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Optimising Well Management Options for Mature Fields - Forties Field Experience

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Abstract

The Forties Field operated by BP Exploration in block 21/10 of the United Kingdom continental shelf was discovered in 1970 with estimated reserves in the order of 4.3 MMB.

In 1995 a decision was made to assess ways to improve further the economics of the field. At BP's request, the well management contractors were encouraged to look for improvements, particularly for well maintenance operations and their impact on the in-fill drilling programmes. Drilling and a significant number of well intervention operations are carried out using the rig, performing either type of operation (i.e. drilling or production) at a particular time can have a negative effect on production.

A Process Intensification approach was utilised to allow transfer of most well interventions to the lower deck. This paper describes the process of evaluating the initial field operating and economic conditions, defining the optimum strategy, developing new surface and downhole equipment and operating practices.

Background

Mature assets such as the Forties field[1] are under constant optimisation and improvement pressures mainly driven by the need to reduce cost and increase efficiency.

In 1992 further steps were taken to optimise some aspects of Forties operations, particularly well maintenance and intervention. These efforts resulted in the development of compact size Coiled Tubing equipment[2] rated to operate in Zone I areas such as the BOP deck, it was designed to perform basic operations such as gas lift and fluid's placement; Table 1 presents the main characteristics of this equipment. The results obtained were quite positive and encouraged BP and its contractors to look for ways to continue improving the way in which well maintenance and intervention was carried out. As part of the optimisation process, BP's strategy included in-fill drilling from some of the platforms in order to improve hydrocarbons recovery.

The conflict between drilling and well maintenance/intervention operations needing the rig was the main challenge to the optimisation process. In early 1995 a decision was made to find cost effective options that could lead to the integration of both types of operation. A study was carried out to identify the main constraints and they were found to be:

- Space availability and platform support facilities.
- Current operating practices.
- Existing surface and downhole equipment.
- Interaction between drilling and intervention activities.

Process and Equipment evaluation

The main type of well intervention operations[3] (i.e. rig assisted (RA) and non rig assisted (NRA) were evaluated as well as side-tracks (ST) and workovers (WO); their processes, equipment (i.e. surface and sub-surface) and methodologies used throughout the field were reviewed[4]. One of the major constraints encountered was the use of the rig to perform certain type of intervention operations. it posed a significant limitation and in some cases it lead to long delays in the drilling programme. RA operations such as wellbore cleanouts utilised conventional CT and pumping equipment located on the top deck. This not only uses the rig but also requires considerable amount of deck space making any drilling activity impossible. Other operations such as under-reaming, sand control, re-completions, cementing and stimulation were also RA type activities and imposed similar limitations.

The obvious solution was then to move as many well intervention operations as practically possible from the pipe deck to the BOP deck.

Processes for these operations were restricted by a cumbersome set up, difficult logistics and orthodox methodologies, particularly jobs requiring fluid mixing and storage. All led to time consuming operations hence, higher operational cost. Other aspects of the process such as flow capacity, friction pressures, fluid lifting efficiency, deck loading and deployment were thoroughly reviewed and they also presented limitations.

Surface equipment set up was one of the main constraints, most existing well intervention equipment is rated for Zone II areas, its configuration and weight made its use from the lower deck impossible. Also, deck loading limitations in the different areas of the four(4) main platforms restricted its use. Other aspects of this equipment such as reel storage capacity, mechanical strength, and horsepower capacity were also found to be a limiting factor. Figure 1 illustrates the differences in weight between Zone II and Zone I CT equipment and figure 2 presents estimated space utilisation for most of the well intervention performed in the field.

Downhole assemblies used for most of these operations were found to be very long. This was not suitable due to the height limitation imposed by the distance between the Christmas trees and the pipe deck. Historically, BHAs have been deployed using the rig which allowed them to cope with the length of the tools. Figure 3 presents a comparison of the BHA's utilised throughout Forties.

Equipment and Process Optimisation

Having defined the main constraints of existing practices and equipment, it was decided to use a *Process Intensification* approach to optimise well intervention operations. Optimisation was divided into two parts, the first considered surface equipment set-up and operation and the second part considered the downhole aspects of the operations. The main changes proposed were :

- Plan drilling and well intervention activity for simultaneous operation (SIMOPS).
- Design and build CT Zone I equipment with the mechanical strength (i.e. ~ 40.000 Lb. pulling capacity) and flow capacity required(i.e. > 0.7 BPM) for the intended operations.
- Utilise a dynamic fluid handling methodology that considers no storage whenever possible.
- Identification of other suitable equipment placement areas within the installations.
- Develop five (5) downhole tools with a maximum BHA length of 14 feet. These tools were a connector, check valve, release joint, flow sub and a cleaning tool.
- Replace shear seal BOPs by surface ball cutter valves.
- Develop alternative deployment methodologies and equipment for longer BHAs.

Equipment Development and testing

Using guidelines and the specifications generated as a result of the evaluation process, a programme was developed in September 1995 to design, build and test the surface and downhole equipment with the goal of having the equipment in the field by April 1996. An alliance was created for the development of downhole components between PSL and tool manufacturer Phoenix Downhole Technology. Three phases composed this development programme, they were as follows:

1. Design of the equipment, including calculations and drawings.
2. Manufacturing of the surface equipment (i.e. CT), downhole tools including prototype building and bench testing and trials in the PSL test well prior to final delivery.
3. Yard testing and commissioning with final equipment certification by the relevant authorities and acceptance by BP.

Candidate Well selection[5]

The main considerations for the well selection process were :

- Wells requiring wellbore cleanouts as the first choice.
- Wells completed with a 4 1/2" liner.
- Wells producing using deep set gas lift systems.
- Wells presenting minimum risk and moderate gains (i.e. low rate producers w/ moderate incremental oil potential).

11 wells were considered to be potential candidates, six (6) were chosen according to the technical and operational criteria developed. Table 2 presents the main characteristics of these wells.

Economics

As with many mature fields implementation of such an optimisation programme was mainly based on whether it was financially viable. Economic assessment was based using a cost benefit analysis.

Variable costs included equipment and personnel cost over a year period. The total capital investment considering the above was in the order of $ K 246.0, with an estimated operating cost of $ M 1.2.

Assuming an oil price of $ 16 per barrel and the cost above, the potential accelerated oil that could be added to the total field production by performing the well interventions in the chosen manner are considerable. The cost benefit analysis indicates significant advantages at rates greater than 500 bpd. Table 3 and Figures 4 & 5 present some aspects of this analysis.

Current status

Equipment was delivered to the field in April 1996 as per the original schedule. Well FB 2-2 in Forties "Bravo" platform was selected for the first operation based on the criteria developed. The initial operations considered the lowest risk possible in order to ensure a period of gradual and safe introduction of the equipment and methodologies to the field.
Two minor problems were encountered during the first operation, the first one was due to the proximity between the reel and the injector head that caused damage to the pipe. The second problem was similar but due to position of the injector head in respect to the gantry crane which again caused minor damage to the pipe. Both problems were solved successfully.

To date, operations such as cleanouts, gas lifting, cement squeeze, milling and under-reaming as well as deployment and recovery of inflatable tools have been carried out using these equipment.

Both BP and its contractors continue to gain more experience with the equipment as progress is made towards full optimisation of the drilling and well intervention operations in the field.

Conclusions

1. Well management and operations in the Forties field has been further optimised by using a *Process Intensification* approach to the way in which existing drilling and well intervention operations are planned and executed.

2. The equipment and methodologies developed will permit BP to perform the required well intervention from the BOP deck for all the platforms in the Forties field.

3. Surface and downhole equipment was designed, built, and commissioned by BP on time and within budget.

4. The financial aspects of optimising well management and operations were very encouraging and offered significant advantages even for incremental oil rates of less than 500 BPD.

5. The "accelerated" incremental oil that can be added to the total field production is significant as compared to the forecasted production using the already existing operational set up.

6. It is envisaged that when fully implemented, most well intervention operations would be carried out from the BOP deck allowing drilling activities to take place with little impact on the other operations and production.

Acknowledgements

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5. Progenitive Services Ltd (PSL): " Optimisation of Well Operations - Equipment Development Programme and Candidate Wells Selection - Forties Asset", Internal report, Aberdeen, UK, Nov. 1995.

Description	Data	Remarks
No. components	3	Skid mounted
Power source	150 HP	Electrically driven
Dimensions	10 x 11 x 5 feet	Average dimensions
Maximum area	140 sqft	Net area
Maximum Weight	8 tonnes	Reel loaded with 12000 feet of 1 1/4"
BOP type & size	Triple w.3.0" I.D.	Drexel
Pulling capacity	20,000 lb.	
No. units in the field	3	2 Deployed in 1993 1 Deployed in 1994
Average Flow capacity	< 0.6 BPM	10,000 feet of 1 ¼" Coiled Tubing

Table 1 - Existing Zone I Equipment Information

Well	Status	Tubing size [Inches]	Liner size / depth	Restriction	Remedial action	Remarks
FD 5-4	DGL	5.5 x 4.5	4 1/2" @ 8421 feet	2.812" I.D. nipple	Cleanout + add perfs	Incremental mbd high !
FB 5-1	DGL	5.5 x 3.5	7.0" @ 7367 feet	2.750" I.D. nipple	Cleanout + gel squeeze	-
FC 5-1	Natural flow	7.0	7.0" @ 7729 feet	5.182" I.D. SSD	Sand Cleanout	Timing is suitable
FD 5-6	Injector	7.0	7.0" @ 12400 feet	5.879" I.D. nipple	Cleanout	mbds 4:1 ratio
FA 1-4	DGL	5.5 x 4.5	4 1/2" @ 8522 feet	3.313" I.D. nipple	Water shut-off	Cement squeeze 85% WC.
FB 2-2	DGL	5.5 x 3.5	7.0" @ 7254 feet	2.750" I.D. nipple	Cleanout + sand control	Good potential

Table 2 - Candidate Wells

INCREMENTAL OIL - MBD	0.5	1	3	5	10
Revenue - $ M	2.88	5.76	17.30	28.8	57.6
Number of Interventions	1	1	5	9	18
CAPEX - $ K	246	246	246	246	246
OPEX - $ M	1.16	1.16	1.16	1.16	1.16
Cash Flow - $ M	0.65	1.91	6.96	11.9	24.6

Table 3 - Cashflow Projections

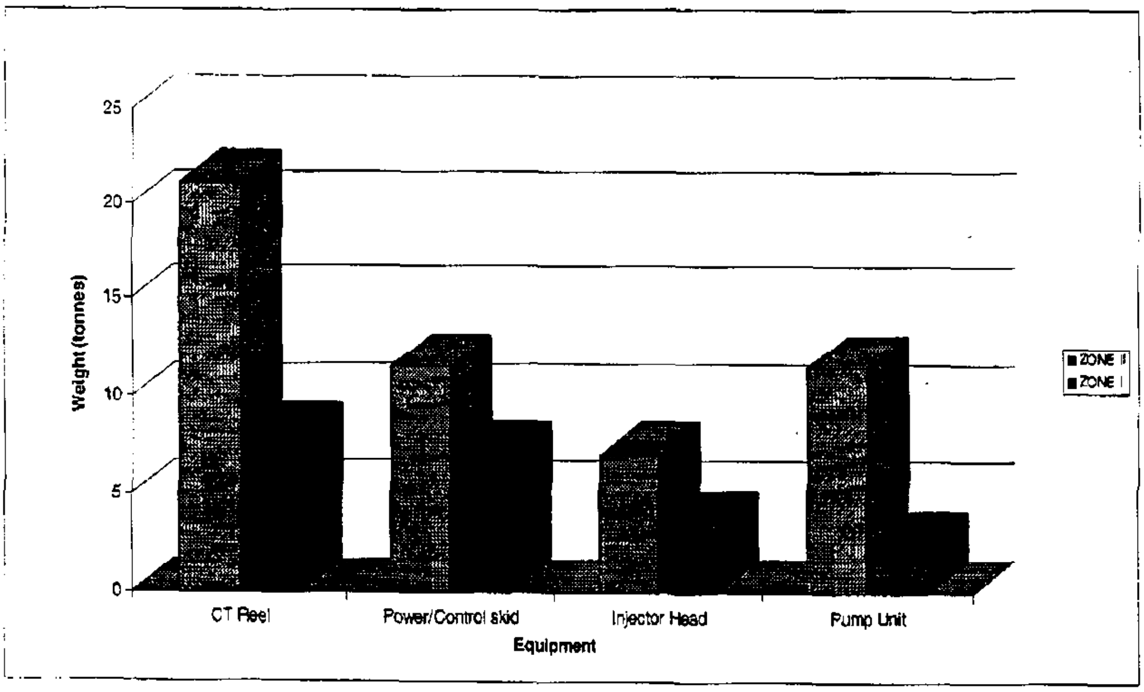

Fig. 1. Equipment weight comparison

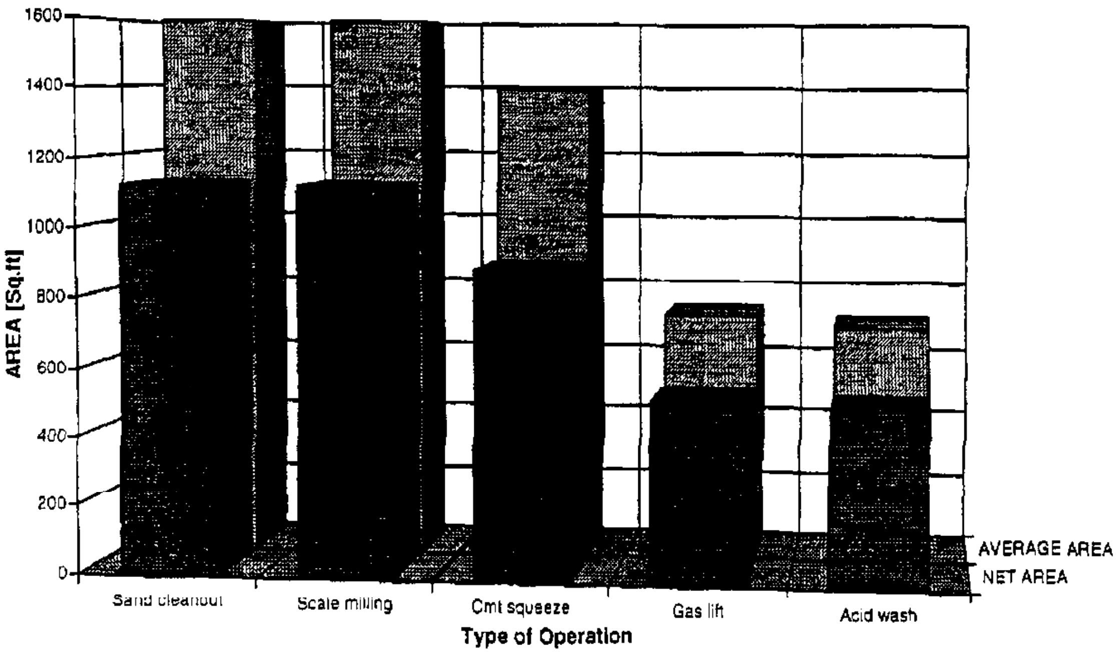

Fig. 2. Space utilisation

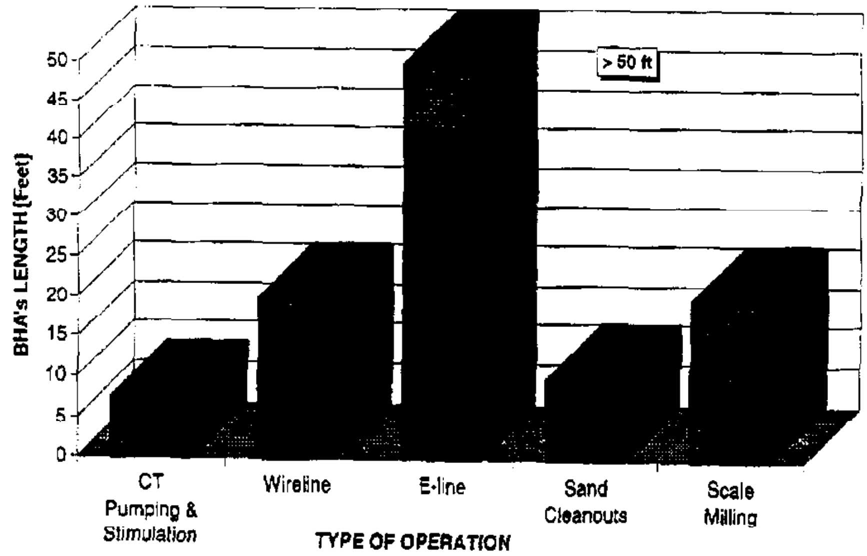

Fig. 3. Typical BHA Lengths

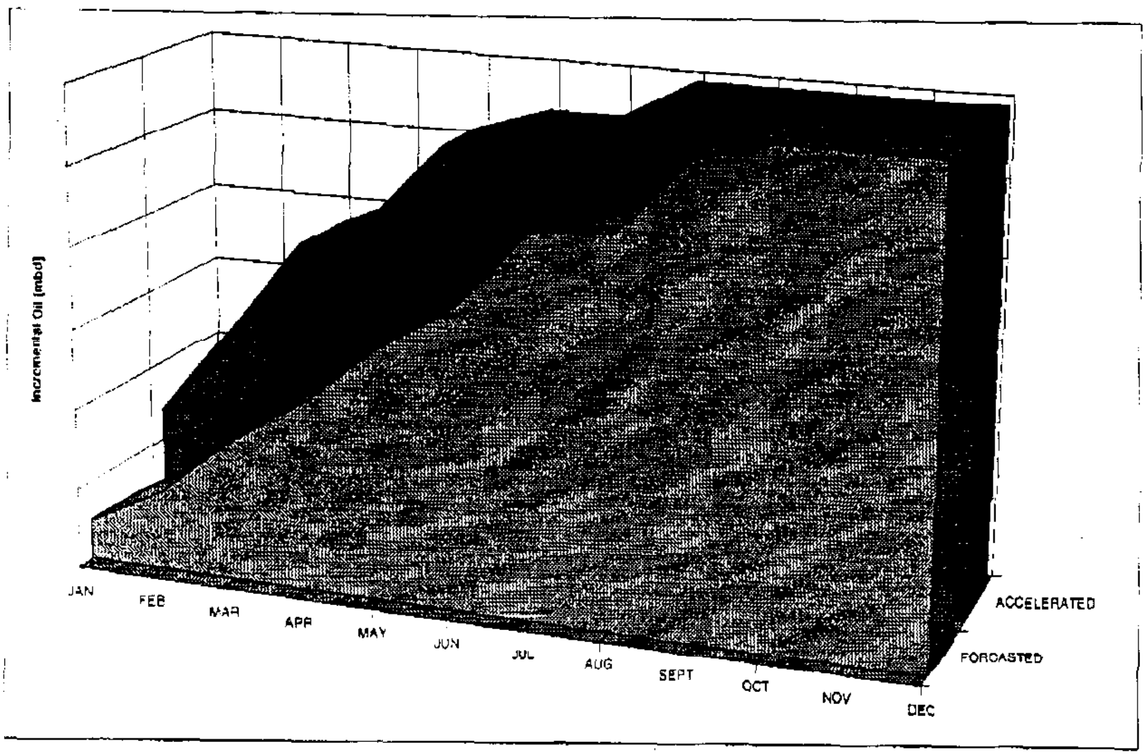

Fig. 4. Accelerated Vs Forecasted Incremental Oil

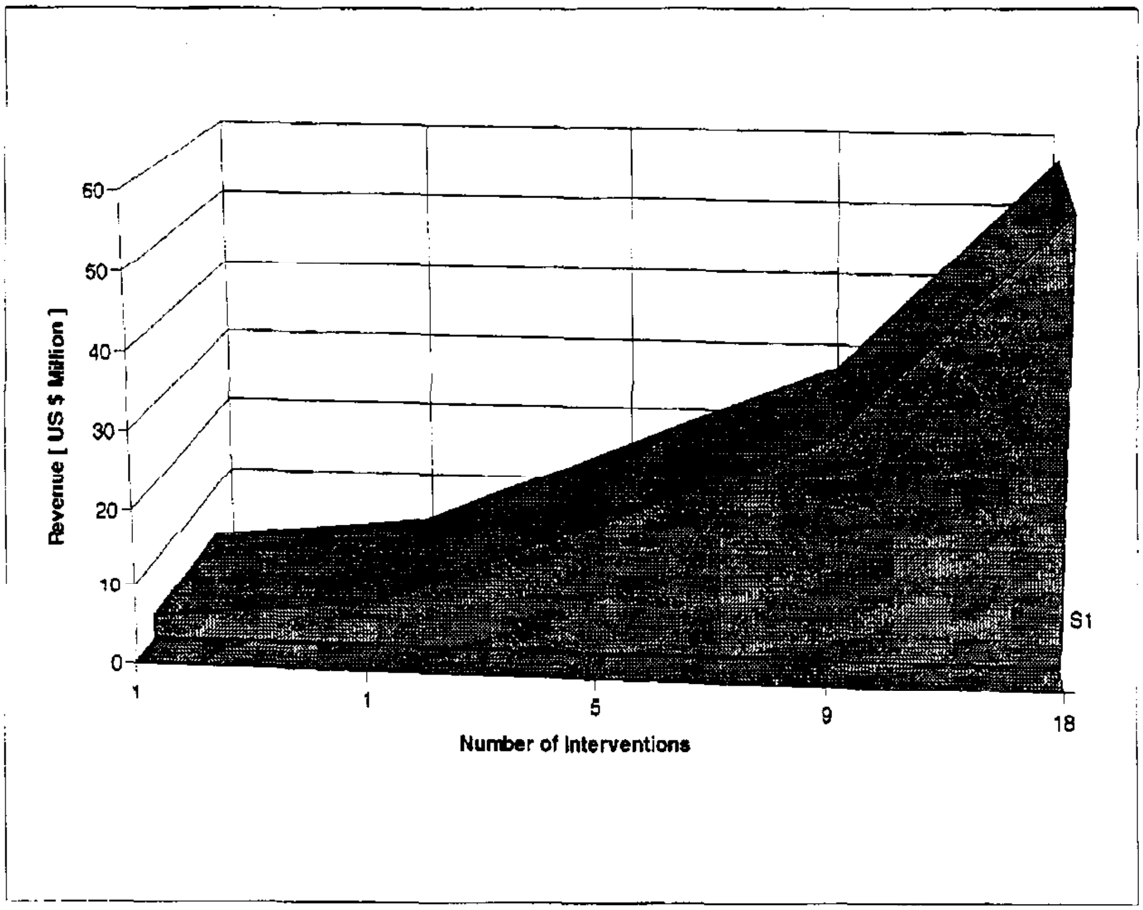

Fig. 5 Number of Well Interventions vs Revenue