# ESTIMATION ON REMAINING RESERVE OF OIL AND GAS BY USING MATERIAL BALANCE METHOD IN MANN OIL FIELD

San Win

*Department of Petroleum Engineering, Technological University (Mandalay), Mandalay, Myanmar*

## ABSTRACT

*Where gravitational segregation occurs during production so that a gas cap forms, if the producing wells are completed low in the formation, their gas oil ratio will be lower and recovery will be improved. The remaining reserve depends on the production points that selected to represent the real well behavior, the way of dealing with the production data, and the human errors that might happen during the life of the field. Reserves estimating methods are usually categorized into three families: analogy, volumetric, and performance techniques. The performance-techniques methods usually are subdivided into simulation studies, material balance calculations, and decline-trend analyses. Reserve Estimators should utilize the particular methods, and the number of methods, which in their professional judgment are most appropriate given; (i)the geographic location, formation characteristics and nature of the property or group of properties with respect to which reserves are being estimated (ii)the amount and quality of available data and (iii)the significance of such property or group of properties in relation to the oil and gas properties with respect to which reserves are being estimated. This research paper is focused to estimate the current production rate of the wells and to predict field remaining reserves by using the geological configuration and the historical production data from CD(3700- 3800) sand in Mann Oil Field.*

**Keyword :** *formation , remaining reserve, behavior, characteristics, production*

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## 1. INTRODUCTION

The material balance is simply a volumetric balance, which atates that since the volume of a reservoir is a contstant, the sum of the volume changes of the oil, the free gas and the water volume must be zero. When an oil and gas reservoir is tapped with wells, oil and gas , and frequently some water , are produced , thereby reducing the reservoir pressure and causing the oil and gas to expand to fill the space vacated by the fluids removed. Where the oil and gas bearing strata are connected with water bearing strata, or aquifers water encroaches into the reservoir as the pressure drop owing to production, decreasing the extant to which the remaining oil and gas must expand and accordingly retarding the decline in reservoir pressure. Method based on production performance data are generally more accurate than those based strictly on inference from geological and engineering data. Data collection is a process of inspection, transforming and modeling data with the goal of discovering useful information, informing and support decision-making .

## 2. BACKGROUND HISTORY DATA OF MANN OIL FIELD

The Mann Oil field is located on the northern plunging end of the 30 miles long Mann-Minbu structural trend in proved oil province of the Central Burma Basin. (approximate Latitude N 20$^{o}$ 9' and Longitude E 94$^{o}$ 51'). The length and width of the producing area is about 10 miles and 1 mile respectively. It is situated on the northern plunging end of the Minbu anticline. It is asymmetric anticlinal fold and has broad crestal portion. The dip ranges between 35 to 45 degrees at the east and 45 to 75 degrees at the west flanks. The dip of the plunge is about 8-10 degree towards north. In this structure, oil exploration has been started since 1909. Many shallow wells had been drilled along the structure in Minbu, Shwelinbin, Htaukshabin, Palanyon Ywathaya, Htontaung and Peppi areas before the SecondWorld War was estimated to be about 3 million barrels. In 1962,1965,1968 and 1975 the geological, geophysical and seismic surveys were carried out. The first well was drilled on the northern part of the Mann Oil Field on 10.2.1970

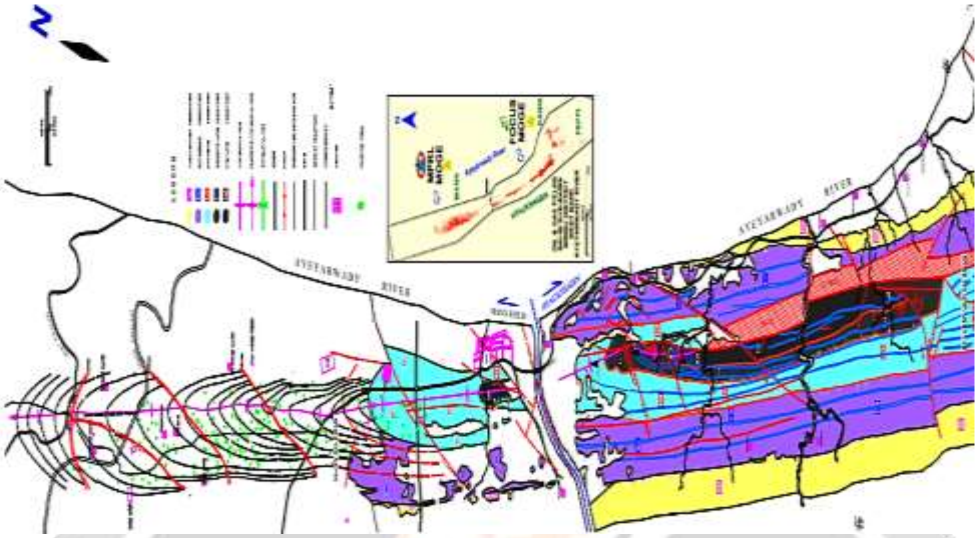

Fig-1 Geological Map of Mann - Htaukshabin Area
Source: Mann Oil Field (2017-18)

## 3.THE COLLECTIVE DATA USED IN RESERVE ESTIMATES

The raw data used in estimating proved reserves include the engineering and geological data for reservoir rock and its fluid content. These data are obtained from direct and indirect measurements. The data available for a given reservoir vary in kind, quality, and quantity. When a reservoir is first discovered only data from a single well are available, and prior to flow testing or actual production, proved reserves can only be inferred. As development of the reservoir proceeds, and flow tests are made or actual production commences, more and more data become available, enabling proved reserves estimates to become more accurate. [2]

Many different kinds of data are useful in making reserves estimates. They may include: data on porosity, permeability, and fluid saturations of the reservoir rocks (obtained directly from core analysis or from various types of electrical measurements taken in a well or several wells); data on the production of fluids from a well or several wells; geologic maps of the areal extent, thickness, and continuity of the reservoir rocks (inferred from well logs, geophysical, and geological data); and reservoir pressure and temperature data. Also involved are economic data including the current price of crude oil and natural gas, and various developmental and operating costs.

### 3.1 Phase Diagram for Reservoir Fluids

Using two component systems have examined various aspects of phase behavior. Reservoir fluids contain hundreds of components and therefore are multicomponent systems. The phase behavior of multicomponent hydrocarbon system in the liquid-vapor region. However, is very similar to that of binary system the mathematical and experimental analysis of the phase behavior is more complex. Figure (1) gives a schematic PT and PV diagram for reservoir fluid system. System which include crude oil also contain appreciable amounts of relatively non-volatile constituents such that dew points are practically unattainable. [3],[5]

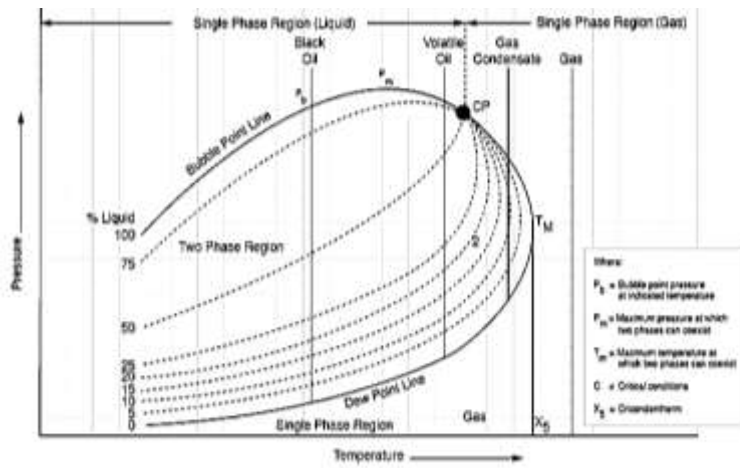

Fig-2 Sample Phase Diagram for Reservoir Fluid
Source: Fundamental of Reservoir Engineering (October 1977)

The behavior of several examples of typical crude oil and natural gas;

- Low-shrinkage oil (heavy oil, black oil)
- High-shrinkage oil (volatile oil)
- Retrograde condensate gas
- Wet gas
- Dry gas

Figure (2) is a useful diagram to illustrate the behavior of the respective fluid types above. However, it should be emphasized that for each fluid type there will be different scales. The vertical lines help to distinguish the different reservoir fluid types. Isothermal behavior below the critical point designates the behavior of oil systems and the fluid is liquid in the reservoir, whereas behavior to the right of the critical point illustrates the behavior of system which are gas in the reservoir. [3]

## 4.UTILIZATION ON MATERIAL BALANCE METHOD

The general form of the material balance equation was first presented by Schilthus in 1941. The Schilthuis material balance equation has long been regarded as one of the basic tools of reservoir engineering for interpreting and predicting reservoir performance.[4]

The zero-dimensional material balance is derived and subsequently applied, using mainly the interpretative technique of Havlena and Odeh, to gain an understanding of reservoir drive mechanism under primary recovery conditions. Some of the uncertainties attached to estimate of in-situ pore compressibility.

### 4.1 General Material Balance Equation

The basis for material balance is the law of conservation of mass (i.e., mass is neither created nor destroyed). The material balance equation (MBE) has long been recognized as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance. The MBE, when properly applied, can be used to:

(i) estimate initial hydrocarbon volumes in place;
(ii) predict reservoir pressure;
(iii) calculate water influx;
(iv) predict future reservoir performance;
(v) predict ultimate hydrocarbon recovery under various types of primary drive mechanisms.

Although in some cases it is possible to solve the MBE simultaneously for the initial hydrocarbon volumes, i.e., oil and gas volumes, and the water influx, generally one or the other must be known from other data or methods that do not depend on the material balance calculations. The accuracy of the calculated values depends on the reliability of the available data and if the reservoir characteristics meet the assumptions that are associated with the development of the MBE. The equation is structured to simply keep inventory of all materials entering, leaving, and accumulating in the reservoir. [2] , [4] [5]

The concept is simply based on the principle of the volumetric balance. It states that the cumulative withdrawal of reservoir fluids is equal to the combined effects of fluid expansion, pore volume compaction, and water influx. In its simplest form, the equation can be written on a volumetric basis as:

Initial volume = volume remaining + volume removed

Since oil, gas, and water are present in petroleum reservoirs, the MBE can be expressed for the total fluids or for any one of the fluids presents.

Several of the material balance calculations require the total pore volume (PV) as expressed in terms of the initial oil volume N and the volume of the gas cap. The expression for the total PV can be derived by conveniently introducing the parameter "m" into the relationship as follows. Initial gas cap volume fraction, m as

$$m = \frac{\text{initial volume of gas cap}}{\text{initial volume of oil in place}} = \frac{GB_{gi}}{NB_{oi}}$$

Solving for the volume of the gas cap gives;

Initial volume of the gas cap, $GB_{gi} = mNB_{oi,}$ bbl. The total volume of the hydrocarbon system is given; (initial oil volume + initial gas cap volume), $NB_{oi} + mNB_{oi} = (PV)(1\text{-}S_{wi})$ Solving for PV given;

$$PV = \frac{NB_{oi}(1+m)}{(1\text{-}S_w)}$$

The Material balance equation (MBE) can be determined separately from the hydrocarbon PVT and rock properties, as follows; Hydrocarbon PV occupied by the oil initially in place is,

Volume occupied by initial oil in place = $NB_{oi}$, bbl Equation . (1)

Hydrocarbon PV occupied by the gas in the gas cap,

Volume of gas cap = $mNB_{oi}$, bbl

Hydrocarbon PV occupied by the remaining oil,

Volume of the remaining oil = $(N - N_p)\, B_o$, bbl

Hydrocarbon PV occupied by the gas cap at reservoir pressure p,

As the reservoir pressure drops to a new level p, the gas in the gas cap expands and occupies a larger volume. Assuming no gas is produced from the gas cap during the pressure declines, the new volume of the gas cap can be determined as:

$$\text{Volume of the gas cap at p} = \left[\frac{mNB_{oi}}{B_{gi}}\right] B_{gi}$$

Hydrocarbon PV occupied by the evolved solution gas

Some of the solution gas that has been evolved from the oil will remain in the pore space and occupies a certain volume that can be determined by applying following material balance on the solution gas:

$$\left[\begin{array}{c}\text{Volume of} \\ \text{the evolved gas that} \\ \text{remain in the PV}\end{array}\right] = \left[NR_{si} - N_pR_p - (N - N_p)R_s\right]B_g,\ \text{SCF} \qquad \text{Equation (2)}$$

PV occupied by the net water influx,

Net water influx = $W_e$ - $W_pB_w$, bbl

Change in PV due to initial water and rock expansion; The connate water and formation compressibility are generally small in comparison to the compressibility of oil and gas. The compressibility of oil, $c_o$, is normally obtained from the bottom-hole tests and depend on the type of oil and amount of solution gas. $c_w$ may be taken as 3×10-6 per psi.

Formation compressibility, $c_f$ varies with the type of rock and its degree of cementation and induration as well as with its porosity and should be determined for a specific reservoir.

However, values of $c_w$ and $c_f$ are significant for undersaturated oil reservoirs and they account for an appreciable fraction of the production above bubble point. Ranges of compressibility are shown in following Table (1).

Table -1 Ranges on Type of Compressibility

| Type of compressibility | Restricted Range |
|---|---|
| Undersaturated oil, co | 5-50×10-6 psi-1 |
| Water, $c_w$ | 2-4×10-6 psi-1 |
| Formation, $c_f$ | 3-10×10-6 psi-1 |
| Gas at 1000 psi, cg at 5000 psi | 500-1000×10-6 psi-1 |
| Gas at 5000 psi, cg at 5000 psi | 50-200×10-6 psi-1 |

Assuming that $G_{inj}$ volumes of gas and Wing volumes of water have been injected for pressure maintenance, the total PV occupied by the two injected fluid is given by;

$$\text{Total volume} = G_{inj}B_{ginj} + W_{inj}B_w \quad \text{Equation (3)}$$

Combing Equation (1) and (3) with and rearranging gives:

$$N = \frac{[N_pB_o+(G_p-N_pR_s)B_g-(W_e-W_pB_w) -G_{inj}B_{ginj}-W_{inj}B_w]}{\left[\begin{array}{c}(B_o-B_{oi})+(R_{si}-R_s)B_g+mB_{oi}\left\{\left(\frac{B_g}{B_{gi}}\right)-1\right\} \\ +B_{oi}(1+m)\left\{\left(\frac{S_{wi}c_w+c_f}{(1-S_{wi})}\right)\Delta p\right\}\end{array}\right]} \quad \text{Equation( 4)}$$

Recognizing that the cumulative gas produced $G_p$ can be expressed in terms of the cumulative gas–oil ratio $R_p$ and cumulative oil produced, then:

$$G_p = R_pN_p$$

Combining Equation (3) with (4) gives:

$$N = \frac{[N_p\{B_o+(R_p-R_s)B_g\}-(W_e-W_pB_w)-G_{inj}B_{ginj}-W_{inj}B_w]}{\left[\begin{array}{c}(B_o-B_{oi})+(R_{wi}-R_s)B_g+mB_{oi}\left\{\left(\frac{B_g}{B_{gi}}\right)-1\right\} \\ +B_{oi}(1+m)\left\{\left(\frac{S_{wi}c_w+c_f}{(1-S_{wi})}\right)\Delta p\right\}\end{array}\right]} \quad \text{Equation (5)}$$

This relationship is referred to as the generalized MBE. [2] , [4] [5] A more convenient form of the MBE can be arrived at, by introducing the concept of the total (two-phase) formation volume factor Bt into the equation. This oil PVT property is defined as:

$$B_t = B_o + (R_{si} - R_s)\, B_g \quad \text{Equation (6)}$$

Introducing Bt into Equation (6) and assuming, for the sake of simplicity, that there is no water or gas injection.

$$N = \frac{[N_p\{B_o+(R_p-R_s)B_g\}-(W_e-W_pB_w)]}{\left[\begin{array}{c}(B_t-B_{ti})+mB_{ti}\left\{\left(\frac{B_g}{B_{gi}}\right)-1\right\} \\ +B_{ti}(1+m)\left\{\left(\frac{S_{wi}c_w+c_f}{(1-S_{wi})}\right)\Delta p\right\}\end{array}\right]} \quad \text{Equation (7)}$$

**4.2 Material Balance Equation As an Equation of a Straight Line**

In developing a methodology for determining the above three unknowns, Havlena and Odeh (1963, 1964) expressed Equation (7) in the following form:

$$N_p\left[B_o+(R_p-R_sB_g)\right]+W_pB_w=\begin{bmatrix} N\left[(B_o-B_{oi})+(R_p-R_s)B_g\right] \\ +mNB_{oi}\left[\frac{B_g}{B_{gc}}-1\right]+1 \\ \left\{N(1+m)B_{oi}\left[\frac{c_wS_{wi}-c_f}{1-S_{wi}}\right]\Delta p\right\} \\ +W_e+W_{inj}B_w+G_{inj}B_{ginj}\end{bmatrix} \quad \text{Equation (8)}$$

Havlena and Odeh further expressed Equation (6) in a more condensed form as:

$$F = N\left[E_o + mE_g + E_{f.w}\right] + (We + W_{inj}B_w + G_{inj}B_{ginj}) \quad \text{Equation(9)}$$

Assuming, for the purpose of simplicity, that no pressure maintenance by gas or water injection is being considered, the above relationship can be further simplified and written as:

$$F = N\left[E_o + mE_g + E_{f.w}\right] + We \quad \text{Equation (10)}$$

in which the terms F, $E_o$, $E_g$, and $E_{f,w}$ are defined by the following relationships :

(a) F represents the underground withdrawal and is given by:

$$F = N_p\left[B_o + (R_p - R_s)B_g\right] + W_pB_w \quad \text{Equation(11)}$$

In terms of the two-phase formation volume factor $B_t$, the underground withdrawal "F" can be written as:

$$F - N_p\left[R_f + (R_p - R_{si})B_g\right] + W_pB_w \quad \text{Equation(12)}$$

(b) $E_o$ describes the expansion of oil and its originally dissolved gas and is expressed in terms of the oil formation volume factor as:

$$E_o = (B_o - R_{oi}) + (R_{si} - R_s)B_g \quad \text{Equation(13)}$$

or, equivalently, in terms of $B_t$;

$$E_o = B_t - B_{ti} \quad \text{Equation(14)}$$

(c) $E_g$ is the term describing the expansion of the gas cap gas and is defined by the following expression:In terms of the two-phase formation volume factor $B_t$, essentially $B_{ti} = B_{oi}$ or:

$$E_g = B_{oi}\left[(B_g/_{Bgi})-1\right] \quad \text{Equation(15)}$$

(d) $E_{f.w}$ represents the expansion of the initial water and the reduction in the PV and is given by:

$$E_{f.w} = (1+m)B_{oi}\left[\frac{c_wS_{wi}+c_f}{1-S_{wi}}\right]\Delta p \quad \text{Equation(16)}$$

Havlena and Odeh examined several cases of varying reservoir types with Equation (9).and pointed out the relationship can be rearranged in the form of a straight line.

For example, in the case of a reservoir in which that has no initial gas cap (i.e., m = 0) or water influx (i.e., $W_e = 0$), and negligible formation and water compressibility (i.e., $c_f$ and $c_w = 0$), Equation (8) reduces to:

$$F = NE_o$$

This expression suggests that a plot of the parameter "F" as a function of the oil expansion parameter "$E_o$" would yield a straight line with slope "N" and intercept equal to 0. The straight-line method requires the plotting of a variable group versus another variable group, with the variable group selection depending on the mechanism of production under which the reservoir is producing.

The most important aspect of this method of solution is that it attaches significance to the sequence of the plotted points, the direction in which they plot, and to the shape of the resulting plot. This significant observation will provide the engineer with valuable information that can be used in determining the following unknowns:

(i) initial oil-in-place N,
(ii) size of the gas cap m,
(iii) water influx $W_e$,
(iv) driving mechanism,
(v) average reservoir pressure.

The applications of the straight-line form of the MBE in solving reservoir engineering problems are presented next to illustrate the usefulness of this particular form. [2] , [4] [5]

**4.3 Gas Cap Drive Reservoir**

Whenever a gas cap is present or its size is to be determined, an exceptional degree of accuracy of pressure data is required. The specific problem with reservoir pressure is that the underlying oil zone in a gas cap drive reservoir exists initially near its bubble point pressure. [2] , [4] , [6]

Therefore, the flowing pressures are obviously below the bubble point pressure, which exacerbates the difficulty in conventional pressure buildup interpretation to determine average reservoir pressure. Assuming that there is no natural water influx or it is negligible (i.e.$W_e$ = 0), the Havlena and Odeh material balance can be expressed as:

$$F = [E_o + mE_g] \qquad \text{Equation(17)}$$

in which the variables, F, $E_o$ equations are similar in previous section and e.g is given by:

$$E_g = B_{oi}\,[[B_g/_{Bgi}] - 1] \qquad \text{Equation(18)}$$

The methodology in which Equation (16) can be used depends on the number of unknowns in the equation. There are three possible unknown in Equation (17). These are,

(i) N is unknown, m is known
(ii) m is unknown, N is known
(iii) N and m are unknown.

In N is unknown, m is known, Equation (16). indicates that a plot of “F versus ($E_o$ + mEg)” on Cartesian scale would produce a straight line through the origin with a slope of “N”. In unknown “m”, known “N”, Equation (16) can be rearranged as an equation of straight line, to give:

$$\frac{F}{N} - E_o = mE_g \qquad \text{Equation(19)}$$

In N and m are unknown, Equation (18) can be re-expressed as:

$$\frac{F}{E_o} = N + mN\,[E_g/E_o] \qquad \text{Equation(20)}$$

**4.4 Water Drive Reservoir**

In a water drive reservoir, identifying the type of the aquifer and characterizing its properties are perhaps the most challenging tasks involved in conducting a reservoir engineering study.

Yet, without an accurate description of the aquifer, future reservoir performance and management cannot be properly evaluated. The full MBE can be expressed again as:

$$F = N\,[E_o + mE_g + E_{f.w}] + W_e \qquad \text{Equation(21)}$$

Dake (1978) pointed out that the term “$E_{f,w}$” can frequently be neglected in water drive reservoirs. This is not only for the usual reason that the water and pore compressibility are small, but also because a water influx helps to maintain the reservoir pressure and, therefore, the Δp appearing in the $E_{f,w}$ term is reduced, or:

$$F = N\,[E_o + mE_g] + W_e$$

If, in addition, the reservoir has an initial gas cap,

$$F = NE_o + W_e$$

In attempting to use the above two equations to match the production and pressure history of a reservoir, the greatest uncertainty is always the determination of the water influx $W_e$. In fact, in order to calculate the water influx, the engineer is confronted with what is inherently the greatest uncertainty in the whole subject of reservoir engineering.These, however, are seldom measured since wells are not deliberately drilled into the aquifer to obtain such information.

**4.5 Saturated Oil Reservoir**

An oil reservoir that originally exists at its bubble point pressure is referred to as a "saturated oil reservoir." The main driving mechanism in this type of reservoir results from the liberation and expansion of the solution gas as the pressure drops below the bubble point pressure. [1] , [4]

The only unknown in a volumetric saturated oil reservoir is the initial oil-in-place "N". Normally, the water and rock expansion term "$E_{f.,w}$" is negligible in comparison to the expansion of solution gas; however, it is recommended to include the term in the calculations. [4] [6]

However, the parameters "F" and "$E_o$" that constitute the above expression are given in an expanded form to reflect the reservoir condition as the pressure drops below the bubble point. The underground withdrawal "F" and the expansion term $(E_o + E_{f,w})$ are defined by:

F in terms of Bo, $F = N_p [B_o + (R_p - R_s) B_g + W_pB_w]$ ,

Or equivalence in terms of $B_t$,

$F = N_p [B_t + (R_p - R_{si}) B_g] + W_pB_w$

$E_o$ in terms of $B_o$, $E_o = (B_o – B_{oi}) + (R_{si} - R_s) B_g$

Or equivalence in terms of $B_t$,

$E_o = (B_t - B_{ti})$

Where,

$Bg = 0.00504 \frac{zt}{p}$

If $p \leq p_o$, $B_o = 0.972 + 0.000147 F^{1.175}$

Villena-Lanzi developed a correlation to estimate co. The correlation is good for pressure and is given by:

$$\ln(c_o)= \begin{bmatrix} -0.664-1.430\ln(p) -0.395\ln(P_b) \\ +0.390\ln(T) +0.455\ln(R_{sob}) \\ +0.262\ln(P_{oAPI}) \end{bmatrix} \quad \text{Equation (22 )}$$

It should be pointed out that it is a characteristic of most solution gas drive reservoirs that only a fraction of the oil-in-place is recoverable by primary depletion methods.

From a solution gas drive reservoir, it is assumed that there is no initial gas cap, thus m=0, and that aquifer is relatively small in volume and the water influx is negligible. Furthermore, above the bubble point, $R_s = R_{si} = R_p$, since all the gas produced at the surface must have been dissolved in the oil in the reservoir.Underthese assumptions, the material balance equation can be described the following;

$$N_pB_o = NB_{oi}\left(\frac{B_o-B_{oi}}{B_{oi}} + \frac{(c_w S_{wc}+c_f)}{1-S_w}\Delta p\right) \quad \text{Equation (23)}$$

The component describing the reduction in the hydrocarbon pore volume, due to the expansion of the connate water and reduction in pore volume, cannot be neglected for an undersaturated oil reservoir since the compressibility $c_w$ and $c_f$ are generally of the same order of magnitude as the compressibility of the oil. [4]

$$c_o = \frac{(B_o-B_{oi})}{B_{oi}\,\Delta p}$$

$$N_pB_o = NB_{oi}\left(c_o \frac{(c_w S_{wc}+c_f)}{1-S_{wc}}\right)\Delta p \quad \text{Equation (24)}$$

Scince there are only two fluids in the reservoir, oil and connate water, then the sum of the fluid saturation must be 100% of the pore volume, or

$S_o + S_{wc} = 1$

$N_pB_o = NB_{oi}\, c_e\, \Delta p$

Thus, the compressibility must be used in conjunction with the hydrocarbon pore volume a solution gas drive reservoir is one in which the principal drive mechanism id the expansion of the oil and its originally dissolved gas.Under more normal circumstances, the gas is prevented from moving towards the top of the structural by inhomogeneities in the reservoir and capillary trapping forces. Reducing a well`s offtake rate or closing it in temporarily to allow gas -oil separation to occur may, under these circumstances, do little to reduce the producing gas oil ratio. The primary recovery factor from such a reservoir is very low and will seldom exceed 30% of the oil in place.[4] , [6]

## 5.5Estimation of Initial Oil in Place by Straight Line Equation in 3700' (CD Sand)

Table -2 3700'(CD Sand ) Fault block Production Data

| Year | Pressure | Np | Gp | Water | GOR |
|---|---|---|---|---|---|
| 1971 | 1840 | 51627.20 | 18.845 | 4 | 0.000365 |
| 1972 | 1780 | 453135.94 | 236.966 | 0.38 | 0.000523 |
| 1973 | 1640 | 576325.73 | 553.239 | 5674.55 | 0.00096 |
| 1974 | 1378 | 604499.08 | 968.548 | 9476.84 | 0.00160 |
| 1975 | 1328 | 548762.77 | 820.891 | 9606.21 | 0.00150 |
| 1976 | 1283 | 547491.48 | 867.891 | 23683.45 | 0.001585 |
| 1977 | 1238 | 549676.75 | 910.162 | 8624.10 | 0.001656 |
| 1978 | 1202 | 445671.00 | 774.017 | 4885.10 | 0.001737 |
| 1979 | 1195 | 322832.07 | 460.848 | 3370.22 | 0.001428 |
| 1980 | 1188 | 300866.19 | 365.006 | 8375.08 | 0.001213 |
| 1981 | 1187 | 856128.59 | 1004.822 | 56718.8 | 0.001174 |
| 1982 | 1188 | 197071.57 | 204.534 | 45644.72 | 0.001038 |
| 1983 | 1191 | 183022.50 | 128.477 | 72799.74 | 0.00070 |
| 1984 | 1193 | 172404.73 | 163.815 | 98487.06 | 0.00095 |
| 1985 | 1192 | 185957.55 | 76.033 | 90997.15 | 0.000409 |
| 1986 | 1185 | 198665.06 | 48.727 | 64579.61 | 0.000245 |
| 1987 | 1182 | 192749.37 | 27.795 | 29224.02 | 0.000144 |
| 1988 | 1177 | 171853.95 | 22.403 | 26022.09 | 0.00013 |
| 1989 | 1166 | 213593.69 | 32.707 | 24146.01 | 0.000153 |
| 1990 | 1142 | 265918.71 | 71.552 | 26633.51 | 0.000269 |
| 1991 | 1119 | 219639.15 | 152.101 | 29057.70 | 0.000693 |
| 1992 | 1100 | 194110.34 | 158.657 | 30437.96 | 0.000817 |
| 1993 | 1080 | 193911.44 | 186.825 | 34362.84 | 0.000963 |
| 1994 | 1059 | 172845.33 | 239.54 | 40179.10 | 0.001386 |
| 1995 | 1043 | 148688.84 | 180.792 | 36288.25 | 0.001216 |
| 1996 | 1027 | 139587.30 | 148.051 | 41167.39 | 0.001061 |
| 1997 | 1009 | 120648.44 | 109.741 | 45235.98 | 0.00091 |
| 1998 | 973 | 93370.92 | 124.899 | 37575.70 | 0.001338 |
| 1999 | 953 | 90290.25 | 129.154 | 43368.38 | 0.00143 |
| 2000 | 934 | 83885.05 | 77.643 | 38542.51 | 0.000926 |
| 2001 | 917 | 75290.56 | 54.467 | 48366.17 | 0.000723 |
| 2002 | 899 | 73414.94 | 47.994 | 40610.61 | 0.000654 |
| 2003 | 881 | 69399.25 | 41.350 | 39128.21 | 0.00060 |
| 2004 | 864 | 64938.64 | 35.995 | 36273.54 | 0.000554 |
| 2005 | 845 | 59599.10 | 34.254 | 35510.40 | 0.000575 |
| 2006 | 826 | 55465.87 | 20.022 | 30455.51 | 0.000361 |
| 2007 | 810 | 52913.88 | 18.230 | 29845.89 | 0.000345 |
| 2008 | 794 | 49465.90 | 17.039 | 29697.40 | 0.000344 |
| 2009 | 781 | 43651.16 | 16.436 | 32136.88 | 0.000377 |
| 2010 | 772 | 40413.86 | 21.433 | 34146.23 | 0.00053 |
| 2011 | 763 | 41488.39 | 23.813 | 30904.85 | 0.000574 |
| 2012 | 755 | 44802.41 | 51.262 | 26869.72 | 0.001144 |
| 2013 | 748 | 43103.58 | 38.941 | 26024.83 | 0.00090 |
| 2014 | 741 | 38507.06 | 26.758 | 24684.84 | 0.000695 |
| 2015 | 739 | 37562.08 | 14.925 | 27195.36 | 0.00040 |
| 2016 | 740 | 39704.22 | 24.383 | 26879.60 | 0.000614 |
| 2017 | 739 | 10116.47 | 5.182 | 7633.630 | 0.000512 |

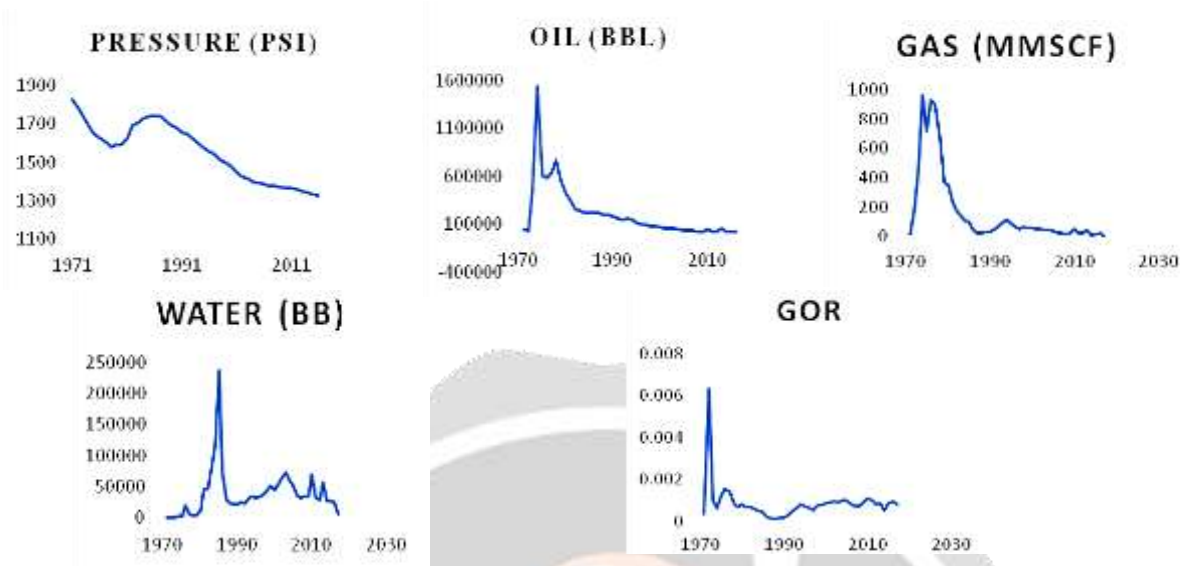


Chart-1 3700'(CD) Fault Block Drive Mechanism Graph

According to these above Chart-1 this curvature reservoir drive mechanism may be ‘water drive mechanism’.

The above production data that the initial oil in place as calculated from the depletion drive reservoir performance data is around 18.029825MMSTB. The values of cumulative production in Mann Oil Field by 3700' sand by using historical data is not quite difference from 16.31 MMSTB;

Present oil recovery percent = $N_p/N \times 100$
=53.62 % ~ 54%
Reserve @ 33% = EUR – Cum
= 101.9435 MSTB

### 5.6 Estimation of Initial Oil in Place by Straight Line Equation in 3800' (CD Sand)

Table -3 3800'(CD Sand) Fault block Production Data

| Year | Pressure | Np | Gp | Water | GOR |
|---|---|---|---|---|---|
| 1971 | 1840 | 51627.20 | 18.845 | 4 | 0.000365 |
| 1972 | 1780 | 453135.94 | 236.966 | 0.38 | 0.000523 |
| 1973 | 1640 | 576325.73 | 553.239 | 5674.55 | 0.00096 |
| 1974 | 1378 | 604499.08 | 968.548 | 9476.84 | 0.00160 |
| 1975 | 1328 | 548762.77 | 820.891 | 9606.21 | 0.00150 |
| 1976 | 1283 | 547491.48 | 867.891 | 23683.45 | 0.001585 |
| 1977 | 1238 | 549676.75 | 910.162 | 8624.10 | 0.001656 |
| 1978 | 1202 | 445671.00 | 774.017 | 4885.10 | 0.001737 |
| 1979 | 1195 | 322832.07 | 460.848 | 3370.22 | 0.001428 |
| 1980 | 1188 | 300866.19 | 365.006 | 8375.08 | 0.001213 |
| 1981 | 1187 | 856128.59 | 1004.822 | 56718.8 | 0.001174 |
| 1982 | 1188 | 197071.57 | 204.534 | 45644.72 | 0.001038 |
| 1983 | 1191 | 183022.50 | 128.477 | 72799.74 | 0.00070 |
| 1984 | 1193 | 172404.73 | 163.815 | 98487.06 | 0.00095 |
| 1985 | 1192 | 185957.55 | 76.033 | 90997.15 | 0.000409 |
| 1986 | 1185 | 198665.06 | 48.727 | 64579.61 | 0.000245 |
| 1987 | 1182 | 192749.37 | 27.795 | 29224.02 | 0.000144 |
| 1988 | 1177 | 171853.95 | 22.403 | 26022.09 | 0.00013 |
| 1989 | 1166 | 213593.69 | 32.707 | 24146.01 | 0.000153 |
| 1990 | 1142 | 265918.71 | 71.552 | 26633.51 | 0.000269 |
| 1991 | 1119 | 219639.15 | 152.101 | 29057.70 | 0.000693 |
| 1992 | 1100 | 194110.34 | 158.657 | 30437.96 | 0.000817 |
| 1993 | 1080 | 193911.44 | 186.825 | 34362.84 | 0.000963 |
| 1994 | 1059 | 172845.33 | 239.54 | 40179.10 | 0.001386 |
| 1995 | 1043 | 148688.84 | 180.792 | 36288.25 | 0.001216 |
| 1996 | 1027 | 139587.30 | 148.051 | 41167.39 | 0.001061 |
| 1997 | 1009 | 120648.44 | 109.741 | 45235.98 | 0.00091 |
| 1998 | 973 | 93370.92 | 124.899 | 37575.70 | 0.001338 |
| 1999 | 953 | 90290.25 | 129.154 | 43368.38 | 0.00143 |
| 2000 | 934 | 83885.05 | 77.643 | 38542.51 | 0.000926 |
| 2001 | 917 | 75290.56 | 54.467 | 48366.17 | 0.000723 |
| 2002 | 899 | 73414.94 | 47.994 | 40610.61 | 0.000654 |
| 2003 | 881 | 69399.25 | 41.350 | 39128.21 | 0.00060 |
| 2004 | 864 | 64938.64 | 35.995 | 36273.54 | 0.000554 |
| 2005 | 845 | 59599.10 | 34.254 | 35510.40 | 0.000575 |
| 2006 | 826 | 55465.87 | 20.022 | 30455.51 | 0.000361 |
| 2007 | 810 | 52913.88 | 18.230 | 29845.89 | 0.000345 |
| 2008 | 794 | 49465.90 | 17.039 | 29697.40 | 0.000344 |
| 2009 | 781 | 43651.16 | 16.436 | 32136.88 | 0.000377 |
| 2010 | 772 | 40413.86 | 21.433 | 34146.23 | 0.00053 |
| 2011 | 763 | 41488.39 | 23.813 | 30904.85 | 0.000574 |
| 2012 | 755 | 44802.41 | 51.262 | 26869.72 | 0.001144 |
| 2013 | 748 | 43103.58 | 38.941 | 26024.83 | 0.00090 |
| 2014 | 741 | 38507.06 | 26.758 | 24684.84 | 0.000695 |
| 2015 | 739 | 37562.08 | 14.925 | 27195.36 | 0.00040 |
| 2016 | 740 | 39704.22 | 24.383 | 26879.60 | 0.000614 |
| 2017 | 739 | 10116.47 | 5.182 | 7633.630 | 0.000512 |

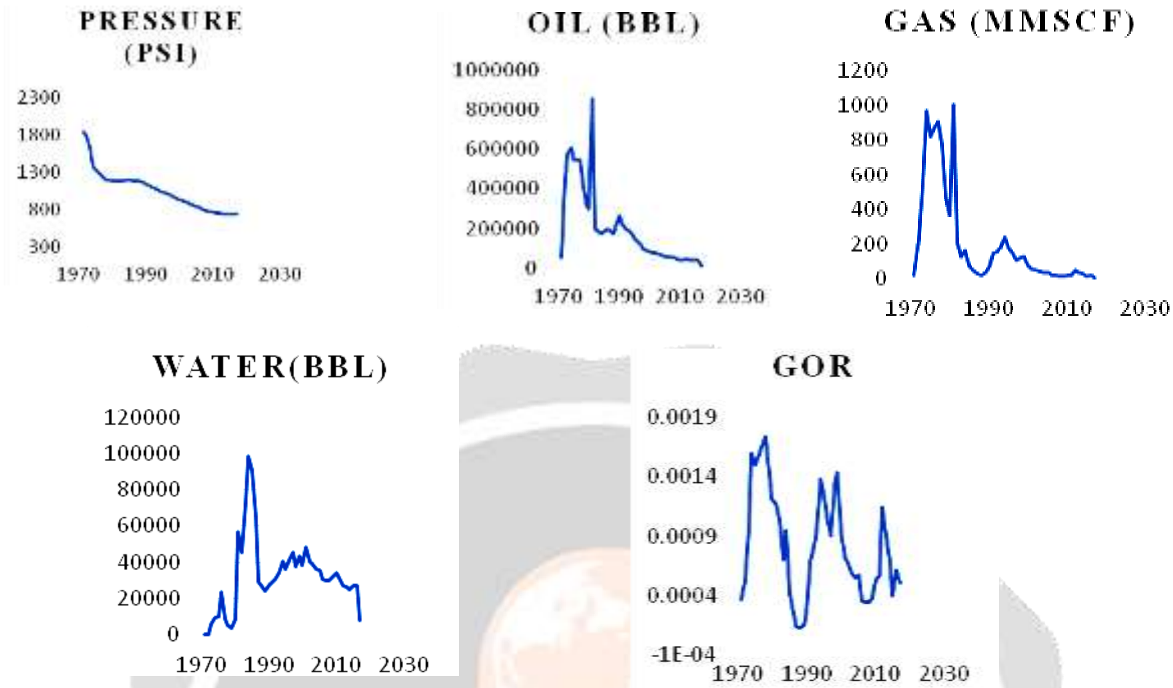


Chart-2 3800'(CD Sand ) Fault Block Drive Mechanism Graph

According to these above Chart-2, this curvature reservoir drive mechanism may be 'solution gas drive or depletion drive mechanism'.

The above production data that the initial oil in place as calculated from the depletion drive reservoir performance data is around 27.19080661 MMSTB. The values of cumulative production in Mann Oil Field by 3800' sand by using historical data is not quite difference from 21.82 MMSTB;

Present oil recovery percent $= N_p/N$
$= 34.76\ \% \sim 35\%$

Reserve @ 33% = EUR – Cum
= 181.45362 MSTB

## 6. **CONCLUSIONS**

This research paper contains the calculation of oil and gas reserves to estimate in the Mann Oil Field structure by the Material Balance method. The mathematical calculation and graphical results can be made to predict future production rate. Reserve estimation of oil and gas by using Material Balance Method is highly depend on field production record, laboratory test and individual well completion design. So the reserve of (3700'-3800'-CD) in Mann Oil Field is irrelevance because of field data information are fragmentary. The total reserves are also mainly depended on economic limit. Economic limit based on gross present value and gross profits. It is a powerful tool that helps determine the reserve, recovery factor, and drive mechanism. It can be applied to a variety of reservoir either with or without water influx. Finally, the author concludes that the calculation by Material Balance method can recommend to estimate the oil and gas reserves when about 20% of the initial estimated reserve is produced, or when 10% of initial reservoir pressure has declined and also used to infer aquifer and gas cap behavior.

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