North Sea FLOW Measurement Workshop

Production optimisation for improved field management by continuous well monitoring

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1 INTRODUCTION

This paper aims to promote better management of oil wells and oil fields. Monitoring and measurement of oil well production has always been challenging. Reasonable estimates of well production are essential for day-to-day reporting and production programming. Reservoir engineers need them for many aspects of field management, for example, updating reserve estimates, planning field extensions and deciding when to apply enhanced recovery processes. Well flowrates are required by production chemists to set the correct concentration of injected chemicals such as corrosion or hydrate inhibitors, demulsifiers, among others. These flowrates are also required for effective sand management.

However, when confronted by volatile oil prices, demands to cut operating costs, changes in ownership of assets and, indeed, short-sightedness by management in the face of these demands, appropriate monitoring of well production is often neglected. Every now and then spectacular examples of the consequences of such neglect hit the headlines. In 2004 Shell admitted to overestimating its reserves by some 20%, leading to a sharp fall in its share price and litigation entailing huge fines, costs and compensation claims that lasted for years afterward. In the 2010 Deepwater Horizon oil spill in the Gulf of Mexico, initial flowrate estimates varied from the BP figures of 1000-5000 bbl/day to the Flow Rate Technical Group's figure of 62,000 bbl/day. It is evident that not knowing the flowrate was significant in the litigation and costs that followed. But there are far more mundane examples where poor production measurements lead to large revenue losses that are not really noticed.

We discuss conventional well test methods and illustrate that they often cannot give accurate estimates of well production. We point out that continuous well monitoring is more and more being recognised as a better alternative. We give examples of the demonstrable benefits such as optimised production, predictive well maintenance and increased revenues. Sadly we concede that despite the clear evidence that continuous monitoring gives significant benefits, there is little apparent active interest from the industry worldwide. We ask why is there such an inconsistency, but we are unable to give good explanations.

2 CONVENTIONAL DETERMINATION OF WELL PRODUCTION

A major problem in determining total well production is the intermittent nature of conventional well testing by test separators or by multiphase meter testing packages. The key assumptions underlying this approach are:

a) well production is normally stable and declines slowly with decreasing reservoir pressure
b) well production does not change when the well is connected to the test equipment.

These may have been reasonable assumptions in the early days of the oil industry when only easy reservoirs could be produced and when continuous monitoring was not feasible. There is strong resistance to doing anything else. After all, the oil industry has been operating for more than 150 years and has been one of the most successful industries of all time. Why change?

Figure 1 Test separator in Nigeria

Figure 1 shows a conventional test separator package of a design common around the world. From a project view it can be considered a good design. It is relatively compact, making it straightforward to transport and install. The instrumentation is at a convenient height for working on, and there is not much complexity.

Unfortunately the above advantages from a project point of view make the equipment poor from a measurement point of view. The compactness may mean there is insufficient residence time to separate the liquid and gas, with possible liquid carry-over in the gas outlet and gas carry-under in the liquid outlet. The liquid flowlines are not very far below the liquid level in the separator and have several bends. This may result in gas breakout at high liquid flowrates. It is not easily practical to change the sizes of the liquid and gas flowmeters, so as the flowrates of the wells change the meters may not be appropriate. Further, can the well testing systems cope with the wide range of fluid compositions and flowrates over field lifetimes? Are these systems operated and maintained properly in the cost-cutting environment prevailing at present?

Using a multiphase meter package as a test separator replacement gives some advantages but there remain the issues of matching the flow range of the meter package to the wells to be tested, and the problem of the flow changing when the well is switched to test.

However, it is becoming widely acknowledged that measuring the flow rate for a few hours per month cannot give a reasonable estimate of the production from many wells, if not most. A good example is NEL's Flow Measurement News. The September 2015 issue of stated that, *"Outdated reservoir management procedures (were) impacting hydrocarbon economic recovery"* and that *"it is clear that periodic measurements are not fit for purpose and only continuous measurements offer the ability to react to dynamic flows"*.

3 EXAMPLES OF CONTINUOUS WELL MONITORING

This section gives examples of continuous monitoring of a variety of wells. There are screw pumped land wells in Russia, a naturally flowing land well in Nigeria, a problem gas lifted offshore well in Brazil and a gas lifted offshore well in Malaysia. They all illustrate our main point that intermittent testing of these wells could not give accurate estimates of production. They also illustrate our opinion that the trend information, showing the dynamic flow profile of the wells, is very valuable in itself, even if an accurate flow figure cannot be given.

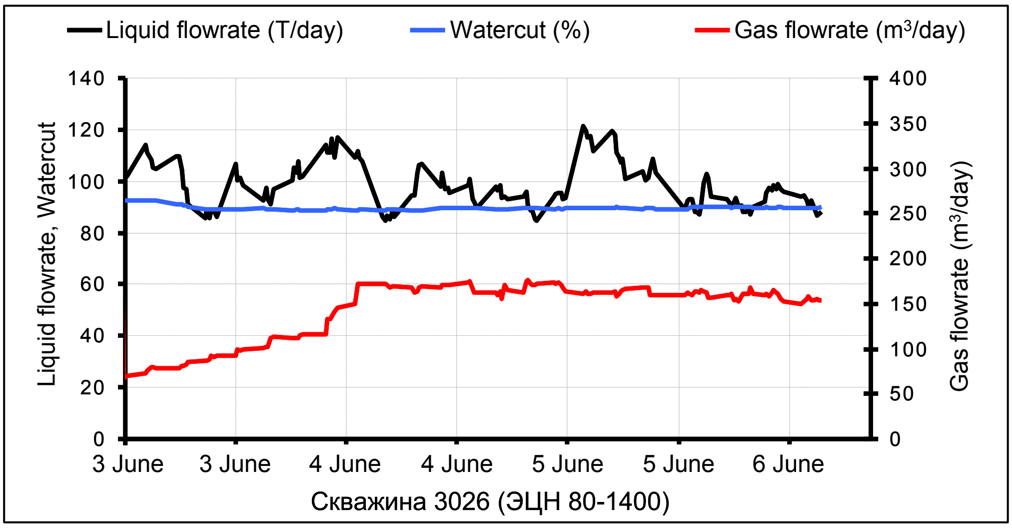

Figure 2. Three days production from well with downhole centrifugal pump

Figure 2 shows the production from a well fitted with a downhole centrifugal pump. For one of the authors (A. Jamieson) this plot was very significant, as when he first saw it, about 2004, it was the first time he had been faced with the fact that oil wells do not produce steadily. Fluid entering the bottom of the well will all be cleared quickly by the centrifugal pump, and the flow at the top of the top will be a good approximation to the flow from the reservoir to the well bore. In this case the liquid flowrate varies between 85 T/day and 122 T/day during a 24 hour period. The gas flow is relatively steady as the centrifugal pump mixes the gas and liquid together. It is evident that testing this well intermittently would give inaccurate results. Note that the production flowrate depends on the type of pump. For a well fitted with a beam pump, the liquid flowrate would be much steadier, with large variations in the gas flowrate.

Translation

Top heading: - Liquid Flow rate (t/day): Water cut (%): Gas Flow Rate (m3/day): Measurement update time (min): Trend (Liquid Flow Rate).

X-axis: Time in days **Left Y-axis:** Liquid Flow Rate
Right Y-axis: Water cut, Gas Flow Rate, Measurement update time

Figure 3. One month's production record from a pumped heavy-oil well

Figure 3 shows a much more recent and more detailed record from Russia of a typical pumped well over a month. The magenta line at the top shows a fairly steady watercut of about 90% and more. The dark blue jagged line shows a very variable liquid flowrate of about 180 T/day at the highest and about 70 T/day at the lowest. The dark trend line shows the average liquid production increasing steadily over the month, not decreasing as expected by conventional thinking. The red gas line at the bottom shows a very variable gas flowrate, from essentially zero to over 40 m^3/day. The cyan line records a parameter which indicates the quality of the measurement, and is not discussed here. Again, it is evident that this well is not suitable for intermittent testing.

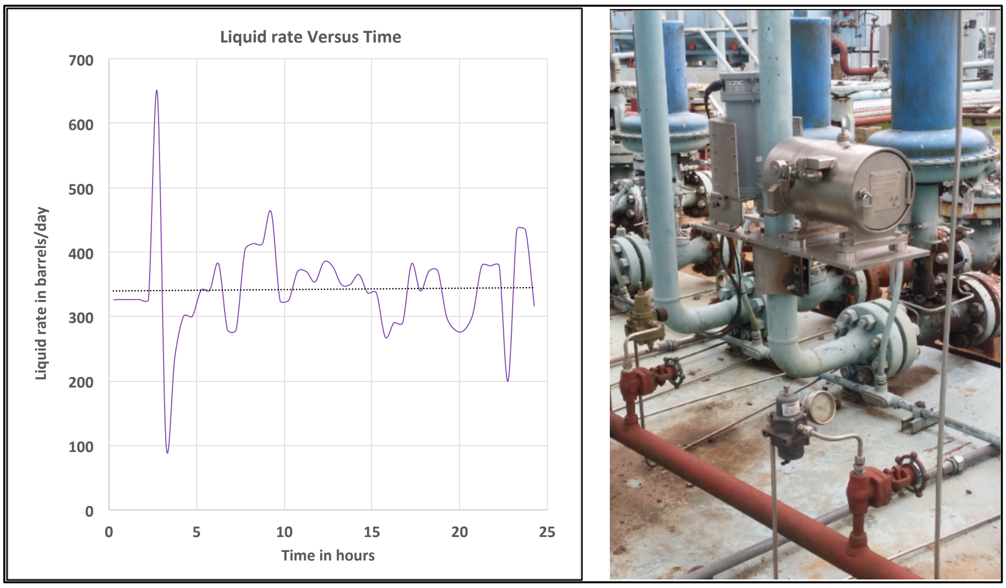

Figure 4. Typical 24 hr Nigerian production, also showing Neftemer well monitor

Figure 4 shows a typical 24 hr record of liquid production from a naturally flowing Nigerian well, together with the clamp-on Neftemer well monitor used. Again, a very large natural variation in flowrate. Assuming a uniform production based on a well test may lead to:

1. Struggling to account for missing production that never was.
2. Struggling to account for excess production.

The next series of figures illustrates a problem with a gas lifted well on a Brazilian offshore platform. The operators had been unable to test this well for some years, and they had no idea how much it was producing. Installing a clamp-on well monitor allowed the problem to be diagnosed and solved over some fifteen days. On each of the fifteen days the well production profile was different and three extracts from the production record are given when the well was misbehaving.

The well monitor is essentially a fast gamma absorption meter, recording the varying countrate as the multiphase mixture passes the gamma ray beam. It is straightforward to calibrate the gamma absorption meter as a gamma densitometer for the well fluids. These densities, in g/cm^3, so that water is 1.0 g/cm^3, are shown in red in the first three figures, 5a, 5b and 5c. The flowrates of liquid and gas are calculated from patterns in the fluctuations in multiphase density. The current algorithm for calculating flowrates was unable to use the extreme fluctuations shown in Figures 5a, 5b and 5c. Hence no flowrates were available, but these were not required to diagnose the problem. This demonstrates that continuous monitoring of significant parameters, in this case multiphase density, can play a very important role in production optimisation.

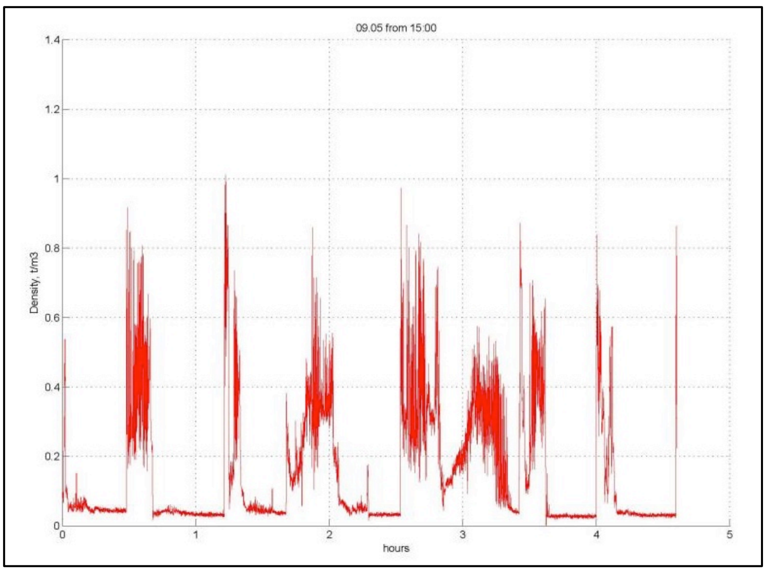

Figure 5a

This is a 5 hr extract from the data. Note particularly the periods of lowest density which correspond to almost dry gas. Adjacent to these one can see periods of wet gas. Then there are periods of low/medium GVF multiphase flow, with spikes of pure water

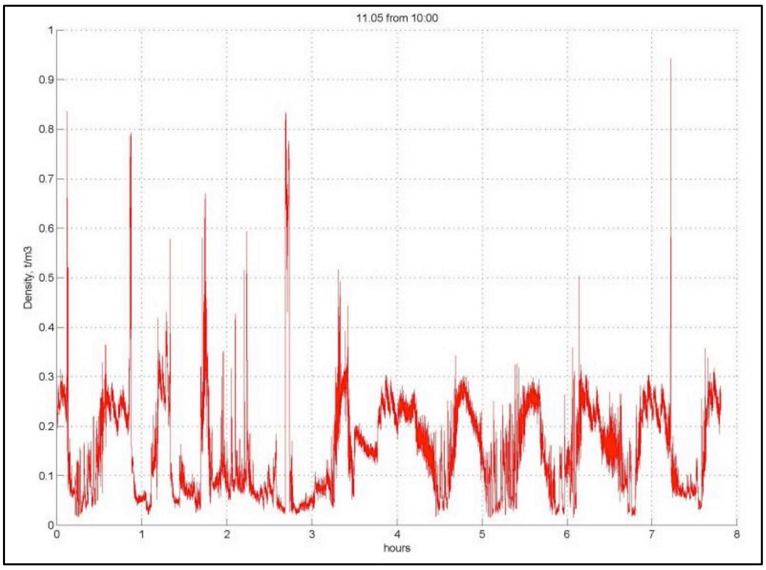

Figure 5b

This is an 8 hr extract from the data. There are no dry gas periods. The first four hours show a more jagged profile with many water spikes. The second four hours indicate a very frothy multiphase mixture, varying in GVF from about 60% to high in the 90s.

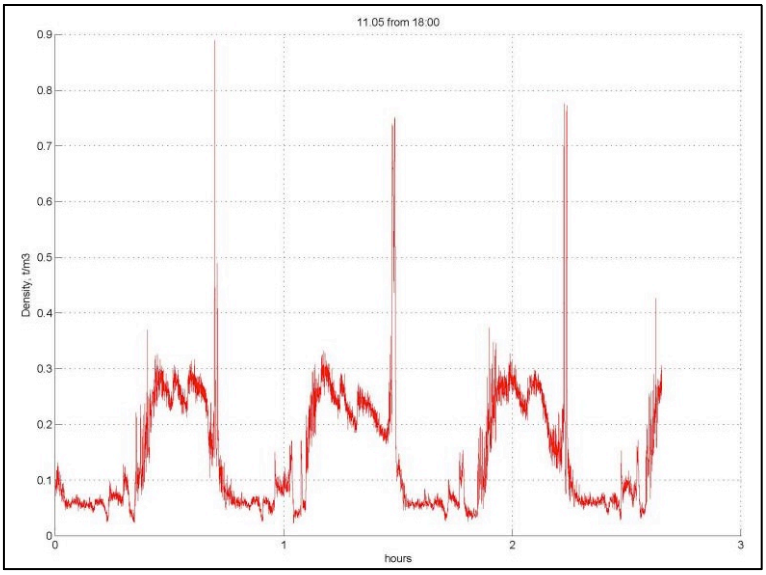

Figure 5c

This is a 3 hr extract from the data showing regular cyclic behaviour where very wet gas of low density is followed by a frothy mixture with a GVF of about 60%. Meanwhile water separates in the well bore and gets expelled in a short duration spike of water.

When they saw this data, the operators realised they were injecting too much gas, resulting in the unstable behaviour of the well. Figure 5d shows the results of reduced gas. Multiphase fluid density in kg/m^3 is in blue. The fluid is varying mostly in an approximate GVF range of 60-75%, with excursions to about 90%. With this kind of multiphase mixture, flow calculations were possible, and the liquid flowrate is shown in magenta in T/day. There were large variations in the flowrate, implying that intermittent testing would give poor results for this well.

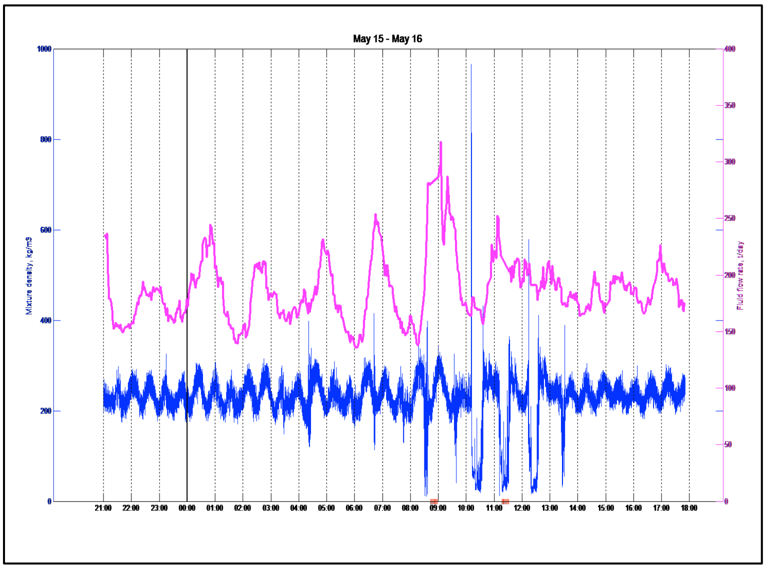

Figure 5d

This is a 21 hr extract from the data. The well has been stabilised and it is possible to calculate flowrates. Note the excursions to high GVF (low density) and the tendency for the well to become unstable. The red dots on the x-axis indicates when the algorithm was unable to calculate flowrates.

The last of these examples of continuous flow measurement comes from a well monitor installed on a gas lifted well on an offshore platform in Malaysia. The results were presented at the South East Asia Workshop in Kuala Lumpur in 2016, and further information may be found in the proceedings.

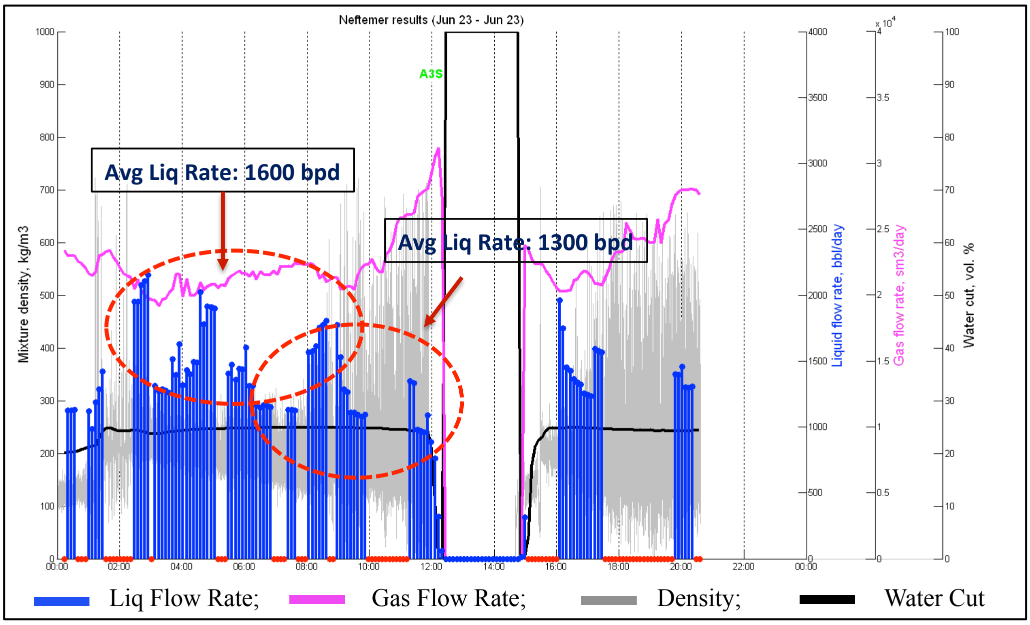

Figure 6. 24 hr data record from gas lifted well on a Petronas offshore facility

The liquid flowrates are shown as blue bars with a circle at the end. This reflects the way in which the well monitor works, and is often preferable to a line, which is used for the gas flowrate (magenta) and the watercut (black). The multiphase density is shown in grey in the background. The red bars on the x-axis show where the algorithm of the well monitor was unable to calculate flowrates for the very high GVF fluid.
The results were reported by Petronas as:

- Large density variation – from 100 kg/m3 to 650 kg/m3
- Liquid variation from 1250 to 2000 bpd (~23% variation)
- Discontinuous Readings – though trend was visible

The variation in liquid flowrate was such that intermittent testing of this well would have given poor results.

4 PRODUCTION OPTIMISATION

It would seem that this should be an important aim in the oil and gas industry. Optimising the production from each and every well would seem to be a matter of course, but unless appropriate tools are provided, it is very difficult for staff to achieve the best results. The previous section has shown that many, we suggest most, oil wells do not produce steadily. Consequently conventional intermittent well testing cannot give good results. This is a major upset to a 150 year tradition.

Three examples are given, first the impact of not making best use of conventional well test data. Second, using continuous monitoring to optimise gas lift gas usage. Third, in monitoring the decline in production of a well and the effects of a work over.

One client made available a large quantity of well test data gathered over many years to assist in the selection of an appropriate test location. On another occasion there was interest in finding wells where production could have been optimised. It was not difficult to find examples. Figure 7 shows test data for one well gathered over nine years. Tubing head pressure, oil flow rate and choke setting are shown on the plot.

In the first two years it appears only five well tests were done, then in the next five years only one well test was done. Then in 2009 well testing restarted and was done at approximately monthly intervals until 2012 when our data stops. It is these last three years from June '09 to November '12 that are of interest.

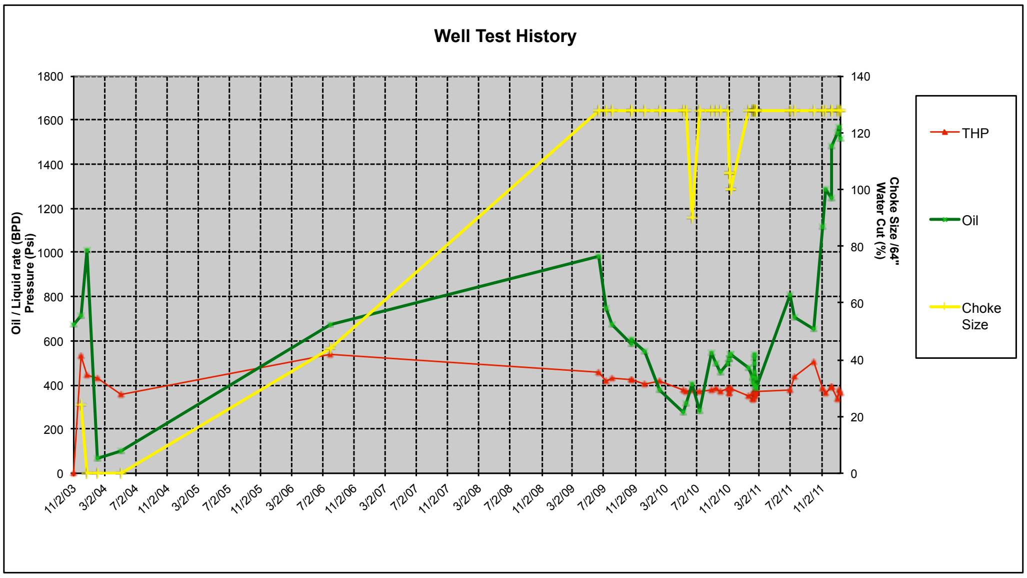

Figure 7. Test history of a well

For this approximately 900 day period the tubing head pressure is fairly constant and the choke setting is more or less constant. It is evident that at the beginning and end of this period, the well can produce at 1000 bbl/day. Indeed at the end of the period, production increased dramatically. Had someone taken an interest in this well? What is clear from a simple estimation of the area under the graph is that about half of the potential production over this period was lost. At \$50/bbl, 1000 barrels for 900 days would generate \$45 million. Half of this is \$22.5 million which could easily pay for the costs of continuous monitoring.

The second example returns to an optimisation exercise carried out on the Malaysian well shown in Figure 6. Again, more details on this exercise can be found in the proceedings of the 2016 South East Asia Workshop in Kuala Lumpur.

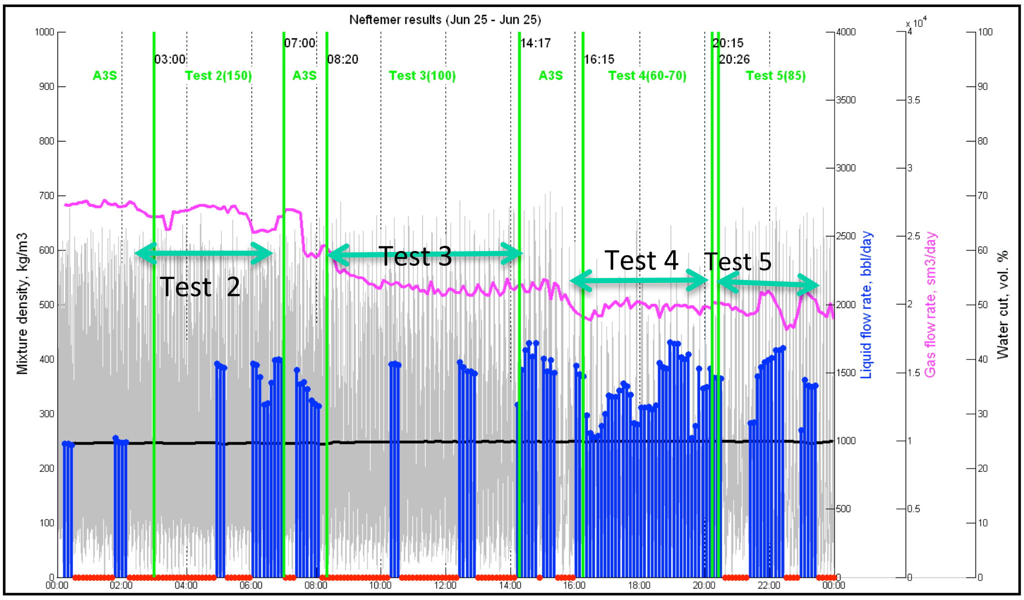

Figure 8. Gas lift optimisation exercise on offshore Petronas facility

The aim of the exercise was to confirm the sensitivity of the clamp-on well monitor and check whether the lift gas usage was optimal. Lift gas was injected at five different rates and the liquid flowrates were determined using the well monitor. Figure 8 shows a plot of the data gathered during four of the five tests. As previously stated, the current algorithm is not optimised for calculating flowrate at very high GVF and there were gaps in the data indicated by the red bars on the x-axis. Nevertheless one can see that there was sufficient data for carrying out this exercise.

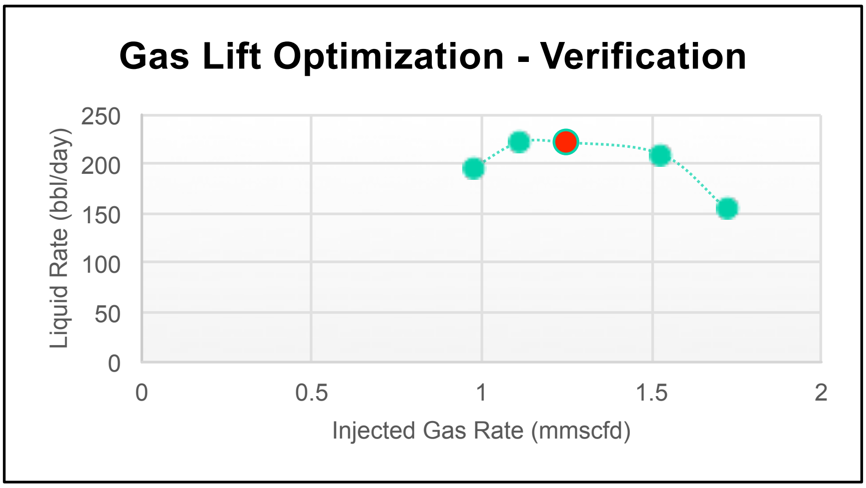

Figure 9. Verification that gas lift was close to optimal

Figure 9 is a plot of liquid flowrate against injected gas flowrate. The red dot indicates the injected gas rate chosen by the production staff. It is evident that this was close to optimal, an excellent achievement given that the staff had very limited means to estimate the correct quantity of lift gas.

The third example on production optimisation demonstrates in Figure 10 how a continuous well monitor can indicate when a well needs some care and attention.

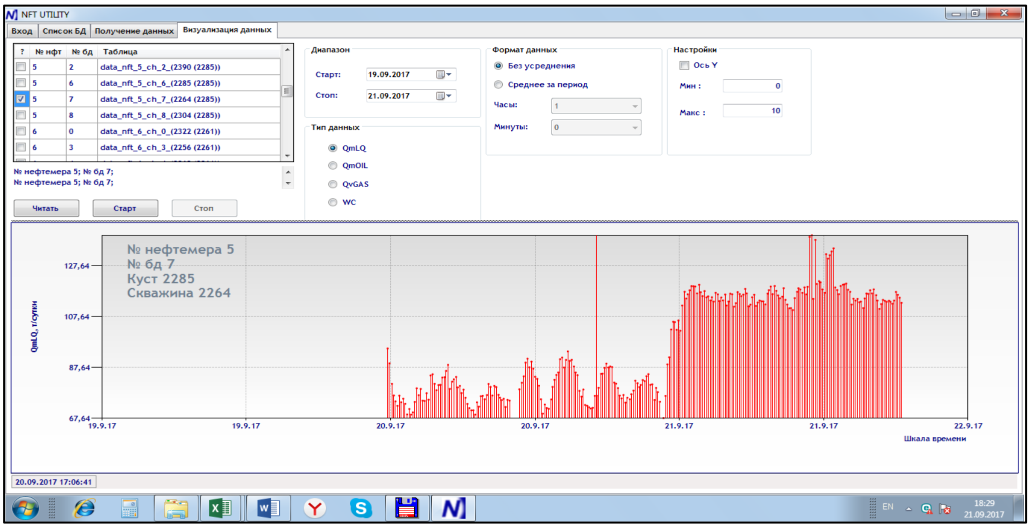

Figure 10. Recent optimisation of a Russian well

Figure 10 shows the liquid flowrate from a Russian well over 2 days before and after corrective action. Before, the flowrate is about 75 T/day, and is irregular. After, the flowrate is about 115 T/day and is less irregular. This represents an increase in production of over 40%.

These examples demonstrate clearly that using continuous measurement of wells makes optimisation of well production much easier compared to using conventional intermittent methods.

5 FIELD MANAGEMENT

Field management involves all departments in oil and gas companies and is never straightforward. If we consider the several field life stages and the departments that may be most responsible, we get the following:

- Exploration phase – this is mostly a Drilling responsibility
- Development phase – Projects are in charge
- Production phase – Operations are now in control
- Improvement phase – is this another Project, or an Operations matter?
- Rundown and decommissioning – Which departments??????

The Reservoir Engineers appear to have been left out, but they are responsible for the source of the company's cash flow, the oil and gas reservoirs. Also left out are the Metering and Measurement community, to whom this paper is mainly targeted. They mostly are concerned with sales or fiscal metering, the 'cash registers' of the company. These are very important, but they do not add a single barrel of oil extra. On the other hand, optimising the production of a very ordinary well can increase the cash flow of the company by some $22.5 million over three years.

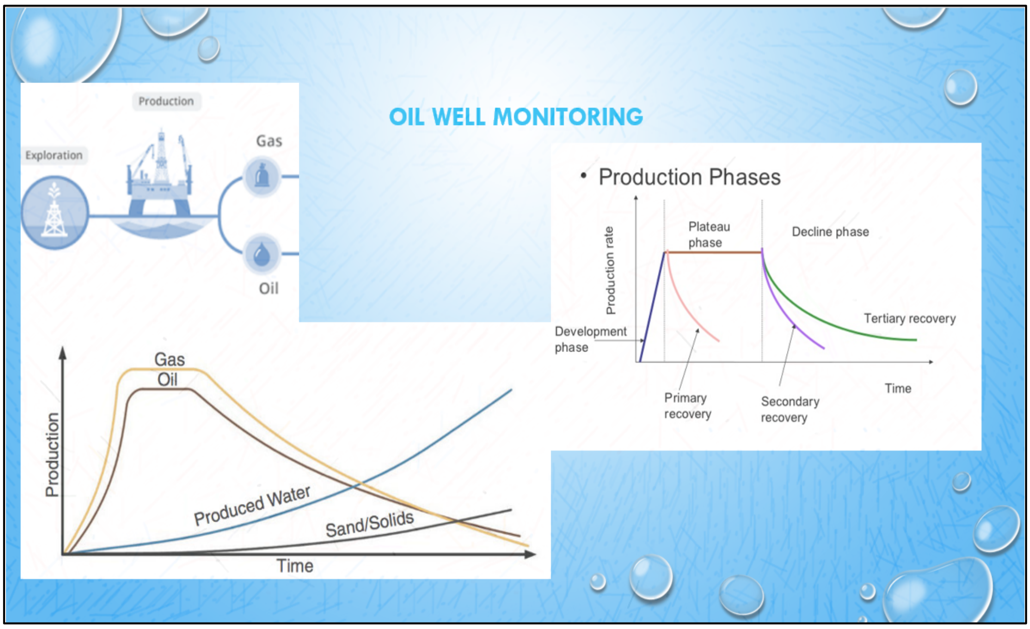

Figure 11. Stages in field life, and the fluids and substances to be measured

Figure 11 illustrates the stages in field life and the various fluids and substances that have to be metered, monitored or measured.

Few reservoir engineers get involved in the details of measuring the oil and gas flows in wells. Few metering and measurement specialists talk to the reservoir engineers. Nor do they talk to production chemists who need to know well flowrates quite accurately to get the correct dosage for demulsifiers, hydrate inhibitors, corrosion inhibitors and a multitude of other additives. Nor do they talk to sand control specialists who need to know well flowrates to set limits to prevent well erosion.

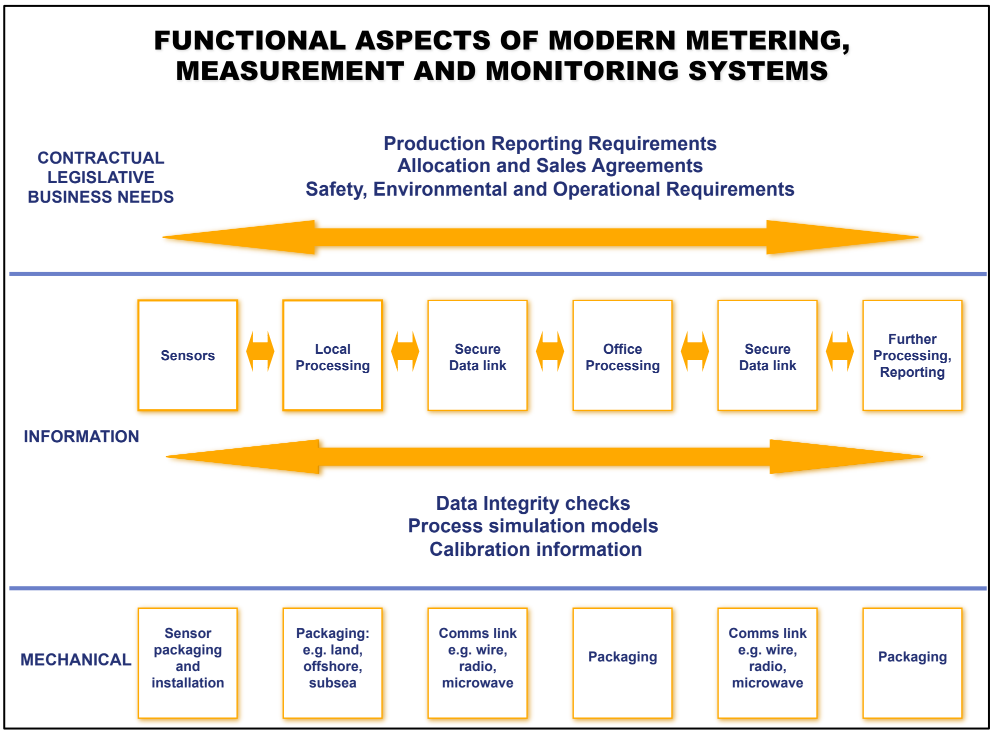

Figure 12. Functional aspects of modern measurement and monitoring systems

Figure 12 splits the functional aspects of modern measurement systems into three areas. At the top are the business needs. These are likely to change with time. If you have no business needs for measurement, you don't need to measure. In the middle are the kinds of information you need to satisfy the business needs. These may also change with time, and this will lead to necessary costs. At the bottom are the wide range of actual equipment that provides the kinds of information that satisfies the business needs. This process should be driven essentially from the top down.

Accordingly, for those involved with measurement at all stages of field development the basic questions, "Why measure?", "What information?" and "What equipment?" should be asked. These all change for the different stages, but unfortunately it is not usual to keep proper track of the changes. And people forget that installed equipment only works properly for part of the field life and will need to be replaced.

6 A WAY FORWARD

This paper presents strong field evidence that oil wells may vary naturally in flowrate by easily over 50% over 24 or 48 hours.

Coming to terms with this means that a 150 year tradition of intermittent well measurement is no longer fit for purpose. A new mind set is required, whereby production from oil wells is monitored continuously. This should result in dramatic improvements in well production optimisation. Better field management should then be a direct and automatic consequence.

Large scale field deployment may be seen as impractical, but this is not the case. Deployment starts with two well monitors on one facility and add more steadily. Repeat this for other facilities until the whole field is done, and then repeat for other fields.

Training of oil company and service company staff is essential. The gradual deployment allows the possibility for excellent on-the-job training. It will require the close collaboration between departments, but this can only be to everyone's benefit.

The timescale to do this is not so long. A reasonable estimate for equipping ten flow stations each with ten wells is four years. Included in this timescale are checks to confirm that the changeover is indeed paying for itself.