WELL PRODUCTIVITY IMPROVEMENT THROUGH EXTENDED REACH HORIZONTAL WELLS

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Introduction

The Banzala Field was discovered in August, 1983 by Well 46-1X, a follow-up to Well 45-2X, which blew out while drilling a shallow gas sand. The field is located 23 miles northwest of Cabinda Town in 150 ft of water.

Although the field was discovered in 1983, appraisal and development of the reservoir was slowed while a solution to the problem of the overlying shallow gas sand (Landana formation) was evaluated. The Landana was originally normally pressured but has been supercharged with gas as a result of the well blowout. Two appraisal wells were successfully drilled in a two year period following the blowout but shallow gas well control problems were encountered on the highest structural location. Well productivity was low under natural flow but productivity indices indicated the likelihood of commercial rates if artificial lift could be utilized.

The hydrocarbon accumulation in the Banzala Field occurs in three primary reservoirs (Mesa, Lago, and Azul) between 1,600 ft and 2,000 ft TVDSS. It is estimated that these sands contain approximately 2.5 billion barrels of oil in place. The productive oil bearing reservoirs are overlain by the Frio (1,000 ft TVDSS) and Landana (425-600 ft TVDSS) gas sands.

Determination of a method to successfully penetrate the shallow gas, the progress of shallow extended reach horizontal drilling techniques, and the advent of coiled tubing deployed electrical submersible pumps have allowed field development to proceed. Four appraisal wells were drilled in 1997. Well 46-02 was cored on the crest of the structure in the first quarter of 1997 and drillstem tested the Mesa and Lago reservoirs. Well 45-08 was drilled in June, 1997 on the west flank of the Banzala structure down dip of the Mesa oil accumulation. The well tested both the Lago and Azul formations. Well 34-02 was drilled on the northeast flank in September, 1997. Well 46-04 was drilled on the south plunge of the structure in December, 1997.

Initial Development Optimization

A multidisciplinary and multicompany approach was determined to be the most effective method to evaluate Banzala development. The first objective was to evaluate the uncertainties in the Azul, Lago, and Mesa reservoirs. This included the uncertainty in classical parameters such as porosity, permeability, and oil saturation along with uncertainties in aquifer size, vertical permeability, and net to gross ratios.

Separate fine-grid geostatistical based simulation models were constructed for three oil reservoirs (Azul, Lago and Mesa) using data acquired from the six Banzala wells with core. The Chevron program SCP® was used to scale up the fine grid models and determine the coarse grid geometry and rock properties that preserved the flow characteristics of the fine grid model.

The oil and gas properties were based on the three valid surface samples obtained from the 1997 appraisal program. All three samples (Mesa, Middle Lago, and Upper Lago) were from the 46-2 flowing drill stem tests. There was uncertainty in the saturation pressure due to errors in measuring the gas production rate.

The second objective was to identify the critical decisions in field development. The variation in reservoir performance due to potential decisions such as well spacing, completion techniques, artificial lift, and pressure maintenance was evaluated. The simulation showed that there was manageable uncertainty in the Mesa Reservoir performance. However, there was much greater uncertainty in both the Lago and Azul reservoirs.

Finally, the simulation model was used to predict overall production performance for the Banzala development and the resulting economics. The Mesa development had a high probability of economic viability with a relatively low degree of uncertainty in ultimate recovery. There was much greater upside potential and downside risk associated with Lago development due to greater uncertainty in well performance. The Azul reservoir development had marginal economics.

Original Development Plan

Due to the varying levels of confidence surrounding the productivity of the three Banzala reservoirs, the Cabinda Association approved a phased development of the Banzala Field during 1997. The Banzala Phase 1 Development focused primarily on the Mesa Reservoir and consisted of five Mesa producers, two Lago producers, and one Azul producer. The Phase 2 Pilot Project was designed to evaluate the Lago Reservoir with all five wells targeted as Lago producers. The full Phase 2 Development will be initiated once the appropriate engineering analysis of the Phase 1 and Phase 2 Pilot Lago performance is completed.

Phase 1 Development

With consideration given to operational and cost efficiencies, it was decided to implement the various development phases utilizing batch drilling and completion techniques. In batch mode, the wells are drilled and suspended in groups, then completed in groups to achieve economies of scale and lower costs. Phase 1 was broken down into two such groups in order to allow for slightly earlier production data. Three wells were initially drilled using the high angle holes with 500 – 800 feet of open hole as recommended by the original simulation study. The BZ-A3 well was drilled to the Mesa, the BZ-A5 well was drilled to the Lago, and the BZ-A7 well was drilled to the Azul. Drilling operations were then suspended, and the three wells were completed utilizing 2 7/8 inch coiled tubing deployed electric submersible pumps.

Results of the first three wells were as follows :

Table 1 - Well Results with Initial Well Designs

Well	Formation	Open Hole Section	Expected Oil Rate (BOPD)	Actual Oil Rate (BOPD)
BZ-A3	Mesa	515’	4000	2000
BZ-A5	Lago	784’	2000	500
BZ-A7	Azul	889’	750	250

This less than expected productivity from the first three wells necessitated the re-evaluation of the remaining five Phase 1 wells. Optimization by simulation was again revisited to make improvements.

Re-evaluation of the Well Designs

The simulation model was updated to reflect the actual well paths and operating constraints. The actual completion lengths were shortened and the minimum allowable pump intake pressure was raised from approximately 150 psia to 420 psia at the pump set depth. The productivity index multiplier was reduced to 1.0 to reflect no production enhancement due to the high angle well. These changes resulted in a reasonable match of the early production history.

Sinusoidal well paths were evaluated using the updated model. The sinusoidal well path was evaluated by modelling the wellbore as a series of horizontal and vertical segments depending on the predominant orientation of the segment through the grid cell. The model demonstrated that significant improvements in productivity could be realized by drilling the well with multiple intersections of the stratigraphic section.

As a result, it was recommended to drill the five Phase 2 Pilot wells with sinusoidal, open hole completions. Three of the wells were drilled with a single sinusoidal section that cut the stratigraphic interval four times. The other two wells were drilled with two open hole sinusoidal sections (multi-sinusoidal laterals). The actual well performance has been slightly better than predicted by the simulator. As a result, the initial high angle completions are being re-drilled.

Table 2 - Mesa Well Results with the Revised Well Designs

Well	Formation	Originally Planned Open Hole Section	Modified Open Hole Section	Actual oil Rate (BOPD)	PI BPD/PSI
BZ-A3	Mesa	515'	No Change	2000	3.6
BZ-A1	Mesa	611'	2659'	4380	18.6
BZ-A2 North	Mesa	749'	3663'	4230	15.4
BZ-A2 South	Mesa		3687'		
BZ-A4 East	Mesa	674'	3209'	4120	16.2
BZ-A4 West	Mesa		1784		
BZ-A6	Mesa	629'	3599'	4060	12.5

Phase 1 Well Productivity Index Comparisons

A comparison of the redesigned Mesa wells against the original high angle Mesa well (BZ-A3) shows a tremendous increase in well productivity indices (PIs). **Table 2** above shows that the redesigned Mesa wells resulted in PIs ranging from 3.5 to 5.2 times greater than the PI in the original BZ-A3 well. This indicates that the redesigned wellbores resulted in dramatic improvements in well productivity as the simulation modelling had predicted.

Banzala Phase 2 Pilot

The Banzala Phase 2 Pilot Project consisted of a five well program targeted for completion in the Lago Reservoir. The purpose of this pilot project was to gather additional reservoir and production data to help with the front-end engineering and design of the full Phase 2 Project. Based on the significant productivity improvements seen in the second stage of Phase 1, it was decided that the design of the Phase 2 Pilot wells should also be re-evaluated. Reservoir simulation optimization runs were used in the redesign of the Phase 2 Pilot wells. As in the second stage of Phase 1, these wells were designed to incorporate a combination of extended reach, sinusoidal, horizontal well paths (singles and multi-laterals) as opposed to the originally proposed high angle paths. As in the second stage of Phase 1, the results of the Phase 2 Pilot wells showed dramatic improvements over the initial Lago completion (BZ-A5). **Table 3** shows a summary of the Phase 2 Pilot results.

Table 3 - Lago Well Results with the Revised Well Designs

Well	Formation	Originally Planned Open Hole Section	Modified Open Hole Section	Actual Oil Rate (BOPD)	PI BPD/PSI
BZ-A5	Lago	784'	No Change	500	2.8
BZ-A8	Lago	678'	3063'	1800	4.6
BZ-A9	Lago	N/A	4224'	1910	11.5
BZ-A10	Lago	N/A	4057'	1870	10.6
BZ-A12 East	Lago	N/A	3956'	1630	7.9
BZ-A12 West	Lago		3705'		

Phase 2 Pilot Well Productivity Index Comparisons

A comparison of the redesigned Lago wells versus the original Phase 1 Lago well (BZ-A5) also shows a great increase in well PIs. **Table 3** above shows that the redesigned Lago wells resulted in PIs ranging from 1.7 to 4.1 times greater than the PI in the original BZ-A5 well. This again indicates that the combination of extended reach, sinusoidal, horizontal wellbores (singles and multi-laterals) resulted in a drastic improvement in well productivity as the simulation modelling had predicted.

Drilling Designs

Low solids mineral oil based mud was used at 8.2 ppg to drill the 8 1/2" and 6" hole sections in order to prevent formation damage in the highly water sensitive Banzala reservoirs. The lubricating effects of the mud also reduced torque and drag which increased the ability for the bottom hole assembly to slide which was critical in controlling the well paths at extended distances. The mud also provided very good hole cleaning through the high angle and lateral sections. Torque and drag models were used in the lateral sections to assist in determining when wiper trips were needed to clean the wellbore and decrease the chance of sticking pipe.

An Annulus Pressure While Drilling sub was used in the bottomhole assembly to confirm downhole circulating pressures which were placed on the formation while drilling the lateral sections. Information was used to calibrate Virtual Hydraulics programs for other well conditions using the mineral oil based mud. Data confirmed that the equivalent circulating densities were not as high as originally predicted.

Logging While Drilling (LWD) tools were utilized while drilling the first 8 1/2" hole section to log the Azul, Lago, and Mesa formations. LWD tools were also used in all 6" lateral hole sections to obtain open hole logs on the lateral sections while drilling.

To achieve the sinusoidal wellpaths in the lateral sections, hole angles ranged from 72° to 118°.

Polycrystalline diamond bits were used with the best run exhibiting a total of over 22,000' with 485 rotating hours at an average rate of penetration of 45 feet per hour.

Drilling operations in all wells were conducted essentially trouble-free.

Selection of the Artificial Lift Method

The low gas-oil ratios exhibited in the Mesa and Lago reservoirs necessitated the installation of artificial lift early in the producing life of the field. Most wells in adjacent fields are gas lifted. However, lift gas was not available at Banzala due to facilities constraints. Discussions with service companies indicated that electrical submersible pump run lives could range from 1 – 2 years in this environment. Well pulling for jointed tubing and electrical submersible pumps would thus require a jack-up rig which would be costly, and production downtime associated with rig scheduling would be likely. To avoid a jack-up requirement, coiled tubing deployed electrical submersible pumps were selected. A coiled tubing unit can accomplish well pulling in this scenario. Eight submersible pumps have been operating for approximately 9 months with only one failure which was due to an incorrect, oversized design. Two of the original eight have been pulled for sidetracks, and the pumps showed only normal wear.

Production Impact

The lengthened and sinusoidal well paths have turned a marginal development project into a very profitable one. Field production with the original well designs would have been less than 10 MBOPD but the improved designs have resulted in field production that is approaching, and expected to exceed, 30 MBOPD. The project is regarded as a triumph of Reservoir Management and Drilling technology over geologic adversity.

Forward Plan

Current plans include the following:

- Further evaluation of well productivities for the different well types (sinusoidal singles and sinusoidal multi-laterals) and investigation of a means to determine the proportion of laterals contributing to the production from the individual wellbores. Currently, the electrical submersible pumps prevent running of production logging tools .

- Additional tests of extended-reach drilling capabilities in the shallow Banzala reservoirs by attempting a well with an additional 4,000’ reach.

- Update the geological and simulation models to incorporate the latest available data in order to properly evaluate the full Phase 2 Development Program.

- A sidetrack of the BZ-A7 Azul well is being evaluated. The entire Azul reservoir will be re-evaluated using reservoir simulation in addition to other reservoir engineering tools.

Conclusions

It is concluded that extended reach, sinusoidal, horizontal wellbores (both singles and multi-laterals) have been solely responsible for accomplishing this highly profitable project. It is also concluded that reservoir simulation was a necessary tool in redesigning the wellbores following the poor results from the three initial completions. Additionally, it has been determined that the sinusoidal nature of the wellpaths, which allowed multiple penetrations of the productive units in each wellbore, is paramount to the success of the completions.

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ABSTRACT : To create value from upstream assets, the international petroleum industry continues to emphasize improvements in Reservoir Management practices. At Chevron, very positive results have been achieved by focusing on horizontal and multilateral drilling in lower productivity reservoirs. The Banzala field, offshore Angola, presented a unique drilling challenge. To avoid the presence of high pressure shallow gas sands, high angle wells were drilled that traversed approximately 700 feet of reservoir section. Resulting well productivities were 50 percent of predicted rates in the Mesa reservoir and 25 percent of predicted rates in the Lago reservoir. These marginal well rates necessitated the well designs be re-evaluated using simulation. Based upon optimization studies, the well paths were lengthened from 700 feet to 3700 feet and the high angle designs were replaced by horizontal, sinusoidal designs in order to intersect as many reservoir units as possible. Productivities in both reservoirs were restored to their original estimates (doubling productivities in the Mesa and quadrupling productivities in the Lago reservoirs). Coil tubing conveyed electrical submersible pumps were installed in both reservoirs. The improved well designs increased field production from less than 10 MBOPD to in excess of 30 MBOPD.

Author H. J. Payne
Professional Profile

H. J. Payne has 25 years experience with Chevron in Petroleum Engineering, Operations, Drilling, Project Management, and Business Development in assignments in the United States and internationally. In the early 1980's, he conducted development optimization studies for Aramco in their Persian Gulf fields. He served as District Manager of the SACROC Unit carbon dioxide project in West Texas from 1987 until 1992. When Chevron re-entered Venezuela in 1996 at Boscan, he was Project Coordinator responsible for development optimization and front-end engineering. Most recently, he was the Petroleum Engineering Manager for Chevron's 450 MBOPD operations in offshore Angola. He is currently Senior Operations Advisor for Chevron's Latin American Business Unit.

He holds Bachelor's and Master's degrees in Petroleum Engineering from the University of Texas at Austin and is a Registered Professional Engineer in the state of Colorado.

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Professional Profile

D. A. Williams has 13 years experience with Chevron in various Petroleum Engineering, Operations, and Government Regulatory Coordination assignments both in the Gulf of Mexico and internationally. He has served as a Reservoir, Production, and Petroleum Engineer on various asset management teams – most recently in Cabinda, Angola as a Lead Petroleum Engineer on the Congo Border Area Asset Management Team, which is responsible for production of 60 MBOPD. His current assignment also includes mentoring Angolan National Employees in order to further develop their Petroleum Engineering skills and experience.

David holds a Bachelor's Degree in Petroleum Engineering from Louisiana State University at Baton Rouge.

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M. E. Smith is Manager, New Field Development with Chevron Overseas Petroleum, Inc. in San Ramon, California. His team is responsible for appraising and developing new field discoveries in Block 0 offshore Cabinda, Angola. He has a Bachelor's Degree in Chemical Engineering from California State University Long Beach and a Master's Degree in Petroleum Engineering from the University of Southern California. He is a Registered Professional Engineer in the state of California.