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Optimization of Subsea Processing By Compression in Offshore West Africa

Samuel Olusegun Oladele[1], Chinwuba Victor Ossia[2], Tayo Awolola[3]
[1]*(1Offshore Technology Institute School of Graduate Studies / University of Port Harcourt, Nigeria)*
[2]*(Department of Mechanical Engineering, faculty of Engineering/ University of Port Harcourt, Nigeria)*
[3]*(TechnipFMC, 22 Gerrard Street / Ikoyi, Nigeria)*
Corresponding Author: Chinwuba Victor Ossia

Abstract: Subsea processing technologies such as boosting, separation, water re-injection and compression has been used in other oilfields but alien to West Africa. The technologies can increase oil recovery, extend the field life, and reduce topside equipment requirements. In this study Subsea, compression was adopted to model a typical field in the Niger Delta region whose data was collected and inputted into Flow Manager™ Software that generated values for production and cost analyses. Though, there are many relevant field parameters but this study focuses mainly on the production profile of gas produced using subsea compression as against natural reservoir pressure. From the results, the field could produce 28,371,557Sm^3/hr using natural reservoir pressure for the field life. Introducing 2-compressors at intervals increased the production to 32,050,438 Sm^3/hr, hence extending the production plateau by 7-years with 13% oil recovery increase. Also, the cost analysis showed a \$115.4m profit after subsea compression integration in this West African field.

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I. INTRODUCTION

In exploration and production, the boundaries of opportunity have been continually pushed from onshore to deepwater development. Africa has one of the highest average finding cost in the world. It cost about \$35.01 to produce a barrel of crude oil in Africa compare to other regions [1]. Deep water project is costly, hence the emphasis has been on increased production and increased oil recovery. The offshore industry is keen on field optimization for maximum output and return on investment. This challenge has been addressed using field tested technology for both Green and Brown Fields. The deployment of the technology comes with field proven advantages. However, the investment of major operator to deepwater exploration is a common trend in Nigeria. Hence, it is imperative to consider subsea processing as development option for the Green and Brown Fields.

Processing implies separation of oil, water, gas, sand, pumping and compression. Subsea processing is the treatment of hydrocarbon or fluid on the seabed to explore some advantages with respect to increase oil recovery, CAPEX and OPEX reduction, debottlenecking of the topside facility and reduce project environmental impacts [2]. This process has significant positive impacts on the entire life of a field. It enables the development of a whole field, which are deemed unprofitable, and enhances field total recoverable reserves [3]. Traditionally, these seafloor systems comprised subsea separation, boosting and gas compression equipment as well as the associated enabling components for electrical power transmission, distribution and subsea controls [4]. This study explores the application of subsea compression technology in West Africa waters to enhance field recovery, boost production and investment.

II. MATERIAL AND METHODS

2.1 Field Description

The oil and gas field (Figure 1) is located 200km of Nigeria in Niger Delta with water depth between 1,100m and 1,400m. The recoverable barrel of oil in the reservoir of this field is about 620million barrel of oil with 1Tcf gas planned to be exported [5]. At peak production, the estimated production rate is 200,000bopd. It is envisaged that it will export 320 MMscfd of gas to the Nigerian Liquefied Natural Gas (NLNG) Plant. The fluid in this field is critical (dependent on pressure, temperature and depth) with API number measure up to 53, which makes it very light oil. The wellhead pressure is up to 430 bars, the condensate temperature fluctuate between 114^{o}C and 116^{o}C. Gas to Liquid ratio in this field is 1600 to 7300 scf/bbl [6]. Reservoir in this field needs huge pressure maintenance equipment. The result of modeling of this field indicates that pressure drop can cause a switch to a dysphasic context, which can impede on the recovery of the hydrocarbon in the reservoir. Hence, there is need for water and gas injection, as well as, intelligent and selective completion in the field development. Multiphase flow measurement is a requirement for development of this field. The formation volume factor is 2 to 5 which necessitate one injection well to one production well.

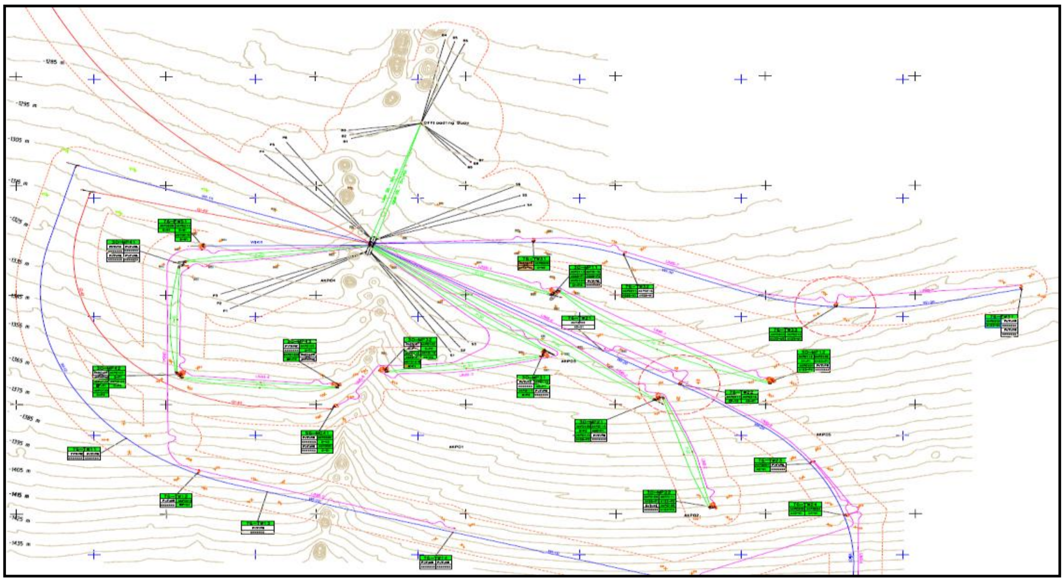

Figure 1: Field Layout of the Case Study

2.2 Field Development

2.2.1 Floating Production Storage and Offloading (FPSO)

Floating, Production, Storage and Offloading (FPSO) unit was used to develop this field. It has 15 topside modules for production and support system; with hull capacity 300 x 61 x 31m. The FPSO hull has 13 off cargo storage used to store the produced condensate after stabilization. It can store about 2 million barrel of oil, the estimated production for 11-days. FPSO has a displacement weight of greater than 4x105 tons, and it is moored with 12 suction anchors, each situated 2km away from the vessel.

The top processing facility comprises of a single train with 4-stages separation system. This topside design has an electrostatic dehydrator to ensure BS & W standard compliance. Stages 1 and 2 separators treat the condensate with hot water from the waste heat recovery units to get the fluid to RVP 10Psi. Water from the reservoir is treated in the vessel to achieve oil-in-water ratio less than 30ppm.

The FPSO separator design is pressure variant, with stages 1, 2, 3 and 4 operating at 80, 24, 8 and 2 bars, respectively. The separator has 4.4m internal diameter with 15.8m length, resulting in huge inventories of gas and condensate on the FPSO.

The dehydration and compression of the associated gas is done through the Glycol (TEG) Contactor. This is to reduce the effect of hydrate formation in the export line and 8" subsea pipeline carrying the injection gas. A buoy located about 1 nautical mile from the vessel is connected by two 16" flexible lines for offloading. The buoy is moored using 9 anchors each about 2km away from the buoy.

2.2.2 Umbilical Flow lines and Risers

Steel Catenary Riser (SCR) was selected because the operator wanted a field proven technology that will attract competitions for its implementation. The SCR fatigue life with respect to the flex (hang-off) joint, which connects to the FPSO, and touchdown point, which connects to the seabed, were specially considered. Fourteen (14) SCR were used in the development. The injection and production flow lines are about 110km. The production and Umbilical (both static and dynamic) are approximately 65km. The gas was tied back to another facility, the 16" gas pipeline that was about 150km.

2.2.3 Subsea Configuration

The wells located 1400m below the water surface are connected with 10 manifolds, 9-production and 1-gas injection. These manifolds are designed with 4-slots. In-line tee was used to supply water injection from the water injection wells. In all, there were 44-wells, comprising 2-gas injection, 20-water injection and 22-production wells. The field has two control modules, located on the seabed and topside. There were 170-connectors on the seabed. The design of the subsea production system was modular making components modules easily retrievable. The subsea system went through rigorous testing to ensure integrity, with in-built redundancy in case of failure.

2.2.4 Hydrate Treatment

i) Challenges

The typical flow assurance problems in the Offshore Niger Delta include:

a) Wax and hydrate issues due to low seabed temperatures being about 4oC.
b) Long riser comes with problem of slugging;
c) Large volume of methanol is required to overcome hydrate formation;
d) Problems of well activation;
e) Challenges of testing one well.

Long no-touch time was adopted and the pipeline was designed to have efficient thermal capability to take care of the hydrate situation.
The problem of slugging was addressed using up-sloping SCR. The intelligent completion of the down hole enabled delay in implementation of activation measures. With effective equipment inside the well bore, sand production is well controlled. The presences of multiphase flowmeters on wells limit well testing operations. In the course of production in this field, hydrate formation is not feasible because of the high fluid temperature.

ii) Procedures

a) Four (4) hours of no touch period
b) Five (5) hours of injecting methanol in wells, jumpers and tress for depressurization of the flow lines and flushing.
c) Four (4) hours of circulating dead condensate for the removal of active crude from production loops
d) One (1) hour of operational margin

These actions will allow the live fluid to stay above the hydrate formation temperature for nine (9) hours upstream of production manifold and fourteen hours from manifold to the FPSO vessel. This inhibition is achieved using wet insulation. In the analysis of the proposed system, it is assumed that the incoming fluid is separated on the seabed with a separator; and that the subsea to shore developmental option will be considered.

2.3 Theory of Model

The appropriate model for the analysis of the field data is Inflow Performance Relationship (IPR), which is useful for understanding reservoir behaviour and quantifying of production rate.

IPR considers the wellbore bottom hole flowing pressure and the production rate of the well. The rate of fluid flow to the wellbore is dependent on driving force, the type of reservoir and the kind of fluid. The pressure difference between the well bore and the reservoir is called drawdown. For a single flow, the graph is linear but when gas is inclusive, that is, gas moving in the formation, at pressure measurement below bubble point, the graph will not be linear.

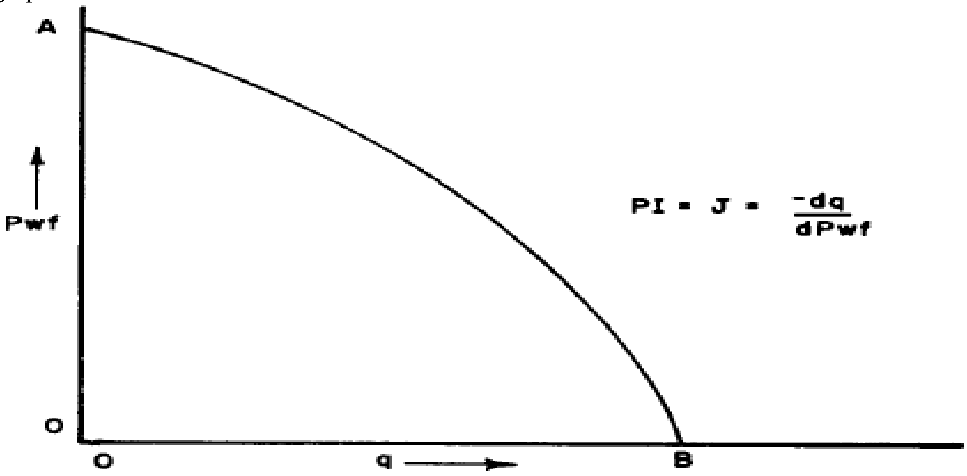

Figure 2: Typical IPR Curve of Bottom Flowing Pressure ( ) Versus Flowrate (q)

$$\dot{q} = \frac{kA}{\mu} \cdot \frac{dp}{dr} \qquad (1)$$

In radial flow equation, the area close to the wellbore will not be above the bubble point even if reservoir average pressure is over the bubble point. This forced gas out of the solution resulting in change in relative permeability of the liquids. When the flow in the wellbore is high, the bottom hole flowing pressure is smaller, hence it causes the IPR curve to bend toward downward direction. When zones of varying relative permeability are opened in a well, the one with the highest relative permeability well contribute more to the production of the well, and then the lower kh zones will contribute, thus the average reservoir pressure of the high kh zones drop faster than the other zones in the well. This causes the zones to start flowing at different flowing bottom hole pressures. At the lower rates or higher flowing pressures of the other zones that start to contribute to the flow. The productivity index of the well improves as more of the zones contribute, so productivity index improves with the lowering of the flowing pressure.

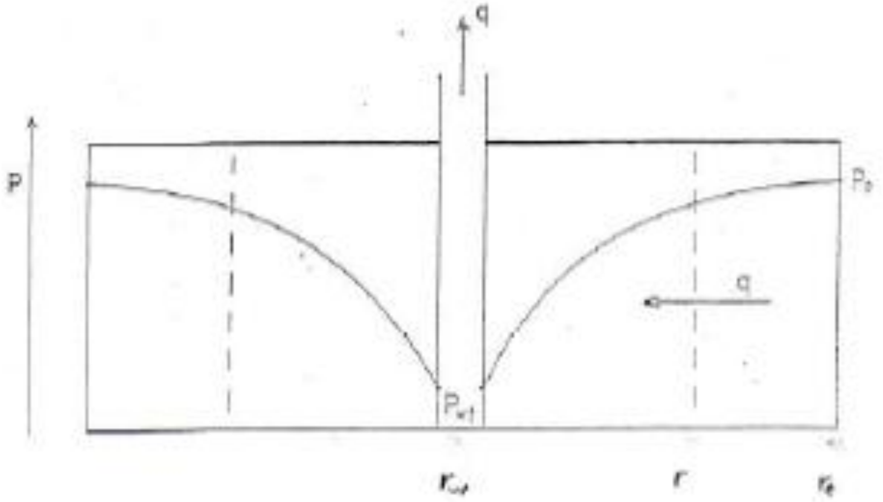

Figure 3: Radial Flow to the Wellbore

From the Figure 3 above, the profile of the change in pressure and the outer boundary pressure Pe is dependent on boundary and initial conditions imposed on the system.
There are different types of IPR correlations in the oil and gas. The correlations can be divided into analytical and empirical. The empirical correlations are Vogel [7], Kilns and Majcher [8], Fetkovich [9], and Wiggins [10]. The known analytical correlations are Del-Castello et al. [11].

2.3.1 Vogel's Correlation Method

In the earlier stage of production, the result of using Vogel correlation aligns with real well inflow performance. However, there is a deviation at the later stage of the life of the reservoir. This is not so good for solution gas drive, which has more free gas at the end of the life of the reservoir than the beginning.
On the assumption given by Weller [12], Vogel [7] developed IPR using program written on the computer with data from 21-wells.

$$\frac{q}{\dot{q}} = 1 - 2\left(\frac{P_{wf}}{\overline{P_R}}\right) - 8\left(\frac{P_{wf}}{\overline{P_R}}\right)^2 \qquad (2)$$

2.3.2 Fetkovich's Approximation Method

The shortcoming of Vogel correlation method [7] is that it is not in concurrence with field data. Hence, Fetkovich [9] suggested a backpressure equation used for saturated oil and gas wells.
According to Fetkovich:

$$q_0 = C\left(P_R^2 - P_{wf}^2\right)^n \qquad (3)$$

For a well with low flow rate, n approaches 1.0 while well with high flow rate, n approaches 0.5. The value of backpressure exponent n and backpressure constant C can be determined graphically. Plotting graph of log-log of $\left(P_R^2 - P_{wf}^2\right)$ and q_0. The slope of the graph is given as $\frac{1}{n}$.

$$J = \frac{0.007082\ khk_{ro}}{\beta_0 \mu_0 \ln\left(\frac{r_e}{r_w}\right) 2P_i} \qquad (4)$$

the equation becomes,

$$q_0 = J'\left(P^2 - P_{wf}^2\right)^n \qquad (5)$$

$$q_0 = J'(P^2)^n \qquad (6)$$

On assumption, the graph of log log q_0 versus ΔP^2 is linear with slope n=1. This assumption was made by Fetkovich [9].

2.3.3 Design Governing Equations

IPR $\quad Q_g = C_R\left(P_R^2 - P_{wf}^2\right)^n \qquad (7)$

TPR $Q_g = C_t\left(\frac{P_R^2}{e^s} - P_{wh}^2\right)^{0.5}$ (8)

PLEM $Q_g = C_{PL}\left(\frac{P_R^2}{PLEM} - P_{SP}^2\right)^{0.5}$ (9)

FLOWLINE $Q_g = C_{FL}(P_{TEMPLATE}^2 - P_{PLEM}^2)^{0.5}$ (10)

The simulation in this study was performed using the FlowManager™ software, an FMC Technologies proprietary software, which is a real-time multiphase metering and flow assurance analyses system for oil and gas production. This package has been in operation since 1995 and is currently operating on 450 wells in over 20 fields globally.

The simulation procedures include:

1) The steady state natural flow condition was established.
2) Identification of compression timing and localization.
3) Implementation of single compressor to achieve the target rate (plateau production)
4) Continue plateau production with single compressor until the suction pressure is so low that it cannot guarantee target production any longer.
5) Continue with decline production with single compressor for the rest of the years.
6) Repeat steps 3, 4 and 5 with two compressors in parallel.
7) Repeat steps 3, 4 and 5 with three compressors in parallel.
8) Repeat steps 3, 4, and 5 with four compressors in parallel.

III. RESULT

3.1 Assumptions

The analysis of available data requires some assumptions. The assumptions made in this study include:

a) All the gas wells are identical in nature;
b) There are equal numbers of well in each template;
c) All the wells have the same distance to the template from the entrance module;
d) The reservoir is a single unit with single pressure regime;
e) No pressure support in the reservoir.

3.2 Natural Flow Production Profile (without Compression)

The conditions for the natural flow production profile without compression include the following parameters.

Pipeline ID	22inches
Pipeline Roughness	1.50×10^{-5}
U Value:	$40W/m^2K$
Onshore Pressure Rating	35bar
Design LNG capacity	$1,168,125m^3/hr$
Field design life	25 years
Initial gas in place	$315x109Sm^3$

This case tests the production rate of the reservoir using her natural energy for production. The production target per hour was set at $1,168,125m^3/hr$ which is the design capacity of the separator with minimum 35bar pipeline rating. With input data defined, the result indicates constant production rate for 15-years at 130 bar wellhead pressure and 180bar reservoir pressure. The plateau declination started after 16th year of production. The initial gas in place of this field is $315x109Sm^3$. At the end of the 25-years of operating this field, the recovered volume of the reservoir was approximately $248x109Sm^3$ of gas, which represent 79% recovery of the reservoir.

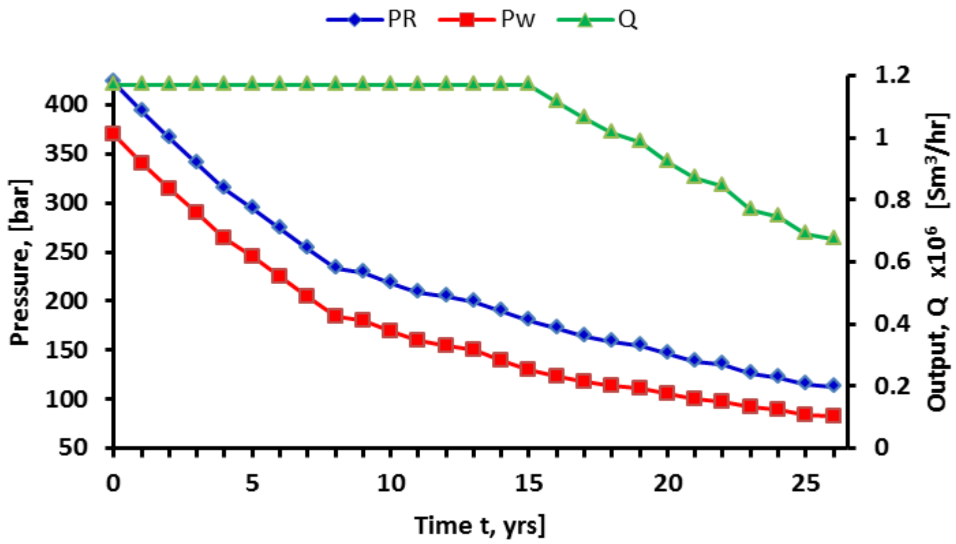

Figure 4: Production profile Q, Reservoir Pressure PR, and Wellhead Pressure Pw for Natural flow field design
This Figure 4 indicates the behaviour of the reservoir pressure and wellhead pressure for the design life period. Naturally, the pressure of the reservoir decrease as the life of the field winds down. The result indicates that plateau production was attained at 180bar reservoir pressure and 130bar wellhead pressure.

3.3 Production Profile with Compression

3.3.1 Production with 1-Compressor

Figure 5 shows the result obtained after the design was configured to use 1-compressor during production. At 146 bar reservoir pressure and 106 bar wellhead pressure, the system produced 1,168,125m^3/hr, at this rate, the plateau was attained in 20th year of production. This is five years gain in production. The system was able to maintain fixed production for 20-years after which decline sets in at 1,129,280m^3/hr which is the 21st year of the life of the field. The end of life production in this field is 886.2m^3/hr.

The cumulative production after 25 years of operation using 1-compressor was approximately 314x109m^3/hr. This is 10.8% increase in gas recovery from the field relatively to using the natural reservoir pressure flow scenario. The result indicates that, using one compressor in this field, the recovery factor is about 87.2%.

3.3.2 Production with 2-Compressors

Figure 5 shows the result obtained after the design was configured to use 2-compressors during production. At 135 bar reservoir pressure and 98 bar wellhead pressure, the system produced 1,168,125m^3/hr, at this rate, the plateau was attained in 22nd year of production. This represents 7-years gain in production. The system was able to maintain fixed production for 22-years after which decline set in at 1,144,146m^3/hr which is the 23rd year of the field life. The end of life production in this field is 976.858m^3/hr.

The cumulative production after 25-years of operating the field using two compressors amount to approximately 320x109 m^3/hr. This is 13% increase in gas recovery from the field relatively to using the natural reservoir pressure for production. The assumptions in this analysis remain the same for the previous consideration. The result indicates that, using 2-compressors in this field, the recovery factor is about 89%.

3.3.3 Production with 3-Compressors

With the use of 3-Compressors during production, at 125.5 bar reservoir pressure and 91.57 bar wellhead pressure, the system produced 1,168,125 m^3/hr, at this rate, the plateau was attained in 23rd year of production. This represents 8-years gain in production. The system was able to maintain fixed production for 22 years before decline set in at 1,144,146 m^3/hr, which is the 23rd year of the field life. The end of life production in this field is 1,028,772 m^3/hr.

The cumulative production after 25-years of operating the field using three compressors amount to approximately 323x109 m^3/hr. This is 13.8% increase in gas recovery from the field relatively to using the natural reservoir pressure for production. The assumptions in this analysis remain the same for the previous consideration. The result indicates that, using one compressor in this field, the recovery factor is about 89.7%.

3.3.4 Production with 4-Compressors

Figure 5 shows the result obtained after the design was configured to use 4-compressors during production. At 125.5 bar reservoir pressure and 91.57 bar wellhead pressure, the system produced 1,168,125m^3/hr, at this rate, the plateau was attained in 23rd year of production. This represents 8-years gain in production. The system was able to maintain fixed production for 23-years after which decline set in at 1,156,1392m^3/hr, which is the 23rd year of the life of the field. The end of life production in this field is 1,058,278m^3/hr.

The cumulative production after 25-years of operating the field using 4-compressors amount to approximately 324x10^9 m^3/hr. This is 14.3% increase in gas recovery from the field relatively to using the natural reservoir pressure for production. The result indicates that, using 1-compressor in this field, the recovery factor is about 90%. There was no significant gain after using the 3rd and 4th compressors.

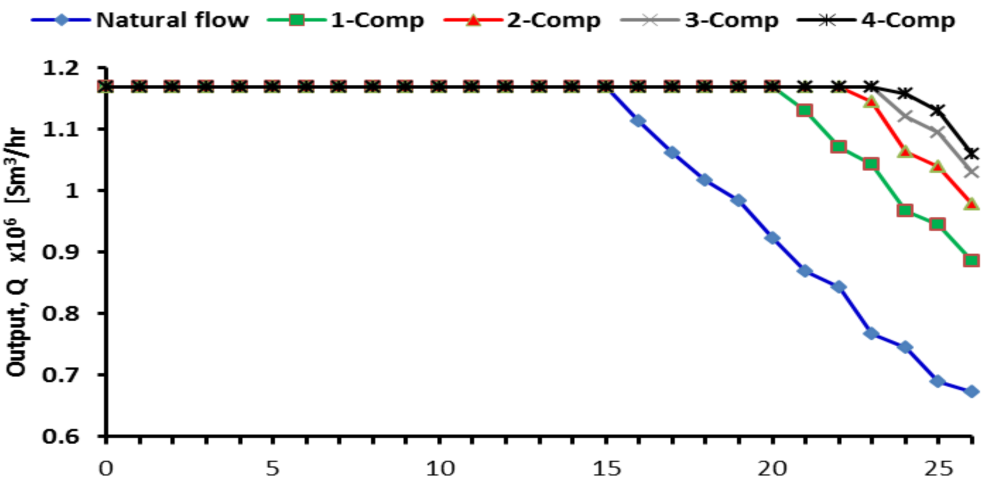

Figure 5: Production Profile for different compressor applications

3.3.5 Summary of different Subsea compression scenarios – Gas Recovery

Figure 6 shows the quantity of gas recovered from the reservoir at the end of 25-years of operating the field, using different compressor configuration. Significant improvement was recorded using one and two compressors. The 3rd and 4th compressors show gain in volume of recovered gas, however, plateau performance of these applications is not appreciable because this could impact the CAPEX and make the field uneconomical.

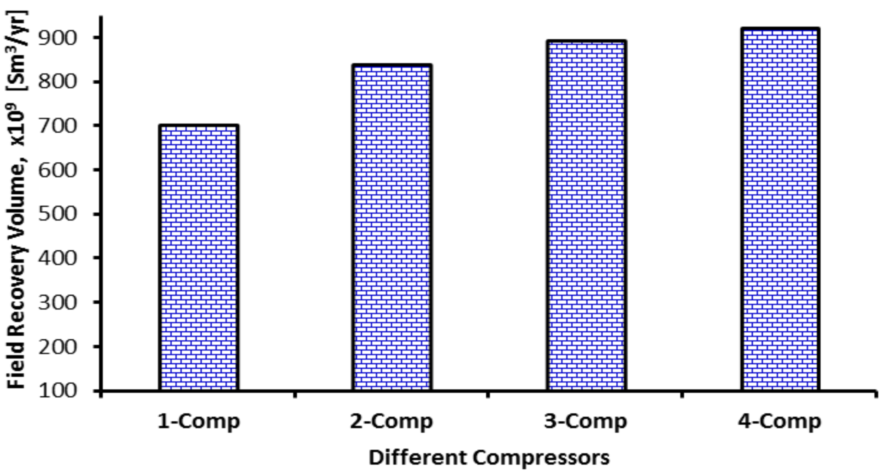

Figure 6: Recovered volume for the 25 years field design life

This corresponds to a field recovery volume of 3.071x106, 3.679x106, 3.918x106 and 4.045x106 Sm^3/hr for 1-Compressor, 2-Compressors, 3-Compressors and 4-Compressors, respectively.

3.5 Economic Analysis

Cost analysis represents an outline, which details the gain and risk associated with projects. It is a technique which comprises different methods to evaluate choices and select the best cost as low as reasonable possible without compromising the project integrity. Cost analysis considers every component of the system to determine how it may impact the project now and in the future. This analysis allows business analysts to make informed decision for capital investment.

There is a variety of cost analyses approach, the suitability of any approach depends upon the purpose of assessment and data availability. It is rarely possible to identify and quantify all costs and outcomes, and the units used may differ.

Subsea gas compression project involves thousands of infrastructure and process. In executing a project of this nature, activities such as feasibility study, concept analysis, front end engineering design (FEED), detail project planning, construction, testing and start-up are an integral of the cost consideration. However, the cost analyses in this project will focus on cost comparison of natural production and scenarios base of compressors. It is exclusive of Pipeline estimate, human resources estimate, onshore facility, Subsea templates, Umbilical, Scrubber, Pumps, Cost of installation, and Power.

3.6 Production volume cost analysis for 25-years life of the field

Based on the hourly production output and field design life of 25-years, the total natural flow production output was approximately 248x109 Sm^3 compared to the 4-compressors output of approximately 283x109 Sm^3. Due to risk and economic considerations, the output will be limited in compression application to 2-compressors with total output of approximately 280 x109 Sm^3. Since 1000ft^3 of gas will cost $3.58, the production for the field per 25years was estimated as in Figure 4.

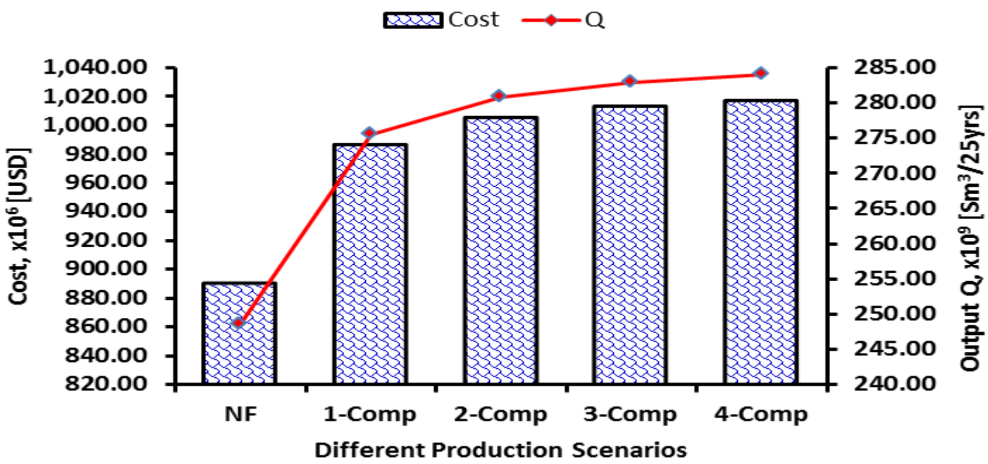

Figure 7: Field production output and cost for different scenarios per 25years

For 25 years predicted production, with natural reservoir energy, the system will generate $889.8m. However, using 2-compressors, $115.4m is additional revenue generated. This is 13% increase in revenue for the system. The cost of 2-compressors application is approximately $20m.

IV. CONCLUSION

The analyses results obtained show that subsea compression is a viable venture in Offshore West Africa. With subsea compression in this case study, the field life was extended by 7-years with additional cost of $115.4m. From the results obtained, it suffices to state that a case for subsea compression technology feasibility in West Africa Region has been established.

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Abbreviations

CAPEX	Capital Expenditure
OPEX	Operationg Expenditure
Tcf	Trillion cubic feet
Mnboe	Million barrels of oil equivalent
NLNG	Nigerian Liquefied Natural Gas
API	American Petroleum Institute
BS & W	Basic Sediment & Water
RVP	Reid Vapour Pressure
TEG	Triethylene glycol
IPR	Inflow Performance Relationship
P_{wf}	Bottom Flowing Pressure
Q	Flowrate
P_e	Outer Boundary Pressure
P_R	Reservoir Pressure
P_W	Wellhead Pressure
q_o	Oil production rate
q_g	Gas production rate
J	Production index
C	Backpressure constant
n	Backpressure exponent
k	Rock permeability
μ_o	Fluid viscosity
B_o	Formation volume factor
r_w	Wellbore radius
r_e	Radius of drainage
s	Skin factor

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