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Modeling the Chance of Commerciality of Petroleum Assets for Economic Development

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Authors' contributions

This work was carried out in collaboration among all authors. All authors read and approved the final manuscript.

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ABSTRACT

The chance to discover hydrocarbon volumes of economic quantity diminishes with progressive discovery in explored basins. Given the preponderance of smaller deposits in extensively explored basins and the cost implications of discovering deposits less than the required Minimum Economic Reserves (MER), explorationists and investors in exploration activities need a framework to evaluate the chance of a successful petroleum resources discovery to minimize the risk of unsuccessful exploration. This study develops a new framework to evaluate the chance of discovery of at least a minimum economic reserves volume in an extensively explored basin. It leverages on the postulation for the determination of probability of hydrocarbon economic success as a building block for the new framework. The model combines the concepts of Minimum Economic Reserves, Discovery Efficiency and Probability to derive an explicit analytical function for discovery efficiency and hydrocarbon probability for a commercial discovery. It digitalizes existing Risk Table to ease the complexity to obtain geological chance of success and hydrocarbon asset

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evaluation for commerciality. Nine Case studies from the prolific Niger Delta basin of Nigeria are used to validate the model. The result of the semi-digital solution of the model shows that three of the studied cases are commercial whereas the remaining six cases are sub-commercial. The study recommends the application of the new framework for hydrocarbon asset evaluation for chance of commerciality to complement models like the cream off curve to predict chance of commercial discovery of hydrocarbon assets.

Keywords: Commerciality; evaluation; exploration; hydrocarbon; petroleum; probability reserves; sub-commercial.

ABBREVIATIONS

MER : Minimum Economic Reserves
MEFS : Minimum Economic Field Size
GCoS : Geological Chance of Success
PRMS :Petroleum Resources Management System

1. INTRODUCTION

The decision to invest in an exploration play or basin is one that often poses a major challenge to petroleum industry investors, geoscientists and explorationists. Also, the optimal entry and if unsuccessful, exit time from exploring the play of a petroleum basin is equally an important decision that explorationists must not ignore [1]. opined that these decisions are of equal significance with the decision to drill a given prospect in a play or basin of interest.

Over the years, as the science of exploration improves, explorationists have identified and applied a variety of methods to evaluate oil and gas plays. One of these methods that have gained much global significance is the “Creaming Curve” methodology, introduced by [2]. Creaming Curve is basically a graph which entails the plot of cumulative discovered hydrocarbon volumes against time (in years) or number of wells drilled. This type of plot is used to predict future exploration success in a petroleum domain using the forecasted trend of possible discoveries. If discoveries are on a general rising trend, it indicates an immature play. If on the other hand, it is a constant trend of cumulative volumes, it depicts a mature play. The most significant underlying implication of the exploration cream curve analysis is the supposition that the largest hydrocarbon deposits in a play are discovered first while exploration activities tend to discover progressively smaller volumes later. Thus, the creaming curve theory proffers a key to economic success to explorationists, which is to enter the play when it is at the “cream” and exit the play when the largest and most economically productive fields have been discovered and confirmed by drilling. Laherre [3] explained that exploration creaming off theory shows that discovery of commercial volumes of petroleum assets becomes difficult as exploration activities progress. It becomes imperative for an investor to predict the economic volume of a discovered asset and its proper classification before making reasonable investment decision.

Successful discovery of hydrocarbon is usually followed by a systematic effort to establish the economic value of the asset to all stakeholders. The exercise is therefore, carried out with utmost sense of importance and reality as overestimation or underestimation of the hydrocarbon reserves values may have severe economic consequences on the stakeholders. Realistic economic estimation thus, requires a combination of field development cost, hydrocarbon price projections and the prevailing fiscal regime of the state with static and dynamic reservoir parameters to generate techno-economic indicators to appraise the discovered hydrocarbon assets’ economic potential. This enhances informed business investment decision. Bradly & Wood [4] stated that the ultimate recoverable hydrocarbon volumes are estimated for several reasons which include: internal company planning, third - party asset valuation, financial reporting and government strategic planning.

Efforts to standardize the methodology for the estimation of hydrocarbon resources, definitions and classification of petroleum resources began in the 1930s [5]. Initial effort was concentrated mainly on proved reserves. These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. Hydrocarbon assets classification into different categories based on economic value is imperative to achieving the economic objective of the petroleum industry investment. An oil producing state should be able to know the fraction of the national hydrocarbon resources that can generate revenue in the immediate term, under prevailing economic environment and technology. This volume of hydrocarbon asset is distinguished from the volume of the resources that can be upgraded to add economic value when economic environment becomes more favourable or with improvement in technology or both. It should also be aware of the potentials it has to replace the depleted discovered resources in the long run with prospective resources. This distinction between commercial and sub-commercially known accumulations (and hence between reserves, contingent and prospective resources) is of immense importance for effective resources management.

The main classes of hydrocarbon resources are defined by SPE-PRMS [5] as follows:

a) Reserves are that part of resources, which have been justified for development and are commercially recoverable. Reserves are comparably more certain for development than the contingent and prospective resources with some significant commercial or technical hurdles that must be overcome to build confidence in the eventual production of the volumes.
b) Contingent resources are those that are potentially recoverable but not yet considered mature enough for commercial development due to technological or business hurdles. For contingent resources to move into the reserves category, the key conditions, or contingencies, that prevented commercial development must be clarified and removed. For instance, all required internal and external approvals should be in place or determined to be forthcoming, including environmental and governmental approvals.
c) Prospective resources are estimated volumes of undiscovered hydrocarbon accumulations. Prospective resources are volumes of petroleum estimated, as of a given date and considered to be potentially recoverable from petroleum accumulations assessed based on indirect evidence but yet be to be drilled. This class of resources are of a higher risk than contingent resources because they have the risk of discovery. There must be hydrocarbon discovery for prospective resources to become classified as contingent resources.

Reserves are further sub-classified into proven, probable and possible categories to reflect the various levels of their chance of development. Proven reserves are limited to those quantities that are discovered and adjudged commercially producible under current economic conditions with high degree of certainty, while probable and possible reserves are commercial under current economic conditions but have different degrees of uncertainties to access and produce them in the prevailing economic and technological conditions. Contingent resources are discovered quantities of hydrocarbon which are not commercially producible under the prevailing economic conditions and available technology. It is equally subdivided into three sub-categories based on the degrees of uncertainty.

Prospective resources have both a chance of discovery and a chance of commerciality, which together comprise the chance of commercial production. The chance of discovery becomes one at discovery of the asset. Thus, contingent resources as well as reserves have only chance of commerciality and development, which represent the chance of the accumulation reaching commercial production status. Reserves should have a very high chance of development which reaches 100% once commercial production is attained.

Doug et al [6] stated that the chance of commerciality is a concept that is fundamental to reserves and resources estimation. SPE/WPC has established a general guideline that could ensure global consistency in defining the various categories of hydrocarbon resources. Various methods have been used to evaluate the chance of commerciality and development of a hydrocarbon prospect, but there is no generally accepted methodology in use presently. Doug et al., [6] therefore, opine that a consistent framework for estimating chance of commerciality and development would be a useful tool. This is because of the subjective nature of many such models in use today in commercial dealings and regulatory disclosures.

The work of Doug et al., [6] primarily focused on the chance of commercial discovery of contingent resources with some consideration on prospective resources given that the reporting of CoC alongside the GCoS for prospective resource is a requirement of some Stock Exchanges. They presented a modified PRMS with indicative GCoS and CoC for each sub-class of resources. This modification concentrated mainly on the vertical axis of the PRMS without any change in the horizontal axis. Their work presented the resource sub-classes in a vertical relationship relative to developmental stages to commercial production status. The authors assigned ranges of probabilities to the sub-classes. These ranges of probability figures are incorporated as generalized figures to serve as indicative ranges only and not as absolute limits that can disqualify estimates that fall outside them.

The assignment of probability figures aimed at determining the GCoS and CoC, though a fair attempt to compute the PRMS, fail to address the subjectivity and prescriptive feature of the PRMS, which the authors had earlier observed and wanted to improve upon. This still leaves this identified gap unaddressed hence the necessity for an improved framework to estimate the GCoS and CoC. These will in turn, enhance the application of PRMS to classify hydrocarbon resources to meet the requirements of the Securities & Exchange Commission on hydrocarbon resources classification.

Doug et al., [6] criticized the SPE-PRMS framework for hydrocarbon resources classification and commerciality determination as descriptive and non-prescriptive. They said it is qualitative and non-quantitative. The authors, therefore attempted to quantify the SPE-PRMS by introducing some subjective probability figures. Their modified SPE-PRMS is presented in Fig. 1.0 below:

According to SPE-Petroleum Resources Management System [7], a hydrocarbon accumulation must be sufficiently defined to establish its commercial viability to be included in the reserves class. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of operator's intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended by [7] as a benchmark, a longer time frame could be applied since there is no consensus yet on a reasonable time frame.

This SPE/PRMS definition of commerciality is not based on a definite quantity, which establishes commerciality when it is attained. Defining commerciality based on operator's "intention to develop" a discovered asset skews the declaration of commerciality to the investment decision of the operator who may choose not to declare it depending on the ranking of that asset on the developmental scale of the operator's total asset portfolio. This may create a challenge of conflict of interest where the operator is different from the asset owner.

Another methodology widely used to establish commerciality is the Minimum Economic Field Size (MEFS). The MEFS, which is at times called Minimum Economic Reserves (MER) is defined as the minimum volume of recoverable oil and gas necessary to make the project an economic success [8]. Some of the most important variables used in MEFS estimation include: the value of oil and gas, the finding costs, the productivity, recovery by well, the proximity to and cost of infrastructure, development options, the cost of applicable technology, royalty payments, transportation tariffs, regulatory costs and tax structure. The MEFS is used as input to cut-off the low end of recoverable resources probabilistic distribution and to eliminate those resources which are non-economic. This cut-off becomes extremely critical for the areas (e.g. ultra-deep waters) where very large investments are involved. Operators use the estimation of minimum required resources which provide Net Present Value (NPV) equal to zero for the full project life cycle considering the most likely development scenario to eliminate the sub-commercial discoveries. The graphical technique is the most widely used form of MEFS.

In Nigeria, one of the statutory requirements for oil block conversion from Oil Prospecting License (OPL) to Oil Mining License (OML) is the establishment of the commerciality otherwise known as economic viability of the discovered hydrocarbon property. In accordance with the provisions of paragraphs 8(b) and 9, Schedule 1 of the Petroleum Act No. 51, 1969, (Cap 350), Laws of the Federation of Nigeria (LFN)[9], an OPL (excluding deep offshore) is required to be capable of producing a commercial quantity of at least 10,000 barrels of crude oil per day before conversion to an OML while for deep offshore, 25,000 barrels of crude oil per day is required. In addition to this, the reserves must be indicated. This implies that the minimum rate approach with some consideration for reserves volume is principally used as a basis to determine the commerciality or economic viability of an oil block in Nigeria.

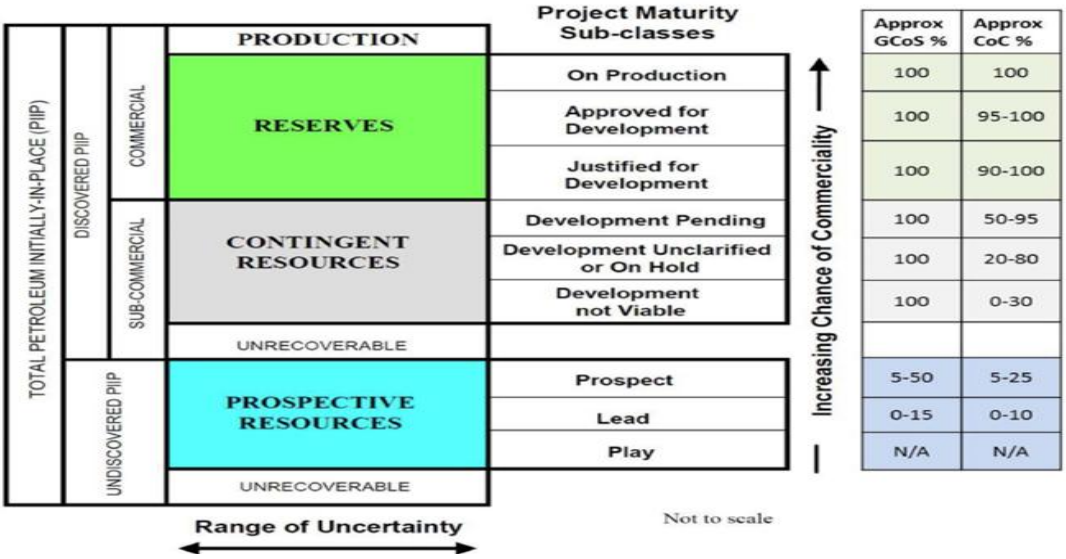

Fig. 1. Modified SPE-PRMS by Doug et al., [6]

This Guideline thus, declares the rates of 10,000bopd and 25,000bopd as commercial rates respectively for onshore and deep offshore blocks in Nigeria without consideration to crude oil price, production cost and desired earning. This implies that irrespective of the crude oil price, an onshore/continental shelf oil block with capacity to produce a minimum rate of 10,000bopd will give a profitable return on investment. Similarly, a deep offshore block producing at a minimum threshold of 25,000bopd will certainly breakeven irrespective of the prevailing oil price throughout the producing life of the field. This is indeed worrisome as crude oil and gas prices and of course, the costs of producing the hydrocarbons and the operator's desired earning from the investment are very important variables in determining the commercial viability of the venture. These minimum rate thresholds can only be tenable in defining the commerciality of petroleum development venture if proven to be determined by a study which shows that irrespective of the prevailing oil price, these rates will yield revenues greater than the total cost of production.

To minimize subjectivity in the framework for commerciality evaluation, SPE-PRMS [10] now recommends a Cash-Flow-Based method with Net Present Value as the key parameter which must involve the following inputs for the calculation:

- The expected quantities of production projected over identified time periods.
- The estimated costs associated with the project to develop, recover, and produce the
  quantities of production at its Reference Point, including environmental, abandonment, and reclamation costs charged to the project, based on the evaluator's view of the costs expected to apply in future periods.
- The estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods including that portion of the costs and revenues accruing to the entity.
- Future projected production and revenue related taxes and royalties expected to be paid by the entity.
- A project life that is limited to the period of entitlement or reasonable expectation thereof.
- The application of an appropriate discount rate that reasonably reflects the weighted average cost of capital or the minimum acceptable rate of return applicable to the entity at the time of the evaluation.

Doug et al [6] observed that the chance of commerciality is commonly used as an input to economic assessments and valuations where it is often quoted without regard for timing and project definition, and with little explanation of the framework used. In such circumstances, it may be deceptive and very simplistic to multiply the project Net Present Value (NPV) by a single chance of development factor to develop a risked

NPV as a substitute for value. It is, therefore, expedient to clearly define the framework for commerciality determination and application. The risked NPV only aid in Final Investment Decision (FID) analysis to decide whether to further develop a discovered and appraised hydrocarbon accumulation.

The chance to discover hydrocarbon volumes of economic quantity diminishes with progressive discovery in explored basins. A higher percentage of smaller deposits progressively constitutes the incremental size distribution of discoveries with successive exploration of the basin. The progressive discovery of smaller volumes of petroleum per unit of exploratory effort results to rise in cost because the value of smaller hydrocarbon accumulations may not be commensurate with the cost of discovery as smaller deposits usually have higher per unit development costs. Given the preponderance of smaller deposits in extensively explored basins and the cost implications of discovering deposits less than the required Minimum Economic Reserves, explorationists and investors in exploration activities need a framework to evaluate the chance of a successful petroleum resources discovery and recovery in extensively explored basin to minimize the risk of unsuccessful exploration.

The paper aims at developing a new framework to evaluate the chance of discovery of at least a minimum economic reserves volume in an extensively explored basin. This will minimize loss of investment cost in petroleum exploration associated with unsuccessful exploration.

2. METHODOLOGY

Minimum Economic Field Size (MEFS), also known as Minimum Economic Reserves (MER) is defined as the least producible volume of hydrocarbon required for E&P investment to be a commercial success. In this study, the Minimum Economic Reserves (MER) version is used for consistency. The principal variables required to estimate MER include: the hydrocarbon volumetric accumulations, the exploration costs, well production rate, development options, availability of facilities and relevant technologies, applicable fiscal regimes, hydrocarbon transport & terminal handling tariffs and regulatory costs. MER is the lowest resource volume, which full project economics (considering the best development option) yields NPV not less than zero.

According to [8], the probability of economic success (P_c) is the likelihood to discover hydrocarbon that is more than the estimated MER. It is given by:

$$P_c = P_g \times P_{mer} \quad (2.1)$$

Where:

P_c = Probability of commercial or economic success
P_g = Probability of geologic success
P_{mer} = Probability of the predicted MER

Singh et al [8] identify P_{mer} and P_g as vital inputs in the evaluation of the exploration projects to establish the chance of commercial status for prospective and contingent resources. They defined P_c or economic success as the chance of discovering an economic accumulation of hydrocarbons, with enough reserves to sustain commercial flow. It is derived as the mathematical product of the P_g and P_{mer}. The two prominent analytical models for MER calculation are Corrie, [11] Model and Wang et al*.,* [12].

Wangs et al*,* [12] MER Model states that: The Minimum Economic Reserves (MER) is the After-Tax Cost (including the cost of geological and geophysical survey, exploration, land rental, transportation and management) divided by the product of the quantity of oil field and Project Total Net Present Value divided by the Total Project Reserves Volume.

Thus: MER = Total Project Cost / (Number of discovered Oil field x (NPV/ Reserves Volume))

$$MER = \frac{Ce \ x \ EUR}{N_f \ x \ NPV} \quad (2.2)$$

Where:

Ce = Total Exploration Cost ($)
EUR = Expected Ultimate Recovery (STB)
N_f = No. of Discovered Fields
NPV = The Project Net Present Value ($)

It should be noted that: After-Tax NPV of income per barrel or Unit Profit = Project total Net Present Value/Reserves Volume.

[11] Minimum Economic Reserves (MER) is given as:

$$MER = [(\frac{1-P_s}{P_s})] \times [\frac{C_e}{\pi_p}] \quad (2.3)$$

Where:

MER = Minimum Economic Reserves (bbls)
P_s = Probability of success (%)
C_e = Exploration Cost ($)
π_p = Expected Unit Profit ($/Bbl)

However, the Richard Corrie Model (Equation 2.3 above) for calculating Minimum Economic Reserves (MER) is applied in this study.

The probability of geologic success (P_g) is most generally estimated by multiplying the probability of the essential geologic factors of a prospect. The geologic factors, also known as risk factors, are independent factors that could cause the prospect to fail. The prospect is deemed to have failed if any of the risk factors fails. The essential geologic factors must coincide for the subsurface hydrocarbon accumulation to exist. The Norwegian Petroleum Directorate [13], identifies the four geologic factors that must coincidentally occur for petroleum to form and accumulate as:

A *source rock* containing enough organic material at optimal temperature and pressure to form petroleum.

A *migration path* that allows the formed petroleum to transit from source to reservoir rock.

Presence of *a reservoir rock* for the accumulation of the formed petroleum.

A *trap system* to retain the petroleum in a reservoir.

The number of discoveries from the total number of prospects, which is known as the historical success rate has been directly employed by itself or in combination of geologic chance factors in some cases as probability of geological success (GCoS).

Snow et al.[14] suggested a simple technique to estimate GCoS. The technique entails combining past success rate with estimation of geologic factors. He stated that (GCoS) is obtained by multiplying historical success rate and four geologic coefficients, which is given as: GCoS (Pg) = Historical Chance of Success x Reservoir Coefficient

x Trap Coefficient
x Seal Coefficient
x Source Coefficient (2.4)

$P_g = P_{source} \times P_{timing/migration} \times P_{reservoir} \times P_{trap} \times P_{seal}$ (2.5)

In addition, scholars have developed some helpful tools to assign probabilities by providing probability scale as reference. One of such tools developed by Rose, [15] is called “Chance Adequacy Matrix” is shown in Fig. 2.0. It shows the probability scale corresponding to four dimensions namely: Risk, Confidence Level, (less likely to more likely), Data quality, Conclusion from data.

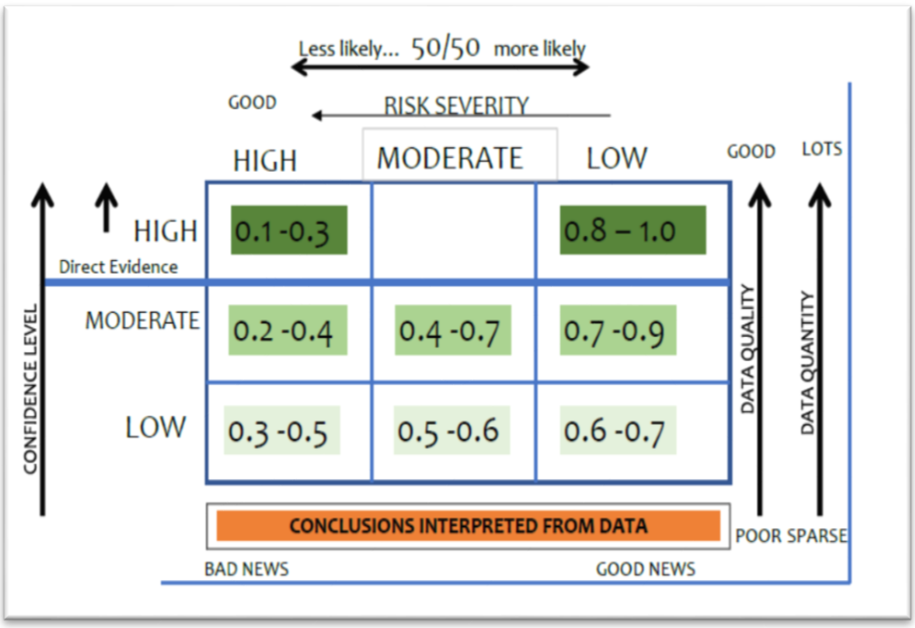

Fig. 2. A chance of adequacy matrix by rose [15]

Milkov, [16] developed a probability Risk Table, which offers a more effective solution by presenting objectivity and reliability in the probability assignment process. The Risk Table provides quantitative probabilities corresponding to different scenarios that combine certain variables for individual geological factor or subfactors. These variables include: Presence of structure, Reservoir facies, Reservoir deliverability, Presence of seal, Mature source rock and Migration.

The Milkov's Risk Table presented in Table 1.0 above provides a simple but methodological way of obtaining GCoS (P_g) by considering the key geologic considerations. It is used in this work to obtain the probability of geological success. However, given the several possible combinations of geological and seismic factors to derive different probability outcomes, Milkov, [16] Risk Table in the existing analogue form can be cumbersome. It is, therefore, expedient to simplify the combination process that give the required probability figure by digitalization.

P_g is one of the vital variables required to establish the likelihood of economic success of a petroleum system. As stated earlier, the simplified Milkov, [16] Risk Table, which is a qualitative description for the relative probability scale to derive the geological chance of success (GCoS, Pg) is used. We developed a mini-digital technique with Visual Basic on Excel Spread Sheet to simplify the application of the Risk Table to determine (P_g). The application of the semi-digital process involves the three major exploration features namely structure, seismic and source used by Milkov, [16] as standards to derive the probabilities as shown in Tables 2.0 and 3.0 below.

Table 1. Qualitative descriptions of the relative probability scale [16]

Structure (closure, geometry, container)				Data (existence and reliability)			
				3D seismic	2D seismic Number of lines per structure (with obligatory availability of in-line and cross lines)		
					Dense (7 lines and more)	Sparse (3-6 lines)	Very sparse (2 lines) (Lead)
Models (existence and reliability)	Seismic mapping and correlation	High-relief structure (≥3 times higher than seismic accuracy) AND low structural complexity (4-way)	Easy to interpret, reliable correlation based on nearby (<50 km) wells	1.00	0.90	0.80	0.60
			Uncertain correlation (horizons are interrupted laterally) or based on remote (> 50 km) wells	0.95	0.85	0.75	0.55
			Difficult to interpret, unreliable correlation (horizons are interrupted by thrust faults, diapirs, etc.) or model developed using analogues without wells in the basin	0.85	0.75	0.70	0.45
		Medium-relief structure (1-3 times higher than seismic accuracy) OR high-relief structure with high structural complexity (3-way, stratigraphic)	Easy to interpret, reliable correlation based on nearby (<50 km) wells	0.80	0.70	0.60	0.35
			Uncertain correlation (horizons are interrupted laterally) or based on remote (> 50 km) wells	0.75	0.65	0.50	0.25
			Difficult to interpret, unreliable correlation (horizons are interrupted by thrust faults, diapirs, etc.) or model developed using analogues without wells in the basin	0.70	0.55	0.45	0.20
		Low-relief structure (lower than seismic accuracy) OR high uncertainty of depth conversion (subsalt, below lava flows) OR areas with rapidly changing lateral velocities in the overburden	Easy to interpret, reliable correlation based on nearby (<50 km) wells	0.55	0.45	0.35	0.15
			Uncertain correlation (horizons are interrupted laterally) or based on remote (> 50 km) wells	0.50	0.40	0.25	0.10
			Difficult to interpret, unreliable correlation (horizons are interrupted by thrust faults, diapirs, etc.) or model developed using analogues without wells in the basin	0.40	0.30	0.20	0.05
		Low-relief structure (lower than seismic accuracy) AND EITHER high uncertainty of depth conversion (subsalt, below lava flows) OR areas with rapidly changing lateral velocities in the overburden		0.35	0.25	0.15	0.05

Table 2. Summary of Milkov, [16] Risk Table

Structure	Seismic	Source
H	A	3D
M	B	2Dd
L	C	2Ds
LL	O	2Dvs

Table 3. Milkov [16] table standard identities description

Description of the Structure Identities	Description of Seismic Identities	Description of Source Identities
H = High relief structure (≥3 times higher than seismic accuracy) AND low structural complexity (4-way)	*A = Easy to interpret, reliable correlation based on nearby (<50Km) wells*	*3D = 3 Dimensional seismic*
M = Medium -relief structure (1-3 times higher than seismic accuracy) OR high-relief structure with high structural complexity (3-way, stratigraphic)	*B = Uncertain correlation (horizons are interrupted laterally) or based on remote (>50Km) wells*	*2Dd = 2 Dimensional dense lines per structure (7 lines & more)*
L=Low-relief structure (lower than seismic accuracy) OR high uncertainty of depth conversion (subsalt, below lava flows) OR areas with rapidly changing lateral velocities in the overburden	*C = Difficult to interpret, unreliable correlation (horizons are interrupted by thrust faults, diapirs, etc) or model developed using analogous wells in the basin*	*2Ds = 2 Dimensional sparse lines per structure (3-6 lines)*
LL = Very Low-relief structure (lower than seismic accuracy) AND EITHER high uncertainty of depth conversion (subsalt, below lava flows) OR areas with rapidly changing lateral velocities in the overburden	*O = Totally poor seismic interpretation and unreliable & unusable correlation*	*2Dvs = 2 Dimensional very sparse lines per structure (2lines)*

Table 2.0 shows the four identities in each exploration feature employed in the assignment of probabilities. The identities under the feature termed – Structure – are H for High, M for Medium, L for Low and LL for Low-Low or Very low. These describes the key geological structures obtainable from a given exploration activity. The identities under the feature – Seismic- has A, B, C and O, which represents different grades of seismic quality as clearly explained in the table in Table 3.0. The last feature termed, Source, has 3D, 2Dd, 2Ds and 2Dvs as the identities, which describes the grade of the seismic acquisition. Table 3.0 is detailed description of the identities.

Table 4.0 above shows the various combinations of the identities from the three features namely Structure, Seismic Quality and Seismic Source give different probability values that represents chance of geological success (CoGS). Milkov, [16] shows with the Risk Table that an exploration asset with high relief and low structural complexity as evidenced by a 4-way closure (H), with a high quality and reliable easy to interpret seismic result (A) obtained with 3D seismic or from correlation from nearby wells not exceeding 50km, will have probability of 1.0. Table 4.0 is composed into executable program using Visual Basic to produce the desired result with simple 4 clicks of the computer.

Fig. 3.0 is the digital version of Table 2.0 showing the four identities in each exploration feature employed in the assignment of probabilities. The identities under the feature termed – Structure – are H for High, M for Medium, L for Low and LL for Low-Low or Very low. These describes the key geological structures obtainable from a given exploration activity. The identities under the feature – Seismic- has A, B, C and O, which represents different grades of seismic quality as clearly explained in the table in Table 3.0. The last feature termed, Source, has 3D, 2Dd, 2Ds and 2Dvs as the identities, which describes the grade of the seismic acquisition.

Fig. 4.0 is a demonstration of the application of the digital portal to obtain the Geological Chance of Success (Pg) of a hydrocarbon asset. The screen shows that the asset under analysis is of a high relief structure with good structural closure (H) that has a poor seismic record (C) obtained from a 2-Dimensional Very Sparse lines (2Dvs). The portal gives the chance of Geological Success (Pg) value at the click of the "EXECUTE" button as 0.45.

The Algorithm for the digitalization of the Milkov, [16] Risk Table is shown in Fig. 5.0 below.

Table 4. Generating table for probability of geologic success (P_g) Value Generation

Identities Combination for P_g Value Generation	
H + A + 3D	1
H + B + 3D	0.95
H + C + 3D	0.85
H + A + 2Dd	0.9
H + B + 2Dd	0.85
H + C+ 2Dd	0.75
H + A + 2Ds	0.8
H + B + 2Ds	0.75
H + C + 2DS	0.7
H + A + 2Dvs	0.6
H + B + 2Dvs	0.55
H + C + 2Dvs	0.45
M + A + 3D	0.8
M + B + 3D	0.75
M + C + 3D	0.7
M + A + 2Dd	0.65
M + C + 2Dd	0.55
M + A + 2Ds	0.6
M + B + 2Ds	0.5
M + C + 2Ds	0.45
M + A + 2Dvs	0.35
M + B + 2Dvs	0.25
M + C + 2Dvs	0.2
L + A + 3D	0.55
L + B + 3D	0.5
L + C + 3D	0.4
L + A + 2Dd	0.45
L + B + 2Dd	0.4
L + C + 2Dd	0.3
L + A + 2Ds	0.35
L + B + 2DS	0.3
L + C + 2Ds	0.2
L + A + 2Dvs	0.15
L + B + 2Dvs	0.1
L + C + 2Dvs	0.05
LL + O + 3D	0.35
LL + O + 2Dd	0.25
LL + O + 2Ds	0.15
LL + O + 2Dvs	0.15

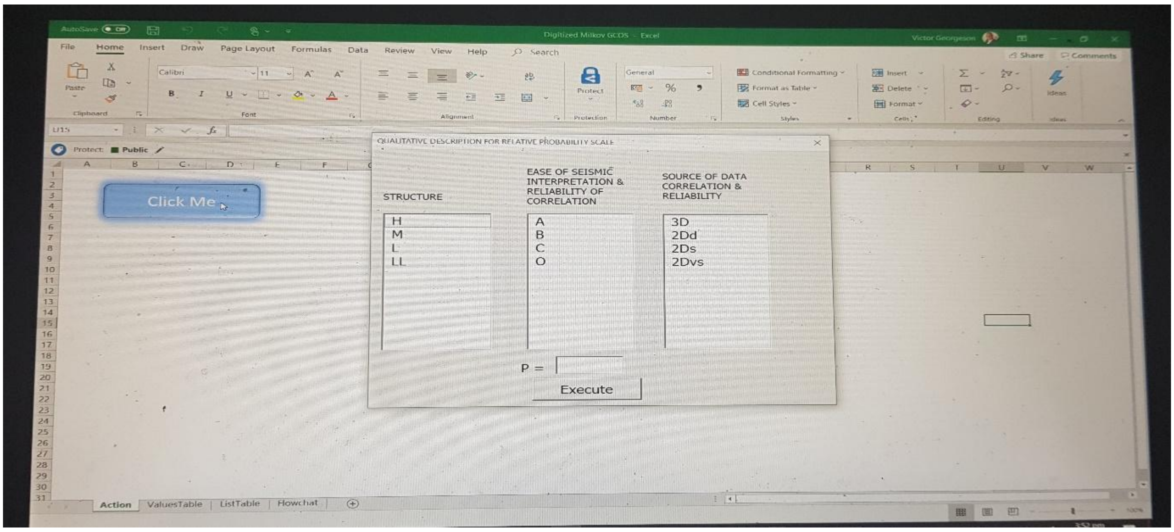

Fig. 3. The digitalized portal for Milkov, [16] risk table

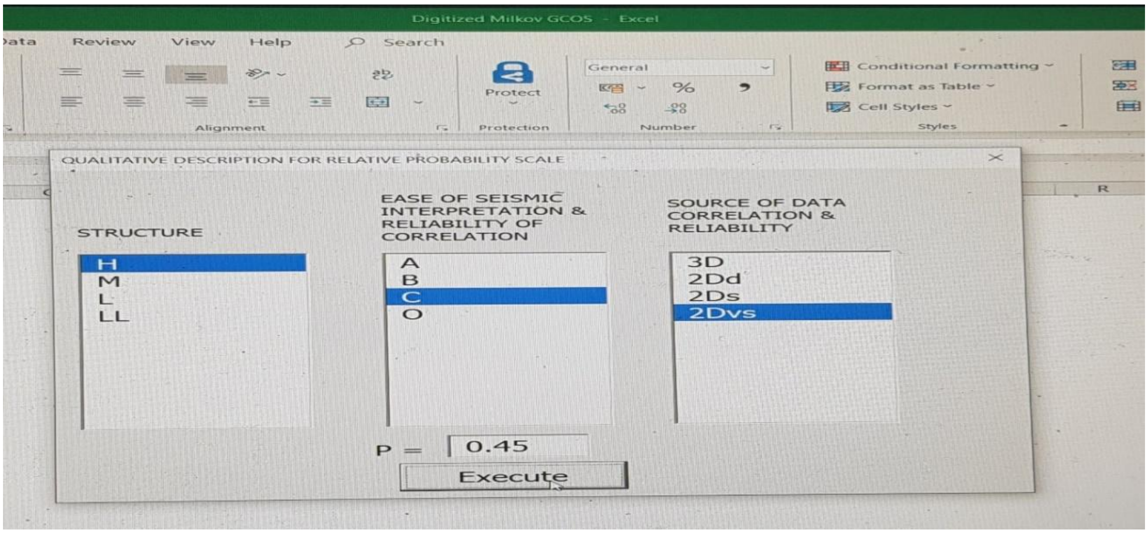

Fig. 4. A demonstration of the use of the digital portal

Researchers [17] and [18] have found that more fields can be successfully discovered when based on evidence from the drilling histories of exploratory wells by applying the concept of "*Discovery Efficiency*" than the random drilling method. Discovery efficiency parameter measures the magnification of the effect of areal extent on the probability with which a field is discovered. Chungchareon, [19] introduced the parameter into the probabilistic model and modified his model by raising the hydrocarbon fields size (S), to the power of the discovery efficiency (β).

Drew et al.,[20] used the discovery efficiency model to predict the quantity of discoverable fields within a given field size-class by depth interval in relation with the cumulative exploratory wells drilled. The analytical form of the model for each depth interval is:

$$F_i(w) = F_i(u)(1 - e^{Øiw}) \qquad (2.6)$$

Where:

$F_i(w)$ is the predicted quantity of deposits within deposit-size class i found by w(net) cumulative exploratory wells.
$F_i(u)$ is the ultimate number of deposits in size-class i;
w is the cumulative net exploratory wells.

$$Ø_i \text{ is a constant equal to } βA_i/B \qquad (2.7)$$

Where:

B is the effective basin size,
A_i is the areal extent of class i deposits, and
β is the discovery efficiency.

When drilling is random, β = 1, and if exploration is twice as efficient as random drilling, β = 2, [20].

The number of undiscovered deposits can be determined from the estimated parameters and the past discovery data by first establishing the ultimate number of discoveries at time t, that is, $F_{it}u(u)$ (for a given basin) using the relation:

$$F_{it}u(u) = F_{it}(w_t)/(1- e^{\varnothing iwt}) \qquad (2.8)$$

Where:

w_t is the cumulative net wells drilled to time t and $F_{it}(w_t)$ is the actual number of the i^{th} size class of deposits discovered in a given basin.

The number of undiscovered deposits in size class *i* at the onset of period *t* is estimated as the difference between $F_u(u)$ and $F_u(w)$.

Using equations (2.6) and (2.7), the model for discovery efficiency (β) is explicitly derived as:

$$\beta = -\frac{B}{A_i W_t} \ln\left[1 - \frac{F_t(S_{mer})}{F_t(U)}\right] \qquad (2.9)$$

Arps et al., [17] established that historical exploration records show that the rate of discovery declines with time in exploration. Discovery Efficiency is employed to measure this phenomenon. The probability model for discovery efficiency relies on two hypothesizes. First, the model portrays the discovery phenomenon as a sampling process without replacement [21]. Second, the probability of discovery of an individual field is proportional to the field size [17].

Chungchareon, [19] combined discovery efficiency and discovered field sizes to formulate a probability function for discovery of commercial hydrocarbon volume. In his postulation, he considered an unexplored area containing *K* possible field sizes $S_1, S_2, ..., S_n$ **(**measured as areal extents) and assumed that each undiscovered field size occurs with frequency $A_1, A_2, ..., A_k$, and by the second postulate, if the drilling locations are chosen randomly, the chance of discovering a field of size S, with the first exploratory field W, can be stated as the ratio of the product of its occurrence and size to the area available for exploration in the underlying basin. He introduced discovery efficiency into the probabilistic model as a parameter that measures the magnification of the effect of areal extent on the probability with which a field is discovered. The framework is modified by raising the hydrocarbon fields size value (S), in the probability expression to the power of the discovery efficiency β**.** He also derived the model for the probability of exploration success with increasing number of exploratory wells in a partially explored basin.

$$P(W_1 = S_j) = \frac{A_j S_j^{\beta}}{\sum_{k=1}^{k} A_k S_k^{\beta}} \qquad (2.10)$$

Where:

K = number of possible field sizes in an area
S_j = the desired field size (MEFS)
A_j = the frequency of occurrence of each field size
W_1 = 1st exploration well
β = the discovery efficiency of the terrain

Chungchareon, [19] further postulated that the probability that the i^{th} well will make a discovery is given by:

$$P(W_i = S_j) = \frac{(A_j - D_{i-1,j})\, S_j^{\beta}}{\sum_{k=1}^{k}(A_k - D_{i-1,k}) S_k^{\beta}} \qquad (2.11)$$

Where:

W_i = the i^{th} discovery well
W_{i-1} = the last discovery well
$D_{i-1,j}$ = the volume of discovery with W_i
$D_{i-1,k}$ = the volume of discovery with W_{i-1}
A_j = the frequency of occurrence of each field size
A_k = the ultimate no. of discoveries

For:

$S_i = S_{mer}$ = the desired class size (The Minimum Economic Field Size Class)
$(A_j - D_{i-1,j}) = F(S_{mer})$ = the frequency of discovery of the desired class size
$(A_k - D_{i-1,k}) = F(S_i)$ = the frequency of discovery of other class sizes

Equation 2.50 is modified to become:

$$P_{mer} = \frac{F\ (Smer)\, S_{mer}^{\beta}}{\sum_{F\,(Si)=1}^{k} F\ (S)_i\, S_i^{\beta}} \qquad (2.12)$$

Substituting Equation 2.9 into 2.12 gives:

$$P_{mer} = \frac{F\ (Smer)\ S_{mer}^{-\frac{B}{A_i W_t}\ln\left[1-\frac{F_t(S_{mer})}{F_t(U)}\right]}}{\sum_{F\ (Si)=1}^{k} F\ \ (S)_i\ S_i^{-\frac{B}{A_i W_t}\ln\left[1-\frac{F_t(S_{mer})}{F_t(U)}\right]}} \qquad (2.13)$$

Equation (2.13) is therefore, our new model to estimate the Chance for Commercial discovery of a hydrocarbon asset. However, because of the complexity in the solution of the model as presented in Equation (2.13), the simplified version (Equation 2.12), whereby the discovery efficiency is estimated separately using Equation (2.9) is applied in this study.

Thus, the Chance of Commerciality of hydrocarbon asset is estimated using Equation (2.1) in the following form:

Pc = Pg value (obtained from Milkov Risk Table)

$$+\ (P_{mer} = \frac{F\ (Smer)\ S_{mer}^{\beta}}{\sum_{F\ (Si)=1}^{k} F\ \ (S)_i\ S_i^{\beta}}) \qquad (2.14)$$

3. RESULT AND DISCUSSION

3.1 Exploration Data Analysis

Various exploration data input is used in the study. They include, basinal cream-off analysis to establish the exploration prospectivity of the Niger Delta basin, exploration well data analysis to ascertain the success rate and exploration cost analysis. The Niger Delta basinal and terrain area size estimate are also carried out. The exploration cost and historical success rate are basic inputs to determine Minimum Economic Reserves using Richard Corrie Model. Basinal/terrain area is a requirement to estimate exploration efficiency.

3.2 Cream-off Curve Analysis of the Niger Delta Basin

The Niger Delta exploration Cream-Off Curve is shown in Fig. 7.0. The required data for the analysis is as presented in Fig. 6.0. This plot is limited to period (1995 to 2020), not by choice but by requisite data availability. Although the Nigerian well drilling data from (1956 to 2020) is available but the corresponding annual discoveries are not comprehensively available.

The analysis shows that the Niger Delta exploration follows an upward trend. This implies that the basin, in which over 8,000 exploration wells are drilled between (1956 to 2020), is mature in exploration activities but still very active in prospectivity. The maturity of the basin, therefore, is not for lack of exploration prospectivity but with regards to availability of huge array of historical exploration data to provide the analytics for guided exploration. The basin is too mature for wild-cat exploration.

3.3 Exploration Wells Analysis

The Niger delta exploration well data analysis presented in Table 5.0 shows that a total of 3,604 exploration wells are drilled between the period of (1951 to 2020). A total of 2,549 of the wells representing 71% are successful while the remaining 1,055 wells representing 29% are dry. Analysis of the data also shows that more discovery wells are drilled in the land and continental shelf (Onshore/shallow offshore terrain) than the relatively newly explored deep offshore and ultra-deep offshore frontier. A total of 2,188 exploration wells are drilled in the onshore terrain. 70% of them (1,532 wells) are successful whereas the remaining 30% (656 wells) are dry. Also 28% (378 wells) of the exploration wells drilled in Offshore terrain of the basin are dry while 72% (966 wells) of the offshore exploration wells are successful. Out of the 72 exploration wells drilled in the deep offshore terrain, 21 of them representing 29% are dry whereas 71% or 51 wells are successful.

3.4 Terrain Area Size Analysis

The Niger Delta terrain area size is estimated using the ArcGIS software with Fig. 8.0 as the input reference map.

The results are as follows: *Onshore Terrain,* from the thick black line in-land to the seashore line has an estimated area of 94,414 km². *Offshore Terrain:* from the seashore to the dotted line marked 200m water depth line has an estimated area of 52,100km². The *Deep & Ultra deep offshore Terrain,* from the 200m water depth line to the thick black line in the sea is estimated to have an area of 153,487 km². These figures obtained from ArcGIS are used in the analysis of this study.

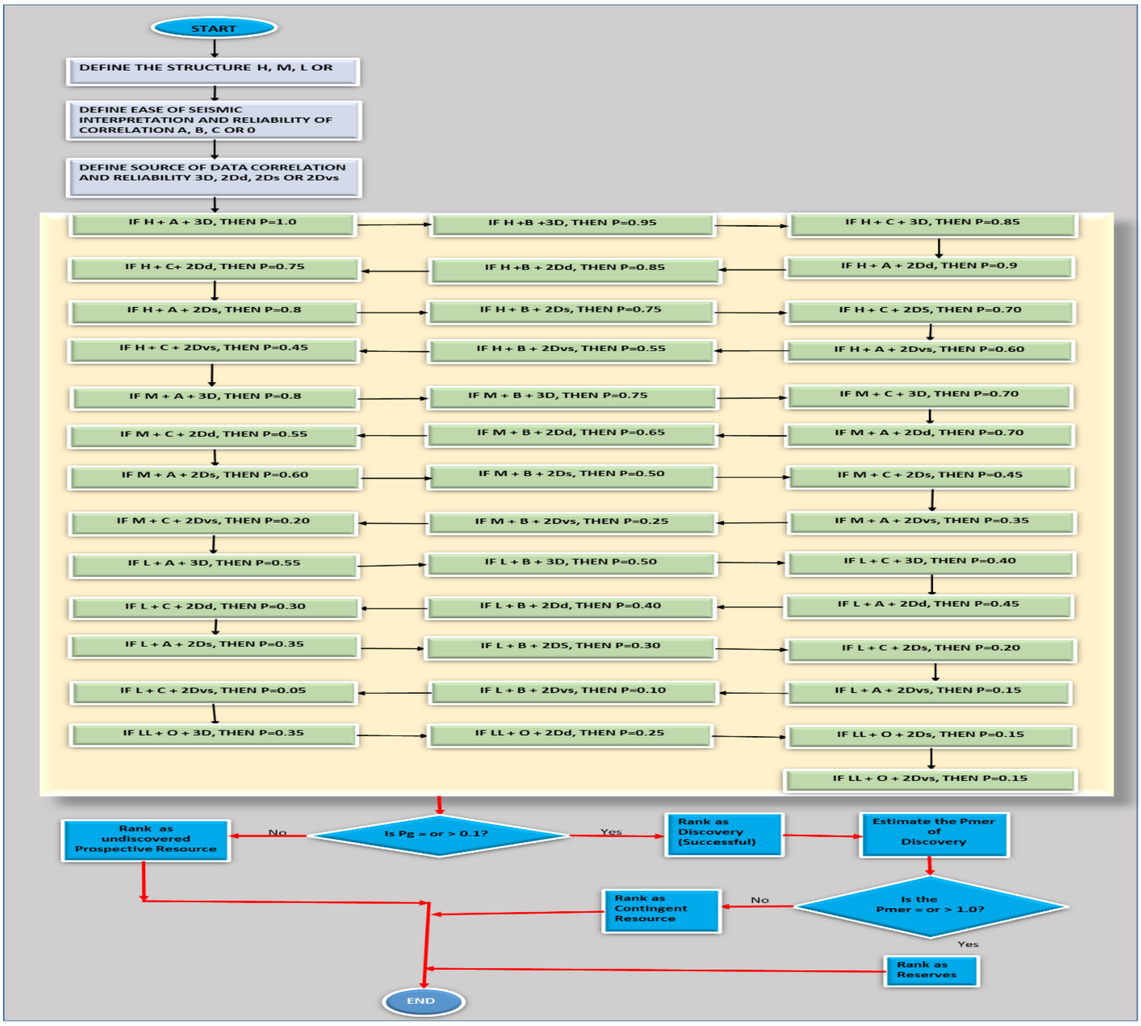

Fig. 5. The Algorithm for the Digitalization of Milkov, [16] risk table

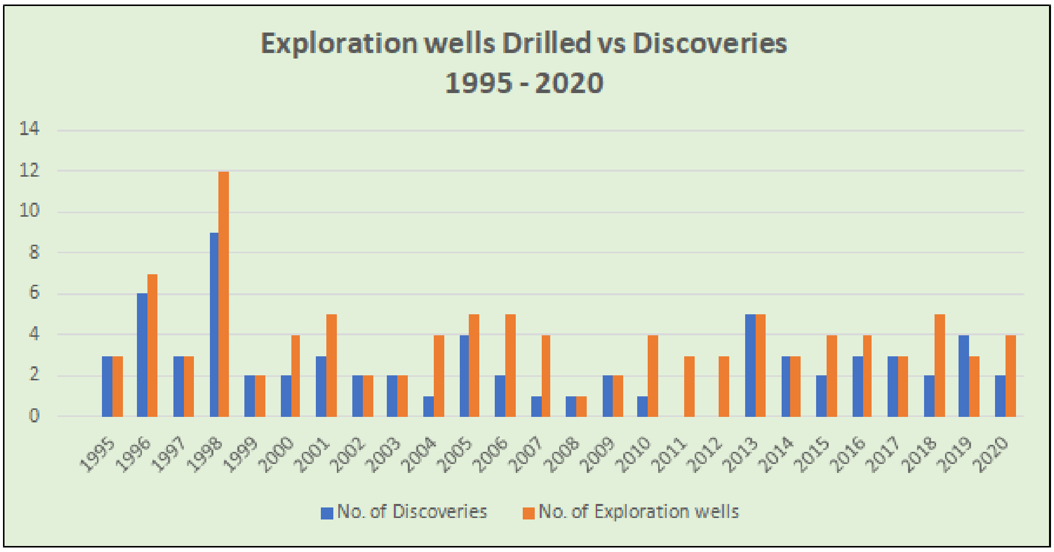

Fig. 6. Exploration wells and the discoveries in Nigeria (1995 – 2020) Source: DPR Nigeria(2020)

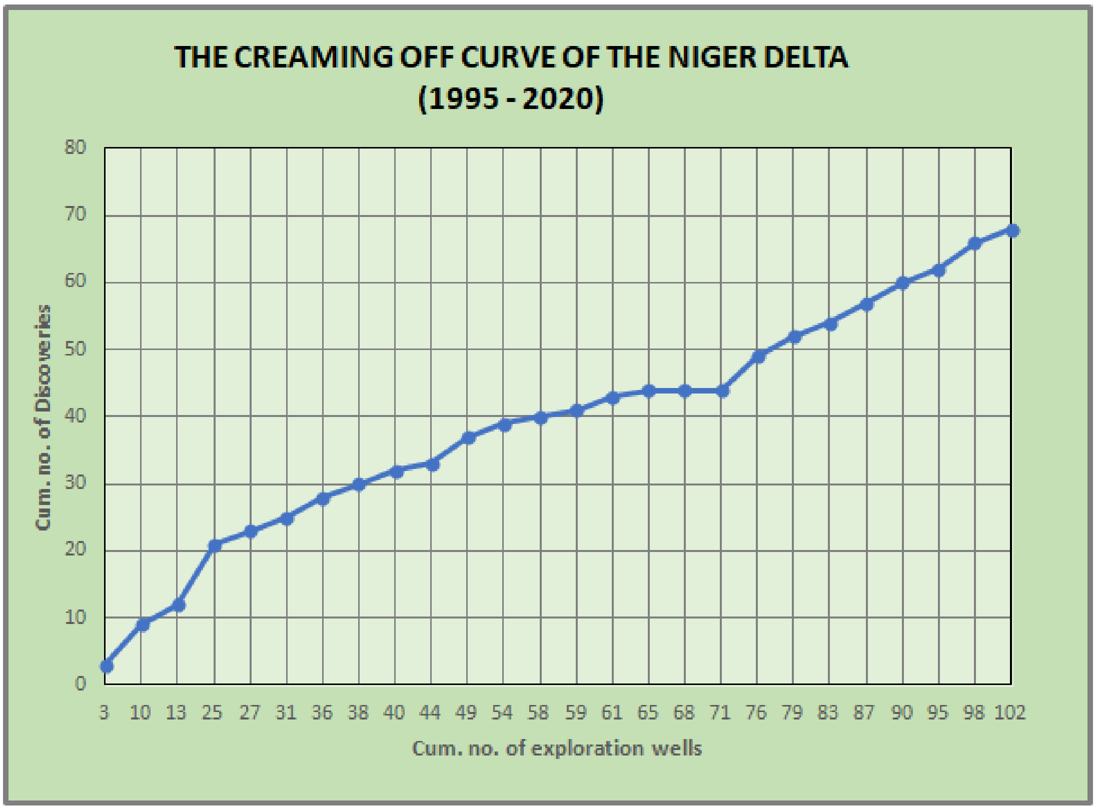

Fig. 7. The Niger Delta Cream Off Curve (1995 -2020)

Table 5. Niger delta exploration well data analysis

Terrain	Dry	Percentage dry	Successful	Percentage successful	Total
Onshore	656	30	1532	70	2188
Offshore	378	28	966	72	1344
DEEP offshore	21	29	51	71	72
Total	1055	29	2549	71	3604

3.5 Exploration Cost Analysis

Exploration Cost (C_e) required to estimate Minimum economic Reserves (MER) using Corrie, [11] Model. The exploration cost is analysed on three subheadings namely: Exploration Rights Acquisition Cost, Geological & Geophysical Studies Cost and Drilling & Formation Evaluation Cost for the nine case studies. The result shows that the three onshore blocks analysed (OPL X_a, OPL X_b & OPL X_c) has exploration cost of $18.5Million, $16.0Million & $14.0Million respectively. The exploration cost for the offshore analysed blocks (OPL Y_a, OPL Y_b & OML Y_c) are relatively higher than the onshore. They are estimated at $22.8Million, $29.8Million and $26.6Million respectively. The exploration cost for the deep/ultra-deep offshore case study blocks (OPL Z_a, OPL Z_b & OML Z_c) are $67.3Million, $71.5Million & $62.2Million respectively.

3.6 Geological Chance of Success Results

Using the information contained in the Milkov, [16] Risk Table and the geological & geophysical descriptions of the case studies, the geological chance of success (P_g) values for the different case studies are generated and presented in Table 6.0 below.

The result shows that Case Study 1.0 (OPL Xa), is a high relief structure with fairly good seismic interpretation, acquired with a 2-Dimensional sparse line seismic, has a P_g of 0.75. Case Study

2.0 (OPL X_b), Case Study 3.0 (OPL X_c), Case Study 5.0 (OPL Y_b), Case Study 6.0 (OML Y_c), Case Study 8.0 (OPL Z_b) & Case Study 9.0 (OML Z_c) with high relief structure and excellent seismic results produced from a 3-Dimensional seismic acquisition have a (P_g) of 1.0. Case Study 7.0 (OPL X_a) though a high relief structure with relatively poor seismic results acquired using sparse lines of a 2-Dimensional seismic has a P_g of 0.75. Case Study 4.0 (OPL Y_a), a low relieve structure with poorly interpreted seismic results acquired with a 3-Dimensional seismic operation has the least P_g of 0.4.

3.7 Minimum Economic Reserves (MER) Results

Corrie, [11] Model (Equation 2.3) is applied to determine the Minimum Economic Reserves (MER) for the nine case studies, which in turn requires the exploration success rate and average exploration cost of the terrain and a reasonable expected unit profit to compute.

The exploration success rate for the onshore, offshore and the deep offshore is estimated using empirical data from the terrains for the period of (1951 to 2020). The exploration success rate is estimated at 70%, 71% and 72% respectively for the onshore, offshore and deep offshore terrains respectively. The exploration cost ranging from USD14million to USD18million are used with modest expected unit profit of $40, $35 and $30 per barrel for onshore, offshore and deep offshore terrains respectively. This yields a MER of 198.23MMboe for Case Study 1.0 (OPL X_a); 197.12MMboe for Case Study 2.0 (OPL X_b) and 200.12MMboe for the third Case Study (OPL X_c) of the onshore terrain.

For the three Case Studies of the offshore terrain, the exploration cost of USD22.8million, USD29.8million and USD26.5million are used with the terrain success rate of 0.71 and $40, $35 & $30 expected unit profit respectively. The resulting minimum economic reserves volume of 221.80MMboe for Case Study 4.0 (OPL Y_a), 331.42MMboe for Case Study 5.0 (OPL Y_b) and 344.56MMboe for Case Study 6.0 (OML Y_c). For the deep offshore terrain with the highest success rate of 0.72, the estimated minimum economic reserves volume for Case Study 7.0 (OML Z_a) with exploration cost of USD 67.2million is 692.43MMboe. The estimated MER volume for Case Study 8.0 (OPL Z_b) with exploration cost of USD71.6million is 841.81MMboe. Case Study 9.0 (OML Z_c) has exploration cost of about USD62.2million and the estimated MER is 853.32MMboe.

3.8 Discovery Efficiency Results for Niger Delta Terrains

The Discovery Efficiency (β) is a veritable input variable to estimate P_{mer}. All the input variables to estimate discovery efficiency are obtainable from historical data except for the effective basin or terrain size, which is carefully determined with the ArcGIS software. The Niger delta basin size is estimated (using the ArcGIS system) to be 301,000km^2 which aligns with the estimate by [22] which put it at 300,000km^2. However, in this work, discovery efficiency estimation is predicated on terrain, hence the onshore, offshore and deep offshore terrain sizes are estimated as presented in Section 3.4 above. The estimated discovery efficiency for the terrains using equation (2.9) are approximately 2.0 for each terrain. This shows the Niger Delta as a mature basin with reasonable huge size of historical exploration data that can provide the required analytics for new exploration activities.

3.9 Estimated Probability of Commercial Discovery (P_c)

The probability of commercial discovery is estimated using Equation (2.12).

Table 7.0 is the summary of the results of the case studies for the onshore terrain, Table 8.0 presents the summary of the results of the case studies for the offshore terrain and Table 9.0 shows similar results for the deep offshore terrain of the Niger delta of Nigeria. The result shows that the framework estimated 0.48 for OPL X_a, 0.7 for OPL X_b and 0.8 for OPL X_c as the Chance of Commerciality (P_c) for the analysed onshore blocks. The blocks made a chance of commercial discovery (P_c) of less than 1.0, which implies that they are all sub commercial, notwithstanding that OPL X_b and OPL X_c have high geological chance of success (P_g) of 1.0 which indicates that they are discovered assets. OPL X_a with P_g of 0.75 and P_c of 0.48 is undiscovered and sub-commercial.

The estimated P_c for the offshore blocks (OPL Y_a, OPL Y_b & OML Y_c) are 0.16, 0.9 and 1.0 respectively. The result implies that OPL Y_a and OPL Y_b with P_c of 0.16 and 0.9 are sub commercial whereas OML Y_c with $P_c$of 1.0 is commercial discovery. However, the P_g result shows that OPL Y_c (P_g = 0.4) is merely prospective and therefore undiscovered whereas OPL Y_b with a P_g of 1.0 and P_c of 0.9 is a discovered but sub-commercial. The block is a contingent resource. The P_g & P_c results of OML Y_c show a discovered commercial asset – reserves. The results for the deep offshore blocks show that OML Z_a with estimated P_c of 0.51 is sub-commercial. OPL Z_b and OML Z_c with estimated P_{mer} of 1.0 respectively are commercial assets.

Table 10.0 is the summary of the results showing the classification of the assets with the estimated probabilities using Doug et al (2014) Matrix. The results show that OML Zc, OML Yc and OPL Zb have commercial reserves but are at various project maturity sub-classes. The estimated probabilities are only able to place the three assets in the Commercial Reserves Class but requires additional information to placed in the Project Maturity Sub-Classes. Assets: OPLs X_b, X_c & Y_b are estimated to be Sub-Commercial discoveries otherwise known as Contingent Resources. OPL Yb is rated as Development Pending whereas OPLs Xb & Xc are of the class of Development on hold on the project maturity ranking of the assets. OPL Xa, OPL Ya and OML Za on the other hand are ranked under Prospective resources. The evaluated asset in OML Za is likely to be an undiscovered deeper exploration prospect in a discovered and producing asset. It is ranked as a prospect in the project maturity level. OPL Ya has the least Chance of geologic Success (Pg) and Commerciality and is ranked as a lead in the prospective resources class. It requires more prospectivity study to further derisk and mature it to the prospective resources level.

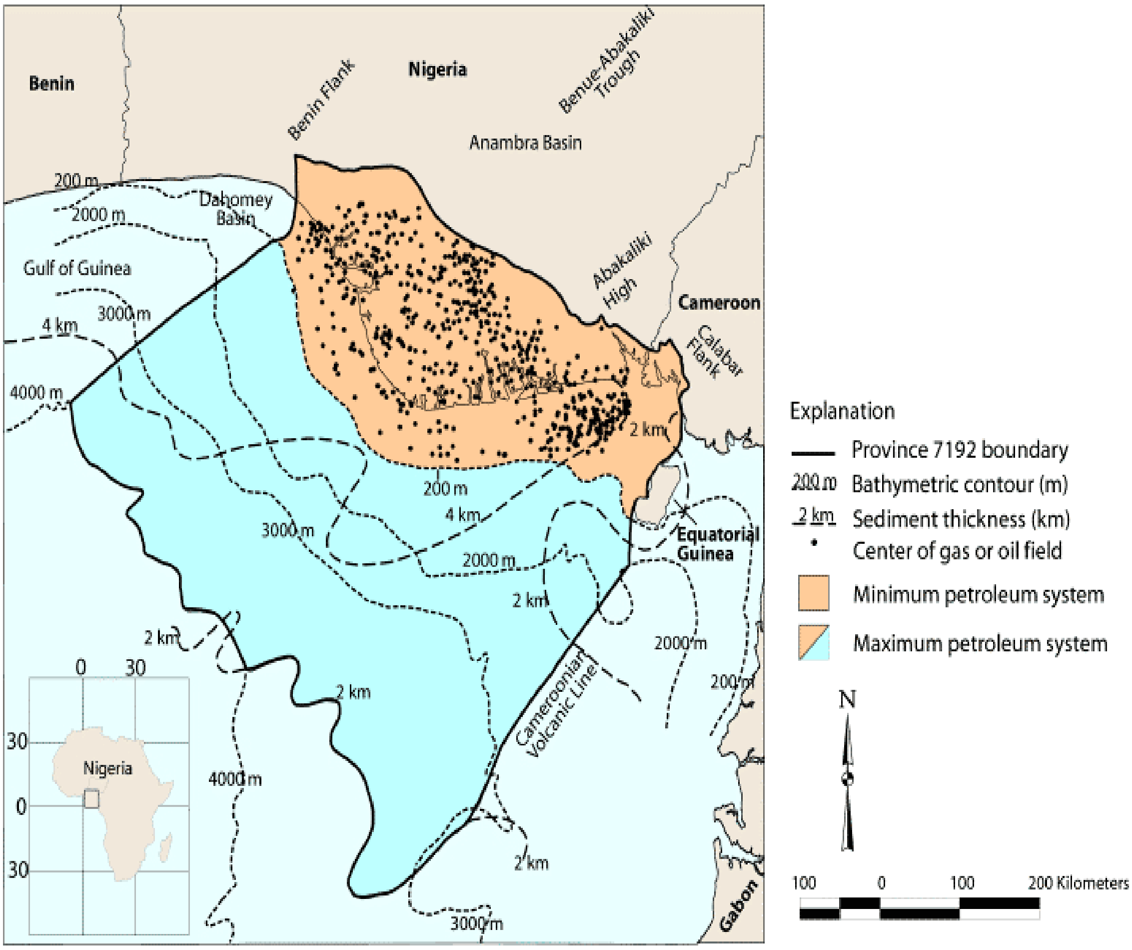

Fig. 8. Map of the Niger delta showing basinal outline (maximum petroleum system) and bounding structural features
Source: (Petroconsultants 1996)

Table 6. The estimated P_g values for the case studies using Milkov,[16] **risk table**

Variables	Asset	OPL Xa	OPL X_b	OPL Xc	OPL Ya	OPL Y_b	OML Yc	OML Za	OPL Z_b	OML Zc
STRUCTURE	H	H	H	H		H	H		H	H
	M							M		
	L				L					
	LL									
SEISMIC	A		A	A		A	A		A	A
	B	B						B		
	C				C					
	O									
SOURCE	3D		3D	3D	3D	3D	3D	3D	3D	3D
	2Dd									
	2Ds	2Ds								
	2Dvs									
VALUE		0.75	1	1	0.4	1	1	0.75	1	1

Table 7. The results of Discovery Efficiency, P_g, P_{mer} & P_c for Onshore Case Studies

Asset	*Probability of Geological Success (P_g)*	*Estimated Minimum Economic Reserves size $S_{MER\ (BBLs)}x10^6$*	*Estimated Discovery Efficiency (β)*	*Total No. of Discoveries in the Terrain (k) $F_t(U)$*	*No. of Discoveries of other reserves Sizes (A_j) $F_{it}(S_i)$*	*Estimated Probability of Min. Economic Size Discovery (P_{mer})*	*Probability of Commercial Success $P_c = P_g \times P_{mer}$*
OPL Xa	*0.75*	*198.23*	*2.2*	*1532*	*216*	*0.64*	***0.48***
OPL X_b	*1.0*	*197.12*	*2.09*	*1532*	*216*	*0.7*	***0.7***
OPL Xc	*1.0*	*200.12*	*2.04*	*1532*	*216*	*0.8*	***0.8***

Table 8. The results of discovery efficiency, P_g, P_{mer} & P_c for the offshore case studies

Asset	*Probability of Geological Success (P_g)*	*Estimated Minimum Economic Reserves size $S_{MER\ (BBLs)}x10^6$*	*Estimated Discovery Efficiency (β)*	*Total No. of Discoveries in the Terrain (k) $F_t(U)$*	*No. of Discoveries of other reserves Sizes (A_j) $F_{it}(S_i)$*	*Estimated Probability of Min. Economic Size Discovery (P_{mer})*	*Probability of Commercial Success $P_c = P_g \times P_{mer}$*
OPL Y_a	*0.4*	*221.8*	*2.0*	*968*	*631*	*0.4*	***0.16***
OPL Y_b	*1.0*	*331.42*	*1.9*	*968*	*631*	*0.9*	***0.9***
OML X_c	*1.0*	*344.56*	*2.0*	*968*	*631*	*1.0*	***1.0***

Table 9. The results of discovery efficiency, P_g, P_{mer} & P_c for Deep offshore Case Studies

Asset	*Probability of Geological Success (P_g)*	*Estimated Minimum Economic Reserves size $S_{MER\ (BBLs)} x10^6$*	*Estimated Discovery Efficiency (β)*	*Total No. of Discoveries in the Terrain (k) $F_t(U)$*	*No. of Discoveries of other reserves Sizes (A_j) $F_{it}(S_i)$*	*Estimated Probability of Min. Economic Size Discovery (P_{mer})*	*Probability of Commercial Success $P_c = P_g \times P_{mer}$*
OML Z_a	*0.75*	*692.43*	*2.1*	*51*	*41*	*0.68*	***0.51***
OPL Z_b	*1.0*	*841.81*	*2.0*	*51*	*41*	*1.0*	***1.0***
OML Z_c	*1.0*	*853.32*	*2.0*	*51*	*41*	*1.0*	***1.0***

Table 10. Assets classification with the estimated probabilities using Doug et al. [6]

Hydrocarbon class	**Project maturity sub-classes**	**Doug et al Class Boundaries**		**Case Study Asset**	**Estimated GCoS %**	**Estimated CoC %**	**Asset Status**
		Approx. GCoS %	**Approx. CoC %**				
Reserves	On Production	100	100	OML Yc	100	100	Commercial
	Approved for Development	100	95 - 100	OML Zc	100	100	Commercial
	Justified for Development	100	50 - 100	OPL Zb	100	100	Commercial
Contingent Resources	Development Pending	100	50 - 95	OPL Yb	100	95	Sub-Commercial
	Development on hold	100	20 - 80	OPL Xb	100	70	Sub-Commercial
				OPL Xc	100	80	Sub-Commercial
	Development not Viable	100	0 - 30				
Prospective Resources	Prospect	5 - 50	5 - 25				
	Lead	0 - 15	0 - 10				
	Play	N/A	N/A				

4. CONCLUSION AND RECOMMENDATIONS

4.1 Conclusion

A successful hydrocarbon discovery is one with such volume, at the prevailing global hydrocarbon price, that can pay for the life-cycle cost of the venture and yield a reasonable profit margin for the investor. The petroleum volume that satisfies this condition is termed commercial volume. This study has provided explorationists with the needed predictive tool to evaluate the chance of commercial hydrocarbon volume availability for a worthwhile exploration venture. The results of this study show that a new framework to estimate the chance of commercial hydrocarbon discovery in an extensively explored basin is developed with the combined concepts of geological chance of success, discovery efficiency and minimum economic reserves. The derivation of the probability for geological success (P_g) with the digitalized Milkov Risk Table and the estimation of the chance of commercial discovery (P_c) using the newly derived model is an improvement over the elicitation method by Doug et al., [6] in their attempt at a quantitative SPE-PRMS. The estimated probabilities aligns with the postulations of Doug et al., [6] for hydrocarbon resources classification and therefore, rightly used to predict the appropriate resources class for the analysed case studies.

In addition to this main objective, the study also made other remarkable contributions. It plotted the Niger Delta basin exploration “Cream-Off Curve” for the first time in a bid to identify its prospectivity status as an extensively explored hydrocarbon basin. The curve is basically used to evaluate the optimal timing to enter or exit a basin for exploration activities. The result of the cream-off curve plot portrays the basin as active with potentials for hydrocarbon prospectivity. The study also estimated the size of Niger Delta basin and the three terrain sizes required to estimate the discovery efficiency of the terrains using the ArcGIS software. The basin is estimated to be about 301,000km^2. This estimate aligns with the work of [20] which puts it at 300km^2. The onshore, offshore and deep offshore terrains of the basin are estimated at 94,414km^2, 52,100km^2 and 153,487km^2 respectively.

4.2 Recommendations

1. The developed new framework for chance of commerciality should be applied in extensively explored basins as a predictive method to evaluate the chance of a hydrocarbon asset to be commercial at discovery.
2. The work has presented a better technique to obtain the probabilities required for asset classification in the Doug et al., [6] Matrix instead of deriving them by elucidation (expert’s experience & judgement).
3. The Creaming-off curve of a basin should be used together with this new framework to evaluate an exploratory basin’s potentials and as a guide to decide the entry or exit time of a hydrocarbon exploration basin.

DISCLAIMER

The products used for this research are commonly and predominantly use products in our area of research and country. There is absolutely no conflict of interest between the authors and producers of the products because we do not intend to use these products as an avenue for any litigation but for the advancement of knowledge. Also, the research was not funded by the producing company rather it was funded by personal efforts of the authors.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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