Economic Analysis of Gas Reinjection for Enhanced Oil Recovery: A Case Study of the Niger Delta

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Authors’ contributions

This work was done in teamwork among all authors. Author SIE designed the study, wrote the first draft of the manuscript and designed the reservoir modeling and simulation processes. Author AJU checked the whole manuscript. Author ACI analyzed the economic aspect of the design and the oil price. All authors read and approved the final manuscript.

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ABSTRACT

The instability of crude oil prices at the international market which results in revenue drop to oil and gas operators, the high cost of drilling multiple injection wells and installing gas reinjection systems in a bid to improve recovery of crude oil, have been of great concern to the Petroleum Industry. The Economic viability of Gas Reinjection for Enhanced Oil Recovery (EOR) (as against the gas flaring operation) was analyzed with 7 wells located onshore, in the Niger Delta region of Nigeria. The production history and reservoir data were gathered with which the cost analyses were conducted. Two scenarios involving seven production wells were evaluated. The first was converting two of the production wells to gas injection wells and producing from the remaining 5 production wells (IN2PROD5) and the other was injecting gas in two newly drilled injection wells and producing from the seven production wells (INJ2PROD7). It was shown that (INJ2PROD5) is a preferred option in extending the productive life of an otherwise depleted and uneconomic oilfield, having higher Net Present Value (NPV), Profitability Index (PI) and Internal Rate of Return (IRR) of -$53MM, 0.93 and 27.40% while the INJ2PROD7 had $161MM, 1.39 and 37.75% at discounted rate of 30% respectively. After subjecting the expected net revenues under various crude oil price sensitivity market vagaries, INJ2PROD5 will stand the test of time as it is less expensive and yielded a higher gross profit which is the major factor in any investment decision making.

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NOMENCLATURES

& : And
< : Less than
@ : At
BBL : Barrel
Bcf : Billion cubic feet
Bg : Gas formation volume factor
Bgi : Initial Gas formation volume factor
Boi : Initial oil formation volume factor
Bscf : Billion Standard Cubic Feet
Bscf/d : Billion Standard Cubic Feet per day
Bw : Water formation volume factor
°C : Degree Centigrade
CO₂ : Carbon-dioxide
EA : Areal Sweep Efficiency
ED : Displacement Efficiency
EV : Vertical Sweep Efficiency
EDBT : Displacement Efficiency at Breakthrough
F : Function
°F : Degree Fahrenheit
Ft : Foot
Ginj : Cumulative Gas Injected
GIIP : Gas Initially in place
Gp : Gas production
H : Reservoir Average Thickness
K : Permeability
Kg : Oil Permeability
Ko : Gas Permeability
Krg : Relative Gas Permeability
Kro : Relative Oil Permeability
M : Mobility Ratio
M³ : Cubic Meters
MMbbls : Million Barrels
Mscf : Thousand Standard Cubic feet
MMscf : Million Standard Cubic Feet
MMscf/d : Million standard cubic feet per day
MMstb : Million stock tank barrel
N : Time of injection
Np : Cumulative oil production
Ns : Initial oil-in-place at the start of injection
P : Pressure
Pc : Critical Pressure
Pi : Initial pressure
PI : Profitability Index
Ppc : Pseudo-critical pressure
Ppr : Pseudo-reduced pressure
Psia : Pounds per square inch atmosphere
% : Percent
Ø : Porosity
Qg : Gas Flow rate
Rp : Cumulative gas-oil ratio
$: US Dollar
Scf/bbl : Standard cubic feet per barrel
Sgi : Initial Gas Saturation
1. INTRODUCTION

In the life of an oil well, the production process usually passes three stages: The primary production, secondary recovery, and the tertiary recovery. After discovery, an oilfield is initially developed and produced using primary recovery mechanisms in which natural reservoir energy which are the expansion of dissolved gases, change in rock volume, gravity, and aquifer influx, drive the hydrocarbon fluids from the reservoir to the wellbores as pressure declines with fluid (oil, water, or gas) production. Primary oil recoveries range between 5 and 20 percent (%) of the original oil-in-place (OOIP) [1]. Secondary recovery methods entailed injecting either water and (or) natural gas into the reservoir to repressurize or maintain pressure and to potentially act as a water and (or) gas drive to displace hydrocarbon. The oil recoveries at the end of both the primary and secondary recovery phases are generally in the range of 20–40% of the OOIP, although in some cases, recoveries could be lower or higher [1]. At the end of secondary recovery a slightly higher recovery range of 35–45% of OOIP was reported in North Sea oil reservoirs [2]. Enhanced oil recovery is the process of re-injecting produced gas back into the reservoir to help in restoring formation pressure and also improve oil displacement or fluid flow in the reservoir [3]. Gas reinjection is the injection of natural gas into an underground reservoir, typically one already containing both natural gas and crude oil, in order to increase the pressure within the reservoir and thus induce the flow of crude oil or else sequester gas that cannot be exported [4].

A substantial amount of residual oil remains in the reservoir at the end of secondary recovery and becomes the target for additional recovery using tertiary recovery or enhanced oil recovery (EOR) methods. EOR is the recovery of oil by injection of a fluid that may or may not be native to the reservoir [5]. EOR is a means of extending the productive life of an otherwise depleted and uneconomic oilfield. It is usually practiced after recovery by other, less risky and more conventional methods, such as pressure depletion and water flooding [6].

Enhanced oil recovery would attempt to recover the remaining 60% trapped in the subsurface.

The reason for injecting fluid is to boost the natural energy in the reservoir and interact with the reservoir rock/oil system to create conditions favourable for residual oil recovery.

Fig. 1 shows the different enhanced oil recovery methods in use. The study shows the pressure maintenance operation using gas injection.

The main objective of the study is to evaluate the economics of injecting gas through two non-performing wells as against injecting gas through two newly drilled injection wells to enhance oil recovery.

Several other things that can be achieved by EOR are; increase in capillary number, reduction in capillary forces, increase in drive water viscosity, providing mobility-control and reduction in oil viscosity and altering the wettability of reservoir rock [7].

Another mode of enhanced oil recovery is the water alternating gas (WAG) where gas is injected for some specific time and stopped for water to be injected alternatingly, in a study in the Niger Delta field, it was observed that gas injection was a better approach [8].

An evaluation study was also carried out on Miscible Water Alternation Gas (WAG) injection by comparing with Lesson learnt from an Immiscible Gas injection pilot [9].

A study showed how a gas injection scheme was rejuvenated by water alternating gas (WAG) opportunity by converting two shut-in gas injection wells to a WAG project [10].
1.1 Significance of Variables

The technically recoverable volumes of oil will depend on the OOIP and the respective recovery factors (RF). The OOIP value is calculated volumetrically as:

$$\text{OOIP} = \frac{(7758 + A + h + f \times \text{Boi})}{\text{Boi}} \quad (1)$$

Where, 7758 = multiplying factor, barrels/acre-feet, A = reservoir area, acres, h = average net reservoir thickness, feet, f = average porosity of formation, dimensionless, Soi = initial oil saturation in pore space, fraction, Boi = oil formation volume factor at initial reservoir pressure, reservoir barrel/stock tank barrel.

1.2 Overall Recovery Efficiency

The overall recovery factor RF of any secondary or tertiary oil recovery method is the product of a combination of three individual efficiencies factors as given by the following generalized expression:

$$\text{RF} = E_{D}E_{A}E_{V} \quad (2)$$

1.3 Oil Recovery Calculations

Oil produced, $N_{p}$ before or after breakthrough = $N_{s}E_{D}E_{A}E_{V}$ when initial water saturation is:

$$s_{wi} = 0, E_{D} = \frac{(S_{w}-S_{gi})}{(1-S_{gi})} \quad (4)$$

At breakthrough,

$$E_{DBT} = \frac{(S_{BT}-S_{g})}{(1-S_{gi})} \quad (5)$$

$$N_{p_{BT}} = N_{s}E_{DBT}E_{ABT}E_{VBT} \quad (6)$$

Assuming $E_{A}$ and $E_{V}$ are 100%.

$$N_{p_{BT}} = N_{s}E_{DBT} \quad (7)$$

Before breakthrough, $S_{wi} = 0$, gas production, Gp = 0 and flow rate of gas, $Q_{g} = 0$. After breakthrough, $S_{wi} = 0$, $E_{A} = E_{V} = 100\%$. 

FIG. 1. Different oil recovery stages

Source: The oil and gas journal 1990. 

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1.3.1 Displacement efficiency calculations

The displacement efficiency $E_D$ is the fraction of movable oil that has been displaced from the swept zone at any given time or pore volume injected. $E_D$ will always leave behind some residual oil because it’s an immiscible gas injection or water flood.

Mathematically, the displacement efficiency is expressed as:

$$ E_D = \frac{\text{Volume of oil at start of injection} - \text{Remaining oil volume}}{\text{Volume of oil at start of injection}} \quad (8) $$

$$ E_D = \frac{(PV)\left(\frac{S_o}{B_o}\right) - (PV)\left(\frac{S_a}{B_o}\right)}{(PV)\left(\frac{S_o}{B_o}\right)} \quad (9) $$

$$ E_D = \frac{\left(\frac{S_o}{B_o}\right) - \left(\frac{S_a}{B_o}\right)}{\left(\frac{S_o}{B_o}\right)} \quad (10) $$

Where, $S_o = \text{initial oil saturation at start of injection}$, $B_o = \text{oil formation volume factor at start of injection, bbl/STB}$, $S_a = \text{average oil saturation in the injection pattern at a particular point during the injection}$.

Displacement Efficiency at constant oil FVF,

$$ E_D = \frac{S_o - S_a}{S_o} \quad (11) $$

Initial oil saturation,

$$ S_o = 1 - S_{wi} - S_{gi} \quad (12) $$

In the swept area, water saturation is considered zero,

$$ S_w = 1 - S_{gi} \quad (13) $$

Substituting in above constant oil FVF equation

$$ E_D = \left(\frac{S_g - S_{gi}}{1 - S_{wi} - S_{gi}}\right) \quad (14) $$

Where, $S_g = \text{average gas saturation in the swept area}$, $S_{gi} = \text{initial gas saturation at the start of injection}$, $S_{wi} = \text{initial water saturation at the start of injection}$; if no initial water is present at the start of injection.

$$ E_o = \left(\frac{S_g - S_{gi}}{1 - S_{gi}}\right) \quad (15) $$

As $S_g$ increases at different stages of the injection, $E_o$ also increases until it reaches maximum when the average oil saturation in the area of the injection pattern is reduced to the residual oil saturation $S_{or}$ or equivalently when

$$ S_g = 1 - S_{or} \quad (16) $$

$E_D$ will continually increase with increasing gas saturation in the reservoir. The problem, of course, lies with developing an approach for determining increase in the average gas saturation in the swept area as a function of cumulative gas injected (or injection time).

1.3.2 Areal sweep efficiency

The areal sweep efficiency $E_A$ is defined as the fraction of the total injection pattern that is contacted by the displacing fluid. It increases steadily with injection from zero at the start of the injection until breakthrough time after which $E_A$ continues to increase steadily. The areal sweep efficiency depends basically on the following three main factors:

- Mobility ratio, M
- Injection pattern
- Cumulative gas injected, Ginj.

1.3.2.1 Mobility ratio

The mobility ratio $M$ is defined as the mobility of the displacing fluid to the mobility of the displaced fluid.

$$ \text{Mobility of oil} = \frac{K_o}{\mu_o} = \frac{K_{ro}}{\mu_o} \quad (17) $$

$$ \text{Mobility of gas} = \frac{K_g}{\mu_g} = \frac{K_{rg}}{\mu_g} \quad (18) $$

$$ M_R = \frac{\text{Mobility of displacing fluid}}{\text{Mobility of displaced fluid}} \quad (19) $$

$$ M_R = \left(\frac{K_g}{\mu_g}/\frac{K_o}{\mu_o}\right) \quad (20) $$

1.3.2.2 Injection pattern

The method of gas injection entails the dispersing of injected gas within the oil column which will cause the oil column to swell, lower the oil viscosity and make it easier for oil to flow; ultimately improving oil recovery. Injection rate is determined by the method of voidage replacement ratio (VRR).

$$ \text{VRR} = \frac{\text{Produced volume}}{\text{Injected volume}} \quad (21) $$

$$ \text{VRR} = \frac{G_p + N_p}{G_i} \quad (22) $$
\[
G_{\text{inj}} = \frac{\text{Injected volume}}{365 \times N}
\]  
(23)

Where; \( G_p \): Gas production, \( N_p \): Cumulative oil produced, \( N \): Time of injection

1.3.3 Vertical sweep efficiency

The vertical sweep efficiency, \( E_V \), is defined as the fraction of the vertical section of the pay zone that is the injection fluid. This particular sweep efficiency depends primarily on the mobility ratio and total volume injected.

2. METHODOLOGY

2.1 Model Design and Description

The reservoir model was rectangular with \((20\times20\times10)\) in dimensions (Figs. 2, 3 and 4); in which the reservoir was made up of 4000 grid blocks. Gas-Oil Contact (GOC) and Oil-Water Contact (OWC) were at -4000 ft and -8000 ft respectively. The gas used for reinjection was the accumulated gas produced during the primary recovery phase. Two scenarios involving seven production wells were used in this project. The first scenario was to convert 2 of the seven wells into gas injection wells and produce from 5 wells (INJ2PROD5) and the second scenario was to drill 2 new gas injection wells and produce from the 7 existing wells (INJ2PROD7). The injection wells for (INJ2PROD5) were located at \((10, 2, 2)\) grid points. For the (INJ2PROD7) scenario, the injection wells were located at \((10, 10, 2)\) grid points respectively. For the (INJ2PROD7), the first injection well and the second injection well were located at \((2, 10, 5)\) and \((10, 1, 2)\) grid points, while both production and injection wells were perforated at the same point. The top perforation interval and the bottom perforation interval were located at 6000ft and 6300 ft respectively.
Fig. 4. Completion design with petrel

Table 1. Fluid properties (FP) of the seven oil wells

| FP                  | Well 1     | Well 2     | Well 3     | Well 4     | Well 5     | Well 6     | Well 7     |
|---------------------|------------|------------|------------|------------|------------|------------|------------|
| $\rho_f$ (lb/ft$^3$)| 0.8224     | 0.5168     | 0.7486     | 0.8541     | 0.9684     | 0.5876     | 0.5891     |
| $\rho_g$ (lb/ft$^3$)| 0.7452     | 0.9866     | 0.665      | 0.2253     | 0.8901     | 0.0254     | 0.0478     |
| API                 | 40         | 35         | 39         | 45         | 36         | 44         | 37         |
| $B_o$ (rb/stb)      | 1.208      | 1.032      | 1.035      | 1.245      | 1.153      | 1.18       | 1.28       |
| $B_g$ (rb/scf)      | 0.0098     | 0.0093     | 0.0293     | 0.0091     | 0.005      | 1.002      | 0.012      |
| T (°R)              | 210        | 185        | 222        | 194        | 158        | 184        | 208.5      |
| P (psi)             | 4000       | 2425       | 2280       | 1720       | 2505       | 2792       | 3540       |
| $\mu_o$ (cp)        | 1.02       | 0.89       | 0.92       | 1.04       | 1.56       | 0.88       | 1.7        |
| $\mu_g$ (cp)        | 0.05       | 0.08       | 0.06       | 0.07       | 0.03       | 0.09       | 0.03       |
| $R_e$ (Mscf)        | 838        | 450        | 320        | 268        | 400        | 336.63     | 1052       |
| K (md)              | 1200       | 843        | 1000       | 1023       | 898        | 1101       | 903        |
| $\phi$ (%)          | 0.25       | 0.24       | 0.21       | 0.2        | 0.21       | 0.23       | 0.22       |
| $S_{wi}$ %          | .21        | 0.2        | 0.2        | 0.19       | 0.18       | 0.15       | 0.2        |

Table 2. Reservoir model data

| Properties                      | Value                     |
|--------------------------------|---------------------------|
| Reservoir type                  | Sandstone                 |
| Rock type                       | Unconsolidated Sandstone  |
| Reservoir depth, ft             | 20,000                    |
| Reservoir Area                  | 4,000 grid blocks         |
| INJ2PROD5, well locations 4 and 7| 10,2,2 and 10,10,2        |
| INJ2PROD7, well locations 5 and 9| 2,10,5 and 10,1,2         |
| Initial reservoir temperature, °F| 170                       |
| Initial reservoir pressure, Psi | 2900                      |
| Well injection pressure, Psi    | 1160, 3019                |
| Maximum reservoir pressure, Psi | 3000                      |
| Permeability, md                | 200                       |
| Porosity, %                     | 0.25                      |
| Oil gravity, API                | 43                        |
| Sgcr                            | 0.05                      |
| Salinity                        | 25,000 ppm                |
| Gas injected, Mscf              | 7,000                     |
Table 3. Estimated cost for operating INJ2PROD5 and INJ2PROD7

| Item                          | 15 years | INJ2PROD5 Cost($) MM | INJ2PROD7 Cost($) MM |
|-------------------------------|----------|----------------------|----------------------|
| Drilling cost incurred for two wells |          | 0.0                  | 8.0                  |
| Completion/Equipment cost for two wells |          | 0.0                  | 12.0                 |
| Operating/Maintenance         |          | 243.7                | 531.7                |
| Cost of converting PROD to INJ well |          | 3.0                  | 0.0                  |
| Cost of purchasing INJ equipment |          | 5.0                  | 10.0                 |
| Cost of gas purchase          |          | 158.2                | 158.2                |
|                               |          | 410                  | 720                  |

2.2 Economics of the Project

The economic structures should evaluate various production strategies, as prediction of future market trends is nearly a crystal ball game, then we should make predictions under diverse economic scenarios to get an idea of good feel for crude oil price sensitivity of the expected net revenues to the vagaries of the market. The quantity of crude oil that will be produced from the project, a price sufficient to recoup all costs of the project and provide an adequate Return on Investment (ROI), and the timing at which reserves in the reservoir will be produced sufficiently.

These estimates are then aggregated for the overall estimates of daily production, cumulative production, and ultimate recovery.

The estimate of the amount to be recovered through EOR application is based on actual reservoir parameters of oil saturation ($S_o$), pore volume (PV) and primary and secondary recovery methods, and the actual recovery calculation differs among techniques. This estimate is displayed as total incremental EOR production and incremental production per year from the time the project was initiated. The estimate of price is based on the projection of cash flows and a set rate of return. Cash inflows are generated by the production of oil. Cash outflow are comprised of the following investment and operating costs: field development expenditures, equipment expenditures, operating and maintenance costs, injection material costs and other costs. The cash flows are expressed as dollars per year from the time of project initiation. The production estimate is matched with investment and operating costs and rates of return to calculate the required price for the oil. Conversely, a spreadsheet is used to compute the rate of return to yield a series of fixed prices.

2.3 Economic Analysis

As with all infrastructural investments in the energy sector, developing reinjection facilities is capital intensive. Investors usually use the return on investment as a financial measure for the viability of such projects. In making a decision whether to invest in a project, the incremental cost to complete that project should be compared with the future net revenue expected to be received from the sale of oil and gas produced from the project. If the expected net revenue is greater than the project cost, the project should be undertaken but if not, the project should be abandoned. Therefore, in making the final decision on whether to convert 2 existing wells to injection or drilling new wells for gas injection will be economical, a thorough economic analysis was carried out.

The estimated costs of both scenarios were analysed and indicate the project magnitude. Oil and gas prices have remained at approximate rates of $37.54/bbl and $4/Mscf March 2020.

2.4 Net Present Value Method

NPV compares the value of a dollar today to the value of that same dollar in the future, taking inflation and returns on investment into account. If the NPV of a prospective project is positive, it should be accepted, otherwise it is rejected.

\[
P = \frac{F}{(1+i)^N}
\]

Where, \(P\) = Present Value, \(F\) = Future, \(i\) = Interest Rate, \(N\) = Number of years

\[
NPV = PV_{at\ 1\ yr} + PV_{at\ 2\ yrs} \ldots + PV_{at\ 15\ yrs} - PV_{at\ 0\ yr}
\]

2.5 Internal Rate of Return (IRR) Method

The internal rate of return (IRR) on investment for a project is the discount rate that would be
required in order to generate a NPV of all cash flow from a particular investment equal to zero.

2.6 Profitability Index (PI) Method

These measures the proportion of the present value of dollars return to dollars invested. If profitability index is greater than 1, then the project is acceptable.

2.7 Comprehensive Analysis (IRR, NPV, PI)

Using the cash flows estimated for both scenarios, the IRR of the projects is calculated as well as the NPV and PI of the projects using 30% discount rates (see Table below).

\[
\text{Profitability} = \frac{\text{NPV of Future Cash Inflows}}{\text{Initial Cash Outlay (Investment)}}
\]  \hspace{1cm} (26)

\[
\text{Cost of drilling per well} = \frac{\text{Drilling Cost}}{\text{Depth}} \times \text{Depth}
\]  \hspace{1cm} (27)

\[
\text{Cost of drilling per well} = \frac{\$5000}{\text{ft}} \times 8,000 \text{ ft}
\]

\[
\text{Cost of drilling per well} = \$40,000,000
\]

\[
\text{Estimated cost of gas purchased} = \frac{\$4}{\text{MSCF}}
\]

\[
\text{Mscf} \times 1000 \text{ scf} = \text{MMBTU}
\]

\[
1 \text{BTU} = 1.032
\]

\[
\text{Cost of gas} = \frac{\text{price of gas} \times \text{Vol} \times \frac{\text{gas injected}}{\text{vol}}}{} \times 0.032 \times \text{years of injection}
\]  \hspace{1cm} (28)

\[
\text{Cost of gas} = \frac{\$4}{\text{MSCF}} \times 7,000 \times 1.032 \times 15 \times 365 \times \text{days}
\]

\[
\text{Cost of gas} = \$158,205,600
\]

3. RESULTS

3.1 Primary Recovery Field Production Data

Figs. 5 and 6 show the field production history and its performance after twelve years of production in terms of FGOR, FGPR, FOPR and FWPR respectively. Production started with OIIP of 141.42 MMBBL and 42.56 MMBBL (30%) was recovered during primary recovery. 98.8 MMBBL (70%) was remaining after this phase of recovery. Gas originally in place (GIIP) was 134.82 BSCF and 46.7BSCF (35%) was recovered during primary recovery phase. 88.07BMSCF (65%) was remaining after this phase. The volume of gas required for gas injection per day is 7,000 MSCF. The volume of gas that is required for gas injection operation for the period of fifteen years is 38.32 BSCF. Therefore, the volume of gas produced during the primary recovery was enough to sustain the injection operation.

![Graph showing field production history](image-url)

**Fig. 5.** FOPR, FGPR and FWPR history during primary recovery
3.2 Simulation Result from (INJ2PROD7)

Figs. 7 and 8 shows the FGPR, FOPR and FWPR of the modelled reservoir. It was predicted that oil production started in 2017 at the rate of 4.380 MMSTB per year and continued with a steady production rate for the next 11 years before it declines to 666.31 MSTB (about 85% declines) at the end of production. A constant gas production rate of 3.84 MMSCF was also observed for the next 10 years before it increases to 16.81 MMSCF in the next 1 year and then declined to 2.15 MMSCF after 3 years of production. The sudden increase in gas production was as a result of reservoir depletion. Water breakthrough occurred after 7 years of production through the period of production.

3.3 Simulation Result from (INJ2PROD5)

Fig. 7 depicts the FGPR, FOPR and FWPR of the modelled reservoir. It was observed that oil production started in 2017 at the rate of 3.65MMSTB per year and continued with a steady production rate for the next 14 years before it declines to 2.72 MMSTB (about 26% decline) at the end of production. A constant gas production rate of 3.22 BSCF was also observed.
for the next 13 years before it increases to 40.63 BSCF within a period of 1 year and then declined to 18.25 BSCF at the end of production. The sudden increase in gas production was as a result of reservoir gas cap expansion which resulted in a corresponding increase in GOR. Water breakthrough occurred after 9 years of production with the rate of 15.19 MMSTB and increases to 29.51 MMSTB at the end of production.

Comparatively, in Fig. 9, the cumulative oil production for both scenarios showed that (INJ2PROD7) was able to recover with in a period of 11 years with a percentage difference of 2% compare to (INJ2PROD5) that took about 14 years of recovery.

3.3 Economic Analysis for (INJ2PROD7) and (INJ2PROD5) Field

Figs. 10 to 12 show the project performances using the three economic indicators which are; the NPV, IRR and the PI. The economic results obtained in terms of NPV at the discounted rate of 30% and injecting gas through existing well will be profitable because of the positive value of NPV.
The economic results obtained in terms of IRR at the discounted rate of 30% shows that 30% discount rate will be profitable because, IRR that will be required to generate NPV of zero is greater than the given discounted rate (30%). The economic results obtained in terms of PI at the discounted rate of 30% show that at 30% discount rate, conversion of existing production well to gas injection will be profitable because PI is greater than 1.

![NPV for “INJ2PROD5” and “INJ2PROD7” discounted rate of 30% and oil price of $40/bbl](image1)

![IRR for “INJ2PROD5” and “INJ2PROD7” @ discounted rate of 30% and oil price of $40/bbl](image2)

![PI for “INJ2PROD5” and “INJ2PROD7” @ discounted rate of 30% and oil price of $40/bbl](image3)
With assumed $40/bbl of crude oil, the projected cost for 15 years was calculated. “INJ2PROD5” had the largest NPV ($161MM) and PI (1.39) at 30% discount rate compared to “INJ2PROD7” with NPV ($53MM) and PI (0.93) respectively. “Scenario a” also has the largest IRR (37.75%). See Table 5.

3.4 The Summary of Field Performances before and after Gas was Reinjected

During primary recovery, about 30% of oil and 35% of gas was recovered before gas was reinjected to enhanced recovery which gave an incremental recovery of about 37%, 39% (oil) and 32%, 52% (gas) for scenarios INJ2PROD5 and INJ2PROD7 respectively. Figs. 13 and 14 show the summary of field performance of both projects before and after injection and the cumulative oil and gas recovery for both scenarios for the predicted period of 15 years.

3.5 Crude Oil Price Sensitivity

The evaluation of crude oil price sensitivity for future market trends was predicted under diverse economic scenarios to get a good feel for expected net revenues. The Fig. 14 shows that at all price levels, both scenarios will stand the test of time except for (INJ2PROD7) which at $43/bbl, IRR is below the discount rate of 30%.

### Table 4. Summary of field performance before and after gas reinjection operation

|                     | “INJ2PROD5” | “INJ2PROD7” |
|---------------------|-------------|-------------|
| Originally in Place (MBBL) | 141.42      | 141.42      |
| Primary Recovery (MBBL)     | 42.56 (30%) | 42.56 (30%) |
| Remaining after Primary Recovery (MBBL) | 98.86      | 98.86      |
| Secondary Recovery (MMBBL) | 52.68 (37%) | 55.12 (39%) |
| Currently in Place (MMBBL)  | 46.18      | 44.19      |
| Originally in Place (MMSCF) | 134.82      | 134.82      |
| Primary Recovery (MMSCF)    | 46.75 (35%) | 46.75 (35%) |
| Remaining after Primary Recovery (MMSCF) | 88.07      | 88.07      |
| Secondary Recovery (MMSCF)  | 43.50 (32%) | 71.06 (52%) |
| Currently in Place (MMSCF)  | 44.56      | 17.01      |

### Table 5. Crude oil price sensitivity analysis @$43/bbl, $45/bbl, $50/bbl, $60/bbl and $70/bbl

| Crude Oil Price ($/bbl) | NPV (INJ2PROD5) | IRR (%) | PI | NPV (INJ2PROD7) | IRR (%) | PI |
|-------------------------|-----------------|---------|----|-----------------|---------|----|
| 43                      | 202             | 33.48   | 1.49| 41              | 29.80   | 1.05|
| 45                      | 232             | 37.00   | 1.56| 75              | 30.02   | 1.10|
| 50                      | 303             | 30.09   | 1.74| 162             | 30.30   | 1.23|
| 60                      | 443             | 30.38   | 2.09| 277             | 30.79   | 1.38|
| 70                      | 587             | 30.79   | 2.43| 478             | 31.22   | 1.66|

4. DISCUSSION

Simulation studies were conducted using data from wells operating in the Niger Delta oilfields. The performance of “INJ2PROD5” and “INJ2PROD7” had been compared. The results obtained from the production forecast showed that “INJ2PROD5” gave higher cumulative oil production. It was observed that oil recovery from “INJ2PROD7” started at the rate of 4.380 MMSTB per year and continued with a steady increase in production rate for the next 11 years before it declines to 2.72 MMSTB (about 85% for the next 14 years before it declined to 2.15 MMSTB after 3 years of production). The sudden increase in gas production was as a result of reservoir depletion. Water breakthrough occurred after 7 years of production through the period of production. It was also observed that for “INJ2PROD5” oil recovery started at the rate of 3.65 MMSTB per year and continued with a steady production rate of 40.63 BSCF within a period of 1 year and then declined to 18.25 BSCF at the end of production (after year of production).
Table 6. Oil revenue generated from both scenarios

| Year | INJ2PROD5 | INJ2PROD7 | INJ2PROD5 | INJ2PROD7 | INJ2PROD5 | INJ2PROD7 | FACTOR | INJ2PROD5 | INJ2PROD7 | NPV | NPV |
|------|-----------|-----------|-----------|-----------|-----------|-----------|--------|-----------|-----------|-----|-----|
| 0    | 3650000   | 4380000   | 4380000   | 5256000   | 17520000  | 21024000  | 0.769231| 410,000,000| 720,000,000|    |    |
| 2    | 3650000   | 4380000   | 4380000   | 5256000   | 17520000  | 21024000  | 0.591716| 134769230.8 | 161723076.9|    |    |
| 3    | 3650000   | 4380000   | 4380000   | 5256000   | 17520000  | 21024000  | 0.455166| 9745106.96 | 124402366.9|    |    |
| 4    | 3650000   | 4380000   | 4380000   | 5256000   | 17520000  | 21024000  | 0.350128| 61342389.97 | 73610867.97|    |    |
| 5    | 3650000   | 4380000   | 4380000   | 5256000   | 17520000  | 21024000  | 0.269329| 47186453.82 | 56623744.59|    |    |
| 6    | 3650000   | 4380000   | 4380000   | 5256000   | 17520000  | 21024000  | 0.207176| 36297272.17 | 43556726.61|    |    |
| 7    | 3650000   | 4380000   | 4380000   | 5256000   | 17520000  | 21024000  | 0.159366| 27920978.59 | 33505174.31|    |    |
| 8    | 3650000   | 4380000   | 4380000   | 5256000   | 17520000  | 21024000  | 0.122589| 2147765.84 | 25773211.01|    |    |
| 9    | 3650000   | 4380000   | 4380000   | 5256000   | 17520000  | 21024000  | 0.0943 | 16521289.11 | 19825546.93|    |    |
| 10   | 3650000   | 4392000   | 4380000   | 5270400   | 17520000  | 21081600  | 0.072538| 12708683.93 | 15292202.69|    |    |
| 11   | 3650000   | 4392000   | 4380000   | 5270400   | 17520000  | 21081600  | 0.055799| 9775910.716 | 11763232.84|    |    |
| 12   | 3660000   | 4392000   | 4392000   | 477236.52 | 17568000  | 19089460.8 | 0.042922| 7540533.871 | 819357.5008|    |    |
| 13   | 3660000   | 4392000   | 4392000   | 477236.52 | 17568000  | 19089460.8 | 0.033017| 5800410.67 | 2309190.081|    |    |
| 14   | 3660000   | 822084    | 4392000   | 986500.8  | 17568000  | 394600032 | 0.025398| 4461854.362 | 1002191.006|    |    |
| 15   | 2718071   | 666316    | 326185.2  | 799579.2  | 130467408 | 31983168  | 0.019537| 2548539.2 | 624843.4113|    |    |

Cash Inflow NPV: 571765323.7
NPV: 161,765,324
Internal Rate of Return IRR: 37.75%
Profitability Index (PI): 1.3945957
The sudden increase in gas production was as a result of reservoir gas cap expansion which resulted in a corresponding increase in GOR. Water breakthrough occurred after 9 years of production with the rate of 15.19 MMSTB and increases to 29.51 MMSTB at the end of production. Comparatively, the cumulative oil production for INJ2PROD5 and INJ2PROD7 scenarios and it was observed that “INJ2PROD7” was able to recover for a period of 11 years with a percentage difference of 2% compared to “INJ2PROD5” that took about 14 years of recovery. To analyze the economic viability of these projects, three economic indicators, Net Present Value (NPV), Internal Rate of Return (IRR) and Profitability Index (PI) were applied to assess the profitability of the projects. For the Net Present Value analysis, it was observed that at assumed $40/bbl of oil at 30% discount rate, “INJ2PROD5” will be profitable because NPV is positive while “INJ2PROD7” is negative because its NPV is at the discounted rate of 30%. For IRR analysis, it was observed that at assumed $40/bbl of oil price at 30% discount rate, “INJ2PROD5” will be profitable because IRR that will be required to generate an NPV of zero is greater than the given discounted rate of (30%) while, “INJ2PROD7” will not be profitable because IRR that will be required to generate an NPV of zero is less than the given discounted rate (30%). For Profitability Index analysis, it was observed that
at assumed oil price at 30% discount rate, “INJ2PROD5” will be profitable because PI is greater than 1 while, “INJ2PROD7” will not be considered because its PI is less than 1 at the discounted rate of 30%.

4.1 Comprehensive of Crude of Price Sensitivity at Various Future Market Trends

In Table 5 the evaluation of crude oil price sensitivity for future market trends was predicted under diverse economic scenarios to get a good feel for expected net revenues. Fig. 14 at all price levels shows that both scenarios will stand the test of time except for “scenario b” at $43/bbl where IRR is below the discount rate of 30%. Oil price sensitivity was conducted at various prices of $20, $30, $40, and $50/bbl, NPV becomes negative as the price of crude oil drop below $26/bbl [6]. This means that below $26 the project will not be economically viable because the cash flow will also be negative.

5. CONCLUSION

5.1 From this Study, the following Conclusion Can be Made

In conclusion, on economic analysis of gas reinjection for EOR has shown that; from the economic analysis:

- Gas reinjection in existing wells gave higher NPV, IRR, PI and low oil production rate.
- Drilling additional injection wells gave low NPV, IRR, PI and high oil production rate but the marginal increase in oil production does not justified the additional investment of drilling additional injection wells.
- Producing from depleted reservoir is less expensive and yields a higher gross profit.
- INJ2PROD5 has the potential of increasing oil production, improving revenue and proved to be economically viable, while INJ2PROD7 is not.
- After subjecting both scenarios under various crude oil price sensitivity, “Scenario a” was less expensive and yielded a higher gross profit and will stand the test of time no matter the drop in the price of crude oil in the future.

5.2 Impotency of the Study

A. Some marginal fields may not be economically viable because the feasibility of this study is based on the OOIP and the RF.

B. The “flare payment” fines is as low as $2.50 per day, for every 1,000 SCF of gas flared or vented which most investors may rather flare than to reinject gas to enhance crude oil production.

The common contrast points of agreement of all the studies on Gas reinjection for EOR could be summarized as follows:

I. Gas reinjection operation was done using both existing wells and drilling additional new wells to compare the economic evaluation of enhanced oil recovery in depleted reservoirs or marginal field [8].

II. From a comparative analysis between an already completed Simultaneous water alternating Gas (SWAG) and a potential WAG scheme, the gas injection pilot results suggested that lean hydrocarbon gas injection with the SWAG injection scheme have little impact on the recovery improvement compared to the base case of water injection scheme [9].

III. Oil price sensitivity was conducted at various prices of $20, $30, $40, and $50/bbl, NPV becomes negative as the price of crude oil drop below $26/bbl. This means that below $26 the project will not be economically viable because the cash flow will also be negative [6].

IV. Gas reinjection application has been proven to be economically viable theoretically; but no field operation has been noted to confirm this assertion.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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