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Comparative Studies and Analyses of the Different Mechanical Sand Control Systems: A Case Study of a Well Completed in the Niger- Delta of Nigeria

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Abstract: Sand production problems are as old as oil drilling itself. It is argued to be the oldest problem plaguing the oil industry. This phenomenon leads to high economic losses in oil and gas production. If the passive methods of sand control of selective and oriental perforations fail, the active methods which involve the chemical and mechanical methods are called into play. This project work compares four mechanical sand control methods; Cased-Hole Gravel Pack, Wire-Wrapped Screens, Pre-Packed Screens and Slotted Liner. It studies the effectiveness of each system, total skin offered and their effects on well productivity. As a control, the data of a well completed without any sand control system in place in the Niger-Delta region of Nigeria was obtained. the IPR/VLP plots were made and the flow efficiencies were calculated. The well was later simulated with the four cases mentioned above and the total skin and flow efficiencies calculated. It was discovered that the flow efficiencies showed a reduction due to the installation of the sand control tools and the skin offered by each sand control system. The flow efficiencies dropped from 0.476 025 to 0.475 977 for Wire-wrapped Screen, 0.475 930 for Cased-Hole Gravel Pack, 0.475 914 for Pre-Packed Screen and finally 0.052 890 for the Slotted Liner. The drops in flow efficiencies were validated by the increasing values of total skin factors from 0 for No Sand Control System, 0.000 484 86 for Wire-Wrapped Screen, 0.002 359 for Pre-Packed Screen, 1.76 for Cased-Hole Gravel Pack and 49.82 for The Slotted Liner. Parameters as Absolute Open Flow Potential (AOFP), Productivity Index (P.I.), Total Skin Value and Liquid (Oil) Production Rate showed that the Wire-Wrapped Screen was the best sand control solution for the given well.
Keywords: Mechanical Sand Control tools, PROSPER, MBAL, Sand Production, Productivity Index, Skin, Flow Efficiency, Absolute Open Flow

I. INTRODUCTION

Almost, if not all producing wells produce with traces of sand. Sand production is one of the concerns that oil and gas companies encounter in unconsolidated formations. The generation of formation sands in conjunction with formation fluids is described as sand production. When wells flow, sands are formed due to the formation's unconsolidation; the unconsolidated sands are very inclined to migrate through the wellbore and to the surface. When a reservoir's threshold pressure is exceeded in order to produce at maximum rate from a sandstone reservoir, sand production occurs, and when the reservoir pressure is more than the wellbore pressure, a large amount of fluid influx from the sandstone reservoir into the wellbore takes place. Produced sand has no economic worth, yet it affects both surface and subsurface equipment severely. As a result, it would be preferable to find a way to eliminate sand production without drastically reducing production rates.

The deployment of efficient sand control practices has allowed oil and gas production to remain stable. Before being applied to oil and gas wells, sand control measures were originally employed in water wells. Sand control in reservoirs helps to avoid or reduce sand production, but utilizing ineffective sand control techniques has a high risk of productivity loss and high skin. Mechanical and chemical sand control techniques were developed to reduce sand production. Gravel pack, pre-packed screen, wire wrapped screens, and slotted liner are the mechanical methods used. Chemical procedures entail injecting chemicals such as liquid resin into the unconsolidated formation surrounding the well through the wellbore.

Sand entering production wells is one of the oldest problems faced by oil companies and one of the toughest to solve. Production of sand during oil production causes severe operational problem for oil producers. Every year the petroleum industry spends millions of dollars in sand cleaning, repair problems related to sand production and lost problems related to sand production and lost revenues due to restricted production rates.

Consequently, sand control has been a research topic for over five decades. The purpose of this research and project work is to help in understanding the causes of sanding, and how it can be predicted and controlled. It will examine the main methods of sand control.

A. *Statement Of Research Problem*

The likelihood of exceeding the reservoir boundaries increases as the reservoir production rate rises. Because of this formation, sand production is directly related to water influx. Nowadays, strategies are employed to determine sand production and formation failure potentials. This is important because it helps the production engineer determine what sand mitigation strategy is to be utilized as well as completion strategy. Limiting production speed to avoid sand production is one strategy used by production engineers.
This research probes into four mechanical sand control tools (Internal Gravel pack, prepacked screen, wire wrapped screens, and slotted liner) to investigate their effectiveness as the best choice sand control tool under the conditions of the simulation.

II. LITERATURE REVIEW

A. *Sand Production In Producing Wells*

The production of formation sand into a well is one of the oldest problems facing the oil and gas industry because of its adverse effects on well productivity and equipment. Vaziri *et al.* (2008) proposed that sand production is normally associated with shallow, geologically young formations that have little or no natural cementation to hold the individual sand grains together. As a result, when the wellbore pressure is lower than the reservoir pressure, drag forces are applied to the formation sands as a consequence of fluid production. If the formation's restraining forces are exceeded, sand will be drawn into the wellbore. The produced sand has essentially no economic value.
On the contrary, formation sand not only can plug wells, but also can erode equipment and settle in surface vessels.
Controlling formation sand is costly and usually involves either:

1) Slowing the production rate
2) Using control techniques.

Bellarby (2009) wrote that reduction in the production rate, which is the most-often applied strategy, is not an economic approach to overcome sand production problem. So, it is preferred to use sand control techniques. Using sand control techniques accompany with additional equipment for well completion. Although this equipment prevents formation sand entering the wellbore by various mechanisms, it also has some disadvantages as:

a) It decreases the reservoir productivity,
b) On the other hand, additional skin factor is caused due to sand control technique.

This indicates that the magnitude of the skin is also an important parameter to choose a sand control method for a sand producer well.
Hence, before choosing a method to prevent sand production, it is important to know the skin factor of the method and evaluate well production economically for a specific period. Skin factors of different sand control methods are investigated and indicated the best method for real case economically (Aborisade, 2011).

B. *Causes of Sand Production*

Vaziri *et al.* (2008) argued that factors and mechanisms leading to sanding are described within an integrated rock and soil mechanism framework. The approach considers the interplay of several mechanisms that can lead to rock breakups and transport. It was used to discuss sanding patterns in several wells in two fields which have been in production for years. They concluded that sanding is generally triggered via several concurrent mechanisms such as stress, drawdown and frequency of shut-downs, bean up rate and water cut.
Carlson *et al.* (2002) concluded that factors controlling the onset of mechanical rock failure include:

- Inherent rock strength,
- Naturally existing Earth stress,
- Additional stress caused by the drilling and production activities.

These causes of sand production can be summarized as:

1) Unconsolidation

An unconsolidated formation is a formation in which the sand particles are loosely arranged, apparently unstratified section of the rock. This occurs when rock particles are not well formed and cemented. The general theory is: The deeper the formation, the more consolidation and the lesser the possibility of sand production. Generally, rocks with a compressive strength below 100psi are prone to sand production.

2) Reduction in Pore Pressure

As production progresses, the reservoir pressure deplete leaving pore spaces in the reservoir almost empty and thereby increasing the overburden pressure of the formation. This increase in pressure may lead to the crushing of well-formed rock particles which further leads to sand production.

3) High Production Rate

Every reservoir is said to have a threshold pressure above which sand will be produced. Operating within this threshold pressure puts the well below its economic limit/rate. Increased production rates are often employed by production technologists in order to maximize production. High production rate brings about high stress on the formation. Sand production in this case occurs as a result of the disorientation and weathering of the rock particles due to extreme pull on the formation; and this occurs when the drawdown is almost twice the compressive strength of deformation.

4) Increased Water Production

Increased water production leads to sand production and this is as a result of:

a) Capillary pressure holding the grains are lost due to the production of water.
b) Flow friction increases due to dual-phase flow.
c) High pressure gradient at the sandface due to higher flow rate for a designed net production.
d) Water may dissolve cementation materials between sand grains.

C. Mechanisms Of Sand Production

Okeh *et al.* (1999) explained that sand production can either be transient, continuous or catastrophic.

1) Transient sand production occurs when sand production declines with time. This usually occurs during clean-up flow after perforation, choke change or water breakthrough.
2) Continuous production occurs when production of sand is continuous, which means that it is present throughout the life of the well. This is usually observed when a well is drilled in a very fragile unconsolidated formation.
3) Catastrophic flow occurs when there is a sudden influx of sand into the wellbore which brings about the death of the well.

D. Sand Production Prediction

Sand prediction is an essential step in the reservoir evaluation and analysis to predict the possibility of sand production and choose a proper control method. Some of the analytical techniques used for sand prediction include:

- Logging analysis,
- Core-based tests,
- Numerical simulators,
- Drill Stem Tests (DST).

1) Logging Analysis

The sonic log and porosity log are the two important log data which are used in the formation evaluation for sand prediction. The sonic log records the transit time, which is the time necessary for the sound wave to travel within the reservoir formation. The shorter travel time less than 50 µm seconds indicates that the sand is hard, has low porosity and high density. On the other hand, the longer travel time more than 95µm seconds indicates that the sand is soft, has high porosity and low density. Bellarby (2009) revealed that a common practice used to determine whether the sand control is necessary for known geologic region is to determine the regularities of sand production using the sonic log readings below and above the sand production. Such technique provides a quick screening if sand control is required. Thus, to utilize such method, calibration with specific geologic formations is required.

2) Core-based Analysis

The common practice for most core analysis is the use of Compressive Strength Test (also called Unconfined Compressive Strength (UCS) test) and the Hardness Test introduced by Brinell. Over the years, these test have proven to be very reliable.

While UCS relies on the fact that the higher the strength of the material, the higher the force needed for uniaxial deformation of the materials, Brinell's Test indicates that the degree of indentation depth determines the hardness of material. Brinell uses a spherical indenter to create controlled dent in a material using controlled indentation force and at a specific time (usually 15 secs.)

3) Numerical Simulators

Numerical models are powerful tools capable of predicting sand production. They also can be integrated with analytical correlations to determine proficient results. The obtained results experimentally can be also employed to validate and calibrate the numerical model. Even though the numerical models have such advantages, there are still some limitations in which extensive efforts have been done to improve model calculations. There are two mechanisms involved in modelling of sand production, which are mechanical instability including degradation near the wellbore and hydro-mechanical instability due to flow-induced pressure gradient on degraded material surrounding the cavity such as perforation and open bottom-hole (Nur, 2019).

Generally, numerical techniques that are used in mechanical modelling are classified into two approaches; continuum and discontinuum. The continuum approach assumes that the body to be analyzed is a continuous non-spatial whole or extent in which no part is the exactly the same but no part is distinct or indistinguishable from the adjacent part.

4) Drill Stem Test (DST)

This is the conventional method of formation testing. The basic drill stem test tool consists of a packer or set of packers, valves or ports that may be opened and closed from the surface, and two or more pressure-recording devices. The tool is lowered on the drill string to the zone to be tested. The packer or set of packers are set to isolate the zone from the drilling fluid column. The valves or ports are then opened to allow for formation flow while the recorders chart static pressures. A sampling chamber traps clean formation fluids at the end of the test. Analysis of the pressure charts is an important part of formation testing.

E. Effects of Sand Production

Sand production produces the following effects:

1) Accumulation in Surface Equipment

When the production velocity is high enough to carry sand up the tubing into surface equipment such as in the heat treater, separator, and so on, a well can be shut down due to sand that has been produced. In order for production to proceed, the sand that had become trapped in the surface equipment must be manually removed. For example, if there is trapped sand in a separator used to separate gas, water, and oil, the separator's capacity to separate the fluids is reduced.

2) Accumulation of Produced Sand Down Hole

When the production velocity is not high enough to push the produced sand to the surface, sand can clog the tubing and fill the casing. As the rate of production decreases, the well progressively fills with sand, and production eventually halt. To clean out the well and restore production, remedial activities will be required, resulting in lost production and increased well maintenance costs.

3) Causes Erosion of Equipment (Surface and Down Hole)

Surface and downhole equipment can be eroded by high-velocity fluids that carry sands, necessitating frequent replacement. When this erosion occurs over time, down hole and surface equipment will completely fail, posing a safety and environmental risk.

4) Collapse of The Formation

As more sand is pushed out with the produced fluid, a void or hole forms behind the casing; if this continues over time, the void grows larger, causing formation collapse when the overlying formation no longer has a support to hold it up. It reduces the permeability of a shale formation.

5) Increased Production Cost

Sand production can lead to increased production cost. Erosion of surface and downhole equipment can lead to their failures thereby requiring either a form of replacement or a maintenance done on the equipment.

F. Sand Control Methods

Sand control can be defined as any method that could be used to hinder the movement of formation sand into the wellbore. The method involved in sand control includes:

1) Passive Sand Control Methods

This method uses non-intrusive measures to control, mitigate or avoid the production of sand from the reservoir. The following techniques are passive sand control methods:

- Orientation Perforation
- Selective Perforation
- Sand Management

2) Active Sand Control Methods

The method relies on the use of filters and screens to control sand production and this is known as intrusive method. The following methods are classified under active sand control systems:

- Standalone Screens (Slotted Liners, Wire-Wrapped Screens, Pre-Packed Screens and the Premium Screens)
- Expandable Sand Screens (ESS)
- Gravel Packs and Frac-Pack
- Chemical Consolidation

3) Gravel Packs

Gravel pack is a common sand control technique deployed in many formations with unconsolidated or poorly consolidated sands. It is a specialized completion method that needs exceptional completion and pumping equipment. The gravel pack is an effective, extensively used and cost effective technique of holding back reservoir sand from produced fluids. It finds use in vertical, inclined and deviated wells.

Irrespective of completion configuration, any gravel pack job tends to achieve the primary objectives of sand-free production, completion longevity and high productivity while minimizing productivity impairment. In achieving these objectives, operators must carry out gravel packs appropriately under a wide variety of field conditions. Thus, gravel packing must be approached from a total systems standpoint which involves interconnected technologies.

- *Open Hole Gravel Packs*

The theory of a gravel pack is to pump gravel as a slurry mix into the well, thus packing the annular space around the tubing throughout the reservoir interval. The aim of this is for the gravel to screen out the reservoir sand, and at the same time allow the production of reservoir fluids. It is commonly used in combination with a form of sand screen, with the sand screen the inmost element, making sure that the grit of the gravel pack is kept in place and not produced. The gravel pack will accumulate around the screen and screen out the reservoir sand.

- *Cased Hole Gravel Packs*

These use typically the same tools and techniques as the Open hole gravel Pack. The difference being that it is desirable with both squeezing and circulating, in attempt to ensure proper packing of the perforations. It is also possible to pack the perforations at a pressure higher than the fracture pressure, in which it is called a “High Rate Water Pack” (HRWP), which may be characterized as a sort of a hybrid between the conventional gravel pack and the frac-pack. The high pressure will guarantee proper packing of the perforations, but at the same time the pressure is not sufficiently high to cause any more than minimal fracture growth.

4) Wire-Wrapped Screens

Wire-wrapped screens offer another alternative for retaining the gravel in an annular ring between the screen and the formation. Pipe-based sand screen is used in stand-alone completions with well sorted formulations or in combination with gravel packed completions. Wire-wrapped screens have substantially more inflow area than a slotted liner. For gravel packed well, the wire-wrapped screen stops the gravel and the fine material will either be stopped by the gravel or be produced through the screens. It can be applied in cased and open-hole completions.

5) Pre-Packed Screens

A pre-packed screen has gravel aggregate within the annulus between the inner base pipe and the outer wire screen. The pre-packed gravel is sized approximately to exclude the fines which accompany the formation fluid during initial production. It can be installed in both open and cased holes. Pre-packed screens offer a degree of depth filtration and the relative high porosity. Over 30% combined with their very high permeability provide minimal pressure drop (Bellarby, 2009). They are easiest to plug than other screens.

6) Slotted Liners

Slotted liners completions are by far the most common completion run in horizontal wells. The primary purpose of the slotted liner is preventing hole collapse in formations that may tend to cave in after being drilled, or as formation pressure decreases.

7) Chemical Sand Consolidation

Hisham *et al.* (2015) defines chemical consolidation is an alternative way to the mechanical sand control system to control sand production in unconsolidated formation in order to strengthen or consolidate sands. The main goal is to cement sand grains together to provide stable compressive strength while maintaining initial permeability as much as possible. This is the most complex sand control method which involves significant risk of damaging the reservoirs and/or ineffective chemical placement. This technique involves multi-stage injection of several chemical into a reservoir.

Chemical consolidators include:

a) Thermosetting and thermoplastic resins
b) Phenol resins
c) Furan resins
d) Amino resins
e) Epoxy resins
f) Polyester resins
g) Urethane foams
h) Alkyl resins

G. Selection Criteria For Proper Sand Control Method

The conditions upon which sand control techniques can be measured and compared are:

1) *Reliability:* Failure in sand control would result in a side track or well abandonment. Hence, careful measures must be taken a historical data is used on reliability to ascertain a similarity in environment, technological update and validity of statistical approach.
2) *Productivity:* To be of use for economics, the reservoir completion productivity needs to be converted to comparable production profiles, which should include the upper completion effect, reservoir depletion and water/gas influx
3) *Costs:* For full comparison, the costs must be all-inclusive.

H. Performances Of Mechanical Sand Control Systems In A Well System

Different sand control systems are employed in different conditions. Weingarten *et al.* (2012) asserted that conventional sand control methods, such as chemical consolidation, wire wrapped screens, gravel packing, frac-and-pack, expandable screens, etc., are implemented based on a sand exclusion philosophy; definitely not any sand control in the production equipment can be accepted.

On the other hand, to avoid sand influx totally, Sanfilippo *et al.* (2017) was of the view that the conventional method is to minimize the production rate to reduce the amount of sand entering the wellbore. Veeken *et al.* (2011) opined that the strategy to control or exclude the sand formation is based on the analysis of sand prediction as mentioned earlier. As a result, it has led to improvement of various numerical approaches to predict the sand production onset (as cited in Morita *et al.*, 2017).

1) Skin (Factor) Values of A Well Due to The Presence of a Mechanical Sand Control Tool

According to Bellarby (2009), skin (factor) is a dimensionless estimation of obstruction to flow. An undamaged well has skin of zero. A damaged well has a positive skin value and a stimulated well will have a negative skin factor.

A review of the work by Abubakar *et al.* (2012) showed the performances of different sand control systems on a well system. While this work is carried out in real time in the Gulf of Mexico, its applicability in many parts of the world is still acceptable.

According to Ayoola *et al.* (2009), the Niger Delta field is made up of largely unconsolidated sandstones. The work by Abubakar *et al.* (2012) showed that out of the four sand control tools within their scope of study; wire-wrapped screens, pre-packed screens, internal gravel pack and the slotted liner; the wire-wrapped screens performed best of all in terms of skin values.

It has been agreed that the lower the skin values, the better the sand control tool. According to Ayoola *et al.* (2009), the feasible sand control tools are the wire-wrapped screen and pre-packed screen. They asserted that the wire-wrapped screens performed best using data obtained from Niger-Delta wells.

Reviews of the works of Adeyanjua & Olafuyibi (2011) showed that wire-wrapped screens, pre-packed screens, internal gravel pack and the slotted liner were important control tools at differing reservoir conditions. They found out that internal gravel packs work at a very large range of formations-consolidated to slightly unconsolidated formations, slotted liners and pre-packed screens are excellent at friable formations while the wire-wrapped screens work best under the loosely consolidated formation of the Niger-Delta. In fact, they established that the wire-wrapped screens are the best sand control systems under the test of study.

2) Effects of Sand Control Tools On Pressure Drop Due to Skin

As a rule of thumb, a higher skin value means that the pressure drop will be high too. Abubakar *et al.* (2012) described a linear relationship between skin value and pressure drop due to skin. They observed that the presence of a sand control tool in the wellbore brought about a little damage to the wellbore.

In their test, they opined that since wire-wrapped screen had the lowest skin value, its pressure drop due to skin was also the lowest. This postulate was further substantiated by Arman *et al.* (2021) who carried out research on sand control tools in the Arabian gulf.

3) Liquid Rate (Oil and Gas Production Rate) and Productivity Index

The Productivity index is a well test measurement indicative of the amount of fluids a well is capable of producing. It is usually described as:

$$PI = \frac{Q}{(P_S - P_f)}$$

PI = productivity index (STB/day/psi)

Q = production rate (STB/day)

P_s = static bottom hole pressure (psi)

P_f = flowing bottom hole pressure (psi).

Difference between the Static bottom hole (reservoir) pressure and the Flowing bottom hole pressure is called **Pressure Drawdown**. This is the pressure that drives fluid from the reservoir into the wellbore by creating an energy gradient. A large drawdown means a low productivity index.

In a study by Carlson *et al.* (2002), it was observed that productivity index varies indirectly as the skin values offered by a sand control system; which means the lower the skin values, the higher the productivity index. In their work where they compared slotted liners and the screens (wire-wrapped and pre-packed screens), they observed that slotted liners and pre-packed screens are best suited to friable formations instead of completely unconsolidated formation. They even observed that a continuous production of fine sand can plug the pre-packed screen even after few hours of installation.

4) Absolute Open Flow (AOF)

Igbokoyi (2011) defined the Absolute Open Flow (AOF) Potential of a well as the rate at which the well would produce against zero sand face back pressure. He asserted that it is used as a measure of gas well performance because it quantifies the ability of a reservoir to deliver gas to the wellbore. Deliverability tests make possible the prediction of flow rates against any particular back pressure, including AOF when the back pressure is zero. The productivity of the well depends on an efficient use of the compressional energy available in the reservoir allowing the reservoir fluids to flow toward the production separator.

Inflow Performance Relationship (IPR) is defined as the well flowing bottom-hole pressure (Pwf) as a function of production rate. It describes the flow in the reservoir. The Pwf is defined in the pressure range between the average reservoir pressure and atmospheric pressure.

The intersection of the PI plot with the x-axis is the flow rate corresponding to a Pwf equal to zero. This point in the IPR plot is known as the Absolute Open Flow (AOF) potential of the well.

Vertical Lift Performance Relationship (VLP), named also Outflow, describes the bottom-hole pressure as a function of flow rate. The VLP depends on many factors including fluid PVT properties, well depth, tubing size, surface pressure, water cut and GOR. It describes the flow from the bottom-hole of the well to the wellhead.

Both the Inflow Performance Relationship and the Vertical Lift Performance Relationship relate the wellbore flowing pressure to the surface production rate. While the IPR represents what the reservoir can deliver to the bottom hole, the VLP represents what the well can deliver to the surface.

The intersection of the IPR with the VLP, called the OPERATING POINT, yields the well deliverability; an expression of what a well will actually produce for a given operating condition (Pressure, PI, Water Cut, GOR, Tubing Head Pressure, Tubing size).

With the publication of Abubakar *et al.* (2012) under review, AOF is directly linked with the productivity index; the higher the productivity index, the higher the AOF. Conclusions by Khamehci *et al*. (2014) using data obtained from an Iranian well and PROSPER as a numerical simulator, showed that any sand control method with the lowest skin may not necessarily be the best sand control system. They were of the view that using skin factor as the major or the only factor to judge the performance of a sand control system downhole may be disastrous.

While the skin value has an intense effect on choosing the sand production method, the skin value and the operation rate are not the only main parameters for choosing the best project. Economic evaluation as well as mechanical tests are the most important tools for taking decisions.

According to Nur (2019) who tested the performances of four mechanical sand control methods (Cased-hole gravel pack, wire-wrapped screens, pre-packed screen and slotted liner), the advantages and disadvantages of each sand control system are summarized in the table below.

Table 2.1: Advantages and Disadvantages of Some Mechanical Sand Control Methods (Nur, 2019).

Sand Control Method	Advantages	Disadvantages
Wire-Wrapped Screens	Simplest and cheapest	Easily damaged in running operations
	Most difficult to plug	Less resistant to erosion
	Best in the lower part of a vertical well	Inaccurate wire spacing can allow the production of formation sand or plug
	Keystone slot	Can be damaged when installing through doglegs, high angle and horizontal sections
	High manufacturing efficiency	
	Profile materials can be stainless steel	
Pre-packed Screens	Moderately expensive	Easiest to plug
	Can withstand some erosion	Easily damaged in running operations
	Best in the upper part of the vertical well and in horizontal wells	
Slotted liner	Not used to control sand production; but to help with borehole stability	Subject to erosion
	Moderate cost	Low reliability
	Easy installation	Easily plugged
	Good for well-sorted sands	High skin
		Low rotational strength
Cased Hole Gravel Pack	Trusted for deep water reservoir	High cost of installation and replacement
	Moderate reliability	Low inflow area
		Subject to erosion
		Easily plugged

III. MATERIALS AND METHODOLOGY

A. Materials

MBAL and PROSPER were used as the main analysis tools for this work.

MBAL (Material Balance) is a Petroleum Engineering software that enables non-dimensional reservoir analysis to be conducted on a field, whether virgin or already in full development. This tool is very helpful, especially in line with other numerical simulators as a quality check of history matching, and/or as a proxy model for fast calculations.

PROSPER (Production and System Performance Analysis Software) is software designed to assist the production and reservoir engineer carryout well production analysis. This is done by allowing the user create models of each component and verifying the models by performance matching. This tool is very helpful in designing well completions, modelling well outflows, analyzing well inflow performances, multilateral completions, thermal modelling and flow assurance predictions.

1) Simulation Data Requirements and Input for MBAL

Table 3.1 Fluid; Black Oil Data

Fluid (Black Oil) Data	
Formation GOR (scf/STB)	490
Oil Gravity (API)	34.9
Gas Gravity (sp. gravity)	0.93
Water Salinity (ppm)	200000
Impurities	
Mole Percent H_2S (%)	0
Mole Percent CO_2 (%)	0
Mole Percent N_2 (%)	0

Table 3.2 Reservoir Data

Reservoir Data	
Temperature (°F)	238
Initial Pressure (psia)	4714
Bubble Point Pressure (psia)	2535
Porosity (%)	13
Connate water saturation (%)	20.5
Water compressibility (1/psi)	3.4×10^{-6}
Initial gas cap	0
Original Oil in Place (MMSTB)	675
Rock Compressibility (1/psi)	4.2329×10^{-6}

2) Simulation Data Requirements and Input for PROSPER

Table 3.3 Fluid Description

Fluid Description	
Fluid	Oil and Water
Method	Black Oil

Table 3.4 Well Description

Well Description	
Flow Type	Tubing flow
Well Type	Producer

Table 3.5 Reservoir Data

Reservoir Data	
Reservoir Temperature (ºF)	238
Reservoir Pressure (psia)	4714
Water Cut (%)	0
Total GOR (scf/STB)	490
Reservoir Model	Darcy
Darcy Reservoir Model	
Reservoir Permeability (mD)	150
Reservoir Thickness (ft)	350
Drainage Area (acres)	2500
Dietz Shape Factor	31.6
Wellbore Radius (ft)	0.583
Well True Vertical Depth (ft)	8400
Tubing ID (in)	3.9
Tubing Depth (ft)	8100
Initial Water Cut (%)	0

3) Sand Control Data

Table 3.6 (Internal) Gravel Pack

Internal Gravel Packing	
Gravel Pack Permeability (D)	40
Perforation Diameter (in)	0.5
Shot Density (1/ft)	10
Gravel Pack Length (in)	2
Perforation Interval (ft)	200

Table 3.7 Wire-Wrapped Screens

Wire-Wrapped Screens	
Production Interval (ft)	200
Screen Outer Radius (ft)	0.40
Screen Permeability (D)	30

Table 3.8 Pre-Packed Screens

Pre-Packed Screens	
Production Interval (ft)	200
Screen Inner Radius (ft)	0.29
Screen Outer Radius (ft)	0.34
Screen Permeability (D)	27

Table 3.9 Slotted liner

Slotted liners	
Production Interval (ft)	200
Liner Inner Radius (ft)	0.3
Liner Outer Radius (ft)	0.34
Slot Height (in)	4
Slot Width (in)	0.01
Slot Density (1/ft)	3
Screen Permeability (mD)	28000

B. Methodology

For the purpose of the project, the reservoir was first modelled using MBAL where certain reservoir properties were estimated and analyzed. Such reservoir properties include: reservoir pressure, bottom-hole temperature, fluid type, Original Oil in Place, porosity, bubble point pressure, permeability, type and nature of formation, formation rock compressibility, drive mechanism.

The modelled reservoir was then history-matched to estimate its similarity with the real-time reservoir data. These results, especially results obtained from rock compressibility, aquifer modelling and drive mechanism determine the results of the PROSPER software. Using the PROSPER software, the well was first modelled without any sand control system in place. This is the control. The same well was subsequently modelled with four different mechanical sand control system in place (modelled independent of each other). They include:

1) Cased hole gravel pack
2) Pre-packed screen
3) Wire-wrapped screen
4) Slotted liner

IV. RESULTS AND DISCUSSION

A. Results of Analysis on MBAL

The analysis of the MBAL software yielded the following results as presented in table 4.1. The estimated and analyzed properties include: Reservoir Pressure (psia), Bottom-Hole Temperature (ºF), Fluid Type, Original Oil in Place (stb), Porosity (%), Bubble Point Pressure (psia), Permeability (mD), Type and Nature of Formation, Formation Rock Compressibility (1/psi).

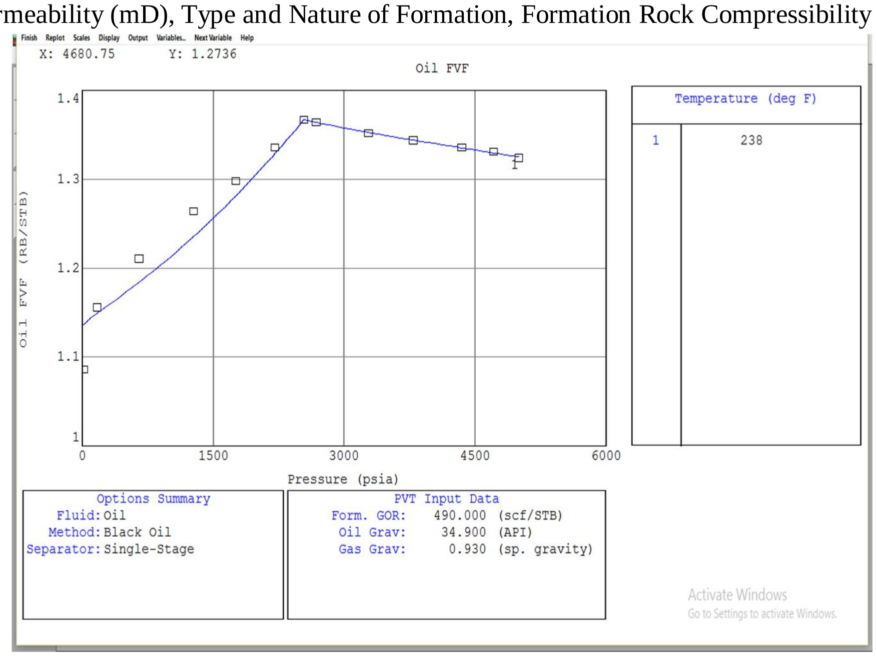

Figure 4.1 The system plot of OFVF against Pressure (psia) indicating under-saturated reservoir conditions

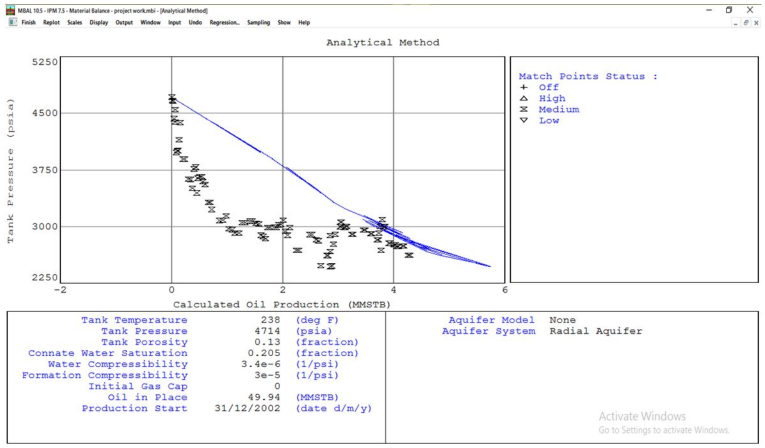

Figure 4.2 Analytical method of History Matching (even after regression)

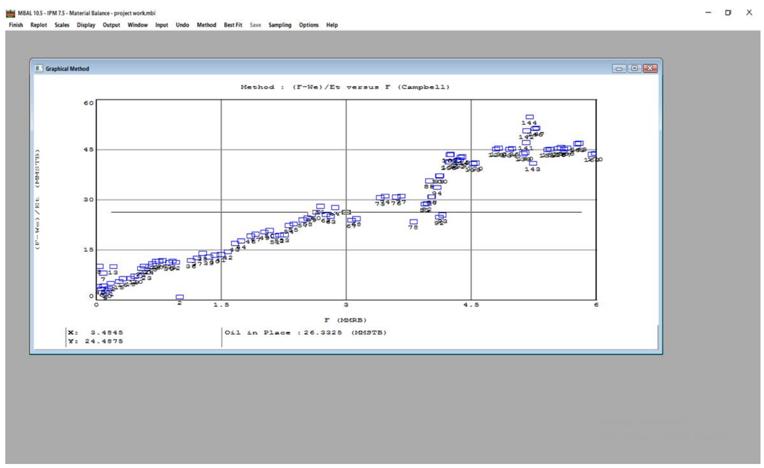

Figure 4.3 Graphical Method of History Matching

Figure 4.4 A comparison of the Stimulated Average Gas Rate (MMscf/day) and Stimulated Average Oil Rate (STB/day) against Time (date day/month/year)

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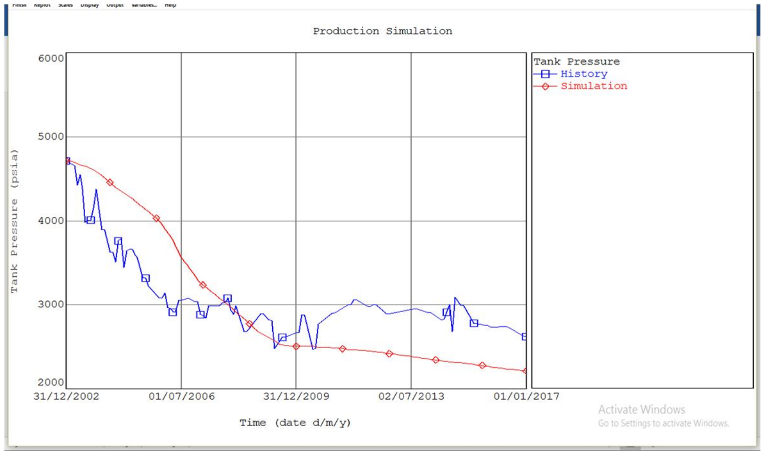

Figure 4.5 A comparative graph showing the plot of tank (simulated) pressure and production history pressure against Time (date day/month/year)

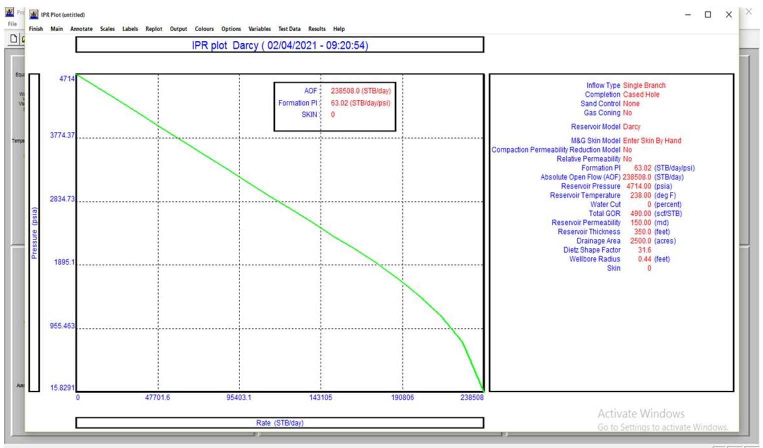

Figure 4.6 IPR curve of the modelled well.

B. Results of Analysis on PROSPER

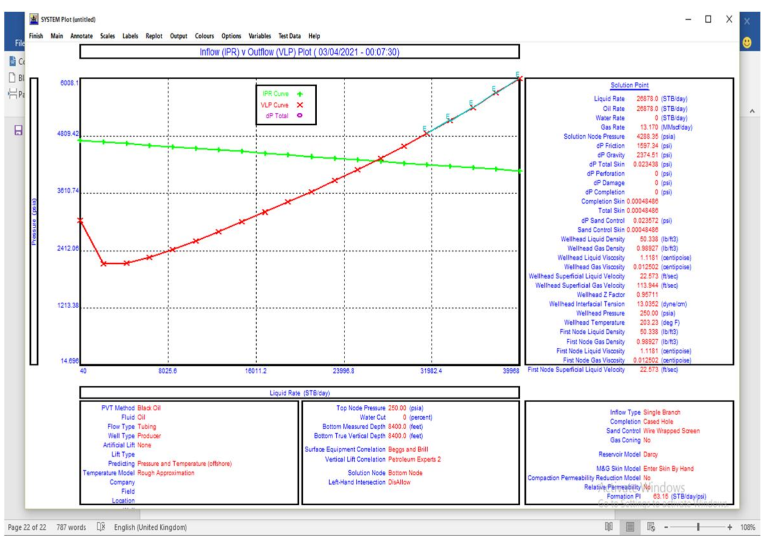

Figure 4.7 IPR/VLP curve of the modelled well

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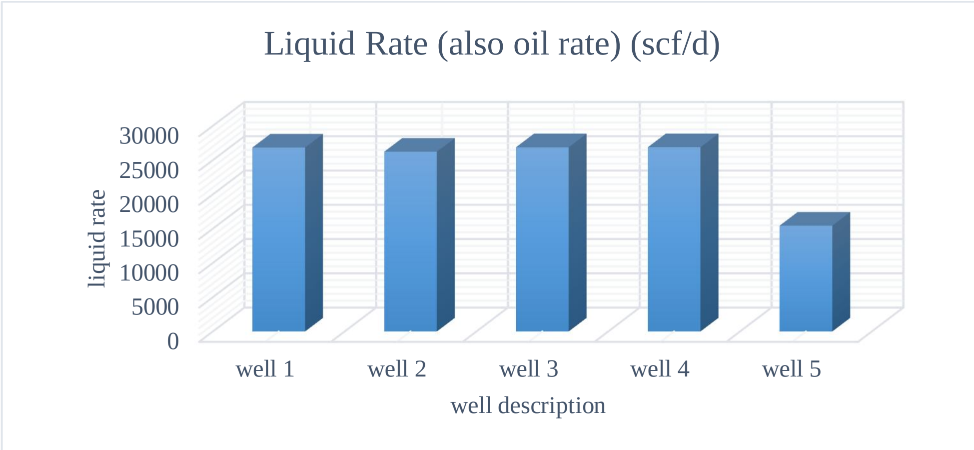

Figure 4.8 Chart showing liquid rate (scf/d) of various well completion strategies

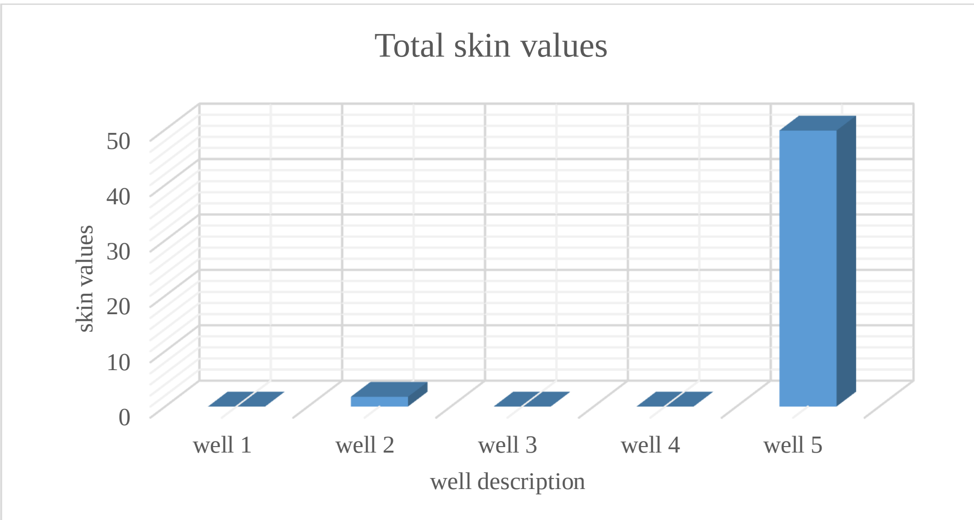

Figure 4.9 Chart Showing Total Skin Values of Various Well Completion Strategies

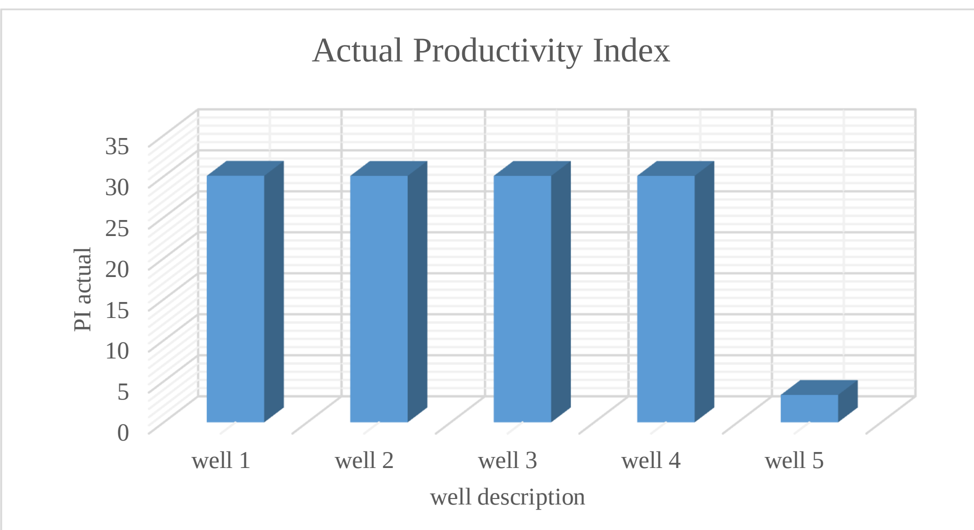

Figure 4.10 Chart Showing the Actual Productivity Index (PI_{actual}) Of Various Well Completion Strategies

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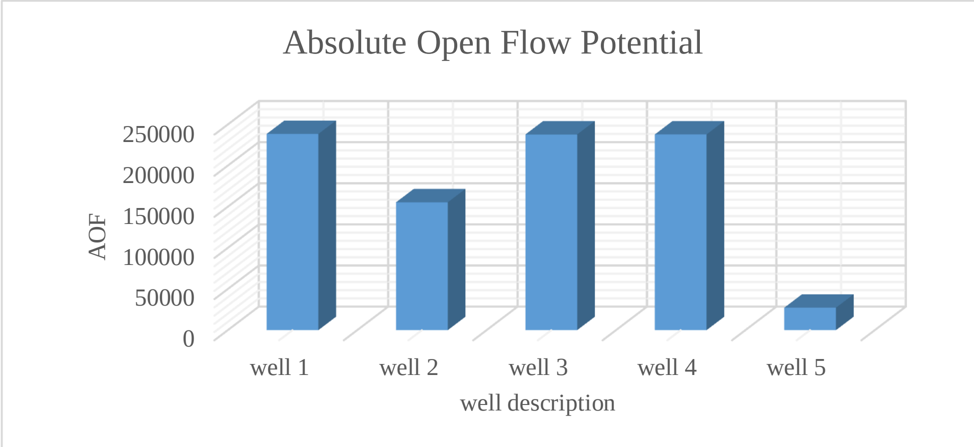

Figure 4.11 Chart Showing Absolute Open Potential (Stb/Day) of Various Well Completion Strategies

V. DISCUSSION

A. Discussion Of Results From Mbal

1) PVT Data

MBAL plots showed that for the reservoir and any well producing from the reservoir, the oil formation volume factor peaked at 1.37 rbbl/STB. As production from the reservoir started, the oil formation volume factor is expected to decline. This assumption agrees with finding by Hisman *et al.* (2017). He explained that the decline means that the oil is being produced, its volume in the reservoir dropped because gas began to evolve from the oil.

However, the graphs indicate that production is still above the system estimated bubble point (2455 psia) because the square are still aligned on the line curve.

Hence, $P_{initial} > P_{bubble\ point}$ i.e. 4714 psia >2455 psia

Real data plots on MBAL showed that for the reservoir and any well producing from the reservoir, the oil formation volume factor also peaked at 1.37 rbbl/STB. As production from the reservoir started, the oil formation volume factor is expected to decline. This decline is not as regular as than on shown in system plot. Nevertheless, the plot means that the oil is being produced, its volume in the reservoir dropped because gas began to evolve from the oil.

However, the graphs indicate that production is still above bubble point (2535 psia) because the square are still aligned on the line curve.

Hence, $P_{initial} > P_{bubble\ point}$ i.e. 4714 psia >2535 psia

2) History Matching

- *Analytical Method*

The plot after analytical history matching shows plenty deviation from normal match. Even after regression analysis was carried out, the simulated model showed some irregular pressure decline which suggests that energy for driving reservoir oil didn't come much from an active aquifer. More regression indicated a stronger energy drive from solution gas as instead of assumed strong aquifer support.

- *Graphical Method*

The plot slightly indicated strong aquifer support but for a very short time, suggesting a partial or limited aquifer support. OOIP is very low at 26.22MMSTB as compared to 675 MMSTB from real-time reservoir data. Since there was no initial gas cap, the drive mechanism is suspected to be solution-gas drive. This is further strengthened by the fact that the graphical graph began to show signs of irregularities immediately after stage of suspected aquifer support.

3) Production History

The plot of reservoir pressure against cumulative fluid (oil) production showed a very convincing one. As the reservoir pressure slowly declined, the cumulative oil production increased. This is the usually expectation while producing because pressure is required to push fluid up to the surface.

The manner of pressure decline is attributed to the rock compressibility value which is quite high, considering that Nigeria is underlain by thin unconsolidated sandstones. Other factors include: water cut, permeability, fluid type etc.

4) Comparative Analyses of Reservoir Characteristics

As expected, the simulated reservoir characteristics, fluid production history and plots should and will be different from real time data history and plots.

As expected, the system obeys the law of "Increasing Production Rate for Decreasing Pressure, that is Boyle's law". This is the logical expectation for every physical continuum, this may be slightly different for a case in reality. Pressure drop in actual wells are not like the theoretical way we propose it to be. Even though pressure drops, though not consistently, the factors below affect the way pressure drops in reservoir.

- Original Reservoir pressure
- Diameter of perforation
- Plugging rate
- Type of completion technique
- Type and nature of formation
- Type of fluid and Oil Originally in Place (OOIP)
- Well drive mechanism

According to analysis, the rock formation, drive mechanisms present and type of fluid determined largely the reasons for the disparities between the reservoir pressure and the simulated pressure. The rock compressibility, which is high since the formation is mostly composed of sandstones showed high possibilities of sand influx into a wellbore. The results from geological and geophysical surveys also showed possibilities of continuous sand production as a result of rock compressibility.

The plot above is a match of the simulated and real time fluid production. The disparity is estimated to be caused by sand production as well as increase in water cut. An increase in production means that water will be largely produced from the well with time. As oil leaves the leaves the void spaces of the reservoir rock, it is being replaced by water until it gets to residual oil saturation. Water sets into the well, which means that initial water saturation will also decrease to connate water saturation. This means that water is invariably being produced too.

One issue that water production brings about amongst others is it triggers the influx of formation sand into the well bore. This is because:

- Capillary pressure holding the grains are lost due to the production of water.
- Water may dissolve cementation materials between sand grains.

B. Discussion Of Results From Prosper

The IPR/VLP is called a flow validation curve. It shows the production engineer if a well can lift fluid naturally without the need for artificial lift. The intersection of the IPR and VLP curve is called operating point and this is to show the deliverability of the well to surface.

1) $P.I._{ideal}$

It is clear from the plots that the measured parameters had varying values as expected. The only parameter with a constant value is the $P.I_{ideal}$. This is quite the case because $P.I_{ideal}$ is a theoretical parameter. The actual P.I showed the expected differences.

For a completion without sand control and assumed undamaged, the flow rate is 26 840.9 stb/d. Completions with sand controls installed should naturally show a decline in the liquid rates. However, the reservoir modelling, further validated by the actual reservoir data showed that the sand production was continuous. At continuous sand production, sand should impede the production of fluid as some fluids are trapped due to sand.

2) Liquid Rates

The liquid rates for Internal Gravel Packing is 26 225.3 stb/d, for Pre-Packed Screen 26 877.3 stb/d, Wire-Wrapped Screen 26 878.0 stb/d and for Slotted Liner is 15 435.3 stb/d. This is due to the highest skin offered by slotted liner, then Interval Gravel Pack, Pre-Packed Screens and finally the Wire-Wrapped Screens. An increasing skin means a greater increase in pressure drop which means a lower drawdown (Bellarby, 2009).

As the control without any sand control on its flow path, well 1 delivers the highest volume of liquid to the surface. Well 2, 3 and 4 also had excellent deliverability volumes to the wellhead.

However, the lowest fluid rate was by well 5. This is because the slotted liner offered the highest skin value when compared to the other sand control system. This is in affirmative to the research carried out by Jon *et al.* (1992) as he found that slotted liners are no options in unconsolidated formations with compressive strength above $4 * 10^{-6}$ psi^{-1}. He observed that well log records showed that slotted liners plugged easily in such formation and will completely fail in just few hours of installation.

In this study, the screens were seen to perform a lot better in offering very reduced skin values than the internal gravel pack and slotted liner. This is due to the nature of the formation – unconsolidated sandstone formation which means that slotted liner and gravel packs will be plugged easily.

According to Jon *et al.* (1992); Omohimoria *et al.* (2016), they independently concluded that the screens were better sand control systems in highly unconsolidated formation. A laboratory test carried out by both researchers showed that pre-packed screens may fail under very transient bottom-hole flowing pressure conditions. However, the same test carried out on the wire-wrapped screens showed better adaptability.

In the case of gravel packs, analyses are carried out to estimate the best gravel packing size for each formation it is to be installed in. The screens are better options in such formation types.

3) Skin (and pressure drops due to skin) Values

A high skin means a low productivity index. Since skin is the damage to the formation which plugs flow, the slotted liner was expected to offer the lowest productivity index considering its very high skin value. The wire-wrapped screen gave the highest of the productivity index of all the sand controls combined because it provided the lowest skin.

According to Akpabio (1994), a high skin value also means a low absolute open potential, which is the highest flow rate that a well can deliver at 0 psig. Since skin is the damage to the formation which plugs flow, the slotted liner was expected to offer the lowest absolute open potential considering its very high skin value. The wire-wrapped screen gave the highest of the absolute open potential of all the sand controls combined because it provided the lowest skin.

VI. CONCLUSION AND RECOMMENDATION

A. Conclusion

No operator will want to produce sand whilst producing hydrocarbons. A good sand management strategy is paramount when production optimization as well as cost justification is in view. Such optimization strategies include:

1) Prediction of what formation produces sand,
2) Prediction of when (at what pressure) the formation will produce sand,
3) Management strategies to mitigate against sand production especially catastrophic and continuous sand production.

From the results and deductions made, the following conclusions were obtained.

- Rock compressibility plays a very important role in determining the manner of pressure decline in a reservoir.
- The nature of formation determines the need for certain sand control tools.
- Screens performed better under the conditions of simulation. This is because the conditions of stimulation were the sandstone formations of the Niger-Delta area of Nigeria.
- Wire-Wrapped Screens offers the least resistance to flow (skin) when compared to the other three sand control systems.
- Slotted liners offer the highest resistance and should be considered under certain conditions after careful analysis have been carried out.
- In the case of gravel packs, analyses are carried out to estimate the best gravel packing size for each formation it is to be installed in.
- Wire-Wrapped Screens offered the best solution for any sand control under the conditions of simulation.

B. Recommendation

1) Sanding issues have still continued to be a problem despite the advances in technology and techniques of sand mitigation as offered by different oil companies. It is safe to say that no sand control system is 100% fail-safe; whether it is chemical or mechanical type.
2) Therefore, manufacturers of mechanical sand control systems also provide workability ranges for their products because not every sand control system works under every condition.

3) Choice of the sand control to be used for completion can be a very difficult decision to make even for experts. Many factors are put into consideration before a final decision is made. Using only skin effect as a major deciding factor may be a rash decision considering the cost implication of Petroleum and Drilling Projects.
4) While selecting a sand control system to be used, whatever decision is taken hitches on the productivity of the well. Other factors, such as questions regarding lifespan, cost of purchase and installation, maintenance and compatibility to the well in questions must have reasonably good answers before any sand control system is installed.

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APPENDIX

Table 1: Well Description with Various Completion Techniques

Well Description	Completion Strategy
Well 1	Completed without Sand Control
Well 2	Completed with Internal Gravel Pack
Well 3	Completed with Pre-Packed Screens
Well 4	Completed with Wire-Wrapped Screens
Well 5	Completed with Slotted Liners

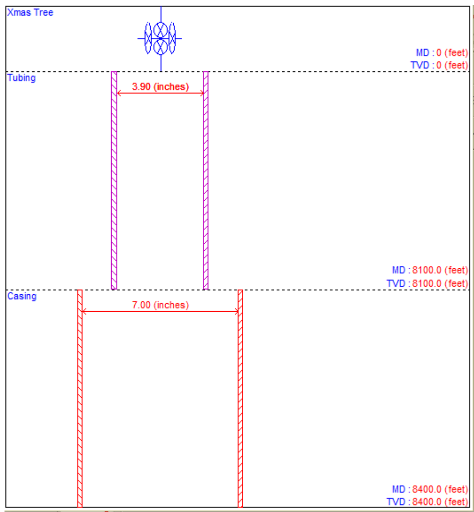

Plate 1: A pictorial representation of the well's vertical lift system

Table 2: Table of The Different Flow Parameters of the Different Completion Strategies

Parameter	Completion Without Sand Control	Completion With Internal Gravel Pack	Completion With Pre-Packed Screens	Completion With Wire-Wrapped Screens	Completion With Slotted Liner
Liquid Rate (stb/d)	26 840.9	26 225.3	26 877.3	26 878.0	15 435.3
Oil Rate (stb/day)	26 840.9	26 225.3	26 877.3	26 878.0	15 435.3
Water Rate (stb/day)	0	0	0	0	0
Pwf (psia)	3584.47	3046.52	3046.52	3046.52	3046.52
Total Skin	0	1.76	0.002 359	0.000 484 86	49.82
dP Sand Control Skin	0	83.63	0.114 69	0.023 572	1 390.98
dP Total Skin	0	83.63	0.114 75	0.023 438	1 390.98
P.I. $_{actual}$	30.061	30.055	30.054	30.058	3.34
P.I. $_{ideal}$	63.15	63.15	63.15	63.15	63.15
Flow Efficiency	0.476 025	0.475 930	0.475 914	0.475 977	0.052 890
AOF (STB/day)	238 508.0	155 383.8	237 897.5	237 904.0	27 233.3