SPE 99408

From Reservoir to Well: Using Technology for World-Class Results in Trinidad and Tobago

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This paper was prepared for presentation at the 2006 SPE Intelligent Energy Conference and Exhibition held in Amsterdam, The Netherlands, 11–13 April 2006.

Abstract

The Mahogany field in Trinidad and Tobago was developed as a dedicated gas field with reserves of 2.6 TCF to supply gas to the Atlantic LNG Plant in 1999. At that time the field was the sole provider of gas to the ALNG project. The vision was to ensure that the field was a world class producer that met the demands on the LNG Train 1 market. It was clear from the onset that the only way to deliver this vision was through the use of technology. Even more so since the field is a highly faulted, complex reservoir, that has a thin oil rim.

With over 1TCF of gas already produced, the Mahogany Team is on its way to delivering this result. Technology has been the backbone of the Mahogany field development, with new technology being used from inception through drilling, reservoir monitoring and production. This intimate surveillance of the wells through new technology has generated a wealth of information. Updated simulation models have been generated using this data, which have led to a deeper understanding of the dynamic fluid distribution in the complicated reservoirs. This in turn has been the critical factor in the successful infill development of the field. It is clear that one of the critical success factors in managing the development and exploitation of the field was the use of technology.

This paper will discuss the use of technology along the value chain of first drill to present and will highlight the real benefits of using technology along the way, primarily highlighting the successful use of fiber optic flowmeters, distributed temperature system, acoustic sand detectors and permanent downhole gauges.

Introduction

The Mahogany field was discovered in 1968, approximately 60 miles off the southeast coast of Trinidad at a water depth of 285 feet. The exploration well (EM2) discovered gas bearing sands. Further analysis had shown that it was a very large gas field. At that time however there were no gas markets hence the field was not developed.

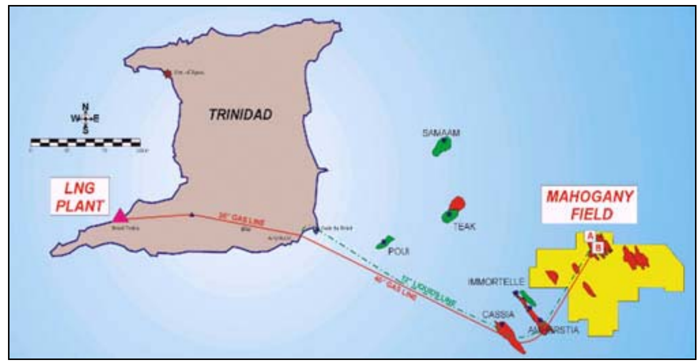


Figure 1 –Map of Trinidad showing location of the Mahogany field.

In 1994 the Atlantic LNG (ALNG) plant was sanctioned, this led to renewed interest in the Mahogany Field and its subsequent development. Further exploration wells were drilled in 1994 (EM3), 1995 (EM4) and 1996 (EM5 & 5X) to prove reserves in the major target sands identified from the reservoir studies. The Mahogany Field is a laterally extensive faulted anti-clinal structure comprising Pleistocene aged sands and shales. It consists of several depositional cycles within an overall deltaic, shore face environment. In addition to the large gas sands there was also a thin oil rim, which also had to be successfully developed.

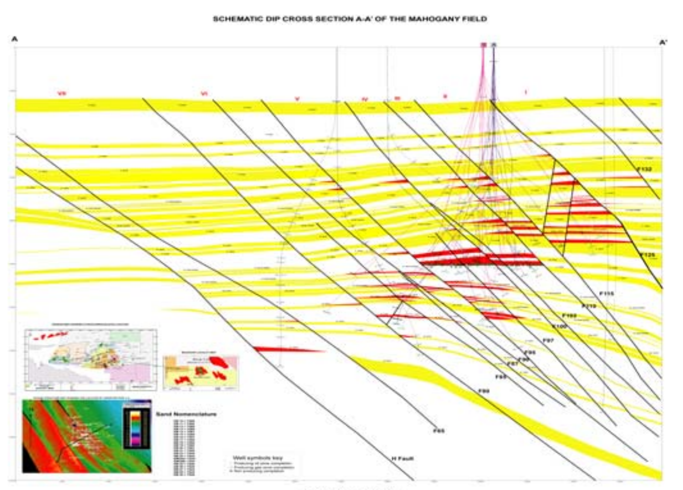


Figure 2 –Mahogany Cross-Section showing complex faulting.

Technology would play a key role to meet contractual agreements as well as effectively depleting this oil rim. This was even more evident, given the fact this was the first major gas field development in Trinidad and Tobago. Technological advances in the field of well surveillance have played a pivotal role in delivering more than half of the field's recoverable reserves.

This paper will highlight the use of technology for surveillance, showing the positive impact it has made to production as well as challenges encountered along the way.

Technological Advances in Surveillance

Permanent Downhole Gauges.

The complex, faulted structure of the Mahogany field introduced the challenge of successfully draining all of the individual fault blocks. The geological analysis was inconclusive on whether all the faults were sealing, hence there was a major uncertainty on the number of wells that were required to both recover the booked reserves and meet the ALNG contracts.

The subsurface team at that time recognized the importance of monitoring the change in reservoir pressure, as this would be a key indicator of the connectivity of the major faults. There was a lot of resistance to periodically shutting in the wells to run traditional wireline conveyed pressure tools, since this would incur production losses.

The proposal was made to use permanent downhole gauges as part of the completion design. This would allow for continuous pressure measurement as well as reduced downtime on producing wells.

The challenge of being the first field, in Trinidad, to use permanent downhole gauges was readily accepted by the completion team.

In the first phase of drilling, sixteen wells were completed with all but three (MA-01, MA-03, MB-01) having permanent gauges. Operationally the installation of the gauges were a success, with MA-05 (a gravel packed, vertical gas well) being the first well in Trinidad to have a permanent gauge installed.

While this was a landmark achievement in technological advances in Trinidad, it did create a number of challenges and key learnings.

The first major challenge faced was data management. Now that the majority of wells had permanent gauges there was a wealth of data that needed to be stored and made readily available on request. To overcome this problem a new control system was installed. This allowed for the real time data to be stored, as well as provided a tool for viewing the pressure data that was recorded every five seconds. BP's FIELD OF THE FUTURE (FotF) ISIS system was not available at the time, which when installed will provide higher frequency of data recording and additional functionality.

Another major challenge that was faced was the uptime of the gauges. The sixteen wells were completed on two platforms (ten wells on Alpha and six wells on Bravo). All of the gauges used on the wells drilled on the Alpha platform had prematurely failed, in some cases, within months after installation. An in depth analysis of the gauges were conducted and the root cause of failure was believed to be the type of downhole gauges being used. After the analysis was concluded the service provider was changed and a different brand of gauge was used on the subsequent wells drilled on the Bravo platform. The uptime of these gauges was much different, with only one failing. Even after the wells are no longer on production the gauges remain online, still sending valuable information to be analyzed.

Well Name	Well Status	Downhole Gauge	Gauge Status
MA-01	Abandoned	No	N/A
MA-02	Shut In	Yes	Failed
MA-03	Shut In	No	Failed
MA-04	Shut In	Yes	Failed
MA-05	Shut In	Yes	Failed
MA-06	Shut In	Yes	Failed
MA-07	Abandoned	Yes	N/A
MA-08	Abandoned	Yes	N/A
MA-09	Shut In	Yes	Failed
MA-10	Shut In	Yes	Failed
MB-01	Shut In	No	N/A
MB-02	Flowing	Yes	Online
MB-03	Shut In	Yes	Online
MB-04	Shut In	Yes	Online
MB-05	Abandoned	Yes	N/A
MB-06	Shut In	Yes	Failed

Table 1 – Gauge status of Phase I wells

After the success of Phase I drilling, Phase II began eight months after the last well was drilled in August 2000. In total twelve new wells were drilled and four Phase I wells were re-completed. In these sixteen completions all but one (MB-08) had a permanent downhole gauges. The performance of these gauges have been a resounding success, with all but one well (MA-15) still online.

Well Name	Well Status	Downhole Gauge	Gauge Status
MA-11	Flowing	Yes	Online
MA-12	Flowing	Yes	Online
MA-13	Flowing	Yes	Online
MA-14	Flowing	Yes	Online
MA-15	Flowing	Yes	Failed
MA-01RC	Abandoned	Yes	N/A
MA-07RC	Flowing	Yes	Online
MA-08RC	Abandoned	Yes	N/A
MB-07	Flowing	Yes	Online
MB-08	Flowing	No	N/A
MB-10	Shut In	Yes	Online
MB-11	Shut In	Yes	Online
MB-12	Shut In	Yes	Online
MB-13	Flowing	Yes	Online
MB-14	Flowing	Yes	Online
MB-05RC	Shut In	Yes	Online

Table 2 – Gauge status of Phase II wells

The MA-01 well was later re-completed in April 2005. The new gas well also has a permanent gauge installed. This gauge is also currently online.

The data obtained from these downhole gauges has been pivotal in the proper management of the reservoirs. There are many examples where this data has changed the way the field was developed. One such example is the depletion of the 21 sand reservoir, which is the second largest reservoir in the Mahogany field. The producing reservoir is divided into two fault blocks (fault block 4 and 5) by a normal fault of varying throw along it. Hence it was unclear whether the entire fault was sealing.

Figure 3 below graphically displays data obtained from permanent downhole pressure gauges in 19 wells completed in Mahogany's 21 sand reservoir from initial completion date to present.

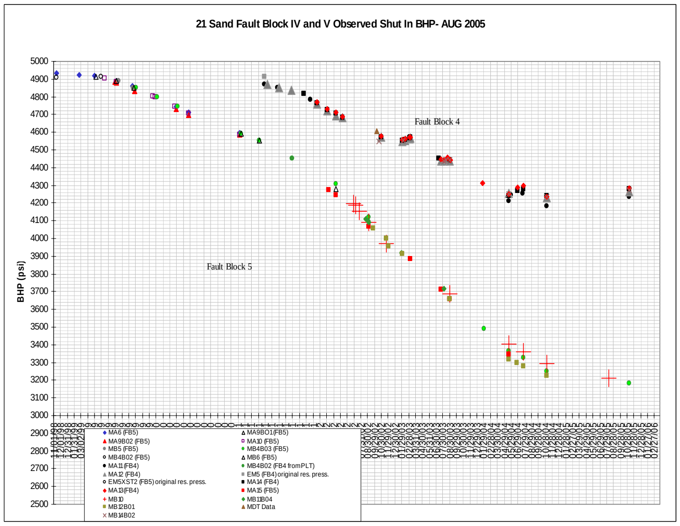


Figure 3 – Shut in bottomhole pressure data in the 21 sand reservoir.

The data clearly shows two separate and distinct pressure trends for the wells located in blocks 4 and 5. This verifies that the blocks are separated by a sealing fault and justifies the geological interpretation of this 21 sand reservoir. It also meant that additional wells needed to be drilled in order to recover the 21 sand reserves. The graph also provides evidence which indicates that both blocks are receiving pressure support from a very strong aquifer since pressure decline rates are being arrested and some data points even indicate re-pressurization by the aquifer in one block (fault block 4). When this data was integrated into the reservoir model it showed a larger energy contribution from the aquifer in block 4 compared to block 5, which further substantiated the geological model since the aquifer was present in the northern and southern ends of the 21 sand in fault block 4 whereas the aquifer gave pressure support only from the southern end of the reservoir in fault block 5. This shut in bottom hole pressure graph is also used to estimate the timing for the onset of high water production in the 21 sand wells. The presence of these gauges also mitigates the use of other more expensive reservoir fluid monitoring tools to predict water breakthrough.

The real time processing and storage of the data collected by the downhole gauges have helped change the depletion strategies of the Mahogany field. One such case is the depletion of the 20 sand. This is the largest reservoir in the Mahogany field and similar to the 21 sand, is also separated into two main producing fault blocks by a normal fault. The Figure 4 illustrates the downhole gauge pressure and gas rate production data from the MB-02 well located in the 20 sand reservoir. Two wells inclusive of MB-02 now produce from this fault block in this reservoir. The plot below shows the effect of production from MA-01 on the reservoir pressure. When both wells are on production the flowing bottomhole pressure in MB-02 is observed to be declining at a constant rate. Even when MB-02 is shut in, the downhole gauge shows the pressure to be declining at the same rate. This provides evidence of MA-01 having a much stronger influence on the pressure system in this block. It also justifies using MA-01 pressure build up data for a more reliable estimate of reservoir parameters than MB-02.

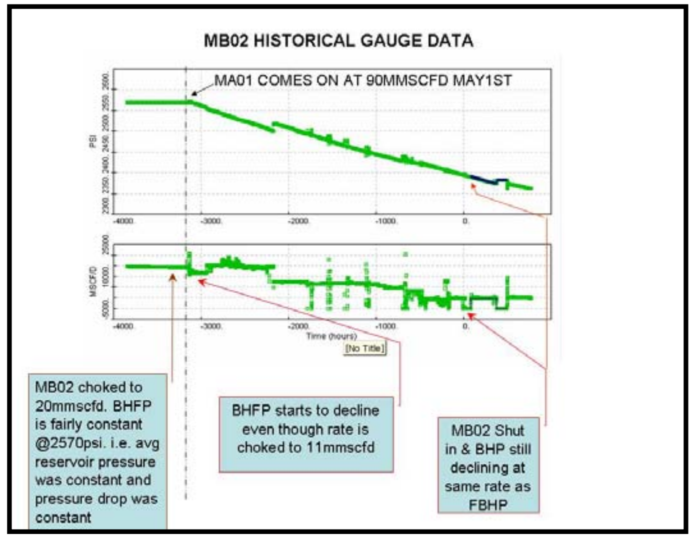
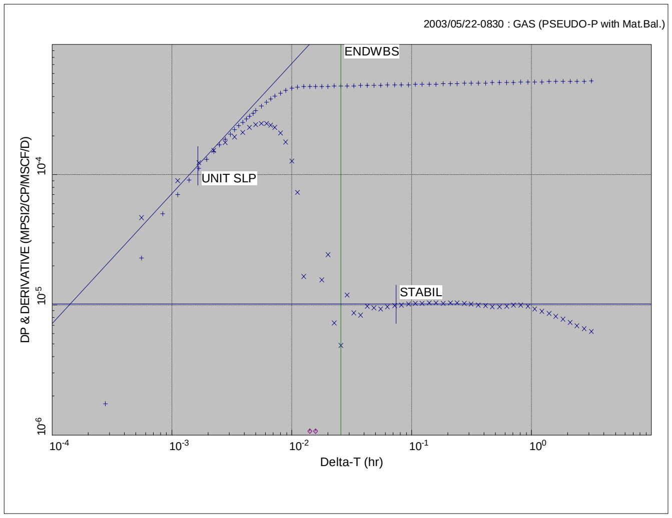


Figure 4 – MB-02 permanent downhole gauge pressure data.

Analysis of the raw data derived from the pressure gauges are interpreted by well test analyses software to determine type of reservoir models, size of reservoir tank by estimating boundary locations, well bore skin, petrophysical reservoir qualities and the productivity index of any well.

The Figure 5 below shows the derivative plot derived from the MB-13 well pressure build up data, also located in the 20 sand. The analysis plot was used to establish the dynamic properties of wellbore storage, mechanical and turbulent skin and effective permeability. Subsequent well test analyses from the same well, as the reservoir was depleted, showed the 'cleaning up' of the well by a reduction of the mechanical skin and an increase in the effective permeability.

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well. storage  = 0.183 BBLS/PSI
Skin(mech)     = 18.9
permeability   = 300. MD
Perm-Thickness = 44500. MD-FEET
Turbulence     = 0. 1/MSCF/D
P-extrap.      = 3393.71 PSI
R(inv) at 0.07370 hr = 140. FEET
Smoothing Coef = 0.,0.
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Static-Data and Constants
Volume-Factor  = 0.8497 RB/MSCF
Thickness      = 148.1 FEET
Viscosity      = 0.01990 CP
Total Compress = 0.0002303 1/PSI
Rate           = 153100. MSCF/D
Storivity      = 0.008459 FEET/PSI
Diffusivity    = 69700. FEET^2/HR
Gauge Depth    = N/A FEET
Perf. Depth    = N/A FEET
Datum Depth    = N/A FEET
Analysis-Data  ID: DATA
Based on Gauge ID: GAU001
```

Figure 5 – MB-13 pressure derivative plot.

Permanent downhole pressure gauges are a vital tool for the petroleum engineer. Well diagnostics and reservoir management depends on the availability and reliability of the data it provides. It is a crucial and cost effective method used in the world of reservoir surveillance.

This pioneering technology in the Mahogany Field has now become the minimum standard for all other gas fields that have been developed in bpTT.

Acoustic Sand Detectors

Most of the fields located offshore of the southeast coast of Trinidad have had problems with sand production. Mahogany was designed to be the first high pressure gas field in Trinidad, which meant that there was very little tolerance for sand. Sand production was not just a risk to hydrocarbon production but also to process, integrity and safety, since any uncontrolled release of high pressure gas can cause an explosion.

In order to get a good handle on sand production, the subsurface team made the decision to utilize sand detector technology on all wells.

After an analysis of the available technology at that time, acoustic sand detectors were installed on all well flowlines. This was the first field wide installation in Trinidad.

Unlike the installation of permanent downhole gauges, there were few installation challenges with the acoustic detectors. Since the database system was already created to handle all of the real time data from the gauges, it was a simple process of storing the sand detector data.

These detectors are now an integral part of the operations of the plant. They give the assurance of sand free production, which allows the Mahogany team to continually push the production drawdown limit of each well, hence ensuring that the maximum production is obtained. There are many success stories of this; a recent one has been the increased production rate from MB-07.

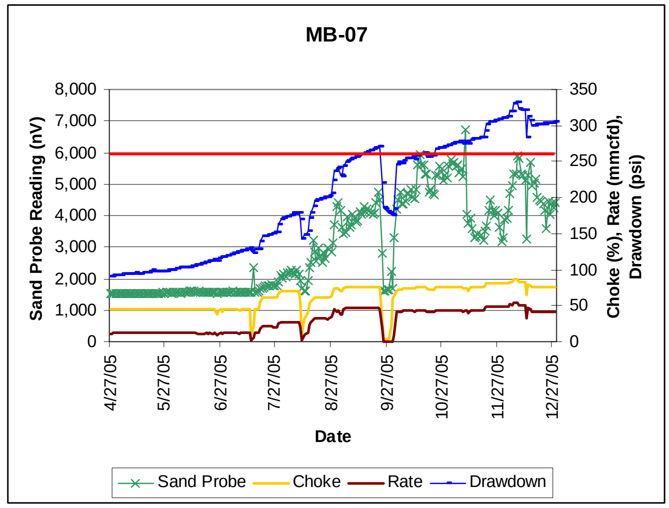

Figure 6 – Production profile for MB-07

MB-07 is a known sand producer; as a result the well was restricted to a fifty percent choke in order to limit the drawdown to 100-150 psi. At that time this was consider to be a safe drawdown limit and the well was produced at a rate of 12 mmcfd. A sand detector calibration showed that the well was not producing sand below 6000nV.

Based on this information the well was slowly ramped up, while closely monitoring for sand production. The end result was a new production rate of 42 mmcfd, with an increased drawdown of 350 psi. This clearly shows how the use of the acoustic sand detector technology has increased gas production in the Mahogany Field.

Sand production in bpTT operated fields have led to choke failure in less than an hour, hence these detectors have played a key role in maintaining platform integrity. There are many examples in the Mahogany Field where sand production has led to choke pieces being totally eroded. If it were not for the acoustic detection system this could have significantly compromise the safety and integrity of the platform. Once such success story is MA-12, where sand production was detected at an early stage, thus preventing an uncontrolled gas release.

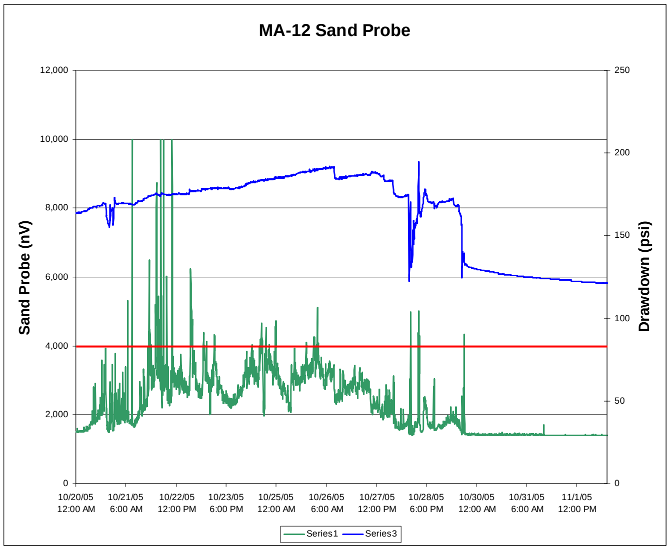

Figure 7 – Sand Production from MA-12

The real time data from the sand probe showed that the well began to produce sand once the reading went above the sand free limit of 4000nV. This was validated by the fact that the drawdown continued to increase. This meant that the bore size of the choke was being increased even though the choke position was constant. At that point the well was shut in and choke was inspected.

Figure 8 –Eroded choke of MA-12

On inspection, the choke was found to be partially eroded. If left unattended, it could have led to a line cut out and an uncontrolled gas release. The choke was replaced and the well was put back in service at a reduced drawdown and at a sand free rate.

This sand detector technology has made a significant impact on the production of the Mahogany Field. It is now being widely used in all fields operated by BP in Trinidad and Tobago.

Tractor Conveyed Wireline Tools

The discovery of a 60ft oil rim in the 21 sand was not part of the original scope of the Mahogany Field development, as the primary focus was to deliver gas to meet contractual agreements. However with 3mmbo recoverable reserves in place, it became an integral part in the field's production. This thin oil rim was relooked and a decision was taken to employ the latest technology in its exploitation. Horizontal wells were used to effectively deplete this zone. In 2001 the subsurface team was unsure on the effectiveness of these horizontal wells. The common belief at that time was that most of the production was entering at the "heel" of the well and very little if any from the "toe". This would mean that more wells would have to be drilled to drain this oil rim. It was proposed to run a production logging tool (PLT) in the horizontal section to measure the productivity.

This was no easy task, since there has never been a PLT done in a horizontal well in Trinidad. The team actively engaged the service providers to get the best possible solution.

In September 2001, the first horizontal well PLT was run in MB-04 using Tractor Technology. This new technology gave the team information that would change the way the oil rim would be developed.

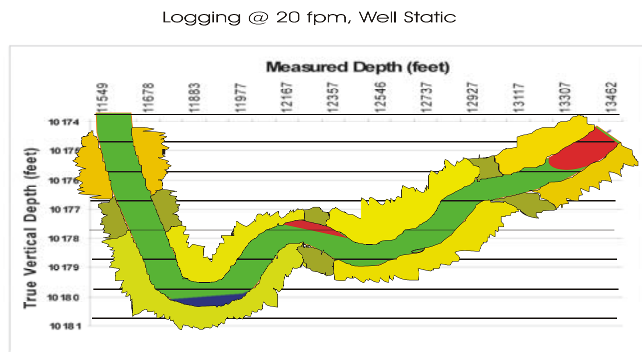

Figure 9 – Fluid Profile across lateral section in MB-04

The results of the PLT showed that the entire length of the lateral was indeed producing. This would have a direct impact on the future horizontal wells that were drilled in the thin oil rim. The next horizontal well, MA-13 would be the longest lateral drilled in Trinidad (4099 feet). MA-13 also has the distinction of being the highest oil rate (12,500 bopd) in Trinidad at that time. This outstanding performance could not have been possible if the subsurface team did not utilize this new tractor technology.

Apart from impacting future wells, the PLT also played an integral part in the way the well was operated. It showed that there was liquid hold up at the low points of the well. It also showed that the majority of gas was entering from the "toe" of the well.

It showed that the frictional losses in the well were less than 5 psi and that there were no voids in the gravel pack. This data meant that the well could have opened up even further thus accelerating production from MB-04

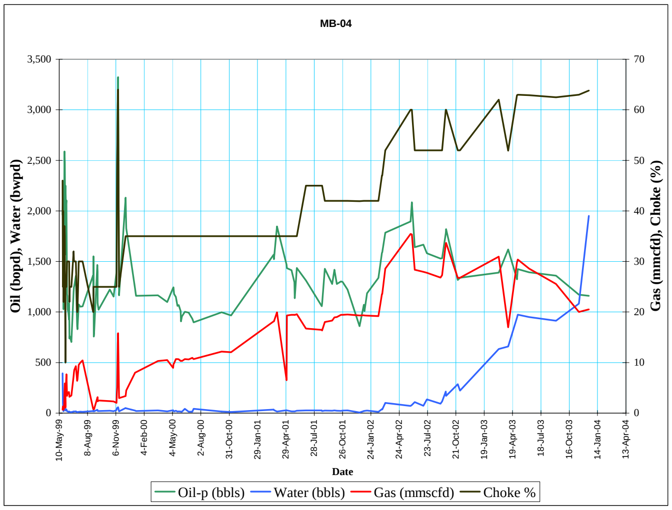

Figure 10 – Production Profile of MB-04

The graph shows that after the PLT was done in September 2001, the choke was further increased in Jan 2002. The oil production increased from 895 bopd to 2084 bopd. While the gas production increased from 19 mmcfd to 39 mmcfd. The increased production levels were maintained until the well eventually “watered out” in June 2004.

The Tractor PLT showed clearly the positive impact new technology can make on production and reservoir management.

Fiber Optic Downhole Flowmeter

In March 2002 a downhole fiber optic flowmeter was installed in a horizontal oil well, MA-15. Accurate measurements in the oil wells in the thin oil rim were difficult to obtain due to the three phase production. This proved to be a major problem in properly simulating the behavior of the thin oil rim. Prior to this all the measurements were made at surface. The use of fiber optics in the oilfield environment in Trinidad was certainly a novelty at this time.

The subsurface team however believed that if it was successfully deployed, it would be able to meet all the objectives of the team.

Even though it was a challenging job for the completions team the fiber optic flowmeter was successfully installed. Operational issues such as the fiber optic cable connection and maintaining full bore access were solved. The subsurface team, for the first time, had real time data on the flow behavior of the horizontal oil well.

Figure 11 – Dowhole flowmeter used in MA-15

This downhole flowmeter was the first of its kind to be installed in Trinidad. It was a gas tolerant two phase meter, when tuned with the well model gave three phase results. It did not just measure flow rates, but also Pressure, Temperature and Hold Up. Since it had no moving parts, there were no mechanical issues, which meant it would have a long up time. The flow meter was able to accurately measure water cuts for the entire range (0-100%).

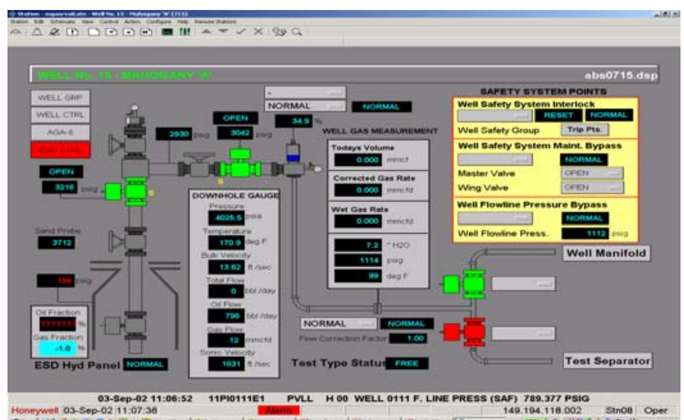

Figure 12 – Wellhead schematic showing data from downhole meter

The fiber optic system was connected to the same database as the permanent downhole gauges and acoustic sand detectors; hence it was able to provide real time information on the change in flow rates.

This new technology provided more accurate flow rate measurements, which improved the reservoir model as well as assist in the liquid allocation process. In addition it allowed for early detection in localized production anomalies on a real time basis. Hence the operating conditions could have been easily adjusted. For example if the water cut were to increase the well’s production could be reduced to control the production. It also meant that the productivity index of the MA-15 well can be tracked on a real time basis.

By having an accurate flowmeter in the well meant that a smaller surface footprint is required. Since smaller test separators will be required.

The use of Fiber optic technology in Trinidad has also made a direct impact on other BP completions. Based on its successful installation three additional fiber optic flowmeters have been installed on other BP operated. In addition it is currently being looked at as a viable option of measurement for future field developments in Trinidad and Tobago.

Distributed Temperature Sensor

After the success of the Tractor PLT that was run in MB-04 and the successful use of fiber optic technology downhole in MA-15, the next step for the subsurface team was to develop a system to continuously measure the flow across the lateral of a horizontal well.

If such a system could be developed then the team would be able to monitor the change in fluid as well as flow rate over time and be able to optimize the well productivity.
After numerous discussions with the various service providers, a Distributed Temperature Sensor (DTS) was chosen. This system would measure the temperature reading every meter across the entire length of the lateral. Using Fiber Optic Technology a pulsed light is sent through the fiber. This light signal is scattered along the fiber and the spectra is measured at every meter along the cable. The ratio of the scatter is directly proportional to the temperature.

This temperature profile would give an indication of the areas of flow along the lateral as well as where there is gas entry, due to the different heat capacities of gas compared to liquid. It would also be able to give an indication of where the static fluid level is located.

While the subsurface team was convinced that this new technology would add value to the reservoir management plan, there was still the major hurdle of installation. This would have been the first of its kind to be installed in Trinidad and the concern of the completion team was the ability to run the fiber optic cable across a 3500 feet lateral section. To overcome this problem, custom fit equipment were built. This would involve modifying all of the completion equipment, from the screens straight to the tubing hanger. To maintain the integrity of the cable across the lateral section, the screens were modified by adding a stamped groove along the body of the screen for fiber optic cable, without sacrificing the operations of the screens. Special clamps were manufactured (dovetail clamps) that would hold the cable within the groove on the screen shroud and still maintain the minimum outer diameter of the screens, thus minimizing the risk of the screens becoming stuck.

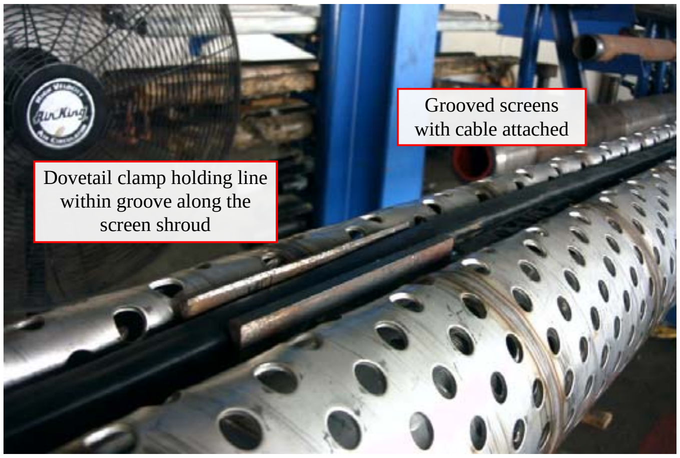

Figure 13- diagram showing groove and specialty clamps

Special mid joint breaks were designed at the end of each joint of screen for mid joint clamps. This would prevent the cable from breaking while preparing the joints on the rig floor, as well as to hold the cable in place while running into the well.

Figure 14 – Diagram showing mid joint clamps

In order to ensure that the cable was not torn while running in the completion tubing each joint was specially treaded with a SLHT-S timed connection. This maintained the alignment of the cable along the entire length of the tubing. The production packer also needed to be modified to allow the cable to pass through yet still maintain its hydraulic integrity. Finally the surface equipment also needed modification as there was now an additional control line to add. Hence the wellhead, seal flange and tubing hangar were modified.

In September 2002 the DTS system was successfully installed in MB-12, a horizontal screen only completion oil well. This would be the first of its kind installed in Trinidad. The fiber optic cable would send temperature data every meter along the length of the well, including a 3500 feet lateral section.

The system needed to be calibrated before the data could have been used. A single-ended fiber optic cable was used, which meant that some other source for calibration was required. The MB-12 was also equipped with a permanent downhole gauge that measured both pressure and temperature. Hence this point was used to calibrate the DTS system. The gauge data was overlaid with the DTS data at the depth of the gauge. The resulting graph showed that the two independent measurement systems overlaid each other within +/- 0.4 degrees Celsius. This gave the subsurface team confidence in the data generated by the DTS system.

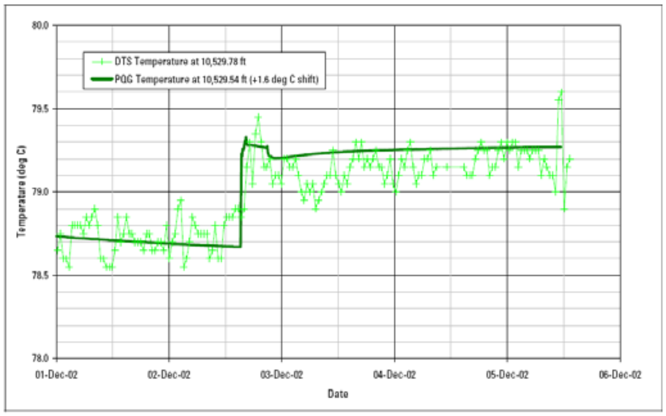

Figure 15 – DTS vs. Gauge data

The DTS system was then used to analyze the well performance. The first check of the system was to interpret the location of the static fluid level. Under static conditions the well should have a column of gas on top of the liquid column. Understanding this liquid level will give an indication of the wellbore storage effect, which would help in interpreting reservoir pressure build up tests. In addition it would help to diagnose if there is an integrity issue in terms of a leaking packer or tubing. Since the liquid (oil and water) has higher heat capacity than the gas there should be a step change in temperature at the liquid level. The temperature data was collected during the first shut in of the well, along the entire length. The graph clearly shows where this occurs; hence the static fluid level was determined.

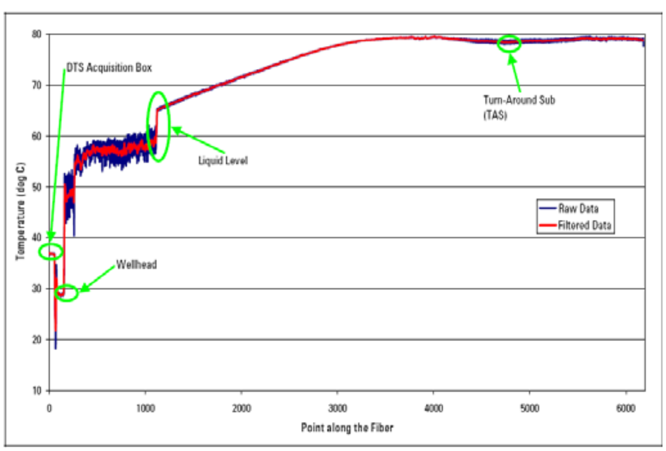

Figure 16- DTS data during shut in period

MB-12 was then put on production; the initial well test showed that the well was producing 1800 bopd with a GOR of 2000 scf/bbl and no water. The DTS data showed that most of the liquid was entering the well from the first half of the lateral, where the temperature is the same as the reservoir temperature, which is indicative of liquid production. The majority of gas was produced from the lower half, since the temperature is less than the reservoir temperature, which indicates a cooling effect associated with gas production. This interpretation matched the geological model that showed the well trajectory had penetrated part of the gas cap. For the first time the subsurface team was able to understand the flow pattern of the horizontal wells placed in the thin oil rim. In additional the data also validated the new theory that the entire length of the lateral section was producing, thus dispelling the notion that only the "heel" of a horizontal well contributes to production.

The DTS system offered however an additional advantage in its repeatability. Since the cable was stationary, the subsurface team was now able to monitor the movement of fluids along the horizontal section with a high degree of confidence. Over a two year period the liquid production had increased to 3000 bbls while the GOR increased to 15000 scf/bbls. Additionally the water cut had increased to 38%. The DTS system was not able to differentiate the difference between water and oil, since the well was horizontal. However it could indicate whether water was entering from the gas section of the well. The data obtained from the repeated DTS results showed a clear indication of increased gas production entering from the lower half of the well. Since the temperature profile shows continued cooling. It was difficult to estimate where the water was entering the well. However the lower half showed only gas entry thus it was relatively safe assumption to make that the water was entering in the top half of the lateral section along with the oil production.

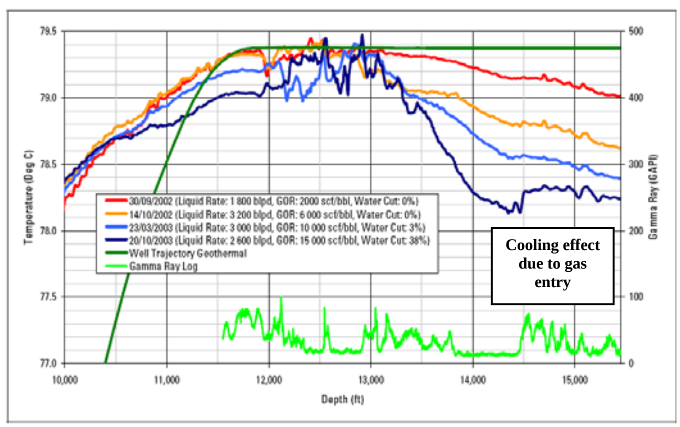

Figure 17 – Graph of repeated DTS data

This repeated DTS data have proved useful in understanding the production from the thin oil rim, especially in the movement of water. Since a number of the thin oil rim horizontal wells have failed due to water production. This data would be used to predict the future performance of the reservoir and also help in optimizing production from the MB-12 well.

The DTS system was able to meet its main objective of understanding the movement of fluid along the horizontal section over time.

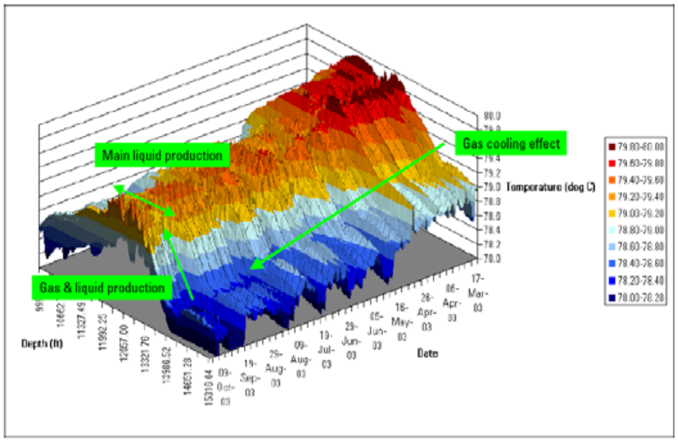

Figure 18 – Visual display of fluid movement

While the DTS system proved to be a challenge in its installation. The wealth of data collected showed how new technology was able to provide increased surveillance as well as better understanding of the reservoir behavior and fluid movement.

To date the MB-12 DTS installation remains the only such installation in Trinidad; however the information collected from the system has spurned interest in many other BP operated fields throughout the world.

Conclusion

The use of technology for well surveillance has played a critical role in developing the Mahogany Field, even though there were many challenges along the way. The data collected have helped with individual well performance as well as developing a better understanding of the reservoirs.

Currently the team is looking at options for determining continuous pressure measurements along the lateral of the horizontal wells, as well as a more effective way of determining the change in fluid composition with the onset of water production.

As an asset, the subsurface team remains committed to maintaining the high standards of surveillance and is continuously looking for new technology that can add value to the development of the field. As the field enters into the mature phase of its depletion, further emphasis is being placed on well and reservoir surveillance.