Modified Rate Threshold Model (M-Rtm) For Chance of Commerciality and Development of Petroleum Assets

Georgeson, Victor U.*, Iledare,Wumi, Ajienka, J. A.
Emerald Energy Institute (EEI), University of Port Harcourt, Port Harcourt Nigeria

Abstract: *Discovered volumes of hydrocarbon should be in such quantity as to pay for the cost of discovery, development, production and abandonment; and yield a reasonable profit margin to be considered for development. This quantity, which differentiates the discovered hydrocarbon into commercial and sub-commercial quantities should be accurately estimated, as it forms the basis for investment decision of discovered hydrocarbon assets. This work evaluates the Rate-Threshold Model (RTM) used in Nigeria to determine the commerciality of discovered crude oil with a view to compare its efficacy with respect to other globally established hydrocarbon resources commerciality models. It applies a modified version of RTM (M-RTM) for commerciality determination using Net Present value as recommended by SPE-PRMS to address the inherent inadequacies in RTM. The result shows that the statutory RTM approach used in Nigeria does not have economic basis as the stipulated commercial thresholds apparently do not represent the true thresholds of commerciality when subjected to known economic metrics. The RTM are not considered alongside such parameters as crude oil price, costs and fiscal regimes. The M-RTM, which is based on established economic metrics gives a comparatively better result. It estimated a minimum economic threshold rate of 25,715 BOPD at oil price of $40/bbl or 10,000BOPD at oil price of about $46/bbl for the onshore/shallow water terrain of Nigeria. The minimum economic threshold for the Nigerian deep offshore is estimated at 26,035BOPD at crude oil price of $40/bbl or 25,000BOPD at crude oil price of about $41/bbl. It estimated the chance of success of exploration activities in the prolific Nigerian Niger Delta region as 0.76 using over fifty years empirical drilled well data from the region. This work recommends a modification of the methods currently used in Nigeria to determine crude oil commerciality to account for the impact of oil price, investment costs, and fiscal terms at various expected earning rates for a more realistic estimation. It thus recommends a review of the Guidelines that specified statutory threshold rates to make the determination of thresholds of commerciality an investment decision of investors, which will be purely driven by economics instead of statutes.*

Keywords: *Hydrocarbon, Commerciality, Rate Threshold, Modified Rate Threshold, Reserves, Minimum Economic Field Size (MEFS)*

I. Introduction

The chance of commerciality is a concept that is fundamental to Reserves and Resources estimation (Doug et al 2014). The Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC) definitions for various categories of reserves have established a general guideline that could ensure consistency in practice globally. According to SPE-Petroleum Resources Management System (PRMS) 2011, ~~a~~hydrocarbon accumulation must be sufficiently defined to establish its commercial viability to qualify for inclusion 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. However, the assessment of commerciality of an accumulation is generally the responsibility of the country or company concerned with the possible development of the accumulation and this will vary according to local conditions and circumstances. Therefore, the resultant effect is different frameworks for resource classification by countries, operators and agencies in the oil and gas industry.

Hydrocarbon assets classification into different categories based on economic value addition 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 resource that can generate revenue, under the prevailing economic environment and technological know-how; and the volume of the resources that can be upgraded to add economic value should economic environment becomes more favorable or with technological advancement 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. Thus, distinction between commercial and sub-commercially known

accumulations (and hence between reserves, contingent and prospective resources) is of immense essence for effective resources management.

McCray (1975) presented the application of economics, probability, and statistics in the petroleum industry Return-on-Investment, decision trees and economic models. The Minimum Economic Field Size (MEFS) is another resource commerciality estimation technique. The MEFS, also referred to as Minimum Economic Reserves (MER), is the minimum volume of recoverable oil and gas reservesnecessary to make the project an economic success. It incorporates 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 in its techniques.

Though, various methods have been used to evaluate the chance of commerciality and development of a hydrocarbon prospect, there is no generally accepted methodology in use presently. Doug et al (2014) therefore observedthat a consistent framework for estimating chance of commerciality and development would be a useful tool given the rather subjective nature of many such estimates in use,forthe commercial dealings and regulatory disclosures.

In Nigeria, a key application of hydrocarbon resourceevaluation and classification is for oil block conversion from Oil Prospecting License (OPL) to Oil Mining License (OML). It is statutorily required to establish the commerciality otherwise known as economic viability of the discovered hydrocarbon asset before conversion to OML. Incidentally, none of the conventional methods of estimating the commerciality of hydrocarbon asset is applied in Nigeria. The regulatory authority applies a Rate Threshold Model (RTM) for the conversion purpose. In accordance with the provisions of paragraphs 8(b) and 9, Schedule 1 of the Petroleum Act No. 51, 1969, an OPL (excluding deep offshore) is required to be capable of producing a commercial quantity of at least 10,000 barrels of oil per day (bopd) before conversion to an OML while for deep offshore, 25,000 bopd is required.
This guideline used in determining commerciality in Nigeria for onshore and deep offshore blocks in Nigeria lacks economic considerations. It suggests that, irrespective of the prevailing crude oil price, an onshore/continental shelf or deep offshore oil block with capacity to produce the minimum rate of the RTM would give a profitable return on investment.

This paper aims to determine the efficacy of the statutory minimum RTM as true thresholds of commerciality in Nigeria, and if otherwise, modify the RTM by integrating key economic variables to ascertain commerciality or otherwise of any hydrocarbon find. Consequently, the modified RTM (M-RTM) would be standardized andcomparedto the SPE-PRMS Framework and Minimum Economic Field Size. It shall present the Nigerian petroleum industry with a more robust multi-variable, economics-based hydrocarbon commerciality determination tool for block conversion. The resulting model shall address the SPE-PRMS recommendation for profitability model for hydrocarbon resources evaluation and classification.

II. Methodological Framework

The methodological framework adopted in the study is the Richard Corrie Modelfor calculating Minimum Economic Field Size (MEFS).

$$MEFS = \frac{EC\ x\ EUR}{N_f\ x\ NPV} \quad \text{.....(1.0)}$$

Where:

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

Richard Corrie Minimum Economic Reserves (MER) which is same as the Minimum Economic Fields Size is given as:

$$MER = \left[\left(\frac{1-P}{p}\right)\right] x \left[\frac{EC}{UP}\right] \quad \text{..... (2.0)}$$

Where:

MER = Minimum Economic Reserves (bbls)
P = Probability of success (%)
UP = Expected Unit Profit ($/Bbl)

Nigerian Model for Commerciality Determination

The RTM methodology stipulated by the Nigerian Oil and Gas Guideline for determining the commerciality of an oil block classifies the terrains into two major categories namely onshore and deep offshore. The shallow waters are grouped under onshore category.

This implies that an oil block with a minimum of three wells drilled in the discovered field or fields which has capacity to produce at aggregate production rates of 10,000BOPD and 25,000BOPD for onshore/continental shelf and deep offshore respectively is commercial irrespective of the prevailing oil price and the cost of development of the block.

If Q_o is the quantity of oil produced in time t, is given by the product of the flow capacity of the field (q_o) and the total flow period (t),

$Q_o = q_{of}(t)$ …….(3.0)

In the context of the Nigerian Regulatory Guideline therefore, Q_o is a minimum of:

10,000t …….. (4.0) for Onshore/Continental shelf;

In the same vain, the Q_o for deep offshore terrain is:

25,000t ……(5.0)

The Minimum Economic Reserve is estimated by simply multiplying Q_o by either the field life orby the lease life. In this study, and for the purpose of equitable comparison of results of estimated Minimum Economic Reserves on equal time scale, the lease life (T) of 20 years is used.

Thus, for Onshore/shallow waters,

MEFS = 10,000t x T…….(6.0)

For deep offshore:

MEFS = 25,000t x T…….(7.0)

Equations (6.0&7.0) above are the current Rate Threshold Model (RTM), which key variables are the production rate (fixed by law) and total production period.

The Proposed Modified Rate Threshold Model (M-Rtm) Methodology

Flow model predictions are frequently combined with price forecasts to estimate how much revenue will be generated from a discovered hydrocarbon asset. The commerciality of discovered oil resources can be evaluated from the first principle on the premise that:

A commercial hydrocarbon asset = Profitable Asset …… (8.0)

Profitable Asset is given *as*:

$\pi(Q) = R(Q) - C(Q)$……..(9.0)

Where π = profit
R = Revenue
C = Total Cost
But, R = P x Q
Where P = Price

Thus, Profit $\pi = P(Q) - C(Q)$……(10.0)

And Profit as a function of various Cost inputs gives

$\pi(Q) = PQ(x,y) - wX - rY$……..(11.0)

where w = per unit cost of input X
r = per unit Cost of input Y

If C(Q) = Total Cost = CAPEX + OPEX + Royalty + Tax,

then Equation (11.0) becomes:

$\pi(Q) = PQ_o - C_T$ ……..(12.0)

where P = Oil price ($)
Q = Cumulative Production or Expected Ultimate Recovery (Bbls)

The net present value (NPV) or net present worth (NPW) is the sum of all the discounted future cash flows. Because of its simplicity, NPV is a useful tool to determine whether a project or investment will result in a net profit or a loss. A positive NPV results in profit, while a negative NPV results in a loss. NPV is a central tool in discounted cash flow (DCF) analysis and is a standard method forusing the time value of money to appraise long-term projects.

Given the (period, cash flow) pairs (T, CF_t) where T is the total number of periods, the net present value NPV is given by:

$$NPV\ (r,T) = \sum_{t=0}^{T} \frac{CF_t}{(1+r)^t} \quad \text{……..……..(14.0)}$$

Where: t – the time of the cash flow

r – the discount rate, i.e. the return that could be earned per unit of time on an investment with similar risk

CF_t– the net cash flow i.e. cash inflow – cash outflow, at time *t*.

Expressing Profitability in terms of Net Present Value, Equation 14.0 becomes:

$$NPV = \sum_{t=t_{0+1}}^{T+t_0} \frac{PQo-(C_T)}{(1+r)^t} \quad \text{…….(15.0)}$$

Equation 3.16 is expanded as:

$$NPV = \sum_{t=t_{0+1}}^{T+t_0} \frac{PQo-(Royalty_{\ t}+CAPEX_t+OPEX_t+Tax_t\ )}{(1+r)^t} \quad \text{…… (16.0)}$$

The variable, Q_o is a function of field flow rate (q_{of}) and flow period (t) and

$$q_{of} = \sum_{n=1}^{N} q_i \quad \text{……..(17.0)}$$

Where:

q_{of} is total field flow rate in BOPD

q_i = individual well flow rate BOPD

n = Number of wells (n=1,2,3…N)

The application of Equation (17.0) as it were, implies a constant flow capacity throughout the lease life. However, the flow rate builds up at a certain rate to the peak production where it stabilizes for some time before declining at some rates to economic limit. Thus, the decline curve concept becomes imperative.We Assume an exponential decline curve pattern for simplicity.

From the general exponential equation for cumulative production, the cumulative production (from the beginning of the exponential decline model, t_{exp} to any production time with rate, q_o), is:

$$Q_{exp} = \frac{q_{iexp} - q_o}{D_{exp}}$$

……(18.0)

$$Where\ \ D_{exp} = \frac{D_i}{1 + bD_i t_{exp}}$$

……(19.0)

and $t_{exp} = b^{-1}\left(D_{exp}^{-1} - D_i^{-1}\right)$ ……(20.0)

Therefore:

$$Q_{exp} = \frac{(q_{iexp} - q_o)(1 + bD_i t_{exp})}{D_i}$$

……(21.0)

$$Q_{exp} = \frac{\left(q_{oi}\left(1+bD_i t_{exp}\right)^{-\frac{1}{b}} - q_o\right)\left(1+bD_i t_{exp}\right)}{D_i}$$

……(22.0)

$$Q_{exp} = \frac{\left[q_{oi}\left(1+bD_i t_{exp}\right)^{\frac{b-1}{b}}\right] - q_o\left(1+bD_i t_{exp}\right)}{D_i}$$

……(23.0)

Substituting Equation (23.0) into (15.0)

$$NPV = \sum_{t=0}^{T} \frac{\left[\frac{P\left[q_{oi}\left(1+bD_i t_{exp}\right)^{\frac{b-1}{b}}\right] - \left[q_0\left(1+bD_i t_{exp}\right)\right] - C_T}{D_i}\right]}{(1+r)^t}$$ ……..(24.0)

The expanded version of Equation (3.25) to show the vital cost components is in the form:

$$NPV = \sum_{t=0}^{T} \frac{\left[\frac{P\left[q_{oi}\left(1+bD_i t_{exp}\right)^{\frac{b-1}{b}}\right] - \left[q_0\left(1+bD_i t_{exp}\right)\right] - (Royalty + CAPEX + OPEX + TAX)}{D_i}\right]}{(1+r)^t}$$ (25.0)

Equation (25.0) is therefore, a Modified-RTM methodology for calculating the commerciality of hydrocarbon discovery with projected production profile. It links the economic parameters (NPV, Oil price and interest rate) to reservoir with flow rate as a proxy for reservoir andfluid characteristics. It is also composed of fiscal regime considerations which are embedded in the Royalty and Tax components of the Model. It gives a more robust estimate of commerciality of the discovered field based on expected flow capacity of the field.An oil block is deemed to be profitable (Commercial) at the prevailing oil price (P) and total development cost if the calculated NPV is greater than zero.

Data Sources and Analysis

The data for the validation of these models are obtained from the prolific Niger Delta Oil producing region of Nigeria. Three fields are selected from the onshore, continental shelf and deep offshore terrains of the Niger Delta.

A critical data input for Richard Corrie's MEFS model is the probability of success of exploration/appraisal wells. Most scholars assume values for this variable in their analysis and stochastically generate different ranges of the probability values. This approach may introduce a level of error and uncertainty in the estimated volume. Therefore, in this work, the probability of success (P_s) for Nigerian petroleum industry is empirically determined by analyzing exploration drilling data from 1956 to 2015.

The result is compared with the RTM. The analytical technique for determining the commercial value of Exploration & Production projects is built on the Net Present Value Analysis which incorporates such parameters as production volumes and rate capacity of oil, CAPEX & OPEX costs, oil & gas prices and fiscal regimes to derive the modified RTM for a more realistic and robust analysis of hydrocarbon commerciality determination in line with the recommendation of SPE-PRMS.

Exploration, production and development costs are three major cost factors. These costs are affected bydifferent geological terrains, such as onshore, swamp, offshore, deep offshore and ultra-deep offshore. The important cost variablessuchas welldepth, water depth (for offshore exploration) andtimespent on activities, are also significant to the costs of exploration, development, and production.

For commerciality, exploration cost has great impact. Exploration costs comprise ofexploration licenses, geological and geophysical costs, costs of drilling and equipping exploratory wells, and others. Exploration Cost is key variable for minimum economic reserves calculation.

The flow rate data input for the Nigerian rate-based model and the profitability model are obtained from Drill Stem Test (DST) or calculated using Darcy's Equation with input data directly from the reservoir and fluid parameters and PVT analysis. This basic data can be used to simulate the production profile of the block or field till end of lease life or field life as maybe required. The general Nigerian Fiscal Terms aresummarized in Appendix A.

III. Results And Discussions

The probability of success (P) is statistically obtained from the Nigerian petroleum industry drilling data bank from inception in 1956 to 2015. A total of 3,337 exploration and appraisal wells wereanalyzed. 2,534 of the wells representing 76% were successful while the balance of 803 wells representing 24% weredry. Analysis of the data also shows that more exploration and appraisal wells weredrilled onland and continental shelf (Onshore/shallow offshore terrain) than the relatively new deep offshore and ultra-deep offshore frontier terrain. A total of 3,271 exploration and appraisal wells were drilled in the onshore/offshore region. 76% of the wells (2,479 wells) were successful whereas the remaining 24% (792 wells) were dry. 20% of the exploration and appraisal wells drilled in the deep waters were dry whereas 80% were successful.

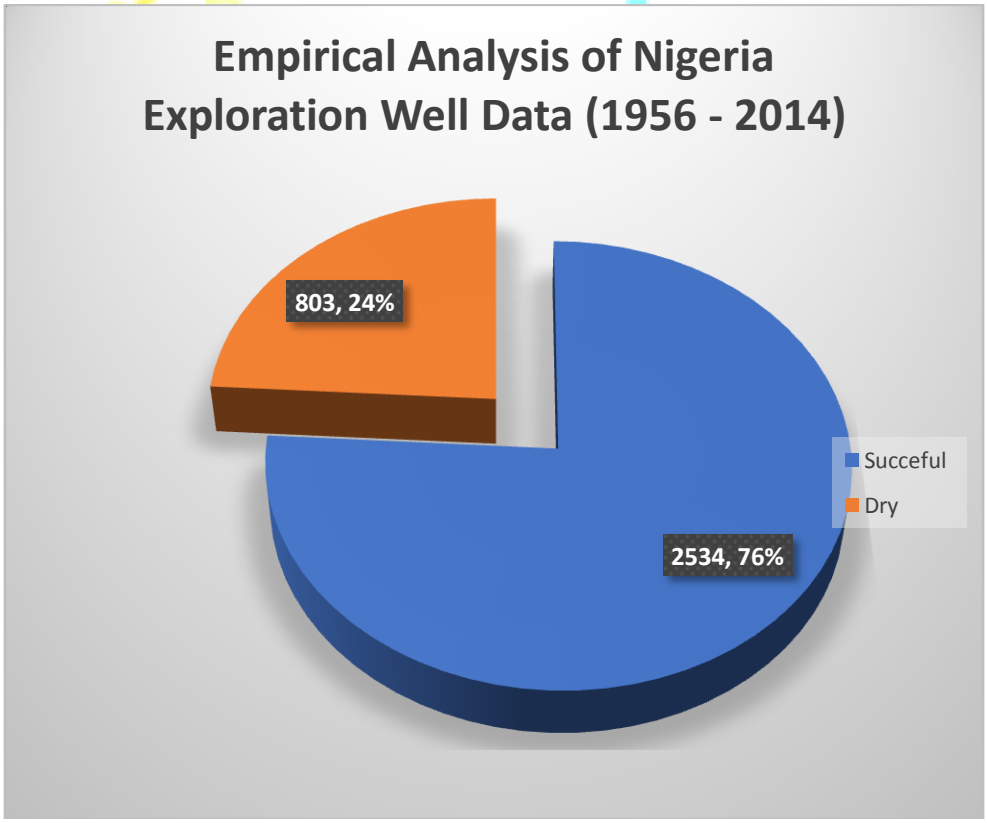


Fig.1.0: The Probability of Success in Nigeria with empirical data

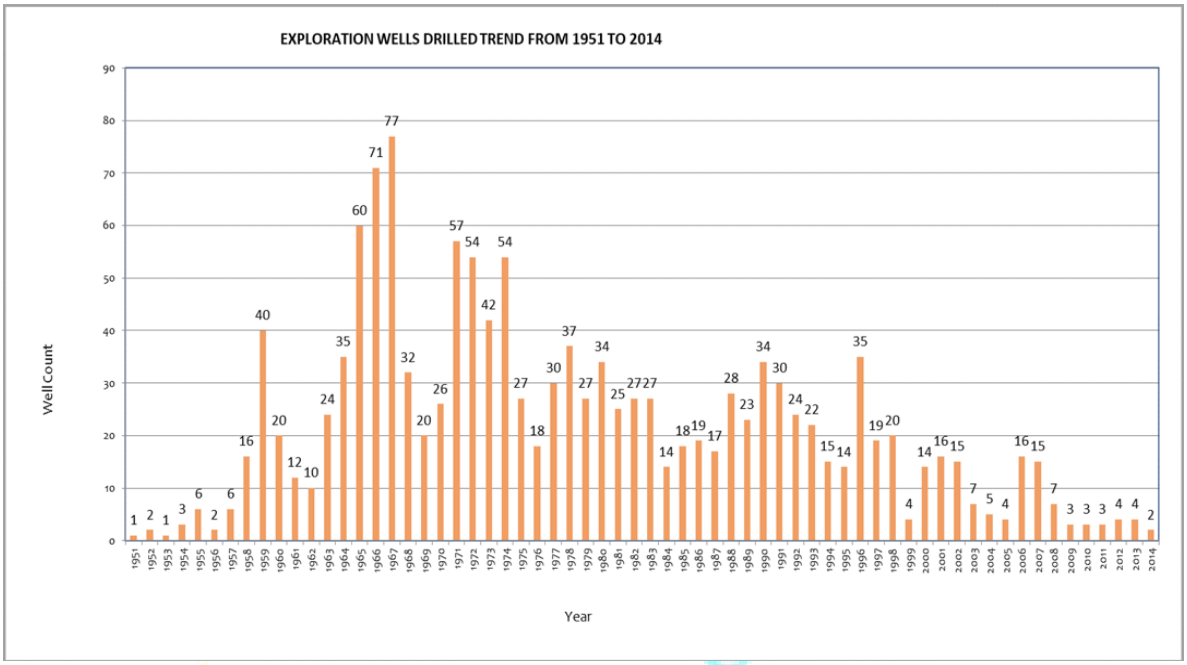


Fig.2.0: Number of exploration wells drilled in Nigeria from 1951 – 2014. *Source: DPR, 2014*

The Richard Corrie's equation for calculating Minimum Economic field size (MEFS) and the economic profitability model are applied to determine the minimum reserves required to establish commerciality and the impact of crude oil price, cost and fiscal regimes respectively, on commercial rates threshold. Most importantly, the specified rates used in Nigeria are evaluated with a view to validate their efficacy as true commercial thresholds. The application of these various methods in this study provided comparative evidence to validate the efficacy of the stipulated threshold rates for the commerciality of discovered hydrocarbon for a logical decision on its continued application or replacement with an improvedversion as creditable alternative.

3.1 Estimation of Minimum Economic Rate Using Richard Carrie Equation

Calculating the Minimum Economic Reserves using Richard Corrie's Model in Equation (1.0)

Onshore/shallow Offshore:

$$MER_{ons} = \left(\frac{0.24}{0.76}\right)\left(\frac{700\ X\ 10^6}{9.6}\right)$$

= 72, 916,666

= 73MMBO

Deep Offshore:

For Deep and Ultra Deep Offshore Terrain with Exploration Cost of about USD 1.8Billion with expected minimum net income of $9.6/barrel gives a Minimum Economic Rate of:

$$MER_{dof} = (\frac{0.2}{0.8})(\frac{1.8\ X\ 10^9}{9.6})$$

= 187,500,000

= 187.5MMBO

3.2 NIGERIAN RATE THRESHOLD MODEL:

EVALUATION OF THE STIPULATED MINIMUM CAPACITY RATES

For onshore operation with a minimum field rate of 10,000BOPD, using Equation (5.0) as:

MEFS = 1000t x T .....(5.0)

This gives a minimum volume of (10,000 x 365 = 3.65 x 10^6) bbls assuming

continuous production at that minimum rate for every day of the year. For a lease life of twenty (20) years, the total minimum economic volume is (10,000 x 365 x 20 = $73x10^6$) bbls for this terrain.
Thus, the $MEFS_{ons}$ = 73MMBO
In the same vain, for deep offshore terrain is:
MEFS = 25,000t x T .....(6.0)
This gives a minimum volume of (25,000 x 365 = $9.125x10^6$) bbls per year and a total minimum economic volume size of:
(25,000 x 365 x 20 = 182.5 x 10^6) bbls for the 20 years lease life.
Thus $MEFS_{dof}$ = 182.5MMBO
Applying these calculated minimum economic volumes $MEFS_{ons}$ and $MEFS_{dof}$ in Richard Corrie Model in equation (1.0) as the Minimum Economic Field Size (MEFS) and estimate the expected Unit Profit and compare it with the Standard Minimum Expected Unit Profit of $9.6/bbl to determine their adequacy or otherwise as minimum threshold volume for commercial development of a hydrocarbon discovery.

Onshore/Offshore:
For Onshore with Estimated MER of 73 x 10^6

$$MER_{ons} = \left[\left(\frac{1-P}{p}\right)\right] x \left[\frac{EC}{UP}\right]$$

$$UP = \frac{EC(1-P)}{MER_{ons}\ (P)}$$

$$UP = (\frac{0.24}{0.76})(\frac{700\ X\ 10^6}{73\ X\ 10^6})$$

UP = $ 9.6/Bbl
Deep Offshore Terrain:

$$MER_{dof} = \left[\left(\frac{1-P}{p}\right)\right] x \left[\frac{EC}{UP}\right]$$

$$UP = \frac{EC(1-P)}{MER_{dof}\ (P)}$$

$$UP = (\frac{0.2}{0.8})(\frac{1.8\ X\ 10^9}{182.5\ X\ 10^6})$$

UP = $9.8/Bbl

3.3. M-RTMANALYSIS USING EXCEL SPREAD SHEET
Equation (23.0):

$$NPV = \frac{\left[\frac{P\ [\ q_{oi}\left(1+bD_i t_{exp}\right)^{\frac{b-1}{b}}\right] - [q_0\ (1+bD_i\ t_{\exp}] - (Royalty\ +CAPEX\ +OPEX\ +TAX)}{D_i}\right]}{(1+r)^t}$$

The above equation is the Modified Rate Threshold Model. It incorporates all key economic variables together with production rates to present a more robust economic analysis of a discovered field.The solution of M-RTM is derived using EXCEL Spreadsheet.

The Nigerian fiscal regimes and Internal Rate of Returns (IRR) of 10% are applied to all cases.
Case 1.0 is evaluated under Joint Venture Contractual Arrangement whereas Cases 2.0 and 3.0 are for Production Sharing Contract. It should be noted that for Cases 2.0 and 3.0, the same cost components are used and the FPSO used for the production is rented. The cost of the vessel is expensed annually, hence it is treated as OPEX.

CASE 1.0 ONSHORE/OFFSHORE TERRAIN WITH FLOW RATE CAPACITY OF 10MBOPD

Case 1.0 is an onshore block for which the sum of USD30Million was paid as signature bonus when the bid was won. The Operator which is in a Joint Venture partnership with the Government embarked on aggressive Exploration activities for two years and made a discovery after spending USD2 Million per year. The Company plans to spend USD 600 Million per year for 2 years to develop the field which simulation studies show that it will stream at initial rate of 5Mbopd to a plateau of 10Mbopd after a year. It will sustain the peak production for 5 years before declining to economic limit rate of 1000bopd. The field's total life is 20 years.

CASE 2.0: DEEP OFFSHORE TERRAIN WITH FLOW RATE CAPACITY OF 25MBOPD

Case 2.0 is a deep offshore discovery with projected peak flow rate of 25MbopdThe Operator plans to run the economics of this Production Sharing Contract block at a minimum oil price of about USD40/bbl and maximum oil price of USD60/bbl. The total planned CAPEX is USD4.4Billion with Variable OPEX of USD0.2/bbl and Fixed OPEX of USD69.2/bbl.

CASE 3.0: NATE FIELD WITH 60M BOPD CAPACITY IN DEEP OFFSHORE NIGERIA

Nate field is discovered by Nate-1x exploration well in aNigerianoff-shoreblocklocatedabout140KmfromNigeriancoastsinanultra- deep-water terrain with awater depth rangingfrom1400 to 2400m. The 1958 Km^2 area size block is owned by two major international oil Companies in a 50-50 working interest.

The greater Nate area for current development plan has been discovered as two geological accumulations namely Nate Main and Nate West fields. Oil was found in the main Nate structure by Nate-1X well (January2005) whilst Nate-2X appraisal well penetrated the Nate West culmination oil bearing (October 2006). The third well, Nate-3 was drilled in Nate-West Extension of the field in 2013.

The evaluations of complex geological environment for appraisal and development of Nate field have been based on good quality seismic coverage and adequate well data from four wells drilled in the block (including one core and a production test). Previous activities were directed at gathering sufficient and appropriate data to image the reservoirs, enhance well planning and field development, within operational limitations. The data acquisition plan supports the optimization of the economic value of the project by ensuring that any identified data gaps are actively closed.

Using these reliable input data in Richard Corrie's equation, the Minimum Economic Reserves (MER) for the Onshore/Offshore is estimated at 73MMBO. The deep offshore estimated MER value using this equation is 187.5MMBO.

It is also estimated that the possible minimum economic reserves that can result from the stipulated oil flow rates assuming geological, reservoir and economic factors sustain the field to continuously flow at that rate for the lease life of twenty years without decline. This assumption may apparently seem unrealistic because oil field production follows a defined pattern of build-up, plateau and decline phase. This profile shows that the production rate is never static at one rate. It increases initially, stabilize and then decline to economic limit rate.
The results calculated for Case 1.0 using RTM on the assumption of single rate regime for the field coincide almost precisely with those obtained with Richard Corrie's equation. Thus, exactly 73MMBO is estimated for onshore/offshore terrain whereas the estimate for deep offshore at 182.5MMBO is only slightly lower than the Richard Corrie's estimate of 187.5MMBO.

When the minimum economic reserves volumes estimated with RTM are applied into Richard Corrie's Equation to estimate the Expected Unit Profit, the results obtained are equal to the average minimum universal value of $9.6/bbl. Richard Corrie's equation is based on probability which is a statistical assumption that the future will act like the past. The cost component is also the expended exploration/appraisal cost and not the future development and production cost. It is also devoid of economic and fiscal components which significantly affect the commerciality of hydrocarbon discovery. On the other hand, the assumptions in the RTM estimate are both simplistic and impractical.

In view of the observed defects in these techniques, it becomes imperative to subject the statutorily stipulated rates and the resulting reserves volumes to further economic analysis with a tool that addresses the identified lapses in the techniques.

The M-RTM with technical, economic and fiscal components presents a more realistic technique. The model follows the natural trajectory of well flow rate of initial build-up, stabilized plateau and decline. Three cases are modelled. Case 1.0 modelled the onshore/shallow water terrain with a statutory recommended minimum capacity rate of 10MBOPD. This Case is modelled on Joint Venture Arrangement because most companies operating in this terrain are under joint venture arrangement. In Case 2.0, the deep-offshore terrain with rate capacity of 25MBOPD is modelled. The aim is to subject these rates to economic and fiscal evaluation to determine whether they represent thresholds of commerciality. Real field and the prevailing fiscal regimesand Nigeria data are used. It is modelled on Production Sharing Contract Arrangement which is quintessential for

this terrain. Case 3.0 is a Case study of real deep offshore field in Nigeria with a flow capacity higher than the required minimum rate but with a slightly lower reserves volume than the deep offshore case.
The resulting economic metrics for Case 1.0 in Appendix 'B', show a non-commercial outcome for the Contractor but Commercial for the Host Government. The Government has a positive Net Present Value (NPV) of $502 whereas the Contractor has a negative NPV of -$51.57 at 10% IRR. Other profitability Indices are also not favourable to the Contractor. The Present Value Ratio (PVR) is negative and Profitability Index is less than 1.0. The Pay Out period is 21 years.

The flow rate is plotted against NPV to determine the threshold rate at crude oil Price of $40/bbl, IRR of 10% and Federal Tax Rate of 50%. The result shows a threshold rate of 25,715 BOPDinAppendix 'D'. However, considering the importance of price in commerciality determination, the analysis is carried out to determine the crude oil price at which the statutory rate of 10,000BOPD will be commercial. The rate is kept constant whereas crude oil price is plotted against NPV in Appendix 'E'. The resulting threshold price is $45.79/bbl.

Appendix 'F'is the Economic Metrics of Case 2.0. It also shows non-commerciality for the Contractor at NPV of -$38.01 whereas Government has a positive NPV value of $124. The PVR for the Contractor is 0.01, a PI of less than 1 (0.99) and a Pay Out of 21yrs. Appendix 'H' shows a Minimum Economic Rate of 26,035BOPD and a Minimum Economic Price of $40.77 as shown in Appendix 'I'. Appendix 'M'shows the economic metrics for case 3.0, the case Study of Nate field. The field flows at a higher rate capacity of 60,000BOPD. It returned a positive NPV of $142, IRR of 25%, PI of 1.05, GRR of 10.3% and a better pay out of 3.91years despite having a lower recoverable reserves volume of 160MMBO compared to 182.5MMBO used for Case 2.0. Appendix 'N'is the sensitivity run on oil price, rate and tax for Case 3.0. The sensitivity runs for all cases show that Oil Rate and Price are more sensitive to Economic parameters which in this case is NPV. Both parameters are essential in determining and defining commerciality of E&P venture.

The results of the analysis with respect to the research objectives show that the statutory threshold rates apparently do not represent the true thresholds of commerciality. The rates are not fixed on economics basis with due consideration for such important variables as crude oil price, costs and fiscal regimes of a given terrain. Though it appears that the calculated threshold rate of 25,715BOPD for the onshore/shallow waters is significantly off the stipulated statutory rate of 10,000BOPD and even closer to the rate for the deep waters, one may be tempted to conclude that same threshold rate of approximately 26MBOPD should be used for all terrains, but the cost, contractual arrangement and fiscal regimes should be considered before drawing such conclusions. The statutory rate becomes commercial at a slightly higher price of about $46/bbl at the conditions of the evaluation.

The RTM, on the face value, appears to compare significantly well with the result of direct computation of the Minimum Economic Rate using Richard Corrie Equation. However, this may lead to erroneous conclusion that the stipulated rates in Nigeria arein line with global standard because the assumptions for that analysis aretoo simplistic and unrealistic. The analysis assumed that the Onshore/Continental Shelf asset flows from the onset at the stipulated rate of 10Mbopd sustainably till the end of the lease life of twenty years. This also applies to the Deep-water asset, which is assumed to flow at a constant rate of 25Mbopd. This negates the normal hydrocarbon production profile that shows a build-up at the early stage to a plateau rate which is sustained for some period before decline to the asset's economic limit rate. The M-RTM appears to be a better realistic model to evaluate the commerciality of a hydrocarbon discovery as it putsinto consideration all the relevant parameters for economic analysis of the reserves.

The comparison of the result of the deep offshore analysis with the Case Study of Nate field both of which are evaluated on similar cost outlay, crude oil price, contractual arrangements of Production Sharing Contract and fiscal regime, shows the impact of rate capacity to the economic performance of upstream project. Although Nate field has relatively lower estimated reserves volume of 160 MMBO compared to Case 2.0 reserves volume of 182.5MMBO, Nate field which flows with a greater capacity of 60,000BOPD gives a far better economic performance than Case 2.0 with a flow rate of 25,000BOPD within the same lease life period of 20years. However, this may not be true when subjected to longer period like the full field life in which case Nate field may reach Economic Limit earlier than Case 2.0 with higher reserves volumes produced at slower rate. Thus, in the long run, Case 2.0 may have more volume recovery. Despite that, the 21years pay out period of Case 2.0 vis-à-vis 3 years pay out for Case 3.0 has already markedcase 2 as a bad investment which is terminated ab initio.

IV. Conclusions & Recommendations

4.1 Conclusions: The analysis ofthe results of this study lays credence to the conclusion that the RTM technique is not suitable for the determination of commerciality of new discoveries of crude oil reserves. The model is devoid of basiceconomic metrics, cost considerations and fiscal regimes and therefore, lacks merit in commerciality determination. Although the analysis, confirms that production rates below the stipulated values may not sustain a viable commercial development of fields in the specified terrain unless at reasonable oil price above $46/bbl, better cost minimization and more favourable fiscal regime, it does not still make RTM an effective technique for commerciality evaluation. The M-RTM technique is more robust to evaluate commerciality subject to availability of more detailed and reliable data. The probability of success for the Nigerian petroleum industry has been established as 0.76 from empirical analysis of the exploration drilling data in the country from 1956 to 2015. The study has therefore, achievedthe objectives of evaluating the efficacy of the RTM technique, proposed M-RTM as a veritable alternative and basis for the review of the Nigerian guidelines on hydrocarbon resources commerciality determination.

The sensitivity study shows the elasticity of the oil flow rate and crude oil price, Company Income Tax (CITA) in the determination of commerciality of discoveries. The result shows that the parameters are very elastic to the commerciality of newly discovered crude oil discoveries. It therefore implies that the fiscal regime, the flow rate of the resource and the quantity of the recoverable reserves are very important factors that impact of commerciality petroleum asset.

4.2 RECOMMENDATIONS:

In view of the above conclusions, it is recommended as follows:

1. The stipulatedstatutory commercial rates of 10,000BOPD for onshore/shallow water terrain and 25,000BOPD for the deep offshore should not be considered as minimum commercial thresholds since they are not backed up by economics.
2. The M-RTM Economic Model applied here, which provides a more robust economic evaluation of new discoveries should preferentially be used over RTM and other simple economic reserves models for commerciality determination to avoid costly mistakes in critical economic decision.
3. There is need to review the NigerianGuidelines that specified statutory threshold rates to make the determination of thresholds of commerciality an investment decision of investors and purely driven by economics instead of statutes.

V. Acknowledgements

We are grateful to Dr. Joseph Echendu for his technical inputs and editing of the manuscript. We also appreciate Mrs. Chinyere Georgeson for her support and guidance in the analysis. We thank Mr. Amadasu, Enorense and Akpomudjere, Okiemute for approval to use some of the data and providing moral support. Finally, we acknowledge the support of Network E&P Nigeria Limited for some vital provisions that eased the stress of the work.

VI. Appendices

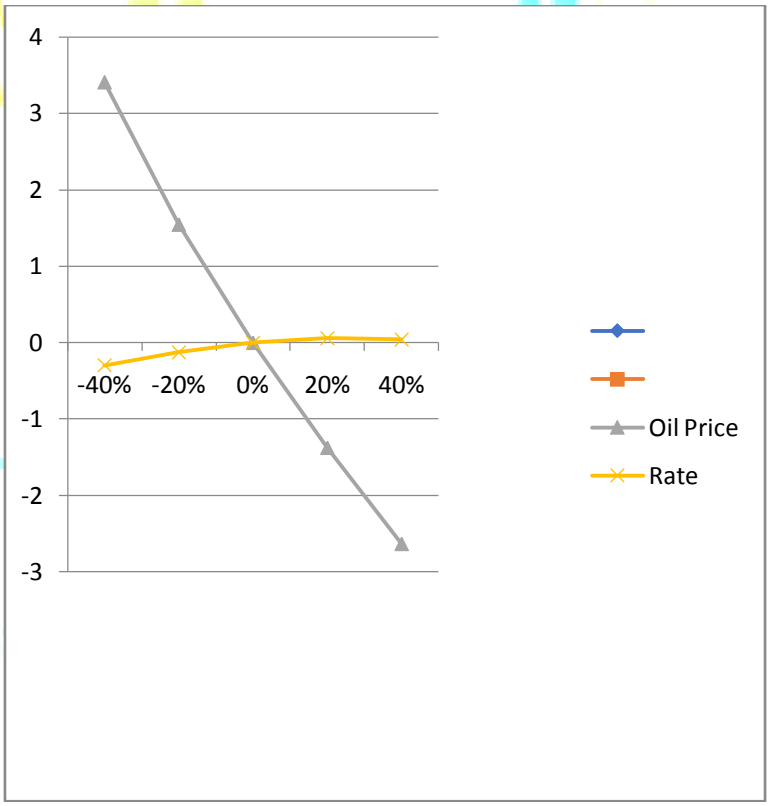
Appendix 'A': Summary of Nigerian Fiscal Regime

FISCAL TERMS FOR JV AND SOLE RISK ROYALTIES				JV & SR	
Terrain			Rates (%)	LIMIT	
Onshore			20.00%	ONSHORE	
Offshore				OFFSHORE	
100M Water Depth			18.50%	100	m
101-200M Water Depth			16.50%	200	m
201-500M Water Depth			12.00%	500	m
500M Water Depth			8.00%		
Inland Basins			10.00%	INLAND BASIN	
				PSC	
ROYALTIES FOR ONSHORE AND SHALLOW OFFSHORE PSC				ONSHORE	
Production < 2000 BOPD			5.00%	2000	bopd
Production btw 2000 & 5000 BOPD			7.50%	5000	bopd
Production btw 5000 & 10,000 BOPD			12.50%	10000	bopd
Producton > 10,000			20.00%		
OFFSHORE UP TO WATER DEPTH OF 100 METERS				SHALLOW	
Production < 5000 BOPD			2.50%	5000	bopd
Production btw 5000 & 10,000 BOPD			7.50%	10000	bopd
Production btw 10,000 & 15,000 BOPD			12.50%	15000	bopd
Producton > 15,000			18.50%		
FISCAL TERMS FOR PSC				PSC	
In areas from 201 to 500 Metres Water Depth			12.00%	500	m
From 501 to 800 Metres Water Depth			8.00%	800	m
From 801 to 1000 Metres Water Depth			4.00%	1000	m
In areas in excess of 1000 Metres Depth			0.00%		
ROYALTY RATES FOR INLAND BASIN			10.00%	INLAND BASIN	
FISCAL TERMS FOR MARGINAL FIELDS				MARGINAL	
Definition	Limit		Rate		
Production < 5000	5000		2.50%	5000	bopd
Production btw 5000 & 10,000 BOPD	10000		7.50%	10000	bopd
Production btw 10,000 & 15,000 BOPD	15000		12.50%	15000	bopd
Production btw 15,000 & 25,000 BOPD	25000		18.50%	25000	bopd
FISCAL TERMS ON ROYALTY ON GAS SALES					
Onshore			7.00%		
Offshore			5.00%		

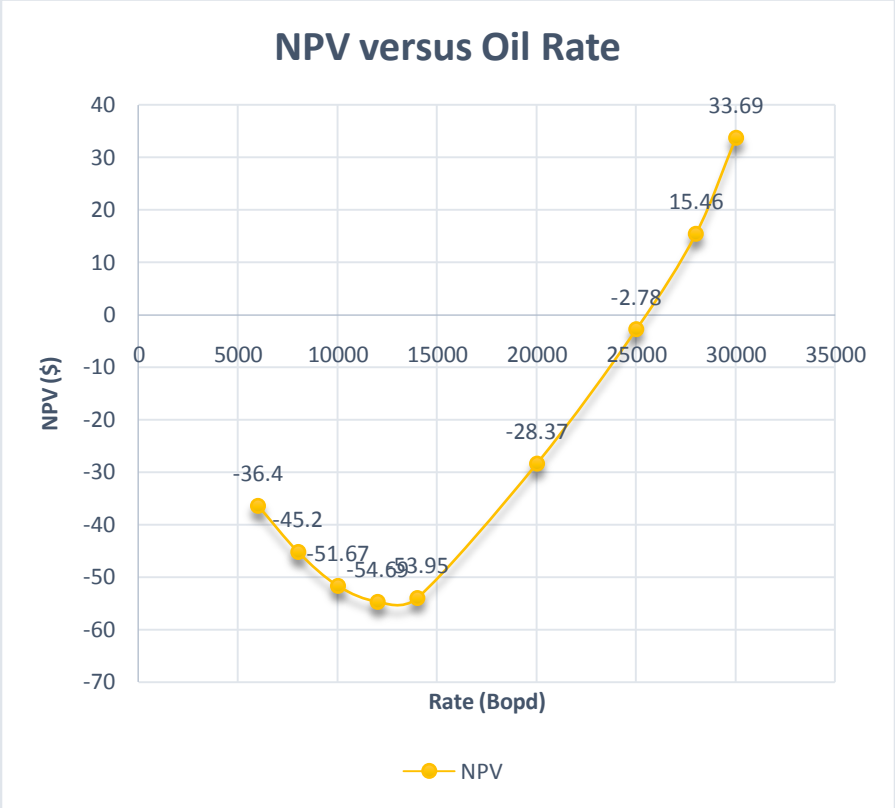
Appendix 'B': Economic Metrics for Case 1.0

Metric Systems Measures			Host Govt. AIT $ MM	Contractor AIT $MM
Net Present Value @	10.00%		$502.56	($51.67)
Internal Rate of Return				8.83%
Present Value Ratio				-0.07
Profitability Index				0.93
Growth Rate of Return				9.6%
Undiscounted Take Statistics			58.5%	41.5%
Discounted Take Statistics			111.5%	-11.5%
Disc. Payout Period, Years				21.00
PV of OPEX @10%, $MM	15.57			
PV of CAPEX @10%, $MM	736.71			
PV of TC @10%, $MM	752.28			
Unit CAPEX, S/Bbl	10.09			
Unit OPEX, S/Bbl	0.21			
Unit Technical Cost, S/Bbl	10.31			

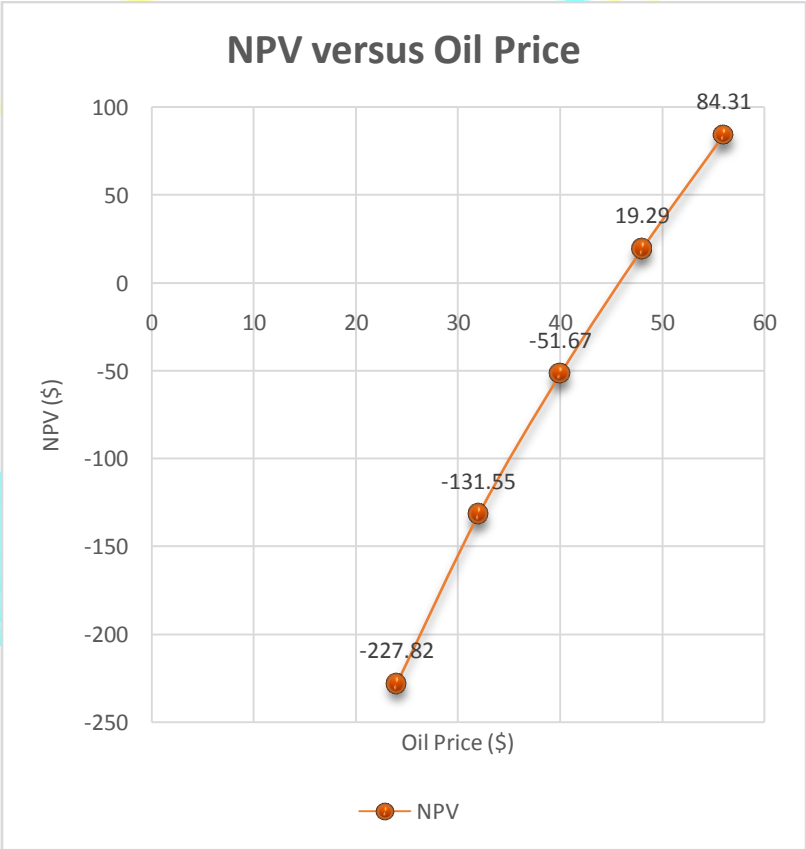
Appendix 'C': Oil Price and Rate Sensitivity for Case 1.0



Appendix 'D': Minimum Economic Rate for Case 1.0



Appendix 'E' Minimum Economic Price for case 1.0

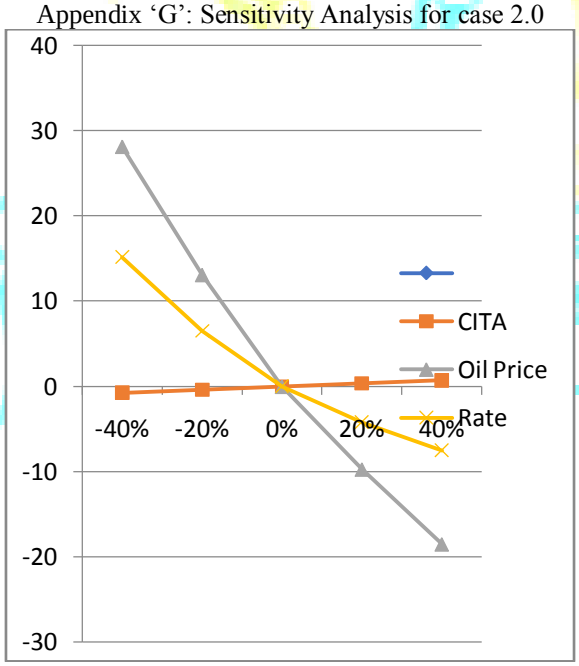


Appendix 'F': Economic Metrics for Case 2.0

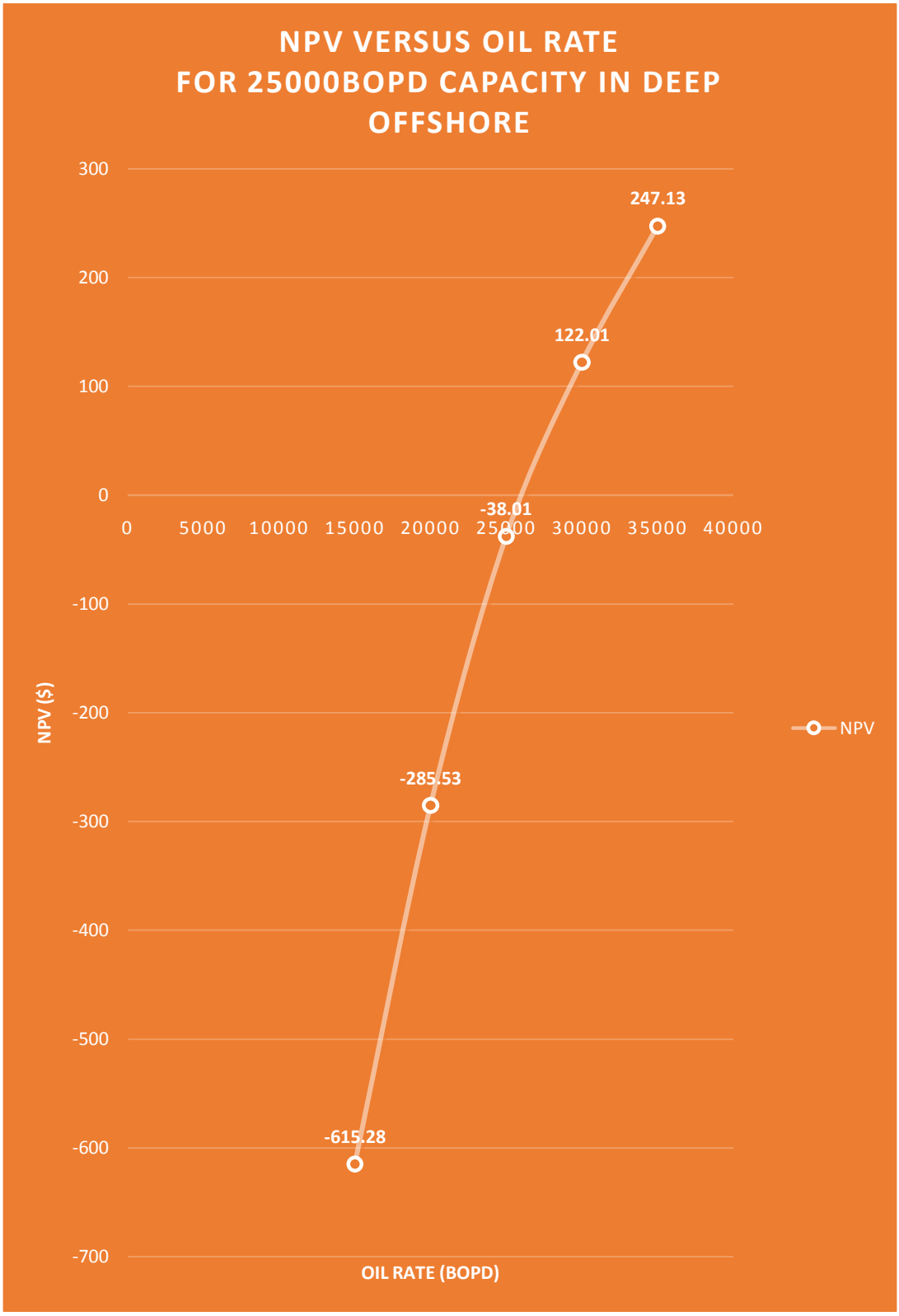
Metric Systems Measures			Host Govt. AIT $ MM	Contractor AIT $MM
Net Present Value @	10.00%		$127.47	($38.01)
Internal Rate of Return				9.54%
Present Value Ratio				-0.01
Profitability Index				0.99
Growth Rate of Return				9.9%
Undiscounted Take Statistics			14.8%	85.2%
Discounted Take Statistics			142.5%	-42.5%
Disc. Payout Period, Years				21.00
PV of OPEX @10%, $MM	1,018.69			
PV of CAPEX @10%, $MM	1,861.10			
PV of TC @10%, $MM	2,879.79			
Unit CAPEX, S/Bbl	10.20			
Unit OPEX, S/Bbl	5.58			
Unit Technical Cost, S/Bbl	15.78			

Table 4.6: Economic Metrics for Case 2.0

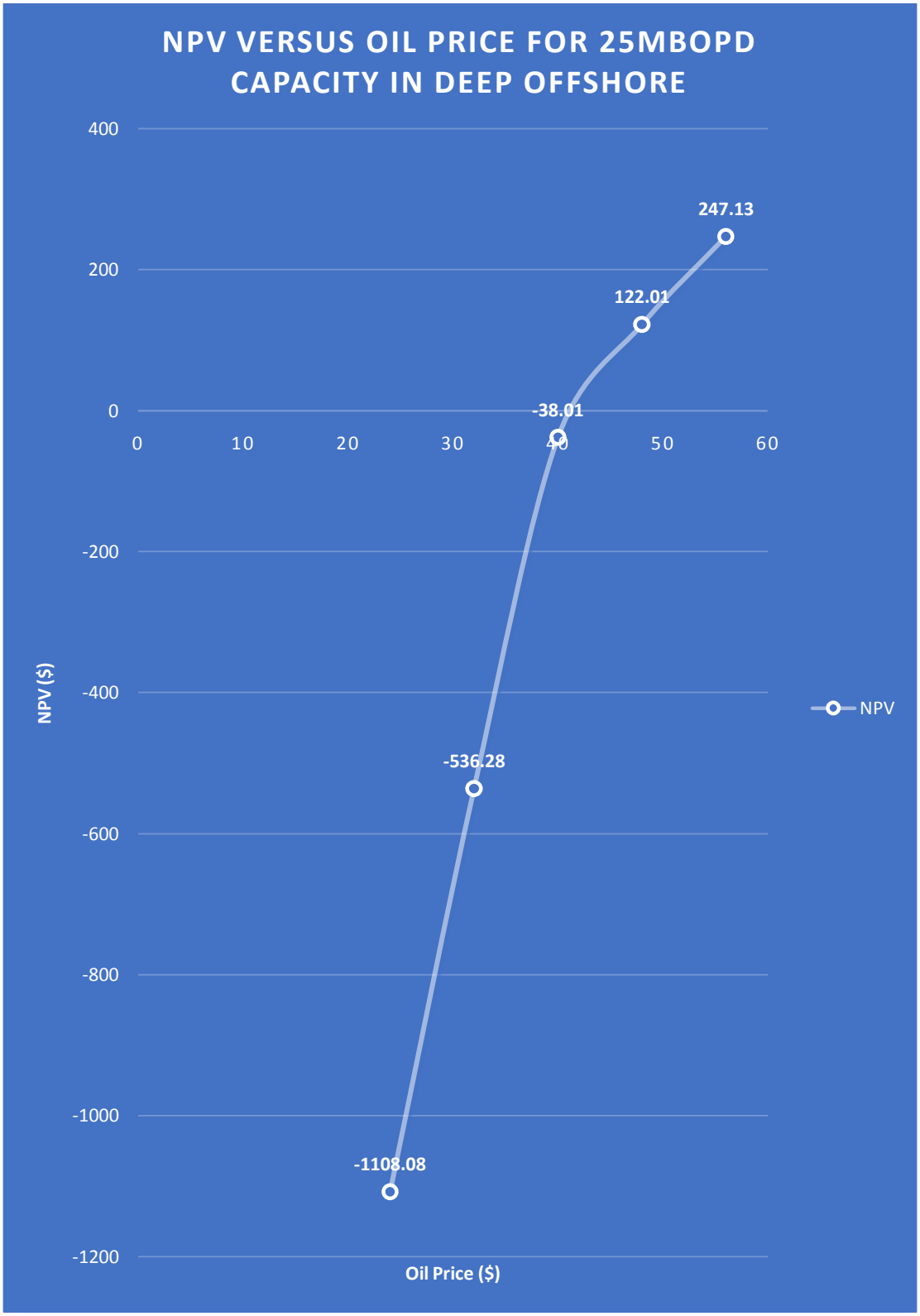
Appendix 'G': Sensitivity Analysis for case 2.0



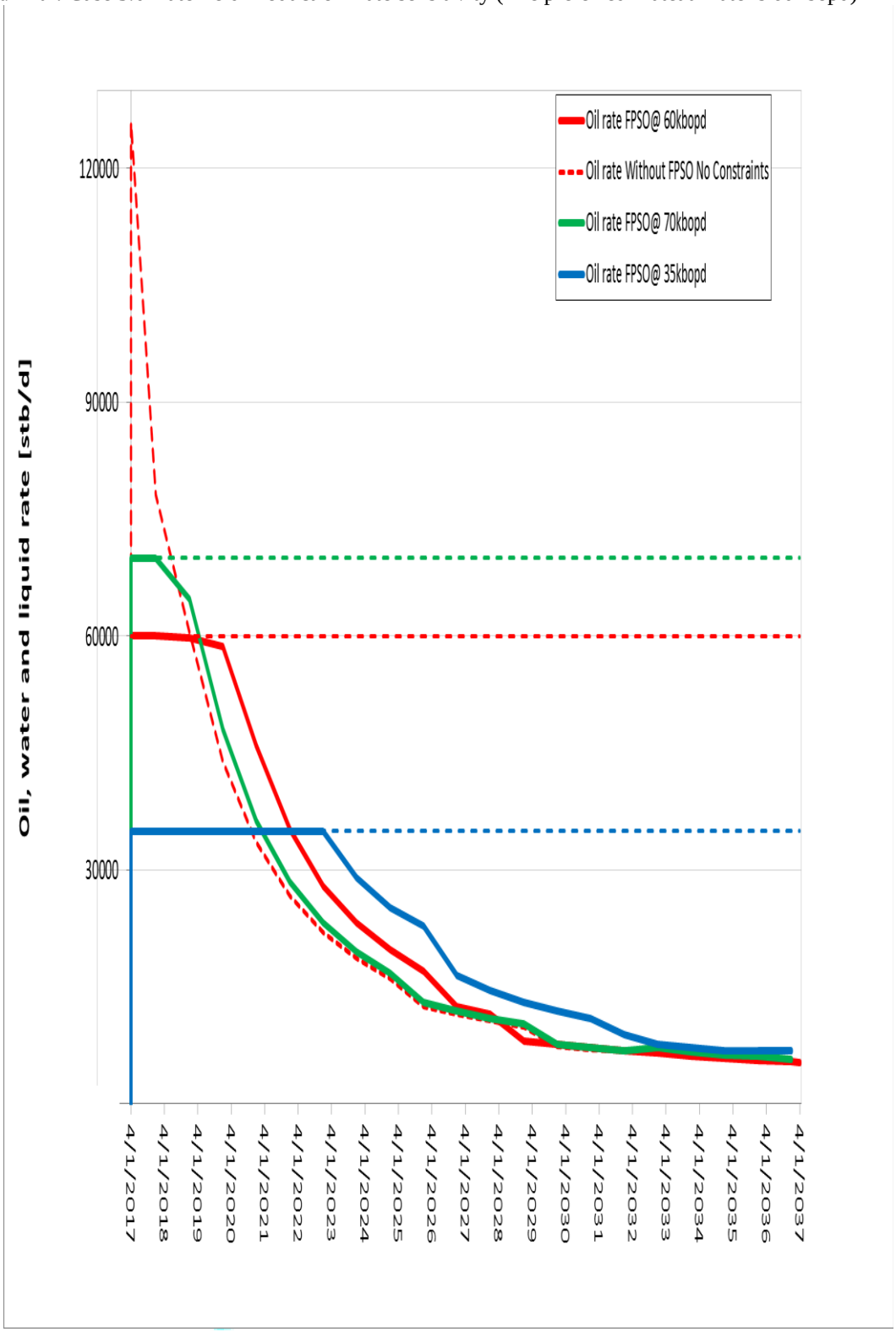
Appendix 'H': Minimum Economic Rate for Case 2.0



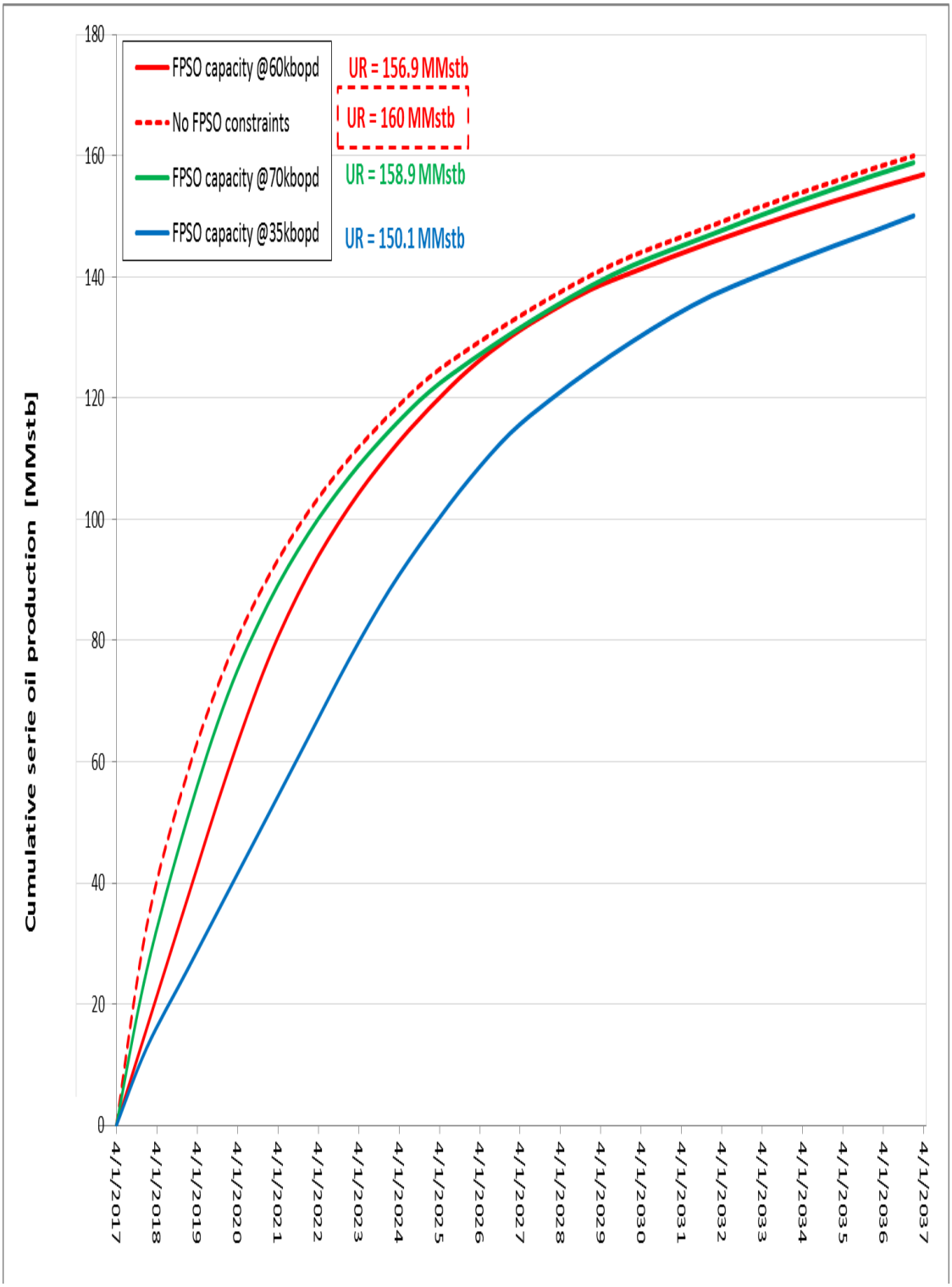
Appendix 'I': Minimum Economic Price for Case 2.0



Appendix 'J': Case 3.0 Nate field Production Rate sensitivity (The preferred Plateau Rate is 60kbopd)



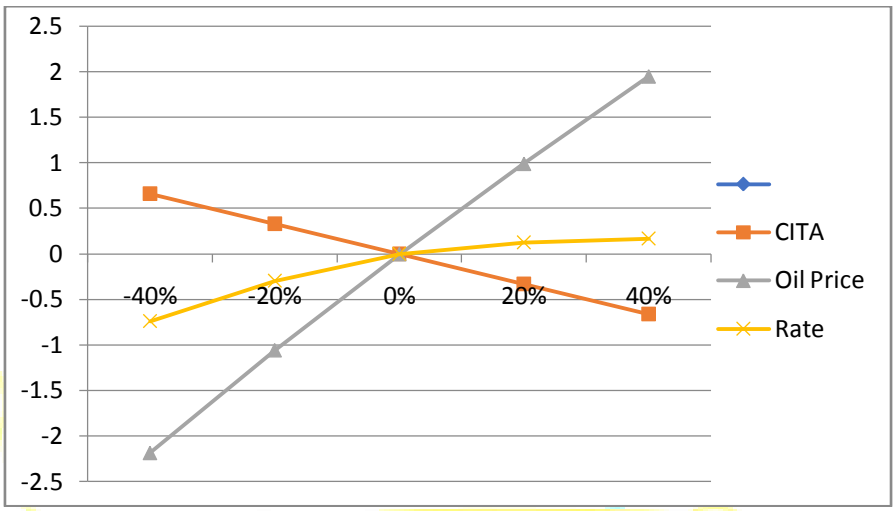
Appendix 'k': Case 3.0 Nate field EUR Sensitivity



Appendix 'M': Economic Metrics for Case 3.0

Metric Systems Measures			Host Govt. AIT $ MM	Contractor AIT $MM
Net Present Value @	10.00%		$1,057.22	$141.96
Internal Rate of Return				24.92%
Present Value Ratio				0.05
Profitability Index				1.05
Growth Rate of Return				10.3%
Undiscounted Take Statistics			109.1%	-9.1%
Discounted Take Statistics			88.2%	11.8%
Disc. Payout Period, Years				3.91
PV of OPEX @10%, $MM	1,023.49			
PV of CAPEX @10%, $MM	1,861.10			
PV of TC @10%, $MM	2,884.59			
Unit CAPEX, S/Bbl	11.63			
Unit OPEX, S/Bbl	6.40			
Unit Technical Cost, S/Bbl	18.03			

Appendix 'N': Sensitivity Analysis for Case 3.0



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