PERIODIC WELL TESTING FOR OPTIMAL CRUDE OIL PRODUCTION

Engr. Uzoigwe FRIDAY
Nigerian Upstream Petroleum Regulatory Commission
19/21 Warri Sapele Road
Warri, Delta State

ABSTRACTS

Well testing is the execution of a set of planned data acquisition activities from the reservoir to broaden the knowledge and understanding of hydrocarbon properties and characteristics of the underground reservoir where hydrocarbons are trapped. This well test data is necessary for the determination of the optimum crude oil production rate of oil wells. Most oil and gas industries use either the empirical approach or the nodal analysis method to determine the optimum rate of crude oil production. The current methods used to determine optimum crude oil production rates from reservoir do not accurately predict the optimum production rates of crude oil in wells as the impact of gas-oil ratio, sand and water cut are ignored. The consequence of this deficiency is the sub-exploitation of reservoir wells by oil producing companies. The pertinent question is what methods can be used to effectively determine the optimum rate of crude oil production from oil wells? Previous studies have looked at the problem and still use either the empirical or the nodal analysis approach. This study seeks to use an analytical approach that attempts to accurately determine crude oil production by taking into account the impact of gas oil ratio, sand production and water cut. Relevant data for the study were obtained through records and personal experiences. The data were analysed and presented in tables and charts. Based on the data analysed, the key finding of the study are the quantity of crude oil production from some local wells in Nigerian Niger Delta using the current methods (empirical and nodal analysis approaches) provided a consistent increase in daily production rate of about 10-15% of crude oil above the reservoir optimum rate when compared with the analytical approach; crude oil production at these rates predisposes the wells to the risk of early water breakthrough, high ratio of gas to oil production and sand production for unconsolidated reservoirs. Based on the findings, the researcher concludes that the analytical method provides a better method of determining the quantity of crude oil that can be optimally produced from an oil well/reservoir. Finally, the researcher recommends the following, Crude oil wells should be produced at the accurate Optimum/Technical allowable rate for efficient exploitation of the reservoirs. Optimum/Technical allowable rate should be determined using the Analytical approach for better reservoir management.

KEYWORDS: Periodic Well Testing, Optimal Crude Oil Production

Introduction

In order to monitor the flow from a particular oil and gas well, a technique called well test is used. The data supplied by this well test is used to determine the maximum efficient rate of production from the well which is critical in the determination of the optimum rate of production from oil wells. Several methods for modeling optimum production have been developed in the past for different reservoir situations. The two basic methods are the Empirical method and the Nodal analysis approach. Whereas the Empirical method has been based on

Gilbert's correlations, Nodal approach uses the fluid property and the energy balance of the flowing fluids in the determination of the optimum rate of producing oil wells. These two methods used to determine the optimum crude oil production rates from reservoirs do not accurately predict the optimum production rates of crude oil in wells as the critical impact of gas-oil ratio, sand and water cut are ignored. The consequence of this deficiency is the sub-optimization of reservoir wells by oil and gas companies.

Therefore, the work in this project uses the analytical approach that enables the estimation of a critical choke, and the corresponding production rate beyond which there is a high risk of early water breakthrough, high gas oil ratio and high sand cut. This method involves the plot of the flowing tubing head pressure (FTHP) versus production rates and chokes versus production rates on the same graph sheet. The point of intersection of the two plots indicates the point of stable equilibrium and the corresponding rate gives the maximum efficient rate of production which is critical in the determination of the optimum rate/technical allowable rate of production for oil wells.

Statement of Problem

The current methods used to determine optimum crude oil production rates from reservoir, i.e. the empirical and nodal methods do not accurately predict the optimum production rates of crude oil in wells as gas oil ratio, sand and water cut are ignored. The consequence of this deficiency is sub-exploitation of reservoir wells by oil producing companies. Therefore, this project seeks to examine an improved analytical method of determining the optimum rate of crude oil production from well test data, thereby reducing recoverable hydrocarbons losses.

Objectives of the Study

To control crude oil withdrawal rates in accordance with technical and conservation considerations so as to eliminate inefficient production practices, and ensure the optimum recovery of the produce-able oil and gas from the reservoir.

The exercise involves:

- Determination of Maximum Efficient Rates of producing wells from well test data.
- Computation of Technical Allowable/Optimum rates of production based on Maximum Efficient Rate and other technical considerations for optimum well production.

Research Questions

This project work was guided by the following research questions;

- The current status for the determination of optimum crude oil production rate.
- The impact of incorrect determination of optimum crude oil production rate.
- Causes of incorrect determination of optimum crude oil production rate.
- Suggested solution to incorrect determination of optimum crude oil production rate.

Literature Review

Applications of optimisation techniques in the upstream oil and gas industry began in the early 1950s and have been flourishing since then. Applications have been reported for recovery processes, planning, history matching, well placement, drilling, facility design and operations.

Several methods for modeling optimum production have been developed in the past for different situations. The two major approaches are; the Empirical method and the Nodal approach. Some of these methods have been based on Gilbert's correlations, while others have been based on fluid property, and yet others have been derived from the energy balance of flowing fluids. In these approaches, the need for detailed reservoir data acquisition is necessary; and their practical application may be limited by availability and accuracy of the acquired well data. The literature review takes a look at the previous works on well testing, previous works on crude oil production Optimisation, conclusion on previous works and the actual position of this project work.

Review of Previous Works on Well Testing

In his book, ***"Introductory well testing" Tom Aage Jelmert,*** **2013,** He stated that well testing may be regarded as part of formation evaluation. The objective of formation evaluation is to provide input to a geologic model, which in turn may provide important input data for an economic model. Decisions, whether to start possible engineering projects or not, are based on economic analysis of a producing well. He stated that Classical well test interpretation depends on simplified analytical models and graphical techniques. The methodology may be described as follows: A pressure/well test is conducted by giving the well at least one perturbation in flow rate. The pressure signature is measured and matched to a mathematical model (equation or graph). Each well has a unique response which depends on the rock and fluid properties. The matched model gives rise to equations that may be solved for selected variables. In conclusion, he opined that well test data interpretation and application depend on the reservoir properties and the interpretation techniques equally depends on the appearance of straight lines graph from well test data which shows up for specific flow periods and types like; radial, linear and pseudo steady flow.

In his book, ***"well testing" by John Lee,*** **1982,** He explains how to use well pressure and flow rates to evaluate the formation surrounding a tested well. In his analysis, he states that the basic test method is to create a pressure drawdown in the wellbore. This will eventually cause formation fluid to enter the wellbore. If we measure the flow rate and the pressure in the wellbore during production or the pressure in the wellbore at a shut in period following production, we usually will have sufficient information to characterize the tested well. His book began with the discussion of basic equations that describe the unsteady state flow of fluids in porous media. He then moves into discussions of pressure buildup tests; pressure drawdown tests; type curve analysis; Fundamental principles are emphasized in his work and much efforts were made to bring the intended audience to the frontier of well test, its importance and applications. In his book ***" Well Testing Techniques" by Rajnesh Gogoi, 2012,*** He defines well testing as the technique and method for the evaluation of well conditions and reservoir characteristics. It involves producing a well at a constant rate or series of rates, some of which may be zero (well closed in), while simultaneously taking a continuous recording of the changing pressure in the well bore using some form of pressure recording device such as gauges. His methods involved using Productivity Well Test and Descriptive/Reservoir Test. In productivity well test, well is produced at several flow rates using the following procedures

- Stabilized Bottom Hole Pressure (BHP) is measured
- Plot of flowing bottom hole pressure versus flow rate is made on a Cartesian graph.
- The Slope of the cartesian graph indicates well productivity.

In Descriptive/reservoir well test, it involves;

- Introducing abrupt changes in production rates
- Associated changes in BHP is monitored and the disturbances
- Other reservoir properties are determined
- A plot of the reservoir pressure (Pw) versus time is produced on a graph sheet.
- Shape of Pw Vs time curve gives the reservoir characteristics.

Review of Previous Works on Crude Oil Production Optimization

In his book ***"Efficient Rate of Production" by H. H. Kavele, 1943***, He used the procedures that involved the classification of reservoirs as a type of drive, pressure-volume behavior of the reservoir fluids, and the inherent characteristics of the reservoir rock measured mainly by its permeability to fluid flow. He outlined certain basic fundamental principles which when followed will lead to increased efficiency of recovery through rate adjustment. In his definition, he stated that withdrawal should be adjusted to a rate that will maintain the producing gas-oil and water-oil ratios at a minimum. Maintenance of reservoir pressure is not the sole measure of successful reservoir control. The rate that conserves reservoir energy must be subject to further adjustment to a lower rate so as to maintain as far as possible the normal gravitational segregation of free gas, oil and water throughout the reservoir. The second and necessary criterion of efficient rate of production is whether the rate maintained is such as to maintain a uniform encroachment into the oil-bearing section of the reservoir, whichever is being relied upon as the energy source. Irregular encroachment of water or gas into the reservoir may isolate productive sections or productive areas, in a manner that renders otherwise recoverable oil, non-recoverable. Premature encroachment of water or gas into a well increases operating costs and the economy of operation, and also leads to excessive production of gas-oil and water-oil ratios with consequent excessive loss of reservoir energy and crude production. These led to the conclusion that experience does establish the fact that rate of withdrawal has a significant influence on the efficiency of the recovery operation but a measure of that efficiency is being developed by advanced reservoir Engineering technology. However, his work does not take into consideration the effects of sand production on the efficiency of recovery.

In his book "***Dynamic Production System Nodal Analysis" by R. F. Stoisits, 1992,*** He used the Dynamic Production System Nodal Analysis (DPSNA) Technique in evaluating the efficiency of a producing well. This technique involves the simultaneous solution of inflow performance, tubing and surface line pressure loss correlations to obtain pressures and flow rates through the system. In this analysis, the entire production system is analysed simultaneously. This allows the analysis to include the impact of a given well's production on the other wells in the system. Nodal analysis approach applies system analysis to the complete wells system from the outer boundary of the reservoir to the sand-face across the perforations and completion section up the tubing string, the flow-line and separator. To predict system performance, the pressure drop in each component is obtained. The node is classified as a functional node when a pressure differential exists across it and the pressure or flow rate response can be represented by some mathematical or physical function. In his findings, the Production System Nodal Analysis Technique was able to predict the impact of a producing zone control strategy on oil production from a system of many wells. These results instill confidence in this technique's ability to predict the incremental rate impact of various projects such as: surface line looping, well stimulation, gas lift, and producing zone control strategies on the production system. However, this technique did not take into consideration the effects of other variables on production such as gas-oil ratio and sand cut.

In his book ***"Optimum Rate Estimate Guide in Mature Water-Prone Reservoir" by Ken Reynolds, July 2011***, his study uses the empirical method that enables estimation of a critical choke, and corresponding production rates beyond which there is a high risk of early water breakthrough. The method involves the plot of the log of the average of well test rates at various choke settings. All the reservoirs investigated in this manner indicated a characteristic parabolic shape with some notable features. Hence characteristic reservoir models corresponding to selected Niger Delta reservoirs in Nigeria were developed and validated with well tests of recent wells. His empirical method involves the plot of the log of the average of well test fluid rates at various choke settings such that the reservoir performance is averaged over the wells for investigation. The plot obtained expresses a logarithmic relationship between choke changes with fluid rates in the reservoir. Reservoirs of the field investigated in this manner indicated a characteristic hump shape in the plot of rate versus choke sizes, coinciding with the maximum (optimum) rate at which to produce the well while mitigating premature water breakthrough. The practical approach proposed by Ken Reynolds was to infer reservoir performance from historical well test data as has been observed for some matured water-flood Niger Delta reservoirs. By observing the manner of previous water breakthroughs in the reservoirs obtained from well tests, graphical models to enable choke control for subsequent wells in the reservoirs can be defined. This method averages the performances of selected wells in the reservoir but exclude problem wells or unusually behaved wells. Ken Reynolds justified the approach by estimating the slope of the straight line section of the rate-choke plot to deduce a threshold choke value beyond which water breakthrough becomes a problem in optimization of crude oil production from the reservoir. Reservoirs investigated with this approach have practically shown deviations at the point where water broke through the wells, though at different times. This means operating beyond this 'safe' limit may not cause immediate water breakthrough into the well, but puts the well at risk. It is then a matter of time; since it is likely that the oil-water surface would have then been pulled in or drawn closer. It is therefore reasonable to operate such a well within the 'straight line' region to avoid early water breakthrough. Ken Reynold approach only takes into consideration the relationship between the critical choke and the water breakthrough, neglecting the effects of sand cut, high gas oil ratio and production within the statutory granted allowable for good reservoir management in producing an oil well.

In his book ***"The Wood Review" by Sir Lan Wood, February 2014***, an independently led review of the United Kingdom Continental Shelf's (UKCS) oil and gas recovery potential in the coming decades. The aim of this review was to assess the current state of operations, production and exploration in the UK and the effects of fluid measurement on the Maximum Efficient Rate (MER) test during well testing. The review conducted a survey of North Sea operators to gain insight into their well testing procedures and uncertainties, and take a look at alternative methods that can be used in place of a test separator system during well test for accurate determination of optimum rate. Sir Lan Wood concluded that down hole flow rate measurements are the most valuable sources of information for Maximum Efficient Rate of an oil well as they provide real-time, continuous, and un-dampened reservoir responses. This provides the most accurate and useful data for reservoir engineers in production optimisation.

Conclusion on Previous Works

Most of the work carried out so far on periodic well testing and crude oil optimization, used basically, the application of Nodal analysis approach and Empirical method to determine the optimum crude production rate for oil producing well. The Nodal analysis technique involves the simultaneous solution of inflow performance, tubing and surface line pressure loss correlations to obtain pressures and flow rates through the system. In this analysis, the entire production system is analysed simultaneously. This allows the analysis to include the impact of a given well's production on the other wells in the system. In Production System Nodal Analysis Technique, the plot of the reservoir pressure versus the flow rate is superimposed on the plot of the tubing head pressure versus the flow rate on the same graph sheet to determine the optimum flow rate of the well.

Empirical method enables the estimation of a critical choke, and corresponding production rate beyond which there is a high risk of early water breakthrough. The method involves the plot of the log of the average of well test rates at various choke settings. All the reservoirs investigated in this manner indicated a characteristic hump shape beyond which there is the risk of water breakthrough in the oil well.

Research Position

The various approaches failed to take into consideration the critical impact of sand production, which is detrimental to the production facilities, high water cut as well as high gas oil ratio and its consequences on the environmental (which usually impact adversely on the environment). It is necessary that when the optimum flow rate of a producing well is determined from the Maximum Efficient Rate of the oil well, the impact of other reservoir data such as the sand cut, water cut, and high gas oil ratio are collectively applied on the Maximum Efficient Rate to get the accurate Technical Allowable/Optimum rate as a justification for good reservoir management. That is what this project work tends to achieve.

Methodology

Classical well test interpretation depends on a simplified analytical models and graphical techniques. The methodology may be described as follows: A well test is conducted by giving the well at least three perturbations in flow rates by changing the chokes at equal incremental steps. The pressure response (pressure signature) is measured and matched to a mathematical model (equation or graph). Each well has a unique response which depends on the rock and fluid properties. The matched model gives rise to equations that may be solved for selected variables. The interpretation techniques depend on the appearance of the cross plot of the tubing head pressure and the choke sizes versus the tubing head pressure and the flow rates on the same graph sheet for specific flow periods.

❖ Procedure for well test depends on the type of well

→**New Well Procedure**: applies to well that have never been tested and worked-over wells. Such wells required a production test on at least **five (5) equal incremental steps of choke opening for a minimum of 12 hours duration**.

→**Routine old well Procedure**: applies to wells on regular production. Such wells required a production test of at least **three (3) equal incremental steps of choke opening for a minimum of 6 hours test duration**

Maximum Efficient Rate Test Procedure/Data Generation

❖ Well Test Sequence:

1st Step: 2-3 hours is allowed for well stabilization for each choke size provided stabilization criteria are met

2nd Step: minimum of 6 hours Flow measurement is allowed per each strings previously on a regular production.

Maximum Efficient Rate/Well Test Programme for Producing Wells

Maximum Efficiency Rate Test is usually conducted at regular intervals on a producing well, to know the maximum rate at which a well can be produced without causing damage to the formation and to control crude oil withdrawal rates in accordance with technical and conservation considerations to eliminate inefficient production practices and ensure the optimum recovery of the produce-able oil and gas. During well test, the produced fluids are isolated from other producing wells and channeled to the test separator. The test separator separates out the individual components of the fluid into liquids and gases – for two phase separator, or oil, water, and gas – for three phase separators. The separated components of oil, water and gas are then metered individually by single phase flow measurement technologies. Using these measurements over the length of the well test, the production rate of the well can be determining. These values are then used as the well production rates until they are updated by the next series of well test data. This flow rate data together with other reservoir parameters allows reservoir engineers to model specific wells in order to optimize its production profile.

Sampling Methods/Analyses

Usually, wellhead samples are collected at strategic periods during the well test for sand cut and BS&W analyses. While the ratio of gas to oil produced is determine from the test separator. If the procedure is followed closely, the results obtained will be reliable and accurate. Special attention must be given to the method of obtaining a representative sample in order to obtained accurate result.

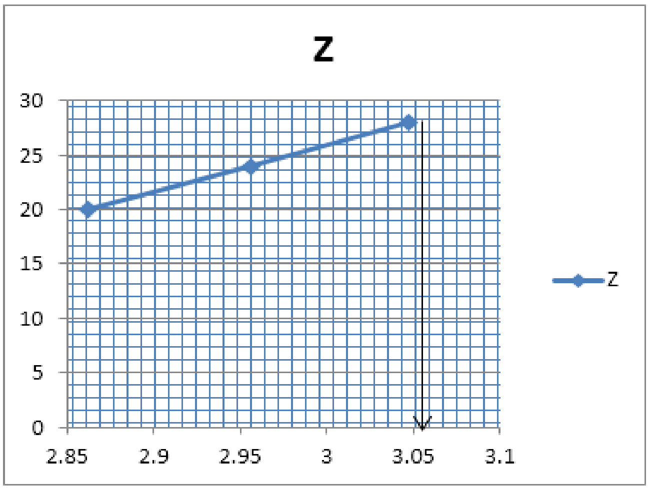
Results and Discussions

Research question 1: Current status for the determination of optimum production rate

Two major methods for modeling optimum production have been developed in the past for different situations. They include the **Empirical method** and the **Nodal analysis** approaches. The Empirical method demonstrated in figure **4.1, 4.3** and **4.5** involve the plot of the log of the average of well test fluid rates at various choke settings such that the reservoir performance is averaged over the wells for investigation. The plot obtained expresses a logarithmic relationship between choke changes with fluid rates in the reservoir. Reservoirs investigated in this manner indicated a characteristic hump shape in the plot of the rate versus choke sizes, coinciding with the maximum rate at which to produce the well while mitigating premature water breakthrough. If a "straight line" is assumed from a reasonably low choke value to a point where the deviation becomes more pronounced along the characteristic curve in the plot then a critical limit of production decline due to water breakthrough can be estimated. This means operating beyond this 'safe' limit may not cause immediate water breakthrough into the well, but puts the well at risk. It is therefore reasonable to operate such a well within the straight line region before the hump point to avoid early water breakthrough for optimum crude oil recovery. In Nodal analysis, the pressure drop, Δp in any part of the production component, varies with flow rate, q. Therefore, a plot of node pressures versus flow rates will produce two curves; the intersection of the two curves satisfies two conditions.

- Flow into the node equals flow out of the node.
- Only one pressure exists at a node.

The procedure is illustrated graphically in Figure **4.2, 4.4** and **4.6** were a plot of the reservoir pressure versus the flow rate is superimposed on the plot of the tubing head pressure versus the flow rate on the same graph sheet to determine the optimum flow rate of the well using well test data from Field X, one of the producing fields in Nigerian Niger Delta area.

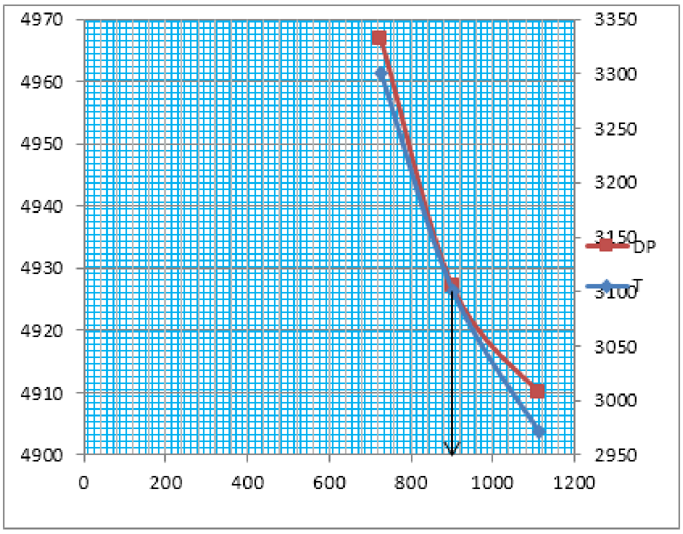


X	LOG X	Z
727	2.862	20
903	2.956	24
1114	3.047	28

Where X = Flow rate (bbls/d)
Z= Choke Size (x/16")

Point of deviation = 3.045 which gives Optimum rate of 1114bbl/d by Empirical approach from table 4.1.

Figure 4 .1: Empirical plot of Well X 4LS



X	THP	DP
727	3300	4966.8
903	3100	4927.0
1114	2971	4910.0

Where X = Flow rate (bbls/d)
THP = Tubing head pressure (psi)
DP = Reservoir pressure (psi)

Point of intersection =900bbls/d which is the Optimum rate by Nodal approach from table 4.1.

Figure 4.2: Nodal analysis plot of Well X 4LS

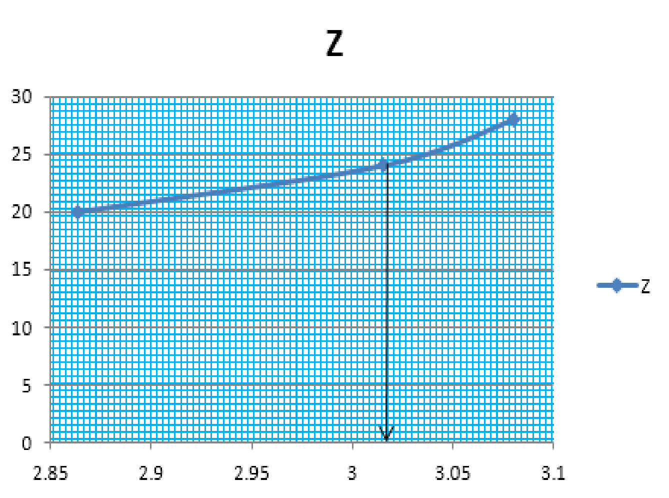


Figure 4.3: Empirical plot of Well X 5LS

X	LOG X	Z
730	2.863	20
1035	3.015	24
1202	3.080	28

Where X = Flow rate (bbls/d)
Z= Choke Size (x/16'')

Point of deviation = 3.015 which gives Optimum rate of 1035bbl/d by Empirical approach from table 4.1.

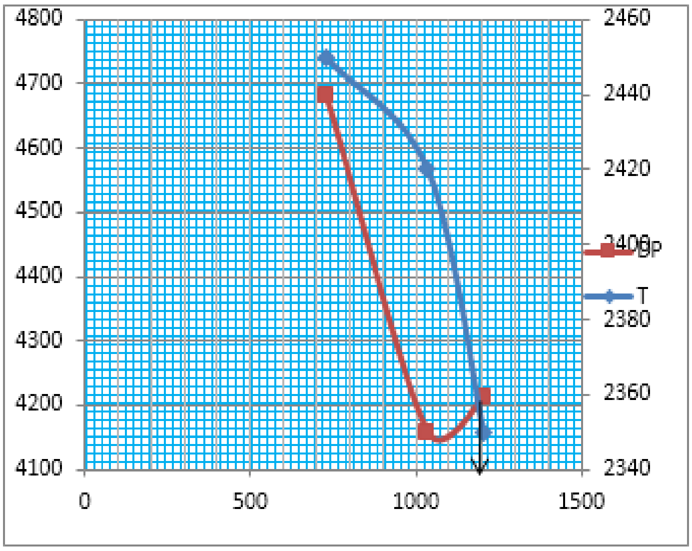


Figure 4.4: Nodal analysis plot of Well X 5LS

X	THP	DP
730	2450	4682.2
1035	2420	4158.9
1202	2350	4213.2

Where X = Flow rate (bbls/d)
THP = Tubing head pressure (psi)
DP = Reservoir pressure (psi)

Point of intersection =1200bbls/d which is the Optimum rate by Nodal approach from table 4.1.

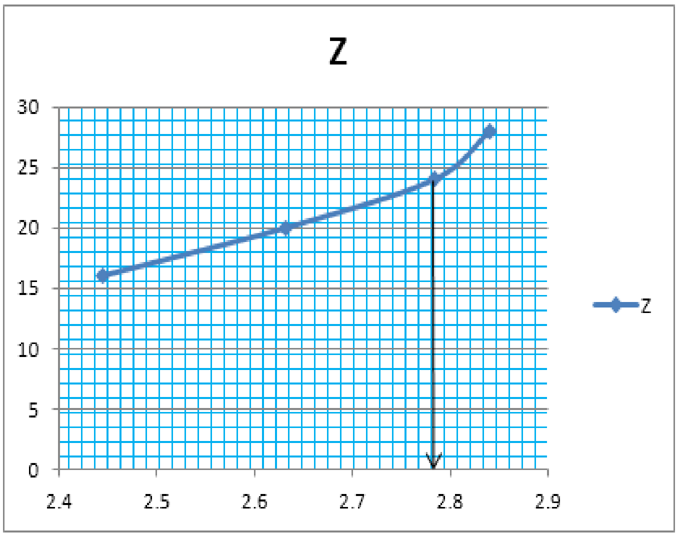
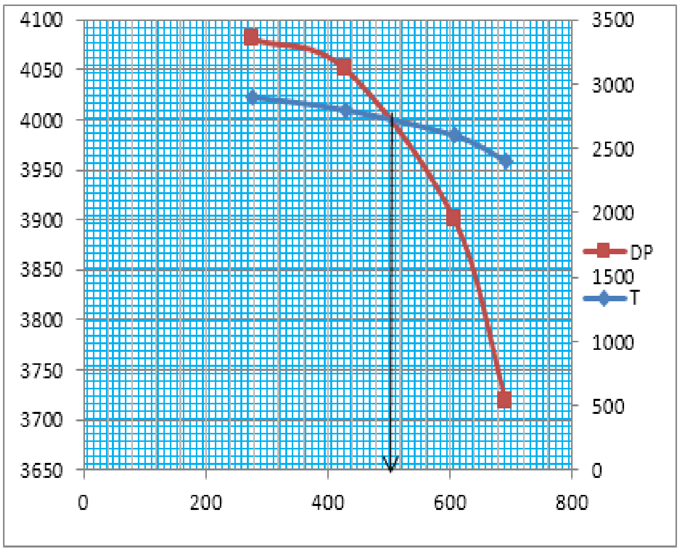


Figure 4.5: Empirical plot of Well X 6SS

X	LOG X	Z
278	2.444	16
429	2.633	20
608	2.784	24
693	2.841	28

Where X = Flow rate (bbls/d)
Z= Choke Size (x/16'')

Point of deviation = 2.77 which gives Optimum rate of 589bbl/d by Empirical approach from table 4.1.



X	THP	DP
278	2900	4080.7
429	2800	4051.1
608	2600	3900.8
693	2400	3718.1

Where X = Flow rate (bbls/d)
THP = Tubing head pressure (psi)
DP = Reservoir pressure (psi)

Point of intersection =500bbls/d which is the Optimum rate by Nodal approach from table 4.1.

Figure 4.6: Nodal analysis plot of Well X 6SS

Research question 2: Impact of incorrect determination of optimum crude oil production rate

- Decline in crude oil production due to early water breakthrough.
- Decline in the reserve base of the country.
- Loss of revenue to the country due to decline in crude oil production.
- Extra cost to recover bypassed crude oil due to incorrect optimization.
- Negative impact of the produced sand and water on the environment/production equipment due to inaccurate optimization of crude oil production.

	OPTIMUM PRODUCTION RATE BY DIFERENT APPROACHES (bbls/d)		
WELL	*EMPIRICAL*	*NODAL*	*ANALYTICAL*
4LS	1114	900	755
5LS	1035	1200	912
6SS	589	500	479

Table 4.1: Optimum rate of Wells X 4SS, 5LS & 6SS by different approaches

A look at figure 4.1 to 4.6 as analysed in table 4.1 shows that the optimum rate figures by Empirical and Nodal approach gives higher production rate of between 10% to 15 % when compared with the Analytical approach. Producing the well at this higher rate will lead to early water breakthrough, high sand cut and high ratio of gas to oil production. The consequences of these impacts would mean that much of the produce-able crude oil from the reservoir will be bypassed due to early water breakthrough which will eventually lead to decline in the ultimate recoverable reserve. High ratio of gas to oil production would equally lead to quick depletion of the reservoir natural energy. Also, producing the well at higher rates increases the risk of sand production from the reservoir and its impact on the production equipment and the environment.

Research question 3: Causes of incorrect determination of optimum crude oil production rate using the existing methods.

- The effects of sand production are not considered in determining the optimum production rate

- The impact of water cut on production is not considered in optimum rate determination.
- High gas production in relation to oil production is not taking into consideration for optimum rate determination.

Accurate estimation of the optimum production rate is one in which the effects of sand cut, water cut and high gas oil ratio are used to scale down the maximum efficient rate of the well to get the technical allowable/optimum rate of production.

Discussion of Findings from Research Questions 1, 2 and 3.

The Empirical and the Nodal approach revealed about 10% to 15% increase in the rate of crude oil production from Field X Wells when compared with Analytical approach. Hence, it is obvious that the use of either Empirical approach or Nodal analysis which considers the relationship between the reservoir pressure, surface pressure, flow rate and choke only for the optimization of crude oil production but ignores the effects of sand production, water cut and high gas oil ratio (as demonstrated by the Analytical approach) from the well will eventually lead to incorrect determination of the optimum production rate. This by extension will lead to poor reservoir management, decline in crude oil production and loses in revenue.

Research question 4: Suggested solution to the incorrect determination of optimum crude oil production rate.

On completion of well test, results of the Maximum Efficient Rate are used to determine the optimum rate of production (Technical Allowable) from the producing wells. The well test results for Field X wells used for these analyses are shown in **table 4.2** below. From the result of the well test, a plot of gross liquid rate versus the choke and the gross liquid rate versus the tubing head pressure is made on the same graph sheet. The point of intersection of the two plots gives the Maximum Efficient rate (MER) as shown in the Maximum Efficient Rate plots in **figures 4.7 to 4.13.** The Maximum Efficient Rate is subsequently used to determine the Technical Allowable (optimum rate) for producing wells by scaling down the Efficient rate of the wells.

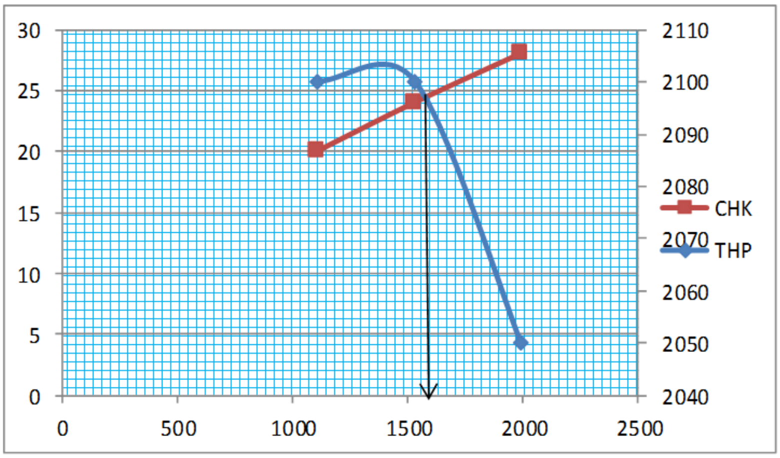


Figure 4.7: Well X1 Maximum Efficient Rate Plot

WELL TEST REPORT

COMPANY: Y **FIELD VISITED: X** **TEST DURATION: 6HRS/CHOKE** **COMPLETION TYPE: SINGLE/DUAL TEST**

DATE: 11/05/2014 TO 26/05/2014 WELL TESTED: X1, 4SS, 4LS, 5SS, 5LS, 6SS, 7SS.

TEST DATE	*Inch*	psig	psig	bbl/d	bbl/d	MMscf/d	Scf/d/bbl	%		pptb	*SEPARATORS*		*AVERAGE RESERVOIR*	
Well X 1	BEAN ($^{x}/64$)	FTHP	FLP	GROSS	NET	GAS	GOR	BS&W	API^0	SAND CUT	STATIC PRESSURE	STATIC TEMP (^{0}F)	PRESSURE (Psi)	TEMP (^{0}F)
11/05/14	20"	2100	217	1107	1104	2.488	2254	0.30	45.3	0.0	200	82	4275.0	227.6
11/05/14	24"	2100	240	1531	1526	3.521	2307	0.30	45.4	0.0	200	78	4284.8	
12/05/14	28"	2050	260	1991	1988	4.729	2379	0.14	45.4	0.0	200	81	4270.3	
Well X 4SS														
13/05/14	20”	2096	220	1060	1058	2.244	2121	0.19	46.4	0.0	200	79	4287.7	227.6
13/05/14	24”	2033	256	1388	1386	3.376	2436	0.12	45.8	0.0	200	78		
14/05/14	28”	1850	270	1797	1794	4.416	2461	0.15	45.2	0.0	200	76		
Well X 4LS														
14/05/14	20”	3300	250	727	654	5.576	7680	10.0	49.8	0.0	200	63	4966.8	333.1
14/05/14	24”	3100	276	903	795	7.513	8338	12.0	48.2	0.0	200	67	4931.1	
15/05/14	28”	2971	323	1114	947	9.925	8925	15.0	49.6	0.0	200	75	4889.2	
Well X 5SS														
17/05/14	20”	2602	250	780	747	3.881	5196	4.18	47.5	0.0	200	64	4027.1	204.4
17/05/14	24”	2450	280	1176	1124	5.591	4974	4.43	47.8	0.0	200	61	4027.1	
18/05/14	28”	1395	300	1360	1239	6.896	5565	8.9	46.2	0.0	200	68	3762.2	
Well X 5LS														
23/05/14	20”	2450	210	730	652	4.033	6186	10.7	44.4	0.0	200	64	4682.8	223.4
23/05/14	24”	2420	220	1035	916	5.263	5746	11.5	45.2	0.0	200	62	4158.9	
24/05/14	28”	2350	300	1202	1072	6.014	5610	10.8	44.6	0.0	200	69	4213.2	
Well X 6SS														
25/05/14	16”	2900	250	278	253	3.734	13432	9.0	53.6	4.9	200	81	4080.7	204.4
25/05/14	20”	2800	340	429	390	4.959	11559	9.0	53.4	4.5	200	63	4051.1	
26/05/14	24”	2600	370	608	535	6.493	10679	12.0	53.4	5.2	200	60	3900.8	
26/05/14	28”	2400	450	693	575	7.306	10543	17.0	53.5	5.0	210	66	3865.5	
Well X 7SS														
12/06/14	16”	3000	280	496	495	2.990	6037	0.10	60.1	0.0	200	68.6	4705.1	215.8
13/06/14	20”	2950	330	750	750	4.056	5415	0.10	59.9	0.0	200	61.5	4525.7	
13/06/14	24”	2900	422	1078	1077	6.158	5720	0.20	56.1	0.0	200	63.0	4411.2	
14/06/14	28”	2700	480	1409	1408	7.627	5443	0.23	54.2	0.0	200	59.0	4098.0	

Table 4.2: **Field X well test Result.**

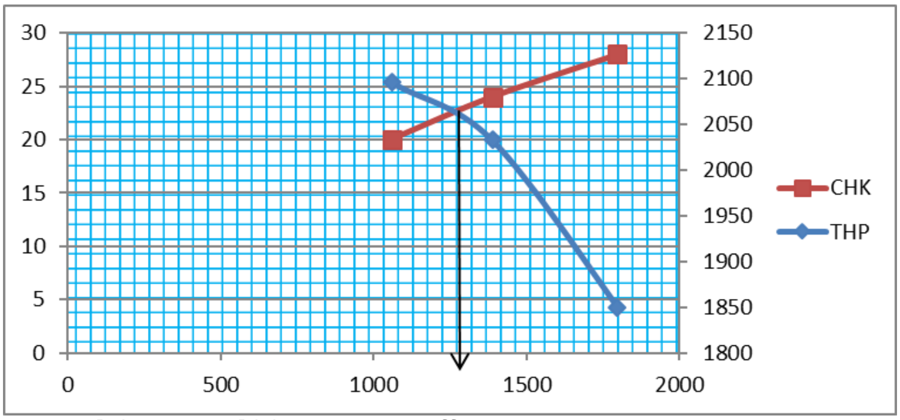


Figure 4.8: Well X 4SS Maximum Efficient Rate Plot

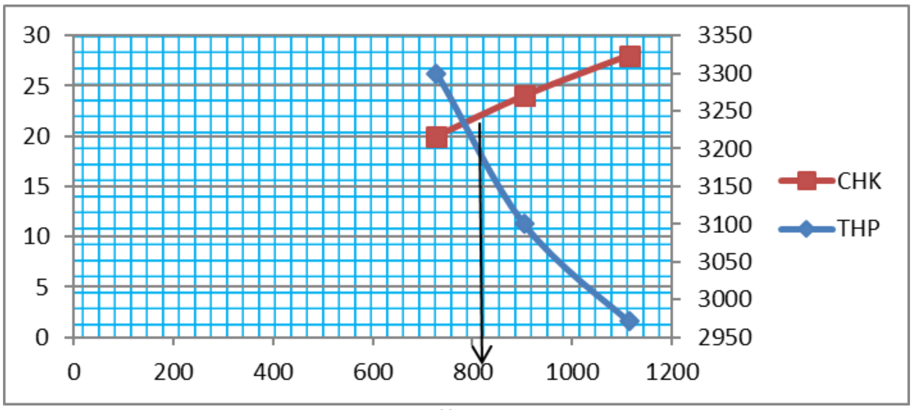


Figure 4.9: Well X 4LS Maximum Efficient Rate Plot

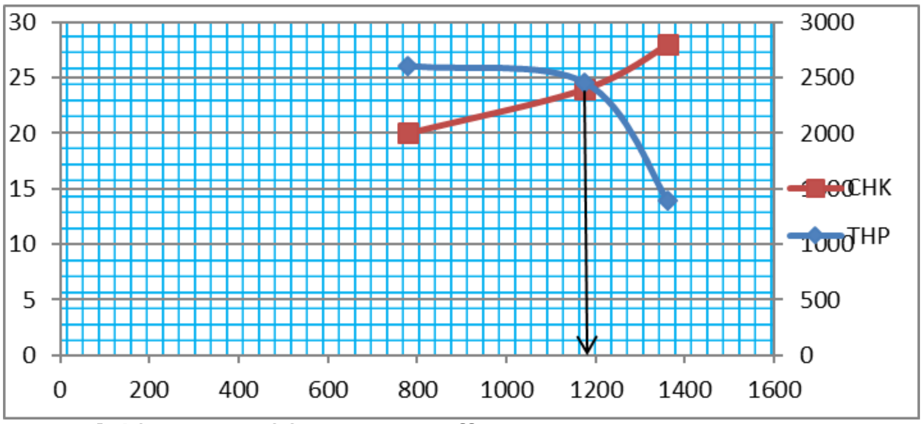
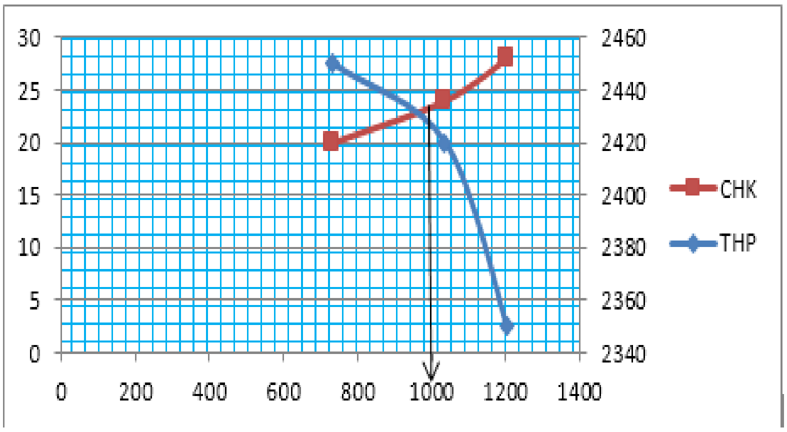


Figure 4.10: Well X 5SS Maximum Efficient Rate Plot



CHK = CHOKE SIZES

THP=TUBING HEAD PRESSURE

GR=GROSS PRODUCTION RATE

Figure 4.11: Well X 5LS Maximum Efficient Rate Plot

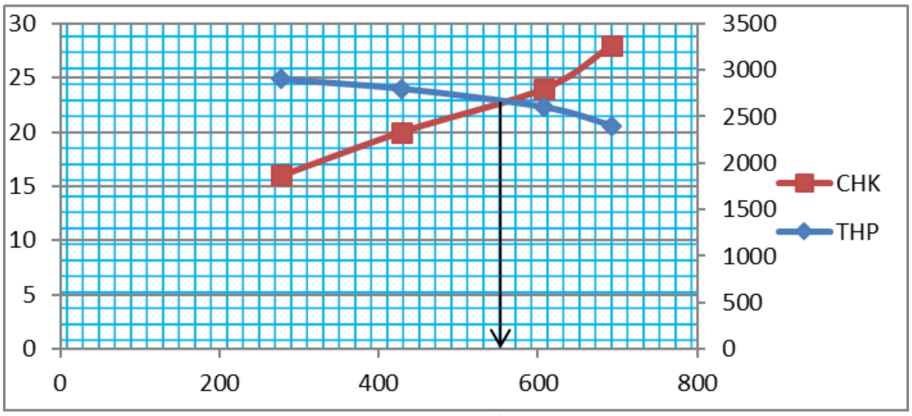


Figure 4.12: Well X 6SS Maximum Efficient Rate Plot

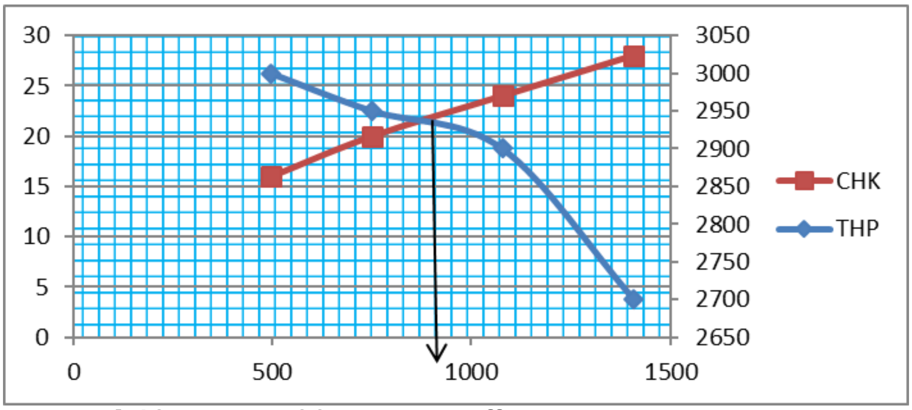


Figure 4.13: Well X 7SS Maximum Efficient Rate Plot

Operating Guidelines for Technical Allowable/Optimum Production Rate

1. Technical Allowable are determined on string by string bases
2. Technical Allowable for one string cannot be transferred to another string.
3. An allowable/optimum rate represents the ceiling of production statutorily permitted from a producing well
4. Under-production from a 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 for a lost production in a previous period or anticipate loss in future production

5. At any time, the permissible production from any string/well or field shall consist only of allowable of producing strings/wells and production from test wells yet to be granted allowable
6. Production in excess of Technical Allowable/optimum rate from wells constitutes an infringement and attracts sanctions in accordance with the Laws and Regulations guiding the oil and gas industries in Nigeria.

Allowable/Optimum Rate Computation

The following considerations are of critical importance in computing the technical allowable/optimum rate for a producing well in Nigeria.

Water cut

- Water production is limited by age of the well and the drive mechanism.
- BS&W is expected to be zero in a non-water drive pool.

Sand Cut

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

Flow Tubing Head Pressure (FTHP)

- This is used to indicate well's condition.
- Drastic fall in THP could be as a result of mechanical obstruction, sand bridging/ impairment of sand face or water loading.
- High THP indicates high gas oil ratio (GOR).
- In water drive or pressure maintained reservoir, GOR is limited to 125% of the initial solution GOR (Rsi) or to a maximum of 4,000scf/bbl unless the produced gas is to be used on an approved gas project.

The factors above, (Water cut, Sand cut and Gas oil ratio) are used in scaling down the Maximum Efficient Rate figure to arrive at the Technical Allowable/optimum rate for all producing wells/strings in Nigeria. The guideline for the computation of allowable/optimum rate from the maximum efficient rate of wells is demonstrated in **table 4.3** below. The criteria above are used as a guide in optimum rate determination among other additional factors usually considered.

FIELD APPLICATION OF THE MER PLOTS

S/N	WELL	MER VALUE FROM GRAPHS OF FIG. 4.7– 4.13	REVIEW	TECHNICAL ALLOWABLE (bbl/d)	REMARK
1	Well X 1	1,550	$BS\&W_{max}$ = 0.3% Sand cut= 0.0pptb	1,550	➢ Low BS&W ➢ Zero Sand cut ➢ No penalty ➢ MER= Allowable
2	Well X 4SS	1,275	$BS\&W_{max}$ = 0.19% Sand cut= 0.0pptb	1,275	➢ Low BS&W ➢ Zero Sand cut ➢ No penalty ➢ MER= Allowable
3	Well X 4LS	795	$BS\&W_{max}$ = 15% Sand cut= 0.0pptb	755	➢ High BS&W ➢ Zero Sand cut ➢ 5% penalty on MER figure for high BS&W ➢ Allowable = 755bbl/d
4	Well X 5SS	1,200	$BS\&W_{max}$ = 8.9% Sand cut= 0.0pptb	1,200	➢ Low BS&W ➢ Zero Sand cut ➢ No penalty ➢ MER= Allowable
5	Well X 5LS	960	$BS\&W_{max}$ = 11.5% Sand cut= 0.0pptb	912	➢ High BS&W ➢ Zero Sand cut ➢ 5% penalty on MER figure for high BS&W ➢ Allowable = 912bbl/d
6	Well X 6ss	563	$BS\&W_{max}$ = 17% Sand cut= 5.2pptb	479	➢ High BS&W ➢ High Sand cut ➢ 10% penalty on MER figure for high BS&W = 507bbl/d ➢ 15% penalty on MER figure for high Sand cut = 479bbl/d ➢ Allowable = 479bbl/d which is the least of the two values (507 & 479).
7	Well X 7SS	890	$BS\&W_{max}$ = 0.23% Sand cut= 0.0pptb	890	➢ Low BS&W ➢ Zero Sand cut ➢ No penalty ➢ MER= Allowable

Table 4.4: Analyses of Technical Allowable/Optimum rate Computation from MER.

The tested wells in Field X have produced below five (5yrs) as of 2014 when the well test data were obtained in respect of BS&W.

Conclusion

From the research conducted within the scope of work in this project, the following conclusions can be drawn. Choke optimisation and flow test methods without a reservoir model guide may lead to a short life-span for an oil well. Producing a well within the range of the Maximum Efficient Rate (MER) of the characteristic plot alone would not eliminate the risk of suboptimisation due to early water breakthrough, high sand cut and high gas oil ratio. The effects of water cut, sand cut and gas oil ratio are necessary for accurate determination of the Optimum/Technical allowable rate of production of oil wells.

Recommendations

The following recommendations are made to provide the industry with accurate method of Optimum rate determination and application.

1. Crude oil wells should be produced within their Optimum/Technical allowable rate.
2. Optimum/Technical allowable rate should be determined using the Analytical approach for better reservoir management.
3. The nature of well production is dynamic. Hence, periodic/regular assessment or test is encouraged for accurate monitoring of well flows to enable operators factor the impact of changes in water cut, sand cut and gas oil ratio.
4. Development of historical trend or history matching methods from well test data is important to ensure full use of the considerable data resources that are available.
5. More stringent monitoring of well test is necessary by both the regulatory body and the operating companies since Optimisation is achieved from well test data.
6. Further studies should be conducted to identify other reservoir parameters that could likely affect the optimum production rate of a well aside sand cut, water breakthrough and high gas oil ratio.

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