TABLE OF CONTENTS

CHAPTER ONE

1.0 INTRODUCTION

Smart well technology has seen rapid evolution in the last decade because of technological advancements. Proper knowledge of this technology, with some risk mitigating techniques make several benefits to an oil company including, the capability of drilling longer horizontal and extended reach wells with great reduction in reservoir management, as well as water and gas breakthrough concerns. Even in some cases unexpected benefits have been discovered from this technology.

The objective of the smart well completion technology is to maximize value, which could include: increased production, improved recovery, minimized capital and operating expenditures. Systems are monitored and operated to optimize a given parameter by varying, for example, the inflow profile from various zones or perhaps the gaslift rate. Remote monitoring and control is achieved with pressure and temperature sensors, multiphase flow meters and flow-control devices.

1.1 DEFINITION OF A SMART WELL

A smart well can be defined as a well that uses mechanical devices, which allow control on pressure and rates down-hole, to optimize production performance and ultimately improve oil reservoir recovery.

Smart wells are installed with down-hole devices, that is, mechanical and electronic equipment that enables operators to control the wells remotely, without intervention using rigs or coiled tubing. A fundamental type of equipment used in smart wells is a down-hole mechanical valve called an interval control valve (ICV), which is pre-set with orifices with different hole sizes.

Interval or flow control valves can be operated automatically, manually or remotely as part of an intelligent completion. They are used to control multiple zones selectively, reduce water cut and gas cut, minimize well interventions, and maximize well productivity. The ICV is activated using an electronic pulse connected to an electrical cable embedded with a feed-through packer.

Smart well completion technology enables operators to optimize production or injection programs, improve reservoir performance, achieve higher extraction ratios, and reduce field-development and intervention costs. The technology’s reliability has been demonstrated in high-productivity wells, and fit-for-purpose intelligent completions are now being installed in wells with lower productivity to help safeguard against reservoir uncertainties and provide incremental production.

1.2 ADVANTAGES OF A SMART WELL OVER CONVENTIONAL WELLS

1.2.1 Eliminating cross flows

Many development wells have multiple targets. During production, there is a tendency that cross flow from a prolific zone into a minor zone may develop. Cross flow is a condition that occurs when two production zones with dissimilar pressures are allowed to communicate. In the past, using conventional completion technologies, minor pays may have been bypassed to protect prolific zones from this cross-flow. Intelligent-completion technology enables operators to take incremental production from zones that would have been bypassed, without creating cross flow conditions or having to recomplete the well. This is achieved either by balancing production from each zone using adjustable valves or by isolating the zones and producing them sequentially.

1.2.2 Improved reservoir management

The benefits of smart well completion technology over conventional completions from a reservoir management perspective transcend those of keeping a single well operating. Using centrally located production nodes interconnected to a network of down-hole and surface well sensors, and administered using logical workflows and dynamic reservoir models, fewer production engineers can manage more wells more efficiently and more effectively. Armed with accurate, up-to-date information, reservoir engineers can plan infill wells, convert producers to injectors, shut in wells or plan interventions to rejuvenate under-performing wells; all justified with solid economic backing and reduced risk.

1.2.3 Optimized commingled production

Smart well technology is particularly useful in its ability to regulate different branches or segments of the well independently; an ability which is valuable for multilateral wells and wells with complex or fragmented structures. It provides a solution to the problem of small, closely spaced reservoirs. Before the inception of smart well technology, such reservoirs usually had to be produced sequentially using conventional techniques like shifting of a sleeve on wire line or coiled tubing, or through work-over and re-perforation of the well, which was wasteful and sometimes economically unviable. With the development of smart well technology, such reservoirs can be commingled, with each branch controlled separately using the variable valves. This translates to an accelerated, constant production, and the absence of a work over (especially in sub-sea wells).

1.2.4 Optimizing ESP performance

Most wells, during production must eventually submit to some form of artificial lift. For several years, electric submersible pumps (ESPs) have been used to produce oil wells or deep-water gas wells. One way to maximize the profitability of ESPs is to equip them with smart systems that measure both well performance and pump performance.

Unlike conventional completion technologies, well performance can be optimized by making incremental changes in pump motor speed using a variable speed drive on the surface. Using down-hole data that is multiplexed up the power cable and transmitted to the field production office, engineers can monitor well performance and take remedial action if warranted. At the same time, pump and motor parameters can be monitored to signal when the ESP needs attention.

The biggest cost items in wells equipped with ESPs are electrical power costs and lost production if the pump goes offline. By monitoring pump performance, electrical power usage can be minimized, and when the pump indicates that it needs attention soon, a replacement can be staged so well downtime is limited to the actual change-out time. This maximizes production time.

1.2.5 Control of produced water

Reservoirs with aquifer influx or, water flood projects can subject the reservoir to a greater chance of water breakthrough or a higher water cut. Produced water reduces fractional flow of oil and may impair oil flow. This leads to a reduced production rate or the ultimate abandonment of the well. Application of smart well completion technology reduces this problem by regulating water production through the use of Inflow Control Valves. Conventional completion technologies do not have this feature.

1.2.6 Better optimized gaslift

Gaslift is used to increase oil production rates or to enable non-flowing wells to flow by reducing the hydrostatic head of the fluid column in the well. Gaslift systems can also mitigate the effects of high water cut and help to maintain tubing head pressure in subsea wells. Conventional gaslift systems pump gas down the annulus from the surface and require a considerable investment in pipelines, compressors, and other equipment. Smart wells eliminate this expensive infrastructure required by the traditional systems. It can generate additional value by eliminating the need for the annular safety valves that can be necessary in conventional gaslift environments, enabling non-associated gas to be produced without recompleting the well, providing operators with a system to control gas and water coning and also eliminates interventions for resizing or replacing conventional gaslift equipment.

1.2.7 Accelerated recovery

Smart wells have also become an important tool for accelerating recovery. Unlike conventional completion technologies, the valves in a smart well can be adjusted to minimize the production of undesirable effluents and to maximize oil recovery.

1.2.8 Intelligent water injection

Water flood projects are usually abandoned at the point where water breakthrough becomes excessive. With the application of smart well completion technology, injection rates can be regulated from the injection well using inflow control valves and the required pressure at each injection point can be properly maintained.

1.3 LIMITATIONS OF SMART WELL TECHNOLOGY

1.3.1 High level of expertise compared with conventional completion technologies

Development of smart wells require a lot of expertise. Experience with the technology selection, development, along with operational excellence in planning and installation is required for a successful deployment of an intelligent well system. Such experienced operators are hard to come by.

1.3.2 Data privacy and cybersecurity risks

In smart well technology, data from the bottom-hole sensors is transmitted to the surface for local or remote monitoring. However, as with any operation or technology that utilizes remote data, there is a threat of privacy in the face of growing data and cybersecurity risks that could lead to declining profits.

1.3.3 Higher Capital cost

The integration of smart well completions incurs a higher capital cost than conventional completions. Smart wells require a higher investment on sensors, special valves and expertise.

1.3.4 Temperature effects

Permanent down-hole equipment reliability as with intelligent wells greatly depend on temperature; gauges in high temperature environment have a shorter expected life time. Current sensor and control systems for down-hole applications have a typical temperature rating of about 180^{o}F. For example, temperature gradients in the Niger Delta range from 1.20 to 3.00^{o}F per 100ft. Most oil reservoirs in Nigeria occur between 3000 and 13000ft. This translates to about 200^{o}F for a fairly deep reservoir. This is beyond the temperature rating for down-hole systems for a smart well, hence, its limitation in Nigeria.

1.3.5 Risk of mechanical failure of components

Control lines, cables and sensors represent the nervous and circulatory system of a smart well. Unlike conventional completions, damage to these elements in a smart well may mean partial or total loss of its functionality. Possible risks may include, line failure particularly during installation, system failure which may be caused by wear, tear, or seizure of moving components.

1.4 WHY HAVE SMART WELLS NOT SEEN WIDE USAGE IN NIGERIA?

Despite the importance and flexibility in production, smart wells are not seen in Nigerian oil fields. One of the reasons smart wells have not been deployed in Nigerian fields is because of issues in “Reconciliation”.

Production is usually “reconciled” to the reservoirs that produced the oil. Smart wells are typically useful in “commingled production”. Despite this importance, production cannot be “reconciled” as the well was produced from multiple reservoirs simultaneously. Inability to cope with this will render commingled production with smart wells useless.

Chemical fingerprinting can be introduced to mitigate this limitation.

1.4.1 Chemical fingerprinting

Chemical fingerprints are unique patterns indicating the presence of a particular molecule, based on specialized analytic techniques. Chemical fingerprinting is a process of determining where a sample of oil (or hydrocarbon residue) originated. Virtually all oils contain the same hydrocarbon structures, but the relative quantities of these structures depend on the source of the oil.

Chemical fingerprinting can be used to differentiate between the production in the different reservoirs even after commingled production. Fingerprinting oil to discover its source is a complex procedure. As a result, oil fingerprinting relies on the expertise and experience of an analytical chemist, who compares the relative quantities of hydrocarbons unique to the production in the different reservoirs.

1.5 PROBLEM STATEMENT

The ability to alter reservoirs remotely, without intervention, is both economical and expedient. Though traditional wirelines are cheap and effective when dealing with easily accessible wells, they may be unfit for subsea and extended reach completions, which have become increasingly prevalent. Furthermore, mechanically manipulating valves thousands of feet below the surface of the ocean can be risky. This has prompted the need for the use of hydraulic and electric power in providing a way to adjust valves without direct intervention.

1.6 AIMS AND OBJECTIVES

The aims and objectives of this project work include the following:

i. To carry out a review on the smart well completion technology.
ii. To compare the economic returns of fields developed with smart well completion technology with those of conventional and horizontal completion technology.
iii. Create solid conclusions in the economic viability of smart well completion technology compared with non-intelligent completions.

1.7 SIGNIFICANCE

The significance of this project are:

i. To assist in decision making on the type of well completion to be used in developing an oil field.
ii. The economic analysis methods will be used to evaluate the profitability of the completion types. This will contribute to the benefit of the industry in considering smart completions for wells in their fields.

1.8 SCOPE OF WORK

This project work is based strictly on using an economic analysis method to evaluate the profitability of the smart well completion compared with other completion types. This will be taking into consideration the drilling and completion costs as well as the advantage of the well installations till the end of the production life. Production forecast will be generated for each completion, thereby enabling future revenues to be estimated.

CHAPTER TWO

2.0 LITERATURE REVIEW

Until the late 1980s, remote monitoring was generally limited to surface pressure transducers around the tree and surface choke, with remote completion control restricted to the hydraulic control of safety valves and (electro-) hydraulic control of tree valves. The first computer-assisted operations optimized gaslift production by remote control near the tree and assisted with pumping, well monitoring and control. Permanent down-hole pressure and temperature gauges are commonly run as part of the completion system and combined with data transmission infrastructure.

With the development, successful implementation, and improving reliability of a variety of permanently installed sensors, it was perceived that the potential to exercise direct control of inflow to the wellbore would provide significant and increased economic benefit. The service industry responded with early complex, high-cost systems designed to provide full functionality, which did not reach wide acceptance because of the perceived low probability of success and resulting high installation risked-cost. To counter these problems, industry responded with lower-cost hydraulic systems, which provided some of the functionality of the initial high-end devices. These systems permit a variety of sensors to be packaged together with the hydraulic control devices to provide a complete intelligent-well completion.

Since the inception of the technology in the late 1990s, the use of intelligent well technology has focused on production acceleration, increased ultimate recovery, reduced operating expenditure (OPEX) and reduced project level capital expenditure (CAPEX).

The first Smart-well Completion was "Well Dynamics' surface controlled reservoir analysis and management system" installed in Saga's Snorre TLP in the North Sea, Norway in the month of August, 1997. Since then, intelligent well technology has been used in many kinds of production wells all over the world, including off-shore wells, vertical conventional wells, horizontal wells and multilateral wells.

In 1998 Well Dynamics used direct hydraulic and mini hydraulic system development of new monitoring systems like Fiber-optics with high level of reliability, accuracy, resolution and stability. Since then, hundreds of smart wells have been installed in different parts of the world.

2.1 CASE STUDIES

Several studies have been published to demonstrate the importance of the application and benefits of smart well completion.

Akram et al. (2001) investigated IWC installations on nine mature, Shell operated prospects located in the Brent and Tern fields, North Sea, UK. The fields produce a combined output of 400 thousand barrels of oil equivalent per day. ICVs were installed to provide on-line remote control of the communication path from the reservoir zones to the tubing. The down-hole flow control enabled perforation of oil, gas and water production zones in a single operation, thus saving costs.

Sharma (2002) presented a method to apply real options theory to quantify the value of intelligent well applications, including the value of reducing project volatility and risk. He described how mathematical model can be incorporated into a larger workflow process to assess entire asset portfolios which can be used as a tool for screening reservoir assets for potential SWC applications and also help optimize the design of the completion.

Yeten et al. (2004) determined the optimal performance of SWs using gradient based optimization technique in conjunction with a reservoir simulator. They considered the effect of uncertainty in reservoir description and equipment reliability and noted that down-hole control can compensate to some extent for geological uncertainty, even when there is the possibility of equipment failure. They also noted that, the impact of equipment reliability was related to both the timing and type of failure; generally, the earlier the valves failed the larger the negative impact.

Vachon and Furui (2005) illustrated how smart wells can enhance the electrical submersible pump (ESP) performance and add flexibility by using down-hole chokes to optimize ESP performance. Their study focused on single ESP wells producing from multiple pay zones. It was established that the intelligent completion systems with remotely controlled chokes allow for optimal production rates, maintain the optimum ESP operating range and reduce risk of pump failure. Thus, IWC eliminates the expense of intervention and the associated loss in production, due to extended ESP life, reduction of cost of replacing damaged pumps and pump down time.

Sakowski (2005) looked at the impact of smart well completions on total economics of field development. Reservoir performance analysis and economic evaluation tools were used to quantify the value of IWC. IWC projects performed better in relatively cost sensitive environments since they can maintain oil production while reducing the capital and operating costs. He noted that the ability to respond to expected changes in reservoir performance is also a valued benefit and the technology has advanced rapidly from more high-cost, offshore application environment to more revenue-sensitive operating environment due to the ability to clearly demonstrate economic value of IWC over alternate conventional completions.

Aggrey et al. (2006) employed a synthetic reservoir to explore and compare the value of extensive, accurate measurements with a higher chance of system failure with the deployment of lower resolution sensors of greater reliability. A methodology to calculate the value of information and expected opportunity loss parameters for IWC of different capabilities was developed. It was shown that value creation from IWC and real time optimization is strongly dependent on the ability of the system to function properly throughout the equipment’s specified lifetime.

Aggrey and Davies (2007) presented an enabler for SWC decision making process where stochastic coupling of the reliability profile and reservoir performance is employed. The proposed workflow allows the inclusion of conventional stochastic analysis for economic and geologic risks. The evaluated scenarios showed increased value potential for IWC implementation.

Anderson et al. (2007) studied the first Maximum Reservoir Contact (MRC) multilateral well, also located in Saudi Arabia. A maximum reservoir well is defined as a well that has a combined reservoir contact area of more than 5km, through the single or multilateral configuration. Intelligent well completions and fibre optic monitoring technology were applied to maximize production volume, resulting in a configuration that produced hydrocarbons at a very high rate with low drawdown values for a prolonged timeframe.

Addiego-Guevara et al. (2008) investigated whether simple reactive control strategies based on a feedback loop between inflow control valve (ICV) settings and surface or down-hole measurements can enhance production and mitigate reservoir uncertainty if they are designed to work across a range of production scenarios. The implementation of an intelligent horizontal well in a thin oil rim reservoir in the presence of reservoir uncertainty was assessed. They evaluated the benefit of using two completions in conjunction with surface and down-hole monitoring. It was found that reactive control strategy can insure against reservoir uncertainty. However, a simple reactive control strategy using variable ICVs adjusted in response to down-hole measurements of phase flow rates yielded a neutral or positive return regardless of reservoir behaviour. They suggested that down-hole reservoir imaging techniques which can monitor fluid flow and saturation changes at a distance from the well may be used in a proactive feedback loop.

Ajayi and Konopczynski (2008) compiled the value of smart wells from many fields around the world, concluding that 9% of total oil recovery could be added by a single smart well. They reported that up to 25% oil-recovery factor could be added by full field implementation of smart wells. The demonstrated economic value generated by smart wells.

i. Saudi Aramco: A maximum reservoir contact project using multilateral wells in South Shaybah Field. The project features a multibranch well with a total of 12 km of drilled holes using five segments controlled with inflow control valves (ICVs). The well produced 12,000 b/d when compared with a traditional horizontal well of 1 km producing 3000 b/d.
ii. Statoil: A subsea water alternating gas (WAG) project using 10 wells to inject gas and water, alternating mode, in the Snorre B Field. The water and gas breakthrough were delayed by 6 months, on average, per producer well, keeping production plateau for longer time than expected without smart wells. The ICVs were installed to control water injection; whereas gas injection was controlled by time.
iii. Kuwait Oil Company (KOC): Onshore stacked multilateral wells with an ICV per branch and 20 internal control devices (ICD) in the Minagish Field. The well had 5000 ft lateral section for each branch using an ICV port per lateral. The water cut was reduced from 75% to 25% in a mature water-flooded reservoir.

Pari et al. (2009) presented a comprehensive review of state-of-the-art intelligent well technology considering the benefits, types of sensors, challenges, economics and application in fractured reservoir. They concluded that IWC aids reservoir management although there could be the risk of system failure. To mitigate the risk of system failure, the use of cable-less power and communication system in IWC was recommended.

Grebenkin and Davies (2010) conducted a study on the impact of geological uncertainty and uncertainty in the dynamic parameters such as fluid contacts, relative permeability, aquifer strength and zonal skin on the flow control ability of an IW to reduce the production uncertainty. The results emphasized the importance of the probabilistic approach for production prediction and illustrated its use as a tool to justify the installation of IW technology in a particular well. It was found that the uncertainty of the dynamic parameters had a higher impact on the total oil production than uncertainty associated with reservoir geology.

Rodriguez and Figueroa (2010) evaluated the applicability of multi-purpose intelligent completions for high productive oil reservoir from both the productivity and the operational standpoints. They noted that IWC in naturally fractured mature fields tends to increase oil production and reduce the field decline. As water production increases, the producing zones can be shut off as needed to reduce the overall production of water. Hence IWC will improve the life cycle value of mature field.

Hudson et al. (2011) reviewed case studies of about thirty (30) oil and gas production fields containing IWs to consider the work process that was used to justify the incremental investment in hardware and installation cost. The study outlined key findings from the review, recommended a project-stage-base modeling workflow and presented opportunities for improvements to support more rigorous and efficient design decisions. They noted that IWC justification is typically attributed to reduction of lifecycle costs, accessing marginal reserves and certain reservoir management concerns and suggested that IWC modeling workflow requires multi-disciplinary collaboration and sometimes require simulation experts to handle reservoir uncertainties.

Dekui et al. (2012) considered some advanced down-hole devices and the prospects for IW application in the Daqing oil field. It was concluded that IWs improves oil recovery and reservoir management. IW technology was effective in Daqing oil field, average water cut decreased from 89% to 70% and average oil production increased by 40%.

Collins et al. (2012) investigated the effect of IWC on Agbami deep-water field, located offshore Nigeria. IWC technology was installed on both production and intelligent wells on the field, so as to alleviate the issues created by the complex stratigraphic architecture and subsurface uncertainty of the reservoir. The Agbami IWC project provided real time monitoring/surveillance and the control necessary for field performance and recovery optimization. It ensured judicious reservoir management by the integration of surveillance plans and production management practices in producing from multiple zones. Between August and November 2010, approximately 10 million BOPD was incrementally added, due to IWC application.

Gulyaev et al. (2012) noted that IW is an important part of production technology from low and extremely low permeable reservoirs. IW equipment with remote down-hole control significantly increased well construction cost but with tax reduction the oil production from such reservoirs become economical.

Lien et al (2012) evaluated the applicability of IWC on the Saramacca Oil fields, located in the Republic of Suriname, South America. For the purpose of real-time monitoring of well performance and down-hole pressure, a fully automated intelligent well system was installed on the field. This aided in early detection of wellbore complications, troubleshooting as soon as detected. There was a recorded increase of approximately 12 barrels of oil per day (BOPD) from the Saramacca oil fields due to IWC adoption, thus compensating for the higher installation cost.

Griffith et al. (2012) evaluated IW system at the Saramacca oil fields. Well performance was monitored monthly based on the volume flow test and flowing bottom-hole pressure (BHP) measurements. Down-hole pressure data was also collected for buildup tests and other reservoir studies. It was concluded that IWC offers several advantages over the conventional well.

CHAPTER THREE

3.0 METHODOLOGY

This project assumes hyperbolic decline in the production forecast. The Net Present Value (NPV) is used to demonstrate the economic viability of the smart completion compared with the conventional and horizontal completions. This analysis was made on three stratified oil reservoirs A, B and C as shown in **Figure 3.1**.

3.1 XYZ FIELD, NIGER DELTA

The XYZ field in the Niger Delta has three stacked reservoirs. Each reservoir has a 10-million-barrel reserve and the wells were drilled to hit all three reservoirs.

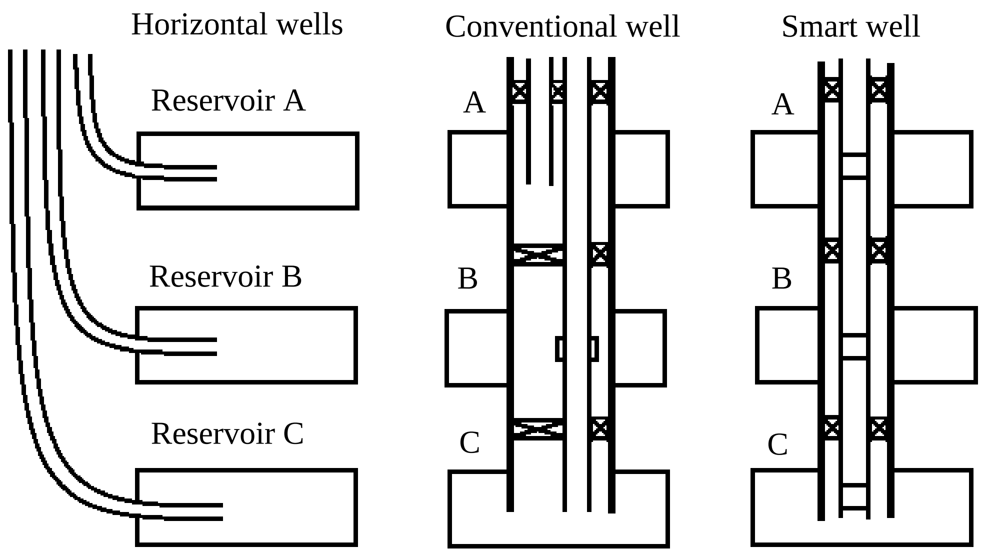

Figure 3.1: Completion options for the three stacked reservoirs.

Three horizontal wells were drilled and completed at the three reservoirs. The horizontal wells produce together. The conventional well was drilled and completed at the three reservoirs. The long and short string produce first. After this, the completion behind the sleeve was produced. For the smart well, all three reservoirs were completed and equipped with smart systems. The completion on the three reservoirs produce together.

3.2 ASSUMPTIONS

This project assumes the following:

i. General hyperbolic decline with b = 0.25.

ii. Economic data: The economic data in **Table 3.1** was used to calculate NCF.

Table 3.1: Economic data.

Oil price	$50/barrel
Bank rate	8% of gross revenue
Tax rate	25% of gross revenue
Royalty	4% of gross revenue
Discount rate	12%
OPEX	20% of gross revenue

iii. Drilling and completion cost data: The drilling and completion costs data in **Table 3.2** was used to calculate NPV.

Table 3.2: Drilling and completion cost data.

Well type	**Costs**
Conventional well	$30,000,000
Horizontal well	$45,000,000
Smart well	$60,000,000

iv. Reservoir data: The reservoir data in **Table 3.3** was used for each well completion calculations.

Table 3.3: Reservoir data.

Reservoirs	**Reserves (barrel)**
A	10,000,000
B	10,000,000
C	10,000,000

v. Production rate data: The production rate data in **Table 3.4**was used for each well completion respectively.

Table 3.4: Production rate data.

Completion type	Initial rate (b/d)	Final or economic rate (b/d)
Conventional	6,000	100
Horizontal	10,000	200
Smart well	15,000	500

3.3 DECLINE CURVE ANALYSIS

Decline curve analysis is the most commonly used method for estimating ultimate recoverable reserves and future well performance. The analysis technique is based on the assumptions that past performance trends can be characterized mathematically and used to predict future performance. It is based on the following fundamental assumptions:

i. That past operating conditions will remain unchanged
ii. The well's drainage remains constant
iii. The well is produced at a constant bottom hole pressure

Decline curves use empirical models that have little fundamental justifications. These models include:

i. Exponential decline
ii. Harmonic decline
iii. Hyperbolic decline

The hyperbolic decline is the more general approach. The other two are degenerations of the hyperbolic model. These three models are related through the following relative decline rate equation (Arps, 1945);

$$\frac{1}{q}\frac{dq}{dt} = -bq^{d}$$

3.3.1 Definition of parameters

"b" is an empirical constant to be determined based on production data. When b = 0, the equation degenerates to an exponential decline model, and when b = 1, the equation yields a harmonic decline model. When $0 < b < 1$, the equation derives a hyperbolic decline model. The decline models are applicable to both oil and gas wells.

3.3.2 Identification of Model

Production data can be plotted in different ways to identify a representative decline model as shown in **Figure 3.2**.

i. If a plot of log (q) versus t shows a straight line, the decline data follows an exponential decline model. If the plot of q versus Np shows a straight line, an exponential decline model should be adopted.
ii. If the plot of log (q) versus log (t) shows a straight, the decline data follows a harmonic decline model. If the plot of Np versus log (q) shows a straight line, the harmonic decline model should be used.
iii. If no straight line is seen in these plots, the hyperbolic decline model may be verified by plotting the "relative decline rate" defined by Arps equation.

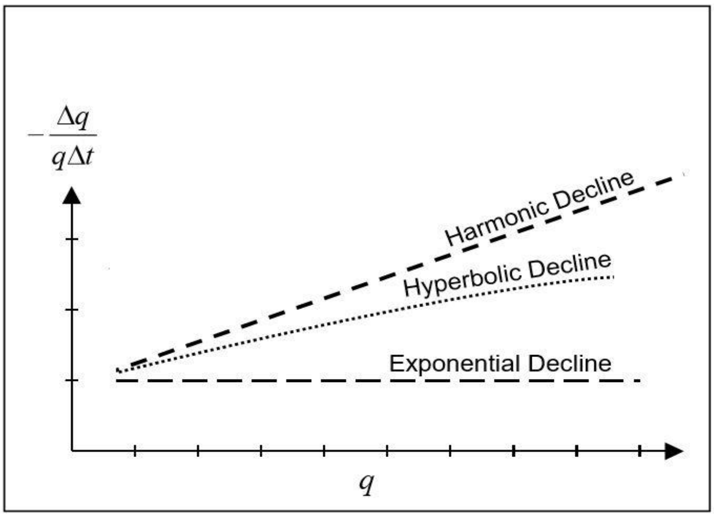

Figure 3.2: Exponential, harmonic and general hyperbolic decline models.

3.4 NET PRESENT VALUE.

NPV is the value of projected cash flows, discounted to the present. It is a financial modelling method used to evaluate the profitability of proposed investments and projects. NPV is used to analyse an investment decision and give a company a clear way to tell if the investment will add value to the company.

NPV is given by the formula:

$$\text{NPV} = \sum_{i=1}^{n} \frac{NCF_j}{(1+i)_j^n}$$

Where, NCF = net cash flow per period, j

i = discount rate

n = time (period)

Typically, an investment with positive NPV will add value to the company while one with a negative NPV will be a net loss. This acts as a guide for decision making as only investments with positive NPV should be made.

3.5 PROCEDURE:

i. The following equation is used to determine t_f(life of the well). "b" is assumed 0.25.

$$t_f = \frac{1-b}{b}\frac{NPD}{q_o}U^{1-b}\frac{U^b-1}{U^{1-b}-1}$$

$$U = \frac{q_o}{q_f}$$

ii. The yearly cumulative production NPD from start to t_f is calculated using:

$$\text{NPD} = \frac{aq_0}{1-b}\left[1-\left(1+\frac{bt}{a}\right)^{\frac{b-1}{b}}\right]$$

$$A = \frac{btf}{\left(\frac{q_o}{q_f}\right)^b - 1}$$

iii. The yearly production is calculated by subtracting the previous cumulative production from the current cumulative production (i.e. NPD_2-NPD_1).

iv. For the conventional well, the long and short strings are produced first. After this, the completion behind the sleeve is produced.

v. All reservoirs are produced simultaneously for the horizontal and smart wells.

vi. The yearly production is multiplied by the oil price to get the gross revenue

vii. The operating cost is 20% of the gross revenue.

viii. NCF is calculated using gross revenue − bank rate − taxes − royalty − operating costs.

ix. The NPV is calculated using:

$$\text{NPV} = \sum_{i=1}^{n} \frac{NCF_j}{(1+i)_j^n}$$

CHAPTER FOUR

4.0 RESULTS AND DISCUSSION

4.1 RESULTS FROM THE CONVENTIONAL WELL

Based on the results from analysis, the production from the long and short string lasted for 26 years. The completion behind the sleeve started producing after the long and short string and production lasted for another 26 years, giving a total of 52 years to recover the reserves. This lead to a lower NPV of 231,595,882 dollars compared with the other wells as cash flow was discounted for 52 years as seen in **Table 4.2**. At the end of the first five years of production, the well had produced only 12,411,916 barrels from its 30,000,000-barrel reserve. **Table 4.1** shows the forecast of production from the conventional well completion.

Table 4.1: Forecast of production from the conventional completion.

Year	Cumm prod (bbl)	Yearly prod (bbl)
0	0	0
1	3834206	3834206
2	6787960	2953754
3	9100150	2312189
4	10935919	1835769
5	12411916	1475997
6	13612132	1200216
7	14598078	985946
8	15415515	817437
9	16098958	683443
10	16674774	575816
11	17163344	488570
12	17580584	417240
13	17939050	358466
14	18248738	309688
15	18517670	268932
16	18752336	234666
17	18958024	205688
18	19139072	181048
19	19299064	159992

20	19440972	141908
21	19567280	126308
22	19680076	112796
23	19781118	101042
24	19871898	90780
25	19953690	81792
26	20000000	46310
27	21917103	1917103
28	23393980	1476877
29	24550075	1156094
30	25467959	917884
31	26205958	737998
32	26806066	600108
33	27299039	492973
34	27707757	408718
35	28049479	341721
36	28337387	287908
37	28581672	244285
38	28790292	208620
39	28969525	179233
40	29124369	154844
41	29258835	134466
42	29376168	117333
43	29479012	102844
44	29569536	90524
45	29649532	79996
46	29720486	70954
47	29783640	63154
48	29840038	56398
49	29890559	50521
50	29935949	45390
51	29976845	40896
52	30000000	23155

Table 4.2: NPV calculation of the conventional completion.

Year	Drilling and completion costs ($)	Gross Revenue ($)	Bank Rate ($)	Taxes ($)	Royalty ($)	OPEX ($)	NCF ($)	NPV ($)
0	30000000	0	0	0	0	0	-30000000	-30000000
1	-	191710304	15336824	47927576	7668412	38342061	82435430	73603064
2	-	147687696	11815015	36921924	5907507	29537539	63505709	50626360
3	-	115609504	9248760	28902376	4624380	23121900	49712086	35384084
4	-	91788400	7343072	22947100	3671536	18357680	39469012	25083270
5	-	73799904	5903992	18449976	2951996	14759980	31733958	18006702
6	-	60010800	4800864	15002700	2400432	12002160	25804644	13073436
7	-	49297300	3943784	12324325	1971892	9859460	21197839	9588826
8	-	40871800	3269744	10217950	1634872	8174360	17574874	7098197
9	-	34172200	2733776	8543050	1366888	6834440	14694046	5298820
10	-	28790800	2303264	7197700	1151632	5758160	12380044	3986043
11	-	25028500	2002280	6257125	1001140	5005700	10762255	3093891
12	-	20862000	1668960	5215500	834480	4172400	8970660	2302545
13	-	17923300	1433864	4480825	716932	3584660	7707019	1766249
14	-	15484400	1238752	3871100	619376	3096880	6658292	1362418
15	-	13446600	1075728	3361650	537864	2689320	5782038	1056356
16	-	11733300	938664	2933325	469332	2346660	5045319	823000
17	-	10284400	822752	2571100	411376	2056880	4422292	644081
18	-	9052400	724192	2263100	362096	1810480	3892532	506183
19	-	7999600	639968	1999900	319984	1599920	3439828	399387
20	-	7095400	567632	1773850	283816	1419080	3051022	316289
21	-	6315400	505232	1578850	252616	1263080	2715622	251356
22	-	5639800	451184	1409950	225592	1127960	2425114	200417
23	-	5052100	404168	1263025	202084	1010420	2172403	160297
24	-	4539000	363120	1134750	181560	907800	1951770	128586
25	-	4089600	327168	1022400	163584	817920	1758528	103442
26	-	1715500	137240	428875	68620	343100	737665	38742
27	-	95855152	7668412	23963788	3834206	19171030	41217715	1932846
28	-	73843848	5907507	18460962	2953754	14768769	31752854	1329468
29	-	57804752	4624380	14451188	2312190	11560950	24856043	929200
30	-	45894200	3671536	11473550	1835768	9178840	19734506	658696
31	-	36899952	2951996	9224988	1475998	7379990	15866979	472863
32	-	30005400	2400432	7501350	1200216	6001080	12902322	343313

33	-	24648650	1971892	6162163	985946	4929730	10598919	251806
34	-	20435900	1634872	5108975	817436	4087180	8787437	186401
35	-	17086100	1366888	4271525	683444	3417220	7347023	139149
36	-	14395400	1151632	3598850	575816	2879080	6190022	104675
37	-	12514250	1001140	3128563	500570	2502850	5381127	81246
38	-	10431000	834480	2607750	417240	2086200	4485330	60465
39	-	8961650	716932	2240413	358466	1792330	3853509	46382
40	-	7742200	619376	1935550	309688	1548440	3329146	35777
41	-	6723300	537864	1680825	268932	1344660	2891019	27740
42	-	5866650	469332	1466662	234666	1173330	2522659	21612
43	-	5142200	411376	1285550	205688	1028440	2211146	16913
44	-	4526200	362096	1131550	181048	905240	1946266	13292
45	-	3999800	319984	999950	159992	799960	1719914	10488
46	-	3547700	283816	886925	141908	709540	1525511	8305
47	-	3157700	252616	789425	126308	631540	1357811	6601
48	-	2819900	225592	704975	112796	563980	1212557	5263
49	-	2526050	202084	631512	101042	505210	1086201	4209
50	-	2269500	181560	567375	90780	453900	975885	3376
51	-	2044800	163584	511200	81792	408960	879264	2716
52	-	857750	68620	214437	34310	171550	368832	1017
							NPV = 231595882	

4.2 RESULTS FROM THE HORIZONTAL WELLS

For the horizontal completions, the three reservoirs were produced in 15 years. Horizontal wells are known to be very productive. The cash flow was discounted for 15 years, giving a very decent NPV of 403,638,224 dollars as seen in **Table 4.4**. At the end of the first five years, the wells had already produced 23,590,371 barrels from its 30,000,000-barrel reserve. **Table 4.3** shows the cumulative production forecast from the horizontal completions.

Table 4.3: Forecast of production from the horizontal completions.

Year	Cumm prod (bbl)	Yearly prod (bbl)
0	0	0
1	8839566	8839566
2	14674314	5834748
3	18679857	4005543
4	21520351	2840494
5	23590371	2070019
6	25134394	1544023
7	26309430	1175035
8	27219429	909999
9	27935094	715665
10	28505655	570561
11	28966098	460443
12	29341758	375660
13	29651283	309525
14	29908611	257328
15	30000000	91389

Table 4.4: NPV calculation of the horizontal completions.

Year	Drilling and completion costs ($)	Gross Revenue ($)	Bank Rate ($)	Taxes ($)	Royalty ($)	OPEX ($)	NCF ($)	NPV ($)
0	45000000	0	0	0	0	0	-45000000	-45000000
1	-	441978304	35358264	110494576	17679132	88395661	190050670	169688096
2	-	291737408	23338992	72934352	11669496	58347481	125447085	100005648
3	-	200277152	16022172	50069288	8011086	40055430	86119175	61297928
4	-	142024656	11361972	35506164	5680986	28404931	61070602	38811472
5	-	103501048	8280083	25875262	4140041	20700209	44505450	25253590
6	-	77201104	6176088	19300276	3088044	15440220	33196474	16818368
7	-	58751848	4700147	14687962	2350073	11750369	25263294	11427831
8	-	45499952	3639996	11374988	1819998	9099990	19564979	7901967

9	-	35783248	2862659	8945812	1431329	7156649	15386796	5548633
10	-	28528050	2282244	7132013	1141122	5705610	12267061	3949665
11	-	23022150	1841772	5755537	920886	4604430	9899524	2845876
12	-	18780300	1502424	4695075	751212	3756060	8075529	2072787
13	-	15476250	1238100	3869062	619050	3095250	6654787	1525105
14	-	12866400	1029312	3216600	514656	2573280	5532552	1132069
15	-	4572150	365772	1143037	182886	914430	1966024	359185
							NPV = 403638224	

4.3 RESULTS FROM THE SMART WELL

The production forecast for the smart well shows that the three stratified reservoirs were produced in just 8 years. The cash flow was discounted for only eight years. This resulted in a greater NPV of 434,975,061dollars as seen in **Table 4.6**. At the end of the first five years of production, the well had already produced 27,326,280 barrels from its 30,000,000-barrel reserve. **Table 4.5** shows the cumulative production forecast from the smart completion.

Table 4.5: Forecast of production from the smart well completion.

Year	**Cumm prod (bbl)**	**Yearly prod (bbl)**
0	0	0
1	12131607	12131607
2	18909376	6777769
3	22989120	4079744
4	25590242	2601122
5	27326280	1736038
6	28528948	1202668
7	29388318	859370
8	30000000	611682

Table 4.6: NPV calculation of the smart well completion.

Year	Drilling and completion costs ($)	Gross Revenue ($)	Bank Rate ($)	Taxes ($)	Royalty ($)	OPEX ($)	NCF ($)	NPV ($)
0	60000000	0	0	0	0	0	-60000000	-60000000
1	-	606580352	48526428	151645088	24263214	121316070	260829551	232883520
2	-	338888448	27111075	84722112	13555537	67777689	145722032	116168712
3	-	203987200	16318976	50996800	8159488	40797440	87714496	62433448
4	-	130056096	10404487	32514024	5202244	26011219	55924121	35540788
5	-	86801904	6944152	21700476	3472076	17360380	37324818	21179104
6	-	60133400	4810672	15033350	2405336	12026680	25857362	13100144
7	-	42968500	3437480	10742125	1718740	8593700	18476455	8357810
8	-	30584100	2446728	7646025	1223364	6116820	13151163	5311534
							NPV = 434975061	

4.4 COMPARISON OF NPV OF THE WELL COMPLETIONS

Economic forecasts using the general hyperbolic decline model shows in **Table 4.7** that the smart well has a net present value of $434,975,061, the horizontal completions with $403,638,224 and the conventional completion with net present value of $231,595,882.

Table 4.7: Comparison of NPV of the well completion types.

Completion type	Drilling and completion costs ($)	NPV ($)
Conventional	30,000,000	231,595,882
Horizontal	45,000,000	403,638,224
Smart	60,000,000	434,975,061

CHAPTER FIVE

5.0 CONCLUSION AND RECOMMENDATION

5.1 SUMMARY AND CONCLUSIONS

This project work presents a review of the economics of smart well completion technology compared with conventional and horizontal well completion technologies.

From **Figure 5.1**, it was demonstrated that the profitability of the smart well completion exceeds that of the horizontal and conventional completions. From the case studies evaluated in this work, smart wells have shown to be 8% more profitable that horizontal wells and over 46% more profitable than conventional wells.

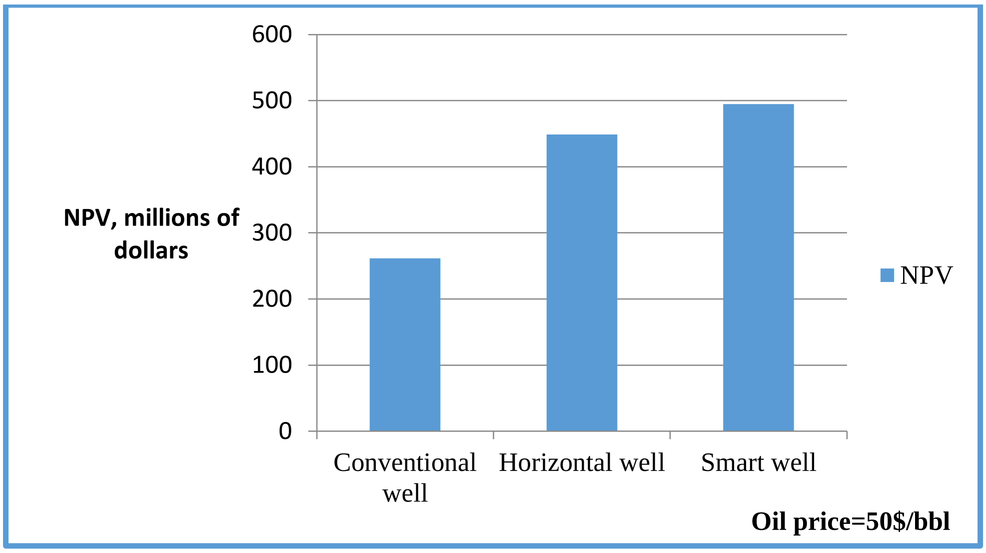

Figure 5.1: Comparison of the well completion types.

Smart wells under the appropriate management strategies could greatly improve oil recovery and NPV, thus, emphasizing the profitability of fields developed with the technology. They incur greater capital cost in drilling and completion and so may not look too attractive at the start of the project.

Based on the results from analysis of case studies presented in this project, the following conclusions were made:

i. The smart well completion is most profitable in that it yielded the highest economic return compared with the horizontal and conventional completions. The smart well gave NPV of $434,975,061, the horizontal wells gave NPV of $403,638,224 and the conventional well gave NPV of $231,595,882.

ii. The smart well completion is the most efficient as it took the least period of time to recover the reserves. The smart well produced for 8 years, the horizontal wells produced for 15 years and the conventional well produced for 52 years.
iii. Even while the conventional well was significantly cheaper, the return of investment was too low compared with the other wells that were marginally more expensive.
iv. For the smart well, the reserves in the three reservoirs were commingled and produced through a single smart well completion wellbore. This resulted in early depletion of the reservoirs and higher economic return. At the end of the first five years of production, the smart well had already produced 27,326,280 barrels from its 30,000,000-barrel reserve.
v. NPV of production from oil fields is dependent on oil price.

5.2 RECOMMENDATIONS

Based on this research, the following recommendations are made:

i. Oil wells in Nigeria should be developed using smart well completion technology as their profitability, as demonstrated by this project work exceeds that of the more popular conventional well.
ii. Smart wells should be especially adopted in offshore and deep water prospects as the downhole sensors can help minimize the need for interventions which can be expensive or impossible.
iii. In scenarios where there is presence of hydrocarbon fluids from two or more separate or stratified reservoirs, smart well completion is recommended as production of reserves via a single production conduit is possible.
iv. Chemical fingerprinting, as presented in this project work should be introduced as a solution to the problem of reconciliation after commingling.
v. The hyperbolic decline curve model was used for the oil production forecast in this project work. More specialized tools for economic modelling of smart wells should be developed as they show a prospect for higher profitability in the near future.
vi. A tool for calculating cumulative production using the hyperbolic decline model was developed during the course of this project. This tool should be adopted by production economists and researchers in the oil and gas sector. This will reduce time required for production forecasts and generally cut costs.

vii. A tool for calculating NPV at a given discount rate was also developed. This tool should be used along with the developed hyperbolic decline tool for economic analysis. This will as well reduce time and generally cut costs.

viii. More research should be done on the system hardware of smart well technology to improve its reliability.

REFERENCES

Ajayi, A. and Konopczynski, 2006. “Intelligent-Well Technology Reduced Water Production in a Multilateral Oil Producer”, Presented in the 2006 SPE Annual Technical Conference and Exhibition, San Antonio, September 24-27, 2006.

Akram N, Hicking S, Blythe P, Kavanagh P, Reijnen P, Mathieson D, 2001. “Intelligent Well Technology in Mature Assets”. Offshore Europe; 4-7 September 2001; Aberdeen, United Kingdom: Copyright 2001, Society of Petroleum Engineers Inc.; 2001.

Collins JR, Neuber EB, 2012. “The Agbami Intelligent Well: Examples Of Active Reservoir Management”. SPE International Production and Operations Conference & Exhibition; 14-16 May 2012; Doha, Qatar: Society of Petroleum Engineers; 2012.

E. Annan Boah, A. Aidoo Borsah, E.T. Brantson, 2018. “Decline Curve Analysis and Production Forecast Studies for Oil Well Performance Prediction: A Case Study of Reservoir X”. The International Journal of Engineering and Science (IJES), Volume 7, Issue 11, Pages 22-30, 2018.

Grebenkin I. M. and Davies D. R. 2010. “Analysis of the Impact of an Intelligent Well Completion on the Oil Production Uncertainty”, SPE 136335 presented at the 2010 SPE Russian Oil & Gas Technical Conference and Exhibition, Moscow, Russia, October, 2010.

Griffith C. R., Simon L. and Lien H. C. A. 2012. “Evaluation of a Smart Well System at the Saramacca Oil Fields – A Case Study”, SPE 157717 presented at the SPE 2012 Energy Conference and Exhibition, Port of Spain, Trinidad, June 11-13, 2012.

Gustavo Carvajal, Stan Cullick, 2018. “Intelligent Digital Oil and Gas Dields”, 2018.

“Intelligent Well Overview”, http://www.slb.com/content/services/completion/intelligent/intelligent_completions.asp?, February 2007.

Konopczynski, M. and Ajayi, 2004. “Design of Intelligent Well Downhole Valves for Adjustable Flow Control”, Presented in the 2004 SPE Annual Technical Conference and Exhibition, Houston, September 26-29, 2004.

Lien HCA, Cliff R, Simon L, Suriname SM, 2012. “Evaluation of a Smart Well System at the Saramacca Oil Fields: A Case Study”. SPETT 2012 Energy Conference and

Exhibition; 11-13 June 2012; Port-of-Spain, Trinidad: Society of Petroleum Engineers; 2012.

Marcio Augusto Sampaio Pinto, Carlos Eduardo Barreto, Ana Teresa F. D.A.S. Gaspar Ravagnani, Denis Jose Schiozer, 2011. “Comparison Between Smart and Conventional Wells Optimized Under economic Uncertainty”, 2011.

M.D. Nahin Mahmood, Zayed Bin Sultan, Navid Yousuf, 2018. “A Review on Smart Well Completion System: Route to the Smartest Recovery, September 2018.

Mohaghesh Shahab D. 2013. “Smart fields, a Data Driven Approach to Making Oil fields Smart” 2013.

Mohammad T. Al-Khalifa, Abdulrahman T. Mishkhes, Keshab N. Baruah, Nashi M. Al-Otaibi, 2013. “Smart Well Completion Utilization to Optimize Production in MRC Well-a Case Study” 2013.

Philip Asante-Mireku, Joel Tetteh, KwabenaOkyere-Nyako, 2016. “Intelligent Well Technology: Incorporation of Smart Controls in Injection Wells to Enhance Sweep Efficiency and Maximize Oil Recovery” May 2016.

P.M. Turner, D.J. Walker, 2003. “Intervention-less Intelligent Completion Technology”, April 1, 2003.Middle East & Asia Reservoir Review, 2007 “Intelligent completions”, Number 8, 2007.

Tariq A. Ali, Chesapeake Energy; James J. Sheng, 2015. “Production Decline Models: A Comparison Study”. Paper presented at the SPE Eastern Regional Meeting held in Morgantown, West Virginia, USA, 13–15 October 2015. SPE-177300-MS

Well Dynamics, 2007. “The Definition SmartWell” http://www.welldynamics.com/technology/smartwell_definition.htm., February 2007.