Integrated reservoir management in a Niger Delta oil rim field

Yetunde M. Aladeitan\(^1\)*, Akeem O. Arinkoola\(^1,2\) and David O. Ogbe\(^1,3\)

**Abstract:** Several hundred million barrels of oil and trillions standard cubic feet of gas are enclosed within the oil rim reservoirs in the Niger Delta. The low recovery from these reservoirs can be attributed to the excessive early water and gas breakthrough at the wells which requires immediate attention. However, the majority of oil rims are thinly bedded and exist between strong aquifers and large gas caps which make preventing water and gas coning a very difficult task. The best approach to optimize production from these oil rims is effective reservoir management which involves evaluation, monitoring, goal setting, and revision of a few strategies for efficient field development. Current strategies to lessen these problems are limited due to their complexities and low recovery factor. This paper presents an integrated reservoir management approach for improved exploitation of an oil rim reservoirs in the Niger Delta. Seven development strategies were evaluated using Net-Present Value (NPV), Internal Rate of Return (IRR), and Discounted Payout Period (DPOP) criteria. In all these strategies, well placement, number of years of production, and production cycle were considered uncertain. The results show that well placement has a significant impact on efficient oil rims development. Therefore, by using a 1500 ft horizontal well, and a concurrent

**ABOUT THE AUTHORS**

Yetunde Aladeitan is a lecturer at the Department of Chemical Engineering of University of Abuja in Nigeria, currently a PhD student of Petroleum Engineering at the African University of Science and Technology, Abuja, Nigeria. Yetunde’s specialization is in reservoir simulation and modelling.

Dr. Akeem Arinkoola holds a PhD in Petroleum Engineering from the African University of Science and Technology, Abuja and is a lecturer in the Department of Chemical Engineering of the Ladoke Akintola University of Technology, Ogbomoso, Nigeria. His research interest is in uncertainty analysis, reservoir modelling, production engineering and chemical product synthesis and optimization.

Professor David O. Ogbe is a visiting Professor of petroleum engineering at the African University of Science and Technology, Abuja, Nigeria. Professor Ogbe’s research interest includes reservoir simulation, reservoir modelling, formation evaluation, reservoir characterization, oil and gas reservoir engineering, well testing.

**PUBLIC INTEREST STATEMENT**

Development of oil rim reservoirs is usually quite challenging as a result of gas and water coning. An effective reservoir management is very crucial in optimizing production from such reservoirs due to its complexity. In this study, integrated reservoir management was carried out to evaluate several development strategies on a reservoir in the Niger Delta region. To identify the optimum strategy, an economic analysis of the produced oil and gas was carried out using the profitability indicators of NPV, DPOP and IRR. Producibility factors, operational constraints and economics of the project are significant in the field development planning.
development strategy, maximum return on investment of 24.2% was achieved within a 3 years payout period. The framework developed in this present study is simple and reproducible and therefore recommended for oil rim development.

Subjects: Engineering Management; Production Engineering; Mining, Mineral & Petroleum Engineering

Keywords: oil rim reservoir; field development strategy; simulation; economic analysis; reservoir management

1. Introduction

Production from thin oil rim reservoirs is challenging because excessive water production and early gas breakthrough in production wells result in low recovery factors. The prevalence of water and gas coning in these reservoirs is attributed to their thin-bedded nature. Complications to reservoir development arise when such reservoirs are sandwiched between strong aquifers and large gas caps. However, majority of these reservoirs are of economic value due to their lateral extents with substantial volumes of oil regardless of their small thickness. Several strategies have been developed to mitigate these problems for effective and efficient exploitation of the asset. A few publications are presented to highlight some of the problems and suggested solutions.

Several studies on the production of oil rim reservoirs indicate that the recovery factor is a function of the rim height, residual oil saturation, well type, well spacing and distance between the fluid contacts (Kydland et al., 1993; Cosmo & Fatoke, 2004; Ehlig-Economides et al., 1996; Kabir et al., 2008). In 1993, Kydland et al. studied well placement in a 22–26 m thick oil rim zone in the Troll field. They reported maximum oil production by completing the wells in the lower part of the oil rim, close to the oil-water-contact; and implemented a gas injection scheme to control the aquifer inflow into the oil zone. Satter et al. (1994) reported the need for an integrated reservoir management team to develop thin oil rim reservoirs. Their team-based approach recommended the integration of geosciences and engineering professionals, tools, technology and data to produce oil rim reservoirs. In a related work, Evans (2000) suggested decision analysis as a framework for conducting integrated reservoir management by combining geological studies and environmental impact assessment. Evans proposed that decision analysis is a vehicle for the integration of disciplines of reservoir engineering, geochemistry, geological studies and risk analysis to optimize the asset net present value. Reservoir characterization is also important in developing thin oil rim reservoirs. Ikomi et al. (2002) reported drilling of side-tracks from existing wells in the Awoba Field X in the Niger Delta. The results of the side-track wells provided an improved understanding of the reservoir characteristics and data on the production performance of the wells in the field. They proposed that this data will be integrated into the field development plan to manage the remaining reserves in Field X. In a study on production optimization, Hasan et al. (2009) indicated a significant increase in oil recovery factors in an oil rim reservoir when a binary integer programming, a production optimization technique was used to determine the choke and rate settings in production and injection wells. Razak et al. (2010) reported improved oil recovery factors (by 35–48%, which is higher than the theoretical recovery efficiency) in their work by understanding water and gas coning tendencies in thin oil rim reservoirs. They highlighted the impact of force balance changes (coning tendency) by increasing the viscous withdrawal with the use of horizontal wells, coupled with gas re-injection to obtain higher recovery efficiency. Iyare and Marcelle-de Silva (2012) carried out an investigation on well placement using a single-well numerical simulator to study the effect of gas cap and aquifer sizes on the production of a thin oil rim reservoir. Their results indicated that placement of the horizontal well below the water-oil-contact (WOC) is more favorable for a large gas cap reservoir; and the well should be placed above gas-oil-contact (GOC) for a reservoir with a small gas cap and large aquifer. Ahmed and Saad (2014) researched on the optimum field management plan for a thin oil rim reservoir in the Nile Delta in Egypt. They proposed the use of horizontal wells for production, and gas-recycling/re-injection in the oil zone to impede the bottom aquifer and improve the sweep efficiency. Balogun et al. (2015)
employed analytical and simulation methods to study the development of a 3 m-thick oil rim reservoir overlain by a huge gas cap in the Niger Delta. They considered two development scenarios, sequential and concurrent oil and gas production, and their results indicated that the development of the oil rim was not economically feasible and therefore recommended a gas-only development strategy. Ogolo et al. (2017) performed a simulation study of a Niger Delta oil rim reservoir. They used horizontal wells to produce the reservoir and considered gas injection as an option to improve the recovery factor and minimize water production. Their study indicated recovery factors of 25–44%. The limitation of their work is the high GOR produced by the horizontal well. A surrogate modelling approach was proffered as a solution to oil rim production optimization (Aladeitan et al., 2019). Their study proposed a surrogate model and provided a framework for understanding the reservoir and fluid properties that impact oil production from thin oil rim reservoirs. The study evaluated a few reservoir development strategies to show the impacts and associated uncertainties of the reservoir and fluid properties including the rim height, reservoir anisotropy, oil viscosity, horizontal permeability, aquifer strengths, and bottom-hole pressure on production performance and oil recovery from thin oil rim reservoirs. To summarize the literature review, we state that the above-mentioned studies underscore the need for improved well placement, reservoir characterization, water and/or gas injection/re-injection, and production optimization in an integrated reservoir development plan to produce thin oil rim reservoirs. In this paper, we study well placement, water and gas injection, and production optimization as an integrated reservoir management approach to develop a thin oil rim reservoir (Reservoir A) in a Niger Delta Field.

2. Location of study area and reservoir description
The Niger Delta is a major hydrocarbon producing basin in Nigeria, where extensive exploration and exploitation has been going on since the early 1960s after the discovery of oil in commercial quantity in 1956. Reservoir A is in the coastal swamp of the Niger Delta, some 40 km north of the present-day coastline and about 40 km South West of Port Harcourt (Figure 1). Its aerial extent spans approximately 30 sq km. It was discovered in 1957. The field is characterized by fault lines on the west of the field and mild crestal faulting parallel to the main boundary fault. A major east to west boundary fault bounds the oil rim reservoirs and therefore explains the depositional and structural history of the field. The field consists of three major fault lines lying almost parallel to each other (Figure 2). The reservoir is divided into two regions along its Z-axis by a thick shale layer. The reservoir is overlain by a large gas cap and underlain by a large aquifer.

The challenges of producing from oil rim reservoirs are often enormous because of the coning of gas and water into the reservoir during production which leads to very low recovery factors. The case study considers the development of a thin oil rim zone sandwiched between a large gas cap and a large aquifer thereby complicating its production. To maximize profit, sound reservoir management using reservoir simulation is proposed. In our methodology, learnings from the first stage of drilling/production are implemented in later phases leading to higher recovery factors and more cost-effective wells. Challenges encountered, solutions and reservoir development plan at various stages are highlighted in this paper.

3. Methodology
Reservoir management transcends the depletion/development plan, it involves the use of an integrated strategy for the efficient exploitation of the reservoir. In this study, a numerical model was built by integrating static and dynamic reservoir properties which was used for determining optimum gas/water injector and oil production well placement. To improve oil recovery, seven different development scenarios were examined by numerical simulation using a commercial simulator. The production from these strategies was evaluated in an economic analysis framework. The best strategy was selected based on the Net Present Value (NPV), Discounted Payout Period (DPOP) and Internal Rate of Return (IRR) criteria.
3.1. Dynamic reservoir model

A three-phase, three-dimensional, dynamic, black-oil model of Reservoir A in the Niger Delta was built from a static model using a commercial software. The oil rim height is an average of 75 ft, and the reservoir has a large gas cap overlying a large aquifer (Figure 2). Table 1 summarizes the reservoir, rock and fluid properties used to build the dynamic model. The grid dimensions are 58 × 18 × 40 in the X, Y, and Z directions with grid sizes of $\Delta X = 180$ ft, $\Delta Y = 50$ ft, $\Delta Z = 16$ ft, respectively. PVT data and relative permeabilities were derived from correlations using input data obtained from an analog field. The reservoir is divided into two vertical regions separated by a thick-shale layer. After model initialization, the stock tank oil in place (STOIIP) is about 56 million stock-tank-barrels (MMSTB), and the initial gas in place (IGIP) is approximately 966 billion standard-cubic-feet (BSCF).
3.2. Well placement and optimization

After building the dynamic model, the next step of this study was to determine the proper placement of the oil production wells to maximize oil recovery. The well placement at various stages during the simulation was based on evaluation of the distribution (or map) of porosity-thickness weighted hydrocarbon saturations, i.e., HphiSo, defined in Equation 1 as a function of the grid block height, net-to-gross ratio, porosity and oil saturation.

\[ HphiSo = Z \times NTG \times \theta \times So \]  

(1)

Where

- \( Z \) = grid block height (ft)
- \( NTG \) = Net-to-gross thickness (fraction)
- \( \theta \) = porosity (fraction)
- \( So \) = oil saturation (fraction)

For the initial placement, the wells were drilled at locations with high porosity-thickness weighted initial oil saturations, i.e., high HphiSoi. In this case, Soi is the initial oil saturation. Regions with high HphiSo were targeted for oil placement after satisfying the set saturation threshold. To optimize the placement of infill-well, a new HphiSo map is generated at any time to evaluate the saturations at potential locations of the well. In some cases, the location of a well can be optimized by comparing the well’s cumulative production of oil, water cut or gas-oil-ratio (GOR) from two or three candidate locations. In this case, the location that gives the highest cumulative oil production, lowest GOR and Water cut is selected. The gas wells are placed in the crestal region of the gas cap using the corresponding porosity-thickness weighted gas saturation HphiSg maps, where Sg is the gas saturation. Figure 3 shows a typical HphiSo map used to identify locations of production wells in the model.

### Table 1. Fluid and rock properties of Reservoir A

| Parameter                        | Value | Unit       |
|----------------------------------|-------|------------|
| STOIP                            | 56    | MMSTB      |
| IGIP                             | 966   | BSCF       |
| Average horizontal permeability  | 1043  | mD         |
| Average vertical permeability    | 10.4  | mD         |
| Average Oil Column height        | 75    | ft         |
| Porosity                         | 0.27  | fraction   |
| Initial Reservoir Pressure       | 3976  | psi        |
| Connate Water Saturation         | 0.2   | fraction   |
| Water-Oil-Contact (region 1)     | 8751  | ft         |
| Gas-Oil-Contact(region 1)        | 8671  | ft         |
| Datum Depth(region 1)            | 8750  | ft         |
| Pressure at Datum Depth (region 1)| 3789 | psi        |
| Water-Oil-Contact(region 2)      | 9363  | ft         |
| Gas-Oil-Contact(region 2)        | 9283  | ft         |
| Datum Depth(region 2)            | 9183  | ft         |
| Pressure at Datum Depth(region 2)| 3976  | psi        |
| Irreducible water Saturation     | 0.2   | fraction   |
| Net-to-Gross ratio               | 0.82  | fraction   |
| Critical Gas Saturation          | 0.05  | fraction   |

Aladeitan et al., Cogent Engineering (2020), 7: 1812474
https://doi.org/10.1080/23311916.2020.1812474

Page 5 of 16
3.3. Reservoir development strategies
The seven reservoir development strategies investigated includes:

**Strategy 1: Base Case Production (Base)**—Only Oil is produced from the rim reservoir for period of depletion, i.e., 20 years.

**Strategy 2: Oil and Gas Concurrent Production (OGCP)**—oil is produced from the oil zone while gas is produced concurrently from the gas cap zone throughout the 20-year production period.

**Strategy 3: Oil and Gas Sequential Production (OGSP)**—oil production is like the Base Case but gas production from the gas cap is introduced after 10 years, i.e., simultaneous oil and gas production for the 11th year to the end of production.

**Strategy 4: Oil and Produced Gas Reinjection (OGRej)**—oil production is like the Base Case but after 5 years, a percentage of produced gas (produced solution gas and the gas coned from the gas cap) is reinjected into the gas cap of the reservoir.

**Strategy 5: Oil and Produced Gas Reinjection followed by Gas Cap Blowdown (OGRejGB)**—this strategy is like Strategy 4 but the gas cap is blown down after 15 years.

**Strategy 6: Oil Production and Water Injection (OPWinj)**—oil production is like the Base Case with simultaneous water injection from the start of production.

**Strategy 7: Oil Production with Water Injection and Produced Gas Reinjection (OPWinjGRej)**—this strategy is like Strategy 6 but after 5 years, a percentage of produced gas is reinjected into the gas cap of the reservoir.

3.4. Production forecast parameters and constraints
Table 2 lists the production parameters and constraints used in the simulation of reservoir performance during the implementation of the seven depletion strategies. The parameters and
constraints were defined to reflect common field operating procedure in the Niger Delta. Additional constraints and limiting parameters are described later in the paper for specific field development strategies.

3.5. Simulation of reservoir performance
Simulation of reservoir performance was carried out for the seven strategies identified in this study for the development of Reservoir A. In each case, six oil production wells (1500 ft-long horizontal wells) were drilled in the reservoir. The oil wells were produced for 20 years in all cases.

3.5.1. Strategy 1: base case oil production (Base)
For the Base Case, only oil was produced from the oil zone using the six wells completed in Reservoir A. Each well was set at an initial production rate of 2000 STB/Day. The simulation was conducted for 20 years to obtain the reservoir performance under this scenario.

3.5.2. Strategy 2: oil and gas concurrent production (OGCP)
In Strategy 2, the six horizontal oil production wells were completed in the oil leg; and three vertical gas producers were completed in the gas cap zone. The wells came on stream at the same time with an average take off rate of 2000 STB/day per oil well. For the gas wells, the initial offtake rate was set at 6000 MSCF/day per well. All oil and gas wells produced for 20 years.

3.5.3. Strategy 3: oil and gas sequential production (OGSP)
For the OGSP, the oil production wells produced initially at 2000 STB/day per oil well for 20 years. At the beginning of the 11th year, three vertical gas wells were completed and produced from the gas cap with an initial production rate of 6000 MSCF/day per well. The gas wells were produced for the next 10 years until the end of the simulation run.

3.5.4. Strategy 4: oil and produced gas reinjection (OGRej)
The oil production wells were operated initially at 2000 STB/day per well. Like the Base Case, the oil producers were operated for 20 years. Note, beginning in the 6th year, 6000 MSCF/day of gas (i.e., produced solution gas and the gas coned from the gas cap) is reinjected into the gas cap of the reservoir. Produced gas reinjection was operated for 15 years.

3.5.5. Strategy 5: oil and produced gas reinjection followed by gas cap blowdown (OGRejGB)
For the OGRejGB development strategy, Reservoir A was operated for 15 years as described in development Strategy 4. Produced gas of 6000 MSCF/day was reinjected into the Gas cap; however, at the end of 15 years, gas reinjection was stopped, and oil production continued with a blow-down of the gas cap for another 5 years. This simulation case was done to evaluate the impact of gas cap blow down on how to best maximize the asset value of Reservoir A.

3.5.6. Strategy 6: oil production and water injection (OPWinj)
In this strategy, Reservoir A was operated like the Base Case, i.e., oil was produced from the six horizontal wells with simultaneous water injection from the start of production for 20 years. Strategy 6 (OPWinj) was studied in this work to evaluate the impact of simultaneous water injection on production performance and economics of developing the asset.

3.5.7. Strategy 7: oil production with water injection and produced gas reinjection (OPWinjGRej)
For the OPWinjGRej strategy, the reservoir was developed majorly as described in Strategy 6; but at the beginning of the 6th year, 6000 MSCF/day of produced gas is reinjected into the gas cap of the reservoir for 15 years. That is, simultaneous oil production and water injection for 20 years combined with 15 years of reinjection of all produced gas after 5 years from the start of the project.

4. Results and discussion
The results obtained from the production forecasts are discussed in this section. Major observations, including predominant drive mechanisms and operational challenges from the results are
also discussed. A comparison of the results from the different development strategies was carried out to determine the best candidate based on the cumulative oil and gas recovery. The results also served as input to the economic analysis presented later in this work.

4.1. Strategy 1: base case oil production
Figure 4 shows the results of producing only oil from the oil leg of Reservoir A for 20 years. The predominant drive mechanism in this strategy is the gas cap expansion and water drive. Similarly, some wells shut down after exceeding the water cut limit between the 17th and 18th year thereby causing a second decline in gas production in Figure 4. The ultimate recovery is 17.5MMSTB of oil and 27.6BSCF of gas as depicted in Figure 4.

4.2. Strategy 2: oil and gas concurrent production (OGCP)
The results of the reservoir performance for the OGCP development strategy are shown in Figure 5. The major drive mechanisms are the solution gas drive, gas cap expansion and water drive. The main challenge for the development of the OGCP strategy in Reservoir A is the high water cut. In Figure 5, the 10th year shows a sharp increase in water cut. Notice that the trend of the cumulative oil production becomes less steep after the 10th year because some wells shut in as a result of high water cut. The ultimate recovery indicated 17.5 MMSTB of and 158 BSCF of gas at the end of the simulation.

4.3. Strategy 3: oil and gas sequential production (OGSP)
Figure 6 shows the results of the simulation of the OGSP development strategy. The oil production profile of the reservoir for the first 10 years of the OGSP is like the first 10-year trend observed in Strategy No 1 (Base Case). Gas production commenced at the beginning of the 11th year. The predominant drive mechanisms in the OGSP strategy are solution gas drive, water drive, and gas cap expansion. The main challenge here is the high water cut. Cumulative oil recovery is 15.2 MMSTB and 89.3 BSCF of gas is produced as depicted in Figure 6.

4.4. Strategy 4: oil and produced gas reinjection (OGRej)
For the OGRej development strategy, the six horizontal oil production wells came on stream at the same time with an initial oil production rate of 2,000 STB/day per well. The wells were produced for 20 years. At the beginning of the 6th year, 6MSCF/day of produced gas (i.e., produced solution gas and the gas coned from the gas cap) is reinjected into the gas cap with 4 gas injection wells, i.e., 20 years of oil production along with 15 years of produced gas reinjection into Reservoir A. Figure 7...
shows the results of the oil, gas and water production performance for this OGRej strategy. The predominant drive mechanisms in this reservoir development strategy are the gas cap expansion drive, solution gas and water drives. The results also indicate that the main operational challenges are handling the high water cut and high GOR during the development of Reservoir A. From the field production data shown in Figure 7, the predicted cumulative oil recovery is 18.7 MMSTB and 113 BSCF of gas produced after 20 years of simulation.

4.5. Strategy 5: oil production supported by gas reinjection then gas cap blowdown (OGRejGB)

For the OGRejGB development strategy, Reservoir A was operated for 20 years using the following scheme: oil production for 20 years; 6MSCF/day of produced gas reinjection was done for 10 years beginning 6th year; and then a blowdown of the gas cap for another 5 years. Figure 8 shows the
The results of the simulations. In Figure 8 the proposed predominant drive mechanisms are solution gas drive combined with gas cap expansion and water drive during the first 15 years. Limited gas expansion drive during Year 16–20 when the gas cap blow down was operating in Reservoir A. Handling the high water cut and GOR is the key field operational challenge to be contended with during the implementation of this development strategy. The cumulative 20-year production is 18.7 MMSTB of oil and 125 BSCF of gas.

4.6. Strategy 6: oil production supported by water injection (OPWinj)

For the OPWinj development strategy, the six horizontal oil wells completed in Reservoir A were produced for 20 years. At the same time, two other wells were injecting water to support the pressure in the reservoir. The results of the 20-year production are shown in Figure 9. The
predominant drive mechanisms are gas cap expansion, solution gas drive, and water drive from the aquifer and injection wells. Operational challenges are majorly the handling of the high water cut and GOR. A cumulative recovery is 18.1 MMSTB of oil and 34.8 BSCF of gas is produced using Strategy 6 to develop Reservoir A.

4.7. Strategy 7: oil production supported by water injection with produced gas reinjection (OPWinjGRej)
The OPWinjGRej development strategy combined oil production with simultaneous water injection. Unlike, Strategy 6, 6MSCF/day of the produced gas reinjected into the gas cap of the reservoir with 4 gas injection wells at the beginning of the 6th year for 15 years. The water injection wells come on stream at the same time with the oil producers. Figure 10 shows the results of the 20-year simulation of developing Reservoir A using Strategy 7. The predominant drive mechanisms in this strategy are
solution gas, water drive and gas cap expansion drives. As shown in Figure 10, there is a sharp increase in the cumulative gas produced around the 8th year. This increase in gas production may be attributed to the gas reinjection program introduced after 5 years of production. The ultimate production predicted from the simulation is 18.62 MMSTB of oil and 115 BSCF of gas.

4.8. Comparison of the cumulative oil and gas production for the development strategies

The comparisons of the cumulative oil and gas produced during the 20-year simulation of all 7 reservoir development strategies are shown in Figures 11 and 12. Figure 11 indicates that best four strategies with very high cumulative oil recovery are Strategy 4 (oil production with produced gas reinjection) Strategy 7 (oil production supported by simultaneous water and gas reinjection), Strategy 5 (Oil production supported by Gas Reinjection then Gas Cap Blowdown) and Strategy 6 (oil production supported by water injection). Figure 12 also shows the strategies with the highest cumulative gas production. They are in order of cumulative gas produced: Strategy 2 (oil and gas concurrent production), Strategy 5 (Oil production supported by Gas Reinjection then Gas Cap Blowdown), Strategy 4 (oil production supported by produced gas reinjection), and Strategy 7 (oil production supported by simultaneous water and gas reinjection).

It is not enough to conclude that the development strategy with the highest cumulative oil production is the optimal strategy without considering the project economics for Reservoir A. The economic analysis presented in the following section is used to determine the best strategy that is not only technically feasible but also economically attractive.

5. Project economic analysis

The economic analysis in this research is based on the calculation of three profitability performance indicators, including the Net present value (NPV), internal rate of return (IRR) and the discounted pay out period (DPOP). The optimum development strategy corresponds to the project with the maximum NPV, IRR and minimum DPOP. We define these profitability indicators in the following section.

Net Present value (NPV)—is the difference between the present value of cash inflow and outflow over a given period. The period of the project in this case is 20 years. This is the most popular petroleum evaluation criterion; it is employed in capital budgeting and investment planning in a bid to analyze the profitability of a projected investment. The definition of NPV is given by
Figure 12. Comparison of Cumulative gas production of all 7 strategies.

\[ NPV = \sum_{i=1}^{n} (CF)_i \times R_i \]  \hspace{1cm} (2)

Where

\( (CF)_i \) = cash flow in year \( i \)

\( R_i \) = Discounted rate in year \( i \), defined as

\[ R_i = \frac{1}{(1 + r)^{i-1}} \]  \hspace{1cm} (3)

Note in Equation 3, \( r \) = interest rate, %

**Internal Rate of Return (IRR)**—is the discount rate that makes the net present value (NPV) of all cash flows from a project equal to zero. IRR is employed in capital budgeting or the estimation of the profitability of potential investments. As a profitability indicator, the higher the IRR, the more profitable is the project. The IRR is calculated using

\[ NPV = \sum_{i=0}^{n} \frac{CF_i}{(1 + IRR)^i} = 0 \]  \hspace{1cm} (4)

Where

\( (CF)_i \) = cash flow in year \( i \)

\( n \) = number of time periods

**Discounted Pay Out Period (DPOP)**—is the time the project will get back its initial investment. It is given by

\[ DPOP = \frac{1}{\frac{1 - \frac{CF}{O}}{r}} \div \ln(1 + r) \]  \hspace{1cm} (5)

Where
\[ O_1 = \text{Initial Investment (Outflow)} \]

\[ r = \text{discount rate} \]

\[ CF = \text{Periodic Cash flow} \]

The assumptions and parameters used in the economic model are listed in Table 3. These parameters are typical for profitability analysis in the Niger Delta.

The profitability of implementing the seven strategies was evaluated using the indices defined in Equations 2 to 5. Table 4 shows the results of NPV, IRR and DPOP obtained from the economic analysis. From the results of the economic analysis, it can be concluded that Strategy 2 (oil and gas concurrent production) is the optimal development strategy for developing Reservoir A since it has the highest NPV, IRR and minimum DPOP.

In ascending order, the various strategies can be rated Strategy 2 > Strategy 4 > Strategy 5 > Strategy 1 > Strategy 6 > Strategy 7 > Strategy 3.

### 6. Conclusion and recommendation

The development of thin oil rim reservoirs such as Reservoir A requires integrated reservoir management planning. Identifying the best development strategy must combine forecast of cumulative oil and gas production from the reservoir with economic analysis. The results show that well placement has a significant impact on efficient oil rims development. Identifying the best development strategy must combine forecast of cumulative oil and gas production from the reservoir and an economic analysis using the produced streams as model input. The oil and gas concurrent development strategy is found to be the best option to produce Reservoir A in the Niger Delta since it has the highest values of the economic profitability indicators with the minimum

| Item                  | Unit          | Value     |
|-----------------------|---------------|-----------|
| Discount Rate         | %             | 15        |
| Oil Price             | $/BBL         | 55        |
| Gas Price             | $/MSCF        | 3.2       |
| Tax Rate              | %             | 20        |
| Operating Expenditure | M$           | 10% of revenue |
| Gas Production well cost | M$       | 18        |
| Oil Production well cost | M$       | 15        |
| Gas Injection well cost | M$       | 20        |

| Strategy | NPV ($MM) | IRR (%) | DPOP |
|----------|-----------|---------|------|
| 1        | 220.25    | 20.0    | 3    |
| 2        | 335.02    | 24.2    | 3    |
| 3        | 159.58    | 10.0    | 6    |
| 4        | 287.34    | 21.4    | 3    |
| 5        | 270.27    | 21.1    | 3    |
| 6        | 219.15    | 18.1    | 4    |
| 7        | 214.26    | 13.2    | 4    |
payout period. The framework developed in this present study is simple and reproducible and therefore recommended for oil rim development.

Funding
The authors received no direct funding for this research.

Author details
Yetunde M. Aladeitan
E-mail: yetty76@yahoo.com
ORCID ID: http://orcid.org/0000-0001-6824-7315
Akeem O. Arinkoola
E-mail: moranroolaakeem@yahoo.com
David O. Ogbe
E-mail: dogreatland@gmail.com

1 Petroleum Engineering Department, African University of Science and Technology, Galadimawa Abuja, Nigeria.
2 Department of Chemical Engineering, Ladade Akintala University of Technology, Ogbomoso, Nigeria.
3 Flowgnds Limited, Port Harcourt, Nigeria.

Citation information
Cite this article as: Integrated reservoir management in a Niger Delta oil rim field, Yetunde M. Aladeitan, Akeem O. Arinkoola & David O. Ogbe, Cogent Engineering (2020), 7: 1812474.

References
Ahmed, S., & Saad, A. (2014). Integrated Approach of Retrograde Condensate Simulation Using Pseudo-Pressures with Modified Equation of State and Velocity Dependent Relative Permeability. Society of Petroleum Engineers. doi: 10.2118/174714.
Aladeitan, Y. M., Arinkoola, O. A., Uddebhulu, O. D., & Ogbe, D. O. (2019). Surrogate modelling approach: A solution to oil rim production optimization. Cogent Engineering, 6(1), 1–15. https://doi.org/10.1080/23311916.2019.1631009
Balogun, O., Adepoju, Y., Ogbullu, A., & Chukwuneke, A. (2015, August 4). Hydrocarbon resource development decision for gas reservoir with 10ft oil rim: Niger Delta case study. Society of Petroleum Engineers. SPE178382-MS. https://doi.org/https://doi:10.2118/178382-MS
Cosma, C., & Fatoko, O. (2004, January 1). Challenges of gas development: Soku field oil rim reservoirs. Society of Petroleum Engineers. https://doi.org/https://doi:10.2118/88894-MS
Ehlig-Economides, C. A., Chan, K. S., & Spath, J. (1996, October). Production Enhancement or Strong Bottom Water Drive Reservoir; SPE 36613 [Paper presentation]. The SPE Annual Technical Conference and Technical Conference and Exhibition, Denver, Colorado, USA, 66–69. https://doi.org/10.2118/36613-MS.
Evans, R. (2000, January 1). Decision analysis for integrated reservoir management. Society of Petroleum Engineers. https://doi.org/10.2118/65148-MS.
Hasan, A. I., Echeverria-Ciurari, D., Foss, B. A., & Kleppe, J. (2009, January 1). Discrete optimization of oil production in thin oil rim reservoir under geological uncertainty. Society of Petroleum Engineers. https://doi.org/https://doi:10.2118/123989-MS
Ikomi, J. G., Nwosu, C. J., Mandhane, J. M., & Akem, B. T. (2002, January 1). Reservoir management scope in a mature Niger Delta field. Society of Petroleum Engineers. https://doi.org/https://doi:10.2118/77669-MS
Iyare, U. C., & Marcelle-de Silva, J. K. (2012, January 1). Effect of gas cap and aquifer strength on optimal well location for thin-oil rim reservoirs. Society of Petroleum Engineers. https://doi.org/https://doi:10.2118/158584-MS
Kabir, C. S., Agbamini, M. O., & Holquin, R. A. (2008, February 1). Production strategy for thin oil rim reservoirs. SPE Reservoir Evaluation and Engineering Journal, 11(1), 73–82. SPE 89755. https://doi.org/10.2118/89755-MS
Kartoatmodjo, S. P., Bohi, C., Badawy, A. M., Ahmad, N. A., Moreno, J. E., Baillon, W., & Friedel, T. (2009, January 1). Optimizing horizontal well placement and reservoir inflow in thin oil rim improves recovery and extends the life of an aging field. Society of Petroleum Engineers. https://doi.org/https://doi:10.2118/122338-MS
Kolkiv, S. V. (2012, January 1). Peculiarities of thin oil rim development. Society of Petroleum Engineers. https://doi.org/https://doi:10.2118/160678-MS.
Kydland, T., Wennemo, S. E., & Olsen, G. (1993, January 1). Reservoir management aspects of producing oil from thin oil rims in the trail field. Offshore Technology Conference SPE 7173-MS. https://doi.org/https://doi:10.4043/7173-MS
Ogolo, N. A., Molokwu, V. C., & Onyekonwu, M. O. (2017). Proposed Technique for Improved Oil Recovery from Thin Oil Rim Reservoirs with Strong Aquifers and Large Gas Caps. Society of Petroleum Engineers, 31. doi: 10.2118/189126-MS
Platts.com (2019, November 20). https://www.platts.com/IM.Platts.Content/InsightAnalysis/NewsFeature/2015/Oil/Africa-Oil-Gas-Energy-Outlook/_images/nigeria-oil-gas-fields.jpg
Rabie, A., Ghoneim, S., & Ali, M. T. (2015, September 14). Challenging field management of thin oil rim reservoir in Nile Delta of Egypt SPE 175800. Society of Petroleum Engineers. https://doi.org/https://doi:10.2118/175800-MS
Razak, E. A., Chan, K. S., & Darman, N. B. (2010, January 1). Breaking oil recovery limit in malaysian thin oil rim reservoirs: Force balance revisited. Society of Petroleum Engineers. SPE130388-MS. https://doi.org/https://doi:10.2118/130388-MS
Samsundar, K., Moosai, R. S., & Chung, R. A. (2005, January 1). Effective reservoir management of thin oil rims SPE-94803-MS. Society of Petroleum Engineers. https://doi.org/https://doi:10.2118/94803-MS.
Satter, A., Vernon, J. E., & Hoang, M. T. (1994, December 1). Integrated reservoir management. Society of Petroleum Engineers. https://doi.org/https://doi:10.2118/22350-PA
