A New Framework for the National Petroleum Production Capacity Determination

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Abstract: *Oil revenue in a very simple form is the product of oil production capacity and the prevailing oil market price, less the costs of production. Since the oil price is an exogenous factor, revenue is therefore maximized by optimizing production and minimizing costs. A flawed production capacity estimation system will result to inaccurate production figures, which in turn gives erroneous revenue projection. Estimation of oil well potential is a measure of well performance or deliverability. Many models used globally to evaluate well performance and productivity are reviewed. The Maximum Efficient Rate (MER) test which has gained global prominence to establish wells and reservoir pools production capacity is the focus of the work. The analysis of MER test results using graphical technique is proven to be tedious, inefficient and ineffective. The Least Square formulation applied in this work has presented an analytical solution that solves the inherent problem of the graphical technique of analyzing Maximum Efficient Rate test results for the determination of a reliable crude oil production capacity. Three case studies from the prolific Niger Delta oil producing region of Nigeria are used to validate the efficacy of the new technique. The technique has mitigated the problem of the graph scale error. The Graph Scale Error in this work is zero, for Case 1 and approximately 200bbls for Case 2 and Case 3 respectively. The new technique ensures repeatability of result and unique end-result value of MER which could not be achieved using the graphical solution. It is recommended that the Least Square Analytical technique system should be applied in preference to the current graphical method for MER test result analysis.*

Keywords: *Maximum Efficient Rate, Technical Allowable Rate, Least Square Formulation, Graphical technique, Pool, Non-Pool, Voidage Replacement Ratio, Well productivity, well Performance*

I. Introduction

The global energy trend suggests a possible significant decline in crude oil demand in future as the Organization for Economic Cooperation and Development (OECD) and other major energy consumers improveon the use of other alternative energy sources. Many advanced economies have announced intention to shift from crude oil product driven vehicles and machines to other alternatives. China continues to rebalance the economy and targets a shift to bio-ethanol as vehicular fuel by 2020. Continuous improvement in the hydraulic fracturing technology sustains the production of shale oil and gas by the United States. Natural gas and renewable energies are predicted to gain dominance in the global energy mix while improvement in energy efficiency remains significantly important in many country's energy policies. The combined effect of all these will be low crude oil demand, if there is no unprecedented increase in the global economy to generate high energy demand drive beyond the capacities of the alternative energy sources to satiate it.

Low oil demand will result in low oil price, if projected supply remains the same, which in turn yields low oil revenue for crude oil producers. Nigeria, which depends largely on oil revenue will be significantly impacted if it fails to understand the global trend and initiate effective mitigationmeasures. The first step for the country is to re-evaluate its crude oil production system with a view to identifying areas of sub-optimal performance and provide effective corrective and optimal measures.

Reserves drive the value of the petroleum industry, but unproduced reserves only have a store of value which future global energy events may improve or deplete. Suboptimal production on the other hand erodes the present value derivable from reserves hence the need to optimize the production value chain to maximize the present worth of the oil revenue.

Oil revenue in a very simple form is the product of oil production capacity and the prevailing oil market price less the costof production.Since the oil price is an exogenous factor, revenue is therefore maximized by optimizing production and minimizing costs. The cost minimization aspect has been well studied with many models.

For instance, Attanasi et al. (1981) introduced a methodology for incorporating economic considerations into resource appraisals for petroleum basins. A cost algorithm was used to calculate estimates of the costs of finding and developing undiscovered oil and gas fields in the Permian basin. Bradley and Woods, (1994) presented a general method for forecasting oil field economic performance that integrates cost data with operational reservoir and financial information. They developed methods for determining economic limits for an oilfield dandits component with special attention given to the economic limits of marginal wells and what they termed the role of underground competition.

Bradley and Woods (1994), further explained that profit is maximized by producing to the point where the marginal cost (MC), defined as the change in total costs to supply an additional unit, for each activity is equal to its marginal revenue (MR); defined as the change into revenues received after selling one more unit. (Bradley and Woods (1994) thus recommended that oil fields, like other businesses, should be operated to maximize returns to share holders (subject to legal, health, safety, and environmental quality constraints).

Davidson (1982), Marks and Moore (1987) independently presented techniques with fixed and oil-rate dependent components of operating costs. These methods however, do not include the influence of associated gas and water productionon costs. Volume, prices and costs are assumed independent.

The production capacity estimation should equally be given much attention. A flawed production capacity estimation system will result to inaccurate production figures, which in turn gives erroneous revenue estimation. Vogel(1968), Fetkovitch (1973) and lots of other scholars referenced hereunderhave studied and developed models for the estimation of production capacities of wells at different conditions.

Estimation of oil well potential is a measure of well performance or deliverability. The pressure differential encountered in lifting reservoir fluids to the surface has been identified as one of the major factors affecting well deliverability. Wellbore flow performance relates to the analysis of the relationship between the pressure and the flow rate in the wellbore as the reservoir fluids move to the surface through the production tubing. Michael Wiggins (2006) estimated that about 80% of the total pressure loss in a flowing well may occur duringuplift of the reservoir fluid to the surface.He also observed that the mechanical configuration of the wellbore, reservoir fluids properties and the production rate are the major determinants of the pressure loss resulting from the fluid movement from the reservoir sand-face to the surface.Anderson(2016) observed that Daniel Bernoulli,in his book "Hydrodynamica" published in 1738established a correlation for estimating this pressure drop in the wellbore based on the mechanical energy equation for flow between two points in a system. Wiggins(1994) presented an easy-to-use IPR for three-phase flow, which is similar in form to Vogel's IPR(Vogel,1968).

Productivity Index (PI) is an established measure of the performance of oil wells. However, Evinger and Muskat (1942) pointed out that the linearProductivity Index relationship does not apply to multiphase flow, rather a curved relationship exists between flow rate and pressure. Therefore, constant productivity index concept is only appropriate for oil wells producing under single-phase flow conditions for pressures above the reservoir fluid's bubble-point pressure. For reservoir pressures below the bubble-point pressure, the reservoir fluid exists as two phases, vapor and liquid; and techniques other than the productivity index must be applied to predict oilwell performance.

Numerous empirical relationships have been proposed to evaluate oilwell performance under two-phase flow conditions. Vogel(1968) was the first to present a simple method for evaluation of oil wells performances. His empirical Inflow Performance Relationship (IPR) is popular in the industry. Fetkovich(1973)proposed the prediction of oil well performance using isochronal testing of the wells and the application of the empirical gas-well deliverability equation proposed by Rawlins and Schellhardt in 1935. Jones, Blount, and Glaze (1976) also proposed a multirate test method which incorporates non-Darcy flow effects.Gallice and Wiggins (2004) provided details on the application of several two-phase IPR methods by comparing and discussing the advantages and disadvantages of their use in estimating oilwell performance.They reviewed and compared five IPRs proposed in the literature for predicting individual-vertical-well performance in solution-gas-drive reservoirs. The IPRs they studied are Vogel, Fetkovich, Jones, Blount, and Glaze, Klins and Majcher, and Sukarno and Wisnogroho. Each IPR was developed for various conditions but essentially represents vertical wells producing from a single solution-gas-drive reservoir under boundary-dominated flow conditions. They assumed a homogeneous reservoir in all the methods except forFetkovich's. Using data from 26 field cases, Gallice and Wiggins (2004) used the five IPR methods to predict the pressure/production behavior for the individual cases. They compared the predictions to the actual well performance and to predictions with other methods and used it to develop an understanding of their reliability.

In certain circumstances, single-phase and two-phase flow may occur simultaneously in the reservoir. This happens when the average reservoir pressure is above the bubble-point pressure of the reservoir oil while the flowing bottom-hole pressure of wells producing from the reservoir is less than the bubble-point pressure. Neely(1967) addressed this situation by developing a composite IPR that Brown(1984) demonstrated. The composite IPR couples Vogel's IPR for two-phase flow with the single-phase productivity index.

The application of the composite IPR and Wiggins' IPR is straight-forward and like applying Vogel's IPR. In applying the composite IPR, the appropriate relationship must be used to estimate the Productivity Index (J) because it depends on the flowing bottom-hole pressure of the test point. The inflow performance curve is derived by adding the estimated oil rates to the water rates to create a total liquid rate.

The application of the models shows that each yield different values for the maximum oil production rate as well as the production rate at a given flowing bottom-hole pressure. As a result, production capacity estimates are dependent on the IPR used in the analysis. An appropriate Model that matches with the reservoir fluid characteristics and production phases is carefully selectedto estimate the Maximum Efficient Rate of a well.

Maximum Efficient Rate, commonly referred to as "MER," is defined byArticle 3451 of 2010 California Code as the highest daily rate of production which can be sustained economically from a particular pool, from existing wells and facilities, for a reasonable period without loss of economically recoverable ultimate production of oil from such pool. It is any rate that will ensure the recovery of maximum possible Estimated Ultimate Recovery (EUR).Technical Allowable Rate (TAR) is the adjusted Maximum Efficient Rate to control crude oil production in accordance with technical and conservation considerations to eliminate inefficient production practices and ensure optimum recovery of the producible oil.

In Nigeria, performance and productivityof wells, the aggregate of which gives the National Crude Oil Production Capacity is estimatedby the analysis of the bi-annual Maximum Efficient Rate (MER) Test used to generate the Technical Allowable Rates for producing wells and/or reservoirs. Section 38 of the Petroleum (Drilling & Production) Regulations, 1969 as amended requires that no well in the country is produced without MER test. The guidelines to conduct the test are stipulated in Sections B5.40 – B5.70 of the Manual of Procedure Guide of the Department of Petroleum Resources (DPR).

Thus, MER defines the relationship between oil flow rate and the Ultimate Recoverable oil volume on the bedrock of economics of oil recovery. It is that maximum flow rate that yields maximum Ultimate Recovery. Maximum oil recovery yields maximum economic returns at a given oil price and specified production costs. In Nigeria, MER is presented as Technical Allowable Rate (TAR) statutorily issued by the petroleum industry regulator by2ndJanuary for the first half of the year and 1stJuly for the second half of a given year.

There are two major categories of wells with respect to MER testing and analysis: Pool and Non-pool wells. Different methods are applied in the analysis of MER Test of the two categories. Pool reservoirs refer to reservoirs where oil production is sustained with the aid of a Pressure Maintenance (PM) Scheme such as water injection, gas injection, water alternating gas injection (WAG), dump flooding, gas recycling and steam injection projects.Ten (10)E & P Companies are currently operating 120 Pressure Maintenance Projects in Nigeria.

The key performance indicators for Pressure Maintenance projects are:

i. Oil rates based on Zero-Net Voidage computed at prevailing injection volumes
ii. Instantaneous and cumulative Injection-Withdrawal Ratios (IWR):
iii. Pressure Decline Analysis
iv. Gas Oil Ratio andWater Cut trends
v. Recovery Fractions and Remaining Reserves
vi. Sum of MER test rates for each pool
vii. Current production rates for each of the pools

The non-pool reservoirs or wells are those on depletion drive. Production is supported by either gas cap drive, or solution gas drive or water drive of gravity drainage or a combination of the drive systems. This paper focuses on the non-pool reservoirs.

The test result for the non-pool wellsaregraphically analyzed by plotting the Flowing Tubing Head Pressures (FTHP) measured during the test and choke sizes against the corresponding net oil flow rates. The point of interception of the curve of FTHP versus net oil rate and choke sizes versus net oil rate plotted on cartesian plain

gives the Maximum Efficient Rate of the well. The Technical Allowable Rate (TAR) is then determined from MER with the simple expression:

$TAR \leq MER$ …….(1)

$TAR = MER - \text{Penalty Factors}$……..(2)

The penalty factors are special considerations to compensate for the impact of such factors as GOR, BS&W, Sand Production & Drawdown to optimize oil production. The magnitude of their impact marks the level of the difference between MER and TAR. However, TAR = MER where Cumulative Effect of Penalty Factors = 0. This happens for a well producing below critical rate (q_c) and under monophasic condition at optimal drawdown and negligible sand production.

Water cut

- Water production is limited to 10% in a water drive reservoir depending on the viscosity of the crude.
- BS&W is expected to be zero in a non-water drive pool otherwise the problem of water channelling or communication would be suspected.

Sand Cut

- Detrimental to the reservoir, surface and sub-surface equipment
- Sand production is limited to 5 lb/1000bbl. For reservoirs deeper than 8000ft, any sand production is viewed seriously because below this level, the formation should be more consolidated.

Productivity Index

- A Productivity Index below 5 b/d/psi indicates that an acidization job may be necessary.

GOR

- In a water drive or pressure-maintained reservoirs, GOR is limited to 125% of the initial solution GOR (Rsi).
- Producing GOR is limited to maximum of 4,000 scf/bbl unless the produced gas is to be used on an approved project.

Draw-Down

- A draw down of between 50 and 100 psi is considered optimum. An upper ceiling of 150 is permissible in exceptional cases. However, this is not applicable for horizontal wells.

Flowing Tubing Head Pressure (FTHP)

- This is used to indicate well's condition.
- Drastic Fall in THP could be because of mechanical obstruction, sand bridging/ impairment of sand face or water loading.
- High THP could indicate high GOR.

The graphical method of determining MER is simple but comparatively less accurate. One of its greatest demerits is failure to produce a unique solution as MER value. The value is influenced by the scale of the graph and any change in the scale produces a different MER value. Most probably, the results of the graphical method from different evaluators will hardly converge.

Replacement of the tedious graphical method with a more accurate analytical solution, will enhance the accuracy of the results of the analysis. It will also provide a unique and reliable test result. It will thus, bridge the gap between the calculated and actual crude oil production capacity. The analytical solution will enhance the efficiency of the process and guarantee timely completion of the deliverables within the specified period.

Nigeria as at 1st January 2019 has a total of 232 producing fields, 2,626 producing wells and 2,939 oil producing strings. This implies that 2,939 graphs will be plotted and analyzed to generate the National Crude Oil Production Capacity per cycle by a limited number of the Regulatory Agency staff. Considering the significance of national crude oil production capacity in revenue forecast, national budget planning and overall

economy of the state, the need for a more efficient and objective method to determine MER and/or TAR cannot be overemphasized.

The study is therefore aimed at creating anew framework to establish a more objective approach to determine the national crude oil capacity by replacing the current subjective graphical methodology with analytical model for analyzing MER test results for MER/TAR. Therefore, the key objectives of the study are to: evaluate the effectiveness of the current graphical method used in National production capacity estimation in Nigeria; derive and establish an analytical solution to mitigate the observed inadequacies of the graphical solution by simplifying the MER analytical process; and make valuable policy recommendations.

II. Materials And Methods

MER testing is a statutory requirement in Nigeria to allow production from wells and reservoirs. It is a bi-annual exercise. The first cycle covers the period of January – June whereas the second cycle covers the second half of the year from July to December. The process of the exercise is as shown in figure 1.0 below. The objective of the exercise is to obtain well/reservoir productivity data. The data obtained are analyzed, to determineMaximum Efficient Rate Test (MER) of the wells and reservoir pools.

Generally, the maximum efficient rate ≥ allowable rate

The Technical Allowable Rate is determined by scaling down the MER considering factors such as:

- Wells Producing History
- The reserves carried by the pools from which the wells are producing
- The well's productivity index (PI)
- Draw-downs
- Producing GORs
- RSI
- Water cut
- Sand Production
- Flowing Tubing Head Pressure
- The general performance of the individual reservoirs
- Pressure Decline of the pool of interest
- Injection volumes into project pools

Technical Allowable is granted on well basis and they are not transferable. An allowable rate represents the ceiling of production permitted from a well. Under-production from a given well cannot be made up from a more prolific well in the pool, nor shall it be allowed to grossly overproduce a well to compensate a lost production in a previous period or anticipated loss in future production.At any time, the permissible production shall consist only of allowable of producing wells and production from test wells yet to be granted allowable. Production in excess of allowable from wells constitutes an infringement and attracts sanctions

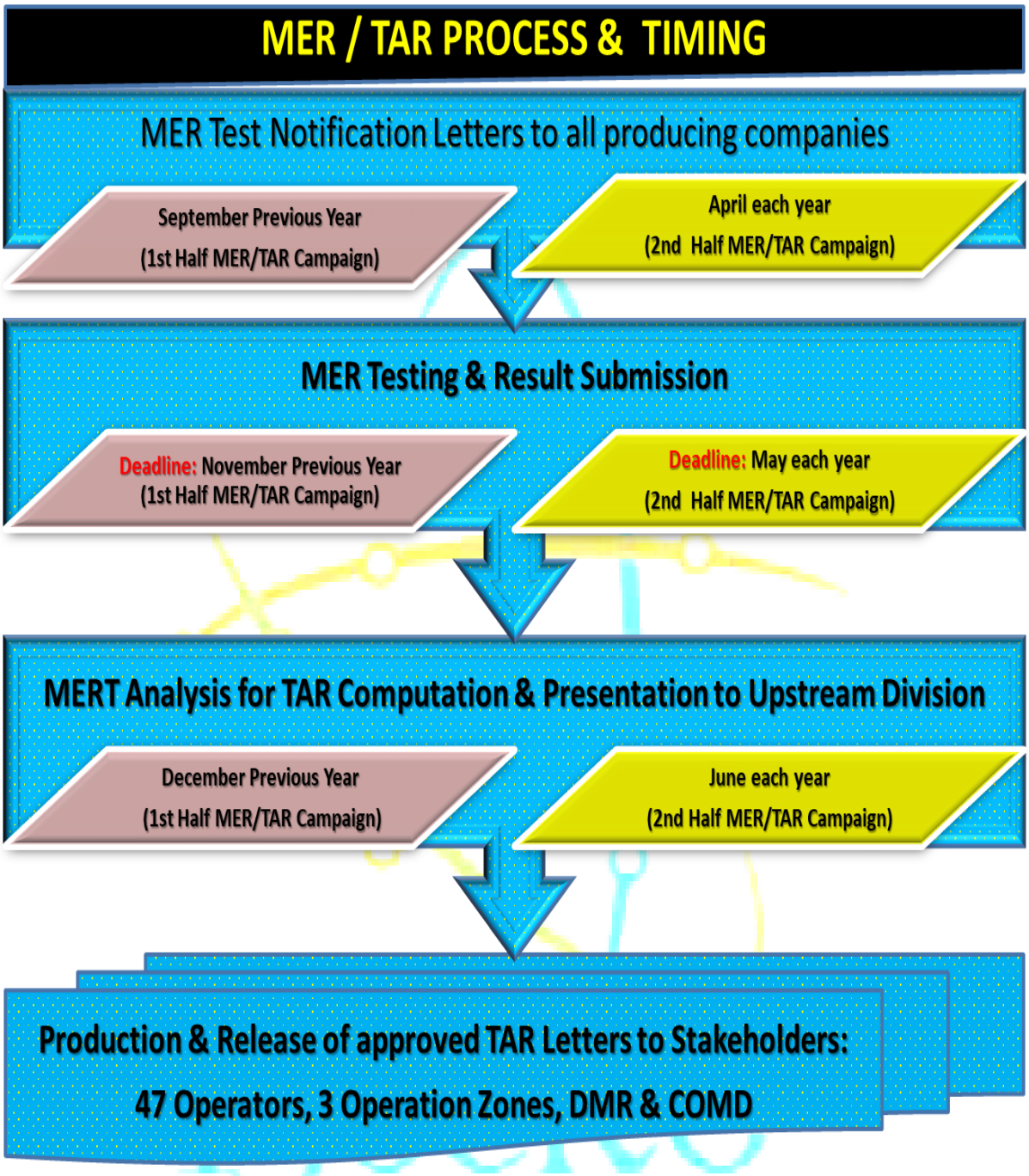


Fig. 1.0: MER/ TAR Process and timing

MER Test Sequence:

1st Step: 3 hours Stabilization for each choke size provided stabilization criteria are met

2nd Step: 6 hours Flow measurement

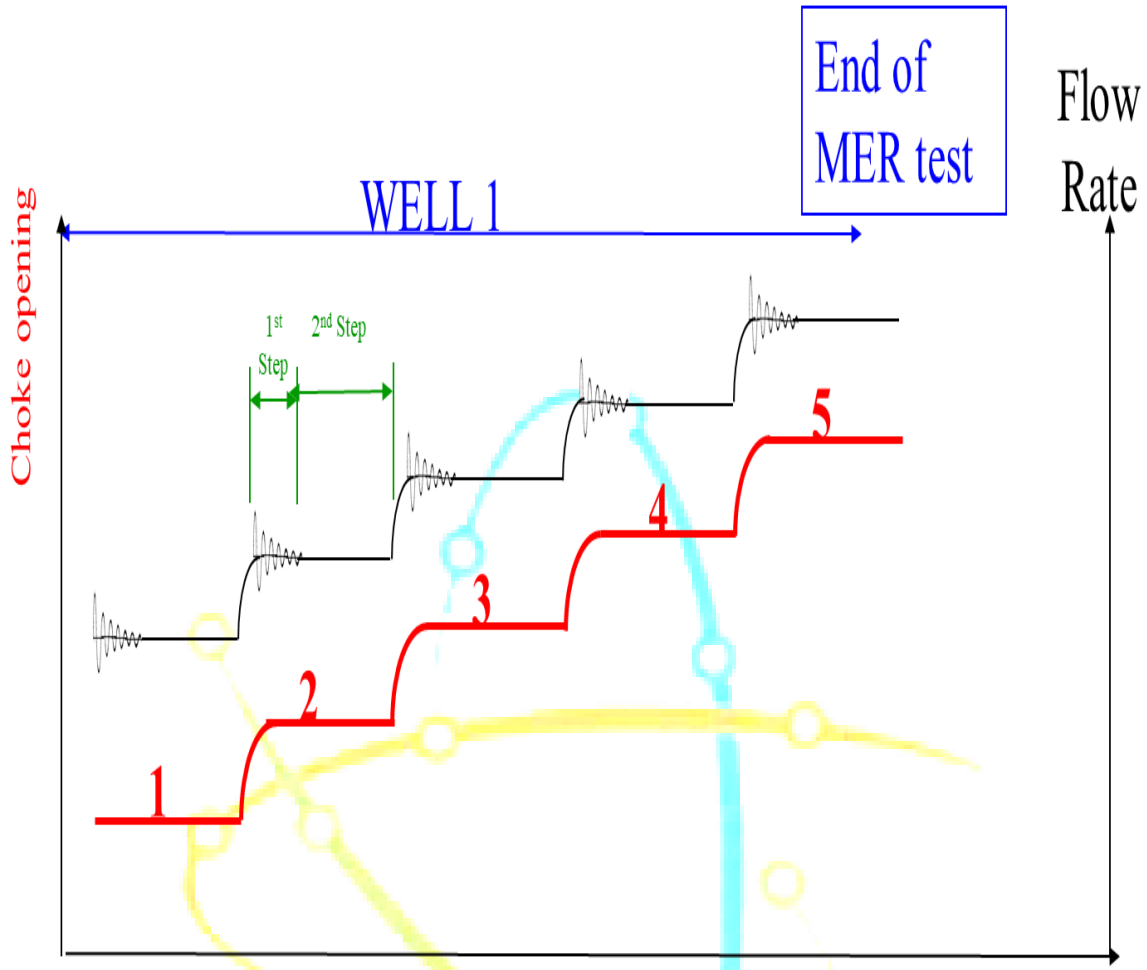


Fig 2.0 The MER Test Procedure

Stabilization Criteria:

Based on Flowing Tubing Head Pressure (FTHP) and test separator flow measurements stability over the stabilization period

Flowing Tubing Head Pressure:

(FTHPmax - FTHPaverage) / FTHPaverage≤ 0.5%

(FTHPmin - FTHPaverage) / FTHPaverage≤ -0.5%

Or, $\frac{\text{FTHPmax - FTHPmin}}{\text{FTHPaverage}} \leq 1\%$

Test Separator Flow Rates, Q

(Qmax - Qaverage) / Qaverage≤ 5%

(Qmin - Qaverage) / Qaverage≤ -5%

Or, $\frac{\text{Qmax - Qmin}}{\text{Qaverage}} \leq 10\%$

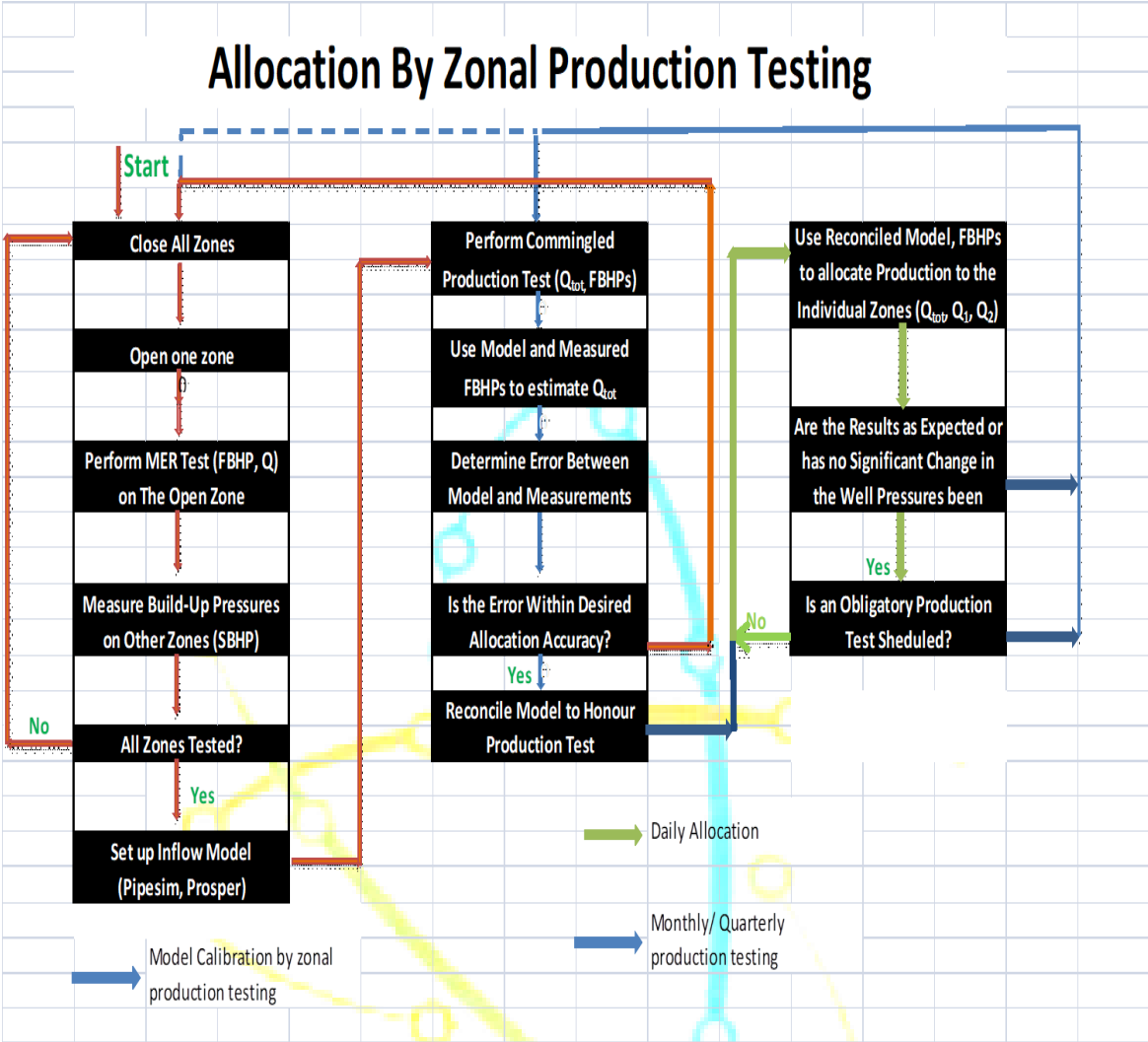


Fig 3.0 Procedure for Testing Multi-Zone Intelligent (Smart Well) Source: DPR 2017

The method of MER Test analysis depends on the category of the wells – whether pool or non-pool. The pool reservoirs are basically analyzed using the Void age Replacement Ratio (VRR) technique while the non-pool reservoirs are analyzed graphically.

$$\text{VOIDAGE REPLACEMENT RATIO (VRR)} = \frac{\textit{injected reservoir volumes}}{\textit{produced reservoir volumes}}$$

$$VRR = \frac{B_w(i_w)}{B_o(q_o) + B_w(q_w) + q_o(GOR - R_s)B_g} \quad \text{…….. (3)}$$

<u>Determination of MER: Cross-plot of THP/Choke vs Rate using Least Square Formulation</u>

MER involves the intercept of two lines of the cross-plot of: THP vs Rate & Choke Size vs Rate. Using Least Square formulation to obtain: Slope (a_T) and intercept (b_T) of the Tubing Head Pressure trendline

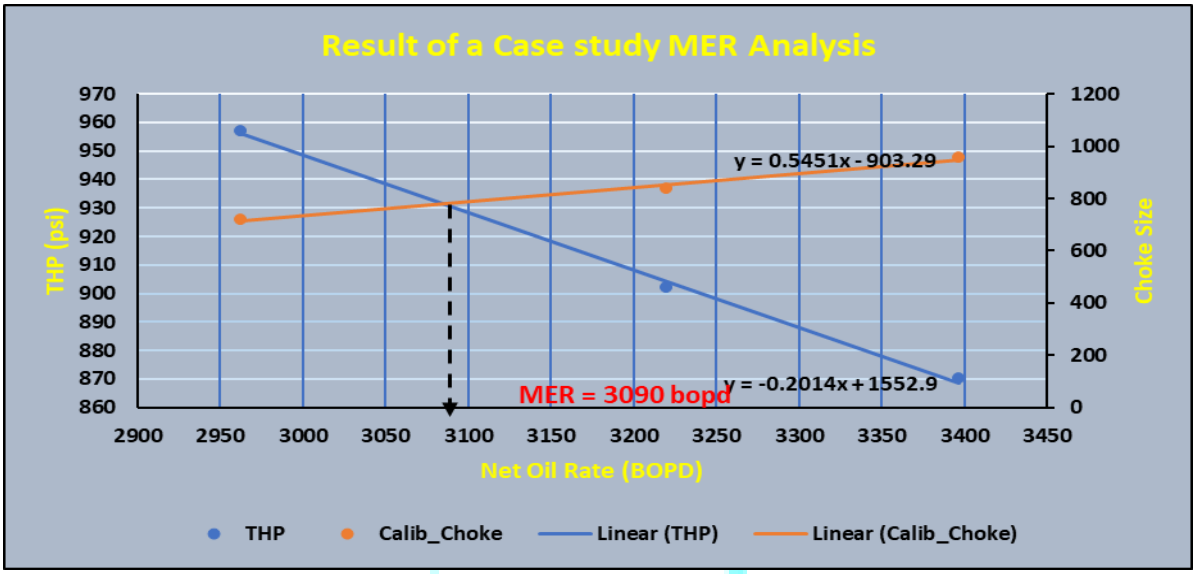


Fig. 4.0 Graphical Solution for well one

1) THP vs Rate (T vs q):

Linear trendline: $T = a_T q + b_T$……(4)

Deriving the Slope and Intercept of the lines using Least Square formulation:

Slope (a_T) and intercept (b_T) of the Tubing Head Pressure trendline

$$a_T = \frac{N_m(\Sigma q * T) - (\Sigma q) * (\Sigma T)}{N_m(\Sigma q^2) - (\Sigma q)^2} \quad \text{……(5)}$$

$$b_T = \frac{(\Sigma T) * (\Sigma q) - (\Sigma q)(\Sigma q * T)}{N_m(\Sigma q^2) - (\Sigma q)^2} \quad \text{……(6)}$$

2) Choke vs Rate (C vs q):

Linear trendline: $C = a_C q + b_C$……(7)

Least Square formulation:

Slope (a_C) and intercept (b_C) of the Choke trendline

$$a_C = \frac{N_m(\Sigma q * C) - (q) * (C)}{N_m(\Sigma q^2) - (\Sigma q)^2} \quad \text{……(8)}$$

$$b_C = \frac{(\Sigma C) * (\Sigma q^2) - (\Sigma q)(\Sigma q * C)}{N_m(\Sigma q^2) - (\Sigma q)^2} \quad \text{……(9)}$$

MER is the Rate (q_M) at which the THP trendline (T) meets the Choke trendline (C)

MER = q_M at which T = C
This implies:

$$(a_T * q_M) + b_T = (a_C * q_M) + b_C \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(10)$$

Or

$$\text{MER} = \frac{b_C - b_T}{a_T - a_C} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(11)$$

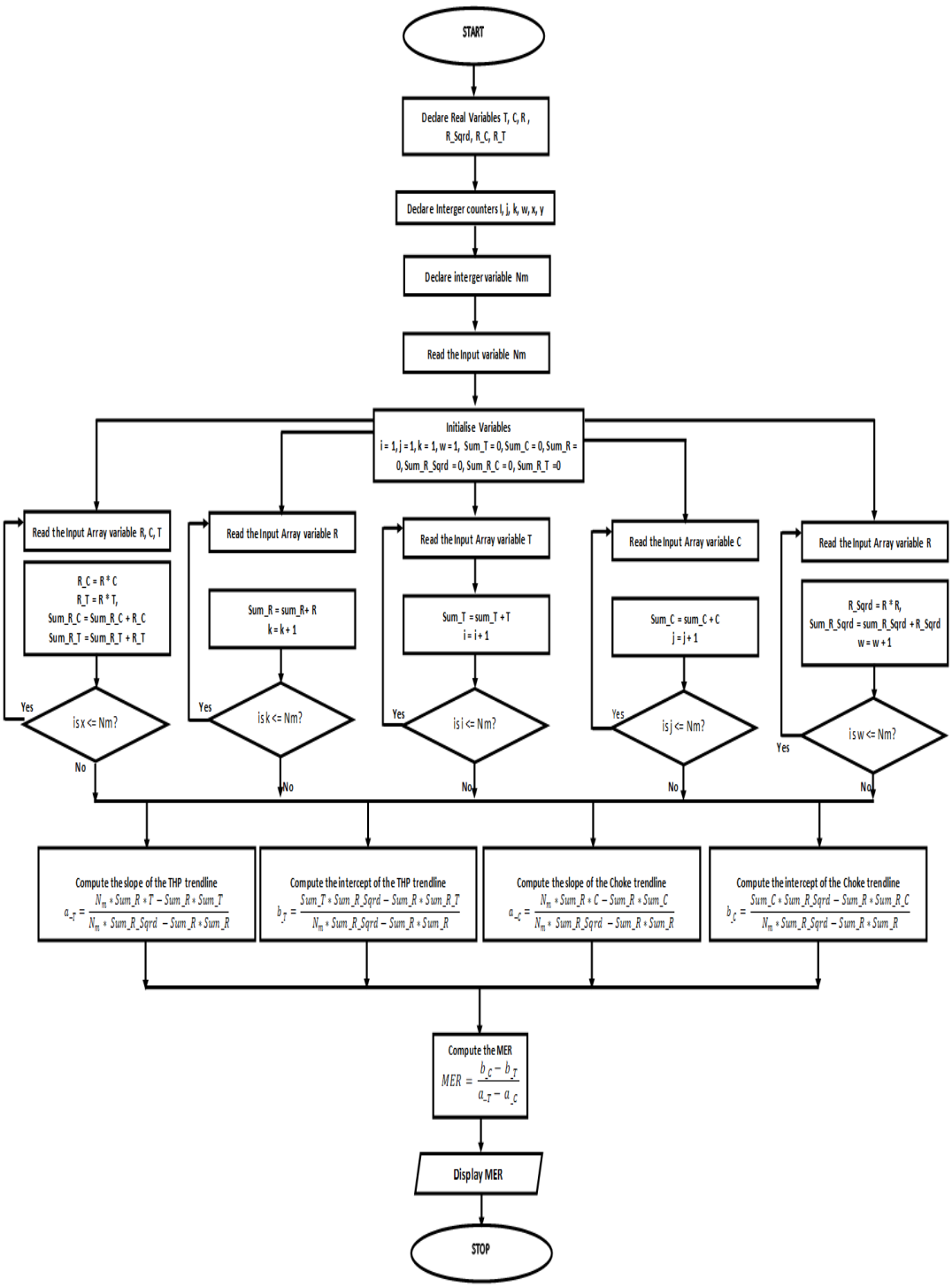


Fig 5.0 the Flow Chart of the Algorithm for the Analytical Solution

III. Results And Discussions

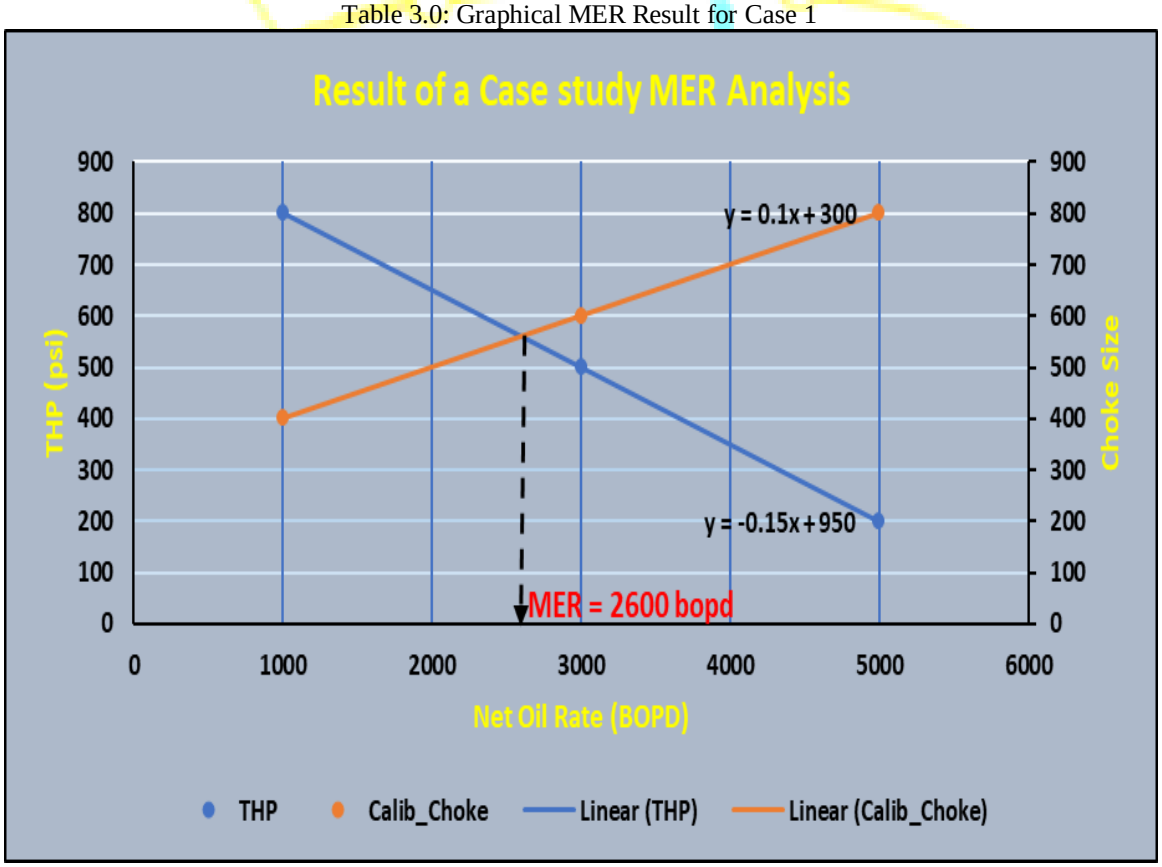
Table 1.0: MERTest Result Analysis for Case 1

Input Parameters									
Rate	Choke	THP	Calib_choke	THP*Rate	$Rate^2$	THP^2	Choke*Rate	$Choke^2$	
1000	20	800	400	800000	1000000	640000	400000	160000	
3000	30	500	600	1500000	9000000	250000	1800000	360000	
5000	40	200	800	1000000	25000000	40000	4000000	640000	
9000	90	1500	1800	3300000	35000000	930000	6200000	1160000	0

Table 2.0: Analytical MER Result for Case 1

ANALYTICAL MER RESULT				
Slope(choke)	Slope(THP)	Intercept(choke)	Intercept(THP))	MER
0.1	-0.15	300	950	2600

Table 3.0: Graphical MER Result for Case 1



Case 1.0 is a well on continental shelf producing on natural depletion. The well was tested on three choke sizes of 20,30 & 40. The corresponding THPs are 800psi, 500psi and 200psi. the Choke sizes and the THPs give oil flow rates of 1000bopd, 3000bopd & 5000bopd. Coincidentally, both graphical and analytical techniques gave the same MER Value of 2,600bopd.

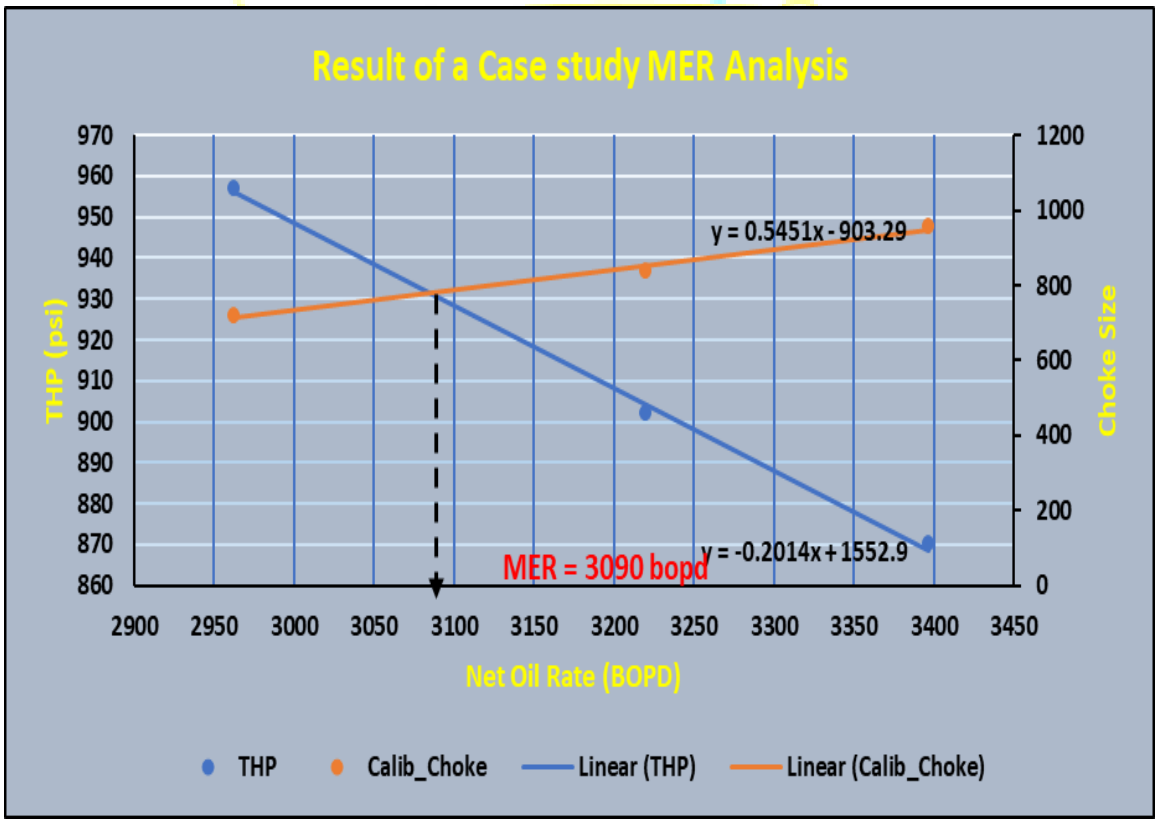
Table 4.0: Case 2.0 MERTest Result Analysis

Input Parameters									
Rate	Choke	THP	Calib_choke	THP*Rate	$Rate^2$	THP^2	Choke*Rate	$Choke^2$	
2963	30	957	718	2835591	8779369	915849	2126693.25	515165	
3220	35	902	837	2904440	10368400	813604	2696347.5	701197	
3397	40	870	957	2955390	11539609	756900	3250929	915849	
9580	105	2729	2512	8695421	30687378	2486353	8073970	2132211	0

Table 5.0: Analytical MER Result for Case 2

ANALYTICAL MER RESULT				
Slope(choke)	Slope(THP)	Intercept(choke)	Intercept(THP))	MER
0.545093514	-0.201435601	-903.2902866	1552.917686	3290.17

Table 6.0: Graphical MER Result for Case 2



Case 2.0 below is deep offshore well also producing on natural depletion. The MER Test was conducted on three choke sizes of 30,35 & 40 with a corresponding THP of 957psi, 902psi & 870psi. The flow rates obtained from the choke sizes and the corresponding THP are 2,963bopd, 3,220bopd, & 3,397bopd respectively. The graphical technique yields MER value of 3,090bopd as against the value of 3,290bopd obtained with the analytical technique.

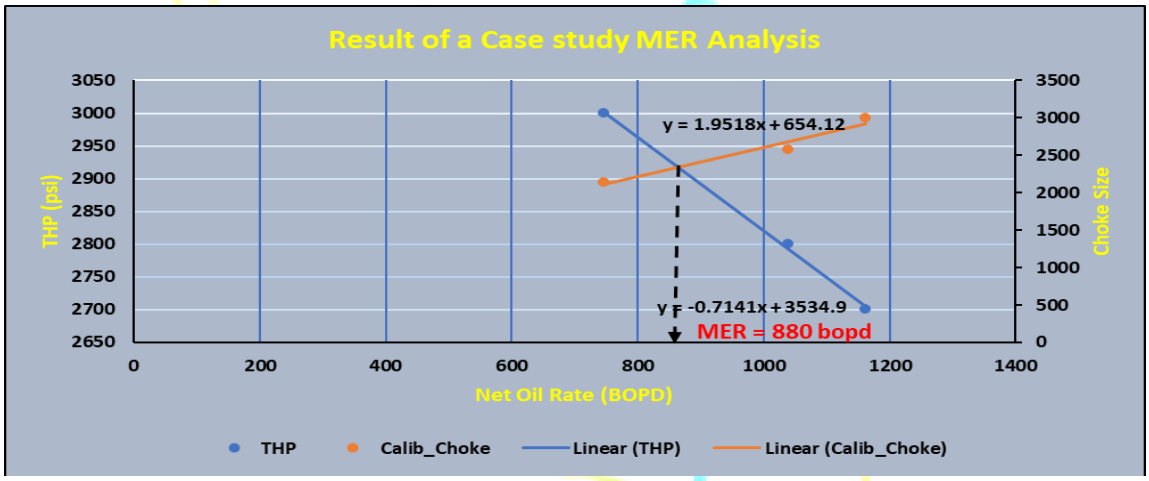
Table 7.0: Case 3.0 MER Test Result Analysis

Input Parameters									
Rate	Choke	THP	Calib_cho	THP*Rate	$Rate^2$	THP^2	Choke*Rate	$Choke^2$	
746	20	3000	2143	2238000	556516	9000000	1598571.429	4591837	
1039	24	2800	2571	2909200	1079521	7840000	2671714.286	6612245	
1162	28	2700	3000	3137400	1350244	7290000	3486000	9000000	
2947	72	8500	7714	8284600	2986281	24130000	7756286	20204082	0

Table 8.0: Analytical MER Result for Case 3

ANALYTICAL MER RESULT				
Slope(choke)	Slope(THP)	Intercept(choke)	Intercept(THP))	MER
1.951791175	-0.714145	654.1190405	3534.861732	1080.575

Table 9.0: Graphical MER Result for Case 3



Case 3.0 is an onshore well tested on choke 20, 24 & 28 at THP of 3000psi, 2800psi & 27000psi. the resulting oil flow rates are 746bopd, 1,039bopd, 1,162bopd respectively. The graphical solution gives MER of 880bopd whereas the MER obtained from analytical solution is 1080bopd.

The differences in the value obtained from graphical and analytical techniques for Cases 2.0 & 3.0 are scale error effect. There is no difference in the MER values for both techniques in Case 1.0 which implies that the scale of the graph is appropriately chosen.

IV. Conclusions & Recommendations

CONCLUSION

The Least Square formulation applied in this work has presented an analytical solution that solves the inherent problem of the graphical technique of analyzing Maximum Efficient Rate test results for the determination of a reliable crude oil production capacity. The technique has mitigated the problem of the graph scale error. The Graph ScaleError in this work is zero, for Case 1 and approximately 200bbls for Cases 2 and 3 respectively. The new technique ensures repeatability of result and unique end-result value of MER which could not be achieved using the graphical solution. The Lease Square Analytical Formulation technique also presents a faster and efficient method of analysis of the MER test result. It therefore guarantees timely analysis of the result of the current 2,819 producing non-pool strings in Nigeria in few hours as against long days of painstaking graph plotting. Only 120 pool strings will be analyzed using the Voidage Replacement Ratio (VRR) technique.The

Least Square Formulation presents a better tool for the Engineers to timely and efficiently analyze the MER test results to meet up with the statutory requirements for presentation of the results.in Nigeria currently, only 47 out of the 87 registered E&P companies are in production with the remaining at various stages towards production. The new tool will equip the engineers to handle future increase in producing strings as more companies come into production.

RECOMMENDATION

In view of the efficacy of the Least Square Formulation Analytical solution to effective and efficient analysis of Maximum Efficient Rate results, it is recommended that the system should be applied in preference to the current graphical method. In Nigeria, the relevant Sections of the Guidelines on the analysis of the MER test results, which stipulated the application of the graphical method, should be reviewed and amended to include the Least Square Analytical method and other techniques likely to be discovered in the near future. The new analytical method should be fully automated using the flowchart presented in this work as a guide for the detailed algorithm for that purpose.

ACKNOWLEDGEMENTS

We are grateful to Dr. Christian Onwunyili for his technical inputs and Dr. Joe Echendu for editing 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.

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