UNCONVENTIONAL ESTIMATION OF OIL AND GAS RESERVES USING PRODUCTION RATES DECLINE TRENDS ANALYSIS

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CERTIFICATION

We certify that this work **"Estimation of Oil and Gas Reserves Using Production Rates Decline Trends Analysis"** was carried out by **Udie, Akifeye Celestine (Reg No. 20054482778)** in partial fulfillment of the requirements for the award of the degree, **Doctor of Philosophy (Ph.D)** in Petroleum Engineering in the Department of Petroleum Engineering of the Federal University of Technology, Owerri, Nigeria.

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DEDICATION

This write up is wholly dedicated to my Lord, Jesus Christ.

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ABSTRACT

Unconventional (projectile and parabolic), methods have been used to estimate oil and gas reserves. Existing oil and gas data from wells in the Niger Delta geological formations (Agbada, Akata and Benin) were used to generate decline constants 'b' that were subsequently used in predicting yearly production data for any given period. The yearly data obtained were validated using the actual yearly production records of the original data source. The validated yearly data were used to generate evaluation curves. The evaluation models were subsequently worked out from the shape of the generated curves. The models were then used to estimate reserves (cumulative and initially in place) in each of the reservoirs. The values obtained compared favorably with the respective storage tank and the volumetric materials balance equations values. The percentage accuracy for gas fields ranged from 99.86% and above, while the percentage accuracy for oil ranged from 98.64% to 99.98%. The results of this research simplifies complex simulation methods, improves dynamic fluids computational analysis, reduces time in the conventional decline analysis and makes it easy to identify dominated flow and rates decline trends. The models are very flexible and can be applied with high accuracy from the reservoir decline stage to abandonment. They are equally used to estimate the remaining reserves based on the time differences between final and production (t_f-t_p) and for the establishment of production and economic decisions techniques.

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Nomenclature

A: Area of the reservoir, *acres or* ft^2

a : Actual decline fraction of production rate

a_1 : = Initial oil or gas production decline

*Agbada Formation***:** Geological formation which consists mainly of sandstones, shale alternation with the sandstones predomination

Akata Formation: This is a Marine pro-Delta mainly shale-stones and siltstones, which crop out in sub-sea outer Delta.

AGA: American Gas Association, generally acceptable standard units

ºAPI*:*Oil or Gas Gravity, API (American Petroleum Institute)

b: Rate Decline Constant, *Mbbl/yr or Mbbl/d*

Bbl: Barrel (Unit of oil or liquid measurement)

Benin formations: This is mainly sand and sandstones, coarse to fine, granular in texture and partly unconsolidated formation.

B_{of}: Actual oil formation volume factor, *rb/stb*

B_{oi}: Initial Oil formation volume factor, *rb/stb*

Bubble Point Pressure: Critical pressure condition for rate decline initiation

CAPEX: Capital Expenses (Development Bills)

D: Depth of the reservoir, *ft*

DCA (Decline Curve Analysis): Mathematical equations, tabulated tables or graphical procedures for studying the oil andor gas production rate, prediction of cumulative oil or projected oil production

Decline Curve (Tend): Graphical representation of oil/gas production rate

Decline Rate: Reduction of a production volume per unit time, *Mbbl/yr*

DPR: Department of Petroleum Resources, NNPC subsidiary

DFCA: Dynamic Fluids Computational Analysis

E_i: Gas expansion factor, %

G: Gas initially in place (GIIP), MMscf

G_p: Cumulative gas recovery in a reservoir, MMscf

GOR: Gas - Oil Ratio, *scf/bbl*

MBE: Materials Balance Equation (quick volume changes estimation)

n: Rate Decline exponential or production decline rate power constants

N: Oil initially in place (OIIP), *stb*

NNPC: Nigerian National Petroleum Cooperation (Oil / Gas operation Age)

N_P: Cumulative oil production in a reservoir, *stb*

OPEX: Operations Expenses (Daily operation costs or bills)

q: Actual hydrocarbons flow rate, *bbl/d or bbl/yr*

q_i : Initial oil or gas production flow rate, *bbl/d or bbl/yr*

STB or stb: stalk tank barrel

SCF or scf: Standard cubic feet, ft^3

t : Time unit (s, hr or yr)

Transient Part or Stage: Unsteady rate in the initial stage of production

Transition Stage: A critical stage which could result into a decline stage

$t_o, t_1, \ldots\ldots\ldots t_f$**:** Unit time, *ft*

γ_g: Gas specific gravity, dimensionless

Z: Gas deviation or compressibility factor, %

$\frac{1}{n}$ **=** h = hyperbolic decline constant

CHAPTER 1

INTRODUCTION

1.1 Background information

Decline curve analysis are mathematical equations, tabulated values or graphical procedures for studying the oil and/or gas production rates, prediction of cumulative oil or projected oil production and estimating the oil or gas initially in place. A field production history is used in projecting future hydrocarbons production rates in a given time. The projected rates are plotted against time, used in the prediction of future production and the initial oil or gas reserves. In some cases standard curves are used for comparison. These standard curves were obtained using field data (called regional data). The curve fit is then extrapolated to predict oil or gas reserves. Decline curve is the basic tool for estimating the recoverable reserves. Conventionally, decline curves analyses are only possible when the production data or history is available, so that the trend can be defined. There are no fundamental theoretical trends for decline curves analyses, but the exercise is based on production data trend. For this the principal challenge is to minimize errors. All data must be understood before use. There are three principal types of decline rate as postulated by the early researcher. These are exponential or constant decline rate, harmonic decline rate and hyperbolic decline rate. This classification is based on constant or variable changes in the factors that influence the fluid flow in a porous medium. Crafts and Hawkins, (1959) stated these factors as follows:

i. Constant well back pressure effects
ii. Active water-drive influences
iii. Boundary conditions in a porous zone
iv. Historical observation of the data
v. Single or multiple phase fluid flow
vi. Combined oil and gas flow as a stream

The equation of a fluid flow through porous media under boundary conditions is based principally on steady-state, semi-steady state and unsteady-state and are applied as deemed fit for any particular situations single or two phase fluid stream. Oil as a single stream can only be mobile if gas is dissolved in it and oil and water combined as a multiphase fluids stream with gas dissolved in the stream for mobility effect. Any stream can exhibit any type of decline rate. It depends on the influencing factors. The analysis can be conducted on only one fluid stream or a combined fluids stream gas oil ratio (GOR). The practical approach to oil or gas production decline rate analysis is to choose the variables such as gas or oil stream that results in a reasonable trend. The decline rate curves are used to predict the future well performances. The accuracy in predicting the future oil or gas stream performances depends on the ability to understand the reservoir characteristics and the standard established for estimating the reserves. In decline curve analysis it is implicitly assumed that factors causing the historical decline in a fluid stream would continue unchanged throughout the forecasting period. **Crafts and Hawkins, (1959)** field records showed that these factors are the reservoir and operating conditions.

a. Reservoir Characterization

i. Reservoir drive mechanisms

ii. Saturation and viscosity changes

iii. Permeability and its distribution

iv. Porosity and its distribution

v. Volumetric mobility of the fluids

vi. Formation grain sizes and arrangement

b. Operating Conditions

i. Fluids flow mechanism

ii. Pressure depletion trend

iii. Decline rate trend
iv. Tubing and choke sizes
v. Number of producing wells
vi. Separation pressure and its operating hours
vii. Work-over jobs effects
viii. Compressors operating hours
ix. Artificial lift effects

In analyzing rate of decline, two primary types were used. The flow rate was plotted against time to predict projection rates and the daily oil or gas production was plotted against time to estimate future cumulative production and reserves originally in place. The most convenient dependent variable is the rate, because extrapolation of the rate-time graph was used directly to forecast the fluid production and economic evaluations. Plots of rate against daily oil or gas production equally provided direct ultimate recovery at a given economic limit and yielded a more rigorous interpretation where the production was influenced by intermittent operations. In this case best rate decline trends analyses were compared with volumetric calculated values, MBE values and recovery factor values. The decline curves analysis results were the estimation tools for the cumulative hydrocarbons production and hydrocarbons initially in place which are fixed in nature. Field records by **Crafts and Hawkins, (1959)** showed that recoverable hydrocarbons are affected by the operating conditions, decline curves analyses are best applicable when the production stabilizes, because of boundary condition dominated flow rate. Most decline curves analysis states that evaluation starts with stabilized flow decline rate. Another school of thought states that decline curves analysis is based mainly on empirical observation of production rate decline and not on theoretical derivation. Any attempts to explain the observed behaviour using a theory of fluid flow in porous media would require the boundary dominated flow relationship. When a well is placed on production, there will be transient flow initially, because the boundary conditions are not active enough. Eventually the reservoir boundaries would be felt and it is only then that decline rate becomes clear and the value of the decline rate constant (b) lies between 0.0 and 1.0 or higher, depending on the reservoir boundary conditions and drive mechanism. Occasionally the decline rate has a value greater than unity. **It** is very useful to have production decline rate model in the Niger Delta and other fields in order to predict projected production rates and estimate both reserves in place and the recovery factor in a reservoir. This equally defines the production decline trend and the process that starts a transient state, peak and decline to minimum level or economic limit rate called abandonment rate. The decline models would enable a prediction of the recovery efficiency profile, gives the investors much knowledge of his business profile or trend.

1.2 Statement of the Problem

Many reserves are abandoned early, because of complex simulation procedures in order to establish motivated economic techniques. Conventionally, volumetric material balance equations (MBE) methods in use are limited to static conditions of the reservoirs and less accurate in the dynamic fluids computation analysis. Equally conventional decline analysis is less accurate, because most researchers assumed exponential or constant rates decline. In reality some reservoirs are not. In this work, mathematical equations or relationships are developed to increase DFCA accuracy and discourage early or premature abandonment of reserves (ref: results in chapter 4).

1.3 Objectives

The main objective of this study is to derive more accurate mathematical rates decline relationship to predict oil and gas reserves. The specific objectives in order to achieve the above aim are:

a. to validated the derived relationship for selected reservoirs, using storage tank records.
b. to correct already existing relationships, using the validated relationships.
c. to economically improve the methods for easy and correct identification of production rate decline trends.
d. to improve the evaluation models quality and results accuracy.

1.4 Justification of Study

This research work is necessary to simplify the complex simulation procedures in the conventional methods for rate decline analysis. This would increase DFCA accuracy, reduce the simulation complexity and time used. The success of this work will give an investor the view of his business and it improves his decision on the business.

1.5 Scope of the Study

This work primarily covers production decline rates characterization for some oil wells in the Niger Delta. The collated data covered the unsteady-stage (early-stage), steady-stage and semi steady-stage (decline-stage) of a reservoir. The complete production data to abandonment can be used for mathematical equations derivations and confirmation. The decline stages data covered the declined constant estimation and applications. The data in the short period production took care of the projected reserves recovery estimation and time required.

CHAPTER 2

LITERATURE REVIEW

2.1 General Field Records on Oil & Gas Production Decline Rate

Gentry and McCray, (1978), stated that models used in oilfield reserves production decline prediction must take a dome-shape. The dome-shape is production rates from unsteady state to maximum, with or without observable steady-state and then decline to minimum through semi-steady state. Their field study results showed that for rate decline constant (b) is zero for:

a. Single phase liquid production

b. High pressure gas production

c. Tubing and choke restricted gas production

d. Poor waterflooding performance

For Higher Value, when 0 $< b < 1.0$

a. Under solution gas drive, the lower the gas relative permeability, the smaller is the gravity of gas produced, hence the decline in the reservoir pressure is slower and accordingly the decline rate is lower with higher value of ***''b''***

b. Simulation studies for range of oil and gas relative permeability showed that o.1 $< b < 0.4$, given an average value of ***b= 0.3***

c. The production data above bubble point are not analyzed with the below the bubble point, because decline analysis is valid when the recovery mechanism and operating conditions do not change with time. Above the bubble point $b = 0$ and the decline rate is constant. Below the bubble point ‘’b’’ increases as in the solution gas conditions.

d. For gas wells o.4 $\leq b \leq 0.5$, or average of $b = 0.45$

e. Conventionally light oil reservoir under edge-water (effective water-drive), $b = 0.5$. If a mechanism maintains the reservoir pressure, the production rate would remain constant example: constant reservoir pressure, the decline tends to zero. An example is gas-injection or water-injection, active water-drive or gas-cap expansion-, small reservoir pressure decline leads to high production driving force with a corresponding small production decline rate. In this case the decline rate constant is theoretically greater than unity ($b > 1$). Much later when the oil column thins up, the production rate would decline exponentially ($b = 0$) and the hydrocarbons production is replaced by water. [***Spivey, et al, 1992]***

2.2 Simulated Production (Generic) Data

Obah, et al (2012) used a dynamic simulator and generated a 3D generic grid model with varying oil column thickness, gas-cap and aquifer size. Their based grid was 10 x 10 grid block in the x and y directions. The model geometry was fixed at 600ft x 600ft in the x and y directions, while the z-direction was varied based on the oil rim thickness. They obtained 3-production forecast models for oil rim reservoirs, using Monte Carlo Simulation approach and generated a probabilistic range of forecasts for decision making in the Niger Delta, Nigeria for 30 years. They found out that oil recovery varies from 3.98 – 37.3MMstb over the 30years prediction. They concluded that horizontal wells are better option for developing reservoirs with oil rim as to conventional wells. They also added that oil recovery is strongly dependent on the oil rim thickness, relative gas-cap size (in-factor), permeability, viscosity and aquifer strength. Their mathematical equation was: $\boldsymbol{N_{p(t)} = \frac{q^*}{D}\left(e^{-D/t_p} - e^{-Dt}\right) + q_i t_p}$

2.3 Constant or Exponential Decline Rate

Arps, (1945) used an empirical relationship and analyzed hydrocarbons production decline curves. In his work he defined hydrocarbons production decline rate as a factional change (a) in the flow rate (q) with respect to time (t). His mathematical equations are:

$$\boldsymbol{a = \frac{-{}^{dq}/_{dt}}{q_i},\ stb/d\ or\ stb/yr\quad and\quad N_p = \frac{q_i - q}{a}} \qquad 2.1$$

Arps, (1956) used his models in the prediction of oilfields production decline rate types. Here Arps pointed out that there are 3-main types of production decline rate power constants (n). These are the constant or exponential decline rate (where n = 0), hyperbolic decline rate ($where\ 0 < n < 1.0$) and harmonic decline rate (where n = 1.0). He plotted production data against time in a semi-log paper and found out that it gives a straight line graph which could be extrapolated to estimate the oilfield reserves. This was possible, because the drop in production per unit time was a constant fraction of the hydrocarbon production rate. $\boldsymbol{a = -\frac{dq}{q\,dt} = constant}$ 2.2

Exponential Decline Rate Equation by Spivey, et al (1992)

$$\boldsymbol{Q_{Dd} = 1 - e^{-t_{Dd}} = 1 - q_{Dd}}$$

2.4 *Hyperbolic and* Harmonic Decline Rate

In the hyperbolic decline rate, he (**Arps**) found out that the decrease in production per unit time as a fraction of the production rate is proportional to a fractional power. The coefficient of his fraction decline when $0 < n < 1.0$ was given as:

$$\boldsymbol{q = \frac{q_i}{(1+nat)^{\frac{1}{n}}}} \qquad 2.3$$

$$N_p = \frac{q_i}{a(1+n)}\left(q_i^{1-n} - q^{1-n}\right) \quad 2.4$$

The coefficient of the decline rate for harmonic decline is unity (n = 1), so the equations become

$$q = \frac{q_i}{(1+nat)} \quad 2.5$$

$$N_p = \frac{q_i}{a} ln \frac{q_i}{q} \quad 2.6$$

***Spivey, et al (1992) Hyperbolic and Harmonic* Decline Rates**

$$Q_{Dd} = \frac{1}{1-b}\left[(1 - 1 + bt_{Dd})^{1-\frac{1}{b}}\right] = \frac{1 - q_{Dd}^{1-b}}{1-b} \quad 2.7$$

$$Q_{Dd} = ln(1 + t_{Dd}) = ln\left(\frac{1}{q_{Dd}}\right) \quad 2.8$$

Slider, (1968) presented a simplified type of hyperbolic decline curves analysis. In his analysis he used rate time data. The actual decline curves data were plotted on a transparent paper and compared to a series of semi-log plots of different oilfields cumulative production decline curves with known values of a & n

Slider, (1983) equally produced tabulated values needed for plotting hyperbolic type curves using the values of $0.1 < n < 0.9$ with 0.1 incremental values (n + 0.1+……. n). He used these in the analysis of production decline curves in order to develop the proper models.

$$q = \frac{q_i}{(1+nat)^{\frac{1}{n}}} \quad 2.9$$

$$a = \frac{(q_i/q)^{\frac{1}{n}}}{nt} \qquad 2.10$$

Gentry, (1982), prepared a series of plots and different values of the rate exponent (**n)** ranging from 0 to 1.0 with an incremental value of 0.1. He used the rate with the cumulative oil production and the intervening time to obtain the values of **''n''** for a production in hyperbolic decline curves.

Gentry, (1986), recommended that conventional decline curves analysis should only be used when the mechanical conditions and the reservoir drainage remain fairly unchanged and the oil-well is produced at steady capacity.

The disadvantages of all these endeavors include:

i. Semi-log types curves used must be analyzed and be sure that the interval used are the hyperbolic decline type-curves. Any miss matched results in wrong modeling.

ii. Another challenge in the semi-log plot and/or cross-match is that an exact fit of the data is not easily possible, but the techniques are relatively rapid in use.

Fetkovitch, (1980), designed an advanced decline curves analysis approach, which has been applicable for changes in pressure or drainage. His approach was similar to pressure testing.

$$\frac{q}{q_i} \quad VS \quad a\,t \quad or \quad q_{Dd} \quad VS \quad t_{Dd}$$

Fetkovitch used different values of ‘’**n**’’, in Arps equations and plotted out curves. From these curves Fetkovitch concluded that Arps’ equations are only suitable for rate-time depletion data, but in transient time data will result in incorrect forecasts. In the full size type curves by Fetkovitch field data were plotted on a tracer paper, which are the same as log-log paper scale as the full-size types curves. The best fit in bbl/unit time would be chosen. A match can be used to obtain values of $q_i \,\&\, q$ for actual data. These data are then used for appropriate equations to be used in the analysis of the rate-time as well as cumulative hydrocarbons production ($N_p \; or \; G_p$).

Hudson and Nurse, (1985), recommended that the most effective method for reserves estimation is the depletion stage.

2.5 Values of Rate Decline Range

Ramsay and Guenero, *(1969),* indicated that the value of rate decline range is ($\mathbf{0.1} < b < \mathbf{0.9}$ and about 40% of the leases have the value of rate decline greater than 0.5, ($\boldsymbol{b} > \mathbf{0.5}$***),***

Fetkovitch, (1984), stated that for commingled layered reservoirs the values of **‘’b’’** lies between 0.5 and 1.0. In such a case decline analysis should be initialized from the start of the decline rate. He added that it is possible under certain production and scenarios that initially the rate does not decline.

Gentry and McCray, (1978), used numerical simulation and showed that layered reservoirs can cause the value of **''b''** to go above unity ($\boldsymbol{b} > 1.\mathbf{0}$).

Bailey, (1982) investigation showed that in some fractured gas wells the rate declined value ''b'' is greater than unity and sometimes as high as 3.5.

2.6 The Power Law Decline Rate Constant Method

Ilk, et al (2008) presented the **''Power - Law''** decline method which uses a different functional form of D-Parameter given by:

$$\boldsymbol{D} = \boldsymbol{D}_{\infty} + \boldsymbol{D}_{\mathbf{1}}\boldsymbol{t}^{-(\mathbf{1}-\boldsymbol{n})} \qquad 2.11$$

D is approximated by a decaying power-law function from transient and through transition flow and exhibits a near constant behavior ($\boldsymbol{ie}\ \boldsymbol{D}_{\infty}$) at very large time. This is contrast to hyperbolic rate decline that leads to a constant behavior at early time and becomes a unit slope power law decaying function at larger times. The advantage of their mathematical equation is that it is flexible enough to cover the transient, transition and boundary dominated flow and to large time reduces to an exponential decline ($\boldsymbol{D} = \boldsymbol{D}_{\infty}$). They then combined their equation with Arps' equation as: $\frac{1}{D} = \frac{q}{dq/dt} + D = D_{\infty} + D_1 t^{-(1-n)}$ 2.12

Solving eqn2.12 gives $eqn2.13$

$$q = q_i \, e^{\left[-D_{\infty} t - \frac{D_1}{n} t^n\right]} \qquad 2.13$$

when:

$D_1 = Decline\ constant,\ \ t \to \infty$

$n = Time\ exponent$ $\qquad q_i = Rate\ intercept\ at\ t = 0$

The difference between their $q_i\ and\ q_i$ in Arps decline models is because it refers to rate at the onset of stabilized flow, while q_i in Arps decline models refers to flow rate at early stage of a well.

Edwardson, et al (1962) provided the mathematical equation for cumulative hydrocarbons values estimation using dimensionless terms:

When $t_D < 200$

$$Q_D = \frac{1.12838 t_D^{0.5} + 1.19328 t_D^{1} + 0.27 t_D^{1.5} + 0.086 t_D^{2}}{1 + 0.62 t_D^{0.5} + 0.041301 t_D^{1}} \qquad 2.14$$

When $t_D > 200$

$$Q_D = \frac{-4.23\ t_D^{0.5} + 2.026\ t_D}{ln\ t_D} \qquad 2.15$$

Bruns, (1986) tried, using fractions as $\frac{1}{2}, \frac{5}{8}\ and\ \frac{3}{4}$ in his dimensionless time-function and found out that using $\frac{1}{2}$ reduces the discontinuity between the transient streams and hyperbolic streams.

Spivey, et al (1992) provided detailed equations for generating the transient and boundary dominated streams of the cumulative hydrocarbons production type curves. They found out that the transition from transient equation to boundary dominated flow equation for cumulative hydrocarbons occurs at $t_{Dd} = 0.6$, compared to Fetkovitch's dimensionless flow rate type curves, where the transition occurs at $t_{Dd} = 0.1$.

Spivey et al, (1992) work showed also that the type curves of cumulative hydrocarbons production can be obtained with their derivative using semi-log to give a set of type curves that use only cumulative hydrocarbons production data and net rate. This is because cumulative hydrocarbons production tends to be much smoother than the original rate data. These plots tend to have less scatter points than the traditional Fetkovitch's type curves. Their derivative $\frac{\mathbf{d(Q)}}{\mathbf{d(\ln t)}}$ is equivalent to the traditional derivative qt and in dimensionless form as: $\mathbf{q_{Dd} \cdot t_{Dd}}$. The product of rate, q and time, t gives the semi-log derivatives of cumulative hydrocarbons production. They plotted $\boldsymbol{q_{Dd} t_{Dd} \; vs \; Q_{Dd}}$.

Johnson and Bollens, (1945) defined the loss-ratio and the derivative of loss-ratio function as:

$$q = q_i\, e^{-\left[D_\infty t + \frac{D_1}{n} t^n\right]} = q_i\, e^{-[D_\infty t + D_i\, t^n]} \qquad 2.16$$

where

$q_i =$ Rate at $t = 0$ (called rate intercept)

$D_1 =$ Decline rate constant intercept at $t = 1\ day$

$D_\infty =$ Decline rate constant at $t =$ infinity (∞)

n = Time exponent and t = Time

$D_i = \frac{D_1}{n}$

2.7 Concept of Integral Type Curves

Blasingame, et al (1989) introduced the concept of integral type curves in the well testing fields. Spivey et al (1992) extended Blasingame and his students' work concept to decline curves analysis. In their work they stated that the hydrocarbons production data are usually very noisy (disarranged). Plotting a rate –integral or cumulative hydrocarbons production should reduce the noise and would make the data much more analyzable. The rate-integral is related to the cumulative hydrocarbons production as defined in the following equations.

$$q_i = \frac{Q}{t} \qquad 2.17$$

$or\ \ in\ dimensionless\ form\ as$

$$q_{Ddi} = \frac{Q_{Dd}}{t_{Dd}} \qquad 2.18$$

where

$q_i = q_{Ddi}$ = Initial production rate

$Q = Q_{Dd}$ = cumulative rate

$t = t_{Dd}$ = time

The dimensionless term is obtained by dividing the cumulative hydrocarbons production by the time of flow. The rate-integral has a direct physical interpretation. It is the average hydrocarbons production rate from the beginning of production to the current time (actual stage).

Advantages in Their Work

i. Blasingame's hydrocarbons production decline techniques are not limited to constant bottomhole flowing pressure like those in Arps and Fetkovitch.

ii. Blasingame, et al, (1989) hydrocarbons production decline techniques account for variations in bottomhole flowing pressure in the transient regime. In addition their analysis can work fine in the changing values of reservoir PVT properties with the changing reservoir pressure for both oil and gas.

iii. Blasingame and his students have developed oil and gas production decline method that accounts for these phenomena. The method uses superposition time function that only requires one depletion stem for type curves matching

iv. One of the importance of his method was the type curves used for matching, were identical to those used for Fetkovitch decline analysis without the empirical depletion streams. When the type curves are plotted using Blasingame's superposition time function the analytical exponential stem of Fetkovitch's type curves becomes harmonic. The significance of this is that if the inverse of this flowing pressure is plotted against time, pseudo steady state depletion at constant flow rate follows a harmonic decline. In effect it allows depletion at a constant pressure to appear as pseudo steady state depletion at constant rate, provided that the rate and pressure decline monotonically. Blasingame improved Fetkovitch's decline curves analysis by the introduction of two additional type curves, which are plotted concurrently with the normalized rate type curves. The rate integral and rate-integral derivative type curves aid in obtaining a more unique match. The derivation of the data obtained when both the rate and the flowing pressure are varying can now be analyzed if the material balance time is used instead of actual production time. This is possible, because an exponential decline would be the harmonic decline stem ($\boldsymbol{q_{Dd}\ vs\ t_{Dd}}$) is exponential and ($\frac{\boldsymbol{q}}{\Delta \boldsymbol{p}}\ \boldsymbol{vs}\ \frac{\boldsymbol{Q(t)}}{\boldsymbol{q(t)}}$) is harmonic.

Blasingame, et al (1989), developed type curves which showed the analysis of transient stems along side with the analytical harmonic decline, but with the rest of the empirical hyperbolic stems absent.

Johnson and Bollens, (1928), used power law and analyzed the loss-ratio and loss-ratio derivatives function. They showed that the derivative equation is flexible enough to cover transient, transition and boundary dominated flow with large time reduces to an exponential decline.

2.8 Fractional Hydrocarbons Decline Rate

Arps, (1945) explained an exponential oil or gas decline rate using a straight line graph that could be extrapolated to initial state of a reservoir conditions. He stated that the data suitable for used in the prediction must satisfy a constant fractional drop in the reserves production. In His work the value of decline exponent used was zero (n = 0). His mathematical model equations are:

$$\frac{q_i}{qdt} = -aq = constant \quad or \quad a = \frac{dq_i/q}{dt} \qquad 2.19$$

$$N_p = \frac{q_i - q}{a} \quad or \quad a = \frac{q_i - q}{N_p} \qquad 2.20$$

In the hyperbolic decline rate analysis the decrease in oil or gas production per unit time as a fraction of the production rate is proportional to a fraction power called ‘’n’’. The fractional power range was given as: 0.1 $< n < 0.9$. Arps, stated that the most efficient data for this type of hydrocarbons production decline curves are the oilfield depletion data. His mathematical definitions were:

$$q = \frac{q_i}{(1+na_1t)^{\frac{1}{n}}} \qquad 2.21$$

$$N_p = \frac{q_i}{a_1(1-n)}\left[q_i^{1-n} - q^{1-n}\right] \qquad 2.22$$

In the harmonic fractional hydrocarbons decline rate, the type curves for oil or gas production decline rate are similar to hyperbolic decline rate determination methods, in that the slope on the semi-log plot decreases with time, but for a harmonic oil or gas production decline rate the decrease in production per unit time is a fraction of the production rate which is directly proportional to the rate. This is observed in reservoir flow dominated by gravity drainage. The fraction power, n = 1 and the mathematical equations he used were:

$$q = \frac{q_i}{1+na_1t} \qquad 2.23$$

$$N_p = \frac{q_i}{a_1} ln\left(\frac{q_i}{q}\right) \qquad 2.24$$

Graphical Representation

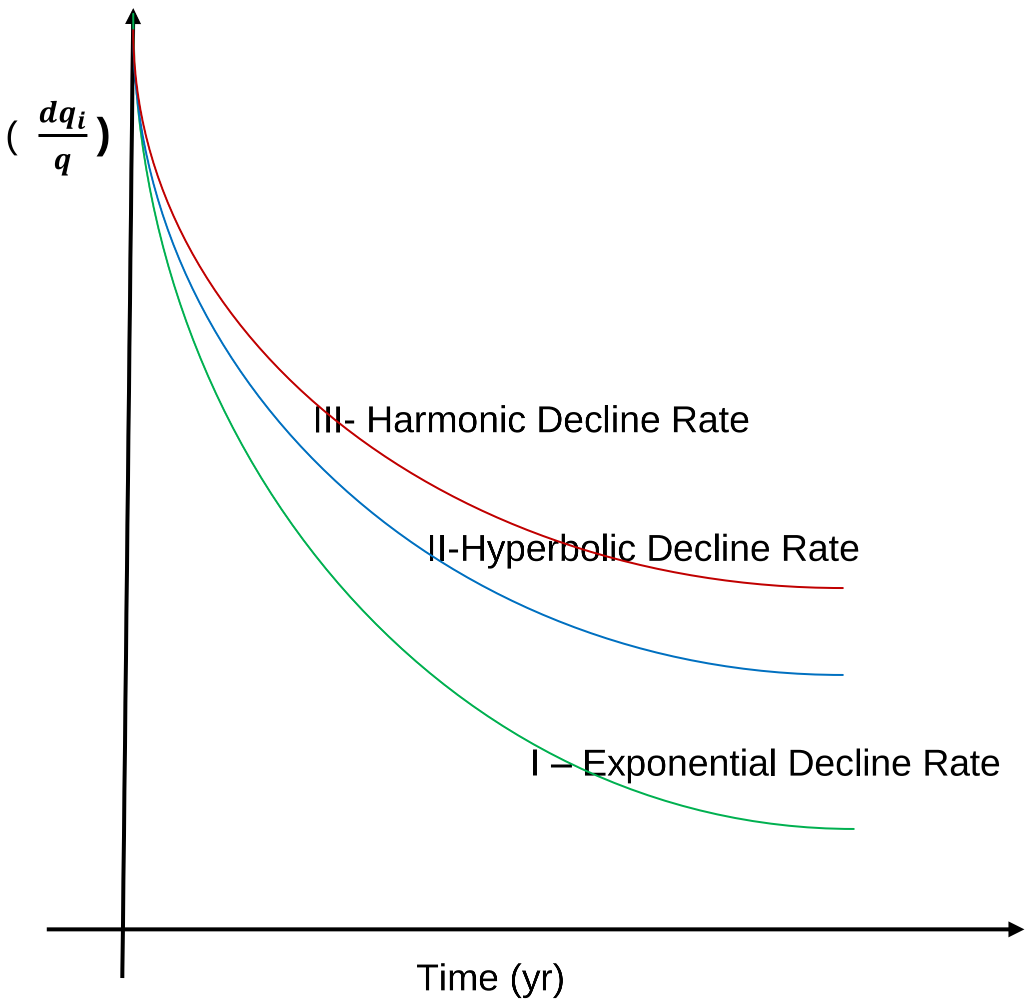

Fig 2.1 Schematic View of Arps' Oil Production Decline Rate Curves

Slider, (1968), recommended that if the data are doubted a mathematical model of an actual cumulative oilfield production data be plotted to determine the percentage fitness with the range as given in the root mean square ($90 < R^2 < 100\%$). The deviation of the model used in generating the graph must generate a line of best fit for the oilfield reserves estimation history. Slider added that the most effective reserves estimation using conventional methods must be determined at the best fitted in the semi-log hyperbolic plots or log-log hyperbolic plots. He stated that the best fitted curves must be suitable for extrapolating to the oilfield reserves initially in place conditions at the reserves point.

2.9 Fractional Decline exponent (n), Obtained Conventionally

Spivey, et al, (1992), field studies showed that fractional decline exponent would be zero (***n = 0***) in the case of:

- Single phase liquid production
- High pressure gas production system
- Tubing and choke restricted gas production
- Poor waterflooding performances

Ramsay and Guenero, ***(1969),*** *showed a h*igher fractional decline exponent value of ($\mathbf{0} < n < 1$) in the case of:

- Production under solution gas drives, the lower the relative permeability the smaller is the ^{o}API gravity of gas produced, hence the decline rate of the reservoir is slower and accordingly the production decline is lower with high value of decline exponent ($\boldsymbol{n} > 1$).

Gentry and McCray, (1978) simulation studies for the range of oil and gas relative permeability ($\boldsymbol{K_{ro}\ and\ K_{rg}}$) have shown that the decline exponent (n) ranges from 0.1 to 0.4 ($\mathbf{0.1} \leq n\ \leq \mathbf{0.4}$**). This** gives an average value of ***0.3.*** The production data above bubble point pressure are not analyzed with the data below the bubble point, because decline analysis valid when the recovery mechanism and the operating conditions do not change with time. Above the bubble point pressure, ***n = 0*** and the decline rate is constant. Below the bubble point pressure the decline const (n) increases as in the solution gas drive condition. For gas wells $\mathbf{0.4} < n < \mathbf{0.5}$ **or** average **of n = 0.45** and conventionally light oil reserves under edge water drive (effective water drive), n = 0.5.

Blasingame, et al, (1989), stated that, if a mechanism maintains the reservoir pressure, the production rate would remain fairly constant. This means that at constant reservoir pressure the decline tends to zero. This is common in pressure maintenance systems, such as gas & water injections, active-water drive, and gas-cap expansion drive, where the hydrocarbons are saturated. Small reservoir pressure decline leads to high production driving force with a corresponding small production decline rate. In this case the decline rate constant is theoretically greater than unity ($\boldsymbol{n} > 1$). Much later when the oil column thins, the production rate would decline exponentially with $\boldsymbol{n} = \mathbf{0}$ and the hydrocarbons production is replaced by water.

Fetkovitch, (1984), concluded that in commingled layered reservoirs the values of **''n''** lies between 0.5 and 1.0. In such a case decline analysis should be initialized from the start of the decline rate. He added that it is possible under certain production and scenarios that initially the rate does not decline

2.10 Natural Reservoirs Hydrocarbons Production Decline

Lantz, (1971), discussed the theory of natural oilfield production decline types and modeling. He stated that, there are 3 basic types, theoretical, semi-theoretical and empirical models that can be used to explain the phenomenon of oilfield hydrocarbons depletion and their models development. An oilfield is one of the natural resources or commodity that is finite and not renewable. Reserves initially in place, $\boldsymbol{N} = \frac{\emptyset\, \boldsymbol{V_i}}{\boldsymbol{B_{oi}}} = \frac{\boldsymbol{Ah\emptyset S_{oi}}}{\boldsymbol{B_{oi}}},\ \boldsymbol{stb}$ **or** $\boldsymbol{G} = \boldsymbol{V_{gi}}\, \emptyset\, \boldsymbol{E_i} = \boldsymbol{Ah\emptyset S_{gi} E_{i}},\ \boldsymbol{scf}$ is a depleting volume ($\boldsymbol{dq}$) with time ($\boldsymbol{dt}$). The mathematical derivative model of $\frac{\boldsymbol{dq}}{\boldsymbol{dt}} = \mathbf{0}$, is hydrocarbons building up, while $\frac{\boldsymbol{d^2q}}{\boldsymbol{dt^2}} = \mathbf{0}$, represents the inflation and peak points. The integral of the second order derivative $\frac{d^2q}{dt^2} = \mathbf{0}$, **give**s $\frac{dq}{dt} = -\boldsymbol{bq^n}$, the depletion decline of the hydrocarbons from its peak towards minimum and further integral gives the value of hydrocarbons initially in place.

2.11 Decline Rate correlation as a function of Time

Poston, (1998), worked on oil and gas production rate decline as a function of time. He found out that the loss of a reservoir pressure or the changing relative volumes of the produced fluids are usually the cause of the rate decline with time. Poston fitted a line through the performance history and assumed this same line trends similarly into the future from the basis for the decline curves analysis concept. He used mainly semi-log rate-time decline curves for different wells located in the same field. Poston concluded that a production history may vary from a straight line to a concave up-ward curve, but in any case the objective of decline curve analysis is to model the production history with the equation of a line. Table 2.1 summarizes Poston's model equation using a line to forecast future hydrocarbons production. He expressed the exponential decline rate in two basic forms:

Table 2.1 Poston Hydrocarbons Production Forecast Model Equations

Log-Rate-Time Shape	***Name***	***Model***	***Decline Trend***
Straight line	Exponent	-	Stepwise
Straight line	,,	Arps	Continues straight
Converging curves	Hyperbolic	,,	Continues curves
Limited curves	Harmonic	,,	Un-converge curves
Un-converging curves	Amended	-	Dual-infinity action to limited curves

- ***Effective or Constant Percentage Decline***

This decline trend shows the incremental rate loss concept in mathematical terms as a stepwise function. Table 2.2 shows the effective and continues (normal) exponential equations.

- ***Normal or Continues Rate Decline***

This decline trend shows the negative shape of curves representing hydrocarbon production rate versus time for oil and gas reservoirs. His equations showed the relationship between normal and effective decline rates. $D = -ln(1-d)$ and conventionally assumes the decline in percentage of a year (% yr). He also showed a comparison of rate, time and cumulative hydrocarbons production relationship for both definitions. Table 2.2 shows the details.

$b = 0$, For the exponential case

$0 < b < 1$, Hyperbolic case

$b = 1$, Harmonic case

Table 2.2 Effective and Continues (Normal) Exponential Equations

Action	***Constant Rate***	***Continues Rate***
Decline Rate	$d = \frac{q_1 - q_2}{q_1}$	$D = \frac{ln(q_1/q_2)}{t}$
Production Rate	$q_2 = q_1(1-d)^t$	$q_2 = q_1 e^{-(Dt)}$
Time elapsed	$t = \frac{ln(q_2/q_1)}{-ln(1-d)}$	$t = \frac{ln(q_1/q_2)}{D}$
Cumulative Recovery	$Q_p = \frac{q_1 - q_2}{-ln(1-d)}$	$Q_p = \frac{q_1 - q_2}{D}$

Poston's Curves Characteristics Conclusion

- All rate-time curves must tend to a downward manner
- The semi.log rate-time curve is a straight line in exponential decline equation while hyperbolic and harmonic decline are curved lines
- The Cartesian rate-cumulative recovery plots are straight lines for exponential, hyperbolic and harmonic are curved
- A semi-log rate-cumulative production plots are straight line for harmonic while exponential and hyperbolic decline rates are curved. Fig 2.1 below shows the types of decline rates.
- Harmonic tends to flatten out with time

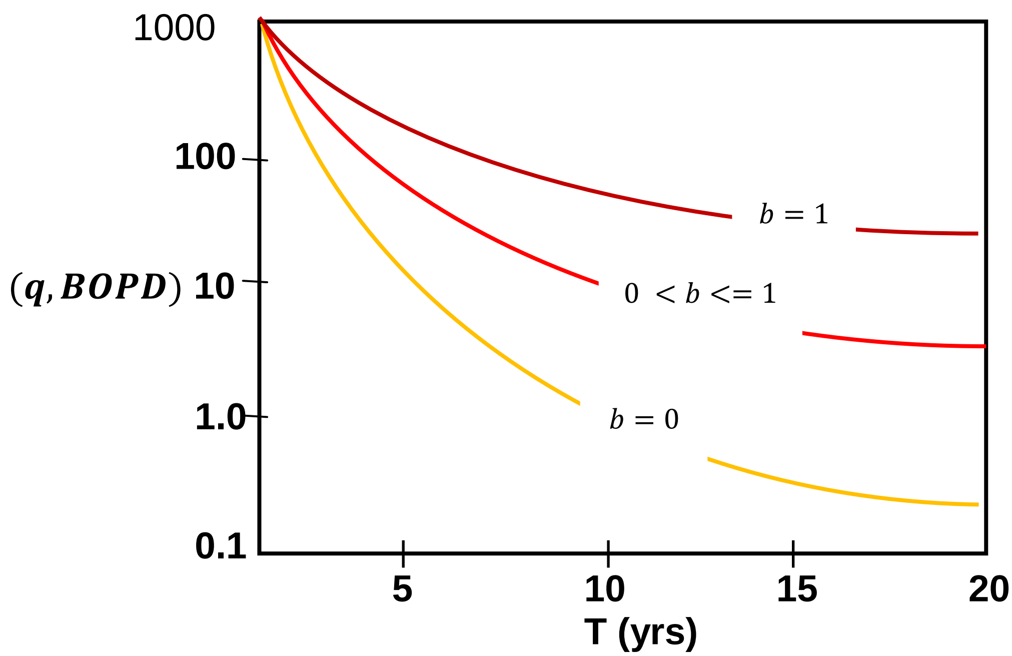

Fig 2.2 Poston's Hydrocarbons Production Decline Trend

Theoretically exponential constant (b) varies in the positive (+ve) or negative (-ve) manner. The –ve values indicate an increasing production rate while the +ve value implies infinite, hence cumulative production must be infinite for $b \geq 1$. This statement shows why exponential term cannot be greater than unity. His study indicated that exponential decline must vary over a large decline constant ($0 < b < 1$)

2.12 Well Production Performance

Golan and Whitson, (1986), defined production decline analysis as a traditional means of identifying well production problems and predicting a well performance with respect to its life based on real production data. They used empirical decline models that have little fundamental justification, similar to those of Arps' exponential decline or constant fractional decline, harmonic decline and hyperbolic decline. Their general model is the hyperbolic decline model and other two models are degeneration of the hyperbolic decline model. These models are related through relative decline rate with mathematical equation as:

$$\frac{dp/dt}{q} = -kq^{d} \qquad 2.25$$

where

d = Empirical constant decline based on production data. When d = 0, the equation degenerates to an exponential decline model. When d = 1, it yields a harmonic decline model and when $0 < d < 1$, the equation yields a hyperbolic decline model. They recommended their model for use in both oil and gas wells.

2.13 Relative Decline Rate

Economides, et al (1994), considered an oil well drilled in a volumetric oil reservoir where they assumed that the wells production rate starts to decline when a critical (lowest permissible) bottomhole pressure (BHP) is reduced. Under the pseudo-steady-state flow condition the production rate at a given decline time (t) was expressed mathematically as:

$$q = \frac{k\,h\,(P_t - P_{wf})}{141.2\,B_o\,\mu\,ln\left(\frac{0.472\,r_e}{r_w}\right) + S} \qquad 2.26$$

where

$\mathbf{P_t}$ = Average reservoir pressure at decline time, t

$\mathbf{P_{wf}}$ = The critical BHP during production decline

The cumulative production of the well after the decline time (t), is:

$$N_p = \int_0^t \frac{k\,h\,(P_t - P_{wf})\,dt}{141.2\,B_o\,\mu\,ln\left(\frac{0.472\,r_e}{r_w}\right) + S} \qquad 2.27$$

or

$$\boldsymbol{N_p = \frac{C_t\,N_i}{B_o}(P_0 - P_t)} \qquad 2.28$$

where

C_t = Total reservoir compressibility

$\boldsymbol{N_i}$ = Initial oil in place in the well drainage area

P_0 = Average reservoir pressure at decline time zero

Edwardson, (1962), provided detailed equations for generating the transient and the boundary dominated streams of the cumulative production type curves. He stated that the transient flow rate and cumulative productions are reported in dimensionless term or form q_D and Q_D respectively as function of dimensionless time, t_D.

Mathematically as:

$$\boldsymbol{Q_D = \frac{-4.29881 + 2.02566\,t_D}{ln\,t_D}} \qquad 2.29$$

The well test based on Q_D and t_D are converted to decline based on Q_{Dd} and t_{Dt}

$$Q_{Dd} = \int_o^{t_{Dd}} q_{Dd} t_{Dd} = \frac{Q_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]} \quad 2.30$$

$$t_{Dd} = \frac{t_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]\left[ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4}\right]} \quad 2.31$$

$$Q_{Dd} = 1 - e^{-t_{Dd}} = 1 - q_{Dd} \quad \textit{For Exponential} \quad 2.32$$

$$Q_{Dd} = \frac{1}{1-b}\left[1 - (1 + bt_{Dd})^{1-\frac{1}{b}}\right] = \frac{1-q_{Dd}^{1-b}}{1-b} \quad \text{(Hyperbolic)} \quad 2.33$$

$$Q_{Dd}\, ln(1 + t_{Dd}) = ln\left(\frac{1}{q_{Dd}}\right) \quad \text{For Harmonic} \quad 2.34$$

Amini, et al, (2007), reservoir model used elliptical flow to govern flow regime in a low permeability gas reservoir with elliptical outer binding. He described these cases as one production from an elliptical wellbore, elliptical fracture or a circular wellbore in an anisotropic reservoir system, which can be considered to be an elliptical inner boundary. They stated that an elliptical reservoir surrounded by an elliptic aquifer is an elliptical outer boundary. They also stated that the reservoir is assumed to be a single-layer system that is isotropic, horizontal and uniform thickness and constant flow rate. Mathematically:

$$q_D = \frac{141.2\ B\mu q}{K\ h\ \Delta P} \quad 2.35$$

$$K = \frac{141.2\ B\ \mu}{h}\left[\frac{q/_{\Delta P}}{q_D}\right] \quad 2.36$$

Agarwal and Gardner, (2008), presented new decline type curves for analyzing production data. Their method builds on Fetkovitch's and Palacio-Blasigame's ideas. They utilized the concept of the equivalence between constant rate and constant pressure solution. They also presented new type curves with dimensionless variables based on the conventional well-test definition as in Fetkovitch and Blasigame. They equally included primary and semi-log pressure derivatives plots (decline analysis inverse formant). They as well presented rate versus cumulative and cumulative versus time plots. Rate – cumulative Production analysis mathematically:

$$Q_{DA} = \frac{t_{DA}}{P_D} = q_D t_{DA} \qquad 2.37$$

$$q_D = \frac{141.2\ qB\mu}{K\ h\left(P_t - P_{wf}\right)} \qquad 2.38$$

Wattenbarger, (1998), observed long linear flow in many gas wells. These were very tight reservoir with hydraulic fractured boundary of the well. Wattenbarger presented new types curves to analyze the production data of gas wells. He assumed a hydraulically fractured well in the centre of a rectangular reservoir. The fracture was assumed to be extended to the boundaries of the reservoir. Figure 2.3 shows his sketch.

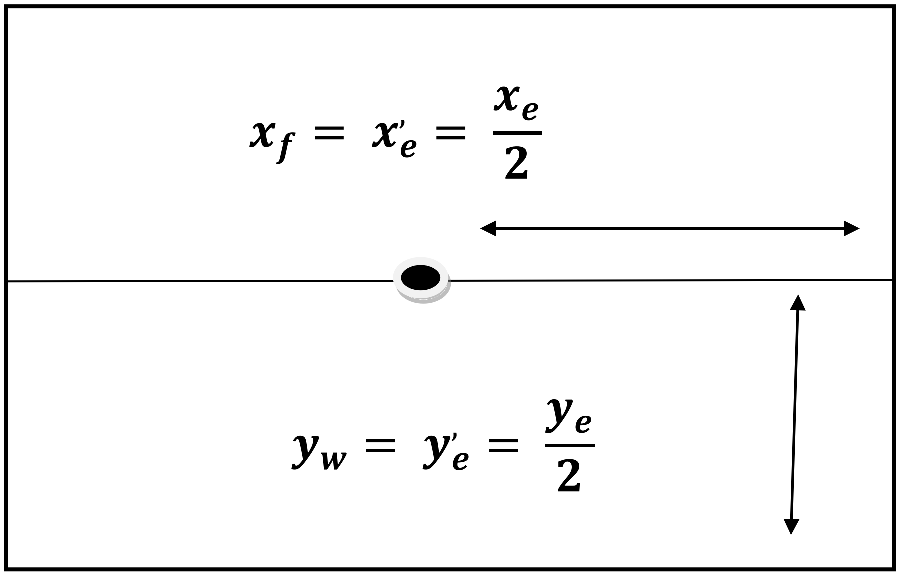

Fig 2.3 Constant rate production in closed reservoir solution:

Mathematically:

$$P_D = \frac{\pi}{2}\left(\frac{y'_e}{x_f}\right)\left[\frac{1}{3} + \left(\frac{x_f}{y'_e}\right)^2 t_{Dd}\right] - \frac{2}{\pi^2}\left(\frac{y'_e}{x_f}\right)\sum_{x=1}^{\infty}\frac{1}{n^2}e^{\left[n^2\pi^2\left(\frac{x_f}{y'_e}\right)^2 t_{Dd}\right]} \qquad 2.39$$

Agarwal, et al, (2008), explained the importance of water influx in gas reservoir. They observed that an appreciably water influx in a gas reservoir acts as pressure maintenance naturally delaying the decline initiation. The benefit is that much of the hydrocarbons are produced. The disadvantage is that such a reservoir is difficult to model, due to less knowledge of the aquifer behavior and life span.

King-Hubbert and Robertson, (2004), suggested in their work ''Modified Hyperbolic Decline'' that at some point in time the hyperbolic decline is converted into an exponential decline. They extrapolated hyperbolic decline over long periods of time and found out that it frequently results in unrealistically high pressure. To avoid this problem, they made their suggestion. They assumed that for a particular example, the decline rate (D) starts at 30% of flow and declines in a hyperbolic manner. When it reaches a specified value say 10% of the hyperbolic decline it converted to an exponential decline. The error here is that exponential decline rate of 10% would be considered in the forecast. Fig 2.4 shows the graphical representation of their work:

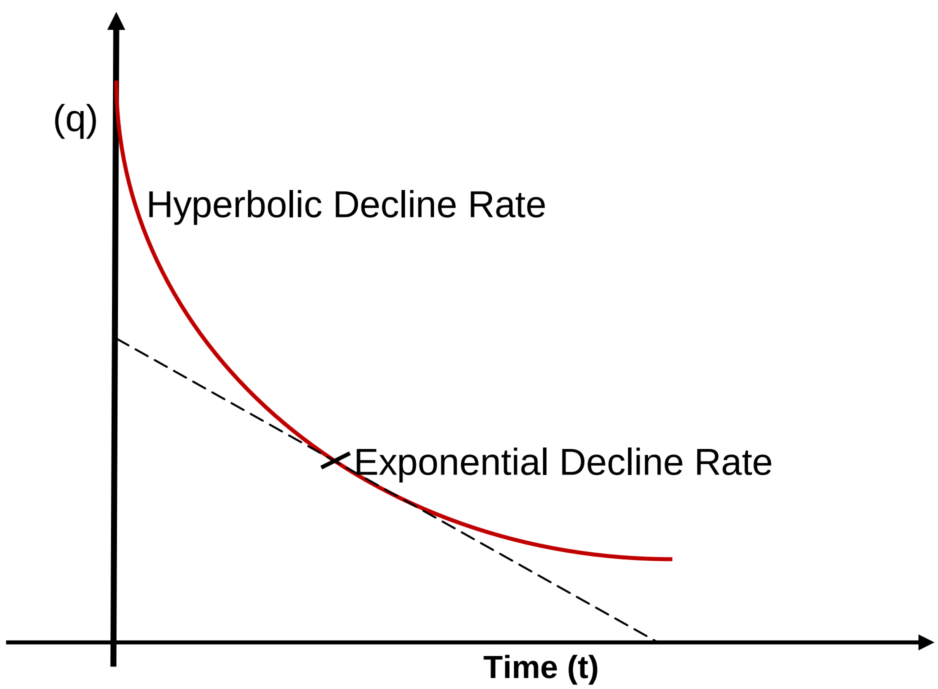

Fig 2.4 Conversion Hyperbolic into Exponential Decline Trend

Mathematically:

$$q = q_i \frac{\left[(1-B)^b e^{-Dt}\right]}{1-B\, e^{(-Dt)^b}} \qquad 2.40$$

$$Q = q_i \frac{1-B}{BD}\left[1 - \frac{1}{1-B\, e^{(-Dt)^{b-1}}}\right] \qquad 2.41$$

When b = 1

$$Q = q_i \frac{1-B}{BD} ln\left[1 - \frac{1-Be^{-Dt}}{1-B}\right] \qquad 2.42$$

Or

$$D = \frac{D_i}{q_i^{b-1}(1+bD_it)^{\frac{1}{b}}} \qquad 2.43$$

$$q = q_i(1+ bD_it)^{-\frac{1}{b}} \qquad 2.44$$

Ramsay and Guerrero, (2002), Study also included relative decline rate and they indicated in their work that about 40% of leases have $b > 0.5$ and commingled layered reservoirs fall between $0.5 < b < 1.0$.

Standing and Katz, (1942), defined the material balance equation as any hydrocarbons system volume balance which equates the production to the differences between the initial volume of hydrocarbons in the reservoir and the actual volume. Mathematically:

$$HCPV = V\emptyset(1- S_{wc}) = G/E_i \quad or \quad G = V\emptyset(1- S_{wc})E_i \qquad 2.45$$

Katz, (1959), defined volumetric MBE for gas recovery mathematically as: $\boldsymbol{E_R} = \frac{(\mathbf{1}-\boldsymbol{S_{wi}})\boldsymbol{B_{gi}}-\boldsymbol{S_{gr}}\boldsymbol{B_g}}{(\mathbf{1}-\boldsymbol{S_{wi}})\boldsymbol{B_{gi}}}$ 2.46

2.14 Reviewed evaluation and Research Proposal

Evaluating the early researchers' works, it is observed that the whole work is based on identifying exponential, hyperbolic or harmonic decline. They used semi-log fit or cross-match that an exact fit of data was not easily possible. The principal challenges of minimizing reserves estimation errors, projecting future reserves production and time required poorly achieved. The attempt to estimate reserves initially in place and the accuracy in DFCA has not been properly delineated. The gap I intent to fill is follows:

- Estimation of reserves initially in place (N)
- Simplification of complex simulation methods they used
- Improve reserves (N_p and N) estimation accuracy from 60 to 67% to 90 and 99%
- Reducing the time used in simulation
- Substituting the exponential, hyperbolic and harmonic decline constants with projectile and parabolic flow decline trends. This is because projectile and parabolic flow trends depend on flow order and not on constants which have been difficult to achieve.
- This research focuses on hydrocarbons production rates decline trends and reserves estimation (N_p and N) decline rates projection.

CHAPTER 3

MATERIALS AND METHODS

3.1 Materials for the research

The materials used for this work were collected from DPR, NNPC namely, daily operation logging data of oil and gas wells located in the Niger Delta areas. The wells covering Exploration (wildcat) wells, Appraisal (out-step) wells and Production (exploration development) wells. The main data were early to abandonment stages rates. The first set of data were specifically from the exploration, appraisal and production wells, because those wells could define early-stage to the actual production data records, while the second set of data were from the tanks-farms yearly production records (surface facilities) of the same Niger Delta formation oil wells These were used mainly for the validating input data.

3.2 Research Methodology

Raw data for the analysis were collated or grouped into three main dynamic characterizations.

a. Initials to abandonment rates of production
b. Initials to a given period rates of production
c. Short periods production rates history

Evaluation Models – I: [Governing Models]

Initial rates to abandonments were plotted against time to generate governing evaluation curves, I Used the curves to obtain rates decline constant, **'' b'',** I Used the decline constant, **'' b''** to predict yearly rates, I Used the yearly rates to build evaluation models and then I used the models to estimate reserves **[N_p & N].**

Evaluation Models – II:

(i) Initial rates to given periods of production were analyzed for decline constant, **‘‘b’’,** I Used the decline constant, **‘‘b’’** to predict yearly rates, I Used the yearly rates to generate evaluation curves to the given periods of production & extrapolated the curves to abandonment, I Used the extrapolated curves to build evaluation models and then I used the models to estimate reserves **[N_p & N].**

(ii) Short periods production rates were equally analyzed for declined trends and constant, ‘‘b’’, I Used the declined constant, ‘‘b’’ to predict yearly rates to abandonments (called generic data), I Used the generic data to generate evaluation curves, I Used the curves to build evaluation models and then I used the models to estimate reserves $[N_p \,\&\, N]$. Figure 3.1 below shows a flowchart of the data collation and figure 3.2 shows the flowchart for quality evaluations and applications.

Step - 1

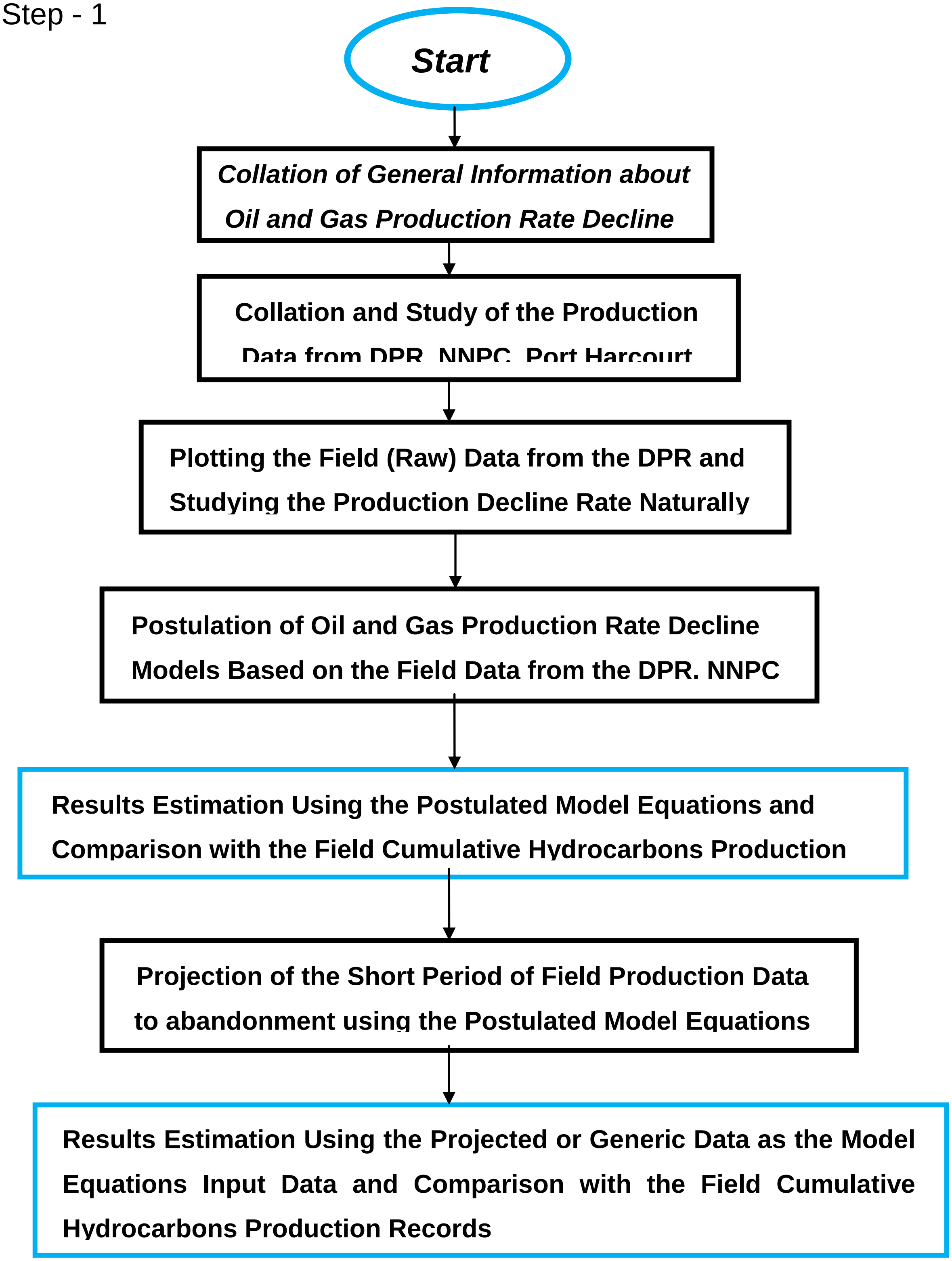

Fig 3.1 General Flowchart for Postulating Models Procedure

Step – 2: Models Quality Evaluation and Applications

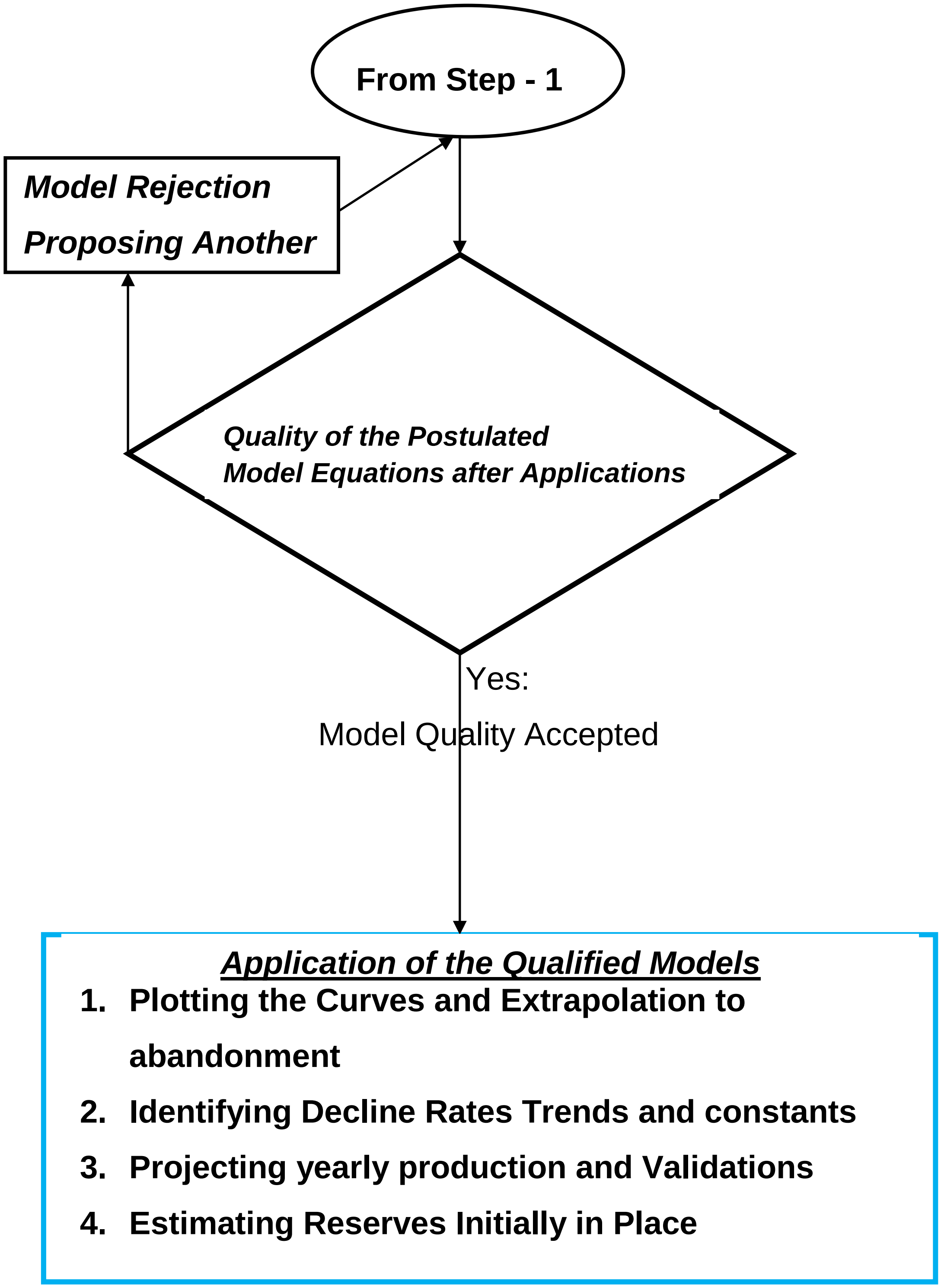

Fig 3.2 General Flowchart for Models Quality Evaluation and Selection

3.3 Analysis Procedures

Data Type – I

These covered the data from the early production stage to abandonment. Table 3.1 shows field data of gas reserves production for $22\frac{1}{2}$ years and table 3.2 shows oilfield production data for 10years.

Table 3.1: Field Data for Gas Production in $22\frac{1}{2}$ ***Years***

Date	Time, t (yr)	Rate q, MM scf/d
1977	**0**	**0**
1978	**1**	**50**
1979	**2**	**100**
1980	**3**	**100**
1981	**4**	**100**
1982	**5**	**100**
1983	**6**	**100**
1984	**7**	**100**
1985	**8**	**100**
1986	**9**	**100**
1987	**10**	**100**
1988	**11**	**100**
1989	**12**	**100**
1990	**13**	**100**
1991	**14**	**100**
1992	**14.45**	**100**
1993	**15**	**89.60**
1993	**16**	**73.34**
1994	**17**	**60.05**
1995	**18**	**49.16**
1996	**19**	**40.25**
1997	**20**	**32.96**
1998	**21**	**26.98**
1999	**22**	**22.09**
1999	**22.5**	**20.00**

Table 3.2: Delta State South Oilfield, March, 1968 to March, 1978

Date	**Time, t (yr)**	Pressure (Psi)	**Rate, q (Stb/d)**	**Rate, q M (stb/yr)**	Cumulative N_p, (M Stb)	B_o (rb/stb)
1968	0	4180	0	0	0	1.308
1969	1	4140	5498	2008.1	2008.1	1.301
1970	2	4119	6125	2237.1	4245.2	1.298
1971	3	4070	5885	2149.5	6394.7	1.297
1972	4	4032	6115	2233.5	8628.2	1.293
1973	5	3998	5640	2060.0	10688.2	1.290
1974	6	3960	4750	1735.0	12423.2	1.289
1975	7	3928	4500	1644.0	14067.2	1.285
1976	8	3930	2900	1059.0	15126.2	1.286
1977	9	3950	2345	856.5	15982.7	1.289
1978	10	398	1830	668.4	16651.1	1.299

Plotting of the collated data on Table 3.1 generated a projectile curve, Figure 3.3 and Plotting the data on Table 3.2 generated projected curve of Figure 3.4.

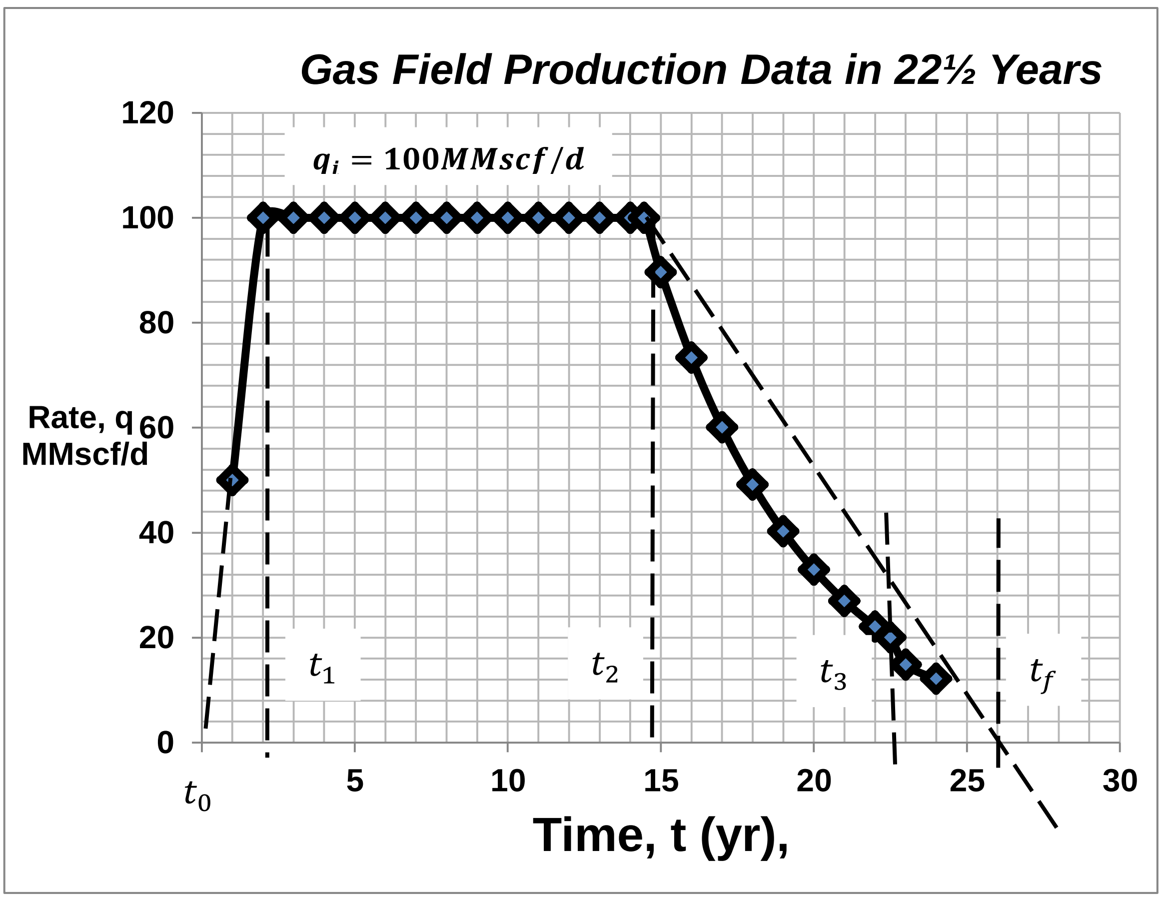

Fig 3.3 Projectile Decline Curve, using Table 3.1

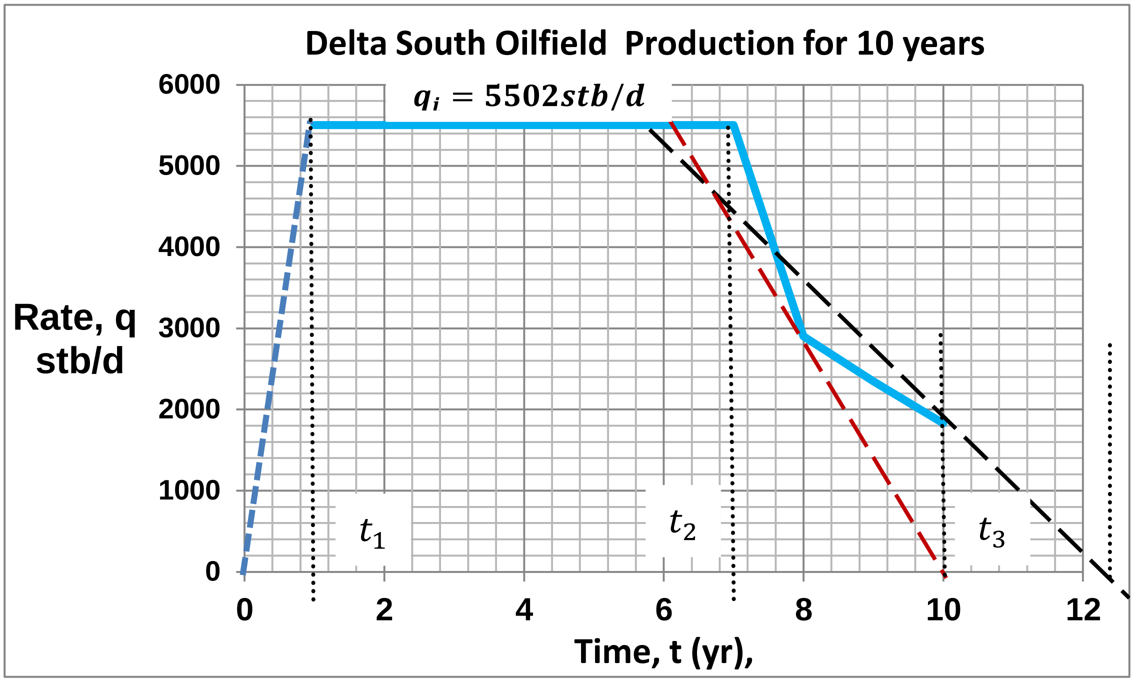

Fig 3.4 ***Projectile Decline Curve, using Table 3.2***

3.31 Postulation of the Projectile Models

In this section the principal method for postulating the evaluation models was the projectile dominated flow of the reserves. The projectile flow was found common in the depletion of natural gas reservoirs from the initial stage to an abandonment stage. Natural gas reserves recovery values table 3.1 were used in plotting the curves which were used to study the complete reserves recovery from the initial stage through the transient stage, steady stage, the decline stage to economic rate called abandonment rate (Figure 3.3) and yearly oil recovery data table 3.2 were used to study complete oil recovery (Figure 3.4). The resulted curves in projectile shapes were used to build the models for studying the decline trends and projected to both given recovery periods for estimating the cumulative reserves and zero declined for estimating the reserves initially in place. Figure 3.3 and Figure 3.4 show more of this.

Procedures:

- An oilfield must contain a reserve initially in place (N), which reduces per unit time, due to hydrocarbons production operations.
- The flow rate (q) of oil stream production continues to change from time, t_o to time, t_1 and from time, t_1 to time, t_2 and from time, t_2 to time, t_3, (Figure 3.3 or Figure 3.4), so that time, t_f could be extrapolated to the initial reserves values.
- The hydrocarbons production (N_p) per unit time declined from the initial value to minimum $\left(\frac{dq}{dt} = -bq^n\right)$. The constant of proportionality is -b.
- The quantity of the reserves remaining in the reservoir is N_f
- ***Construction:*** Join pt-B to pt-E giving the trapezium ABEO and pt-B to pt-D giving the trapezium ABDO respectively. The general equation for natural production of an oilfield reserves is given as Eqn3.1 and Eqn3.2:

I. Evaluation Model – 1: *The Projectile Gas or Oil Flow*

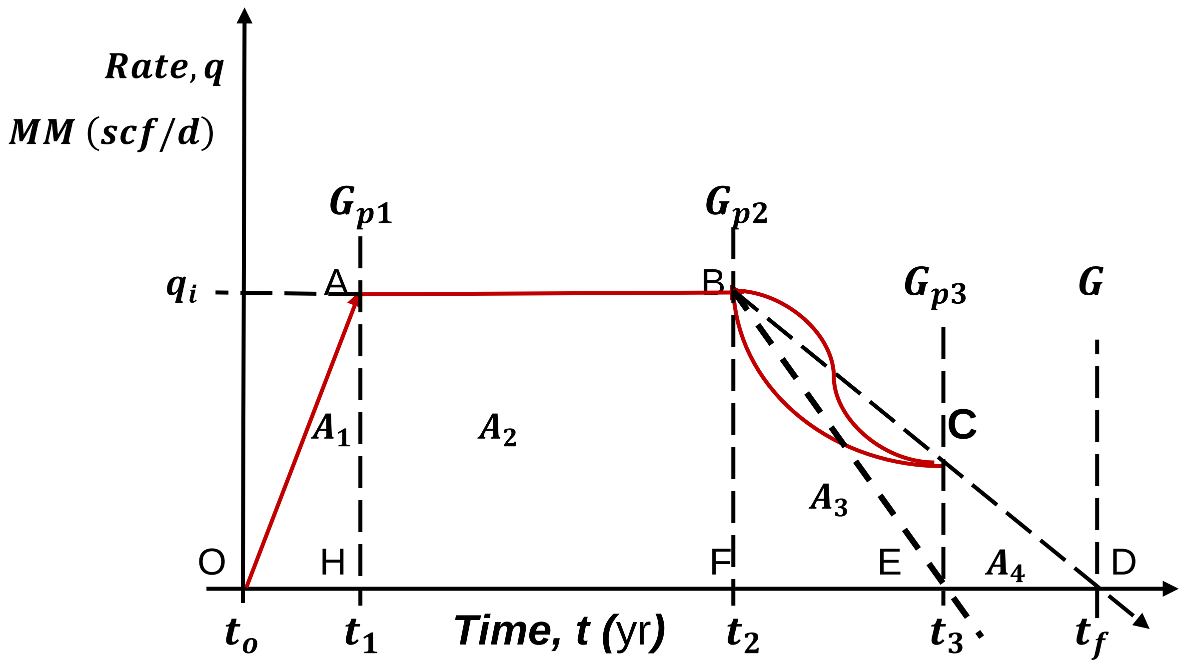

Fig 3.5 Schematic of Gas Flow during Production

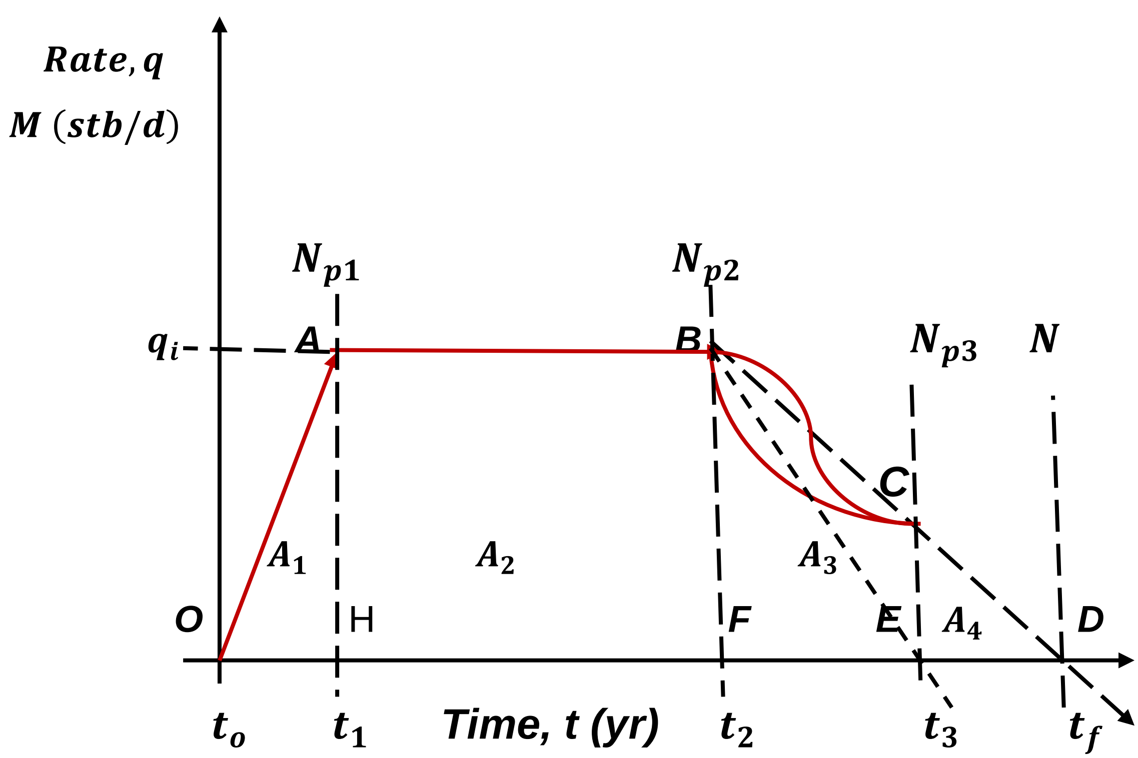

Fig 3.6 Schematic of Oil Flow during Production

$$\begin{bmatrix} Actual\ Reserves \\ Produced\ in\ a \\ Given\ Time \end{bmatrix} = \begin{bmatrix} Actual\ Reserves \\ Initially\ in\ Place \end{bmatrix} - \begin{bmatrix} Actual\ Reserves \\ remaining\ in\ Place \end{bmatrix}$$

$$G_p \quad = \quad G \quad - \quad G_f \qquad 3.1$$

$$N_p \quad = \quad N \quad - \quad N_f \qquad 3.2$$

Using Figure 3.5, the actual gas reserves produced in a given time and gas initially in place are expanded as:

$$[Gas\ Produced] = [Area\ of\ the\ Trapezium\ ABEO]$$

$$[Gas\ Produced] = \frac{1}{2}[Sum\ of\ the\ Parallel\ Sides] * [Height]$$

$$G_p = \frac{q_i}{2}[(t_2 - t_1) + (t_3 - t_0)] \qquad 3.3$$

Or

$$[Gas\ Produced] = [Area\ of\ the\ Trapezium: ABEO]$$

$$[Gas\ Produced] = [A_1 \quad + \quad A_2 \quad + \quad A_3]$$

$$A_1 = Area\ of\ \Delta AHO$$

$$A_1 = \frac{q_i}{2}[t_1 - t_0] \qquad 3.4$$

$$A_2 = Area\ of\ the\ rectangle\ ABFH$$

$$A_2 = q_i[t_2 - t_1] \qquad 3.5$$

$$A_3 = Area\ of\ \Delta BEF$$

$$A_3 = \frac{q_i}{2}[t_3 - t_2] \qquad 3.6$$

Adding up Eqn3.4, 3.5 and 3.6 gives Eqn3.7

$$G_p = \frac{q_i}{2}[(t_2 - t_1) + (t_3 - t_o)] \qquad 3.7$$

Using the equation of the curve part of Figures. 3.5/3.6

$$A_3 = [Gas\ recovered\ in\ Decline\ rate\ Stage]$$

Projected Hydrocarbons Production

$$G_p = \frac{[q_i - q]}{b} \quad or \quad qt \qquad 3.8$$

$$N_p = \frac{[q_i - q]}{b} \quad or \quad qt \qquad 3.9$$

The general equation for natural production of an oilfield reserves is the product of the rate-constant and the actual rate raised to power-n. This is given mathematically by Eqn3.10:

$$\begin{bmatrix} Actual\ Change \\ in\ Production \\ Rate\ with\ Time \end{bmatrix} = \begin{bmatrix} A\ Decline\ Rate \\ Constant \end{bmatrix} \begin{bmatrix} Actual\ Rate\ in \\ n - order \end{bmatrix}$$

$$\frac{dq}{dt} = -bq^n \qquad 3.10$$

Using the curve in Figure 3.5/Figure 3.6 and Eqn3.10, the actual oil or gas production rate in a given time is postulated as follows:

$When\ n = 1$: $\quad 1^{st}\ Order\ Decline\ Rate\ Parabolic\ Flow$

$$\int_{q_i}^{q} \frac{dq}{q} = -b \int_o^t dt \qquad 3.11$$

Solving Eqn3.11 gives, the governing equation, Eqn3.12

$$lnq - lnq_i = -bt \qquad 3.12$$

The governing equation, Eqn3.12 is used to obtain hydrocarbons production rate (q) by removing the log in Eqn3.12 and rearranging gives Eqn3.13. To estimate the rate-constant (b), Eqn3.12 is rearranged to obtain Eqn3.14

$$q = q_i \, e^{-bt} \qquad 3.13$$

$$b = \frac{ln(q_i/q)}{t - t_i} \qquad 3.14$$

Cumulative reserves Production Models

The general equation for natural production of an oilfield reserves is the product of the hydrocarbons flow rate and the actual time elapsed. This is given mathematically in Eqn3.15 and Eqn3.16:

$$\begin{bmatrix} Actual\ Cumulative \\ Hydrocarbons \\ Produced\ With\ Time \end{bmatrix} = \begin{bmatrix} Actual\ Production \\ Rate\ Per\ Unit\ Time \end{bmatrix} \begin{bmatrix} Actual\ Time \\ That\ Elapsed \end{bmatrix}$$

$$G_p = qdt \qquad 3.15$$

$$N_p = qdt \qquad 3.16$$

Using Figure 3.3 or Figure 3.4, Eqn3.15 or Eqn3.16, the actual gas or oil cumulative production at a given time is postulated as follows:

$$G_p = \int_o^t qdt \qquad 3.17$$

$$N_p = \int_o^t qdt \qquad 3.18$$

But $q = q_i e^{-bt}\ in\ Eqn\ 3.13$, substituting this in Eqn3.17 gives Eqn3.19, the cumulative gas production and in Eqn3.18 gives Eqn3.20, the cumulative oil production.

$$G_p = \int_o^t q_i e^{-bt} dt \qquad 3.19$$

$$N_p = \int_o^t q_i e^{-bt} dt \qquad 3.20$$

Solving Eqn3.19 gives Eqn3.21, the governing equation for gas cumulative production and solving Eqn3.20 gives Eqn3.22, the governing equation for actual oil cumulative production.

$$G_p = \frac{q_i}{b}\left[1 - e^{-bt}\right] \qquad \text{For gas systems} \qquad 3.21$$

$$N_p = \frac{q_i}{b}\left[1 - e^{-bt}\right] \qquad \text{For oil systems} \qquad 3.22$$

This implies that the projected hydrocarbons production is:

$$A_3 = G_{p3} = \frac{q_i}{b}\left(1 - e^{-bt}\right) \qquad 3.23$$

Similarly:

$$N_{p3} = \frac{q_i}{b}\left(1 - e^{-bt}\right) \qquad 3.24$$

Summing up Eqns3.4, 3.5 and 3.23 gives Eqn3.25

$$G_p = q_i\left[t_2 - 0.5(t_1 + t_o) + \frac{\left(1 - e^{-bt_3}\right)}{b}\right] \qquad 3.25$$

Equations 3.3, 3.7 and 3.25 are the gas production decline analysis evaluation models postulated.

Reserves Initially in Place (G or N) Postulation

$$\begin{bmatrix}\text{Actual Gas Reserves}\\ \text{Initially in Place}\end{bmatrix} = \begin{bmatrix}\text{Area of the}\\ \text{Trapezium ABDO}\end{bmatrix}$$

$$[\text{Gas in Place}, G] \quad = \quad [\text{Area ABDO}]$$

$$[\text{Area ABDO}] = \frac{q_i}{2}\left[(t_2 - t_1) + \left(t_f - t_o\right)\right]$$

$$G = \frac{q_i}{2}\left[(t_2 - t_1) + \left(t_f - t_o\right)\right] \qquad 3.26$$

Equation 3.26 is the actual gas initially in place (GIIP). This is very possible since gas production is the product of the flow rate, q and time, t ($G = q * t$).

Similarly

Using Figure 3.6, the actual oil reserves produced in a given time and the actual oil initially in place were postulated in the same procedure.

Mathematically:

$$N_p = \frac{q_i}{2}\left[(t_2 - t_1) + (t_3 - t_0)\right] \qquad 3.27$$

$$N_p = q_i\left[t_2 - 0.5(t_1 + t_o) + \frac{1}{b}\left(1 - e^{-\mathrm{b}t_3}\right)\right] \qquad 3.28$$

Equations 3.24, 3.27 and 3.28 are the oil production decline analysis evaluation models postulated.

Reserves Initially in Place:

$$N = \frac{q_i}{2}\left[(t_2 - t_1) + \left(t_f - t_o\right)\right] \qquad 3.29$$

Equation 3.29 is the actual oil initially in place (OIIP). This is possible since oil production is the product of the flow rate, q and time, t (yr).

3.32 Postulation of the Parabolic Models

Data Type – II and type III

These were the data from gas and oil wells production in the given number of years. Table 3.3 shows data for reserves production declined in a year, Table 3.4 shows the records for reserves production declined in a year as well and Table 3.5 shows the data for reserves production decline in just a month. These data were projected to yearly rate decline between five and twenty yearly (called generic data).

Table 3.3 Oilfield Production Test Data in One Year (1996): Well – 21A

Time, t (yr)	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0
Rate, M stb	96.3	92.9	89.80	86.80	84.00	81.40	79.00	76.70	74.50	72.50

Table 3.4 Oilfield Production Test Data in One Year (1999): Well – 21B

Time, t (yr)	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0
Rate, M stb/d	956.3	92.8	89.50	86.40	83.50	80.70	78.10	75.50	73.20	70.90

Table 3.5 Oilfield Production Test Data in One Month (Sept. 1996)

Time, t (yr)	0.0	0.0831				
Rate, M stb/d	100	96.00				

Procedures:

- An oilfield must contain a reserve initially in place (N), which reduces per unit time, during production operations.
- A reserve must decline right from initial stage during production in a parabolic bell-shape (Figure 3.7a) or dome-shape (Figure 3.7b), double-apex shape (Figure 3.7c) or single-apex shape (Figure 3.7d)
- The flow rate (q) of oil stream production continues to change from time, t_o to time, t_1, (Figure 3.7c and Figure 3.7d) so that time, t_f could be estimated.
- The actual change in a production rate per unit time is $dq \propto \boldsymbol{q^n dt}$ and the constant of proportionality is –b or it is the product of the decline rate constant, b and flow rate raised to power-n ($-\boldsymbol{bq^n}$).
- The cumulative hydrocarbons production (N_p) per unit time would be reduced from the maximum at bubble point (transition state) value to minimum at a given time. The quantity of the reserves remaining in the reservoir is N_f at time t_f.

II. Parabolic *Flow in* Oil or Gas Stream

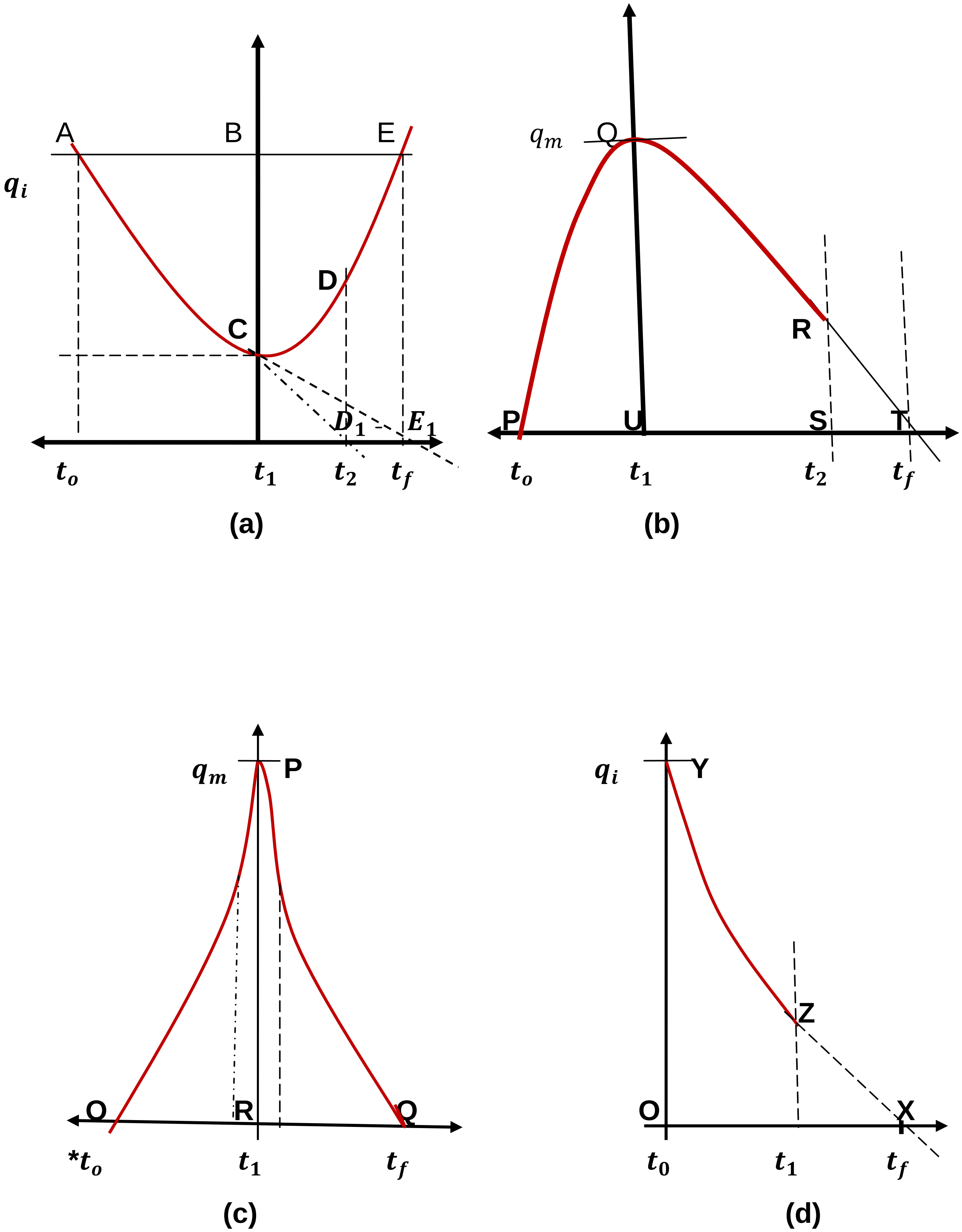

Fig 3.7 Schematic of Oil or Gas in Parabolic Flow Regime

Evaluation Model - II

The bell shape of Figure 3.7a depicts an oil well production reducing or recovering from maximum value at bubble point pressure, point – A to point-C, an apparent abandonment. After reconsideration enhanced recovery methods were used to displace more hydrocarbons from point-C to point-D. This may even be possible by reducing the original residual oil saturation. The model equations in this case depend on the displacement ratio of the displacing fluid to the displaced fluid. The curve can be extrapolated from point - D to point – E, for estimation of oil or gas reserve initially in place. Extension of the curve AC to D_1at t_2, called curve AD_1 gives the total cumulative fluid production and evaluation models-II were used for the estimation. Extension of curve-AC to E_1 at t_f gives curve AE_1, evaluation models-II were equally used for estimating the fluid reserve initially in place. The dome shape of Fig 3.7b indicates a parabolic flow rate from lowest at point-P to a maximum point – Q and declines to abandonment at point – R. The curve can be extrapolated from point - R to point – T, for estimation of oil or gas reserve initially in place by extension of curve-QR at point-R to T in time-t_f. Then evaluation models-II used. Figure 3.7c is similar to Figure 3.7b, only that the transition time is sharper in the curve of

Figure 3.7c. There is little or no difference in the models equations of the types of flow. In the case of Figure 3.7d the reservoir pressure is just slightly above the bubble point or at bubble point pressure. The implication of this case is that decline starts right from the early stage of production at point –Y to point - Z. The curve can be extrapolated from point - Z to point – X, for estimation of oil or gas initially in place.

while the parabolic flows were used to postulate the model from the decline point to the given economic rate called abandonment rate. The decline rate may set in at short production period or right from the early production stage of the reservoir. The early production data were projected to both economic recovery periods for estimating the cumulative hydrocarbons production and induced abandonment for estimating the hydrocarbons reserves initially in place. The postulated models determinant confirmation equations were the projectile dominated fluid flow and the field recovery results. Table 3.1 shows the projectile dominated hydrocarbons (gas) production trend and table 3.2 shows the projectile dominated hydrocarbons (oil) production trend. The outstanding advantages of the decline stage models include:

- Prediction of the daily oil/gas production rate and cumulative recovery in a given period. This enables the operator to equally predict the abandonment period and the cumulative recovery value.
- Good prediction of the reserves in place when the decline rate stage is converted to a projectile dominated flow stream.

3.33 Hydrocarbons Production Models

Basically 3 types of decline trends in oil and gas recovery were used 1st order equation where n = 1, 2nd order equation where n = 2 and fraction order equation where $n < 1 \; or \; n < 2$. The general equation for natural production of an oilfield reserves is the product of the rate-constant and the actual rate raised to power-n. This is given by parabolic flow regime (Eqn3.30):

$$\begin{bmatrix} \boldsymbol{Actual\ Change} \\ \boldsymbol{in\ Production} \\ \boldsymbol{Rate\ with\ Time} \end{bmatrix} = \begin{bmatrix} \boldsymbol{A\ Decline\ Rate} \\ \boldsymbol{Constant} \end{bmatrix} \begin{bmatrix} \boldsymbol{Actual\ Rate\ in} \\ \boldsymbol{n - order} \end{bmatrix}$$

$$\frac{dq}{dt} = -bq^n \qquad 3.30$$

Using the curve in Figure 3.7c and Eqn3.30, the actual oil or gas production rate in a given time is postulated as follows:

$\boldsymbol{When\ n = 1}$: $\quad \boldsymbol{1^{st}\ Order\ Decline\ Rate\ Parabolic\ Flow}$

$$\int_{q_i}^{q} \frac{dq}{q} = -b \int_{o}^{t} dt \qquad 3.31$$

Solving Eqn3.31 gives the governing equation, Eqn3.32

$$\ln q - \ln q_i = -bt \qquad 3.32$$

The governing equation, Eqn3.32 is used to obtain hydrocarbons production rate, q and the rate-constant (b). To obtain the rate, q, remove the log in Eqn3.32 and rearranging gives Eqn3.33

$$q = q_i e^{-bt} \quad 3.33$$

To estimate the rate constant (b), the governing equation is applied at point-A, point-B and point-C of Figure 3.8 below generating 3 equations and simultaneously each pair is solved for **"b"**.

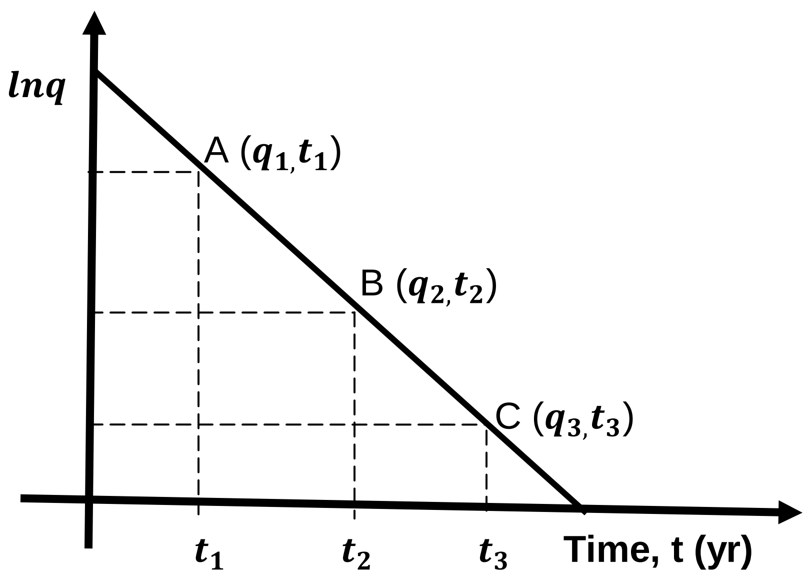

Fig 3.8 Parabolic Rate Decline Plot

At point-A and point-B, the rate decline equations are Eqn3.34 and Eqn3.35. Solving these simultaneously give Eqn3.36.

$$\boldsymbol{lnq_1 \; - \; lnq_i = \; -bt_1} \qquad 3.34$$

$$\boldsymbol{- (lnq_2 \; - \; lnq_i = \; -bt_2)} \qquad \textit{3.35}$$

(3.34) –(3.35) $\boldsymbol{ln\frac{q_1}{q_2} = b(t_2 - \; t_1)}$ **or**

$$\boldsymbol{b \quad = \quad \frac{ln(q_1/q_2)}{t_2 - t_1}} \qquad 3.36$$

If $\boldsymbol{b_1 = \; b_2 = \; b_3 = . \; . \; . \; . \; . \; . \; . \; . = \; b_n}$ it implies uniform decline and $n = 1$, so the equation $\boldsymbol{b \; = \; \frac{ln(q_1/q_2)}{t_2 - t_1}}$ would be used in projecting the flow rate, q for a give time, t. That is $\boldsymbol{q_1 \; at \; t_1, \; q_2 \; at \; t_2}$, $\boldsymbol{q_3 \; at \; t_3}$, ... $\boldsymbol{q_n \; at \; t_n}$ using Eqn3.33.

Projected Cumulative Reserves Production Models

$$\boldsymbol{G_p = \; \frac{q_i}{b}\left[1 - e^{-bt}\right]} \qquad \text{For gas systems} \qquad 3.37$$

$$\boldsymbol{N_p = \; \frac{q_i}{b}\left[1 - e^{-bt}\right]} \qquad \text{For oil systems} \qquad 3.38$$

$\boldsymbol{When\; n = 2}$: $\boldsymbol{2^{nd}\; Order\; Decline\; Rate\; Parabolic\; Flow}$

$$\boldsymbol{\int_{q_i}^{q} \frac{dq}{q^2} \quad = \quad -b\int_{o}^{t} dt} \qquad 3.39$$

Solving Eqn3.39 gives Eqn3.40

$$\boldsymbol{\frac{1}{q_i} - \; \frac{1}{q} = \; -bt} \qquad 3.40$$

Multiply LHS of Equ3.40 by q_i and rearrange gives Equ3.41, the governing equation.

$$\boldsymbol{q \;\; = \;\; \frac{q_i}{(1 \; + \;\; bt)}} \qquad 3.41$$

The governing equation (Eqn3.41) is the 2nd order decline rate used to obtain hydrocarbons production rate, q and the rate decline-constant, b when the decline exponent is two ($\boldsymbol{n} = \mathbf{2}$). To estimate the rate constant, **''b''** the governing equation is applied at point-A, point-B and point-C of Figure 3.9 below generating 3 equations and simultaneously each pair is solved for **''b''** or just re-arranged making b the subject of the formular ($q = \boldsymbol{q_i} - \boldsymbol{bqt}$). Plotting $\boldsymbol{q}$ $\boldsymbol{vs}$ $\boldsymbol{t}$, the slope is $-\boldsymbol{bq}$ and intercept is q_i.

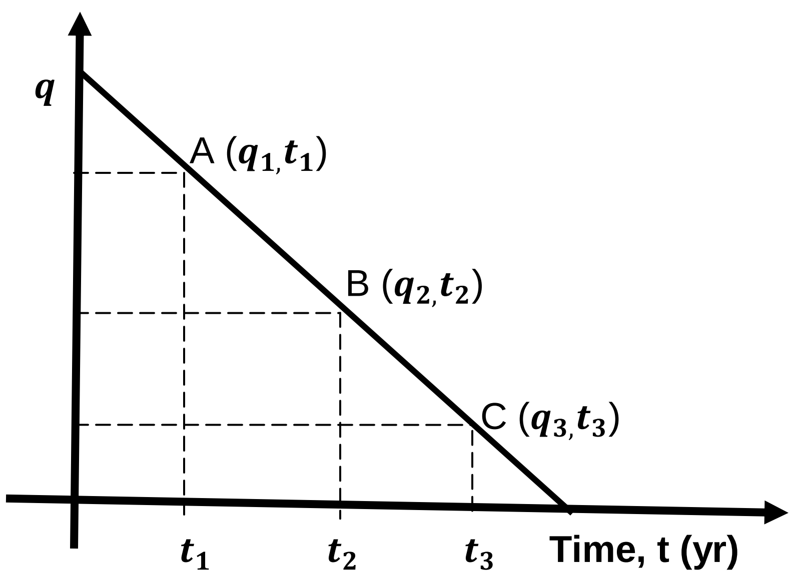

Fig 3.9 Parabolic Rate Decline Plot

At point-A and point-B, the rate decline equations are Eqn3.42 and Eqn3.43. Solving these simultaneously give Eqn3.44.

$$q_1 = q_i - bq_1t_1 \qquad 3.42$$

$$-(q_2 = q_i - bq_2t_2) \qquad 3.43$$

(3.19) –(3.20) $q_1 - q_2 = b(q_2t_2 - q_1t_1)$

$$b = \frac{q_1 - q_2}{q_2t_2 - q_1t_1} \quad or \quad \frac{q_i - q}{q\,t} \qquad 3.44$$

If $b_1 = b_2 = b_3 = \ldots\ldots. = b_n$, indicating a uniform decline rate $when,\ n = 2$, so the equation, $b = \frac{q_1 - q_2}{q_2t_2 - q_1t_1}$ or $\frac{q_i - q}{q\,t}$ would be used in projecting the flow rate, q for a given time, t. That is $q_1\ at\ t_1,\ q_2\ at\ t_2,\ q_3\ at\ t_3, \ldots\ldots\ldots q_n\ at\ t_n$ using Eqn3.41.

Projected Hydrocarbons Production Models

$$G_p = \frac{[q_i - q]}{b} \quad or \quad qt \qquad \text{For Gas} \qquad 3.45$$

$$N_p = \frac{[q_i - q]}{b} \quad or \quad qt \qquad \text{For Oil} \qquad 3.46$$

When $n < 1\ or\ 1 < n < 2$

The value of, $b_1 \neq b_2 \neq b_3 \neq \ldots\ldots. \neq b_n$, it indicates non-uniform decline rate. In this case an average decline would be used or the decline rate would be estimated at each point, in the projected flow rate, q within the given time, t. This means $b_1\ at\ t_1$ is calculated and used for $G_{p1}\ or\ N_{p1}$, $b_2\ at\ t_2$ is equally calculated and used for

G_{p2} *or* N_{p2}, b_3 *at* t_3 is also calculated and used for G_{p3} *or* N_{p3}, and so on to b_n *at* t_n is used for G_{pn} *or* N_{pn},

$$q = \frac{q_i}{1 + bt} \qquad (i = 0, 1, 2, 3, , , \ldots\ldots, n) \tag{3.47}$$

$$b \approx \sum_i^n \left[\frac{q_i - q_{i+1}}{q_{i+1} * t_{i+1}}\right] \; Meaning:$$

$$b \approx \frac{1}{n}\left[\frac{q_i - q_1}{q_1\, t_1} + \frac{q_i - q_2}{q_2\, t_2} + \frac{q_i - q_3}{q_3\, t_3} + . \;\; . \; . + \frac{q_i - q_n}{q_n\, t_n}\right] \tag{3.48}$$

Projected Hydrocarbons Production

$$G_p = \frac{[q_i - q]}{b} \quad or \quad qt \tag{3.49}$$

$$N_p = \frac{[q_i - q]}{b} \quad or \quad qt \tag{3.50}$$

3.4 Cumulative Hydrocarbons Production Model

The general equation for natural production of an oilfield reserves is the product of the hydrocarbons flow rate and the actual time elapsed. This is given by parabolic flow regime (Eqn3.51 and Eqn3.52):

$$\begin{bmatrix} Actual\ Cumulative \\ Hydrocarbons \\ Produced\ With\ Time \end{bmatrix} = \begin{bmatrix} Actual\ Production \\ Rate\ Per\ Unit\ Time \end{bmatrix}\begin{bmatrix} Actual\ Time \\ That\ Elapsed \end{bmatrix}$$

$$G_p = qdt \tag{3.51}$$

$$N_p = qdt \tag{3.52}$$

Using Figure 3.7c, Eqn3.51 or Eqn3.52, the actual gas or oil cumulative production at a given time is postulated as follows:

$$G_p = \int_o^t qdt \tag{3.53}$$

$$N_p \quad = \quad \int_o^t q dt \qquad 3.54$$

But $q = q_i e^{-bt}$ *in Eqn* 3.33, substituting this in Eqn3.53 gives Eqn3.55, the cumulative gas production and in Eqn3.54 gives Eqn3.56, the cumulative oil production.

$$G_p = \int_o^t q_i e^{-bt} dt \qquad 3.55$$

$$N_p = \int_o^t q_i e^{-bt} dt \qquad 3.56$$

Solving Eqn3.55 gives Eqn3.57, the governing equation for gas cumulative production and solving Eqn3.56 gives Eqn3.58, the governing equation for actual oil cumulative production.

$$G_p = \frac{q_i}{b}\left[1 - e^{-bt}\right] \qquad \text{For gas systems} \qquad 3.57$$

$$N_p = \frac{q_i}{b}\left[1 - e^{-bt}\right] \qquad \text{For oil systems} \qquad 3.58$$

Eqn3.56 is the governing equation, used for estimating the gas cumulative production value, G_p and Eqn3.58 is used for the oil cumulative production value, $\mathbf{N_p}$. The governing equation, Eqn3.57 is used to obtain the rate-constant, b for gas production system and Eqn3.58 is used to obtain the rate-constant, b for oil production system.

$$G_p = \frac{q_i}{b}\left[1 - e^{-bt}\right] \quad or \quad G_p = \frac{[q_i - q_i\, e^{-tb}]}{b} \qquad 3.59$$

But, $q = q_i e^{-bt}$, substituting this in Eqn3.55 and re-arrange gives Eqn3.60

$$q - q_i = -bG_p \qquad 3.60$$

Similarly: $q - q_i = -bN_p$ 3.61

To estimate the rate constant, **''b''** using cumulative gas or oil production, Eqn3.60 or Eqn3.61 is applied at point-P, point-Q and point-R of Figure 3.10 below, which shows a plot of cumulative hydrocarbons production against the rate. The plot generated 3 equations and two of the equations were solved simultaneously for **''b''** as follows:

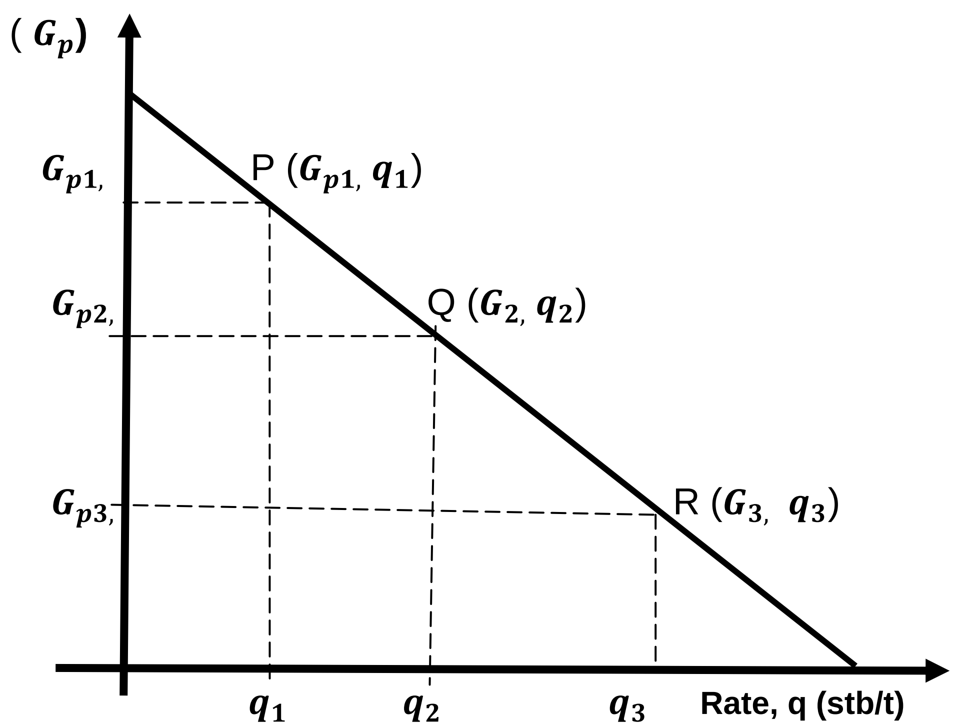

Fig 3.10 Cumulative Hydrocarbons Production Plot

At point-P and point-Q, the rate decline equations are Eqn3.62 and Eqn3.63. Solving these simultaneously give Eqn3.64.

$$\boldsymbol{q_1 \quad - \quad q_i \; = -bGp_1} \qquad 3.62$$

$$\textbf{-}\,\boldsymbol{(q_2 \quad - \quad q_i \; = -bG_{p2})} \qquad 3.63$$

(3.61) – (3.62) $\boldsymbol{q_1 - q_2 = b(G_2 - G_1)}$

$$\boldsymbol{b} = \frac{\boldsymbol{q_1 - q_2}}{\boldsymbol{G_2 - G_1}} \qquad \text{For Gas} \qquad 3.64$$

Similarly: $$\boldsymbol{b} = \frac{\boldsymbol{q_1 - q_2}}{\boldsymbol{N_{p2} - N_{p1}}} \qquad \text{For Oil} \qquad 3.65$$

If $\boldsymbol{b_1 = b_2 = b_3 = \ldots\ldots\ldots = b_n}$ it implies uniform decline, so the equation $\boldsymbol{b} = \frac{\boldsymbol{q_1 - q_2}}{\boldsymbol{G_2 - G_1}}$ could be used in projecting the hydrocarbons production, G_p for a give time, t. This means that the projected gas produced is done as follows: $\boldsymbol{G_{p1}\ at\ t_1\ using\ b}$, $\boldsymbol{G_{p2}\ at\ t_2\ using\ b}$, $\boldsymbol{q_3\ at\ t_3\ , using\ b}$, $\boldsymbol{\ldots\ldots\ldots q_n\ at\ t_n using\ b}$ in **E**qn3.57 for gas production and Eeqn3.58 for oil production respectively.

Parabolic Flow Type – 2, Short Transient and Transition Time

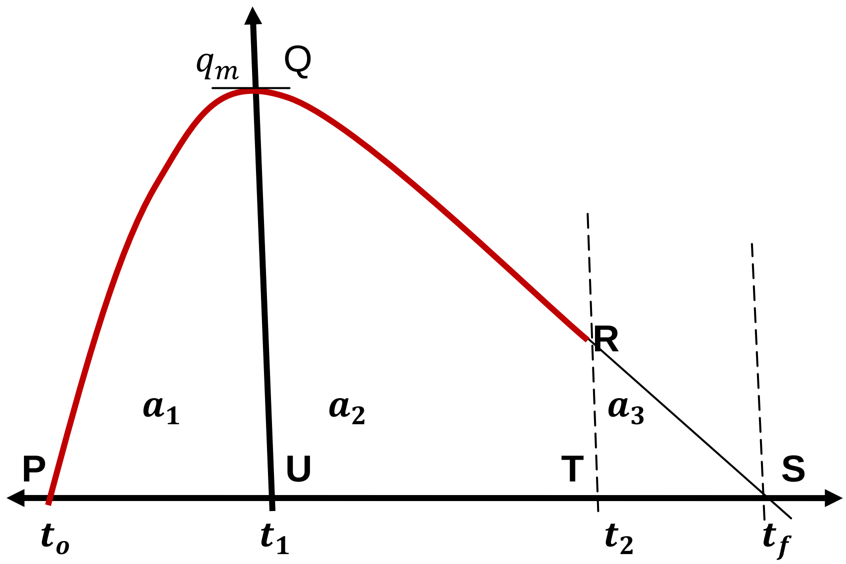

Fig 3.11 **Schematic of Oil or Gas in Parabolic Flow Regime**

In this case the reservoir started by building up the internal energy for some time from time, t_o to time, t_1 in figure 3.11, because the reservoir was fairly saturated, so failed to attain boundary dominated flow at initial state. Instead it built-up from the initial stage to the transient and transition stage at point – Q, but the flow period was too short. To this effects steady state flow (called the plateau) was not observed in the curve at time, t_1 instead rate decline state sets in from time, t_1 to time, $\boldsymbol{t_2}$**.** After this the rate decline state sets in with or without transition state, from time, $\boldsymbol{t_2}$ to time, $\boldsymbol{t_f}$ covering the total or cumulative gas or oil recovery value (in scf or stb). Any recovery from time, $\boldsymbol{t_2}$ to time**,** $\boldsymbol{t_f}$ covers the hydrocarbons supposed to be the residual oil or gas of that reservoir. The complete depletion of the hydrocarbons in that reservoir (called hydrocarbons initially in place) is from time, $\boldsymbol{t_o}$ **to time,** $\boldsymbol{t_f}$**.** The equation of the area of that shape (trapezium) is the value of the hydrocarbons initially in place (Figure 3.11). This is only obtainable in theory for reserves estimation, so it is an extrapolated value.

Hydrocarbons Production per Unit Time (stb/yr) Model

$$\begin{bmatrix} \boldsymbol{Total\ Hydrocarbons} \\ \boldsymbol{Production\ per\ Time} \end{bmatrix} = \begin{bmatrix} \boldsymbol{Area\ of} \\ \boldsymbol{Curve, a_1} \end{bmatrix} + \begin{bmatrix} \boldsymbol{Area\ of} \\ \boldsymbol{Curv, a_2} \end{bmatrix}$$

$$\boldsymbol{G_p} = \frac{\boldsymbol{q_i}}{\boldsymbol{2}}[(\boldsymbol{t_1} - \boldsymbol{t_0}) + (\boldsymbol{t_2} - \boldsymbol{t_1})] \qquad \text{For Gas} \qquad 3.66$$

$$\boldsymbol{N_p} = \frac{\boldsymbol{q_i}}{\boldsymbol{2}}[(\boldsymbol{t_1} - \boldsymbol{t_0}) + (\boldsymbol{t_2} - \boldsymbol{t_1})] \qquad \text{For Oil} \qquad 3.67$$

3.5 Hydrocarbons Initially in Place, stb (Figure 3.11) Models

$$\begin{bmatrix} \boldsymbol{Total\ Hydrocarbons} \\ \boldsymbol{in\ Place\ initially} \end{bmatrix} = \begin{bmatrix} \boldsymbol{Area\ of} \\ \boldsymbol{Curve, a_1} \end{bmatrix} + \begin{bmatrix} \boldsymbol{Area\ of} \\ \boldsymbol{Curv, a_2 + a_3} \end{bmatrix}$$

$$\boldsymbol{G} = \frac{\boldsymbol{q_i}}{\boldsymbol{2}}\left[(\boldsymbol{t_1} - \boldsymbol{t_0}) + (\boldsymbol{t_f} - \boldsymbol{t_1})\right] \qquad \text{For Gas} \qquad 3.68$$

$$\boldsymbol{N} = \frac{\boldsymbol{q_i}}{\boldsymbol{2}}\left[(\boldsymbol{t_1} - \boldsymbol{t_0}) + (\boldsymbol{t_f} - \boldsymbol{t_1})\right] \qquad \text{For Oil} \qquad 3.69$$

Parabolic *Flow Type – 3: Sharp Transient and Transition Time*

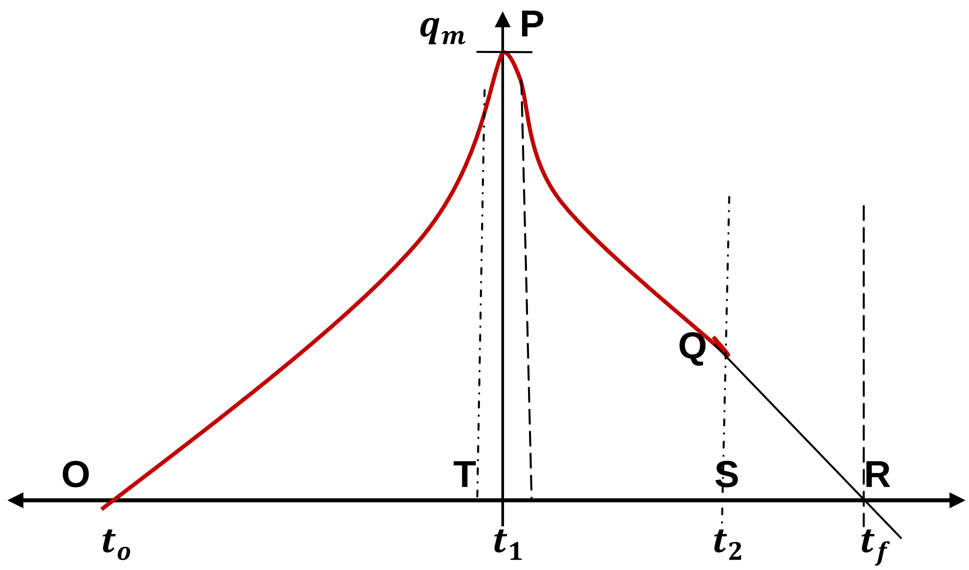

Fig 3.12 Schematic of Oil or Gas in Parabolic Flow Regime

This case is similar to the above case, only that the Parabolic flow type has sharp transient and transition Time. The area of the curve is equivalent to the total hydrocarbons produced or initially in place.

Hydrocarbons Production per Unit Time, stb/yr (Figure 3.12)

$$G_p = \frac{q_m}{2}[(t_1 - t_0) + (t_2 - t_1)] \quad \text{For Gas} \quad 3.70$$

$$N_p = \frac{q_m}{2}[(t_1 - t_0) + (t_2 - t_1)] \quad \text{For Oil} \quad 3.71$$

Hydrocarbons Initially in Place, stb

$$G = \frac{q_m}{2}\left[(t_1 - t_0) + (t_f - t_1)\right] \quad \text{For Gas} \quad 3.72$$

$$N = \frac{q_m}{2}\left[(t_1 - t_0) + (t_f - t_1)\right] \quad \text{For Oil} \quad 3.73$$

Parabolic ***Flow with no Observable Transient or Transition***

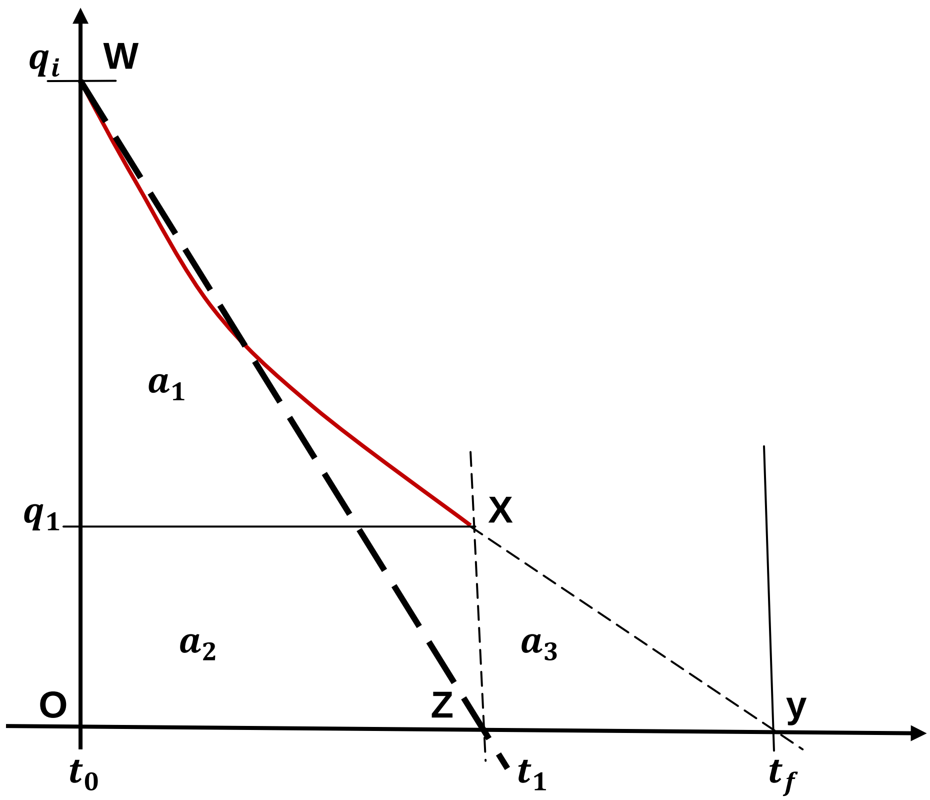

Fig 3.13 Schematic of Oil or Gas in Parabolic Flow Regime

In this case the oilfield reservoir was on steady state. The boundary conditions were felt right from the start. If the reservoir is not externally supported, it may be difficult to deplete the reservoir completely.

Cumulative Reserves Production Evaluation Models (Figure 3.13)

$$\begin{bmatrix} Total\ Hydrocarbons \\ Production\ per\ Time \end{bmatrix} = \begin{bmatrix} Area\ of \\ Curve, a_1 \end{bmatrix} + \begin{bmatrix} Area\ of \\ Curv, a_2 \end{bmatrix}$$

$G_p = \frac{q_i}{2}[t_1 - t_0]$ $\quad$ ($or\ G_p = \frac{q_i}{b}[1 - e^{-bt}]$: Ref: Eqn3.43**)** $\quad$ 3.74

$G_p = \frac{q_i - q_1}{2}[(t_1 - t_0)] + (q_1 - q_0)(t_f - t_1)$ $\quad$ For Gas $\quad$ 3.75

$$N_p = \frac{q_i - q_1}{2}[(t_1 - t_0)] + (q_1 - q_0)(t_f - t_1) \qquad \text{For Oil} \qquad 3.76$$

Reserves Initially in Place (stb) Evaluation Models (Figure 3.13)

$$\begin{bmatrix} Total\ Hydrocarbons \\ in\ Place\ initially \end{bmatrix} = \begin{bmatrix} Area\ of \\ Curve, a_1 \end{bmatrix} + \begin{bmatrix} Area\ of \\ Curv, a_2 + a_3 \end{bmatrix}$$

$$G = \frac{q_i}{2}\left[t_f - t_0\right] \qquad \text{For Gas} \qquad 3.77$$

$$N = \frac{q_i}{2}\left[t_f - t_0\right] \qquad \text{For Oil} \qquad 3.78$$

This research work focuses on hydrocarbons production decline rate projection, hydrocarbons cumulative production and hydrocarbons initially in place estimation. The primary data used were the early production rate to project future rates in a given time piece. The values were used to plot curves and the generated curves were empirically used to build the models. In a case where the production data were fairly enough to take care of the buildup flow rate, the steady state (plateau) rate and the decline flow rate, the field data were used directly to generate the curves. The model developed using field data had high percentage of accuracy. The advantage of using projectiles and parabolic methods in model development is that such a model is very flexible. The models could be applied with high accuracy right from the initial reservoir stage, through the transient stage, transition stage to the decline rate stage. If the user is empirically observant enough and tactful the model could be used in an induced hydrocarbons production operation. If the user is not empirically observant enough, he has to use fluids displacement methods in the induced recovery operations. The disadvantage is that the models do not take care of pressure drawdown, so the projected rate decline trend or cumulative hydrocarbons production trend depend on pressure sustainability.

Table 3.6: Evaluation Models for Projectile Flow

Type	Eqn	Model Equation	Remarks
Projectile Gas Flow Models	3.3	$G_p = \frac{q_i}{2}[(t_2 - t_1) - (t_3 - t_0)]$	
	3.14	$b = \left.\frac{ln(q_i/q)}{t - t_i}\right\}$ $For\ n = 1$	
	3.25	$G_p = q_i\left[t_2 - 0.5(t_1 + t_o) + \frac{(1 - e^{-bt_3})}{b}\right]$	**Cumulative Gas, M SCF Fig 3.1**
	3.26	$G = \frac{q_i}{2}\left[(t_2 - t_1) + \left(t_f - t_o\right)\right]$	**Fig 3.1: Gas Initially in Place, SCF**
Projectile Oil Flow Models	3.27	$N_p = \frac{q_i}{2}[(t_2 - t_1) + (t_3 - t_0)]$	
	3.28	$N_p = q_i\left[t_2 - 0.5(t_1 + t_o) + \frac{(1 - e^{-bt_3})}{b}\right]$	**Cumulative Oil, Stb Fig 3.2**
	3.29	$N = \frac{q_i}{2}\left[(t_2 - t_1) + \left(t_f - t_o\right)\right]$	**Oil Initially in Place, Stb Fig 3.2**

Table 3.7: Evaluation Models- I, for Parabolic Flow

Type	Eqn	Model Equations	Remarks
Decline Rate for ($n = 1$)	3.33	$q = q_i e^{-bt}$	**Stb/time, t**
	3.36	$b = \frac{ln(q_1/q_2)}{t_2 - t_1}$	**Per time, t**
	3.37	$G_p = \frac{[q_i - q_{i+1}]}{b_{yr}}$ or $G_p = \frac{q_i}{b}(1 - e^{-bt})$	**Fig 3.3**
	3.38	$N_p = \frac{[q_i - q_{i+1}]}{b_{yr}}$ or $N_p = \frac{q_i}{b}(1 - e^{-bt})$	
Decline Rate for ($n = 2$)	3.40	$q = \frac{q_i}{1 + bt}$	**Per time, t** **Fig 3.3**
	3.43	$b = \frac{q_i - q}{q\,t} = \frac{q_1 - q_2}{q_2 t_2 - q_1 q_1}$	
	3.44	$G_p = \frac{[q_i - q]}{b}$ *or* qt	
	3.45	$N_p = \frac{[q_i - q]}{b}$ *or* qt	
Decline Rate for fractions ($n < 1$) or ($n < 2$)	4.46	$q = \frac{q_i}{1 + bt}$ $(i = 0, 1, 2, 3, , , \ldots\ldots, n)$	**Fig 3.3**
	3.47	$b \approx \sum_i^n \left[\frac{q_i - q_{i+1}}{q_{i+1} * t_{i+1}}\right]$ *Meaning*: $b \approx \frac{1}{n}\left[\frac{q_i - q_1}{q_1\,t_1} + \frac{q_i - q_2}{q_2\,t_2} + . \; . . . + \frac{q_i - q_n}{q_n\,t_n}\right]$	
	3.48	$G_p = \frac{[q_i - q]}{b}$ *or* qt	
	3.49	$N_p = \frac{[q_i - q]}{b}$ *or* qt	
For Easy Time Unit Conversion		$e^{-bt} = (1 - b)^t$, (Taylor''s Expansion) $(1 - b/yr) = (1 - b/m)^{12} = (1 - b/d)^{365.25}$ $b/yr = 12 * b/m = 365.25 b/d$	

Table 3.8: Evaluation Models – II, for Parabolic Flow

Type	Eqn	Model Equations	Remarks
Projected Gas Production	3.56	$G_p = \frac{q_i}{b}\left[1 - e^{-bt}\right]$ or $G_p = \frac{[q_i - q_{i+1}]}{b_{yr}}$	**Scf/time, t**
Projected Oil Production	3.57	$N_p = \frac{q_i}{b}\left[1 - e^{-bt}\right]$ or $N_p = \frac{[q_i - q_{i+1}]}{b_{yr}}$	**Stb/time, t**
Gas Decline Rate	3.63	$b = \frac{q_1 - q_2}{G_2 - G_1}$	Gas systems, MM scf
Oil Decline Rate	3.64	$b = \frac{q_1 - q_2}{N_{p2} - N_{p1}}$	Oil systems, M stb
Cumulative Gas, Scf	3.65	$G_p = \frac{q_i}{2}[(t_1 - t_0) + (t_2 - t_1)]$	**Using Curves**
Cumulative Oil, Stb	3.66	$N_p = \frac{q_i}{2}[(t_1 - t_0) + (t_2 - t_1)]$	**Using Curves**
	3.67	$G = \frac{q_i}{2}\left[(t_1 - t_0) + (t_f - t_1)\right]$	**Parabolic Gas Flow Curves**
Initial Hydrocarbons In Place	3.68	$N = \frac{q_i}{2}\left[(t_1 - t_0) + (t_f - t_1)\right]$	**Parabolic Oil Flow Curves**
	3.69	$G_p = \frac{q_m}{2}[(t_1 - t_0) + (t_2 - t_1)]$	
	3.70	$N_p = \frac{q_m}{2}[(t_1 - t_0) + (t_2 - t_1)]$	
	3.71	$G = \frac{q_m}{2}\left[(t_1 - t_0) + (t_f - t_1)\right]$	
	3.72	$N = \frac{q_m}{2}\left[(t_1 - t_0) + (t_f - t_1)\right]$	
Initial Hydrocarbons In Place	3.73	$G_p = \frac{q_i}{2}[t_1 - t_0]$ or $N_p = \frac{q_i}{2}[t_1 - t_0]$	
	3.74	$G_p = \frac{q_i - q_1}{2}[(t_1 - t_0)] + (q_1 - q_0)(t_2 - t_1)$	
	3.75	$N_p = \frac{q_i - q_1}{2}[(t_1 - t_0)] + (q_1 - q_0)(t_2 - t_1)$	
	3.76	$G = \frac{q_i}{2}\left[t_f - t_0\right]$	
	3.77	$N = \frac{q_i}{2}\left[t_f - t_0\right]$	

3.6 *Projected Hydrocarbons Production Models*

This section presents the application of the evaluation models, using regional (field) data and generic (projected data from field records) data. These data were collated from the 3 basic types of formation in the Niger Delta, Nigeria. This was possible through the Department of Petroleum Resources (DPR) and Research & Development (R & D), Nigerian National Petroleum Cooperation (NNPC).

3.61 Application of the Model Equations Using Regional Data

Table 3.9: Yearly Gas Production Rate from 1977 to 1999 (Raw Data)

Date	Time, t (yr)	Rate q, MM scf/d	Rate q, MM scf/yr	Cumulative Gas G_p, MMSCF
1977	**0**	**0**	**-**	**-**
1978	**1**	**50**	**18,262.50**	**18,262.50**
1979	**2**	**100**	**36,525.00**	**54,787.50**
1980	**3**	**100**	**36,525.00**	**91,312.50**
1981	**4**	**100**	**36,525.00**	**127,837.50**
1982	**5**	**100**	**36,525.00**	**164,362.50**
1983	**6**	**100**	**36,525.00**	**200,887.50**
1984	**7**	**100**	**36,525.00**	**237,412.50**
1985	**8**	**100**	**36,525.00**	**273,937.50**
1986	**9**	**100**	**36,525.00**	**310,462.50**
1987	**10**	**100**	**36,525.00**	**346,987.50**
1988	**11**	**100**	**36,525.00**	**383,512.50**
1989	**12**	**100**	**36,525.00**	**420,037.50**
1990	**13**	**100**	**36,525.00**	**456,562.50**
1991	**14**	**100**	**36,525.00**	**493,087.50**
1992	**14.45**	**100**	**16,436.25**	**509,523.75**
1993	**15**	**89.60**	**15,000.00**	**524,523.75**
1993	**16**	**73.34**	**26,787.44**	**551,311.19**
1994	**17**	**60.05**	**21,933.26**	**573,244.45**
1995	**18**	**49.16**	**17,955.69**	**591,200.14**
1996	**19**	**40.25**	**14,701.31**	**605,901.45**
1997	**20**	**32.96**	**12,038.64**	**617,940.09**
1998	**21**	**26.98**	**9,854.45**	**627,794.54**
1999	**22**	**22.09**	**8,068.37**	**635,862.91**
1999	**22.5**	**20.00**	**3,301.35**	**639,164.26**

Plotting of the collated data on Table 3.9 generated a projectile curve (Figure 3.14).

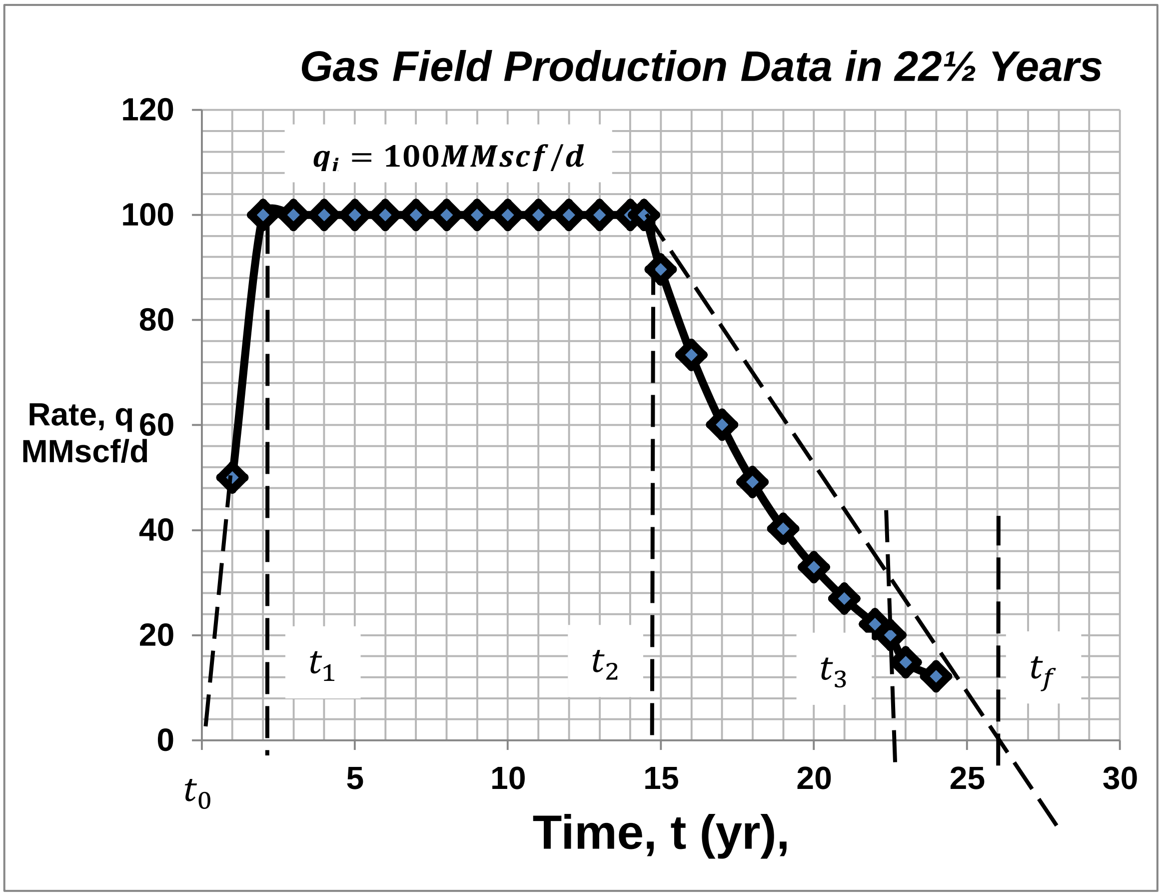

Fig 3.14 Projectile Decline Curve, using Table 3.9, Eqn3.33 and Eqn3.36

Using the curve, $q_i = 100\ MMscf/d$, $t_o = 0$, $t_1 = 2years$, $t_2 = 14.45yrs$, $t_3 = 22.5yrs$ and $t_f = 25.8$ were estimated. Putting these values in Eqn3.7/Eqn3.25, the decline constant using Table 3.9 $b_{15} = ln\frac{q_{15}}{q_{16}} = b_{16} = \ln\frac{q_{16}}{q_{17}} = b_{17} = ln\frac{q_{17}}{q_{18}} = ... = b_n = \frac{q_{n-1}}{q_n} = 0.2$, the cumulative gas production (G_p) was obtained and in Eqn3.26 Gas initially in place (GIIP) was also obtained. These were comparable with Standing and Katz, (1942) MBE for volumetric gas reservoir. $\boldsymbol{Ref}$: $\boldsymbol{Appendix - c}$: $\boldsymbol{G_p = 637.06 * 10^9 scf\ and\ GIIP = 699.7 * 10^9 scf.}$

$$G_p = \frac{365.25 * 100}{2}[(14.45 - 2.0) + (22.5 - 0)] = \mathbf{638.274\ MMM\ scf}$$

or

$$G_p = \frac{365.25*100}{2}\left[14.45 - 0.5(2 + 0) + \frac{(1 - e^{-0.2*(22.5-14.45)})}{0.2}\right] = \mathbf{637.370. MMMscf}$$

$$G = \frac{365.25 * 100}{2}[(14.45 - 2) + (25.8 - 0)] = \mathbf{698.541MMMscf}$$

The challenge was that the computer could not extend the curve axis to abandonment stage ordinarily, so playing with the projected values enabled scaled the axis beyond the economic production stage. That gave extrapolation values of the trend to initial stage of the production.

Table 3.10: Yearly Oil Reserves Production Rate, March, 1968 to March, 1978

Date	**Time, t (yr)**	Pressure (Psi)	**Rate, q (Stb/d)**	**Rate, q M (stb/yr)**	Cumulative N_p, (M Stb)	B_o (rb/stb)
1968	0	4180	0	0	0	1.308
1969	1	4140	5498	2008.1	2008.1	1.301
1970	2	4119	6125	2237.1	4245.2	1.298
1971	3	4070	5885	2149.5	6394.7	1.297
1972	4	4032	6115	2233.5	8628.2	1.293
1973	5	3998	5640	2060.0	10688.2	1.290
1974	6	3960	4750	1735.0	12423.2	1.289
1975	7	3928	4500	1644.0	14067.2	1.285
1976	8	3930	2900	1059.0	15126.2	1.286
1977	9	3950	2345	856.5	15982.7	1.289
1978	10	398	1830	668.4	16651.1	1.299

Plotting the data on Table 3.10 generates the curve of Figure 3.15.

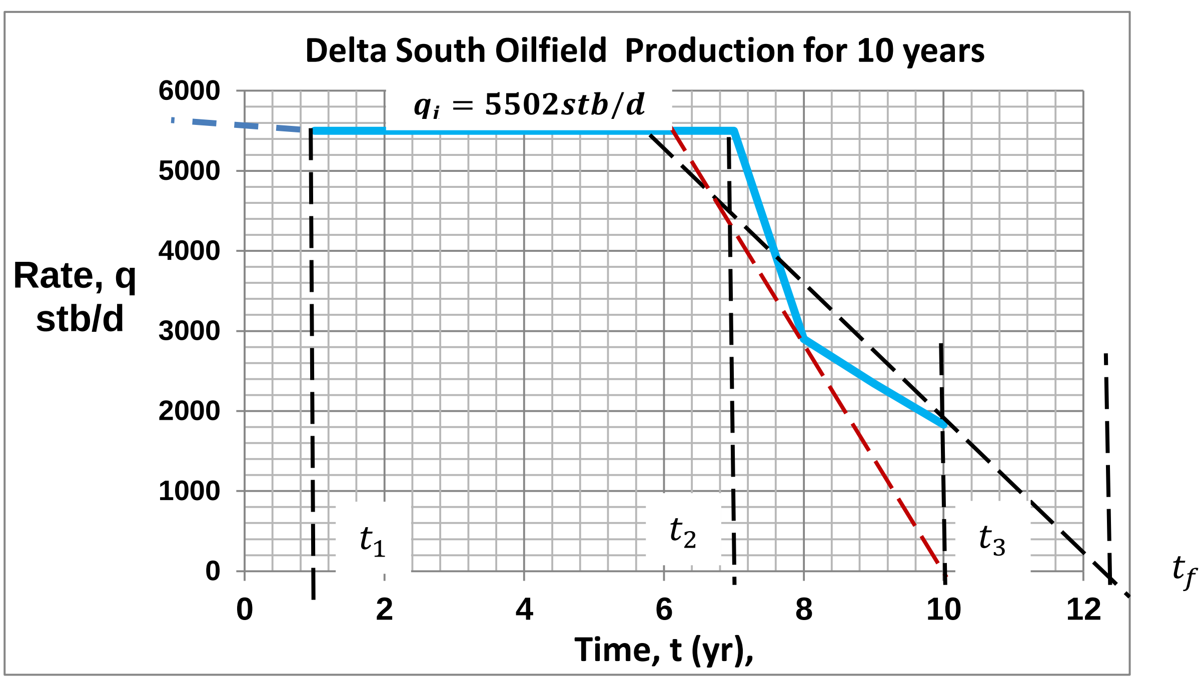

Fig 3.15 ***Projectile Decline Curve, using Table 3.10, Eqn3.33 and Eqn3.36***

Extrapolation of the curve from time t_3 to time, t_f I was able to estimate the hydrocarbons (Oil) initially in place. Data from the field records and solution from the curve (Figure 3.15) showed that, $q_i = 6000stb,\ t_o = 0,\ t_1 = 1yr,\ t_2 = 7yrs,\ t_3 = 10yrs$ and $t_f = 12.5yrs$. Since decline constant, $\boldsymbol{b_1} \neq \boldsymbol{b_2} \neq \boldsymbol{b_3} \neq ... \neq \boldsymbol{b_n}$ was not uniform, Eqn3.47 was used to obtain ‘’b’’, and putting this value in the Eqn3.27, the total or cumulative oil production (N_p) was obtained and in the Eqn3.29, Oil initially in place (OIIP) was also obtained. The values were comparable with results The recovery factor was 83.26%.

$$\mathrm{N_p} = \frac{365.25 * 5502}{2}[(7-1)+(10-0)] = \mathbf{16,877M\ stb}$$

$$\mathrm{N} = \frac{365.25 * 6000}{2}[(7-1)+(12.5-0)] = 20,\mathbf{271Mstb}$$

The challenge in this case was to curve-fit the plotted figure in order to extrapolate to the initial stage. The initial production rate trend was up and down, so average value was used as initial rate steady stage before the decline rate set into the production. The average value was necessary because from zero to the 6th year the rate was unsteady or the transient period was under an external energy influences. The external energy influences equally affected the early decline rate trend, so that two different decline rate trends were observed in the curve generated. The second decline rate trend set in later when the reservoir pressure was enhanced by reservoir pressure maintenance.

3.62 Application of the Evaluation Models Using Generic Data

The importance of generic or projected data is to project future field performance where we have short period of production data which are equally used to estimate oil or gas initially in place.

(i) In a production test, an oil-well flow rate declined from $100\ Mstb/d\ to\ 96\ Mstb/d$ in a month. (a) Predict the production rate in 5years. (b) Estimate the total hydrocarbons recovery in the 5years of production. (c) Estimate the hydrocarbons initially in that oilfield and its recovery factor.

Solution - I

a. Prediction of the production rate ($n = 1$)

$q_i = 100Mstb/d$, q $= 96Mstb/d$, $t_o = 0$ and t $= \frac{1}{12} = 0.083yr$ Putting these values in eqn3.36 the decline rate constant (b) was obtained and in eqn3.33, $\boldsymbol{q_1 = q_i e^{-bt} = 100e^{-0.4900*1} =}$ **61.27.** The rate was tabulated on Table 3.11 and plotted against tine generated figure 3.16, which shows the curve for the projected rate or data.

Table 3.11: Yearly Projected **Oil Production Rate from 1 Month Data**

Date	Time T, (Yy)	Rate, q Mstb/d)	Rate, q M stb/yr))	Cumulative G_p, M Stb
1996	0	100.0	-	-
1997	1	61.26	28,875.14	28,875.14
1998	2	37.55	17,681.54	46,556.68
1999	3	23.00	10,842.62	57,399.30
2000	4	14.09	6,641.28	64,040.58
2001	5	8.63	4,302.40	68,342.98
Total Oil Production in five years is 68,572,895.59 M stb				

[Source: Table 3.5]

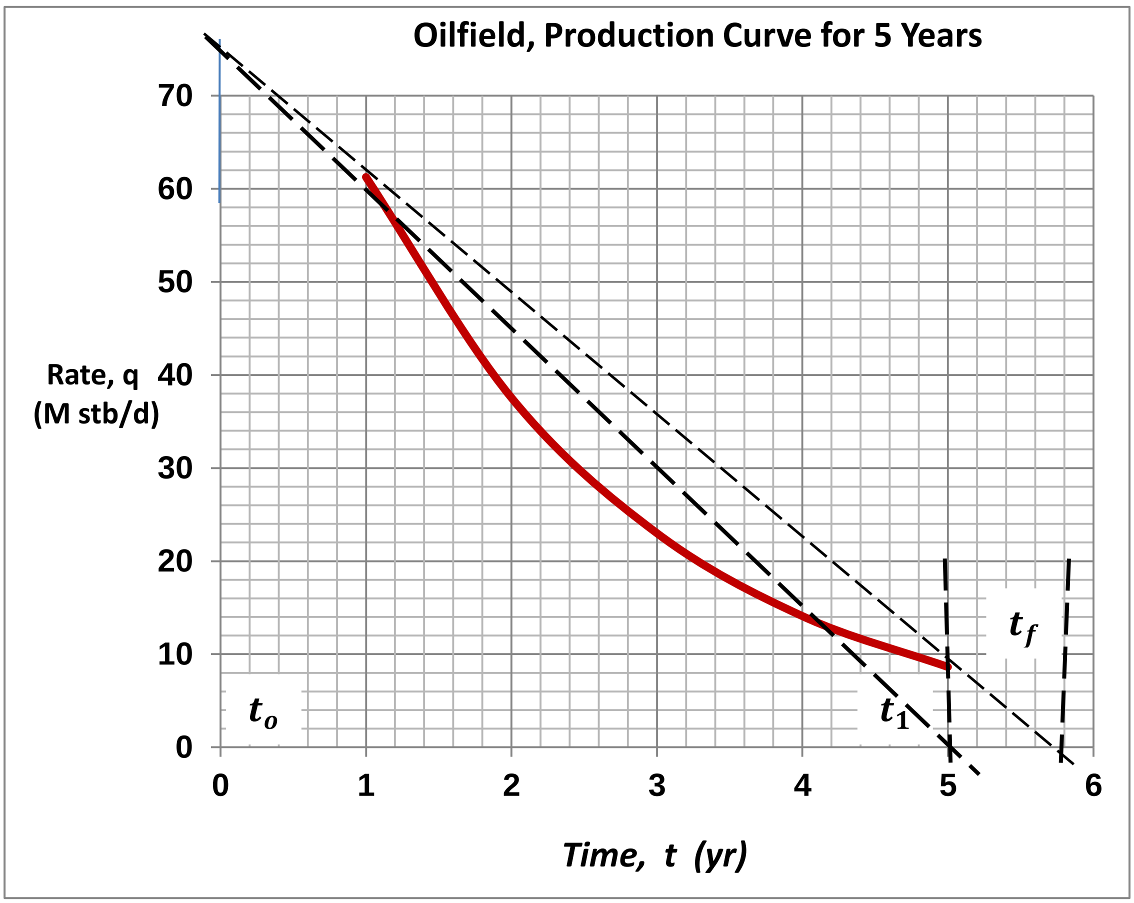

Fig 3.16: Curve Generated from the Projected Rate or Data on Table 3.11

b. ***Estimation of the Hydrocarbons Recovery***

Solution from the curve showed that, $q_1 = 75.0stb,\ t_o = 0,\ t_1 = 5yrs$ and $t_f = 5.8yrs$. Putting these values in the model Eqn3.73, the total or cumulative oil production (N_p) was obtained as:

$$\mathrm{N_p} = \frac{365.25 * 750}{2}[5 - 0] = \mathbf{68,484.38M\ stb}$$

c. **Estimation *of the Hydrocarbons Initially in Place***

The curve was extrapolated from time t_1 to time, t_f where I could estimate the hydrocarbons (Oil) initially in place using the model Eqn3.77 as:

$$\mathrm{N} = \frac{365.25*100}{2}[5.8 - 0] = 105{,}922.5\mathbf{Mstb}$$

d. ***The Hydrocarbons Recovery Factor (E_R)***

Recovery factor is the ratio of the cumulative hydrocarbon production to the hydrocarbon initially in place.

Mathematically:

$$\boldsymbol{E_R} = \frac{\mathbf{100} * \mathrm{N_p}}{\boldsymbol{N}} = \frac{\mathbf{100 * 68484.38}}{\mathbf{105922.5}} = \mathbf{64.67}\%$$

The challenge in this very short production history was to identify the decline trend in a field of operation. The only remedy in this type of case would be to produce a well from initial rate to $1^{st},\ 2^{nd},\ 3^{rd},\ 4^{th}$ or more decline rates to ascertain the production rate decline trend.

(ii) Using Table 3.3 page 52 which shows a production test of an oil-well which was produced for 1 year and the flow rate declined trend. In this case the challenge was to:

(a) Predict the yearly production rate in 10 years.

(b) Estimate the total hydrocarbons recovery in 10years of production.

(c) Estimate the hydrocarbons initially in place and its recovery factor.

To this effect the evaluation models postulated earlier were used and predicted the production rate in 10 years and equally estimated the total or cumulative hydrocarbons recovery in 10 years. The projected rate values were used and generated a curve Figure 3.17. The curve generated was used in the confirmation of the evaluation models, which were used. Solution-II shows the estimated cumulative hydrocarbons produced in 10 years and the hydrocarbons initially in place.

Solution - II

a. Prediction of the production rate

Using Table 3.3

$q_1 = 96.3\ M\ stb/d$, $q_2 = 92.9\ M\ stb/d$, and $q_3 = 89.8\ M\ stb/d$ $t_1 = 0.1$, $t_2 = 0.2$ and $t_3 = 0.3yr$. Putting these values in Eqn3.43 the decline rate constant (b) was obtained. The decline rate exponent was a 2nd order decline trend ($\mathbf{n} = \mathbf{2}$) as follows: $b = \frac{q_i - q}{q\ t} = \frac{100-92.9}{92.9*0.2} =$ 0.3821 and substituting ''b'' in Eqn3.40, the yearly flow rate was also obtained as $\boldsymbol{q_1} = \frac{\boldsymbol{q_i}}{\mathbf{1} + \boldsymbol{bt_1}} = \frac{\mathbf{100}}{\mathbf{1} + \mathbf{0.3821*1}} = \mathbf{72.35}$ and the results tabulated on Table 3.12. Figure 3.17 shows the curve generated from the projected rate or data on Table 3.3 and using the Eqn3.77, Oil initially in place (OIIP) was equally obtained.

Table 3.12: Yearly Oil Projected **Production Rate Well – 21A**

Date	Time T, (Yy)	Rate, q M stb/d	Rate, q MM stb/yr))	Cumulative N_p, M Stb
1996	0	-	-	-
1997	1	72.35	**26,430.68**	**26,430.68**
1998	2	56.68	**20,702.37**	**47,133.05**
1999	3	46.59	**17,017.00**	**64,250.05**
2000	4	39.55	**14,445.63**	**78,555.68**
2001	5	34.36	**12,549.99**	**91,145.67**
2002	6	30.37	**11,092.64**	**102,238.31**
2003	7	27.21	**9,938.45**	**112,176.76**
2004	8	24.55	**8,966.89**	**121,143.65**
2005	9	22.53	**8,229.08**	**129,372.73**
2006	10	20.74	**7,575.29**	**137,000.10**
Total Oil Production in ten years is 138,795 M stb				

[Source: Table 3.3]

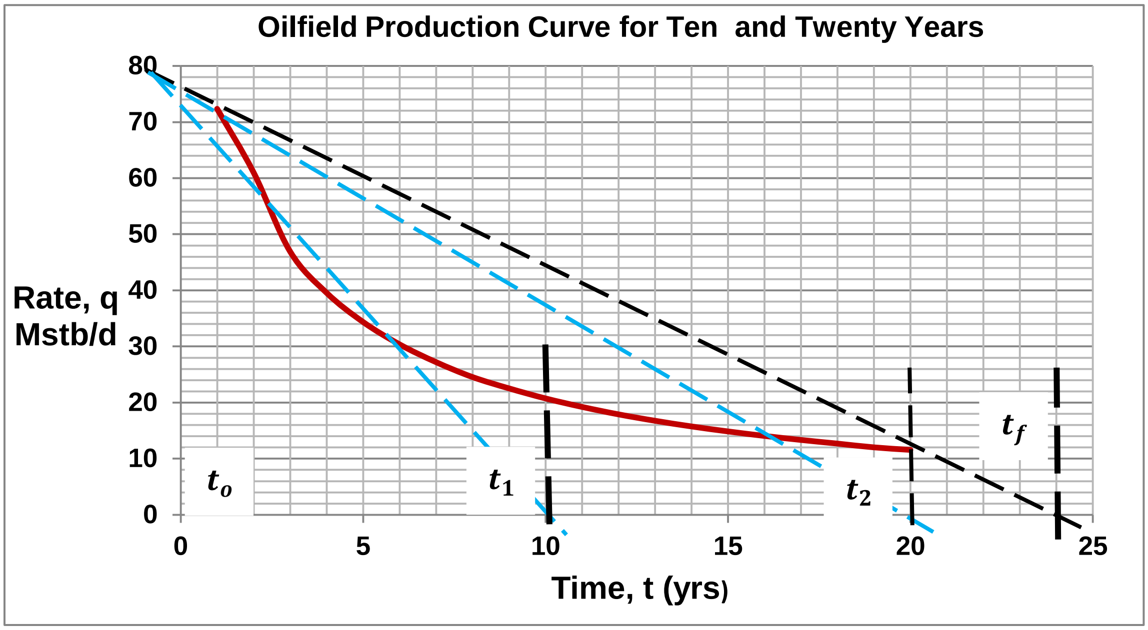

Fig 3.17: Curve Generated from the Projected Rate/ Data on Table 3.12

b. Estimation of the Hydrocarbons Recovery

Solution from the curve/graph showed that the rate, $q_1 = 76\ stb/d$, $t_o = 0$, $t_1 = 10\ yrs$, $t_2 = 20\ yrs$ and $t_f = 24\ yrs$. Putting these values in the model Eqn3.77, the total or cumulative oil production (N_p) was obtained as follows:

I. $$\mathbf{N_p = \frac{365.25*76}{2}[10-0] = 138,795\ Mstb}$$

II. $$\mathbf{N_p = \frac{365.25*20}{2}[20-10] = 36,525\ Mstb}$$

If the reservoir pressure was maintained early enough, say from ten years up to 20 years the total oil recovery would have been improved as shown below:

III. $$\mathbf{N_p = \frac{365.25*76}{2}[20-0] = 277,590M\ stb}$$

c. Estimation *of the Hydrocarbons Initially in Place*

Extrapolation of the curve from time t_1 to time, t_f I was able to estimate the hydrocarbons (Oil) initially in place using the model Eqn3.77 as:

$$\mathbf{N} = \frac{\mathbf{365.25 * 100}}{\mathbf{2}}[\mathbf{24 - 0}] = \mathbf{438, 300\ Mstb}$$

d. The Hydrocarbons Recovery Factor (E_R)

Recovery factor is the ratio of the cumulative hydrocarbon production to the hydrocarbon initially in place. Mathematically:

$$\boldsymbol{E_R} = \frac{\mathbf{100}\mathrm{N_p}}{\boldsymbol{N}} = \frac{\mathbf{100 * 138795000}}{\mathbf{438300000}} = \mathbf{31.67}\%$$

$$\boldsymbol{E_R} = \frac{\mathbf{100}\mathrm{N_p}}{\boldsymbol{N}} = \frac{\mathbf{100 * 175320000}}{\mathbf{438300000}} = \mathbf{40}\%$$

If the reservoir pressure was maintained the recovery factor would have been improved as shown below:

$$\boldsymbol{E_R} = \frac{\mathbf{100}\mathrm{N_p}}{\boldsymbol{N}} = \frac{\mathbf{100 * 277590000}}{\mathbf{438300000}} = \mathbf{63.33}\%$$

(iii) Using Table 3.4 Page 52 which shows a production test of an oil-well which was produced for 1 year and the flow rate declined. (a) Predict the production rate in 10 years. (b) Estimate the total hydrocarbons recovery in 10years of production. (c) Estimate the hydrocarbons initially in place and its recovery factor.

To match up the challenge the models equation postulated earlier were used and predicted the production rate for ten years and estimated the corresponding hydrocarbons recovery and the results tabulated on Table 3.13. The projected rate values were used and generated a curve Figure 3.18. The curve generated was used in the confirmation of the evaluation model equations, which were used. Solution-III shows the estimated cumulative hydrocarbons produced in 10 years and the hydrocarbons initially in place.

Solution - III

a. Prediction of the production rate ($1 > n < 2$)

Putting the values on Table 3.4 into Eqn3.46 the average decline rate was obtained. Substituting the average ''b'' in Eqn3.47, the yearly flow rate was also obtained and tabulated on Table 3.13. Figure 3.18 shows the curve generated from the projected rate or data on Table 3.13.and using Eqn3.47, Oil initially in place (OIIP) was as well obtained.

$$b \approx \frac{1}{n}\left[\frac{[q_i - q_1]}{q_1\, t_1} + \frac{q_i - q_2}{q_2\, t_2} + \frac{q_i - q_3}{q_3\, t_3} + .\ \ . . + \frac{q_i - q_n}{q_n\, t_n}\right] \approx 0.4/yr$$

$$q_1 \approx \frac{q_i}{1 + bt_1} = \frac{100}{1 + 0.4 * 1} \approx 71.00 \text{ M stb/d}$$

***Table 3.13: Yearly Projected* Oil Production Rate from Well – 21B**

Date	Time T, (Yy)	Rate, q M stb/d	Rate, q MM stb/yr))	Cumulative N_p, M Stb
1996	0	-	-	-
1997	1	71.00	26,480.63	26,480.63
1998	2	55.56	20,293.29	46,773.92
1999	3	45.45	16,600.61	63,374.53
2000	4	38.46	14,047.52	77,422.05
2001	5	33.33	12,173.78	89,595.83
2002	6	29.41	10,742.00	100,337.83
2003	7	26.32	9,613.38	109,951.21
2004	8	23.81	8,696.60	118,647.81
2005	9	21.74	7,940.54	126588.35
2006	10	20.00	7,305.00	133,893.35
Total Oil Production in ten years is 138,795 M stb				

[Source: Table 3.4]

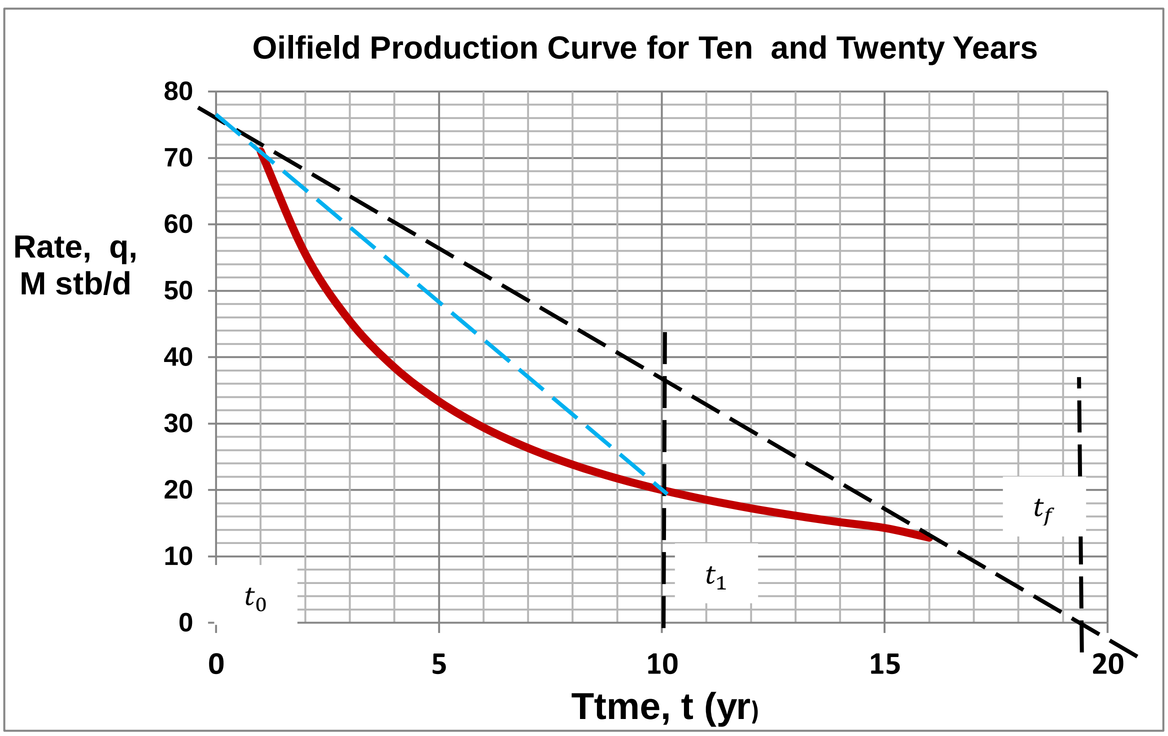

Fig 3.18: Curve Generated from the Projected Rate or Data on Table 3.13.

b. Estimation of the Hydrocarbons Recovery

Solution from the curve showed that the rate, $q_1 = 73.5\ stb/d$, $t_o = 0$, $t_1 = 10\ yrs$ and $t_f = 19.5\ yrs$. Putting these values in the model Eqn3.73, the total or cumulative oil production (N_p) was obtained as follows:

i. $\mathbf{N_p = \frac{365.25*73.5}{2}[10 - 0] = 134,229M\ stb}$

ii. $\mathbf{N_p = \frac{365.25*20}{2}[19.5 - 10] = 34,699M\ stb}$

If the operator had maintained the reservoir pressure early enough, say from ten years up to 19.5 years the total oil recovery factor would have been improved from 38% to 73.5% as shown in solution-III, subsection – d below.

iii. $\mathbf{N_p = \frac{365.25*73.5}{2}[19.5 - 0] = 261,747M\ stb}$

c. Estimation *of the Hydrocarbons Initially in Place*

The curve was extrapolated from time t_1 to time, t_f and I was able to estimate the hydrocarbons (Oil) initially in place using the model Eqn3.77.

$$\mathbf{N = \frac{365.25*100}{2}[19.5 - 0] = 356,119\ Mstb}$$

d. The Hydrocarbons Recovery Factor (E_R)

Recovery factor is the ratio of the cumulative hydrocarbon production to the hydrocarbon initially in place. Mathematically:

$$E_R = \frac{100\mathrm{N_p}}{N} = \frac{100 * 134{,}229}{356{,}119} = 38\%$$

$$E_R = \frac{100\mathrm{N_p}}{N} = \frac{100 * 168{,}928}{356{,}119} = 47.4\%$$

If the reservoir pressure were maintained the recovery factor would have been improved as shown below. Economic evaluation in this case would be the best method to enhance pressure maintenance consideration.

$$E_R = \frac{100\mathrm{N_p}}{N} = \frac{100 * 261{,}3747}{356{,}119} = 73.5\%$$

CHAPTER 4
RESULTS AND DISCUSIONS

4.1 Results

***4.1.1* Evaluation Model – 1:** Figure 4.1 and figure 4.2 show S*chematic of oil and gas cumulative production and initially in place respectively, while T*able 4.1 shows the confirmed projectile evaluation models equations for *projectile gas and oil flow.*

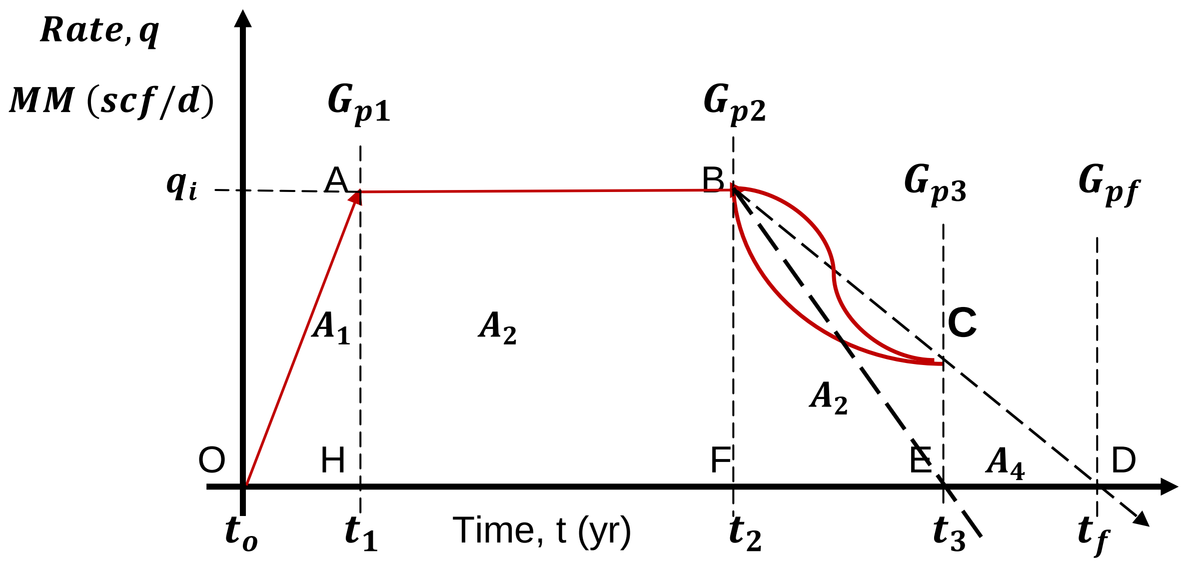

Fig 4.1 Schematic of Cumulative Production and Initial Gas

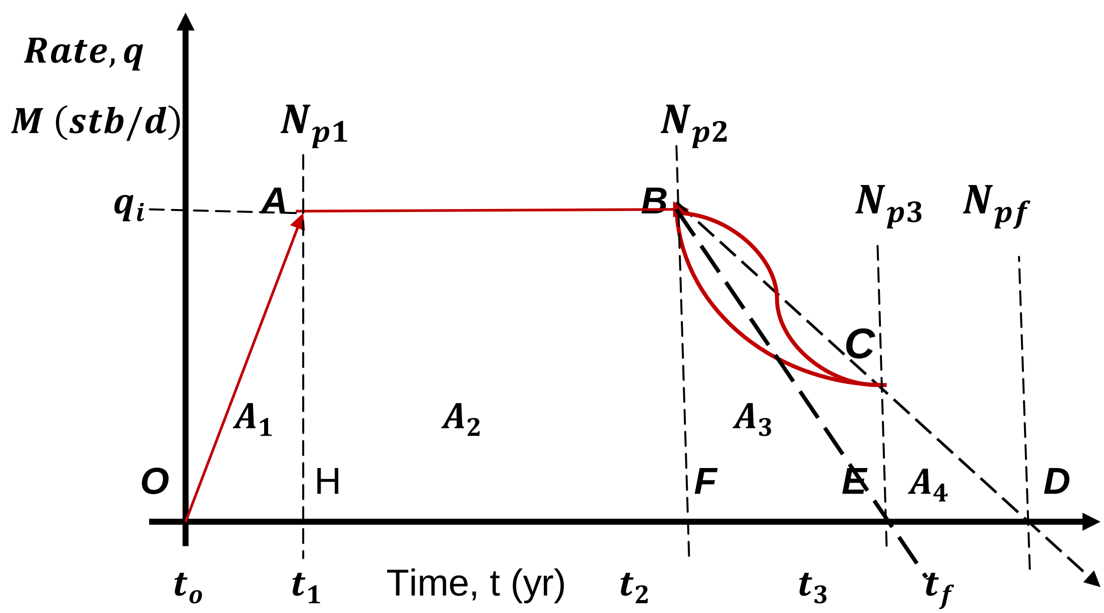

Fig 4.2 Schematic of Cumulative Production and Initial Oil

Table 4.1: Confirmed Projectile Evaluation Models

Type	Eqn	Model Equation	Remarks
Projectile Gas Flow Models	3.3	$G_p = \frac{q_i}{2}[(t_2 - t_1) - (t_3 - t_0)]$	**Cumulative Gas, M SCF Fig 3.1**
	3.14	$b = \frac{ln(q_i/q)}{t - t_i}$ For $n = 1$	
	3.43	$b = \frac{q_i - q}{q\,t}$ For $n = 2$ or others	
	3.25	$G_p = q_i\left[t_2 - 0.5(t_1 + t_o) + \frac{(1 - e^{-bt_3})}{b}\right]$	
	3.26	$G = \frac{q_i}{2}\left[(t_2 - t_1) + (t_f - t_o)\right]$	**Gas Initially in Place, SCF Fig 3.1**
Projectile Oil Flow Models	3.27	$N_p = \frac{q_i}{2}[(t_2 - t_1) + (t_3 - t_0)]$	**Cumulative Oil, Stb Fig 3.2**
	3.28	$N_p = q_i\left[t_2 - 0.5(t_1 + t_o) + \frac{(1 - e^{-bt_3})}{b}\right]$	
	3.29	$N = \frac{q_i}{2}\left[(t_2 - t_1) + (t_f - t_o)\right]$	**Oil Initially in Place, Stb Fig 3.2**

***4.1.2* Evaluation Model – 2:** Figure 4.3 shows s*chematic of oil and gas cumulative production and initially in place respectively, while T*able 4.2 shows the confirmed parabolic fluid flow regime evaluation models equations for parabolic gas and oil flow.

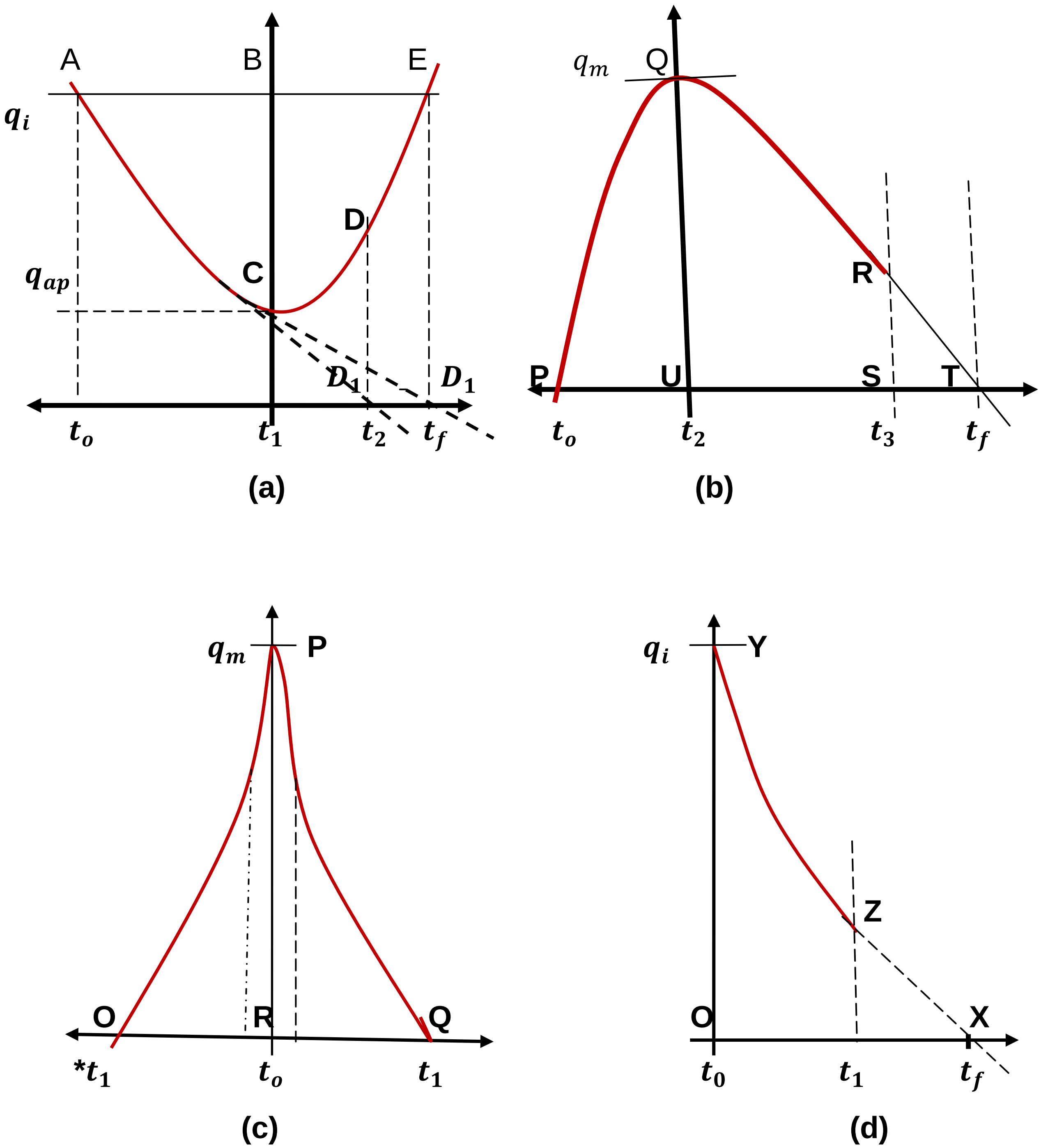

Fig 4.3 Cumulative Production and Initial Oil or Gas in Parabolic Flow Trend

Table 4.2: Confirmed Parabolic Evaluation Models – I

Type	Eqn	Model Equations	Remarks
Decline Rate for $(n = 1)$	3.33	$q = q_i e^{-bt}$	**Stb/time, t**
	3.36	$b = \frac{ln(q_1/q_2)}{t_2 - t_1}$	**Per time, t**
	3.37	$G_p = \frac{[q_i - q_{i+1}]}{b_{yr}}$ **or** $G_p = \frac{q_i}{b}(1 - e^{-bt})$	**Fig 3.3**
	3.38	$N_p = \frac{[q_i - q_{i+1}]}{b_{yr}}$ **or** $N_p = \frac{q_i}{b}(1 - e^{-bt})$	
Decline Rate for $(n = 2)$	3.40	$q = \frac{q_i}{1 + bt}$	**Per time, t** **Fig 3.3**
	3.43	$b = \frac{q_i - q}{q\,t} = \frac{q_1 - q_2}{q_2 t_2 - q_1 q_1}$	
	3.44	$G_p = \frac{[q_i - q]}{b}$ *or* qt	
	3.45	$N_p = \frac{[q_i - q]}{b}$ *or* qt	
Decline Rate for fractions $(n < 1)$ or $(n < 2)$	4.46	$q = \frac{q_i}{1 + bt} \quad (i = 0, 1, 2, 3, , , ..., n)$	
	3.47	$b \approx \sum_i^n \left[\frac{q_i - q_{i+1}}{q_{i+1} * t_{i+1}}\right]$ ***Meaning:*** $b \approx \frac{1}{n}\left[\frac{q_i - q_1}{q_1 t_1} + \frac{q_i - q_2}{q_2 t_2} + . \; . . . + \frac{q_i - q_n}{q_n t_n}\right]$	**Fig 3.3**
	3.48	$G_p = \frac{[q_i - q]}{b}$ *or* qt	
	3.49	$N_p = \frac{[q_i - q]}{b}$ *or* qt	
For Easy Unit Time Conversion		$e^{-bt} = (1 - b)^t$, (**Taylor''s Expansion**) $(1 - b/yr) = (1 - b/m)^{12} = (1 - b/d)^{365.25}$ $b/yr = 12 * b/m = 365.25 b/d$	

4.1.3 Cumulative Hydrocarbons Production Models

The general equation for natural production of an oilfield reserves is the product of the hydrocarbons flow rate and the actual time elapsed.

Parabolic *Flow Type – 2, Short Transient and Transition Time*

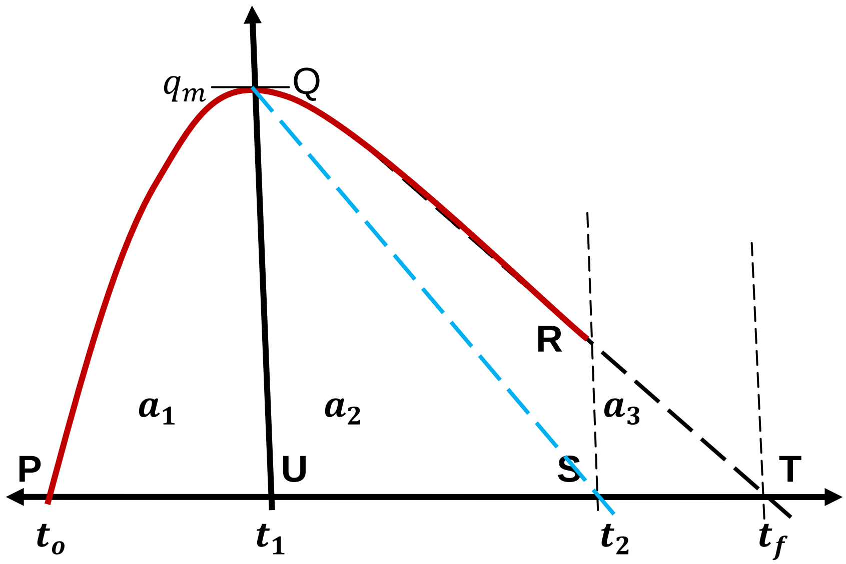

Fig 4.4* Schematic of Oil or Gas in Parabolic Flow Regime *Type – 2

Parabolic *Flow Type – 3: Sharp Transient and Transition Time*

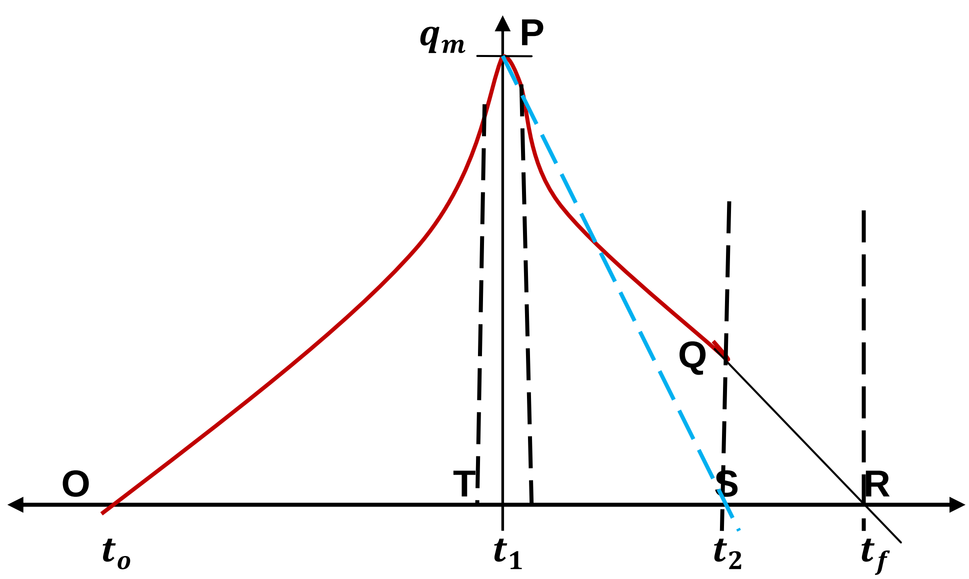

Fig 4.5 Schematic of Oil or Gas in Parabolic Flow Regime *Type – 3*

Parabolic *Flow with no Observable Transient or Transition*

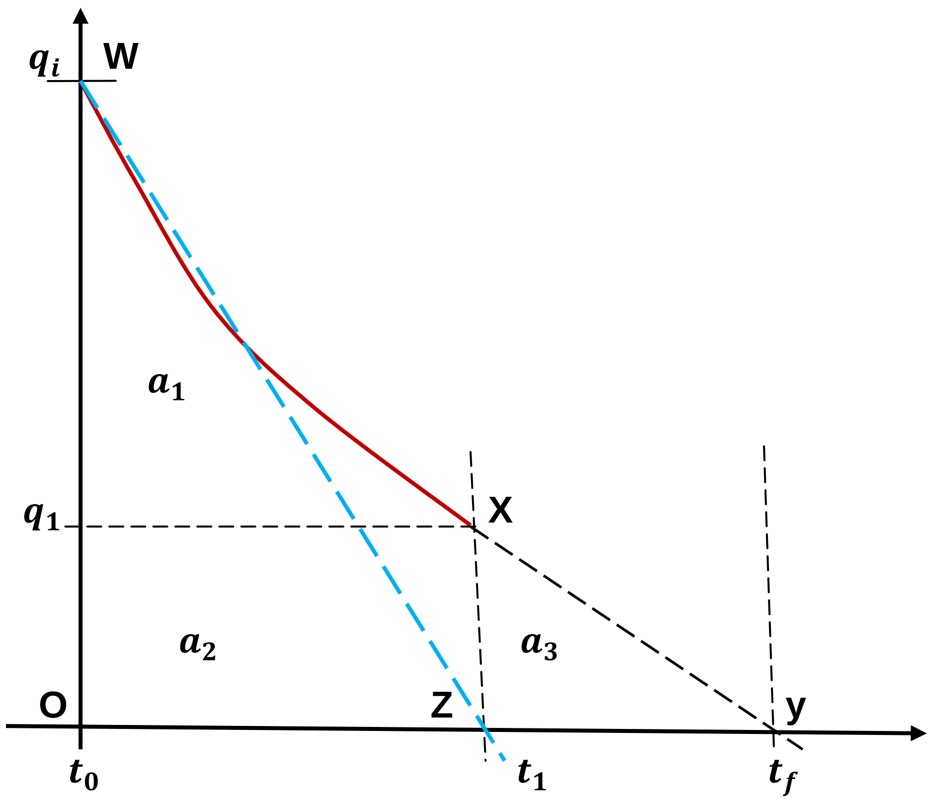

Fig 4.6 Schematic of Oil or Gas in Parabolic Flow Regime *Type – 4*

Table 4.3: Confirmed Parabolic Evaluation Models – II

Type	Eqn	Model Equations	Remarks
Oil and Gas Decline Rate	3.63 3.64	$b = \frac{q_1 - q_2}{G_2 - G_1}$ $\quad b = \frac{q_1 - q_2}{N_{p2} - N_{p1}}$	**Per year**
Projected Gas Production	3.65	$G_p = \frac{q_i}{b}\left[1 - e^{-bt}\right]$ or $G_p = \frac{[q_i - q_{i+1}]}{b_{yr}}$	**Per year**
Cumulative Gas Production	3.56 3.57 3.65 3.66	$G_p = \frac{q_i}{2}[(t_1 - t_0) + (t_2 - t_1)]$ $G_p = \frac{q_m}{2}[(t_1 - t_0) + (t_2 - t_1)]$ $G_p = \frac{q_i}{2}[t_1 - t_0]$ $G_p = \frac{q_i - q_1}{2}[(t_1 - t_0)] + (q_1 - q_0)(t_2 - t_1)$	Gas Production for a given time in years
Projected Gas Production	3.67	$N_p = \frac{q_i}{b}\left[1 - e^{-bt}\right]$ or $N_p = \frac{[q_i - q_{i+1}]}{b_{yr}}$	**Per year**
Cumulative Oil Production	3.68 3.69 3.70 3.71	$N_p = \frac{q_i}{2}[(t_1 - t_0) + (t_2 - t_1)]$ $N_p = \frac{q_m}{2}[(t_1 - t_0) + (t_2 - t_1)]$ $N_p = \frac{q_i - q_1}{2}[(t_1 - t_0)] + (q_1 - q_0)(t_2 - t_1)$ $N_p = \frac{q_i}{2}[t_1 - t_0]$	Oil Production for a given time in years
Initial Gas in In Place	3.72 3.73 3.74 3.75 3.76 3.77	$G = \frac{q_i}{2}\left[(t_1 - t_0) + (t_f - t_1)\right]$ $G = \frac{q_m}{2}\left[(t_1 - t_0) + (t_f - t_1)\right]$ $G = \frac{q_i}{2}\left[t_f - t_0\right]$	**Total Recoverable Gas**
Initial Gas in In Place		$N = \frac{q_i}{2}\left[(t_1 - t_0) + (t_f - t_1)\right]$ $N = \frac{q_m}{2}\left[(t_1 - t_0) + (t_f - t_1)\right]$ $N = \frac{q_i}{2}\left[t_f - t_0\right]$	**Total Recoverable Oil**

4.1.4 Projectile Model Application Results

Table 4.4: Projectile evaluation Model Results Using Field Data

Date	Time, t (yr)	Rate q, MM scf/d	Rate q, MM scf/yr	Gas Production G_p, MMSCF
1977	**0**	**0**	**-**	**-**
1978	**1**	**50**	**18,262.50**	**18,262.50**
1979	**2**	**100**	**36,525.00**	**54,787.50**
1980	**3**	**100**	**36,525.00**	**91,312.50**
1981	**4**	**100**	**36,525.00**	**127,837.50**
1982	**5**	**100**	**36,525.00**	**164,362.50**
1983	**6**	**100**	**36,525.00**	**200,887.50**
1984	**7**	**100**	**36,525.00**	**237,412.50**
1985	**8**	**100**	**36,525.00**	**273,937.50**
1986	**9**	**100**	**36,525.00**	**310,462.50**
1987	**10**	**100**	**36,525.00**	**346,987.50**
1988	**11**	**100**	**36,525.00**	**383,512.50**
1989	**12**	**100**	**36,525.00**	**420,037.50**
1990	**13**	**100**	**36,525.00**	**456,562.50**
1991	**14**	**100**	**36,525.00**	**493,087.50**
1992	**14.45**	**100**	**16,436.25**	**509,523.75**
1993	**15**	**89.50**	**15,000.00**	**524,523.75**
1993	**16**	**73.34**	**26,787.44**	**551,311.19**
1994	**17**	**60.05**	**21,933.26**	**573,244.45**
1995	**18**	**49.16**	**17,955.69**	**591,200.14**
1996	**19**	**40.25**	**14,701.31**	**605,901.45**
1997	**20**	**32.96**	**12,038.64**	**617,940.09**
1998	**21**	**26.98**	**9,854.45**	**627,794.54**
1999	**22**	**22.09**	**8,068.37**	**635,862.91**
1999	**22.5**	**19.99**	**3,301.35**	**639,164.26**
22.5 years			**639,164.26**	

Source [Generated from table 3.1 and Model Eqn3.37]

$$q = q_i e^{-bt} \qquad b = \frac{ln(q_1/q_2)}{t_2 - t_1}$$

$$G_p = \frac{[q_i - q_{i+1}]}{b_{yr}} \quad \text{or} \quad G_p = \frac{q_i}{b}\left(1 - e^{-bt}\right)$$

Source [Generated Using Table 4.4]

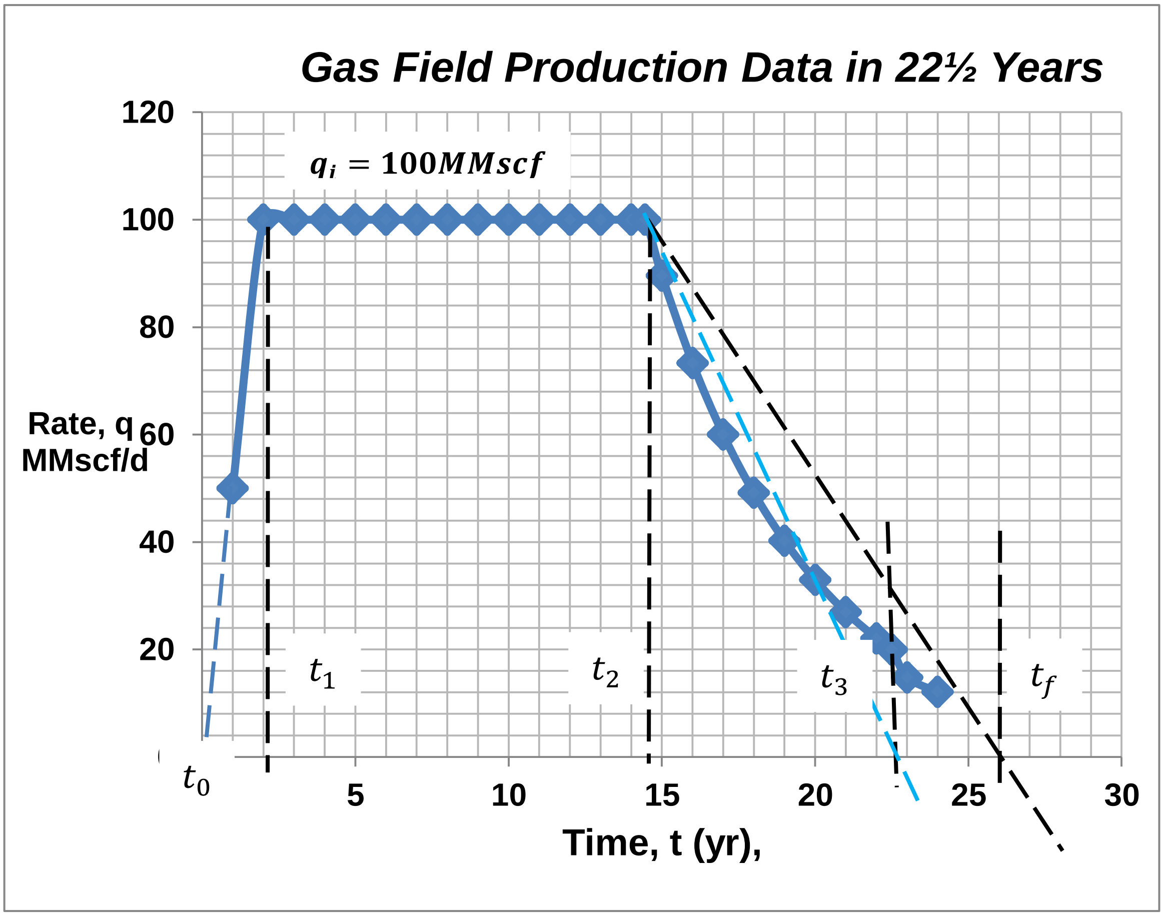

Fig 4.7 Projectile Decline Curve, using Table 4.4, eqn3.33 and eqn3.36

Using the above curve, $q_i = 100\ MMscf/d$, $t_o = 0$, $t_1 = 2years$, $t_2 = 14.45yrs$, $t_3 = 22.5yrs$ and $t_f = 25.8$ were estimated. Putting these values in eqn3.3 or eqn3.25, the decline constant ($b_1 = b_2 = b_3 = . . \ ... = b_n = 0.2$) so it was uniform, the total or cumulative gas production (G_p) was obtained as $\mathbf{638.274.38\ MM\ scf}$ **(**Table 4.4**)** and was comparable with the field production records of 639,164.26 MMscf. The values were equally used in eqn3.26, Gas Initially in Place (GIIP) was also obtained to be $\mathbf{698,541.00MMscf}$. The percentage accuracy of 99.86% and the comparison with Craze and Buckley (1945) MBE in appendix-C, the percentage accuracy was 99.984%.

Table 4.5: Models Results in Delta State South Raw Data

Date	**Time, t (yr)**	Pressure (Psi)	**Rate, q (Stb/d)**	**Rate, q M (stb/yr)**	Cumulative N_p, (M Stb)	B_o (rb/stb)
1968	0	4180	0	0	0	1.308
1969	1	4140	5498	2008.1	2008.1	1.301
1970	2	4119	6125	2237.1	4245.2	1.298
1971	3	4070	5885	2149.5	6394.7	1.297
1972	4	4032	6115	2233.5	8628.2	1.293
1973	5	3998	5640	2060.0	10688.2	1.290
1974	6	3960	4750	1735.0	12423.2	1.289
1975	7	3928	4500	1644.0	14067.2	1.285
1976	8	3930	2900	1059.0	15126.2	1.286
1977	9	3950	2345	856.5	15982.7	1.289
1978	10	398	1830	668.4	16651.1	1.299

Source [Generated from table 3.2 and Model Eqn3.37]

Source [Generated Using Table 4.5]

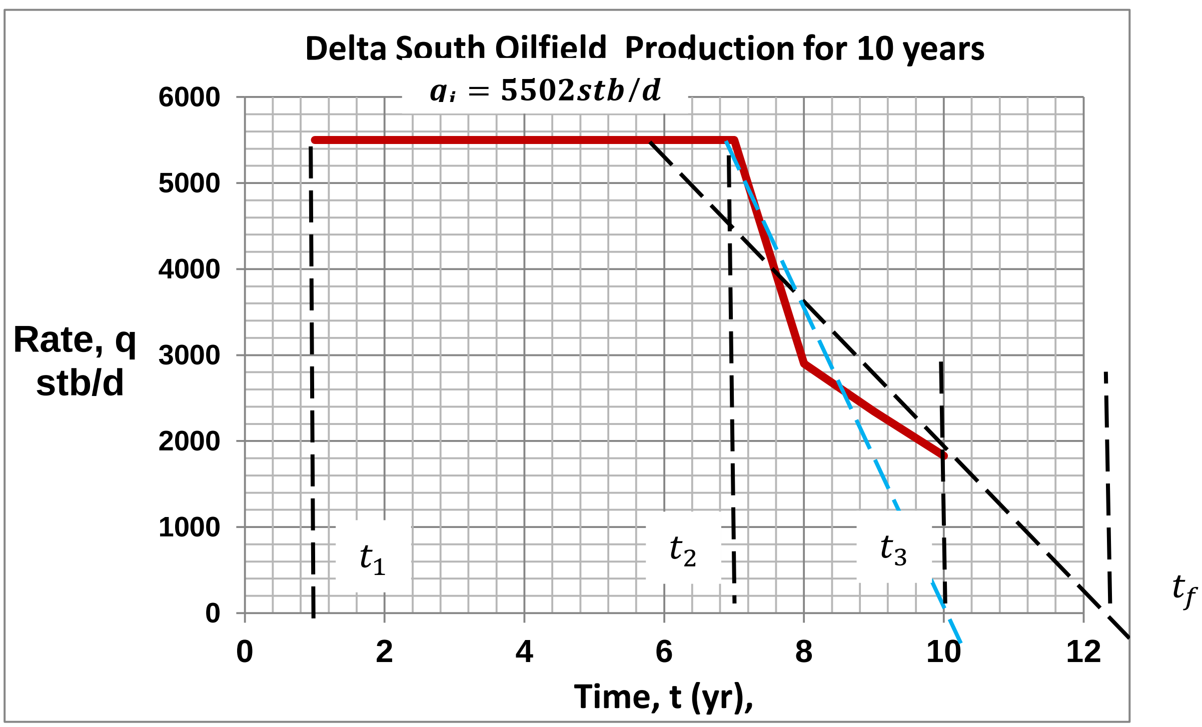

Fig 4.8 ***Projectile Decline Curve, using Table 4.5, Eqn3.33 and Eqn3.36***

The curve (Figure 4.8) was extrapolated from time t_3 to time, t_f the hydrocarbons (Oil) initially in place was estimated. The extrapolation was possible, because the data from the field records and solution from the curve (Figure 4.8) showed that, $q_i = 6000stb,\ t_o = 0$, $t_1 = 1yr$, $t_2 = 7yrs$, $t_3 = 10yrs$ and $t_f = 12.5yrs$ and the decline constant, $\boldsymbol{b_1} \neq \boldsymbol{b_2} \neq \boldsymbol{b_3} \neq . . . \neq \boldsymbol{b_n}$ (was not uniform), it implied that Eqn3.25 could not be used, so Eqn3.3 was used instead to estimate the total or cumulative oil production ($N_p = \mathbf{16,877M\ stb}$) and Eqn3.26 to estimate Oil initially in place ($OIIP = 20,\mathbf{271Mstb}$) and recovery factor was estimates as $E_R = 83.26\%$. These were comparable with the field production data in all ramifications. Table 4.5 shows the oilfield hydrocarbons production records. The percentage accuracy is 98.64%. The results were equally comparable with Craze and Buckley (1945) MBE, appendix-C and the result accuracy was 99.3%

4.1.5 Model Equations Application Results Using Generic Data

The importance of generic or projected data is to project future field performance where we have short period of production data which are equally used to estimate oil or gas initially in place.

Solution - I

a. Prediction of the production rate ($n = 1$)

Input Data:

$q_i = 100Mstb/d$, q = $96Mstb/d$, $t_o = 0$ and t = $\frac{1}{12} = 0.083/yr$

These values were used in the model Eqn3.36 to estimate the decline rate constant (b) and the decline rate constant was used in Eqn3.33 and obtained the cumulative gas production.

$$q_1 = q_i e^{-bt1} = 100e^{-0.4900*1} = \mathbf{61.27.}$$

$$G_{p1} = \frac{q_i}{b}\left(1 - e^{-bt}\right) = \frac{365.25\ 100)}{0.4900}\left(1 - e^{-0.49*1}\right) = 28,875.14$$

$$G_{p2} = \frac{q_1}{b}\left(1 - e^{-bt}\right) = \frac{365.25 * 61.26)}{0.4900}\left(1 - e^{-0.49*1}\right) = 17,6889.14$$

Table 4.6: Models Results from Yearly Projected Oil Production Rate Well – 21A

Date	Time T, (Yy)	Rate, q Mstb/d)	Rate, q M stb/yr))	Cumulative G_p, MM Stb
1996	0	-	-	-
1997	1	61.26	28,875.14	28,875.14
1998	2	37.55	17,681.54	46,556.68
1999	3	23.00	10,842.62	57,399.30
2000	4	14.09	6,641.28	64,040.58
2001	5	8.63	4,302.40	68,342.98
Total Oil Production in five years				68,342,98

[Source: Table 3.11]

Source [Generated Using Table 4.6]

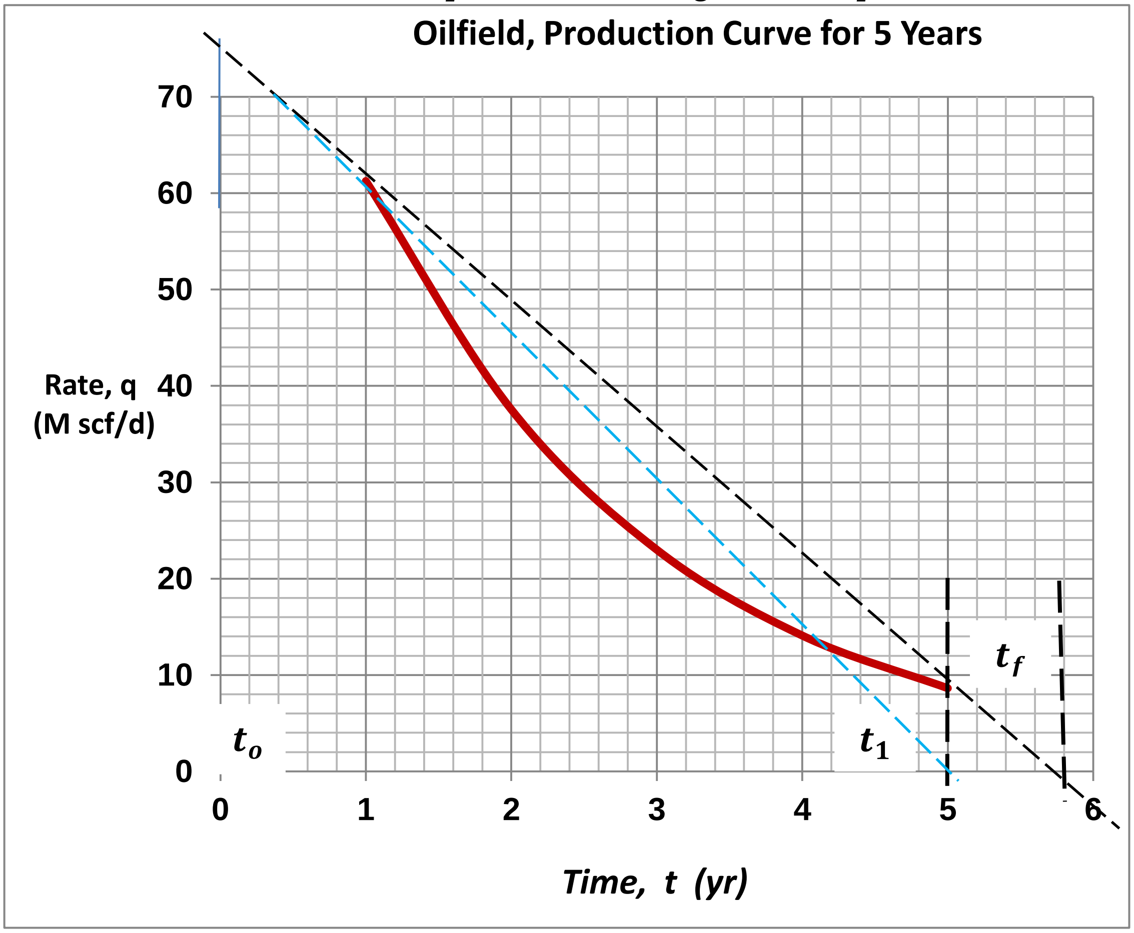

Fig 4.9: Curve Generated from the Projected Rate or Data on Table 4.6.

b. Estimation of the Hydrocarbons Recovery

Solution from the curve (Figure 4.9) showed that, $q_1 = 75\, stb$, $t_o = 0$, $t_1 = 5yrs$ and $t_f = 5.8yrs$. These values were used in the model Eqn3.73 as the input data for estimation of the total or cumulative oil production ($N_p = 68{,}484.38\, Mstb$). The value was comparable to the tabulated estimation value ($N_p = 68{,}342.98\, Mstb$, Table 4.6). The percentage accuracy is 99.98%

$$\mathrm{N_p} = \frac{365.25 * 75}{2}[5 - 0] = \mathbf{68,484.38M\ stb}$$

c. **Estimation *of the Hydrocarbons Initially in Place***

The curve was extrapolated from time t_1 to time, t_f and I was able to estimate the hydrocarbons (Oil) initially in place using the model Eqn3.77 as shown below.

$$\mathrm{N} = \frac{365.25*100}{2}[5.8 - 0] = 105{,}922.5\mathbf{Mstb}$$

*d. **The Hydrocarbons Recovery Factor (E_R)***

Recovery factor is the ratio of the cumulative hydrocarbon production to the hydrocarbon initially in place. Mathematically:

$$\boldsymbol{E_R} = \frac{\mathbf{100}\&\%\mathrm{N_p}}{\boldsymbol{N}} = \frac{\mathbf{100 * 68484.38}}{\mathbf{105922.5}} = \mathbf{64.67}\%$$

The challenge in this very short production history was to identify the decline trend in a field of operation. The only remedy here was to project the data up to the 5 years of operation in order to identify the production rate decline trend. That was production data from initial rate to 1^{st}, 2^{nd}, 3^{rd}, 4^{th} or more decline rates.

Solution - II

*a. **Prediction of the production rate ($n = 2$)***

$q_1 = 96.3\ M\ stb/d$, $q_2 = 92.9\ M\ stb/d$, and $q_3 = 89.8\ M\ stb/d$

$t_1 = 0.1$, $t_2 = 0.2$ and $t_3 = 0.3yr$. With these production data as the input data, Eqn3.36 was used for predicting the decline rate as follows:

$b = \frac{q_i - q}{q\ t} = \frac{100-92.9}{92.9*0.2} = 0.3821/yr$, this ''b'' was substituted in Eqn3.46, for the yearly flow rate: $\boldsymbol{q_1} = \frac{q_i}{1+bt_1} = \frac{100}{1+0.3821*1} = \mathbf{72.35}$

$Using\ Eqn3$.49 the yearly cumulative oil production was obtained. Mathematically:

$$N_{p1} = \frac{365.25*(q_i - q)}{b} = \frac{365.25*(100-72.35)}{0.3821} = \mathbf{26,430.68}\ Mstb$$

$$N_{p2} = 365.25q_1 = 365.25 * 56.68 = \mathbf{20,702.37}\ Mstb$$

The resulted values were tabulated on Table 4.8 below.

Table 4.7: Model Results from Projected Oil Rate, Well – 21A

Date	Time T, (Yy)	Rate, q M stb/d	Rate, q M stb/yr))	Cumulative N_p, M Stb
1996	0	-	-	-
1997	1	72.35	26,430.68	26,430.68
1998	2	56.68	20,702.37	47,133.05
1999	3	46.59	17,017.00	64,250.05
2000	4	39.55	14,445.63	78,555.68
2001	5	34.36	12,549.99	91,145.67
2002	6	30.37	11,092.64	102,238.31
2003	7	27.21	9,938.45	112,176.76
2004	8	24.55	8,966.89	121,143.65
2005	9	22.53	8,229.08	129,372.73
2006	10	20.74	7,575.29	137,000.10
Total Oil Production in ten years				**137,000.10 Mstb**

Source [Generated from Table 3.12 and Model Eqn3.37]

Source [Generated Using Table 4.7]

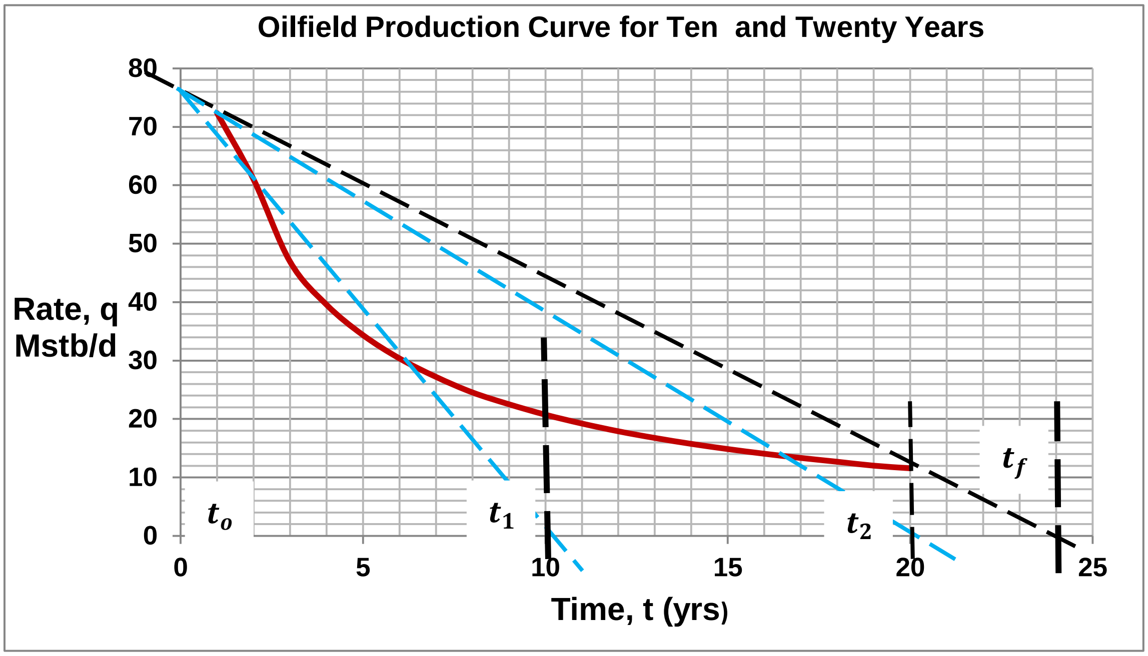

Fig 4.10: Curve Generated from the Projected Rate or Data on Table 4.7.

b. *Estimation of the Hydrocarbons Recovery*

Solution from the curve (Figure 4.10) showed that the rate, $q_1 = 75\ stb/d,\ \ t_o = 0,\ \ t_1 = 10\ yrs,\ \ t_2 = 20\ yrs$ and $t_f = 24\ yrs$. These values were used as the input data in the model evaluation Eqn3.49 and the total or cumulative oil production (N_p) was obtained. Mathematically:

$$\mathbf{N_p} = \frac{\mathbf{365.25*75}}{\mathbf{2}}[\mathbf{10-0}] = \mathbf{136,969\ Mstb}$$

$$\mathbf{N_p} = \frac{\mathbf{365.25*20}}{\mathbf{2}}[\mathbf{20-10}] = \mathbf{36,525\ Mstb}$$

The percentage accuracy is 99.98%

The total recovery estimated in both ten and twenty years were small, but if the reservoir pressure were maintained early enough, say from ten years up to 20 years the total oil recovery would be improved as shown below:

$$\mathbf{N_p} = \frac{\mathbf{365.25*75}}{\mathbf{2}}[\mathbf{20-0}] = \mathbf{273,969\ Mstb}$$

c. Estimation *of the Hydrocarbons Initially in Place*

The curve in figure 4.10 was extrapolated from time t_1 to time, t_f and the hydrocarbons (Oil) initially in place was estimated using the model Eqn3.77.

$$\mathbf{N} = \frac{\mathbf{365.25*100}}{\mathbf{2}}[\mathbf{24-0}] = \mathbf{438,300\ Mstb}$$

d. The Hydrocarbons Recovery Factor (E_R)

Recovery factor is the ratio of the cumulative hydrocarbon production to the hydrocarbon initially in place. Mathematically:

$$E_R = \frac{100\mathrm{N_p}}{N} = \frac{100*136969000}{438300000} = 31.25\%$$

$$E_R = \frac{100\mathrm{N_p}}{N} = \frac{100*175320000}{438300000} = 40\%$$

When the reservoir pressure was assumed maintained the recovery factor would be improved as shown below:

$$E_R = \frac{100\mathrm{N_p}}{N} = \frac{100*277590000}{438300000} = 63.33\%$$

Solution - III

a. Prediction of the production rate ($1 > n < 2$)

The values on Table 3.9 were input into the model evaluation Eqn3.47 the average decline rate constant (b) was obtained. The average ’’b’’ was substituted in Eqn3.46, the yearly flow rate was also obtained as follows:

$$\boldsymbol{b \approx \frac{1}{n}\left[\frac{q_i - q_1}{q_1\, t_1} + \frac{q_i - q_2}{q_2\, t_2} + \frac{q_i - q_3}{q_3\, t_3} + . \; . \; . \; . + \frac{q_i - q_n}{q_n\, t_n}\right] \approx 0.4}$$

$$\boldsymbol{q_1 \approx \frac{q_i}{1 + bt_1} = \frac{100}{1 + 0.4 * 1} \approx 71.00\ Mstb/d}$$

$$\boldsymbol{q_2 \approx \frac{q_i}{1 + bt_2} = \frac{100}{1 + 0.4 * 2} \approx 55.56\ Mstb/d}$$

The resulted data were tabulated in Table 4.9 below.

***Table 4.8: Projected* Production Rate from 1996 to 2006**

Date	Time T, (Yy)	Rate, q M stb/d	Rate, q MM stb/yr))	Cumulative N_p, M Stb
1996	0	-	-	-
1997	1	71.00	26,480.63	26,480.63
1998	2	55.56	20,293.29	46,773.92
1999	3	45.45	16,600.61	63,374.53
2000	4	38.46	14,047.52	77,422.05
2001	5	33.33	12,173.78	89,595.83
2002	6	29.41	10,742.00	100,337.83
2003	7	26.32	9,613.38	109,951.21
2004	8	23.81	8,696.60	118,647.81
2005	9	21.74	7,940.54	126588.35
2006	10	20.00	7,305.00	133,893.35
Total Oil Production in ten years is 133,893.35 M stb				

Source [Generated from Table 3.13 and Model Eqn3.37]

Figure 4.11 shows the curve generated from the projected rate or data on Table 4.8 and using Eqn3.46, Oil initially in place (OIIP) was also obtained.

Source [Generated Using Table 4.8]

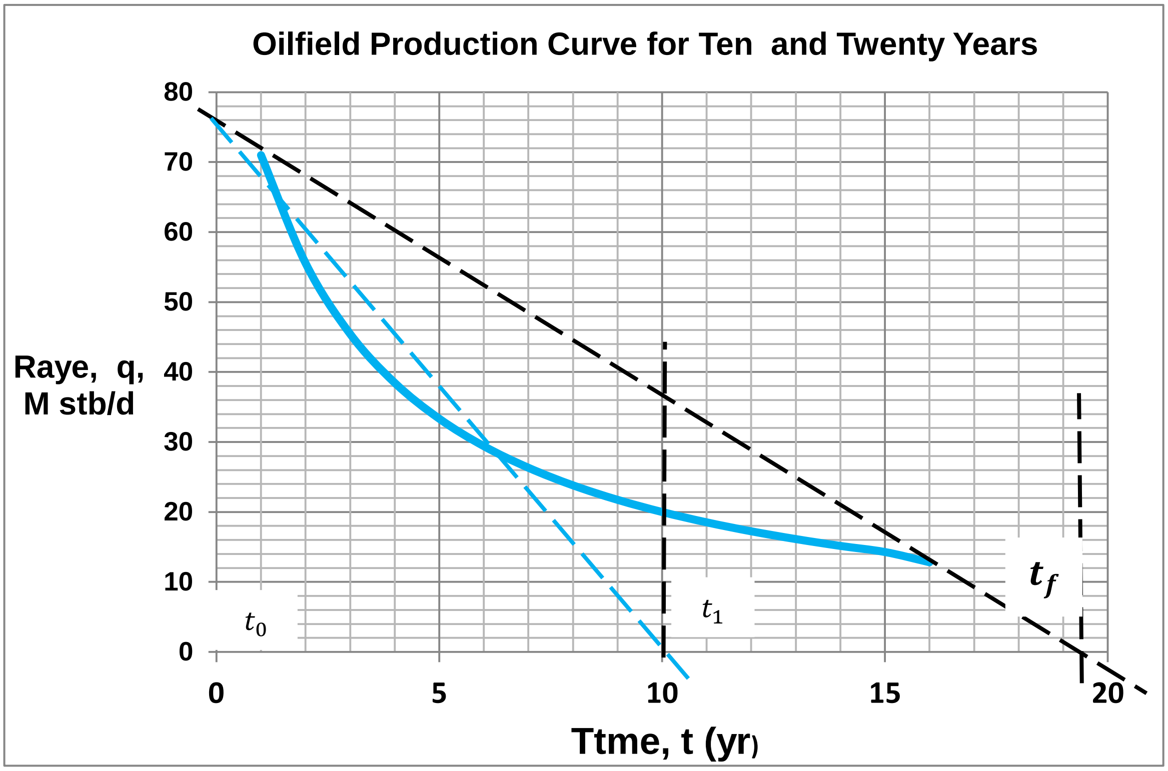

Fig 4.11: Curve Generated from the Projected Rate or Data on Table 4.8.

b. Estimation of the Hydrocarbons Recovery

Solution from the curve (Fig 4.11) above showed that the rate, $q_1 = 73.5\ stb/d$, $t_o = 0$, $t_1 = 10\ yrs$ and $t_f = 19.5\ yrs$. These values were put into the model evaluation Eqn3.49, the total or cumulative oil production (N_p) was obtained as shown below.

$$\mathbf{N_p = \frac{365.25*73.5}{2}[10 - 0] = 134,229M\ stb}$$

The percentage accuracy of 99.75%

$$\mathbf{N_p = \frac{365.25*20}{2}[19.5 - 10] = 34,699M\ stb}$$

The estimated cumulative production was low, if the reservoir pressure was maintained early enough, say from ten years up to 19.5 years the total oil recovery would have been improved as:

$$\mathbf{N_p} = \frac{\mathbf{365.25*73.5}}{\mathbf{2}}[\mathbf{19.5-0}] = \mathbf{261,747M\ stb}$$

c. Estimation *of the Hydrocarbons Initially in Place*

The curve (Figure 4.11) was extrapolated from time t_1 to time, t_f and I was able to estimate the hydrocarbons (Oil) initially in place using the model evaluation Eqn3.77 as shown below:

$$\mathbf{N} = \frac{\mathbf{365.25*100}}{\mathbf{2}}[\mathbf{19.5-0}] = \mathbf{356,119\ Mstb}$$

d. The Hydrocarbons Recovery Factor (E_R)

Recovery factor is the ratio of the cumulative hydrocarbon production to the hydrocarbon initially in place. Mathematically:

$$\boldsymbol{E_R} = \frac{\mathbf{100}\&\%\mathrm{N_p}}{\boldsymbol{N}} = \frac{\mathbf{100*134,229}}{\mathbf{356,119}} = \mathbf{37.7}\%$$

$$\boldsymbol{E_R} = \frac{\mathbf{100}\&\%\mathrm{N_p}}{\boldsymbol{N}} = \frac{\mathbf{100*168,928}}{\mathbf{356,119}} = \mathbf{47.4}\%$$

When the reservoir pressure was assumed maintained the recovery factor was improved as shown below. Economic evaluation in this case would be the best method to enhance pressure maintenance consideration.

$$\boldsymbol{E_R} = \frac{\mathbf{100}\&\%\mathrm{N_p}}{\boldsymbol{N}} = \frac{\mathbf{100*261,747}}{\mathbf{356,119}} = \mathbf{73.5}\%$$

4.2 Discussions

4.2.1 Projectile Dominated Fluids Flow Regime

An oil or a gas reservoir production performance naturally results into a projectile flow trend when both the internal and external energies control the flow trend. In this case the boundary conditions are not felt yet. The principal mechanism which controlled the oil and/or gas reservoir flow performance at the early stage was an external energy drive system. That was possible, because the production rate increased in the initial stage from minimum to a peak value in a given time. On a peak value the rate was stable for another given time called the plateau or transient part or stage of hydrocarbons production flow. The plateau stage was equally the initial reservoir conditions before the boundary dominated flow conditions were felt. After the peak value the transition stage set in. A transition stage is a critical stage which could result into a decline stage. In a transition stage the flow rate tended to be unstable in another given time, but some cases the instability may not be noticeable. Once the decline trend sets in, the flow rate would decline from the peak value towards the economic flow rate value called an abandonment flow rate. The decline trend is classified into three main orders the first-order, second-order and fraction-order (less than any of the two orders). Third order equations which are mainly wave propagation are very rare, so this research work does not cover the third order equations of oil and/or gas flow during production operations. In the third order equations, the wave tends to undergo simple harmonic motion (SHM) and most SHM tend to damped oscillation. The SHM is defined by the equation, $\boldsymbol{y} = \boldsymbol{a}\boldsymbol{x}^{\boldsymbol{n}} + \boldsymbol{b}\boldsymbol{x} + \boldsymbol{c}$, with the solution as: x **=** $\frac{\boldsymbol{b}}{\boldsymbol{2a}} \pm \frac{\sqrt{\boldsymbol{b}^{2} - \boldsymbol{4ac}}}{\boldsymbol{2a}}$. When the value of $b^2 - 4ac$ is negative, meaning that $b^2 < 4ac$ the flow equation $\boldsymbol{y} = \boldsymbol{asinx} + \boldsymbol{bcosx} + \boldsymbol{c}$ is perpetually observed, which is not common in the oil and/or gas fluid dynamics. Most projectile fluid dynamics or flow commonly tends to 1st order equation especially gas stream flow regimes, because the stability in the gas stream and 1st or 2nd order equation of fluid dynamics for oil, because of the instability in the flow and unsteady decline of the internal energy system of the reservoir. This is best explained when the external energy influence on the decline trend is negligible. In the research case the transient flow period was long, but the steady state was longer. That was possible because the reservoir was saturated, and failed to attain boundary dominated flow at initial state. It started by building up the internal energy for some time from time, $\boldsymbol{t_o}$ to time, $\boldsymbol{t_1}$ in fig 4.1. The steady state flow (called the plateau) started from time, $\boldsymbol{t_1}$ to time, $\boldsymbol{t_2}$**,** after that the rate decline state set in with short or unobservable transition state, from time, $\boldsymbol{t_2}$ to time, $\boldsymbol{t_3}$ covering the total or cumulative gas or oil recovery value (in scf or stb). Any un-recovery fluid from time, $\boldsymbol{t_3}$ to time, $\boldsymbol{t_f}$ was the hydrocarbons supposed to be the residual oil or gas in that reservoir. The complete depletion of the hydrocarbons in that reservoir (called hydrocarbons reserves initially in place) was estimated from time, $\boldsymbol{t_o}$ to time, $\boldsymbol{t_f}$. The equation of the area of that shape (trapezium) was used as the value of the hydrocarbons reserves initially in place. The value was confirmed with the field estimated value. The value of the hydrocarbons reserves initially would only be obtainable by the value of the extrapolated shape of that curve. Figure 4.1 shows a projectile gas flow trend, Figure 4.2 shows that of a projectile oil flow trend and Table 4.1 shows the model equations for projectile fluids dynamics.

4.2.2 Parabolic Fluid Flow Regime

An oil or a gas reservoir production performance naturally results into a parabolic dominated flow trend when only the internal and little or no external energies control the flow trend. In this case the boundary conditions effects are set into effect after a short period of production or are the boundary conditions effects are set in right from the start of a reservoir production date. The principal flow mechanism in the oil and/or gas reservoir flow performance was an internal energy drive system with some external energy effects, which decline sharply after a short time of the reservoir production. The initial reservoir conditions were controlled by the boundary dominated flow conditions. The plateau or transient part or stage of hydrocarbons production flow was absent in the parabolic dominated flow trend and the transition stage was sharp or very short. In a transition stage the flow rate tended to be unstable in another short time and the instability was not noticeable in some plots. Once the decline trend sets in just like the projectile flow, the flow rate declined from the peak value towards the economic flow rate value called an abandonment flow rate. The production rate decline trend in parabolic dominated flow trend was classified into three main orders the first-order where the decline exponent was unity ($\boldsymbol{n = 1}$) and the decline trend production decline rate value ‘b’’ was fairly steady, second-order where the production decline rate value ‘b’’ was fairly steady as well, but decline exponent was two ($\boldsymbol{n = 2}$) and less than any of the two orders ($n < 1\, or\, 1 < n < 2$), where the production decline rate value ‘b’’ was not steady. In the case when the order was either less than one or less than two ($1 < n < 2$), the production rate decline tended to increase from the initial stage (peak value) towards the minimum value of the reserves or sharply changed to a decline production rate in a short time. The plateau or transient stage of hydrocarbons production flow seemed to be absent and the transition stage was not noticeable. The reservoir boundary dominated flow conditions were felt, as soon as the decline trend set in and the production flow rate declined from the peak value towards the economic flow rate value called an abandonment flow rate.

If $\boldsymbol{b_1} = \boldsymbol{b_2} = \boldsymbol{b_3} = \ldots\ldots = \boldsymbol{b_n}$ and $n = 1$, it implies uniform decline so Eqn3.33 would be suitable for use in projecting the flow rate, q for a give time, t. That is $\boldsymbol{q_1\ at\ t_1,\ q_2\ at\ t_2,\ q_3\ at\ t_3,}$ $\ldots\ldots\ldots \boldsymbol{q_n\ at\ t_n}$using eqn3.33.

If $\boldsymbol{b_1} = \boldsymbol{b_2} = \boldsymbol{b_3} = \ldots\ldots = \boldsymbol{b_n}$ and $n = 2$, it indicates uniform decline, so Eqn3.40 would be used in projecting the flow rate, q for a give time, t. That is $\boldsymbol{q_1\ at\ t_1,\ q_2\ at\ t_2,\ q_3\ at\ t_3,}\ \ldots\ldots\ldots \boldsymbol{q_n\ at\ t_n}$ using Eqn3.40.

When $\boldsymbol{n < 1\ or\ \ 1 < n} < 2$

The value of, $\boldsymbol{b_1} \neq \boldsymbol{b_2} \neq \boldsymbol{b_3} \neq \ldots\ldots \neq \boldsymbol{b_n}$, it indicates non-uniform decline rate. In this case an average decline would be used or the decline rate would be estimated at each point of the projected flow rate, q within the given time, t. This means $\boldsymbol{b_1\ at\ t_1}$ must be calculated and used for $\boldsymbol{G_{p1}\ or\ N_{p1}}$, $\boldsymbol{b_2\ at\ t_2}$ would equally be calculated and used for $\boldsymbol{G_{p2}\ or\ N_{p2}}$, $\boldsymbol{b_3\ at\ t_3}$ is also calculated and used for $\boldsymbol{G_{p3}\ or\ N_{p3}}$, and so on to $\boldsymbol{b_n\ at\ t_n}$ for $\boldsymbol{G_{pn}\ or\ N_{pn}}$**.** Figure 4.3 shows a parabolic hydrocarbons production flow trend and table 4.2 shows the model equations for parabolic fluids dynamics.

4.2.3 Cumulative Hydrocarbons Production Models

The general equation for natural production of an oilfield reserves is the product of the hydrocarbons flow rate and the actual time elapsed. In the research case the reservoir started by building up the internal energy from time, $\boldsymbol{t_o}$ to time, $\boldsymbol{t_1}$ in figure 4.4, because the reservoir was fairly saturated, so failed to attain boundary dominated flow at initial state. Instead its energy built-up from the initial stage to the transient and transition stage at point – Q, but the flow period was too short for clear observation. To that effects steady state flow (called the plateau) was not observed in the curve at time, $\boldsymbol{t_1}$ instead rate decline stage set in from time, $\boldsymbol{t_1}$ to time, $\boldsymbol{t_2}$**.** After that the rate decline stage set in with little or no transition state, from time, $\boldsymbol{t_2}$ to time, $\boldsymbol{t_3}$ covering the total or cumulative gas or oil recovery value (in scf or stb). Any un-recovery from time, $\boldsymbol{t_3}$ to time**,** $\boldsymbol{t_f}$ estimated value, was the hydrocarbons supposed to be the residual oil or gas of that reservoir. The complete depletion of the hydrocarbons in that reservoir (called hydrocarbons reserves initially in place) was estimated from time, t_o to time, t_f. The equation of the area of that shape (trapezium) was used to estimate the value of the hydrocarbons reserves initially in place (Figure 4.5). That was only obtainable using the estimated area of the extrapolated shape. That was similar to the above case, only that the Parabolic flow type had sharp transient and transition Time. The area of the curve was estimated as an equivalent value to the total hydrocarbons recoverable or initially in place.

4.2.4 Parabolic *Flow with no Observable Transient or Transition*

The parabolic flow trend with no observable transient or transition case, the oil well flow rate was on transition state at initial production point. The boundary conditions were felt right from the start. That was, because the reservoir was not externally supported. Usually it may be difficult to deplete the reservoir completely. The value of the area of the curve was estimated as an equivalent value to the total hydrocarbons reserves initially in place. This research work focuses on hydrocarbons production decline rate projection, hydrocarbons cumulative production and hydrocarbons reserves initially in place estimation. With that in mind, the primary data used were the early production rate to project future rates in a given time. The values were used to plot curves and the generated curves were empirically used to build the models. In a case where the production data were fairly enough to take care of the buildup flow rate, the steady state (plateau) rate and the decline flow rate, the field data were used directly to generate the curves. The models developed using field data have high percentage of accuracy. The advantage of using projectiles and parabolic methods in model development was that such models were very flexible. The models were applied with high accuracy right from the bubble point pressure of the reservoir, through the transient stage, transition stage to the decline rate stage. The user must be empirically observant enough and tactful in using the model in an induced hydrocarbons production operation, else the user must use fluids displacement methods in the induced recovery operations. The disadvantage was that the models did not take care of pressure drawdown, but the projected rate decline trends or cumulative hydrocarbons production trends depend on pressure sustainability.

4.2.5 Application of the Evaluation Models Using Generic Data

The advantage in using generic data is mainly to enhance hydrocarbons production projected values. This makes it easy to predict future hydrocarbons production performances and take decision on the reservoir pressure management. The results showed high accuracy on the forecast. The percentage accuracy for gas fields ranged from 99.86% and above, while the percentage accuracy for oil ranged from 98.64% to 99.98%. Table 4.9 shows the comparison of the model results with the tanks, tabulated and Craze - Buckley MBE estimated values, while Table 4.10 shows a comparison of the models results with the tabulated values and Table 4.11 shows a comparison of the model and tabulated values.

Table 4.9: The Model Results for Gas Compared with the Tank and MBE Values

S/No	Value Used	$G_p, MMscf$	Accuracy	$G, MMscf$	Accuracy
1.	Models	637.40	99.86%	698.54	99.98%
2.	Tanks	637.06		-	
3.	Tabulated Tables	639.20		-	
4.	Craze and Buckley MBE	639.20		699.7	

Table 4.10: The Model Results for Oil Compared with the Tank and MBE Values

S/No	Values Used	$N_p, MMstb$	Accuracy	$N, MMstb$	Accuracy
1.	Models	16.88	98.64%	20.27	99.30%
2.	Tanks	16.70		-	
3.	Tabulated Tables	16.65		-	
4.	Craze and Buckley MBE	16.65		20.12	

Table 4.11: Model Results Using Generic Data Compared with Tabulated Oil Values

S/No	Values Used	$N_p, Mstb$	% Accuracy	N, Mstb	% Accuracy
1	Models Tabulated Values	68.50 68.34	99.77%	105.92 -	-
2	Models Tabulated Values	136.96 137.00	99.97%	438.30 -	-
3	Models Tabulated Values	134.23 133.90	99.75%	356.12 -	-

Source [Model Result Table 4.2 and Appendix-A]

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

5.1 **Conclusion**

- Mathematical models equations were successfully derived for studying reservoirs fluids depletion from the peak value at decline stage to an economic value called abandonment.
- Decline rate trends analysis showed two types of flow p*rojectile dominated flow regimes a*ttributed to external and little or no boundary conditions effects and *Parabolic flow regimes whose p*rincipal mechanism is due to internal and boundary conditions effects. The projectile dominated flow models were mainly used and generated curves for predicting hydrocarbons production performances. When the reservoir pressure is above its bubble-point pressure, projectile dominated flow is possible and evaluation models-I should be used, but when the reservoir pressure is closed or at bubble-point pressure, the parabolic dominated flow is possible in that well and evaluation models-II should be used. This is because the bubble point pressure is the critical point for critical rate. Highly above the bubble point the dominated fluids flow is the projectile type, while slightly above the bubble point pressure down to the abandonment point parabolic dominated fluid flow regime is expected. The parabolic dominated fluid

flow models were used to predict future recovery from the decline stage to an economic rate (abandonment). The extrapolation of the curve from the decline point to the economic rate point on the t-axis at t_f gave the total reserves in place.

Observations

- When yearly rates projected to abandonment or close to it are used to generate curves, the models give high accuracy estimated reserves (N_p and N)
- When first and last points of the decline stages are extrapolated for actual flow rate (q) and time (t), as the models input data, they give high accuracy estimated reserves (N_p and N)
- ***Yearly r***ates and pressure depletion trend synergy was necessary to predict transient and steady states periods, but was not used here.
- Projected production performances of reserves and estimation of the reserves initially in place percentage accuracy for gas fields ranged from 99.86% and above, while the percentage accuracy for oil ranged from 98.64% to 99.98%..

5.1.1 Contributions

The result of this research simplifies complex simulation methods, improves DFCA accuracy and makes it easy to identify dominated flow and rates decline trends.

a. Technologically

1. High accuracy evaluation models for predicting future hydrocarbons productions and estimation of initial reserves fluids in place were successfully developed, using production rate decline trend analysis.
2. The models could be tactfully used right from the initial state of a reservoir through the transient, transition and to the decline rate stage.
3. The model could equally be tactfully used in an induced hydrocarbons operation (pressure maintenance) at decline stage to improve the pressure management in a reservoir. This is possible, because when a reservoir pressure is maintained, it prevents critical rate and the recovery is high. The example of these benefits on production test solution-I (Table 4.7 and Figure 4.10) and test solution-II (table 4.8 and Figure 4.11).
4. The projectile and parabolic dominated fluids flow methods using both fields (regional) and projected (generic) data to generate the

curves which clearly identified hydrocarbons flow trends. This is possible, because the generated curves give clear pictures of the hydrocarbons production performances right from the initial stage to the rate decline trend of a reservoir. Conventionally when a reservoir initial pressure is much above the bubble point pressure, the rate decline would be delayed until the reservoir attains a pressure near the bubble point pressure. Then the boundary dominated flow regime set in. After the boundary conditions set in an observable production rate decline is felt. In this case, the projectile and/or parabolic flow models account for production rate changing conditions (Eqn3.3, 3.25, 3.26, 3.27, 3.28 and 3.29). The resultant effect is that the accuracy is high (about 99.8%). A field performance could be estimated with high certainty or good economic evaluation assurance, using these flexible evaluation model equations.

5. The disadvantage is that the models do not take care of pressure drop, but the projected rate decline trend or cumulative hydrocarbons production trend depend on pressure sustainability.

6. A prosy model which could successfully and easily predict a rate decline constant ‘‘b’’ and could integrate it into the master program for future production forecast and estimation of reserves (hydrocarbons initially in place) was developed. Appendix – B.

7. The outstanding advantage of this research work is that a prosy model can predict a production trend in a reservoir that was developed. The benefit of the prosy model is that it can show the production trend graphically. The graphical solution enhances the plan for the reservoir pressure management through pressure maintenance or re-pressurization.

5.2 Recommendations

a. First and last points of the decline stage must be extrapolated to the axes in order to obtain actual flow rate, q and time, t as the model input. This gives high estimation accuracy.

b. Only projected rates to abandonment stage close to it should be used to estimate reserves. It improves reserves estimation accuracy.

c. Yearly rates and pressure decline synergy is not used and production depends on pressure sustainability. Hence it is recommended that pressure maintenance should be used (if required) to manage the reservoir pressure for economic recovery.

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APPENDIX – A

Volumetric MBE for Models Validations

This part contains volumetric MBE for the research models validation or comparison. Application of ***Standing and Katz, (1942) MBE*** for volumetric gas reservoir using the field data, the cumulative production value was $\mathbf{639.165} * 10^9 scf$ and GIIP was $699.7 * 10^9 scf$. These values were comparable to the model results, page 75. Table A-1 shows the field data and table 3.4 page 74 shows the well ***data for gas production in.*** $\mathbf{22\frac{1}{2}}$ ***Years.***

Table A-1: Initial ***Gas Well Data which was Produced for*** $\mathbf{22\frac{1}{2}}$ ***Years***

Parameters	Symbol	Values
Reservoir Pressure	P_i	*4300 psia*
Formation Temperature	T_i	*200°F(660°R)*
Gas Volume	V_g	$17.76 MMMcu.ft$
Formation Porosity	Ø	*19 %*
Connate Water Saturation	S_{wc}	*20 %*
Gas Specific Gravity	γ_g	*0.85*
Gas Deviation Factor	*Z*	*0.89*
Gas Formation Volume Factor	B_{gi} & B_g	
Gas Expansion Factor	E_i	$\frac{35.37P_i}{ZT_i}$

Detailed Estimation procedure:

$$\boldsymbol{GIIP = G = V_g \emptyset (1 - S_{wc}) E_i = \frac{35.37\, V_g\, \emptyset\, P_i (1 - S_{wc})}{ZT_i} = 699.7 MMMSCF}$$

$$\boldsymbol{G_p = \frac{G\,(B_g - B_{gi})}{B_g} \quad or \quad Tank\, Volume = 639.165 MMMSCF}$$

Application of ***Standing and Katz, (1942) MBE*** for volumetric oil reservoir using the field data, the cumulative oil production (N_p) value was $\mathbf{16.877} * 10^6\mathbf{stb}$ and oil initially in place (N) was $20.\mathbf{116} * 10^6\mathbf{stb}$. These values were comparable to the model results, page 76. Table A-2 shows the field data and Table 3.5 page 76 shows the oil well ***data production in 10*** $\boldsymbol{Years}$***.***

Table A-2: Initial Oil *Well Data which was Produced for 10* $\boldsymbol{Years}$

Parameters	Symbol	Values
Reservoir Pressure	P_i	
Formation Temperature	T_i	
Oil Volume	$V_o = Ah$	$25{,}500\ ac.ft$
Formation Porosity	$\emptyset$	*19 %*
Water Saturation	S_w	*30 %*
Pay-zone Thickness	*h*	*59ft*
Pay-zone Total Area	*A*	*433.5acres*
Gas Formation Volume Factor	B_{gi} & B_g	*1.308 & 1.2975*

Detailed Estimation procedure:

$$\boldsymbol{STOIIP = N = \frac{7758\, V_o \emptyset (1 - S_{wc})}{B_{oi}} = 20.116 MMSTB}$$

$$\boldsymbol{N_p = \frac{N\,(B_o - B_{oi})}{B_o} \quad or \quad Tank\, Volume = 16.651 MMSTB}$$

Excel for graphs was applied on both regional and generic production data. On Table 4.4, Figure 4.7 was generated page 97 (ref: Eqn3.33 & Eqn3.36) from the projectile flow, on table 4.5, Figure 4.8 was generated page 99 (ref Eqn3.33 & Eqn3.36), on Table 4.6, Figure 4.9 was generated page 102, on table 4.7, Fig 4.10 was generated (ref Eqn3.37) and Fig. A1 – A8, were generated using ***Obah, et al*** generic data. The simulated production data were good attempts, but lacked decline credibility, except well Run-5 in figure A3 which declined normally. Another problem with their generic data was that they do not account for the build-up rate or time, so that reduced the percentage accuracy.

Evaluation Models Application Using Simulated Production Data

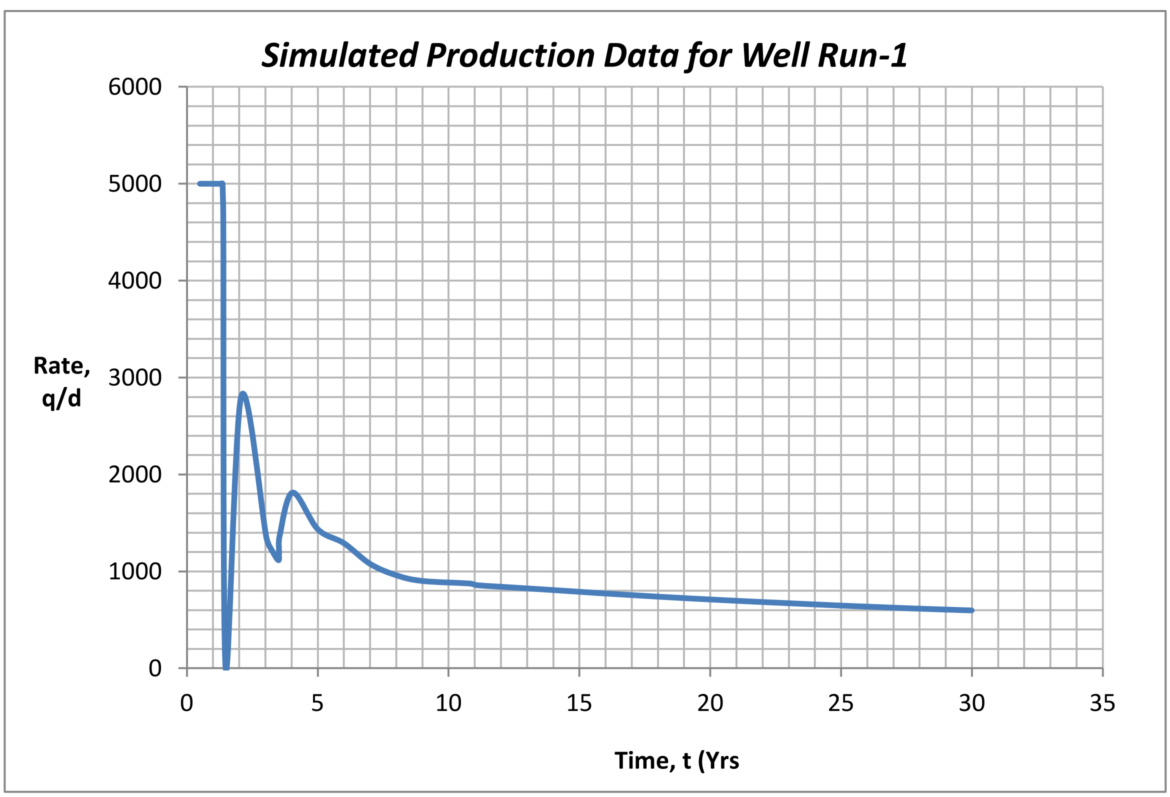

Fig A1: Simulated Production Data RUN-1 by Aniefiok and Obah

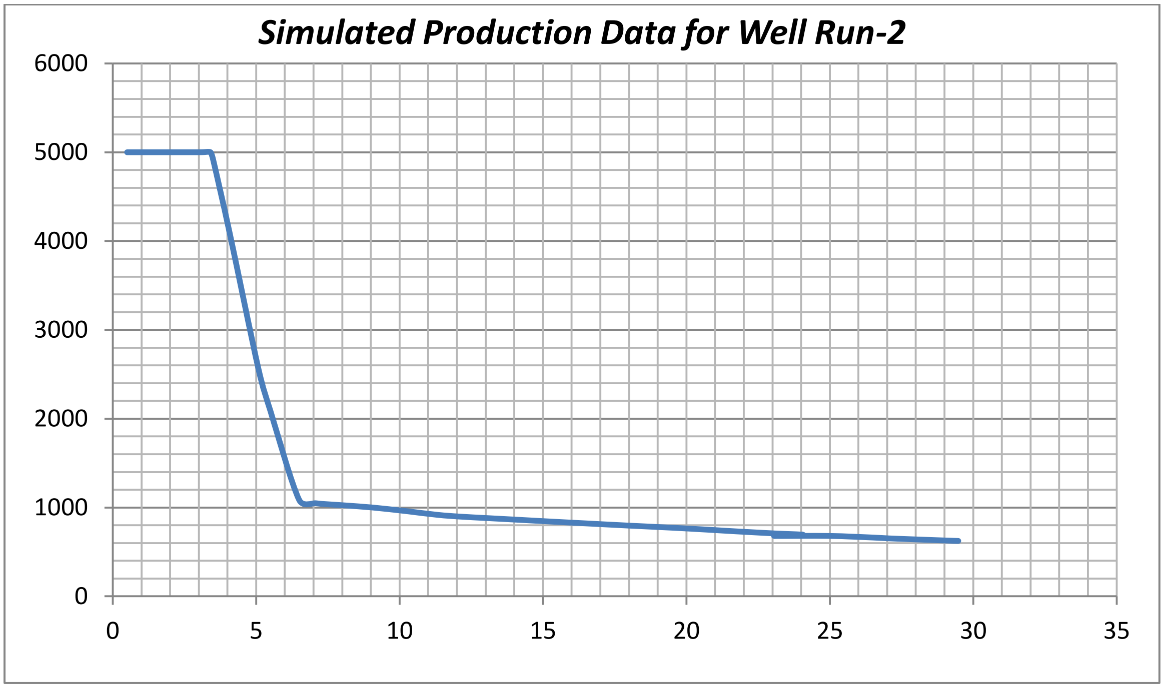

Fig A2: Simulated Production Data RUN-2 by Aniefiok and Obah

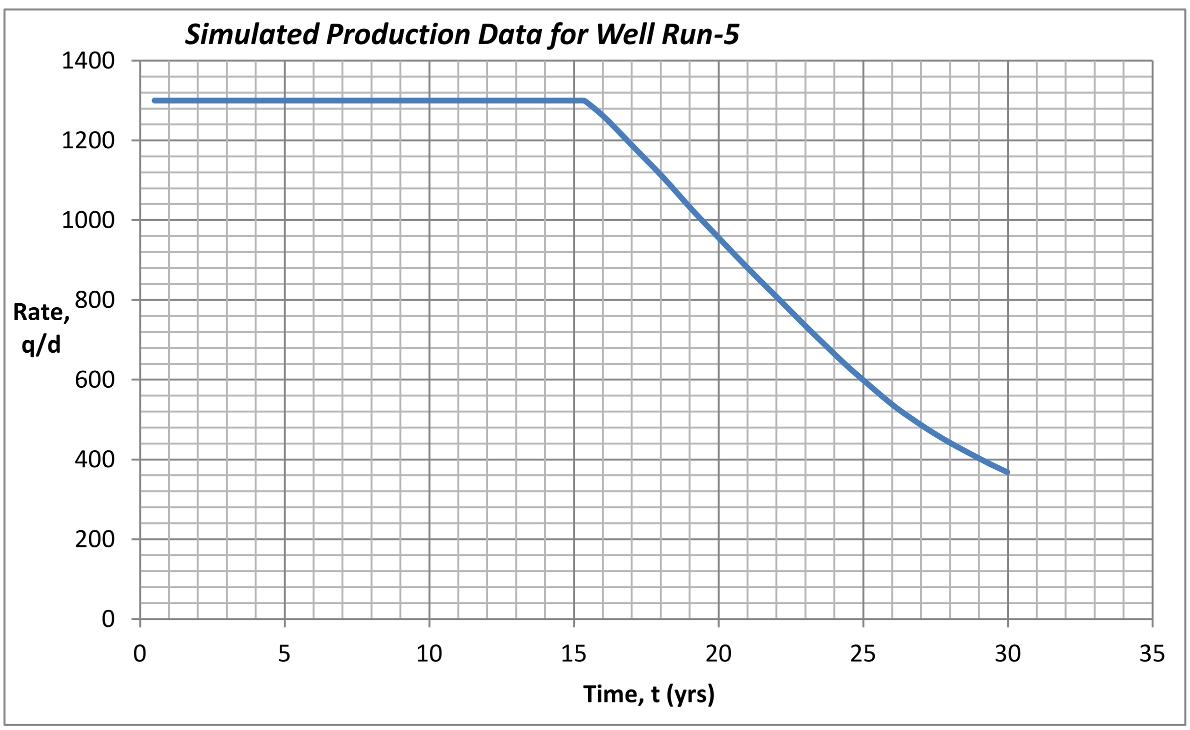

Fig A3: Simulated Production Data RUN-5 by Aniefiok and Obah

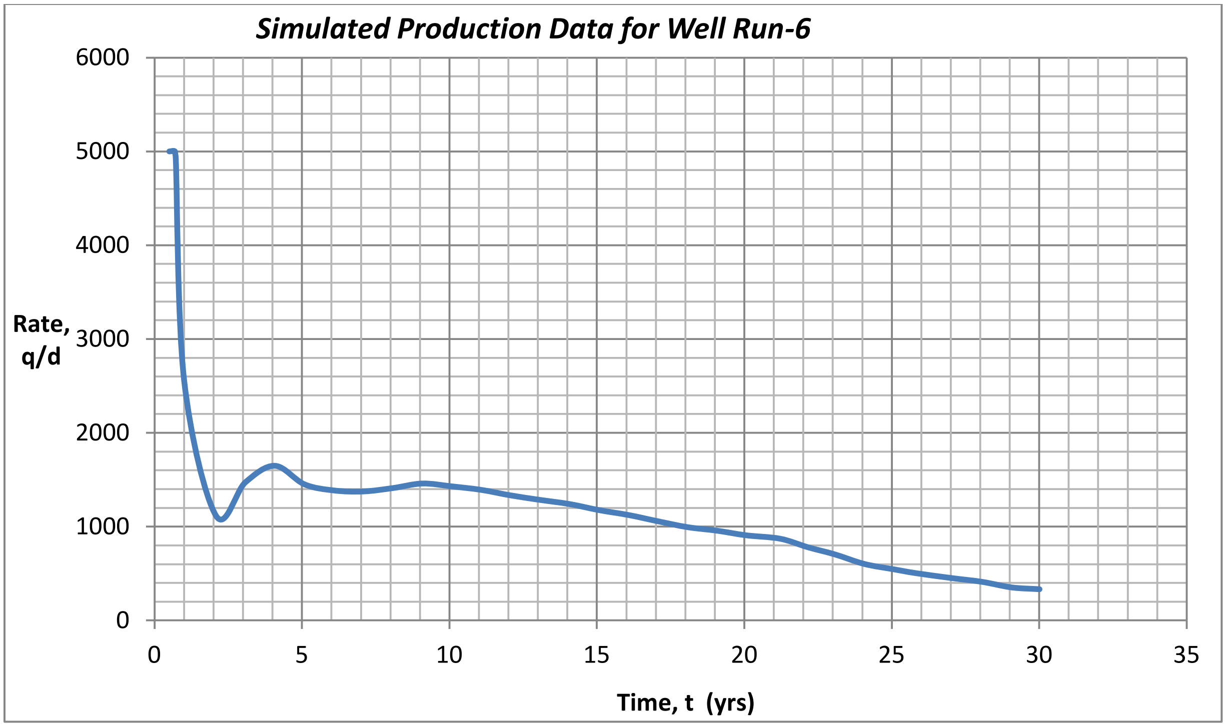

Fig A4: Simulated Production Data RUN-6 by Aniefiok and Obah

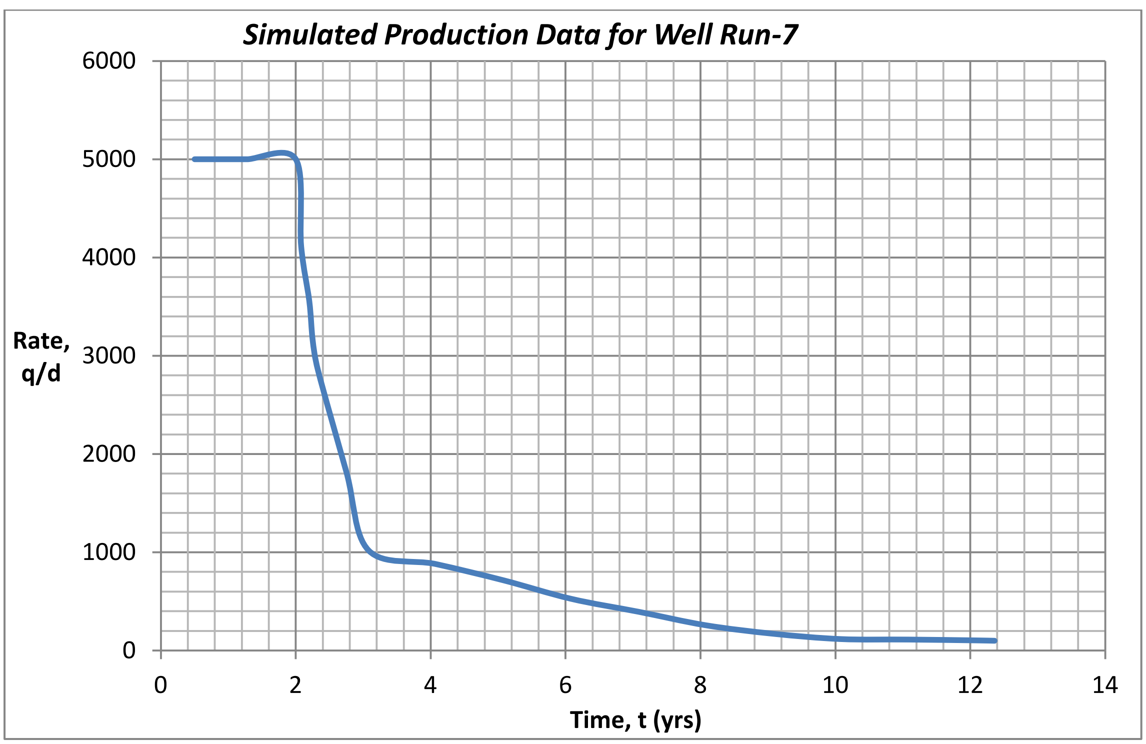

Fig A5: Simulated Production Data RUN-7 by Aniefiok and Obah

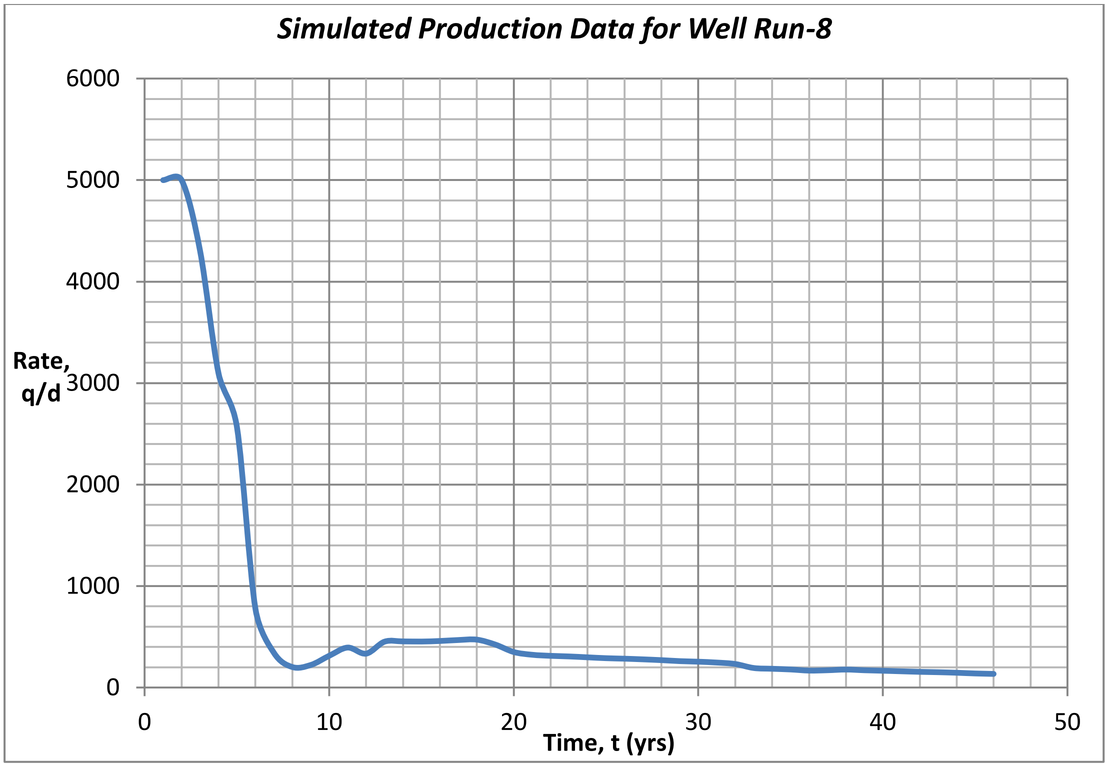

Fig A6: Simulated Production Data RUN-8 by Aniefiok and Obah

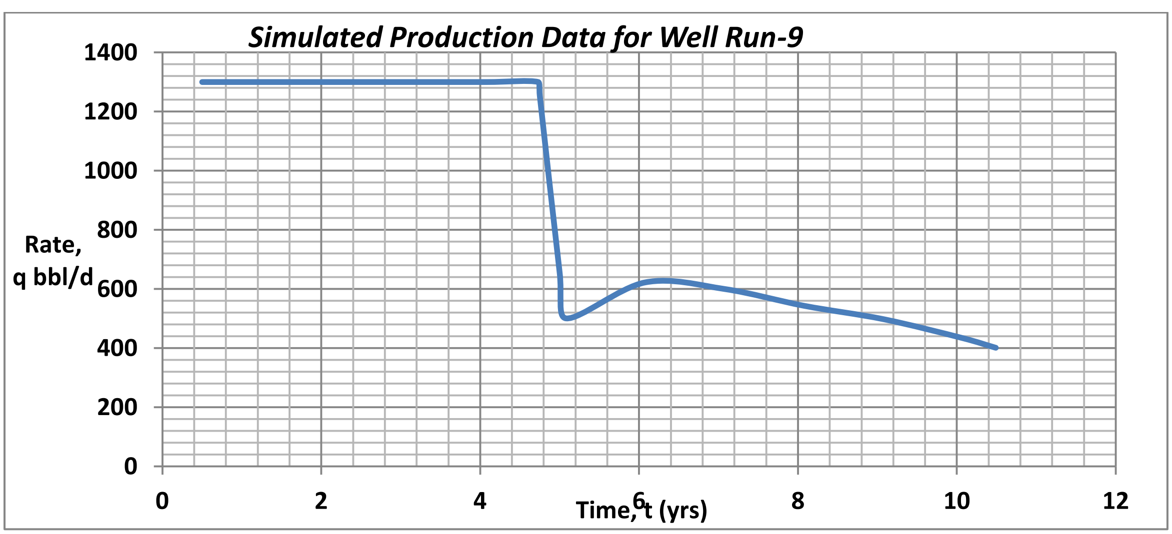

Fig A7: Simulated Production Data RUN-7 by Aniefiok and Obah

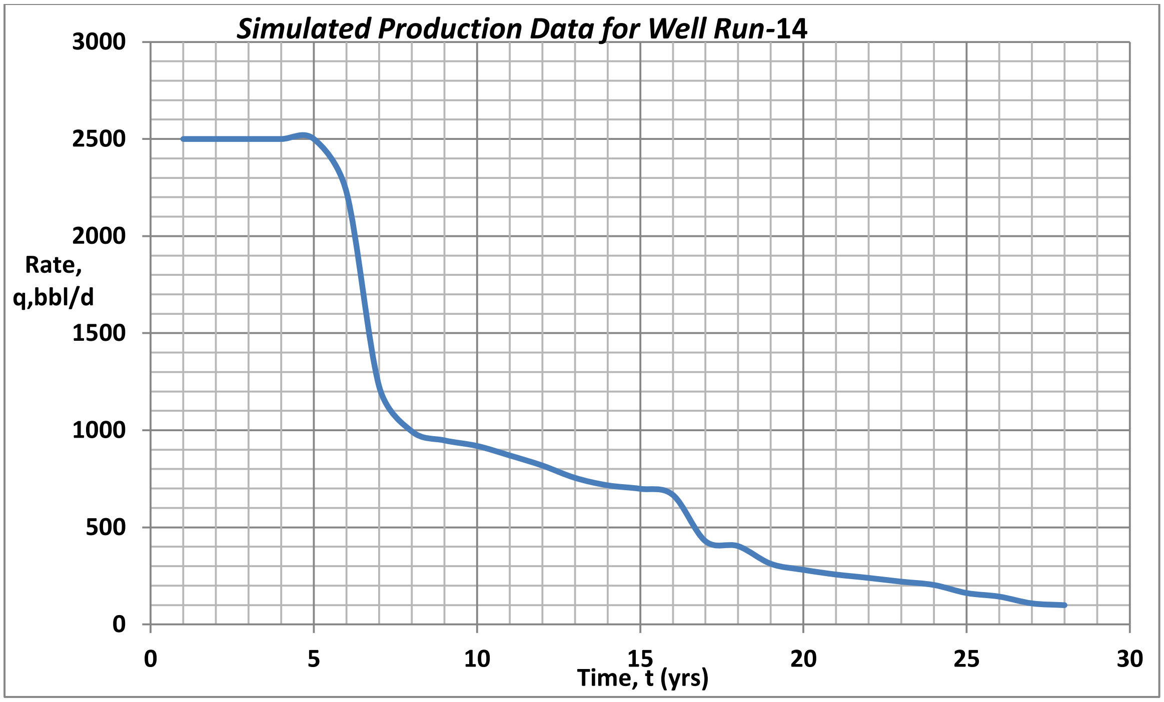

Fig A8: Simulated Production Data RUN-7 by Aniefiok and Obah

APPENDIX – B

Estimation of Oil and Gas Initially in Place using decline Curves analysis
Using *FORTRAN-77* Program

Model – 1A: Projectile Evaluation Model Equation

```
      C A:   CUMULATIVE HYDROCARBONS PRODUCTION ESTIMATION
      C A1: CUMULATIVE GAS PRODUCTION (CUMGAS) ESTIMATION
             WRITE (*,*) ''INPUT THE VALUES OF QI, T, T1, T2 AND T3''
             READ (5, 100) QI, T, T1, T2, T3
100   FORMAT (3X, 5F17.4)
        110  QI1 = QA, T = TA, T1 = T1A, T2 = T2A, T3 = T3A
             OPEN (UNIT = 6, FILE = 'CUMGAS.RST')
120   CUMGAS = 0.5*QI*((T2-T1)+(T3-T0))
             CUMGAS = CUMGAS1
        130  WRITE (6, 140) CUMGAS
        140  FORMAT (3X, F17.4)
        210  STOP
             END
```

OR

Model – 1B: Projectile Evaluation Model Equation

```
      C      WHEN EDECLINE CONSTANT, B IS KNOWN
      C A:   CUMULATIVE HYDROCARBONS PRODUCTION ESTIMATION
      C A1: CUMULATIVE GAS PRODUCTION (CUMGAS) ESTIMATION
             WRITE (*,*) ''INPUT THE VALUES OF B, QI, T, T1, T2 AND T3''
             READ (5, 100) B, QI, T, T1, T2, T3
101   FORMAT (3X, 6F17.4)
        110  B=B1, QI1 = QA, T = TA, T1 = T1A, T2 = T2A, T3 = T3A
             OPEN (UNIT = 6, FILE = 'CUMGAS.RST')
121   CUMGAS = QI*((T2-0.5*(T1+T)+(1-EXP(-B*T3)/B))
             CUMGAS = CUMGAS1
        130  WRITE (6, 140) CUMGAS
        140  FORMAT (3X, F17.4)
        210  STOP
             END
```

Model – 1C: Projectile Evaluation Model Equation

```
     C A:   HYDROCARBONS INITIALLY IN PLACE ESTIMATION
     C A1: TOTAL GAS INITIALLY IN PLACE (G) ESTIMATION
            WRITE (*,*) ''INPUT THE VALUES OF QI, T, T1, T2 AND TF''
            READ (5, 100) QI, T, T1, T2, TF
102  FORMAT (3X, 5F17.4)
       110  QI1 = QA, T = TA, T1 = T1A, T2 = T2A, TF = TFA
            OPEN (UNIT = 6, FILE = 'G.RST')
122  G = 0.5*QI*((T2-T1)+(TF-T))
            G = G1
       130  WRITE (6, 140) G
       140  FORMAT (3X, F17.4)
       210  STOP
            END
```

Model – 1D: Projectile Evaluation Model Equation

```
     C A:   CUMULATIVE HYDROCARBONS PRODUCTION ESTIMATION
     C A1: CUMULATIVE OIL PRODUCTION (CUMOIL) ESTIMATION
            WRITE (*,*) ''INPUT THE VALUES OF QI, T, T1, T2 AND T3''
            READ (5, 100) QI, T, T1, T2, T3
103  FORMAT (3X, 5F17.4)
       110  QI1 = QA, T = TA, T1 = T1A, T2 = T2A, T3 = T3A
            OPEN (UNIT = 6, FILE = 'CUMOIL.RST')
123  CUMPOIL = 0.5*QI*((T2-T1)+(T3-T))
            CUMOIL = CUMOIL1
       130  WRITE (6, 140) CUMOIL
       140  FORMAT (3X, F17.4)
       210  STOP
            END
```

or

Model – 1E: Projectile Evaluation Model Equation

```
     C      WHEN EDECLINE CONSTANT, B IS KNOWN
     C A:   CUMULATIVE HYDROCARBONS PRODUCTION ESTIMATION
     C A1: CUMULATIVE OIL PRODUCTION (CUMOIL) ESTIMATION
            WRITE (*,*) ''INPUT THE VALUES OF B, QI, T, T1, T2 AND T3''
            READ (5, 100) B, QI, T, T1, T2, T3
104  FORMAT (3X, 6F17.4)
       110  B=B1, QI1 = QA, T = TA, T1 = T1A, T2 = T2A, T3 = T3A
            OPEN (UNIT = 6, FILE = 'CUMOIL.RST')
124  CUMGAS = QI*((T2-0.5*(T1+T)+(1-EXP(-B*T3)/B))
            CUMOIL = CUMOIL1
       130  WRITE (6, 140) CUMOIL
       140  FORMAT (3X, F17.4)
       210  STOP
            END
```

Model – 1F: Projectile Evaluation Model Equation

```
    C A:   HYDROCARBONS INITIALLY IN PLACE ESTIMATION
    C A1: TOTAL OIL INITIALLY IN PLACE (TN) ESTIMATION
           WRITE (*,*) ''INPUT THE VALUES OF QI, T, T1, T2 AND TF''
           READ (5, 100) QI, T, T1, T2, TF
105 FORMAT (3X, 5F17.4)
      110  QI1 = QA, T = TA, T1 = T1A, T2 = T2A, TF = TFA
           OPEN (UNIT = 6, FILE = 'TN.RST')
125 TN = 0.5*QI*((T2-T1)+(TF-T))
           TN = TN1
      130  WRITE (6, 140) TN
      140  FORMAT (3X, F17.4)
      210  STOP
           END
```

Model – 2A: Parabolic Evaluation Model Equation

```
C A:   Hydrocarbons Production Decline Rate Constant Estimation
C A1: Hydrocarbons Production Decline Rate Constant (B) Estimation
       WRITE (*,*) ''INPUT THE VALUES OF QI, TI, Q1, T1, Q2, T2 …. QN, TN''
       READ (5, 100) QI, TI, Q1, T1, Q2, T2, Q3, T3, Q4, T4,  …. QN, TN
  100  FORMAT (3X, 10F17.4)
  110  QI=Q1A, Q1=Q1A, Q2=Q2A, Q3=33A, Q4=Q4A, TI=TIA, T1=T1A,
     1 T2=T2A, T3=T3A, T4 =T4A
       OPEN (UNIT = 6, FILE = 'B.RST')
  120  B1 =2.303*LOG(Q_1/Q_2)/(T_2 - T_1)
       B1 = BA
  121  B2 = 2.303*LOG(Q_2/Q_3)/(T_3 - T_2)
       B2 = BB
  122  B3 = 2.303*LOG(Q_3/Q_4)/(T_4 - T_3)
       B3 = BC
  123  B4 = 2.303*LOG(Q_4/Q_5)/(T_5 - T_4)
       B4 = BD
  130  WRITE (6, 140) B1, B2, B3, B4, B5
  140  FORMAT (3X, 5F7.2)
       IF (B1.EQ.B2 AND B2.EQ.B3) GOTO 150
       IF (B1.NE.B2 AND B2.NE-B3) GOTO 160
       IF (CAP.LE.1E-5) GOTO 190
  150  FORMAT (X '= First Order and n = 1', 5F7.2) GOTO 180
  160  FORMAT (X '= NOT FIRST ORDER, TRY SECOND ORDER',) GOTO 170
  170  STOP
       END
```

```
C       Model 2A1
C       COMPUTATION OF DAILY FLOW RATE, Q FOR 1ST ORDER (N=1)
180     WRITE (*.*) " INPUT THAT INITIALY FLOW RATW, Q, B, T"
        READ (5.190) Q, B, N
190     FORMAT (*.3F7.2)
        QO = Q, B1 = B AND N1 = N
C       INITIATE THE COUNTER, I
        I = 0.0
        T = 0.0
        COMPUT THE RATE, Q IN THE 1ST TO Nth year
200     QI = QO*EXP(-B*TI)
        QI = QI1 AND TI = TI1
        WRITE (*.210) QI, TI
210     FORMAT (*. "QI =  " F7.2 // "TI =" F7.2"
C       INCREAMENTAL COUNTER
        GPI = (QI/B)/*(1 – EXP – (BTI))
        I  =  I + 1
        T = T + 1
  220   WRITE (*, 230) QI, B, GPI
230     FORMAT (*, " GPI =', F12.2 // "'B = ', F12.2" // QI = ', F12.2")
C       CHECK THE VALUE OF THE COUNTER
        IF (I.LE.N) GOTO 200
        IF (I.GT.N) GOTO 240
 240    STOP
        END
```

Model – 2B: Parabolic Evaluation Model Equation

```
C A:    Hydrocarbons Production Decline Rate Constant Estimation
C A1: Hydrocarbons Production Decline Rate Constant (B) Estimation
        WRITE (*,*) "INPUT THE VALUES OF QI, TI, Q1, T1, Q2, T2 …. QN, TN"
        READ (5, 100) QI, TI, Q1, T1, Q2, T2, Q3, T3, Q4, T4,  …. QN, TN
 106    FORMAT (3X, 10F17.4)
 110    QI=Q1A, Q1=Q1A, Q2=Q2A, Q3=33A, Q4=Q4A, TI=TIA, T1=T1A,
      1 T2=T2A, T3=T3A, T4 =T4A
        OPEN (UNIT = 6, FILE = 'B.RST')
 124    B1 = (QI − Q1)/(Q1 ∗ T1)
        B1 = BA
 125    B2 = (QI − Q2)/(Q2 ∗ T2)
        B2 = BB
 126    B3 = (QI − Q3)/(Q3 ∗ T3)
        B3 = BC
 127    B4 = (QI − Q4)/(Q4 ∗ T4)
        B4 = BD
 130    WRITE (6, 140) B1, B2, B3, B4,  . . . . . , BN
 140    FORMAT (3X, 5F7.2)
       IF (B1.EQ.B2 AND B2.EQ.B3) GOTO 150
        IF (B1.NE.B2 AND B2.NE-B3) GOTO 160
```

```
 150  FORMAT (X '= SECOND Order and n = 2', 5F7.2)
 160  FORMAT (X '= NOT FIRST ORDER, TRY LESS THAN ORDERS',)
 270  STOP
      END
```

```
C     Model 2B1
C     COMPUTATION OF DAILY FLOW RATE, Q FOR 2ST ORDER (N=2)
 180  WRITE (*.*) " INPUT THAT INITIALY FLOW RATW, Q, B, T"
      READ (5.190) Q, B, N
 190  FORMAT (*.3F7.2)
      QO = Q, B1 = B AND N1 = N
C     INITIATE THE COUNTER, I
      I = 0.0
      T = 0.0
      COMPUT THE RATE, Q IN THE 1ST TO Nth year
 200  QI = QO/(1 - B*TI)
      QI = QI1 AND TI = TI1
      WRITE (*.210) QI, TI
 210  FORMAT (*. "QI =  " F7.2 // "TI =" F7.2"
C     INCREAMENTAL COUNTER
      NPI = (QO - QI)/(B))
      I  =  I + 1
      T = T + 1
 220  WRITE (*, 230) QI, B, NPI
 230  FORMAT (*, " NPI =', F12.2 // '"B = ', F12.2" // QI = ', F12.2")
C     CHECK THE VALUE OF THE COUNTER
      IF (I.LE.N) GOTO 200
      IF (I.GT.N) GOTO 240
 240  STOP
      END
```

Model – 2C: Parabolic Evaluation Model Equation

```
C A:  Hydrocarbons Production Decline Rate Constant Estimation
C A1: Hydrocarbons Production Decline Rate Constant (B) Estimation
      WRITE (*,*) "INPUT THE VALUES OF QI, TI, Q1, T1, Q2, T2 …. QN, TN"
      READ (5, 100) QI, TI, Q1, T1, Q2, T2, Q3, T3, Q4, T4,  …. QN, TN
 107  FORMAT (3X, 10F17.4)
 110  QI=Q1A, Q1=Q1A, Q2=Q2A, Q3=33A, Q4=Q4A, TI=TIA, T1=T1A,
     1 T2=T2A, T3=T3A, T4 =T4A
      OPEN (UNIT = 6, FILE = 'B.RST')
 128  B = (1/N)*((QI - Q1)/(Q1 * T1)+ (QI - Q2)/(Q2 * T2)+ (QI - Q3)/(Q3 * T3))+ . .
     1 +  (QI - QN)/(QN * TN))
      B = BA
 130  WRITE (6, 140) B
 140  FORMAT (3X, F17.4)
 150  STOP
      END
```

```
C      Model 2C1
C      COMPUTATION OF DAILY FLOW RATE, Q ½-ORDER (N < 1 OR N <2)
180    WRITE (*.*) " INPUT THAT INITIALY FLOW RATW, Q, B, T"
       READ (5.190) Q, B, N
190    FORMAT (*.3F7.2)
       QO = Q, B1 = B AND N1 = N
C      INITIATE THE COUNTER, I
       I = 0.0
       T = 0.0
       COMPUT THE RATE, Q IN THE 1ST TO Nth year
200    QI = QO/(1 - B*TI)
       QI = QI1 AND TI = TI1
       WRITE (*.210) QI, TI
210    FORMAT (*. "QI =  " F7.2 // "TI =" F7.2"
C      INCREAMENTAL COUNTER
       NPI = (QO - QI)/(B))
       I  =  I + 1
       T = T + 1
  220  WRITE (*, 230) QI, B, NPI
230    FORMAT (*, " NPI =', F12.2 // "'B = ', F12.2" // QI = ', F12.2")
C      CHECK THE VALUE OF THE COUNTER
       IF (I.LE.N) GOTO 200
       IF (I.GT.N) GOTO 240
 240   STOP
       END
```