18TH NORTH SEA FLOW MEASUREMENT WORKSHOP 2000

OPERATIONAL EXPERIENCE AND UTILIZATION OF THE DATA FROM THE SUBSEA MULTIPHASE FLOWMETER IN THE WEST BRAE FIELD

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INTRODUCTION

The West Brae Field, formerly the West Brae and Sedgwick Fields, is a subsea development comprised of two lower Eocene sands spanning two blocks. The field produces from a single well in Block 16/06a which is tied back to a subsea manifold in Block 16/07a, where the production from five additional wells is commingled before being transported to the Brae 'A' platform for processing. Each well has downhole temperature and pressure gauges, and a multiphase flow meter is located at the manifold from which the flow from any single well may be measured. Production from the field is currently 35,000 barrels of oil per day.

This paper discusses the performance and economic benefits of the Framo multiphase meter, which has provided reliable flow rate data over the last three years and also demonstrates what has been achieved with the constant monitoring of flow and pressure information.

FIELD HISTORY AND DEVELOPMENT

History

West Brae is a lower Eocene field located 160 miles north-northeast of Aberdeen, Scotland in 350 feet of water in the UK Central North Sea. Production comes from two saturated oil horizons, the Balder and the underlying Flugga. Both are turbidite deposits consisting of well-sorted, fine-grained sands with exceptional permeability. The oils in the two zones are biodegraded, of moderate gravity (22 API), low GOR (300 scf/stb) and have an in situ viscosity of between 3 and 5 centipoise.

The field was discovered in 1975 with the Pan Ocean Well 16/07-2, which found gas in the Balder and oil in the Flugga. Two delineation wells were drilled in Block 16/07a, the 16/07a-31 in 1990 and the 16/07a-32 in 1991.

The neighbouring Block 16/06a was awarded to Conoco in 1972. Enterprise Oil, which later became operator of that block, earned an interest by drilling well 16/06a-2 in 1985. This well found oil in the Balder and a thin non-productive Flugga. Two final appraisal wells were drilled in Block 16/06a, the16/06a-4 and its horizontal sidetrack 16/06a-4Z. At the time the Block 16/06a accumulation was known as Sedgwick Field.

Development of the blocks was delayed for years for both technical and economic reasons. With the advancement of subsea and horizontal well technology, the operators of the two blocks agreed to a joint development in which production would be split 67.5 percent to the Brae Group and 32.5 percent to the Sedgwick Group until an agreed to cap is reached at which time all production will be allocated to the Brae Group. As development drilling proceeded, it was realised that hydrocarbon communication exited in the Balder between the fields. Ultimately six production wells, three each in the Flugga and Balder, and a single Balder injection well were drilled. In 1998 the field names were combined and the development is now called West Brae, which is operated by Marathon Oil.

Figure 1 depicts a plan view of the horizontal wells together with West Brae's relationship to the adjacent fields.

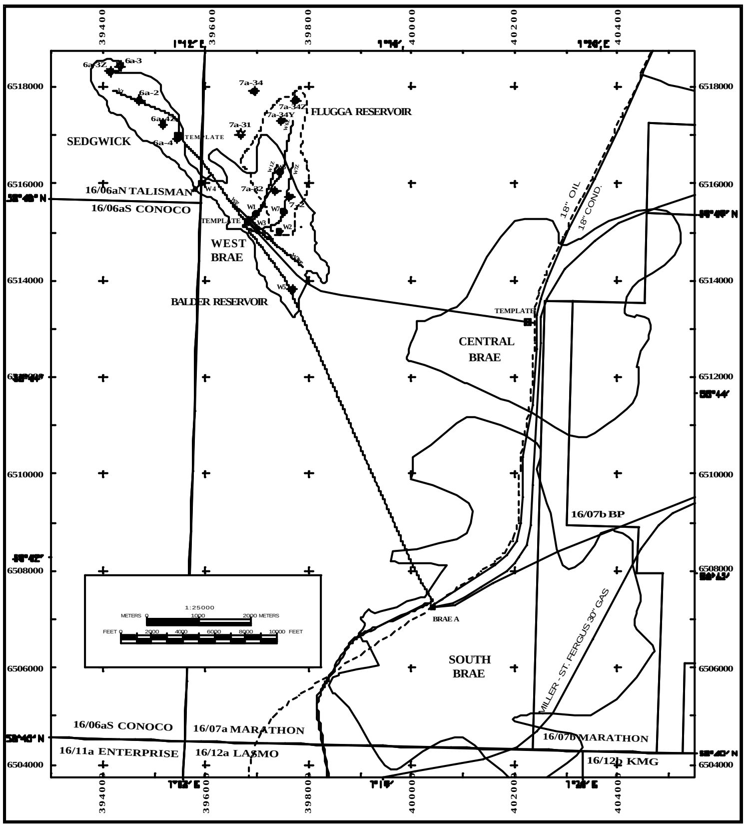

Figure 1 - Map of West Brae Field

Infrastructure

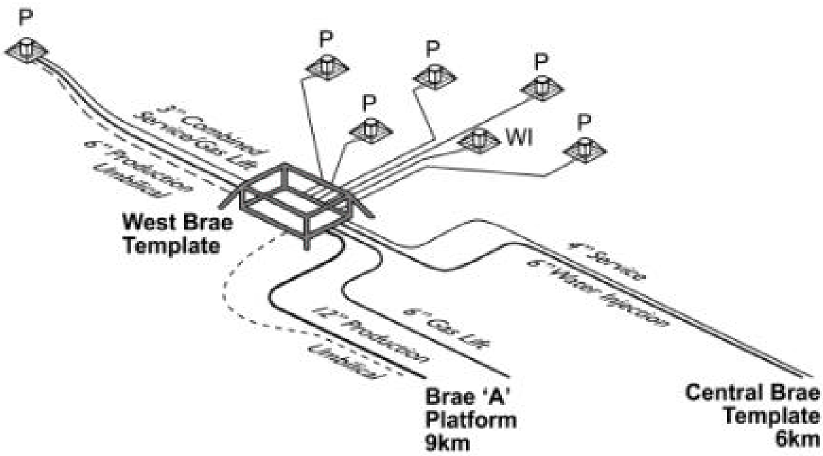

Figure 2 - Subsea Infrastructure of the West Brae Field

Figure 2 shows the current West Brae infrastructure. The 16/06a-V1 is located 2.2 km from the production manifold, and is connected to it via a 6" production line and a 3" combined gas lift and service line. All other production wells are tied to the manifold by way of jumper lines. From the manifold the oil is transported through a 12" line to the Brae 'A' platform located 8.8 km from the production manifold. Gas lift is also supplied from Brae 'A' by way of a 6" line.

Water for injection into the 16/07a-W4 is supplied from the Central Brae Field located roughly six kilometres from the field.

Host Platform Measurement Systems

The process train for West Brae consists of two stages of separation preceded by a slug catcher and followed by a booster pump. The oil then enters the Forties pipeline system (see below).

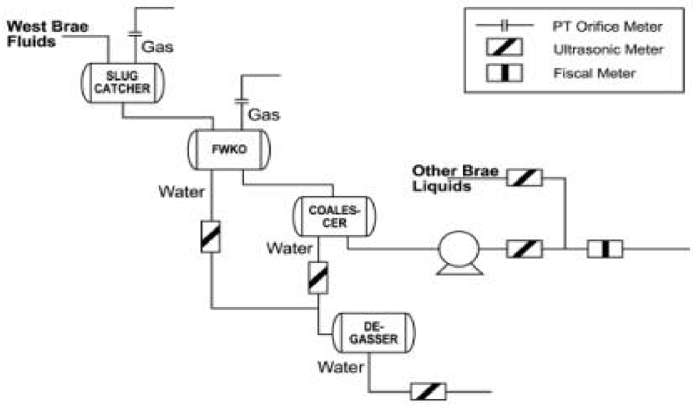

Figure 3 - Process Train for West Brae Fluids on Brae 'A' Platform

Gas taken off of the slug catcher and free water knock out is measured with orifice metering and P, T, Z corrections. Oil is metered with an ultrasonic metering tube at the outlet of the booster pump before being commingled with other Brae liquids. A dedicated fiscal meter then measures the combined Brae fluids. Water is metered ultrasonically at the free water knockout and coalescer before entering the de-gasser, but the primary water meter is located after the de-gasser.

A. Kennedy and I. Simm[1] stated that reasonable levels of uncertainty for the fiscal, gas, and ultrasonic meters are +/- 0.25%, +/- 10%, and +/- 1% respectively. They also demonstrated a 1.3% upward bias of the ultrasonic oil meter to the fiscal meter.

Data generated by well or subsea instrumentation are collected by the platform MCS before being forwarded to other devices. Readings from all instruments are usually sampled at one minute intervals, but twelve minute and one hour averages are the normal recording rates for the data software package ODD. The interface of the flowmeter is performed through a jumper cable that connects to the Kvaerner SubSea Electronic Module. This module provides a transparent link at 1200 bauds to a topside computer, which acquires data. The Platform MCS collects data from the Modbus slave port of the topside computer.

Selection Process for Installation of a Multiphase Meter

At the time of development the installation of a subsea multiphase meter was justified for the following reasons:

- Reduced downtime
- Enhanced production performance monitoring
- Enhanced reservoir management.

The only alternative considered to a multiphase meter was testing by difference. A dedicated test line was considered to be too costly and down hole metering was and still is frontier technology. It was estimated that testing an individual well by difference would require between eight and twelve hours given the flowline capacities and stabilisation times. From this the loss of cash flow in a year was estimated for various field rates and testing frequencies. At a rate of 30,000 BOPD the loss of cash flow in a year for the differential testing of six wells at eight hours per test and $18 per barrel varied from $720,000 for quarterly testing (each well every quarter) to $2,160,00 for monthly testing.

Additionally, it was argued, although no attempt was made to quantify the financial effects, that a subsea multiphase meter would provide more accurate production monitoring and benefit reservoir management. Since it was known that flow would be affected by pipeline pressure, testing by difference would necessarily require adjustment. The use of correlations together with the downhole gauges while being of broad utility are increasingly inaccurate with increasing water cuts and gas-oil ratios. The optimisation of gas-lift volumes could be quickly made with a subsea meter, and the coning of gas or oil would be immediately recognisable.

The platform has gas handling constraints, and for reservoir management reasons, the production of free gas is not an option. Given the expectedly high productivity indices of the wells are, and coning thresholds for gas and water of roughly 15 and 3 psi respectively, the accurate monitoring of rates and pressures is essential. It was known at the time that water coning would be inevitable, and the control of water production would best be done with real time, accurate rate information.

All of the above benefits were weighed against the £750k cost in 1996 of the meter and subsea installation, and the fact that at the time the meters were a new and largely untested technology. Should the meter not have been installed or should it fail, testing by difference remains the only alternative.

The selection of a sub-sea flowmeter using Dual Energy-Venturi combination over the other technologies was the result of an in-depth evaluation and included the following factors:

- Robust measurement principle with no requirement of calibration against a reference (i.e. no flowing calibration) and independence of flow regime
- An performance contract
- Cost effectiveness
- Marinization of the equipment
- Low pressure drop allowable through the system
- Previous sub-sea experience
- Intervention cost minimisation

Framo Meter Principles

Humphrey et al[2] has described the selected meter system. The subsea meter is based on an insert design, which allows for an easy retrieval of the all the critical items such as electronics, transducer, gamma isotope, detector, Venturi and ROV-mateable connector for power, signal and flushing media. In the case of the West Brae implementation, the retrieval of the insert was planned to be supported by diver, in an effort to minimise capital investment. Diver intervention would be required to disconnect the meter from the SubSea electronic module.

Figure 4 shows a cross section of the meter used and Figure 5 shows the complete meter assembly.

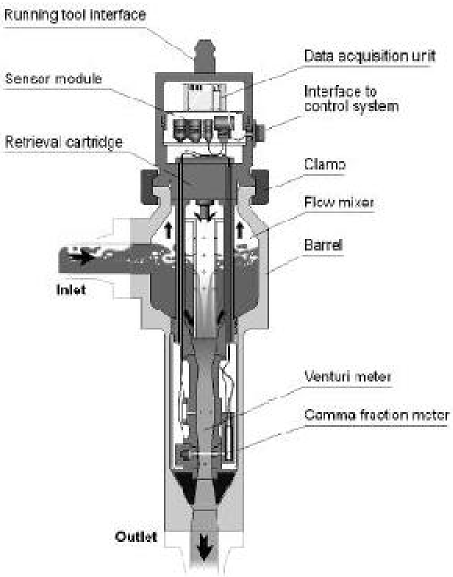

Figure 4 - Subsea Framo Multiphase Flow Meter

Figure 5 - Meter during Installation in the Subsea Manifold

Initial Set-up of the Meter

Fluid properties acquired during the exploration and appraisal phase of the field were used to set up the parameters in the subsea multiphase flowmeter. The parameters have proven to be sufficiently accurate to satisfy the accuracy requirement for the well testing, with the exception of the over prediction of the water production. The only parameter that was set in situ, was the empty pipe reference that was performed in during the commissioning of the meter with the meter subsea in 1997.

Salinity

Changes of salinity affect the Dual Energy gamma attenuation of the produced water, and therefore could impact the computation of the Water Liquid Ratio performed in the subsea multiphase flowmeter (P. Harrison et al [3]).

The water injection scheme calls for replacement of 70% of the produced liquids in the Balder sand, and is performed through the W4 vertical injector well. The salinity of the seawater injected in the reservoir is about half of the reservoir water. Eventually, injected water may breakthrough in some of the producing wells.

Reservoir simulation showed that sea water break through would only occur in well W2Z. All other wells in the field would be economically abandoned prior to the breakthrough of the injection water.

Furthermore, the utilisation of salinity and tracer tracking in the simulator enables a quantification of the salinity changes at the well W2Z. Figure 6 illustrates the salinity profile after 8.5 years of injection of seawater on a vertical cross section of the reservoir along the axis of the production wells W2Z, W3 and V1 and the W4 injector well. One can observe that the seawater is breaking through only at the tip of well W2Z.

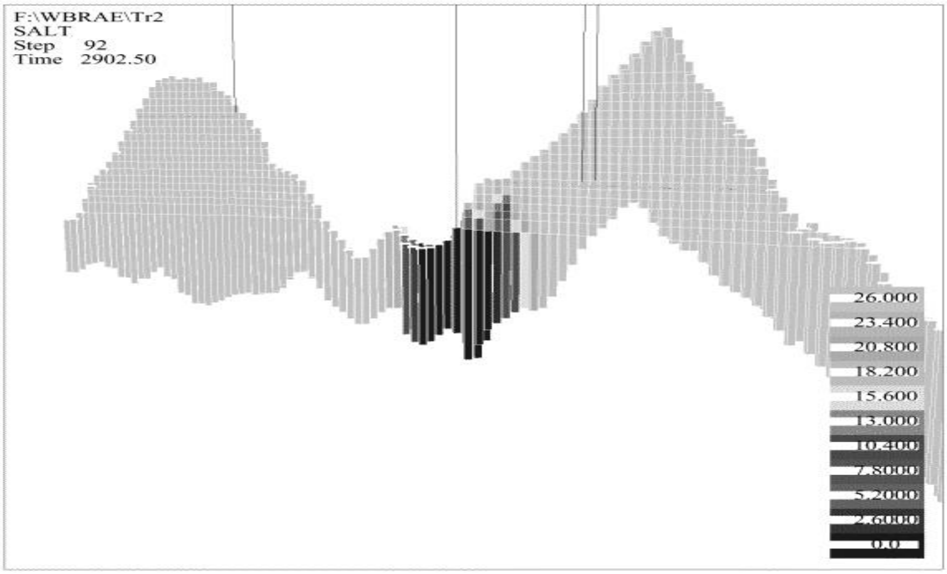

Figure 6 - Cross Section of Balder Sand Depicting the Variations of Salinity in the Reservoir at the Time of Injection Water Breakthrough at Well W2Z

The profile of salinity change versus time is shown in the Figure 7 for the field and W2Z. The reduction of effective salinity of the water metered for the well W2Z will result in an underestimation of the water cut by the multiphase flowmeter after 6 years if not accounted for. The recommended procedure consists in updating the multiphase flowmeter water parameters after the sixth year of operation with salinity information once a year. The salinity information will be obtained from the result of commingled water sample analysis and flowrate information from the individual wells. Such procedure leads to a maximum absolute error of 1.2 % on the estimation of the Water Cut, as illustrated in the Figure 7.

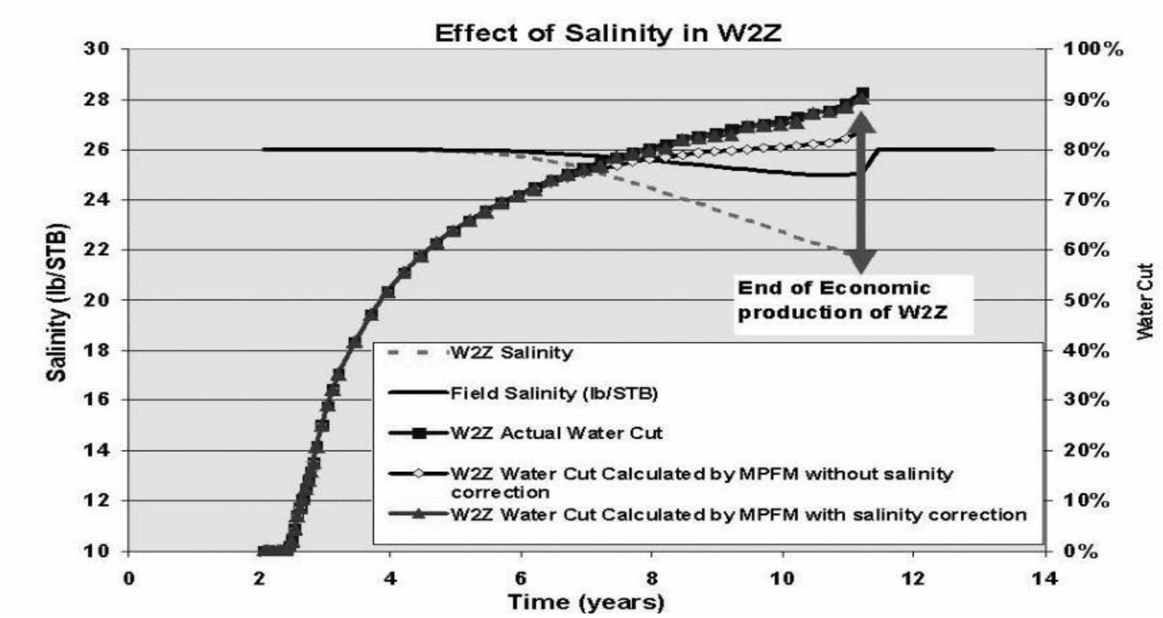

Figure 7 - Effect of Salinity in W2Z

Furthermore, the configuration of the piping of the subsea multiphase flowmeter will also allow for in-situ confirmation of the salinity, when the meter is bypassed (no flow through the meter). In such case, after segregation of the phases, the measuring section will be mostly exposed to water and therefore allow for an in-situ determination of the water attenuation.

Performance of Multiphase Meter

The conditions under which the meter is operating are nearly ideal: a gas volume fraction (GVF) of 50-60%, a water liquid ratio of 0-10%, a relatively low temperature (50C), and flowing pressures of 35 bar. A. Kennedy and I. Simm showed that within the first eight months of production the multiphase meter:

- Was within +/- 5% of the platform ultrasonically measured oil rates
- Showed a slightly higher water cut compared with pipeline samples
- Measured a free gas-oil ratio of +/- 280 scf/stb (roughly the GOR of the PVT analysis) compared to a platform GOR of +/- 225 scf/stb.

It should be noted at that time that the water cut was measured with pipeline samples which are often inaccurate, although the trend may have been prophetic. Sonic meters for measuring water production were installed a year after first oil. Since agreement between the multiphase meter and the ultrasonic meters has been demonstrated and no more accurate system for measuring water on the platform is in place, all subsequent comparisons between the multiphase meter and the platform will be made with the ultrasonic meters.

Since the its installation in October 1997, the multiphase meter itself has functioned without difficulties. A software problem did, however, develop between the MCS and the dedicated Framo computer during the summer of 1999, and for four months no data was received. Once the third party communication issue was resolved, data collection was returned to normal and no subsequent problems have arisen.

When compared with the sonic meters, the total liquid rates measured by the multiphase meter are within at least 1.0% over the life of the field. Figures 6 presents a comparison for currently measured liquid rates. During periods of stable platform production the values agree within the stated one percent. Since the well tests considered the potential of the well under the current operating constraints, and not platform interruptions, only the peaks of each curve should be viewed for comparison. A similar analysis during stable flow periods eighteen months into production yielded agreement to within 0.4 percent.

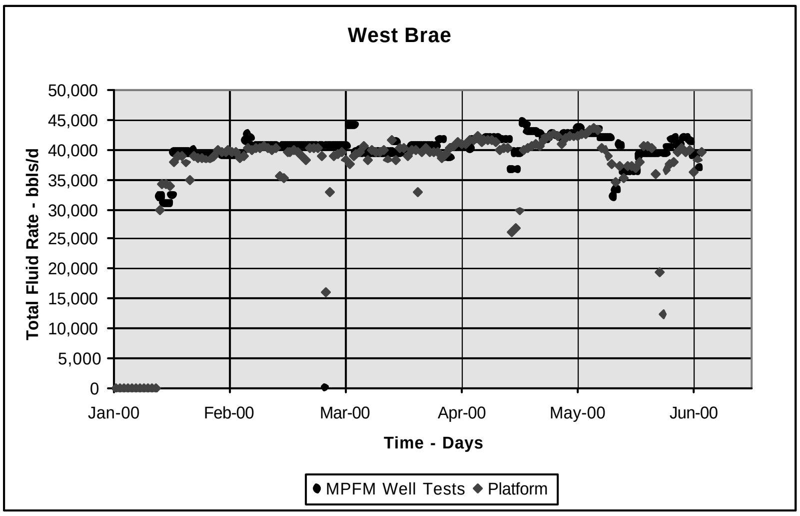

Figure 8 - Comparison of Total Field Liquid Rates

It was noticed that after the field began to produce water in excess of ten percent the multiphase meter was over predicting the amount of produced water. While it would have been ideal to close all but a single well to calibrate the meter constants, the loss of production required to perform the test was not acceptable, so a simple algebraic correction to the water cut was made instead with the results presented in Figure 9. If more precision is required in the future an update of the fluid properties will be made or empty pipe parameters will be measured, but for now the correction is more than adequate.

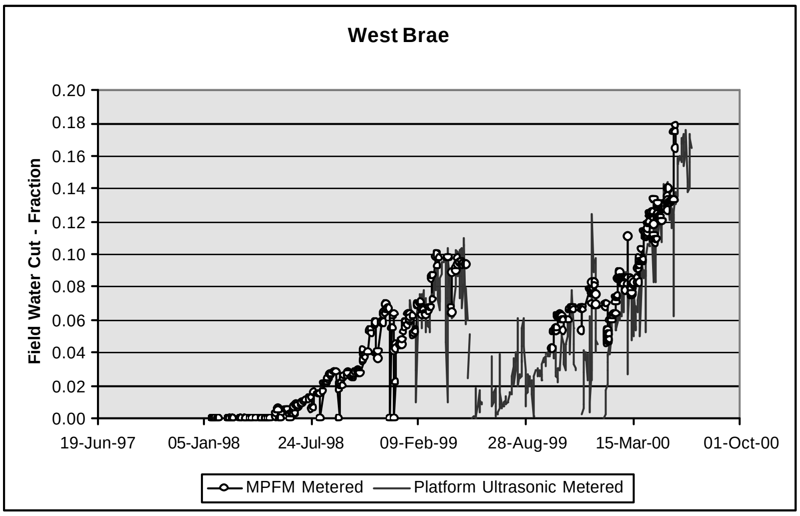

Figure 9 - Comparison of Field Water Cuts

Use of the Multiphase Meter Data

Each well is normally passed through the multiphase meter for periods of one to two days unless circumstances on the platform warrant otherwise. More frequent tests were conducted earlier in the life of the field, but with the current level of understanding, this sampling rate is sufficient. Data from the multiphase meter are used for the detection of gas coning, for monitoring water cuts, for the generation of well controls for daily use and for reservoir simulation from which investment and overall field management decisions are made.

Primarily, the meter is used in conjunction with the downhole pressure gauges to determine well controls, with a drawdown normally set just below the coning threshold for gas, in order to maximise oil production. This must be done on a trial and error basis since heterogeneity and incalculable skin factors preclude the analytic determination of the drawdown. That the wells are often close to this threshold may be seen when the backpressure is reduced and a GOR increase is observed in one of the wells. Additionally, when total water production becomes a problem, as it has on a few occasions, the liquid rates on selected wells may be optimally reduced with the knowledge from frequent testing.

Gas coning was first detected in the 16/07a-W1Z, a Flugga producer, after roughly six months of production. It was believed then that a gas cap did not exist in the Flugga, but an unexplained rise in the tubing pressure caused suspicion. At the time the increase in the field gas-oil ratio measured on the platform was probably insufficient to recognise an increase in GOR in one of the wells. After passing the W1Z through the meter and reducing the rate and hence the pressure differential the GOR was returned to its original (Figure 8) This confirmed the presence of a gas cap and also demonstrated the speed at which the gas cone collapsed. Gas coning has also been observed periodically in the W2Z and the W3.

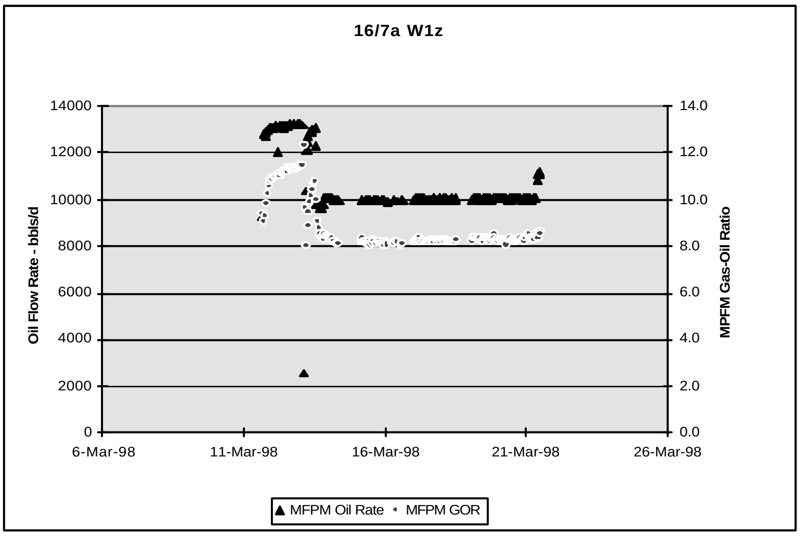

Figure 10 - Detection and Remedy of Gas Coning in W1Z

An unexpected benefit of the meter was seen with an explanation for the unexpected and episodic water production in the 16/07a-W2Z, the well nearest the water injection well. In the early part of 1999 the W2Z was swinging between a fifteen and thirty percent water cut seemingly without reason. After plotting the W2Z water cut and the W4 water injection rate as a function of time it was realised that a direct connection existed between the two wells (Figure 9). With no water injection the W2Z produced a background fifteen percent caused by a cone, but with injection a second source is seen, probably the result of a channel between the two wells. This undoubtedly would not have been realised had the wells been tested by difference

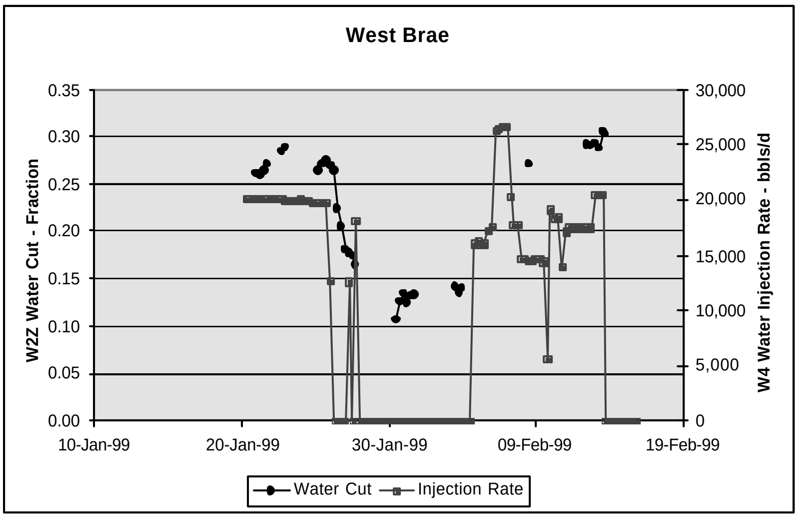

Figure 11 - Effect of Injection Rate in W4 on Water Cut in W2Z

The last primary use of the meter is for the creation of rate controls for reservoir simulation. For the West Brae models the total liquid rate is used as the input from which the quality of the description is measured by the closeness of the model bottom hole pressures and water production. In high permeability systems the relationship between pressure and withdrawals is crucial. Since drilling began three models have been constructed, each based on new geologic information. Typically after six months the additional rate information is added to the model and it is re-run to access the interpretation. Little of substance has changed with the last two models. As examples of the current model, the graphs for the input to the W1Z and the generated matches to actual data are presented in the following figures.

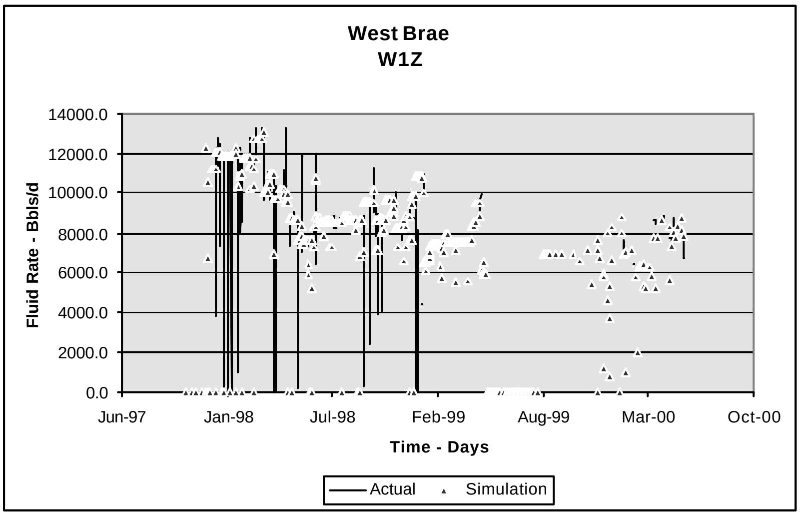

Figure 12 - Comparison of Liquid Rates in W1Z – MFPM and the Simulator

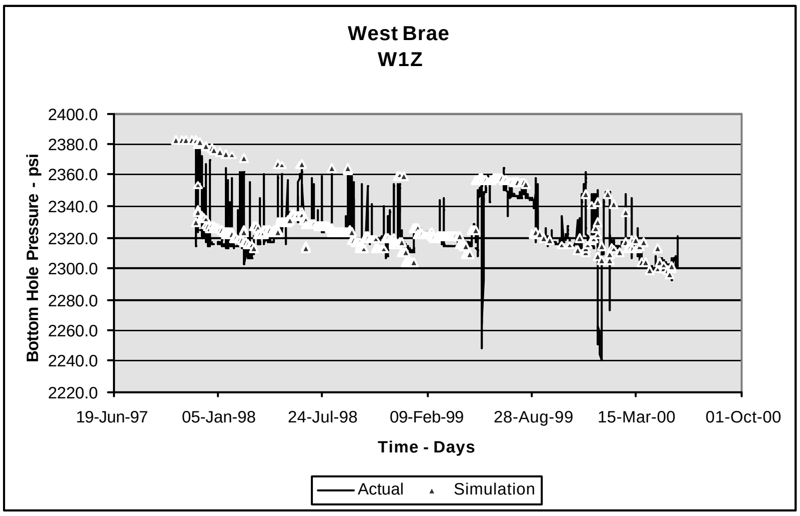

Figure 13 - Comparison of Pressures in W1Z – Downhole Gauge and the Simulator

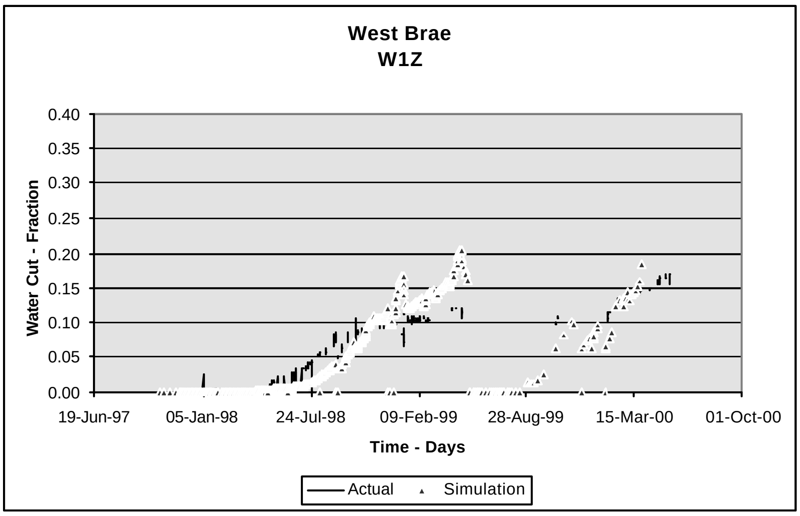

Figure 14 - Comparison of Water Cuts in W1Z – MFPM and the Simulator

Within the last year the existing model was used to justify the drilling of the 16/07a-W7 which has behaved as prognosed, and added 6,000 barrels per day of water free production to the field. Simulations have also bracketed the time at which an additional injection well would be needed leading to better capital management, and have quantified the effects of reservoir pressure loss.

Economic Value of the Subsea Meter

The reasoning used in the initial justification for the purchase of the meter remains valid. From the beginning of operation in October 1997 through June of this year approximately 325,000 barrels of oil were produced which would otherwise not have been had the wells been tested by difference on a monthly basis. Given the need for information with which to control the wells, it is unlikely that less than monthly differential testing would have occurred had the meter not been installed. This resulted in $5.8 million of added revenue, and may be compared with a total cost of £750k (roughly $1.2 MM) for the meter and its installation. Continuing the analysis into the future, a total of 725,000 incremental barrels of oil could be gained by continuous testing, and with a fixed platform life most of this added production would result in lost reserves. It could be argued that most of the production lost in differential testing would be regained at a later time, particularly with a longer platform life, but even with the most conservative economic assumptions, a net present value analysis of continuous testing would yield positive results.

The value for other uses of the multiphase meter are to some degree is tied into the value of testing in general. Would production be optimised if the wells were tested by difference? Would the wells that were coning gas be identified without the meter? Would water production be minimised when needed? Would the simulation model yield results that would have led to a different development had only monthly data been used? These and others are typical of the questions that must be asked when evaluating the meter. Undoubtedly the meter by itself and used in conjunction with the other instruments is of benefit in all of the aforementioned applications, but the quantifying the value is little more than speculation. Without these data the immediate recognition of opportunities for increased oil flow that would otherwise be done by trial and error at the cost of increased labour and oversight and lost or postponed revenue. It further provides a redundancy to the other measurement devices, the pressure gauges in particular, which are used for production monitoring. The loss of any subsea device in a system without redundancy would either lead to expensive intervention and lost opportunity.

Value must be given to the chain provided by the constant monitoring of the reservoir and its management. Optimising the economics requires quality data which maximises production through well constraints and from which confidence in future investments may be made in part from the simulations which use these data. The confidence in the predictions then leads to confidence in the production settings closing the chain.

Lessons / Recommendations for Future Installations

- Increase baud rate of the communication to the multiphase flowmeter to allow for better diagnostic capabilities during normal operations

- Installation of subsea sampling port as in the MacAdam and Monan Fields (Ref. 2).

- Replacement of the jumper connection between the Multiphase flowmeter and the SubSea Electronic Module by a stab-in connector to allow for diverless retrieval of the meter insert

- Isolation valves upstream and downstream the meter

- Injection line within the meter

CONCLUSIONS

- The Framo multiphase meter has performed reliably for the three years since its installation.
- The meter has provided tangible economic benefit over testing by difference resulting in added revenue of between 0.65 and 1.3 percent.
- Rate information provided by the meter has driven simulation efforts that have been integral in implementing revenue enhancing projects and better managing capital.
- While more difficult to quantify, the field has benefited through the rather fast optimisation of well constraints and led to better understanding and management of the field.
- The meter continues to provide exceptionally accurate total fluid rates. The current discrepancy between the platform and metered water rates will be resolved with an update of the fluid properties and an empty pipe test sometime in the future.
- No subsea intervention has been required
- None of the type of hardware problems reported by Humphrey et al has been encountered in the West Brae implementation.

ACKNOWLEDGEMENTS

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