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Research

Well Test Analysis, Inflow Performance Evaluation, and Reservoir Deliverability Assessment of Abura-6 Well, Niger Delta Basin, Nigeria.

Akenbor, B. O.

Department of Geology, Federal University, Otuoke, Nigeria

Correspondence should be addressed to: akenborbo@fuotuoke.edu.ng

Abstract: This study presents an integrated well test and reservoir performance evaluation of the Abura-6 well located in the Niger Delta Basin, Nigeria. Multi-rate production tests were conducted across four reservoir intervals (6A86, 5A86, 3A86, and 1A86) to evaluate productivity, fluid properties, and reservoir deliverability characteristics. Productivity index (PI) and inflow performance relationship (IPR) analyses were performed to quantify reservoir efficiency and production potential. The 6A86 interval exhibited superior performance with a maximum oil rate of 2,608 BPD and a calculated productivity index of 1.14 BPD/psi. Lower intervals demonstrated increasing water cut and heavier crude characteristics, particularly within 3A86 and 1A86 sands. Results indicate significant vertical heterogeneity, varying permeability regimes, and differing aquifer influences across the tested intervals. The findings provide a technical framework for choke optimization, completion strategy, and field development planning in the Abura Field and comparable Niger Delta reservoirs.

Keywords: Well Testing, Productivity Index, Inflow Performance Relationship, Reservoir Deliverability, Niger Delta Basin.

1. Introduction

Reservoir performance evaluation through well testing remains one of the most reliable methods for quantifying productivity, permeability behavior, and reservoir drive mechanisms (Ahmed, 2019). In multi-layered deltaic reservoirs such as those of the Niger Delta Basin, vertical heterogeneity significantly influences production response and development strategy (Doust & Omatsola, 1990).

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The Abura Field, located within the onshore Niger Delta petroleum province, comprises stacked sandstone reservoirs deposited within paralic sequences of the Agbada Formation. The Abura-6 well penetrated multiple hydrocarbon-bearing sands, which were individually tested under controlled choke conditions to determine deliverability and production characteristics.

This study integrates:

- Multi-rate production test data
- Productivity index (PI) calculations
- Inflow performance relationship (IPR) modeling
- Reservoir heterogeneity evaluation
- Engineering and development implications

2. Geological Setting

The Niger Delta Basin is a prolific Tertiary delta system composed of three primary lithostratigraphic units: the Akata Formation (marine shale), Agbada Formation (paralic sand-shale sequences), and Benin Formation (continental sands) (Short & Stauble, 1967).

Hydrocarbon reservoirs in the Abura Field occur within the Agbada Formation and consist of stacked, channelized sandstone bodies characterized by variable permeability and porosity. Vertical facies changes and structural compartmentalization strongly influence production performance.

3. Materials and Methods

3.1 Well Test Procedure

Multi-rate production testing was performed using choke sizes ranging from 16/64 in. to 32/64 in. Stabilized production parameters recorded included:

- Gross oil rate (BPD)
- Tubing head pressure (THP)
- Flow line pressure (FLP)
- Gas–oil ratio (GOR)
- Basic sediment and water (BSW)
- Oil gravity (°API)

3.2 Productivity Index Calculation

The Productivity Index (PI) was computed using:

PI=qPr−PwfPI = \frac{q}{P_r - P_{wf}}PI=Pr−Pwfq

Where:

q = oil rate (BPD)

Pr = reservoir pressure (assumed 3,000 psi for analytical modeling)

Pwf ≈ tubing head pressure

3.3 Inflow Performance Relationship (IPR)

For undersaturated conditions, a linear IPR approximation was used:

q=PI(Pr−Pwf)q = PI (P_r - P_{wf})q=PI(Pr−Pwf)

The shape of the IPR curve provides insight into reservoir drive mechanism and multiphase flow effects.

4. Results

4.1 Well Test Summary

Reservoir Interval (ft)	Choke Size (1/64 in.)	Gross Oil Rate (BPD)	THP (psi)	FLP (psi)	BSW (%)	GOR (SCF/STB)	Oil Gravity (°API)	Gas Rate (MSCFD)
6A86 (9298–9304)	20	955	785	190	Traces	304	31.6	–
	24	1,423	800	195	0	238	31.6	–
	32	2,608	710	195	0	261	31.6	–
5A86 (9150–9156)	20	886	623	190	4	214	28.2	–
	24	1,029	575	190	15	230	28.2	–
	28	1,275	540	195	23	240	28.2	–
3A86 (8709–8713)	20	211	125	85	0	166	19.6	35
	24	604	108	88	0	44	19.6	27
	32	1,015	85	80	70	28	19.6	29
1A86 (8248–8254)	16	95	170	60	0	221	16.0	21
	20	424	165	75	3	77.8	16.0	33
	28	780	130	115	3	54.8	16.0	40

Note. THP = Tubing Head Pressure; FLP = Flow Line Pressure; BSW = Basic Sediment and Water; GOR = Gas–Oil Ratio; STB = Stock Tank Barrel; MSCFD = Thousand Standard Cubic Feet per Day.

Discussion

The 6A86 interval demonstrated superior productivity, achieving a peak oil rate of 2,608 BPD at a 32/64 in. choke. The consistent oil gravity of 31.6°API and negligible water cut indicate favorable reservoir quality and strong drive support.

In contrast, the 5A86 interval showed progressive increases in BSW with increasing choke size, suggesting proximity to a water contact or heterogeneity within the sand body. The 3A86 reservoir exhibited significant water production (70%) at higher choke sizes, indicating coning tendencies or partial water breakthrough.

The shallowest interval, 1A86, produced heavier oil (16°API) with moderate gas rates, reflecting different depositional or diagenetic conditions.

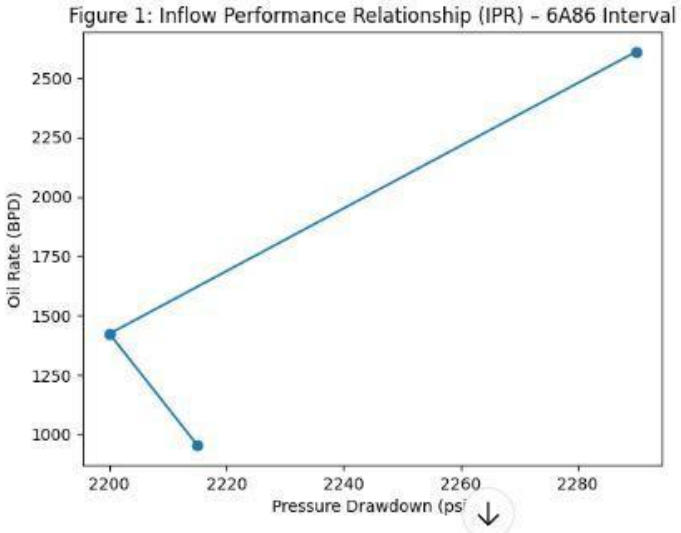
Overall, the results highlight vertical reservoir heterogeneity and underscore the importance of selective completion and choke optimization strategies.

5. Productivity Index and IPR Analysis

5.1 Productivity Index Results (6A86)

Choke	Rate (BPD)	THP (psi)	Drawdown (psi)	PI (BPD/psi)
20	955	785	2215	0.43
24	1423	800	2200	0.65
32	2608	710	2290	1.14

Figure 1: Inflow Performance Relationship (IPR) - 6A86 Interval



The increasing PI suggests improved inflow efficiency at higher drawdown.

Figure 2: Oil Rate vs Choke Size – 6A86 Interval

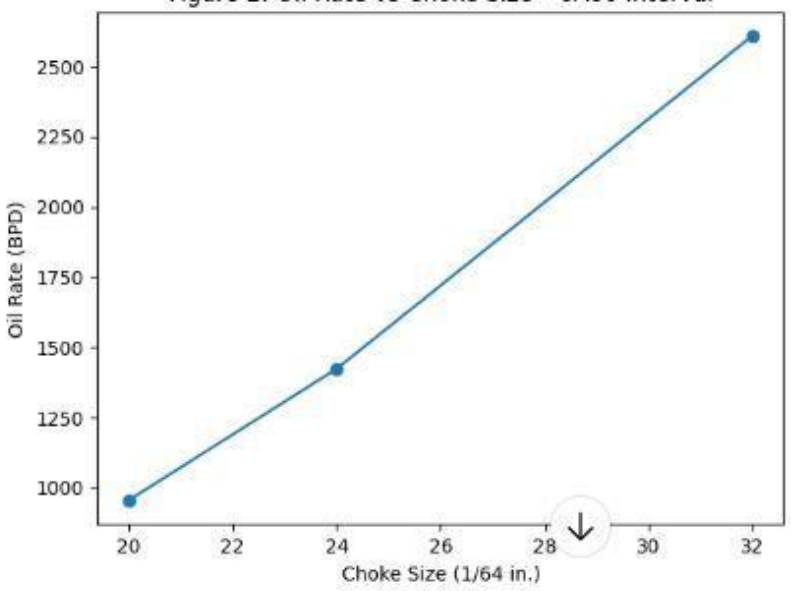
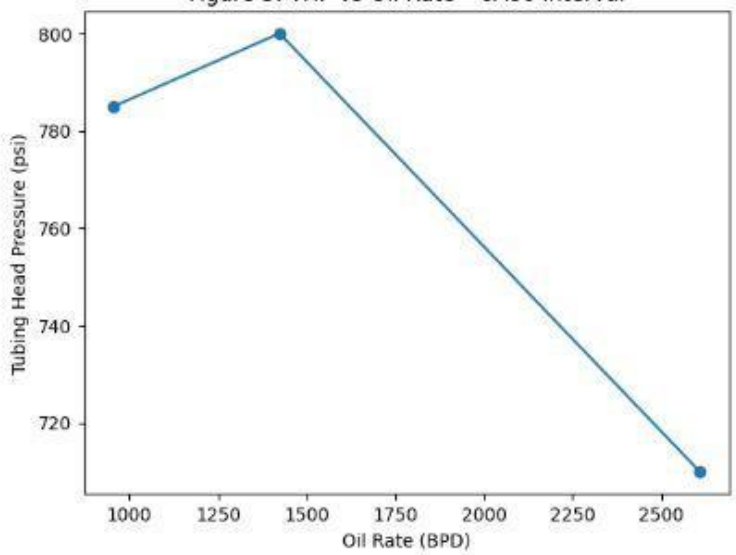


Figure 3: THP vs Oil Rate – 6A86 Interval



5.2 Interpretation

- Near-linear IPR response indicates likely undersaturated conditions.
- High PI value (1.14 BPD/psi) reflects favorable permeability.
- Minimal water cut confirms structural positioning above oil-water contact.

IPR and Productivity Index Results – Abura-6 (6A86 Interval)

Assumption: Reservoir pressure (Pr) = **3000 psi**

Approximation: Flowing bottom-hole pressure (Pwf) ≈ THP (field approximation for demonstration).

Productivity Index (PI)

Choke (1/64 in.)	**Oil Rate (BPD)**	**THP (psi)**	**PI (BPD/psi)**
20	955	785	0.431
24	1423	800	0.647
32	2608	710	1.139

Interpretation:

- PI increases significantly at larger choke size.
- Maximum PI = **1.14 BPD/psi** at 32/64 in.
- This suggests improved inflow efficiency at higher drawdown.
- The response is approximately linear, indicating likely undersaturated or weak solution-gas drive behavior within test limits.

IPR Curve

The generated IPR plot (Rate vs Pressure Drawdown) shows:

- Increasing oil rate with increasing pressure drawdown.
- No strong curvature typical of Vogel-type saturated reservoirs.
- Deliverability is strong in 6A86 compared to lower intervals.

6. Comparative Reservoir Performance

6.1 6A86 Reservoir

- Highest productivity
- Light crude (31.6°API)
- Negligible water
- Strong commercial target

6.2 5A86 Reservoir

- Moderate productivity
- Increasing water cut
- Possible coning behavior

6.3 3A86 Reservoir

- Significant water breakthrough
- Reduced oil mobility
- Aquifer-supported system likely

6.4 1A86 Reservoir

- Heavy oil (16°API)
- Lower PI
- Higher viscosity effects

7. Reservoir Heterogeneity

Vertical heterogeneity is evident through:

- Variation in oil gravity (16°–31.6°API)
- Differing GOR trends
- Contrasting water production behavior

These variations reflect depositional facies shifts and compartmentalization typical of deltaic reservoirs.

8. Engineering Implications

8.1 Choke Optimization

Optimal choke range for 6A86: 24–32/64 in.

Avoid excessive drawdown in 5A86 and 3A86 to limit water coning.

8.2 Completion Strategy

- Selective completion recommended.
- Downhole flow control devices may mitigate water breakthrough.
- Zonal isolation advised for lower-quality sands.

8.3 Development Planning

6A86 should serve as primary development target.

Secondary reservoirs require careful water management planning.

9. Economic Implications

Higher productivity intervals significantly reduce lifting cost per barrel. The superior PI of 6A86 implies:

- Faster payout period
- Higher net present value (NPV)
- Improved field economics

Water-prone intervals may increase operating expenditure (OPEX) due to separation and disposal requirements.

10. Limitations

- Reservoir pressure assumed at 3,000 psi
- Pwf approximated from THP
- No buildup test data included

- No detailed permeability or skin calculations available

Future work should incorporate pressure transient analysis for more accurate reservoir characterization.

11. Conclusion

Integrated well test and IPR analysis confirm that the 6A86 interval exhibits the highest production potential in Abura-6. The maximum productivity index of 1.14 BPD/psi indicates strong permeability and reservoir connectivity. Other intervals display increasing water cut and heavier crude characteristics, reflecting vertical heterogeneity.

The study provides a quantitative basis for optimized choke management, selective completion, and field development planning in the Abura Field.

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