

Predictive Modeling of Nigerian Peak Condensate using Hubbert's Zero Annual Reserve Rate

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ABSTRACT

In this work, a model was developed using Kamalu's (2010) natural resource depletion word equation in one hand and Hubbert zero rate of annual reserve concept on the other hand. Experimental data was collected from Nigerian Ministry of Petroleum and Minerals, 7 KofoAbayomi Street, Victoria Island, Lagos to validate the model. It gave coefficient of correlation of 0.99997 and 0.99517 for discovery and production of Nigerian condensate respectively. It was also established that Nigerian condensate will exhaust in the year 2518AD when the discovery and production values will be equal to 110MMB. The research reveals that there is a gentle interaction between the cumulative discovery and production and serious interaction between annual discovery and production as years roll by. This work can be used by Nigerian government to plan their condensate budget both nationally and internationally and to cushion their position in OPEC and the world.

Keyword--- Predictive modeling, Nigerian peak condensate, Zero rate reserve, Intersection.

gas produced from many natural gas fields. While many countries that are endowed with this high priced commodity whose supply is also highly restricted have exploited its tremendous advantage, Nigeria is just beginning to harness this resource (Kamalu, 2010; Nwabueze, 2000).

Condensate production has remarkable advantages. Apart from the fact that condensate is more profitable than crude oil on equal volume basis and has more percentage yield of white components than crude oil, its production on a wider scale will create more favorable chances for Nigeria in the international oil market (Nwabueze, 2000).

Since condensate is typically liquid in ambient condition and also has very low viscosity, condensate is often used to dilute highly viscous heavier oils that cannot otherwise be efficiently transported via pipelines. For instance, condensate is frequently mixed with bitumen from oil sands (Nkemakolam et al., 2014).

Nigeria has a huge condensate reserve, but since its discovery in 1985, it has not been properly harnessed. Therefore, we need to know more about Nigerian condensate production, as to reduce our over dependence on crude oil production.

The problem therefore is to create a working scenario to know the production capacity, and of course, the possible uses of condensate. Since oil and gas alone amount to almost 90% of the economy, production of condensate will be a huge boost to it.

When the discovery and production machinery has been fully understood, Nigeria may discover that she has more condensate than even gas. That means, we can supply the entire Africa with petroleum in decades to come.

I. INTRODUCTION

The importance of hydrocarbon condensate has grown significantly and continuously in the last eighty-five years. With enhanced understanding and prediction of properties and phase behavior of gas-oil systems, it has been possible to develop operating programs for the recovery of liquids from otherwise gaseous hydrocarbon streams (Nwabueze, 2000).

Condensate refers to the liquid phase produced in the condensation of steam or another gas. Natural gas condensate is a low-density mixture of hydrocarbon liquids that are present as gaseous components in the raw natural

The objective of this work is to obtain mathematical model which will interpret and predict the Nigerian petroleum condensate time history scenario or profile using Hubbert concept of zero annual reserve rate. That is, the model will be able to predict when the Nigerian condensate will peak and exhaust as well as its ultimate recovery. By ultimate recovery we mean, the maximum amount of condensate producible or that the rock is ready to let go. The peak production is termed “geologically-imposed” because the rock decides how much condensate that it is going to let go, and not the entire condensate in the ground.

Nigeria cannot afford to disregard a high revenue yielding resource like the petroleum condensate just because she thinks she has enough from oil and gas.

This work covers establishing a predictive model that will govern the peak production, the ultimate recovery and exhaustion time using Hubbert’s concept, of zero annual rate reserve: It will only be covering Nigerian conventional condensate, that is condensate that rushes up by itself without the use of the enhanced oil recovery technique, during production.

II. LITERATURE

2.1 ABOUT CONDENSATE

Natural gas condensate is a low density mixture of hydrocarbon liquids that are present as gaseous components in the raw natural gas produced from many natural gas fields. It condenses out of the raw gas if the temperature is reduced to below the hydrocarbon dew point of the raw gas.

The natural gas condensate is also referred to as simply condensate, or gas condensate, or sometimes natural gasoline because it contains hydrocarbons within the gasoline boiling range. Raw natural gas may come from

any one of the following three types of gas wells (Agala and Erlekin, 2005; Bradely, 1992).

- Crude oil wells: Raw natural gas that comes from crude oil wells is called *associated gas*. This gas can exist separate from the crude oil in the underground formation, or dissolved in the crude oil.
- Dry gas wells: These wells typically produce only raw natural gas that does not contain any hydrocarbon liquids. Such gas is called *non-associated gas*.
- Condensate wells: These wells produce raw natural gas along with natural gas liquid. Such gas is also *non-associated gas* and often referred to as wet gas.

2.2 COMPOSITION

There are many wet gas fields worldwide and each has its own unique gas condensate composition. However, in general, gas condensate has a specific gravity ranging from 0.5 to 0.8, and is composed of hydrocarbons such as propane, butane, pentane, hexane, etc. condensates may contain additional impurities such as;

- Hydrogen sulphides (H₂S)
- Thiols, traditionally also called mercaptans (denoted as RSH, where R is an organic group such as methyl, ethyl, etc)
- Carbon dioxide (CO₂)
- Straight-chain alkanes having from 2 to 12 carbon atoms (denoted as C₂ to C₁₂)
- Cyclohexane and perhaps other naphthenes
- Aromatics (benzene, toluene, xylene, and ethyl benzene)

(Furcht et al., 2010)

2.3 SEPARATION OF THE CONDENSATE FROM THE RAW NATURAL GAS

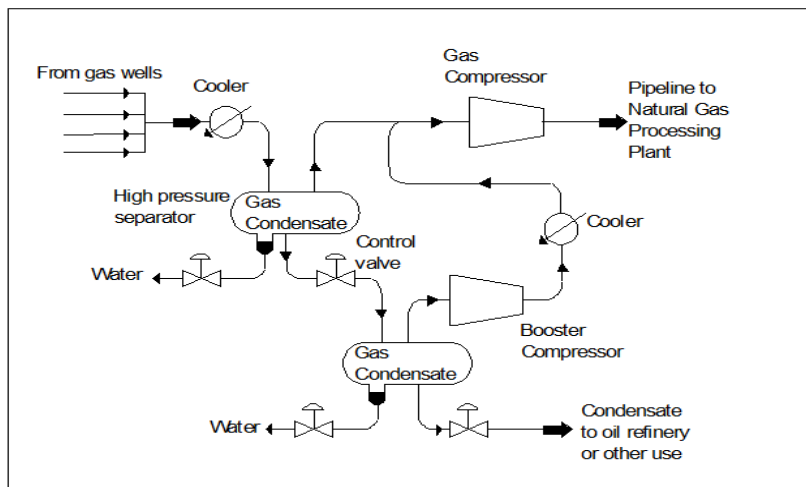


Fig 1.0: Schematic flow diagram of the separation of condensate from raw natural gas (Jann-Rune, 2004)

There are literally hundreds of different equipment configurations for the processing required to separate natural gas condensate from a raw natural gas. The schematic flow diagram above depicts just one of the possible configurations (Jann-Rune, 2004; Jessen and Orr, 2004).

The raw natural feedstock from a gas well or a group of wells is cooled to lower the gas temperature to below its hydrocarbon dew point at the feedstock pressure and that condenses a good part of the gas condensate hydrocarbons. The feedstock mixture of gas, liquid condensate and water is then routed to a high pressure separator vessel where the water and the raw natural gas are separated and removed. The raw natural gas from the high pressure separator is sent to the main gas compressor (see Fig 1).

The gas condensate from the high pressure separator flows through a throttling control valve to a low pressure separator. The reduction in pressure across the control valve causes the condensate to undergo a partial vaporization referred to as a flash vaporization. The raw natural gas from the low pressure separator is sent to a "booster" compressor which raises the gas pressure and sends it through a cooler and on to the main gas compressor. The main gas compressor raises the pressure of the gases from a high and low pressure separators to whatever pressure is required for the pipeline transportation of the gas to the raw natural gas processing plant. The main gas compressor discharge pressure will depend upon the distance to the raw natural gas processing plant and it may require that a multi-stage compressor be used (Jann-Rune, 2004).

At the raw natural gas processing plant, the gas will be dehydrated and acid gases and other impurities that will be removed from the gas.

Then, the ethane (C₂), propane (C₃), butane (C₄) and pentane-plus higher molecular weight hydrocarbons referred to as C₅₊ will also be removed and recovered as byproducts.

The water removed from both the high and low pressure separators may need to be processed to remove hydrogen sulfide (H₂S) before the water can be disposed of underground or reused in some fashion.

Some of the raw natural gas may be re-injected into the producing formation to help maintain the reservoir pressure, or for storage pending later installation of a pipeline (Jann-Rune, 2004).

2.4 CONDENSATE PRODUCTION IN NIGERIA

According to Nwabueze (2000), condensate production will uplift the economy as its production is out of OPEC regulation. Also, condensate is more profitable than crude oil on equal volume basis as its price is comparable to the price of naphtha. Normally, the greatest harvest of condensate is from gas-condensate reservoirs operated with cycling plants.

The importance of hydrocarbon condensate has grown significantly and continuously in the last seventy-five years. With enhanced understanding of prediction of properties and phase behavior of gas-oil systems it has been possible to develop operating programs for the recovery of liquids from otherwise gaseous hydrocarbon streams.

While many countries that are endowed with this highly priced commodity, whose supply is also highly restricted, have exploited its tremendous advantage, Nigeria is just beginning to harness this resource. It is natural to expect that after forty years, Nigerian should and must have acquired sufficient technical and commercial management skills of the entire spectrum of oil and gas and on associated activities if not full technological competence.

Apart from the fact that condensate is more profitable than crude oil on equal volume basis and has more percentage yield of white components than crude oil, its production on a wider scale will sell Nigeria better in the international petroleum market.

Gas condensate reservoirs in Niger Delta and around the world are becoming increasingly important as an additional liquid recovery and demand for light oil and natural gas. During reservoir depletion, liquid condensate out of the gas as pressure drops below dew point. Most of the condensed liquid is lost to the reservoir. Recovery of lost condensate from gas condensate reservoirs require careful reservoir analysis and technology.

In this study, technical and economic know-how are combined to select the best production strategy that optimizes recovery of condensate which could have been lost in the reservoir. In the technical design aspect, fluid characterization and compositional simulation are integrated to develop a model which predicts total field production of condensate. Net-present-value (NPV) is used in economic evaluation to optimize the profit from different production strategies used (Nkemakolam, et al., 2014).

"Condensates" tend toward the lighter end of the spectrum, "crude" to the heavier. Since most hydrocarbon liquids are pretty close to (CH₂)_n formula, the "energy" (heating value) content per pound is fairly constant (to a decent first approximation, about 17,000BTU/lb.

"Condensate" tend to be lighter in color, too, all the way to water-clear and often to straw-yellow or light green, though some are deep black. "Oils" run a broad range of colours from deep black to light straw, with varying tints of green, brown, red, and even blue (Jame, 2008).

2.5 CLASSIFICATION OF CONDENSATE

For brevity, hydrocarbon condensate could be classified as heavy, medium and light, depending on the type of reservoir from where it is produced, how it is recovered and its density (see Table1 below).

Table 1.0: Classes of hydrocarbon condensate (McCain, 1990).

Class	Source	Density range	Appearance	RVP
Heavy	Retrograde Gas well	40-60 ⁰ API	Brown, Orange, Green, Water-white	<13
Medium	Wet Gas wells	35-75 ⁰ API	Water-white	<14
Light	Dry Gas wells/ Separator Gas	>75 ⁰ API	Water-white	>14

Retrograde Gas

Initially the retrograde gas is totally or preponderantly gas in the reservoir. As reservoir pressure decreases to the dew point line and beyond, liquid condenses out from the gas to form free liquid in the reservoir or at surface facilities. When the condensate are allowed to form in the reservoir, such liquid will normally not flow and cannot be produced.

The lower limit for the initial producing Gas Oil Ratio (GOR) for a retrograde gas could be taken as 3500scf/bbl. Although the upper limit is not well defined, it is important to say that for practical purposes when the producing GOR is greater than 40,000scf/bbl, the reservoir fluid can be classified as wet gas since the quality of retrograde liquid in the reservoir is very small.

Typical stock-tank liquid gravity of retrograde condensate or heavy condensate is between 45 and 60⁰API, however condensate of about 40⁰API exist. The liquid can be lightly colored, brown, orange, greenish or water-white.

Usually the surface gas that is separated from this category of condensate at surface facilities is very rich in intermediates and often is processed to remove liquid propane, butanes and pentanes plus (gas plant condensate), (Fevang and Whitson, 1995).

Wet Gas

A wet gas exists solely as gas in the reservoir throughout pressure reduction. Thus, no liquid is formed in the reservoir. However, conditions of surface facilities are such that some liquids are caused to form.

For practical purposes, a stream of petroleum gas, which produces more than 40,000scf/bbl can be treated as, wet gas. Producing GOR and stock tank liquid gravity remain constant during the life of a wet gas reservoir (Bradley, 1992).

The stock tank liquid of a wet gas reservoir has eicosanes plus (C₂₀₊) concentration that is typically less than 0.5% on mole basis. Consequently, liquids of this extraction are appropriately termed medium condensate or wet gas condensate. It is usually water-white with gravity range of 55 to 75⁰API (Fan et al., 2006).

Dry Gas /Separator Gas

Dry gas is predominantly methane with some intermediates and does not form hydrocarbon liquid at surface except free water that is usually knocked out. In reality, dry gas is akin to separator gas from oil/retrograde/wet gas wells regardless of the level of intermediates contained in the gas. Extraction of liquid

from this kind of gas is achieved by physical processes which include phase separation, cooling, compression, absorption, adsorption, refrigeration and in any combination of these. Liquids so extracted are termed plant liquids which comprise ethane, propane, butanes and pentanes plus.

The pentane plus obtained in this fashion is called gas plant condensate. Usually the concentration of decanes plus (C₁₀₊) is in trace quantities at best otherwise it is zero. It is water-white and has typical densities that are greater than 75⁰API. (Nwabueze, 2000).

2.6 RECOVERY OF CONDENSATE IN GAS CONDENSATE RESERVOIR

Condensate blocking results to heterogeneities within the wellbore region and farther in the reservoir as the radius of condensate ring expands which leads to impairment to well productivity and loss of valuable condensed liquid as the condensate content in the formation increases. Exploiting a gas condensate reservoir without pressure maintenance leads to high gas recovery with relatively low condensate recoveries (Jessen and Orr, 2004).

This then poses major concern in these reservoirs as improvement in gas productivity and recovery of condensate lost in the reservoir is sort. Studies have shown that producing a gas condensate reservoir by pressure depletion results to a high recovery for the gas but low recovery for the condensate. (El-Banbi and McCain, 2000). This means the richer the condensate the more liquid drop out of the gas in the reservoir.

Consequently, large fractions of the original condensate reserves are lost in the reservoir. The only viable and most practical technique of stimulating this kind of reservoir to enhance the recovery of gas and condensate is by gas cycling. This can be of two kinds; reinjection of miscible hydrocarbon gas (dry gas or produced gas) and injection of immiscible non-hydrocarbon gases. Based on the problems militating against the production of this immense resource, the oil and gas industry is in search of new approaches to enhance condensate recovery through maintaining reservoir pressure to prevent condensate loss or re-vaporization to extract heavier hydrocarbon components condensing out in the formation. Previous works have shown that after a pressure decline below saturation pressure liquid bank is formed and sufficient quantity of the original condensate in place is lost in the formation with a reduction in gas productivity (El-Banbi and McCain, 2000; Amini et al., 2011).

Evaluation of condensate lost in gas condensate reservoirs helps us to understand the concept of gas condensate production and quantify the lost resource and its revenue.

This highlights the relevance of maximum recovery of condensate without condensation in the reservoir. It could be achieved either through partial or full pressure maintenance. Re-evaporation of condensed liquid reduces the flow constraint imposed on gas condensate system below saturation pressure (Furcht et al., 2010; Hottelling, 1931).

Development of gas condensate fields demands understanding of phase and flow behavior exhibited by this kind of reservoir. Most gas condensate reservoirs are discovered at pressure above dew point when the flow in the reservoir is single phase. Concern arises when the pressure drops below the dew point near the wellbore. From this two phase flow starts at the vicinity of the wellbore. The situation results to deposition of condensed liquid around the wellbore leading to blockage of pores previously occupied by gas phase (Fevang and Whitson, 1995).

The deposited liquid hydrocarbon grows in radius until the saturation of the condensed liquid is high enough for the liquid to become mobile. That is when saturation exceeds critical condensate saturation. The condensed liquid that blocks the pore space limits the flow of gas (Fan et al., 2006).

According to El-Banbi and McCain (2000) as the condensate bank radius extends to the reservoir boundary, condensate saturation reduces as a result of a re-vaporization of the condensate, and, an improvement in gas productivity is observed. Therefore, injection of more gas into the reservoir will help vaporize the condensed liquid and improve production revenue. The value of loss in production is determined by the reduction in the relative permeability to gas at the vicinity of the well compared to that at the inner region close to reservoir boundary.

The contributing parameters in developing the optimum strategy for the recovery of condensate are the phase behavior, relative permeability and production scheme. The same factors are responsible for the impairment of well deliverability near the wellbore. Adequate modeling of flow behavior will address this deliverability problem. Well producing scheme may impose significant influence on the phase behavior. That is, pressure depletion creates two phase flow which impacts on reservoir performance while gas cycling prevents condensation and re-evaporates the condensed liquid thereby eliminating the problems associated with phase changes.

The flow behavior in gas condensate reservoirs are complicated by the dependency of relative permeability on velocity and interfacial tension close to wellbore (Henderson et al., 1996).

In a multi-phase flow relative permeability depends on interfacial tension between the phases but this can be resolved to improve permeability by creating a miscible condition (Jesson et al., 2004).

Produced gas re-injection can be used to create miscible system in the reservoir. So, cycling of produced gas can be used to re-evaporate the condensed liquid thereby reducing the influence of interfacial tension during flow. Different techniques have been used to study improvement of gas and condensate reservoir productivity (Hearn and Whitson, 1995; Robin-Simone et al., 2008). Amongst which are injection of organic and inorganic gases, injection of solvents for wettability alteration, water injection and use of heat stimulation.

Different techniques have been used to study improvement of gas and condensate reservoir productivity. The convenience of the gas injection operation for a specific gas condensate reservoir is strongly tied to the flow characteristics of the reservoir and phase behavior of the fluid (Ayala and Ertekin, 2005).

III. MODEL THEORY AND DEVELOPEMENT

If we represent the cumulative production by the symbol Q_P , the cumulative proved discoveries by Q_D (producible discovery: not all discovery are producible), and the proved reserves by Q_R , then for each year,

$$Q_D = Q_P + Q_R \text{ or } Q_R = Q_D - Q_P \quad (1)$$

The relation between rates of change of these quantities with time is obtained by taking the derivative with respect to time of equation (1), giving

$$\frac{dQ_D}{dt} = \frac{dQ_P}{dt} + \frac{dQ_R}{dt} \text{ or } \frac{dQ_R}{dt} = \frac{dQ_D}{dt} - \frac{dQ_P}{dt} \quad (2)$$

in which, $\frac{dQ_D}{dt}$ is the rate of discovery,

$\frac{dQ_P}{dt}$ is the rate of production, and

$\frac{dQ_R}{dt}$ is the rate of increase of the proved reserves (Hubbert, 1956).

The manner in which the three quantities Q_D , Q_P , and Q_R must vary with time during the entire history of petroleum condensate production from start to finish must be approximately as follows:

The cumulative production Q_P , when plotted as a function of time, will increase slowly during the early stages of petroleum condensate production, increase more and more rapidly with time to about the halfway point, and then continue its ascent by rising slowly, and finally leveling off as the ultimate figure Q_∞ , as production ceases (Hubbert, 1956)

The curve of proved reserves Q_R will start at zero, rise gradually until a maximum is reached at about the halfway point and then gradually decline to zero.

As condensate must be found before it can be produced, the curve of cumulative proved discoveries

Q_D must closely resemble that of cumulative production, except that it must plot ahead of the production curve by some time interval Δt , which on itself may vary during the cycle (Hubbert, 1956)

A plot of the family of the three curves Q_D , Q_P and Q_R is shown in Fig 2.0 as they may be expected to appear in the case of cumulative production, of petroleum condensate in Nigeria.

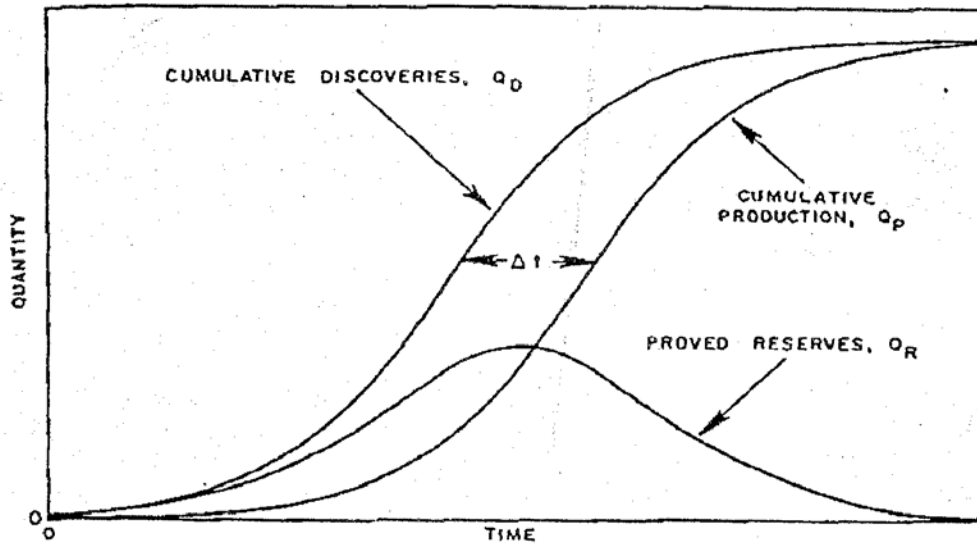


Fig 2.0: Cumulative discoveries and production, and proved reserves

Because of the close similarity between the curve of cumulative proved discoveries and that of cumulative production, it follows that the study of the discovery curve must give one a preview of what production will do at a time of approximately Δt in the future (Hubbert, 1956).

Taking the time derivatives of the three curves shown in Fig 2.0 gives us the rate of discovery, rate of production, and rate of increase of proved reserves, which are plotted as a function of time in Fig 3.0. It will be noted that the rate of discovery will reach a peak at about mid-range, and thereafter, gradually decline to zero.

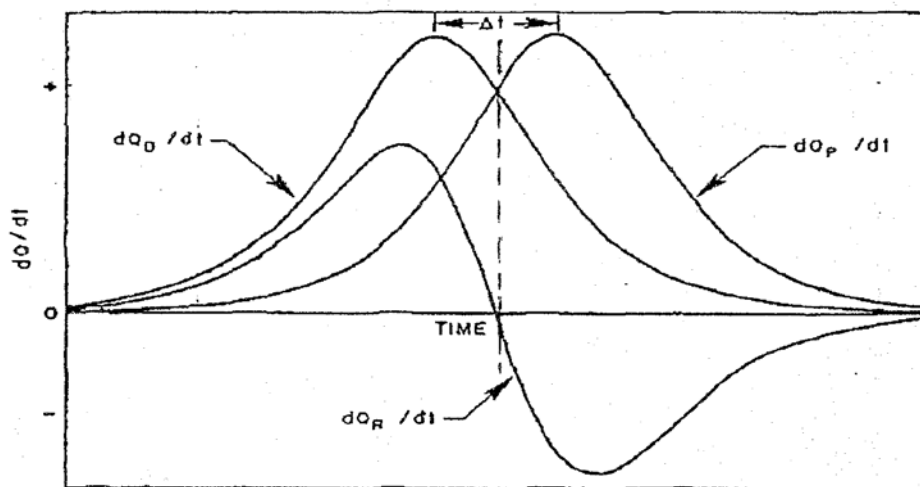


Fig 3.0: Rates of discovery, production and change of proved reserves

The rate of production will reach a peak at a time about Δt after that of discovery, and the increase of proved reserves will change from positive to negative about halfway between the discovery and production peaks. The

reserves themselves, Q_R , will reach a maximum at the same time.

The relations between the three curves at this midpoint can be seen by noting that when reserves reach

their maximum value, their derivative with time becomes zero.

$$\frac{dQ_R}{dt} = 0 \tag{3}$$

Which when inserted into equation (2) gives

$$\frac{dQ_D}{dt} = \frac{dQ_P}{dt} \tag{4}$$

This tells us that when reserves reach their maximum value, the curve of discovery rate and production rate will

cross, production going up and discovery going down. This is shown in Figure 2.0.

3.1 MODEL DEVELOPMENT (CURRED FROM KAMALU'S UNPUBLISHED PHD THESIS)

According to Kamalu(2010), all deplitable (exhaustible) natural resources obey the general world equation.

$$\left(\begin{array}{c} \text{Change in actual} \\ \text{natural resource} \\ \text{reserve during a} \\ \text{period of time} \end{array} \right) = \left(\begin{array}{c} \text{Actual} \\ \text{natural} \\ \text{reserve} \\ \text{(in-situ)} \end{array} \right) - \left(\begin{array}{c} \text{Production of} \\ \text{natural} \\ \text{reserve} \end{array} \right) + \left(\begin{array}{c} \text{Immigrant} \\ \text{natural} \\ \text{reserve} \end{array} \right) - \left(\begin{array}{c} \text{Emigrant} \\ \text{natural} \\ \text{reserve} \end{array} \right) \tag{5}$$

This can be written for condensate as:

$$\left(\begin{array}{c} \text{Change in actual} \\ \text{condensate reserve} \\ \text{during a period of} \\ \text{time} \end{array} \right) = \left(\begin{array}{c} \text{Actual} \\ \text{condensate} \\ \text{reserve} \\ \text{(in-situ)} \end{array} \right) - \left(\begin{array}{c} \text{Condensate} \\ \text{production (or} \\ \text{discovery)} \end{array} \right) + \left(\begin{array}{c} \text{Immigrant} \\ \text{Condensate} \\ \text{reserve} \end{array} \right) - \left(\begin{array}{c} \text{Emigrant} \\ \text{condensate} \\ \text{reserve} \end{array} \right) \tag{6}$$

Assumptions in the development of this model

1. The in-situ condensate in the rock is a constant(E) (7)
2. Let the production (discovery) of condensate be a turbulent exponential term,

$$\frac{Eb}{b-a} e^{-t/b} \tag{8}$$
3. Let the immigrant condensate reserve be a turbulent exponential term,

$$\frac{Ea}{b-a} e^{-t/b} \tag{9}$$
4. Let the emigrant condensate flow be laminar flow of a negligible creeping significance or zero.
5. If the change in condensate flow during a particular time is represented by (y) (10)
6. a and b are time constants while E is a volume constant.

Then combining items 1 to 5 into equation 6 after simplification, yields

$$y = Q = E \left(1 + \left(\frac{1}{b-a} a \exp\left(\frac{-t}{a}\right) - b \exp\left(\frac{-t}{b}\right) \right) \right) \tag{11}$$

Model (11) is a cumulative (sigmoidal) production or discovery profile with t as time independent variable in years and y (or Q) is dependent variable as condensate volume in (mmB). When model (11)is differentiated with respect to time, we obtain,

$$\frac{dy}{dt} = \frac{dQ}{dt} = \frac{E}{b-a} \left[\exp\left(\frac{-t}{a}\right) - \exp\left(\frac{-t}{b}\right) \right] \tag{12}$$

This model (12) which is an annual production /discovery model has a dumb-bell profile. To obtain a peak production, model (12) is further differentiated with respect to time, i.e. at $\frac{d^2y}{dt^2} = 0$, to yield

$$t_{peak} = \frac{ab}{b-a} \ln\left(\frac{b}{a}\right) \tag{13}$$

Recall that $y = Q_P = Q_D$, though the numerical values for the characteristic constants of the model for production and discovery are not necessarily going to be the same, so that their coefficient of correlation (R2) are not the same.

But from (4), $\frac{dQ_P}{dt} = \frac{dQ_D}{dt}$, since model (11) is used as both production and discovery model.

3.2COLLECTION OF DATA

The data for this work were collected from Nigerian Ministry of Petroleum and Minerals, 7 KofuAbayomi Street, Victoria Island Lagos. This data is the aggregate of all the discovery and production data of different oil companies operating in Nigeria. (seeTable 2.0)

Table 2.0: Nigerian Annual Condensate Reserve and Production

Year	Condensate Reserves (MMB)	Condensate Production (MMB)
2006	0	0

2007	5,183.10	46.98
2008	5,202.05	43.48
2009	5,351.67	81.00
2010	5,313.97	100.27
2011	5,077.81	120.71

Table 3.0:Nigerian Cumulative Condensate Reserve and Production

	Year	Condensate Reserves (MMB)	Condensate Production (MMB)
0	2006	0	0
1	2007	5,18.3	46.98
2	2008	10,385	90.46
3	2009	15,736.67	171.46
4	2010	21,050.64	271.73
5	2011	26,128.45	392.44

3.3 CURVE FITTING

The scatter diagrams of the cumulative data obtained (Table 3.0) from Nigerian Ministry of Petroleum and Minerals were plotted. The models so obtained were superimposed on the scatter diagrams to check for their goodness of fit, and predictions were made therefrom.

IV. PRESENTATION OF RESULTS

The results of the computations in the previous section are as shown in Figs 4 to 8 and Table 4.0.

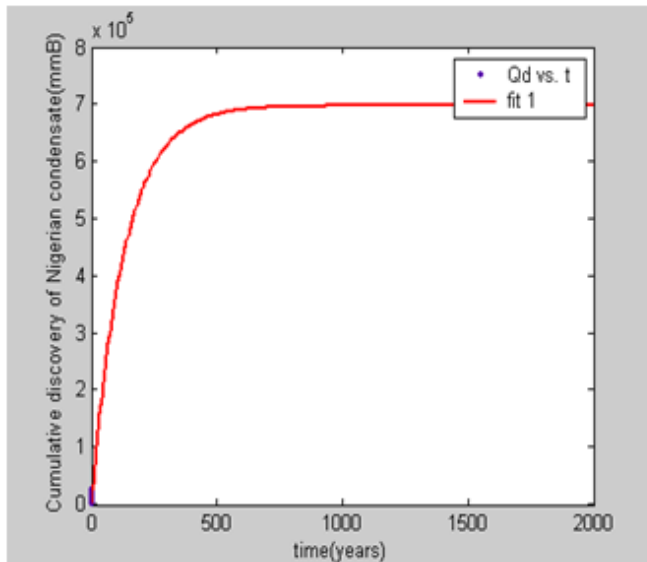


Fig4: Cumulative discovery of Nigerian condensate (R²=0.99997,model)*

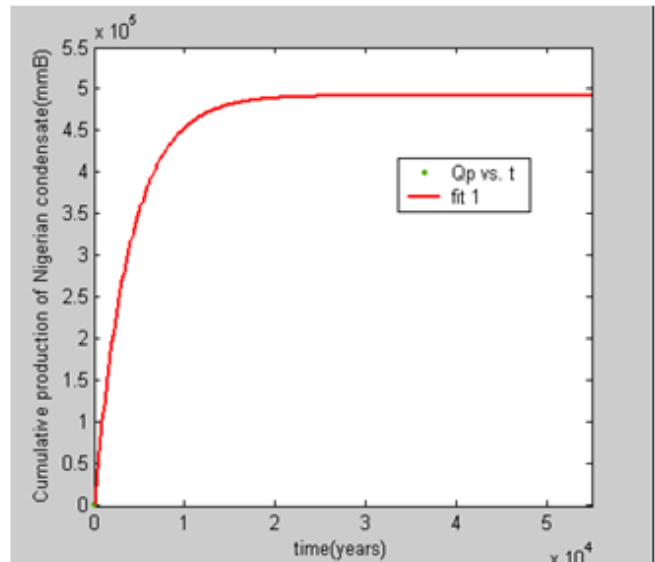


Fig 5: Cumulative production of Nigerian condensate (R²=0.99517,model)*

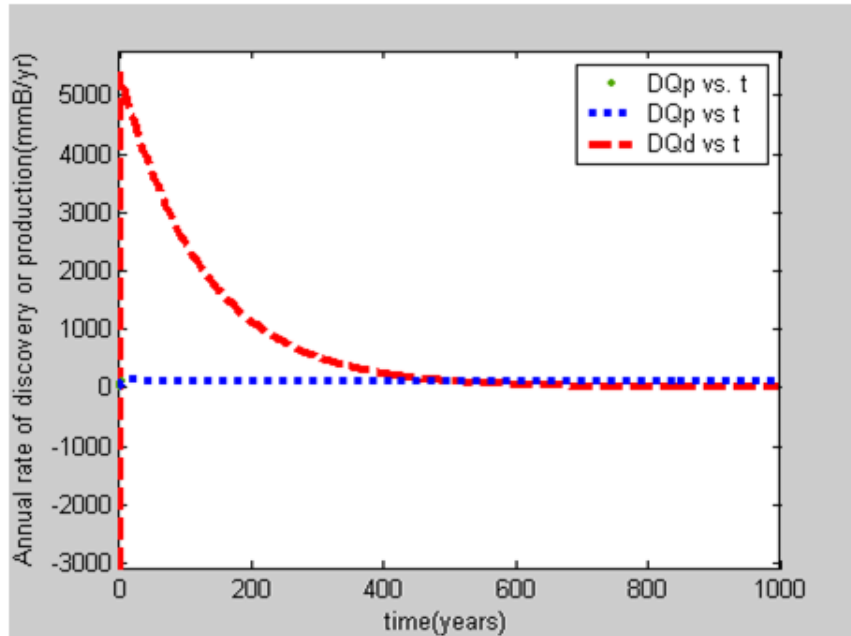


Fig 6: Annual rate of discovery or production of Nigerian condensate_model*

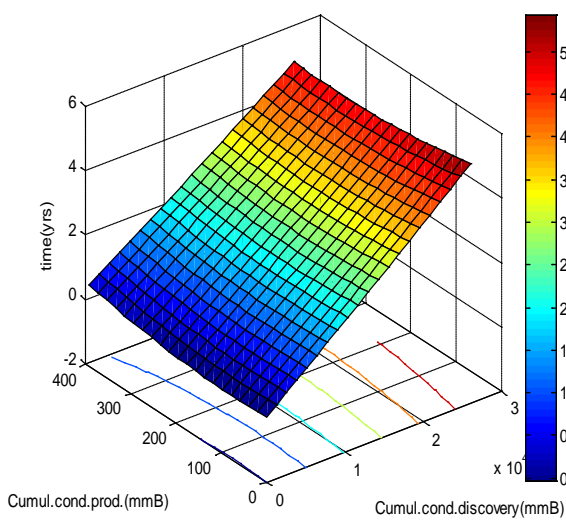


Fig 7: 3-D plot of Nigerian condensate cumulative discovery and production against time

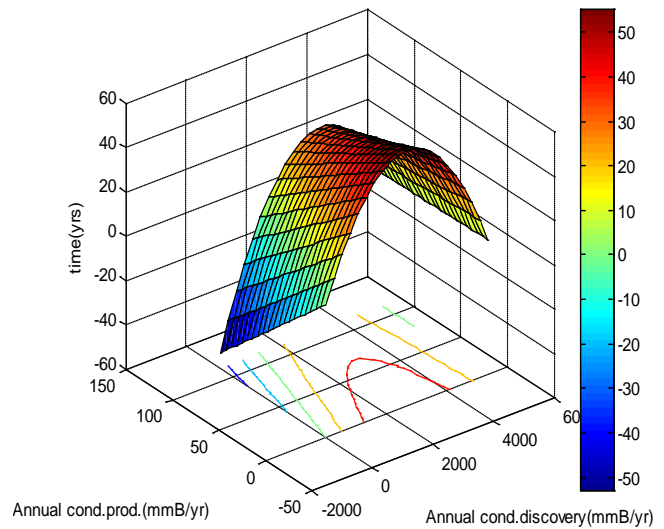


Fig 8: 3-D plot of Nigerian annual condensate discovery and production against time

Table 4.0: Coefficients (at 95% confidence bound) and statistical goodness of fit of the model.

	Discovery model data	Production model data
R ²	0.99997	0.99517
E	6.973 x 10 ⁻⁵	4.92 x 10 ⁻⁵
A	129.7	2.097
B	0.03959	3925
	U _d :f (1556.9)=697,254MMB	U _p :f (48,652.7)=492,035MMB

Intersection:f (512.742)=109.928 MMB

IV. RESULTS DISCUSSION

In Figs 4 and 5, the cumulative discovery and production of Nigerian condensate are plotted with very high coefficient of correlations (R^2) of 0.99997 and 0.99517 respectively.

According to Hubbert concept, the rate of change in natural reserve will be equal to zero i.e equation (3), when the rate of change of discovery is equal to rate of change of production i.e equation (4). This occurred at the intersection of the plots of the rate of change of discovery and that of production as shown in Fig 6 to reveal that it will happen in 512 years from 2006, i.e. 2518AD when the production and discovery values are equal to approximately 110MMB.

In Fig 7, the cumulative condensate production and discovery interact as shown by the cursor contour on the floor of the 3-D plot. The lines on the floor are gentle curves and are not parallel to either of the axis on the floor. Also, Fig 8 shows a serious interaction between annual condensate production and annual condensate discovery as depicted by the serious curves on the floor of the 3-D plot.

V. CONCLUSION

In this work, a model was developed using Kamalu's (2010) natural resource depletion word equation in one hand and Hubbert zero rate of annual reserve concept on the other hand. Data was collected from Nigerian Ministry of Petroleum and Minerals, 7 Kofo Abayomi Street, Victoria Island Lagos, to validate the model. It gave coefficient of correlation of 0.99997 and 0.99517 for discovery and production of Nigerian condensate respectively. It was also established that Nigerian condensate will exhaust in the year 2518AD when the discovery and production values will be equal to 110MMB. This research reveals that there is a gentle interaction between the cumulative discovery and production and serious interaction between annual discovery and production as years roll by.

This work can be used by Nigerian government to plan their condensate budget both nationally and internationally and to cushion their position in OPEC and the world.

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APPENDIX

Algorithm for making 3-D surface response plot

1. Write out the values of x_1 , x_2 and y

$$\begin{cases} x_1 = [&]^t; \\ x_2 = [&]^t; \\ y = [&]^t; \end{cases}$$

2. Go to statistical; regstats ($y[x_1, x_2]$, 'quadratic').

This regstats command truncates the cubic model in the MATLAB toolbox at the term containing a_5 i.e.

$$y = a_0 + a_1x_1 + a_2x_2 + a_3x_1x_2 + a_4x_1^2 + a_5x_2^2 + a_6x_1^2x_2 + a_7x_1x_2^2 + a_8x_1^3 + a_9x_2^3$$

3. As beta values are entered the toolbox declares ' a_i ' values

$$a_0 = ; a_1 = ; a_2 = ; a_3 = ; a_4 = ; a_5 =$$

4. Write mesh command

$$[x_1, x_2] = \text{meshgrid}(x_{1(\min)} : \bar{x}_1 : x_{1(\max)}; x_{2(\min)} : \bar{x}_2 : x_{2(\max)});$$

5. Write out the truncated quadratic with the declared a_i s

$$y = \hat{a}_0 + \hat{a}_1 * x_1 + \hat{a}_2 * x_2 + \hat{a}_3 * x_1 * x_2 + \hat{a}_4 * x_1.^2 + a_5 * x_2.^2;$$

6. Write out surface plot and enter; **surf** (x_1, x_2, y)

7. Enter: Matlab toolbox makes a 3-D plot