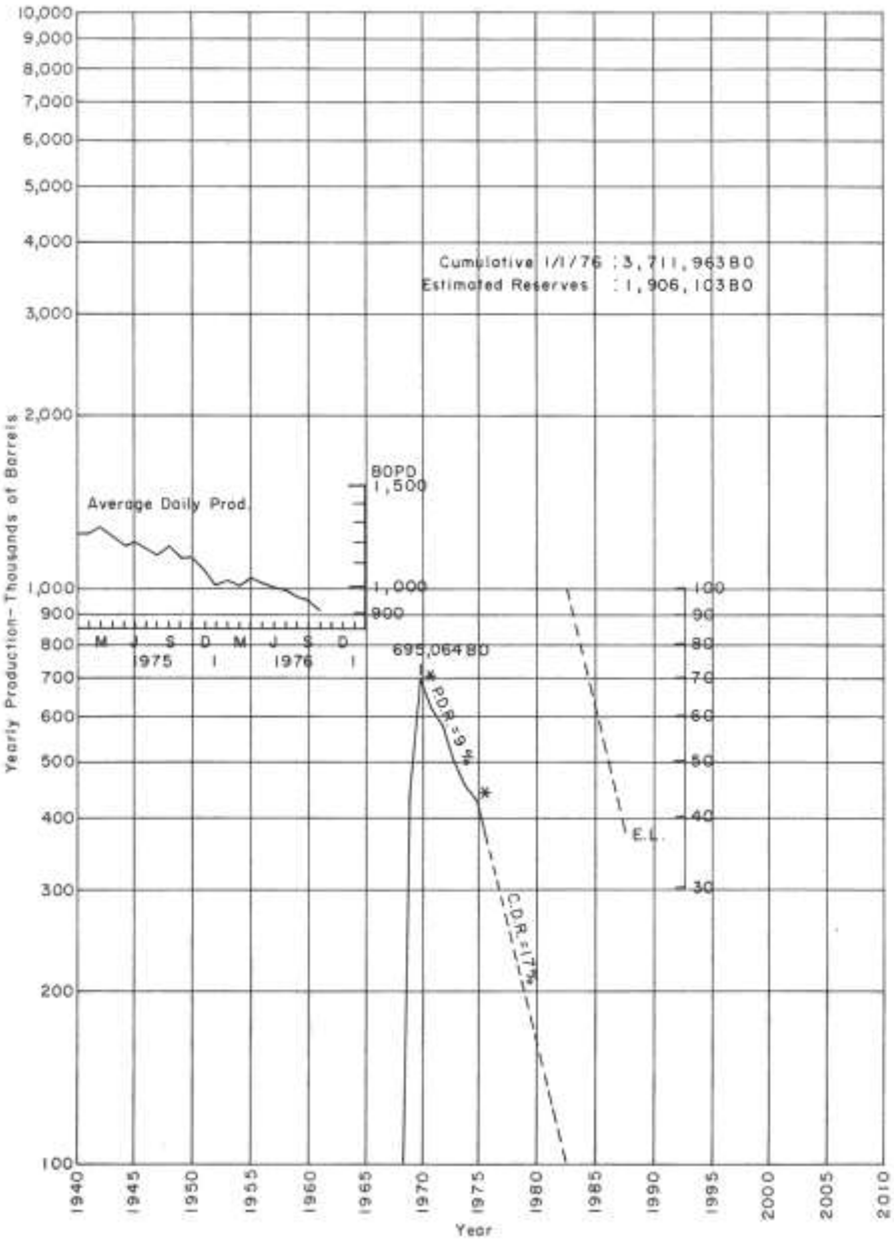

FIGURE 42—Hobbs (Blinebry) Pool.

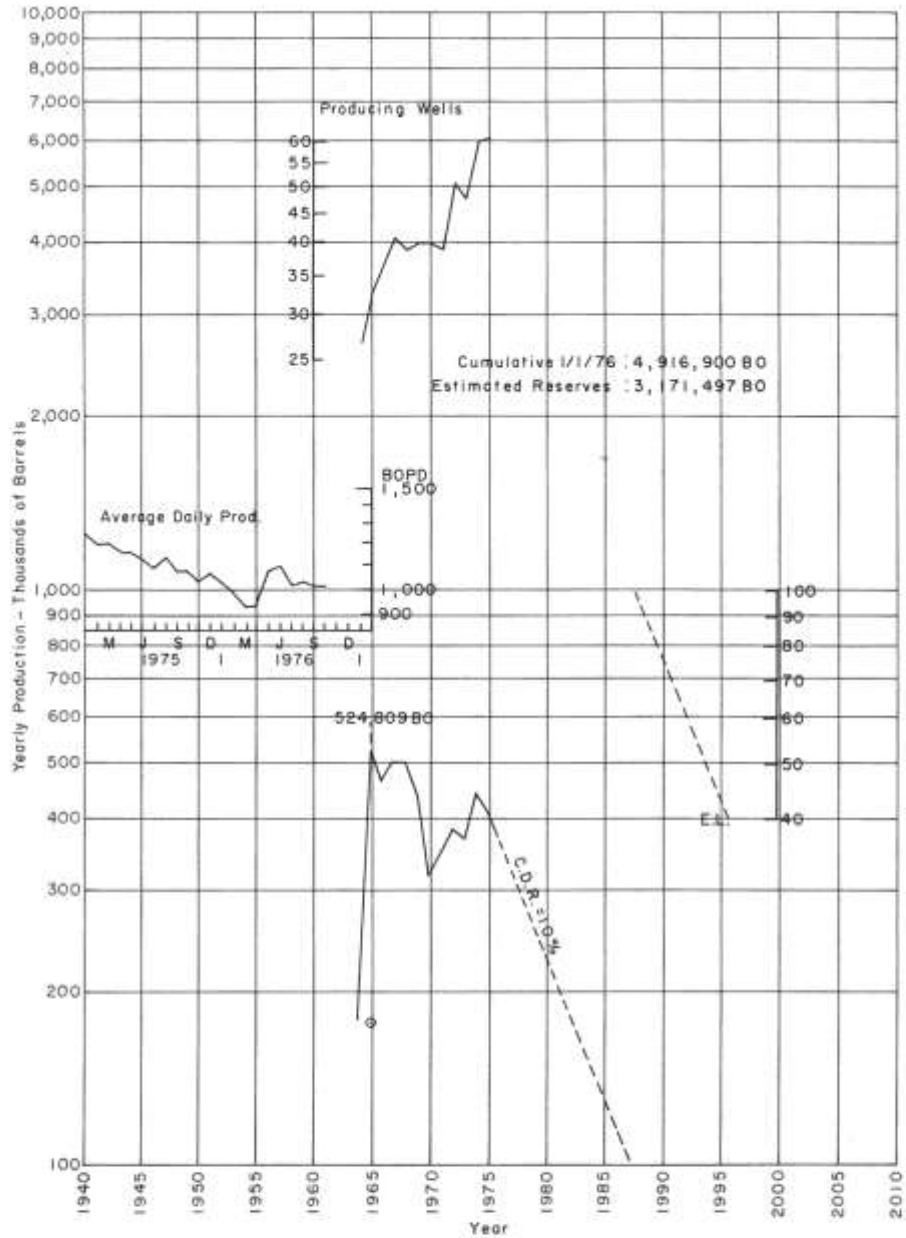

FIGURE 43—Flying M (San Andres) Pool.

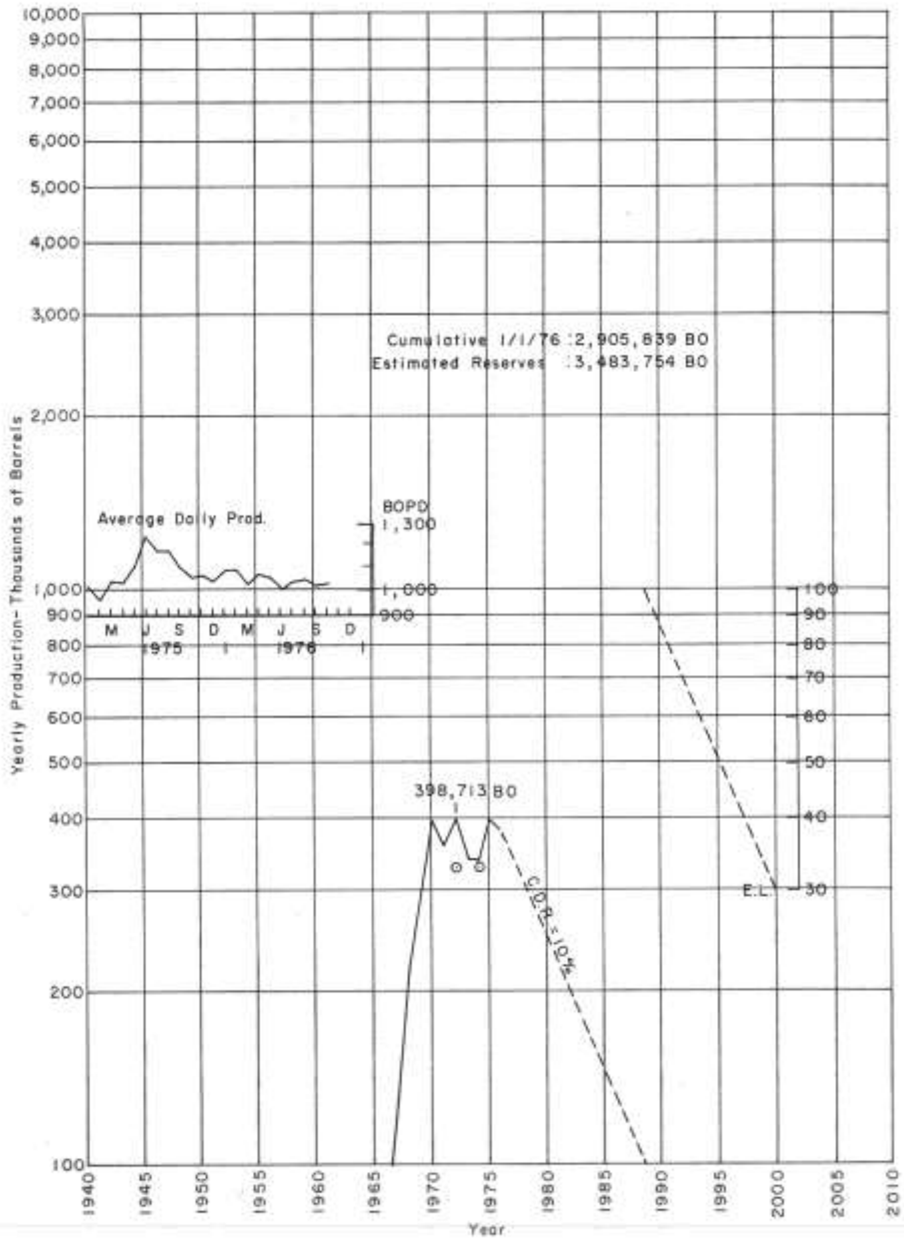

FIGURE 44—HOSPAH, SOUTH (LOWER SAND) POOL.

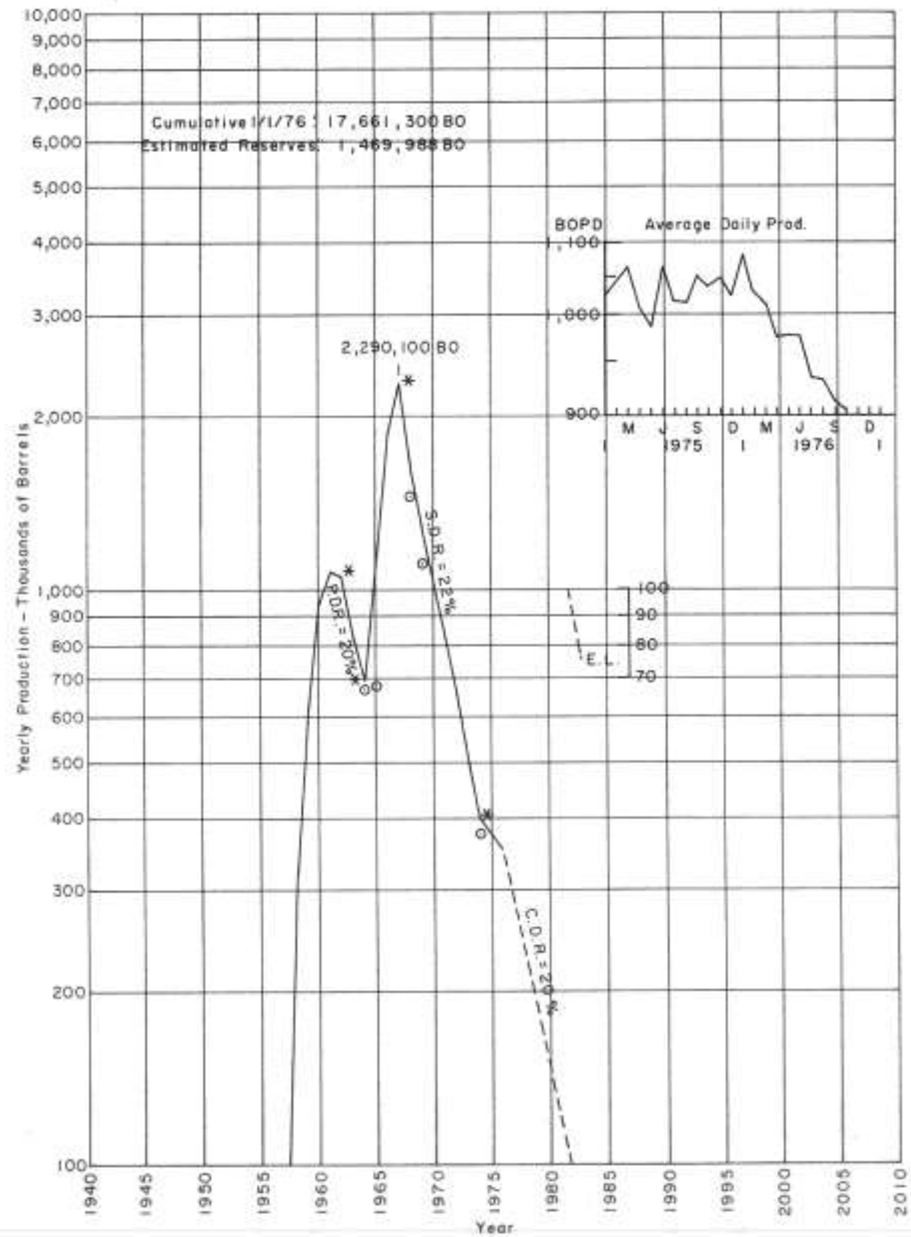

FIGURE 45—PEARL (QUEEN) POOL.

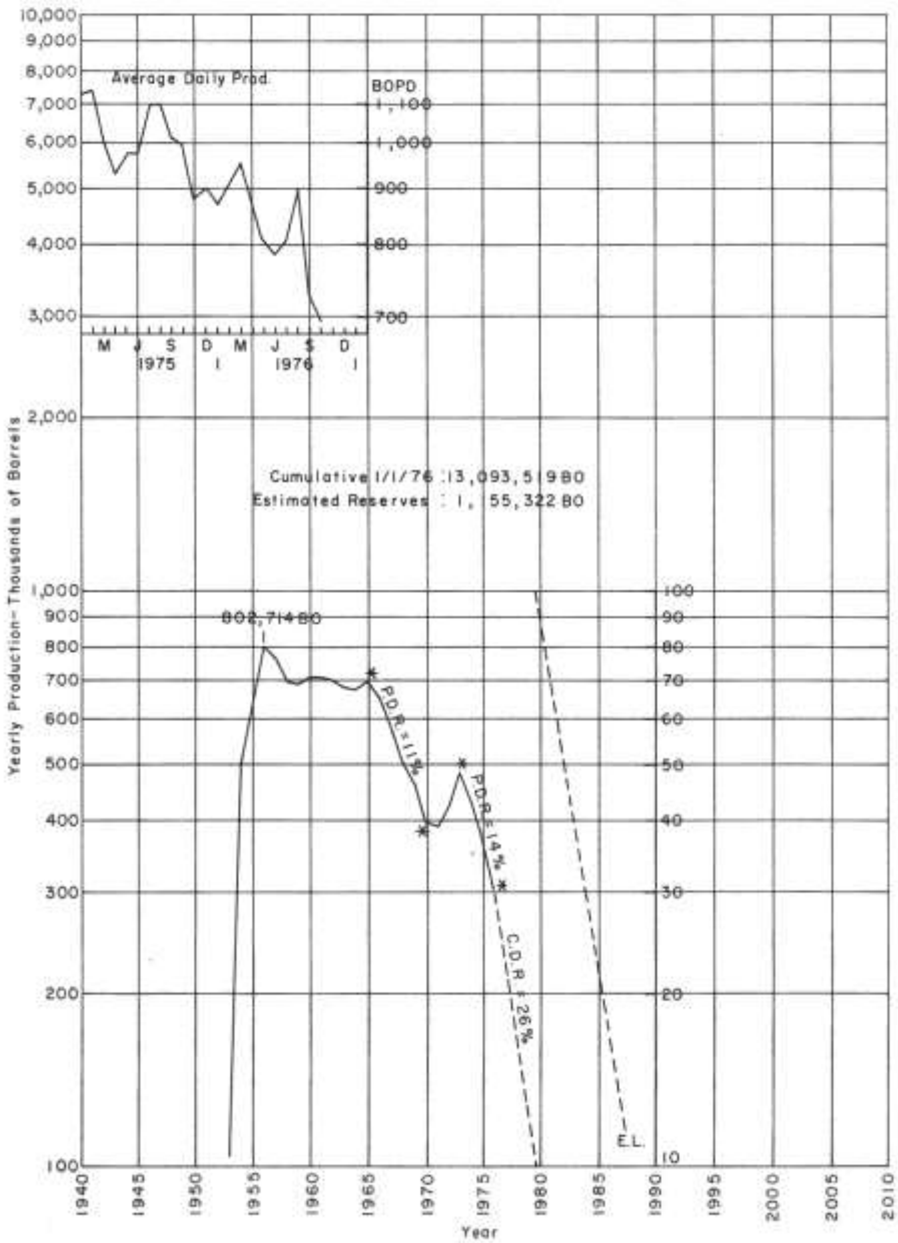

FIGURE 46—BRONCO (SILURIAN-DEVONIAN) POOL.

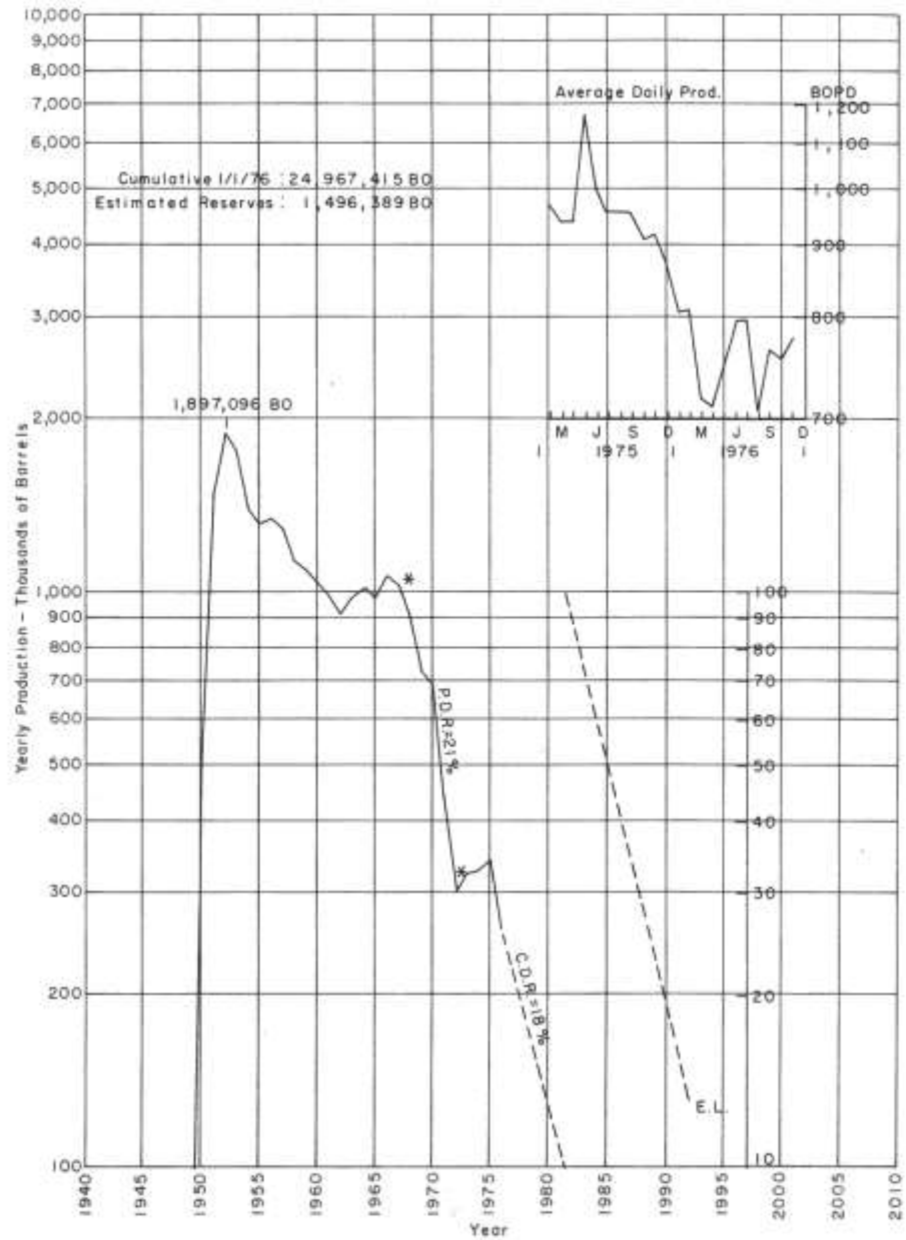

FIGURE 47—BAGLEY (SILURIAN-DEVONIAN) POOL.

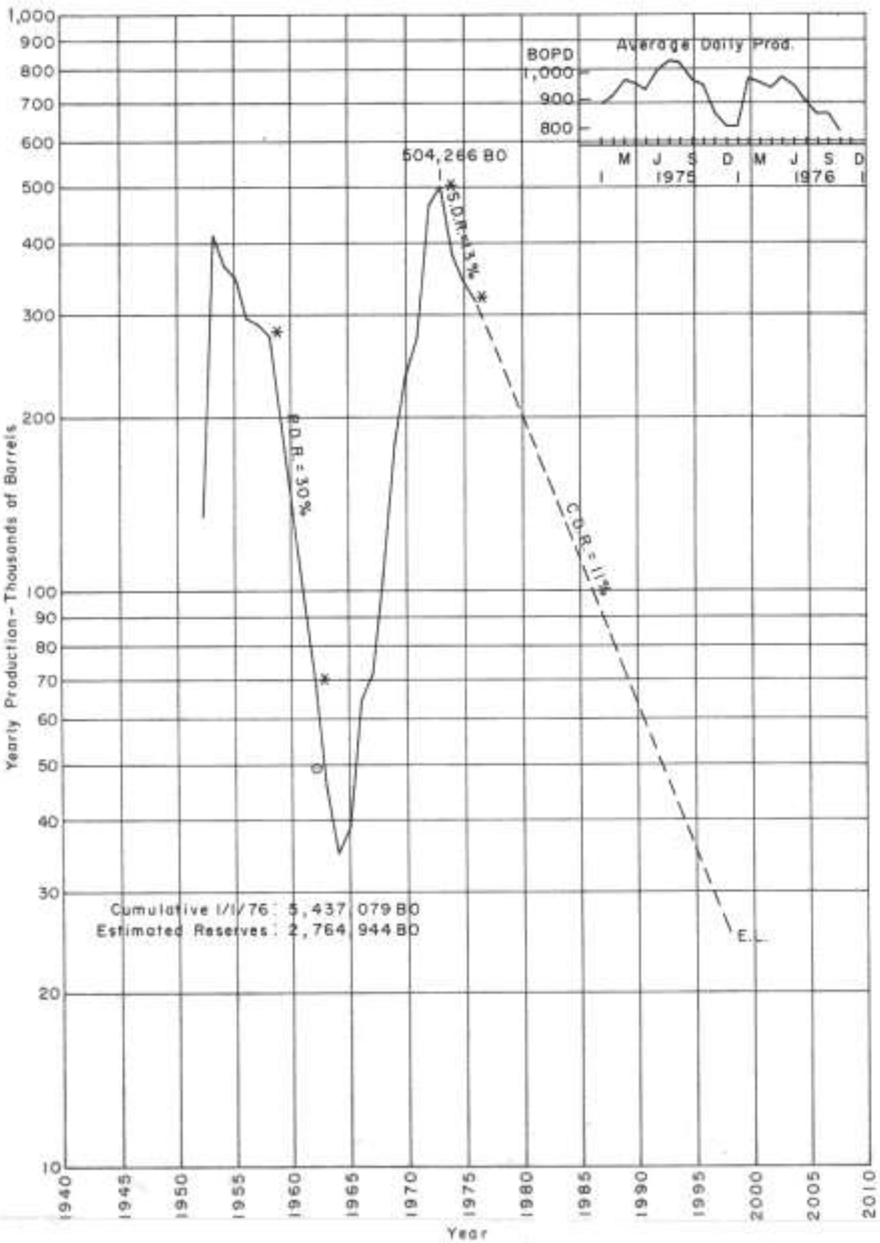

FIGURE 48—DOLLARHIDE (DEVONIAN) POOL.

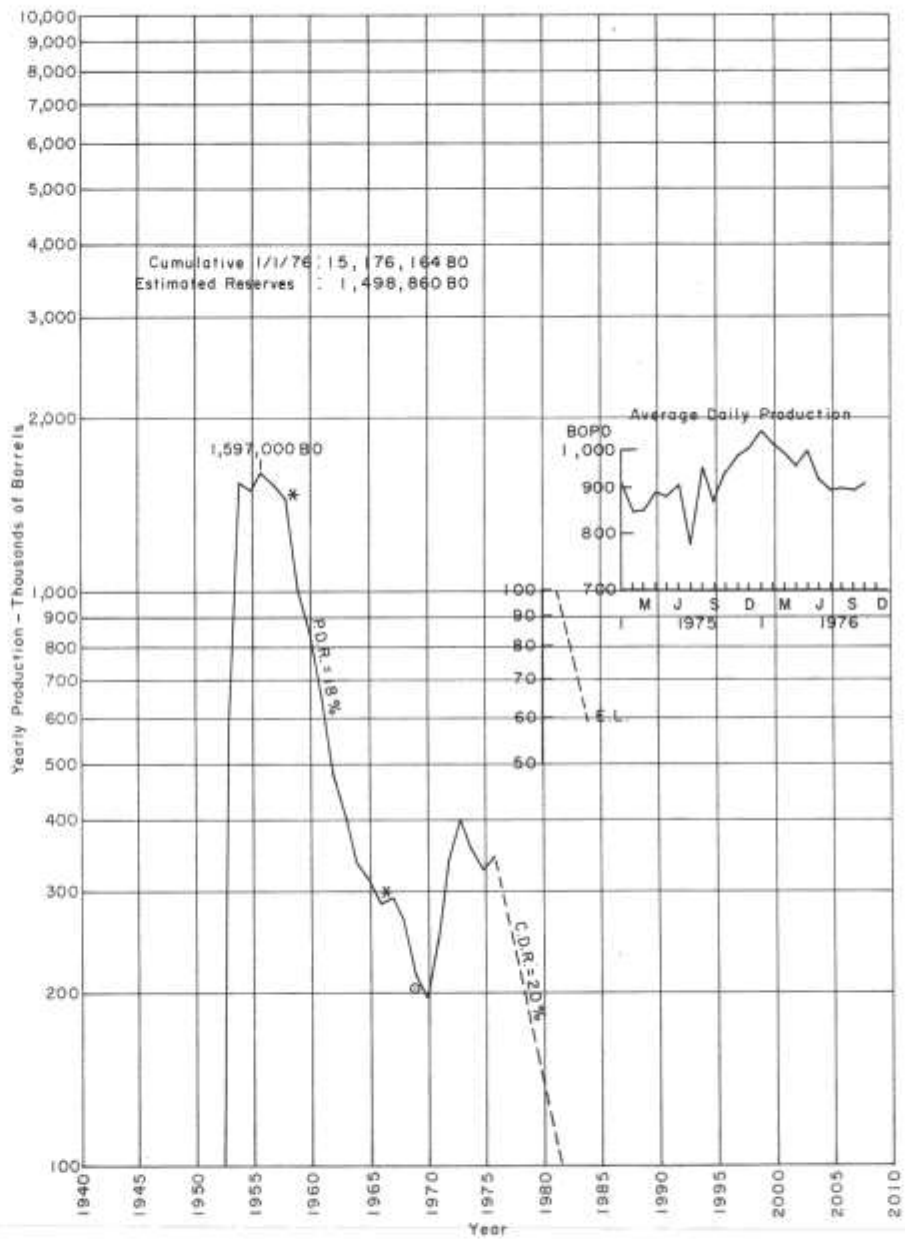

FIGURE 49—DOLLARHIDE (TUBB-DRINKARD) POOL.

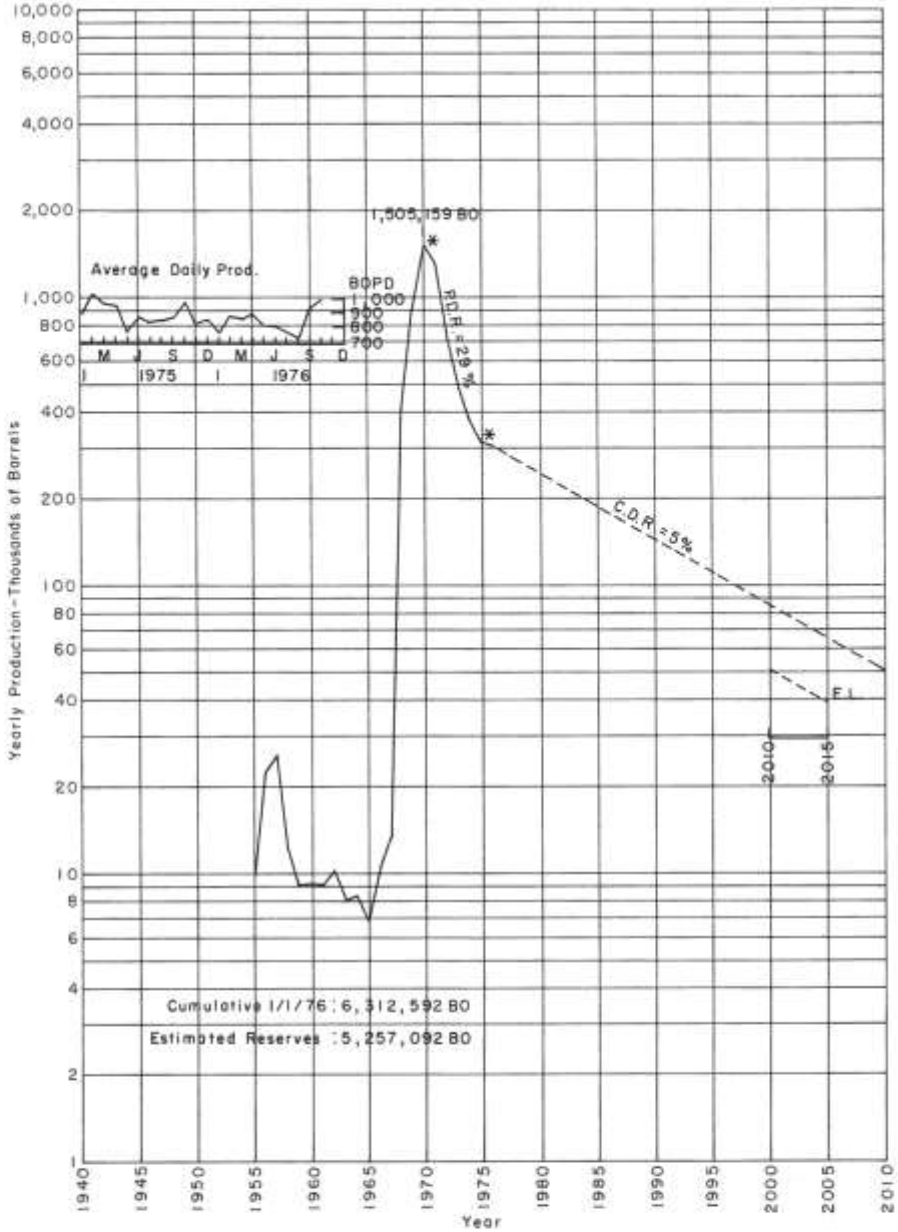

FIGURE 50—BAUM (UPPER PENNSYLVANIAN) POOL.

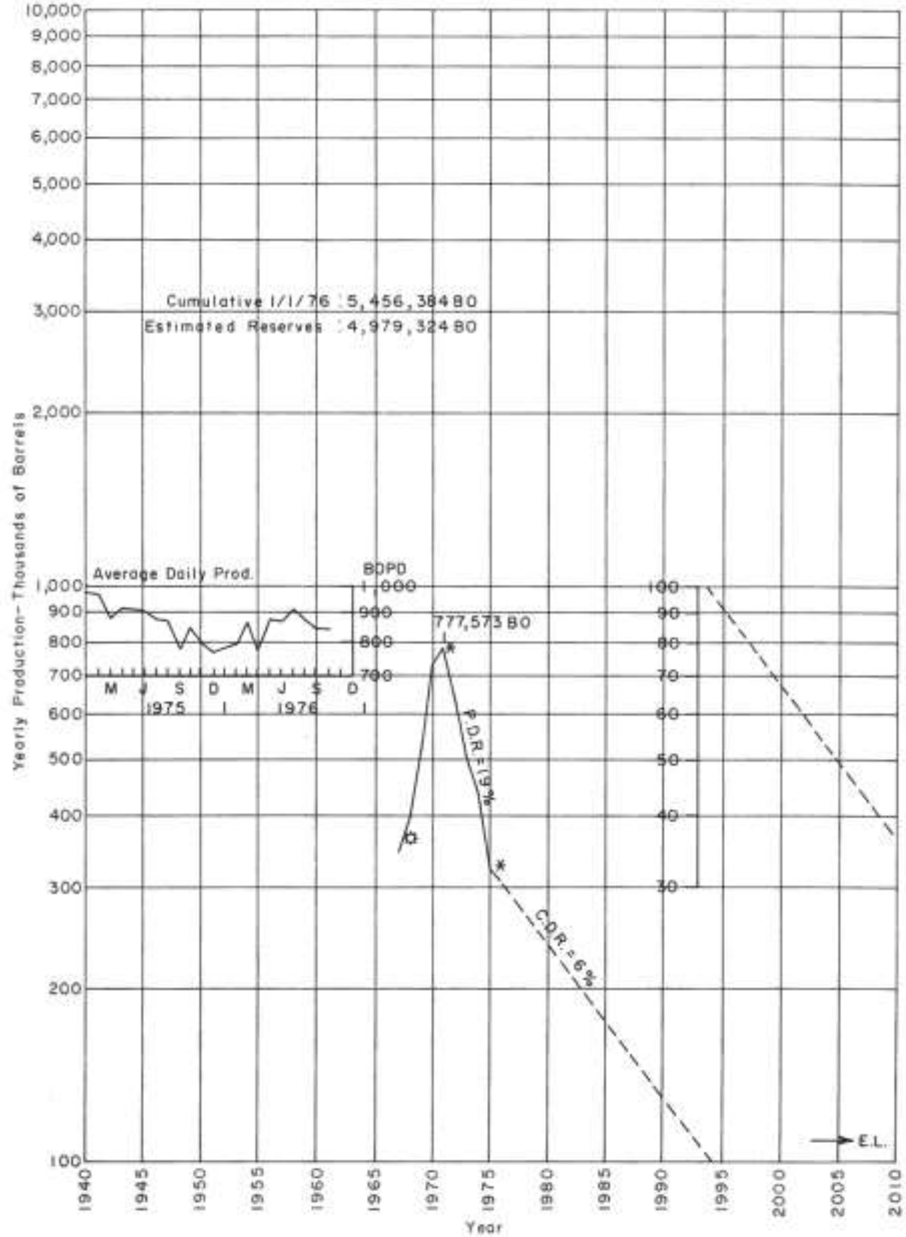

FIGURE 51—PUERTO CHIQUITO, WEST (MANCOS) POOL.

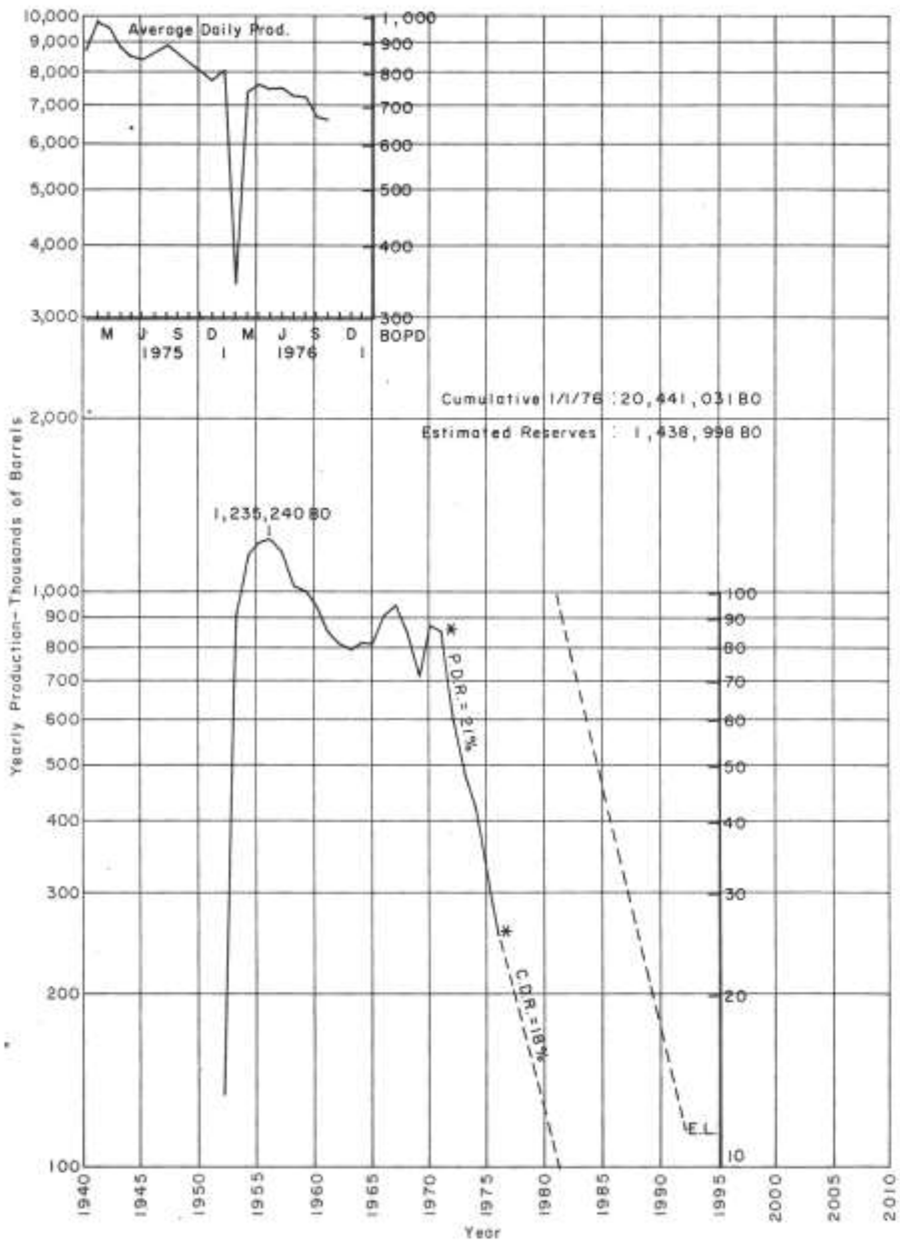

FIGURE 52—MOORE (DEVONIAN) POOL.

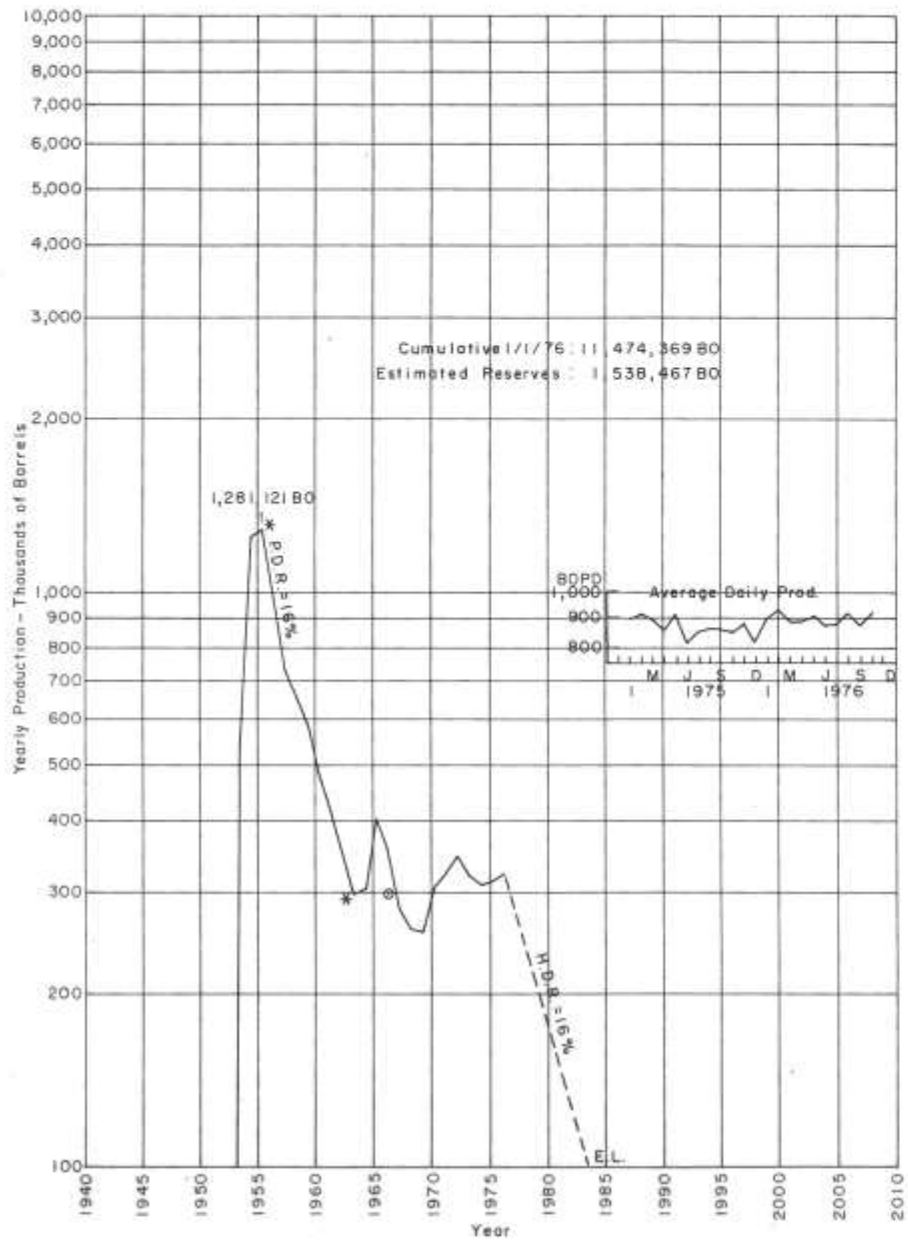

FIGURE 53—LOVINGTON (PADDOCK) POOL.

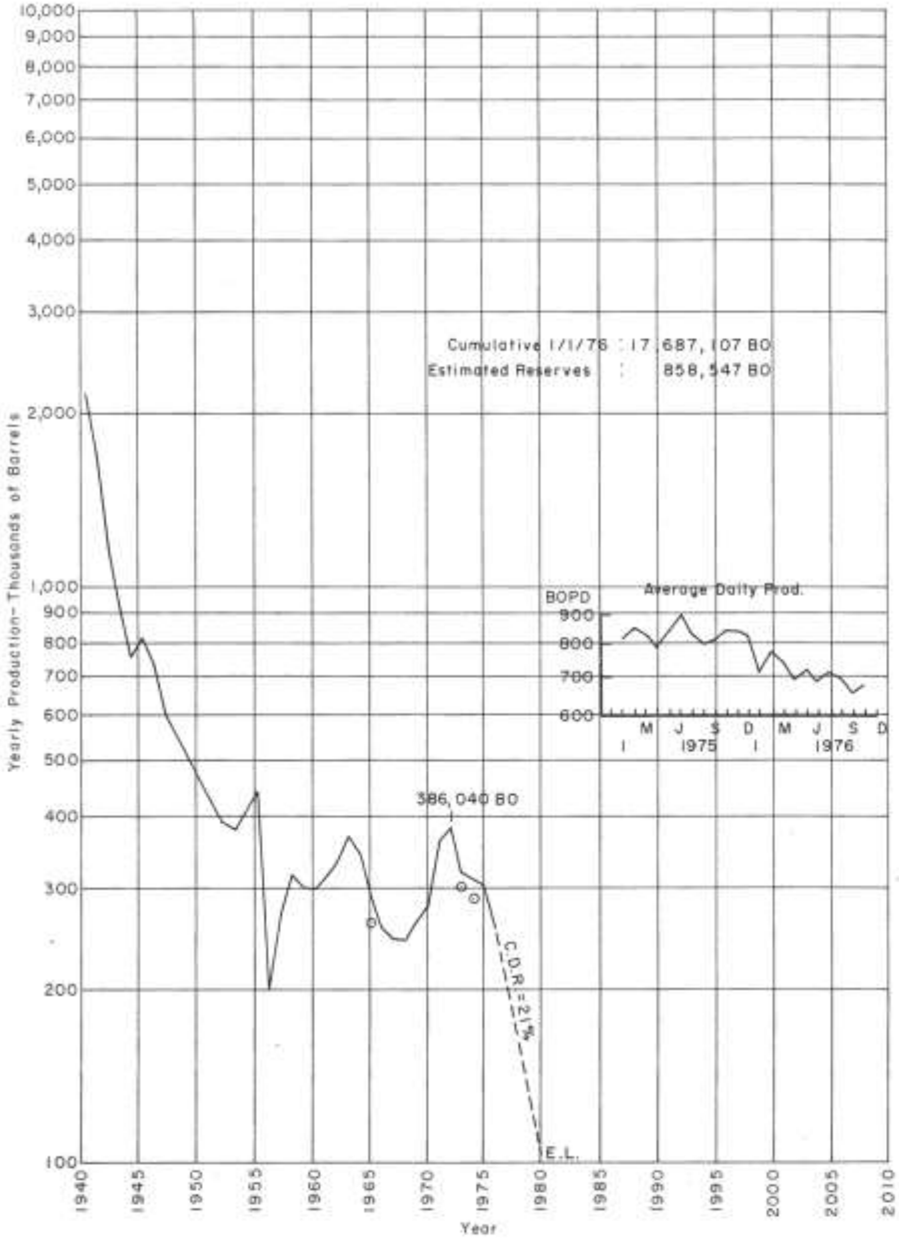

FIGURE 54—PENROSE-SKELLY (GRAYBURG) POOL.

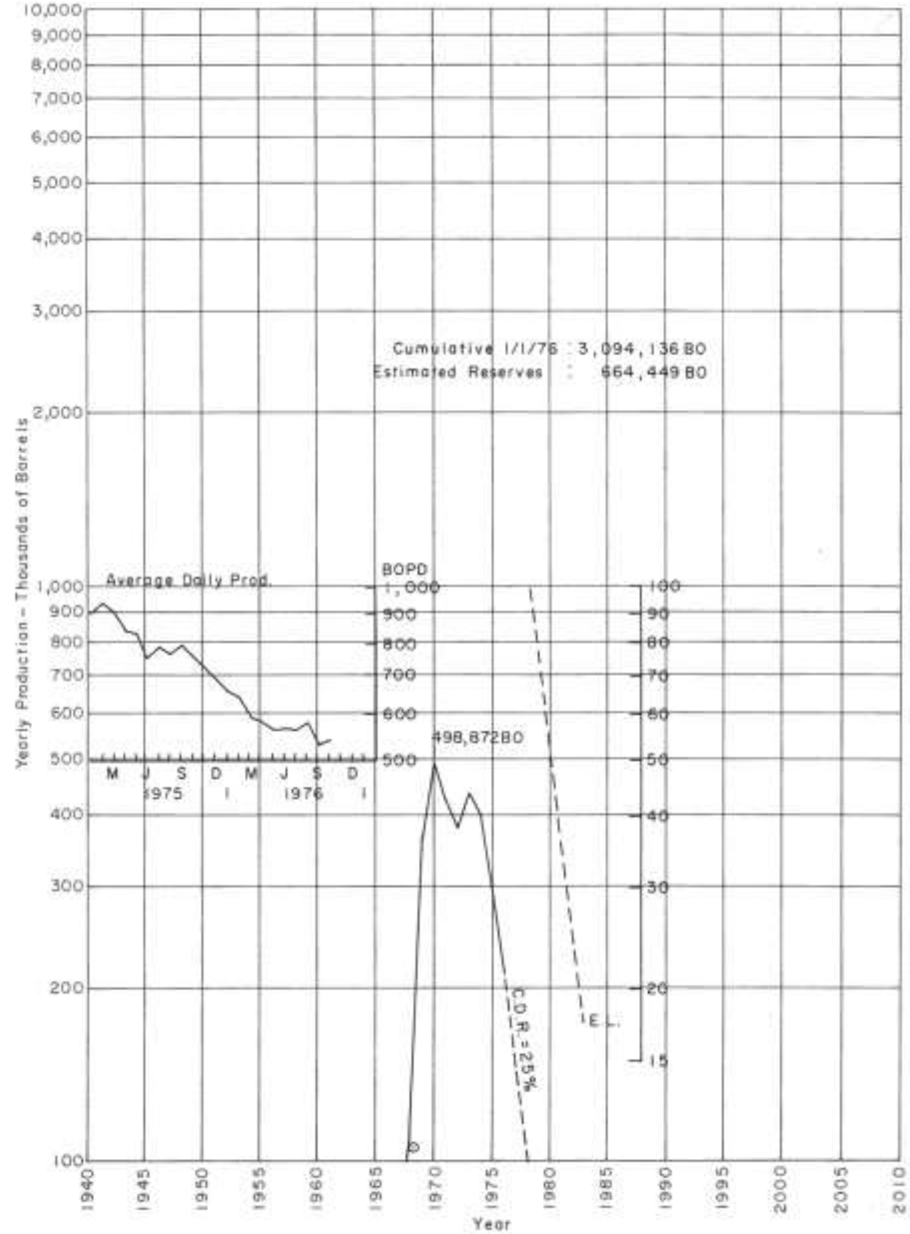

FIGURE 55—HOSPAH, SOUTH (UPPER SAND) POOL.

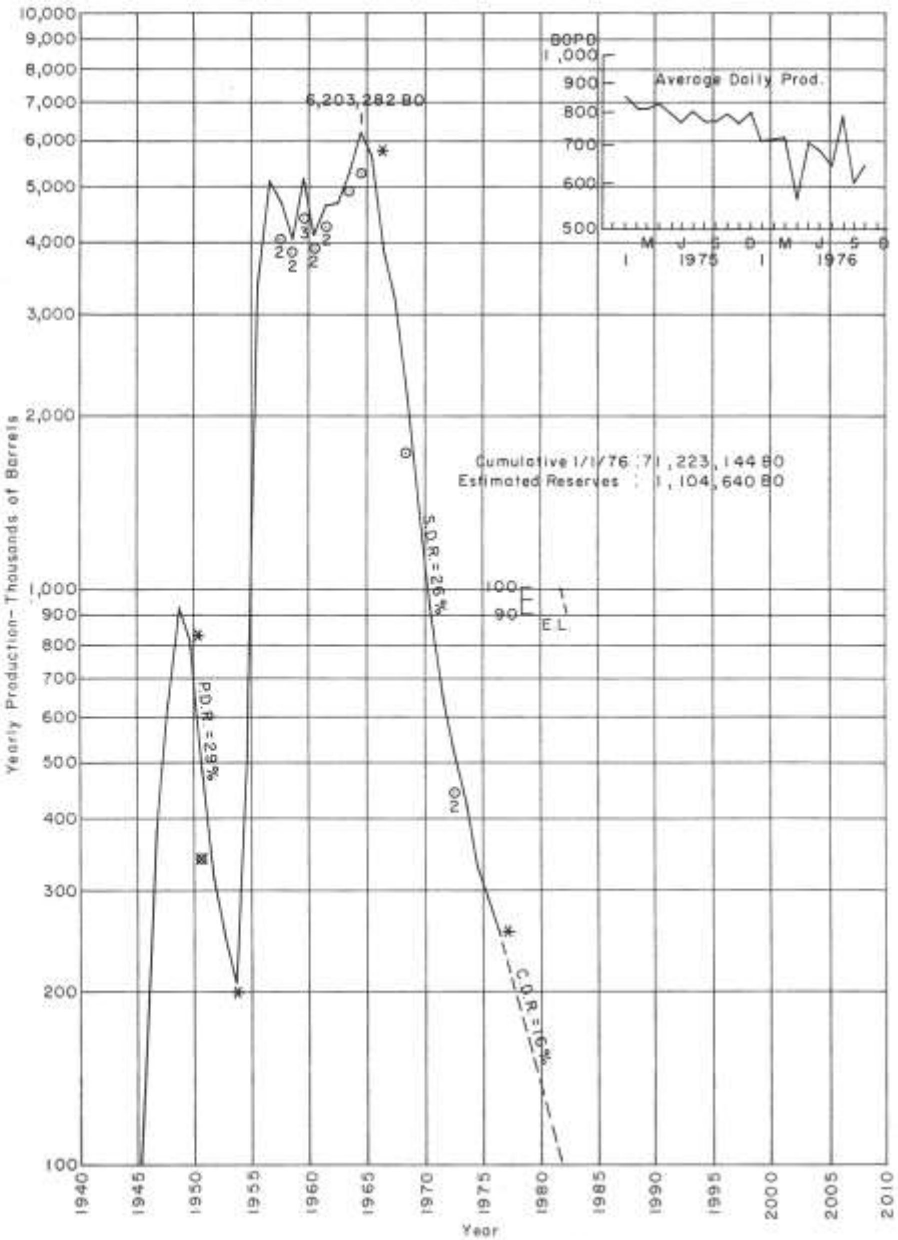

FIGURE 56—CAPROCK (QUEEN) POOL.

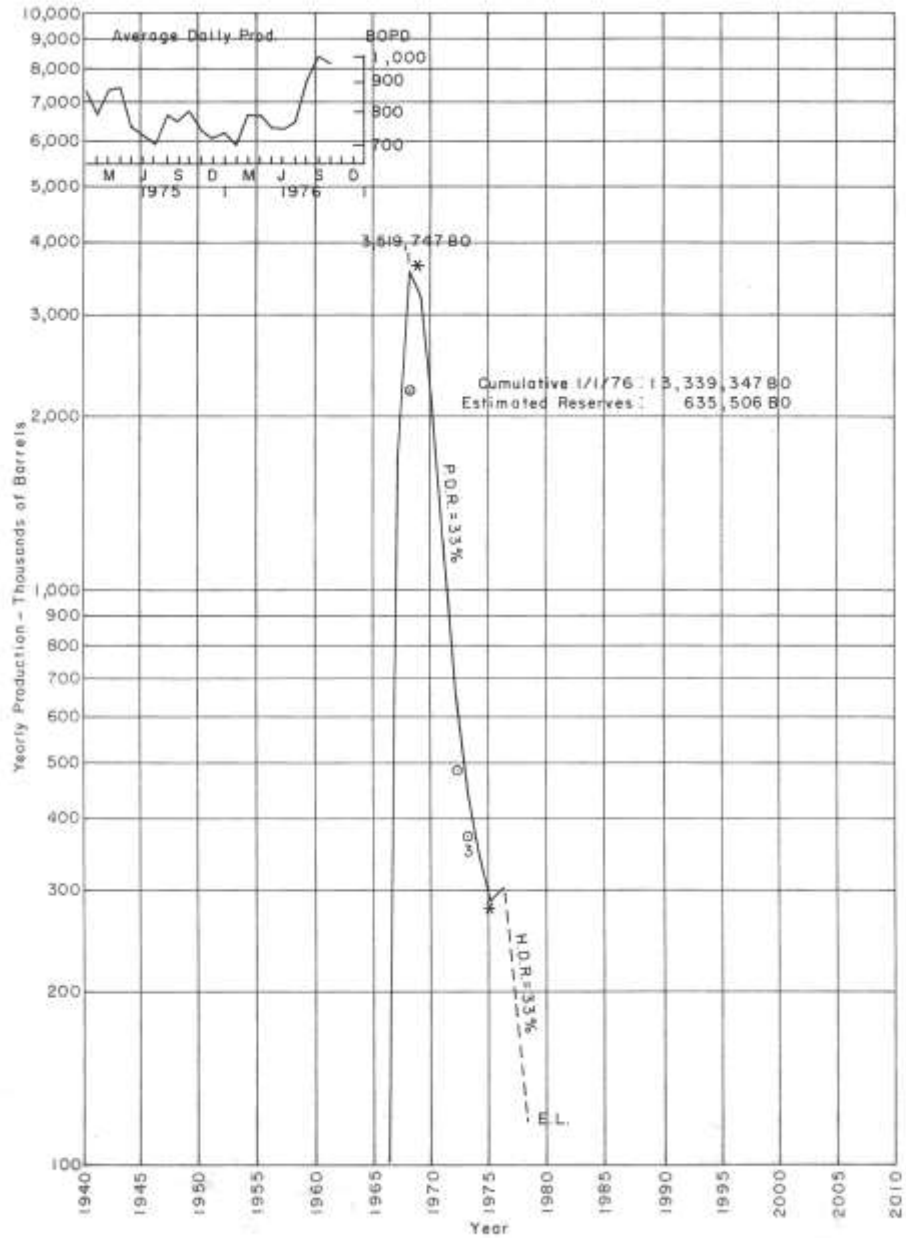

FIGURE 57—CATO (SAN ANDRES) POOL.

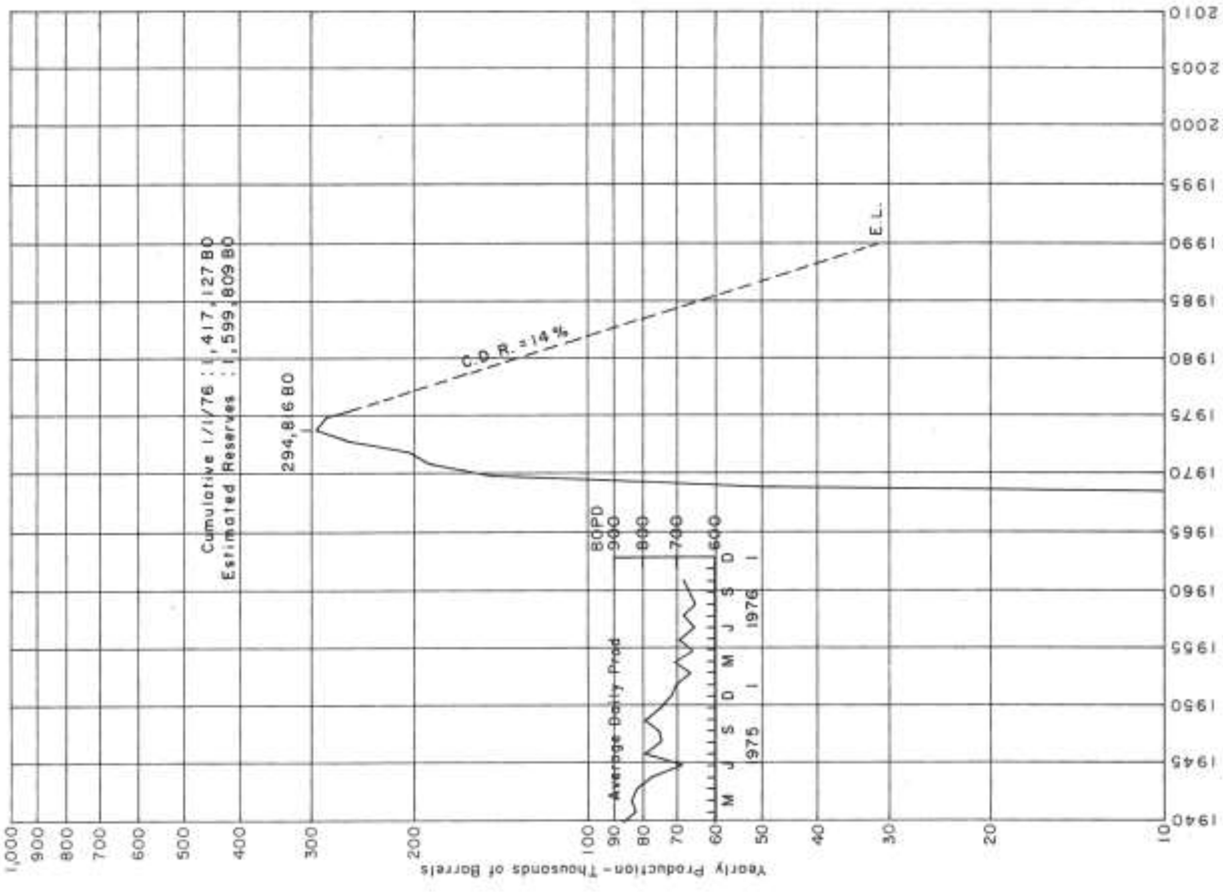

FIGURE 58—SAWYER, WEST (SAN ANDRES) POOL.

Type faces: Text in 10 pt English Times, leaded one point
References in 8 pt. English Times, leaded one point
Display heads in 24 pt. English Times bold

Appendices: Camera-ready copy furnished by NM Bureau of Mines & Mineral Resources

Presswork: Miehle Single Color Offset
Harris Single Color Offset

Binding: Saddlestitched with softbound cover

Paper: Cover on 65 lb. Ivory Nekoosa Cover
Text on 60 lb. White Offset

Ink: Cover—PMS 334
Text—Black