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Accelerate your brown field production at low cost

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Summary

More than 70% of the current world oil production is from matured fields. Almost 50% of the oil reserves are from 30 big mature fields. Mature fields are proven and their performance is predictable. The challenge is how to extend the production life of these fields cost effectively. Application of extensive reservoir management principles in the following three forms were proved to improving oil production at a low cost which would in turn result in field life extension. The three basic concepts are: (1) Reduction of reservoir uncertainty through enhanced surveillance and revisiting the fundamentals (2) Optimization of operating procedures and resources to improve efficiency through integrated system analysis and (3) Application of new Technologies for remedial activities. This paper provides field examples where the application of these principles resulted in (1) Increase in oil production (2) Reduction in operating cost (3) Reduction in production decline rate leading to field life extension.

Keywords: *Brownfield, Mature field, Production enhancement, System Analysis*

Introduction

Oil fields after a certain production period is called mature. There are many definitions of mature field. A more specific definition of a mature field is, the field reached its peak production or producing field in a decline mode or the field reached its economic limit after primary and secondary recovery efforts[1]. Increasing water and gas production, decreasing reservoir pressure, aging equipments with integrity issues, low flow efficiency are the other major indicators of maturity. Since more than 70% of the world oil production is from mature fields, the mature field development has been, and will increasingly be the subject of concerned for the operators. The average recovery factor of the word is estimated to be around 35%. Additional recovery over this easy oil depends on the application of available fit for purpose new technologies to make it economically viable and reservoir management strategies.

This paper presents the three basic concepts of improving production from a mature field at a low cost. The three basic concepts are 1) Reduction of uncertainties 2) Improving system efficiency and 3) Application of new technologies. Application of these three basic principles not only improved the production but also at lower cost compared to additional oil from new drilling from mature fields. Field case histories showing production enhancement through the application of these principles are presented.

Mature Field Production System

In order to improve the performance of the mature filed, it is necessary to understand the entire production system and its components. Figure-1 depicts the typical mature field production system.

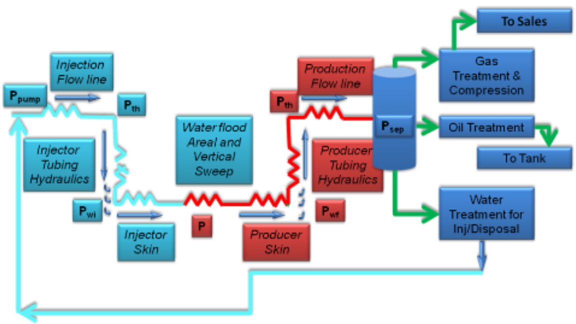

Figure 1: Typical oil production system in a mature field

The major components in the system are 1) Reservoir, 2) Well (Producer & Injector), 3) The surface facilities to handle oil and gas processing and 4) Produce/injection water treatment facility. The main challenges in the mature field are (1) Rapid decline in oil production due to high water and gas production (2)Water breakthrough leading to high water handling (3) Low pressures and low system efficiencies (4) More nonproductive wells (5) Flow assurance problems (6) Costly and complicated workovers due to integrity issues. All the above challenges can be overcome by the basic three concepts.

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The Process

A multidisciplinary team was created to apply sound well and reservoir management principles to identify optimization opportunities at well and reservoir level as wells at surface facilities level. The multidisciplinary team consists of subsurface, surface and operational experts. The team established a simple process for identification of production enhancement activities. This process starts with the preparation of well book that contains the details of individual well and its performance analysis to identify opportunity if any with recommended remedial actions. Typical well book contains (1) Location map showing the well path including a structural surface, waterflood pattern, the locations of perforations whether open or closed, faults mapped from seismic, sedimentary facies and fractures from borehole image logs, (2) Well inflow information from PLT (3) Initial and most recent saturation logs (4) production history plot annotated with all interventions, (5) Artificial lift details (6) Completion details (7) Decline curve reserves forecasts with the simulator forecast overlaid, (8) volumetric reserves for the area, (9) modeled inflow performance and outflow curves and (10) well interference plots. (11) Nearby well details. For each well, a forward plan is made, taking into account aspects such as well integrity status, indications of un-swept oil from reservoir analysis, surface bottlenecks if any. The recommended forward plan for a well then depends on whether sufficient information exists to warrant immediate remedial action, or if additional data is needed to better understand the problem. After the review the well-action-plans are input to a database called opportunity register that captures the current well status and what steps are needed to further optimize the well.

The ranking of the activity is done using the economic forecast for each intervention, taking into consideration the expected oil gains and the cost based on likely job scope. The team was also responsible for detailed design and execution of the activities in order to have good quality control. Feed back is provided in the form of an after action review which is done within two weeks of the job completion. This document summarizes the well intervention, covering the objectives, outcome and lessons learned. Any findings from either the execution or from the data collection are then fed back to the team to improve future activities.

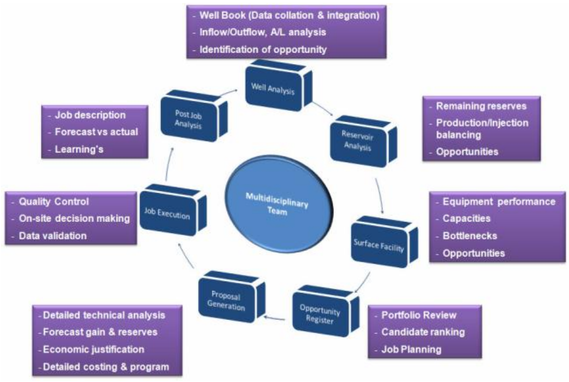

Figure 2: The Optimization Process

Reduction of Reservoir Uncertainty

Reservoir uncertainty can be reduced by

1) Revisiting fundamentals and
2) Improved surveillance methods.

Revisiting fundamentals

Rebooking of reserve has always been a challenge due to uncertainties and difficulties in the estimation of residual oil saturations and locating exact reservoir boundaries. The reservoir uncertainty pertaining to 1) Remaining reserves, 2) By passed oil, 3) Heterogeneity, 4) Fluid fronts and 5) production and injection data. Many instances have been reported in the literature for revisiting the fundamentals have resulted in reduced uncertainties and improved understanding of the reservoir and the well performances.

A good example of revisiting fundamentals is presented by the author Dr. Neil Williams[4] in his SPE distinguished lecturer program[2]. Kutubu is Papua New Guinea's largest oil field. It came on line in 1992 and the production rates declined rapidly in 2001. The field shutdown with that decline rate was estimated around 2008. A full field review was conducted to reassess the field performance including the remaining reserves. In the full field review process an emphasis was given to revisit the fundamentals in the areas of 1) Seismic data interpretation, 2) Petrophysical properties 3) Facies, 4) RFT data 5) Well performance and 5) Well stimulation techniques. The team came out with an alternate theory of compartmentalisation to explain the non-uniform oil column. The compartmentalization theory opened up a series of opportunities in areas that were previously considered non-prospective due to the tilted contact concept. Accordingly a follow-up action was taken to drill new wells in the previously considered non-prospective area. This has resulted in not only arresting the oil production but also extended the life of the field up to 2 decades.

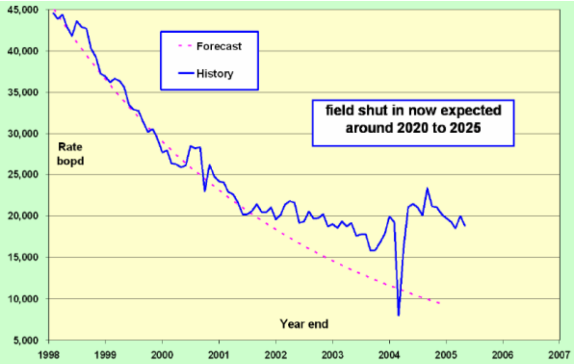

Figure 3: Example showing the benefit of revisiting fundamentals (Courtesy – SPE Distinguished program 2008-2009).

Another example of revising the damaging mechanism of a mature reservoir has resulted in enhanced oil production through improved water injection distribution.

The stimulation history from this field showed that 28% HCl was used for stimulating the wells until 1998. From 1999 onwards only 15% acid was used. The number of stimulation treatments in this field has increased dramatically over the last few years due to the introduction of well and reservoir management techniques. Stimulation treatments prior to the year 2000 were limited to new well stimulations (infill wells). Hence, there was a significant scope for improvement identified by the multi disciplinary team. However, the main challenges of stimulation were:

- Effectively stimulating the matrix within a conductive fracture environment.
- Selectively stimulating the layers with the highest oil saturation.
- Minimizing acid injection into zones with high water saturation.
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The team has revisited the fundamentals considering the challenges to establish the damaging mechanism, select suitable chemicals and placement methods and come out with different placement methods for different type of wells and tried various chemical and mechanical diverting systems.

The wells were monitored for a year after the stimulation jobs to establish the sustainability and effectiveness of stimulation. The following table shows the improvement after revisiting the fundaments and revising the recipe and the placement procedures.

Item	Before	After
Liquid Decline Rate	70% to 73 %	23% to 39%
Average Net Oil Gain	165 Bbls/d	280 Bbls/d
Expected Gain	190 Bbls/d	260 Bbls/d
No Of Wells	12	11

Table 1: Performance of producers before and after revising recipe and procedure.

Similar efforts were made to analyze the injector performance as well and it is shown in Table-2

Item	Before	After
Decline Rate/year	57% to 94%	25% to 73%
Average Injection Gain/well	3750 Bbls/d	4980 Bbls/d
Average Expected Gain/well	3600 Bbls/d	3850 Bbls/d
No Of Wells	22	16

Table 2: Performance of Injectors before and after revising recipe and procedure.

Improved Surveillance

It was a belief that the sweep across the horizontal hole is uniform. However, after regress surveillance and data gathering we have noticed that the sweep is not uniform. Hence, saturation logging in horizontal wells were recorded to see the sweep behind the casing. This surveillance data gathering has generated many optimization activities like addition perforation and stimulation. A typical example of additionalperforation and stimulation opportunity identification is presented in Figure-4.

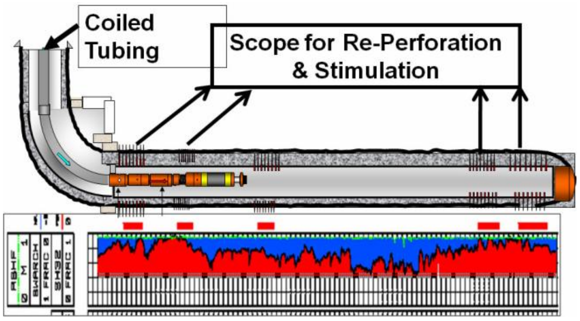

Figure 4: Identification of optimization activity through improved surveillance.

Another example of improved surveillance in an injector is shown in figure-4. This well is an injector with 500 meters of 6 1/8" horizontal open-hole. Initially this open-hole was treated with normal 15% HCl through coiled tubing placement. Stimulation was carried out with coiled tubing and using surfactant based diverting system. In order to assess the effectiveness of stimulation, PLTs were conducted before and after the job. Figure 5 shows the injection profile. It can be seen from this figure-5 that the revised recipe and the placement technique has improved the injection profile in a uniform manner along the horizontal section.

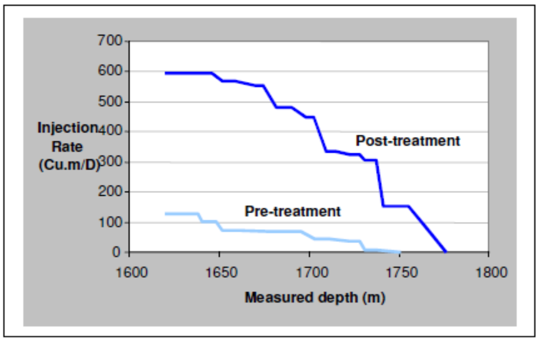

Figure 5: Injection profile before and after stimulation.

Efficiency Improvement

Efficiency is the key issue in mature field development. Improving the efficiency of the artificial lift systems will have great impact on lifting cost. Hence, a great effort was put for the optimization of artificial lift systems. This field is operating with 40% of the wells contributing 50% of oil production with Electrical Submersible Pump (ESP) and 60% of the wells with gas lift. With this high dependence on ESPs it is a challenge to manage these wells. The challenge consists of 3 aspects: ensuring optimum performance of the ESP, replacement of failed ESP in a manner that minimised deferment and optimising the well performance. In order to ensure optimum performance of the ESPs, they are modelled and these models are regularly updated. From these models, one can determine how the ESP is running. In most cases the ESPs are running fine, but in some cases the ESP should be up- or downsized. Interventions are planned for up or downsizing of ESPs. It is also possible to identify, whether the ESP has partly failed (e.g. Stages have fallen out or a tubing leak is developing). This enables pro-active replacement of the ESP. Replacement of failed ESPs focuses on getting the well back on stream as fast as possible to minimize deferment. This is achieved by pro-actively replacing ESPs, which shows indication of a failure, and by working closely with vendor and well services to coordinate the workovers. In addition, a dedicated workover unit is assigned to do ESP replacements. The following figure-6 shows the deferment reduction by optimizing the ESP replacement process.

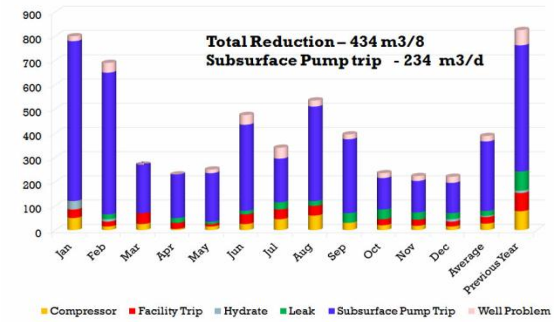

Figure 6: System efficiency improvement through optimization of resources

A new method[3] was introduced in 2004 to reduce cost for additional perforation jobs, while at the same time reducing the cycle time. Prior to introducing this technology, the operation to add perforations was done by first employing a CT unit to clean the horizontal wellbore, and then another CT, with an electric line to log the well. Subsequently, a hoist was mobilised to perforate and stimulate. This lead to a cycle time that was typically 2-3 months before first oil reached the tank. We have introduced new technology1 that enables cleanout, logging, stimulation and perforation with a single coiled tubing intervention, which includes a plastic coated "e-line" logging string and a new coiled tubing perforating head. All new systems are in complete compliance with the most stringent safety criteria. The new method has also resulted in a cost saving of approximately $100,000 USD per well, leading to a saving of 1 million dollars for the 10 jobs that were executed in 2004. The cycle time of a typcial job is around 10 days, which is considerably shorter and leads to accelerated production.

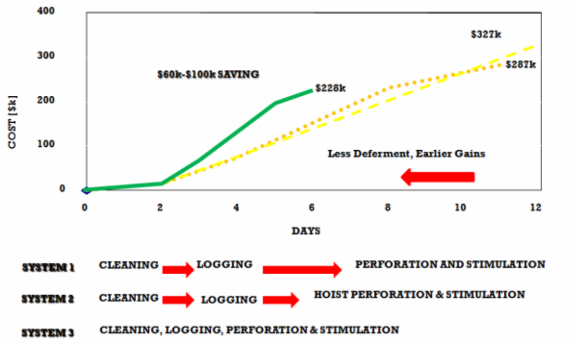

Figure 7: System efficiency improvement through optimization of process and procedures

Application of New Technology

Use of diverting stimulation systems[4]

This field has complex geology with sporadic hydraulically conductive fractures and leached beds. Stimulation has been a challenge in this type of environment. It is clear that acid placement efficiency is of paramount importance to ensure that excessive amounts of acid are not injected into the conductive fractures, many of which are conduits to sources of water. Various methods have been utilised in the past including the use of mechanical isolation, and foamed acid. Recently, stimulation practises have been changed to the use of diverting stimulation systems. These systems have provided improvements in acid placement, manifested by lower water cuts post stimulation compared to other non-diverting systems.

Effective cleaning out of horizontal holes with reverse circulation through coiled tubing[5]

Several methods of cleaning deviated and horizontal wells have been developed over the years. One of the most common methods is running-in with coiled tubing and circulating the solids out with a liquid or multiphase fluid. However, solids tend to settle on the low-side of the wellbore in highly deviated or horizontal wells, and when coupled with low reservoir pressure, can lead to continuous losses to the formation. This increases the difficulty in bringing debris up to the surface, reducing the cleanout efficiency. Reverse circulation trials were carried out in three horizontal open-hole injectors in this field. The cleanout method was a combination of venturi junk basket and reverse circulation. The initial venturi run was made to identify the top of fill and to remove the larger fill particles. This was then followed by reverse circulation to remove the smaller particle out of the wellbore. Post cleanout injection rates increased on an average by 15% over the pre-cleanout rates. Further to evaluate the effectiveness of this method, spinner runs were made along the horizontal open-hole section before and after the cleanout jobs. The results revealed that injection was more uniform along the horizontal open-hole section after the reverse circulation when compared to the few points of injection before the cleanout. Implementation of this reverse circulation process is now planned for producers in which it is not possible to remove acid insoluble materials by normal cleanout methods.

Service the Limit (StL)

This is the process by which all the operations are analysed and the best practices are drawn considering all the risks involved before carrying out the job. It is similar to the 'Drill-the-Limit' process for new wells. Typically this is done by the multi-disciplinary team consisting of a reservoir engineer, a production technologist, and operations engineer, servicing the limit specialist, the job supervisors and technicians. The main objective of this exercise is to reduce the time and cost of operations by drawing best practices and novel ideas. The outcome of a StL process for the single rig-up CT solution is shown in Figure 5. Such a system was also introduced for other the hoist operations. This process has improved the efficiency of the operations and resulted in cost savings.

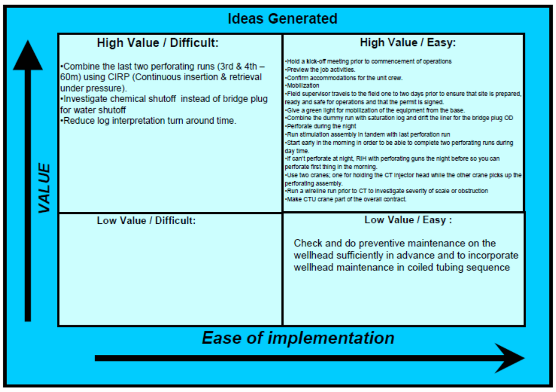

Figure 8: Ideas generated during a "Service the well on paper for a single rig-up coiled tubing intervention"

Conclusions

In order to see the overall impact of all the improvements, the scorpion plot, the cumulative cost on the vertical axis and the cumulative gains on the horizontal axis are plotted after ranking the jobs based on dollar spent on gaining a barrel of oil. The tail portion of the graph consists of those jobs that either gave no gains or had negative gains. As seen from the scorpion plot for 2003 and 2004, a notable improvement in efficiency has been made during 2004. Also it indicates that a reduction in OPEX of 20% with an increase in net oil gains of 10% (Figure 9).

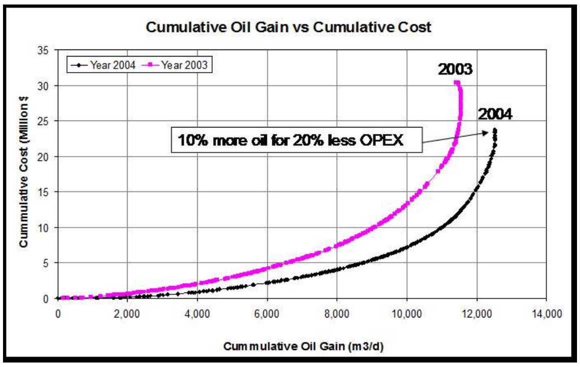

Figure 9: Jobs Efficiency comparison through scorpion plot

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