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PRODUCTION OPTIMIZATION OF ELECTRIC SUBMERSIBLE PUMPING WELLS

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ABSTRACT

The downhole monitoring tools are permanent gauges equipped with electrical submersible pumping (ESP) bottom-hole assembly, below the motor. Each gauge sends nine measurements per minute to the surface in real time yielding an incredible volume of information. Down-hole gauges supply accurate information about the reservoir, down-hole, and the pumping system. This knowledge, in turn, is used to increase the run life of the ESP system through optimization of the reservoir pressure and ESP system performance.
The purpose of this paper is to introduce real applications of down-hole monitoring technique used for monitoring, controlling and optimizing the ESP wells. The applications have resulted in a significant decrease of ESP wells failure rates and increase of both ESP runlife and cumulative production per run. The recorded data are used by the reservoir and production engineering staff in order to overcome problems such as high ESP failure rate, high motor temperature, and low potential (influx) of wells, overload, under current and tubing leakage and consequently to monitor ESP wells production and pressure behavior.

This paper demonstrates the long-term benefits of using subsurface permanent gauges to complement ESP equipment and provide real-time data to optimize well and/or field production. Case studies illustrate both offshore and onshore problems. Examples are given of wells that have been converted into successful ESP completions through proper interpretation of the gauge measurements and use of the information to optimize production. This paper will outline the direct measurements that can be taken and illustrate how they can be used, real-time, to increase production, diagnose well and ESP performance and achieve protection and control of the ESP system to extend ESP runlife.

Keywords: Optimization, ESP, Permanent Gauges, Runlife, Pressure, Pump Upgrade and Well Performance

الأداء الأمثل للآبار التي تعمل باستخدام المضخات الكهربية الغاطسة

نظراً لأهمية تقييم ومتابعة أداء الآبار التي يتم انتاجها باستخدام المضخات الكهربية الغاطسة وكذلك التحكم في عمليات انتاجها فقد تم استخدام أجهزة قياس وتحكم لهذا الغرض. هذه الأجهزة يتم إنزالها إلي قاع البئر مع هذا النوع من المضخات ويتم متابعتها من السطح من خلال شاشة وأجهزة تسجيل وتحكم رقمية.
والغرض من هذه الورقة هو تقديم تطبيقات حقيقية لهذه التقنية التي تستخدم في عمليات التحكم والرصد والمراقبة لتحسين أداء هذه الآبار. وقد أدت التطبيقات التي تمت للآبار البرية والبحرية الي انخفاض ملحوظ لتكلفة المضخات الكهربية الغاطسة وزيادة في كل من عمر تشغيل الآبار وتقليل عمليات صيانة الآبار بالإضافة

الي زيادة الانتاج التراكمي لهذه الآبار. وقد تم استعراض عدد من المشكلات التي تم التغلب عليها باستخدام هذه التقنية وما كان يمكن معرفتها أو التعامل معها بدون استخدامها مثل مشكلة انخفاض مستوي السائل اسفل المضخة مما يؤدي الي حرق محرك المضخة وغيرها من المشكلات التي تم التعرض لها.

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INTRODUCTION

Electrical submersible pumping (ESP) wells optimization using downhole monitoring is an excellent method of diagnosing conditions and determining the appropriate approach to avoid loss of production or of the well.

Most ESP analysis, troubleshooting and control systems are based on the use of electrical parameters to predict ESP and well performance

A discussion of the importance of measurement will be undertaken and related to the benefit of using measured pressures to diagnose performance of the ESP produced well.

The use of directly measured pressures and temperatures and their benefits for control of the ESP system and prevention of premature system failure will be highlighted.

Surface measurements alone cannot easily distinguish reservoir effects from effects of the submersible pumping system. The multistage centrifugal pump is driven by an electric motor. The pump and motor are normally suspended from the production tubing with the motor positioned below the pump, which discharges directly into the production tubing. 1 The pressure and temperature gauges below the motor provide information at the interface between the reservoir and the pump.

Control and monitoring of pump performance are essential to achieving long run life. Using real-time data of downhole and surface parameters, personnel can maintain the equipment within its recommended operating range and have the capability to detect abnormal operating conditions and take appropriate actions that avoid failures. Historical trend analysis can also be used to identify changes in pump and reservoir performance. This analysis, therefore, provides input data to assist reservoir modeling. 2

Monitoring of the pumping system and well performance is achieved through the use of downhole multiple gauges as shown in fig 1. The downhole monitoring system provides a 'semi-redundant' measure of flowrate, intake pressure and temperature, discharge pressure, vibration, leak of current and motor winding temperature. Digital signal processing techniques are used to eliminate noise and measure the frequencies with a high degree of accuracy and resolution. The millivolt-level signals, which were once unidentifiable, can now produce pressure and temperature measurements with resolutions suitable for reservoir analysis. In fact, as the frequency and fidelity of the data increase, the accuracy and precision of the model increase as well.

The use of permanent downhole monitoring systems is increasing globally, both in numbers of installations and in new applications for the technology. Although applications were once centered on reservoir management, these systems are now being used for pump control, gas lift control, prevention of workovers, improve fracturing operations, better understanding of downhole injection, and many other applications related to optimizing production operations. After processing of the incoming signals, the data virtually looks like as it comes from a sensor sitting two feet apart and not kilometers away at the bottom of a well. [3-4]

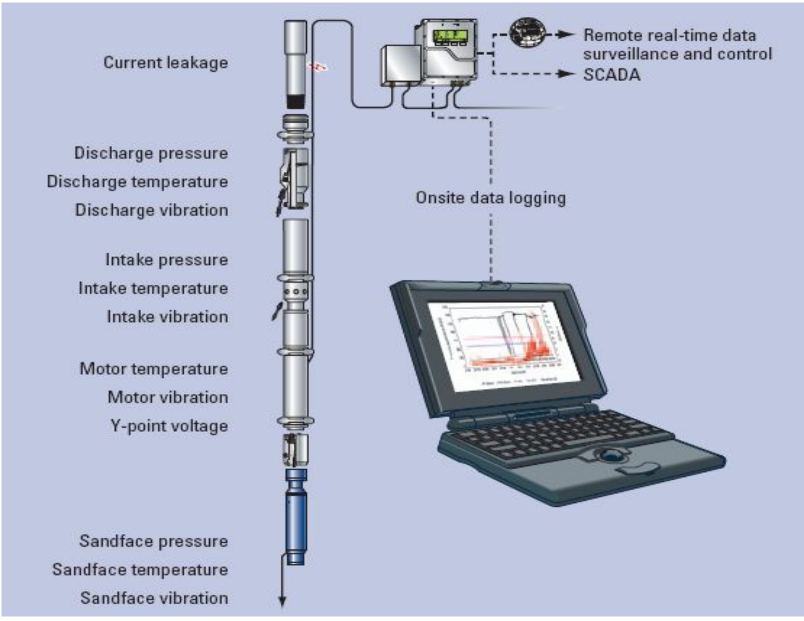

Fig 1: Downhole ESP monitoring Tools

DISCUSSION

ESP wells represented the highest producers in the oil industry, therefore it is very useful to monitor and assess their performance. Optimizing the performance of ESP wells means maximizing their run-life, reduce maintenance and workover costs. The following factors are contributed in optimization process:

- Running the ESP in the optimum operating range based on their performance or characteristics curves.
- ESP motor should be operated with electric voltage according to the name-plate voltage
- ESP motor operating temperature should be below the maximum safe value in order to avoid burning of same. To overcome the overheating of motor, it is requested cooling of motor via formation fluid while the recommended cooling velocity across motor to be less than 1 ft / sec.

Motor failure (burned or shorted) due to overheating because of lack of motor cooling process. Cause of insufficient motor cooling:

1. Low fluid velocity passing across motor body and housing due to low production rate and / or large annular between casing and motor. Motor shroud is used in case of using small motor series to sustain the recommended fluid cooling velocity.
2. Sever tubing leak; in this case the fluid dropped from tubing to the pump intake above motor without passing through it, which overheated with time, if not noticed.
3. During start-up of new wells after completion operations, in some cases, if the

well is full and using small pump, the pump operated, taking the fluid from the full casing before sharing of the formation in the production. During this period the motor temperature increases, if it is not observed, the motor could be burned.

Production Optimization

Figure 2 shows a typical pressure response in a well with an ESP installed. If the pump intake and discharge pressures are not known and instead guessed, simulated or measured inaccurately, it changes the whole pressure response within the wellbore. Knowledge of these values is required to ensure that we understand the ESP operating conditions, the pump is optimally sized and that production is optimized.

From a production standpoint the most important parameters are the pressures across the ESP: after all the function of the ESP is to add energy and cause a pressure change in the wellbore to allow the well to flow at a higher rate. If we measure intake pressure ($P_{i)}$ and discharge pressure ($P_{d)}$ we know the exact pressure response in the wellbore and can therefore consider the wellbore as a hydraulic system. When ESP discharge and intake pressures are known and used in conjunction with the ESP performance curve they can be used to validate or determine a number of useful operating conditions such as: validate fluid properties; plot pressure across the pump (dP) vs. frequency; infer downhole flowrate; and calculate bottomhole flowing pressure. *Table 1* provides a summary of the information that can be detected using two measured pressures.

It is worth to understand a naturally flowing well in terms of pressure and depth. In order to analyze a naturally flowing well it is required to use well test data, pressure information from a flowing gradient survey and a nodal analysis software package. The pressure and flowrate information provide known measured data points to validate the software model. The methodology is to validate the fluid property assumptions by using the software to match a predicted pressure to a measured pressure and then, having accurately validated the model, it can extrapolate it to interpret changing wellbore conditions. The important point of this course of action is, in validating the fluid properties for the produced fluids, to understand and model the well from a hydraulic standpoint (pressure and depth).

When using an ESP in a well it is required to stick the pump in the wellbore and immediately start to consider the well response in terms of head and amps. Neither of these parameters is a direct measurement of well performance! If we consider the traditional approach to ESP design and well analysis, the wellbore pressure response (tubing flow regime) is converted into feet of head. Electrical parameters are then used to calculate how much work the motor is doing and therefore how much head the pump is producing. The well pressure response is then plotted on a flow versus head curve for the particular ESP, with a cross representing the operating point of the system. This technique works after a fashion and was necessary when it was the only tool available. Today it is proved that the majorities of ESP specialists are considering static and dynamic fluid levels and total dynamic head rather than static reservoir pressure, bottomhole flowing pressure or pump dP. The reality is a better method exists.

Table 1: Summary of calculated / derived parameters that can be obtained from the gradient traverse plot.

Above the pump	• Validate PVT • Watercut • Fluid specific gravity at pump discharge • Tubing GOR • Measure friction effect
Across the pump	• Validate Q, frequency, number stages • Measure viscosity and emulsion effects • Fluid specific gravity at the pump intake • % free gas at the pump intake • Obtain operating point for pump curve
Below the pump	• Calculate bottomhole Pwf • Obtain PI or Pr

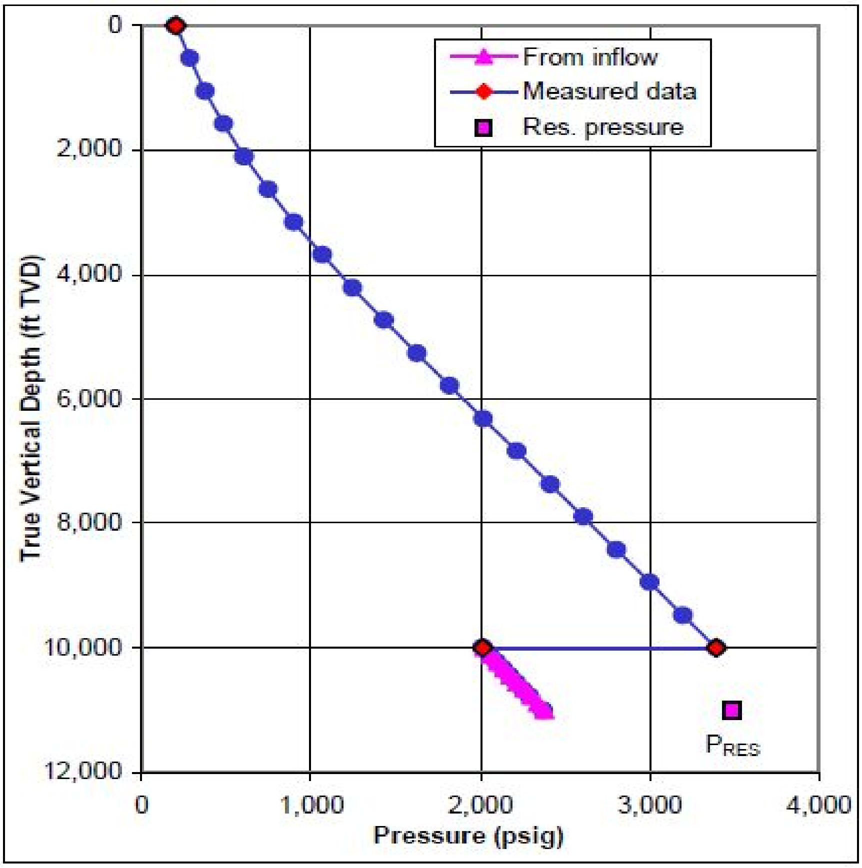

Figure 2: A typical pressure response in an ESP produced well.

ESP Optimization

ESP Downgrading or Upgrading

In a new well or new installation startup, the pressure-temperature gauge provides early measurement of well productivity. Over-sizing in new wells can lead to ESP damage. This is readily detected by low flowing bottom-hole pressure (BHP) followed by an increase in temperature resulting from lower-than-expected flow rates. A variable-speed drive can be installed to extend the pump operating range, or low-rate intermittent production can be maintained until the well cleans up to the expected flow rate.

Well W – 67 shows the added value of multisensor real time measurements. The intake pressure performance shows steep depletion with a fluid flow rate of 150 m3/d. This high depletion rate indicated there was no pressure support and that the block penetrated by this well was too small to be drained by another producer, which in turn modified the Company strategy. Moreover, to maintain production, the operating conditions were changed to downgrade the pump without pulling it to surface. Fig. 3 illustrates the pressure and production performance of this well. When the production was cut to 50 m3/d in August 2001, the pressure attitude became stable.

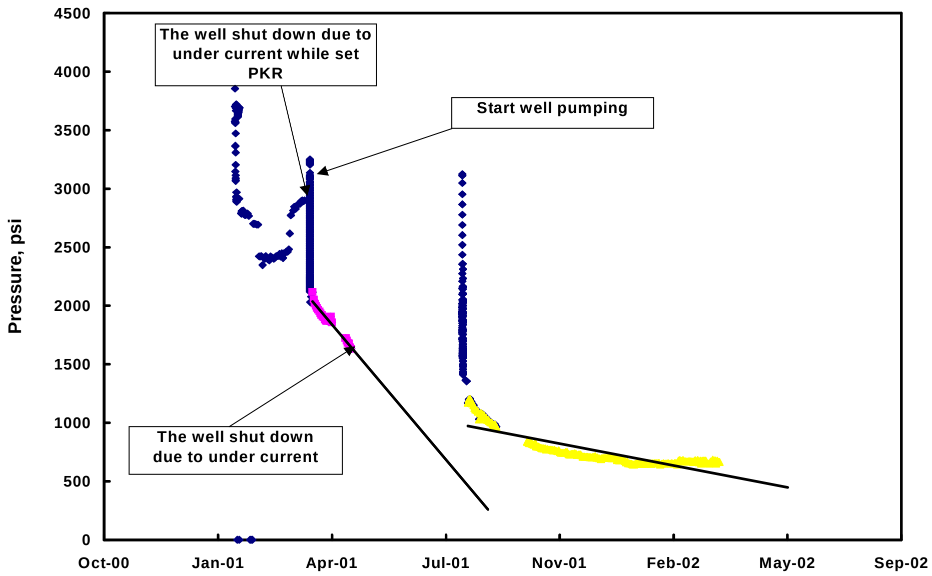

Fig. 3 – Well W - 67 Pressure Performance (Pi)

An opposite situation was encountered in Well W – 34. Water injection approached this well early in 2000 as indicated by an increase in the intake pressure and a decrease in produced water salinity and gradual increase in W/C (Fig. 4). The reservoir pressure increase resulted in a draw-down increase and hence more fluid flow. A decision was made to upgrade the ESP. See Table 2 for specifics.

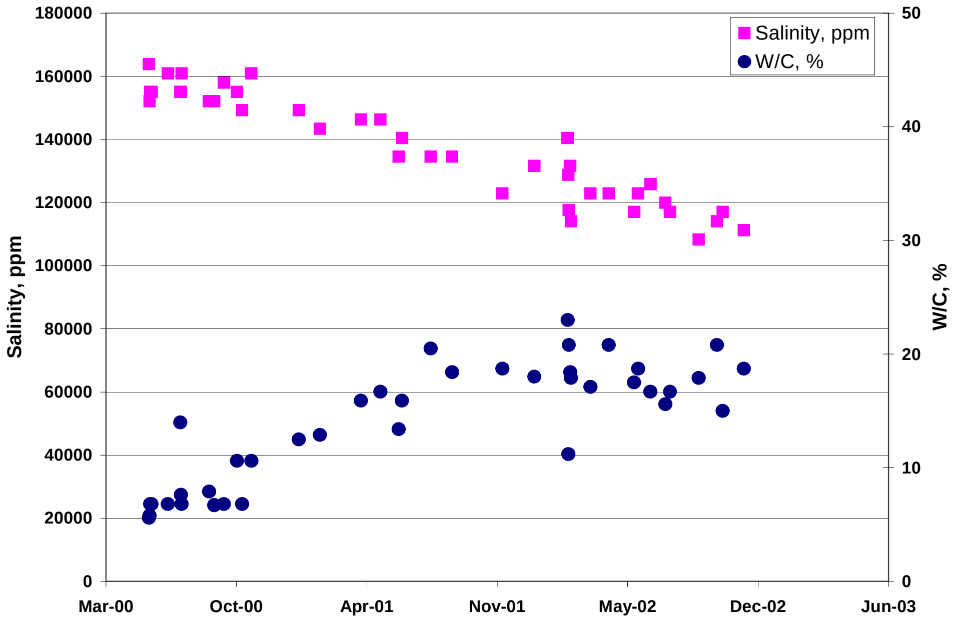

Fig. 4 – Well W - 34 Water Cut and Salinity Performance

As seen from Table 2, the flow rate doubled and the well maintained this production level for more than 1 year with a W/C of 20%. A simple feasibility study can determine the gain from the sensor compared with the cost of its downloading and even the cost of upgrading the pump.

Table 2 – Upgrading Criteria

	Before	After
Pump Type & Size	Reda-GN-4000	Reda-GN-7000
Q, bbl/d (G/Net)	2,830/2,320	5,280/4,330
HP	250	450
Stages	259	326

Formation Identification

Additional benefits of the downhole monitoring tools measurements are improved to assist reservoir management and maximum recovery of reserves; e.g., a low reservoir pressure can be raised by more water injection to the area[5].

This is the case of Well W - 84; 600-psi drop in the intake pressure within 5 months resulted in a decrease in flow rate from 400 to 140 m3/d. This fast depletion led to a decline in the area development plan; no new drilling due to limited block extension. Therefore, the well was switched to produce from the upper reservoir (Rudeis) at a rate of 500 m3/d.

Reservoir Pressure Monitoring

Wells that have been on production for a considerable time have steady-state pressure conditions. Because the production is maintained at a constant rate by the pump, any pressure change is the direct result of interference from another well. Injection-well interference tests give early indications of inter-well communication and add confidence to development planning decisions.

The production from Well W - 68 was at a critical level, so the well was shut in to observe the multisensor pressure reading and evaluate the performance of the near injector in supporting the reservoir pressure. Fig. 5 illustrates a 200-psi pressure increase. Well W - 34 is another example of a downhole multisensor used to monitor reservoir pressure performance.

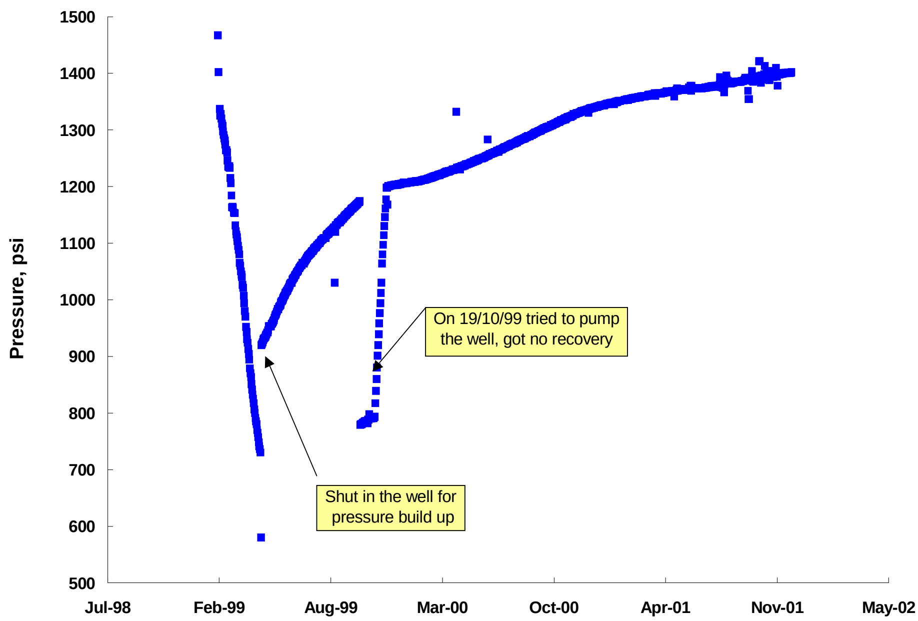

Fig. 5: Well W - 68 Pressure Performance (Pi)

Pump Efficiency

For a conventional BHP survey with gauges run on slick line, a well must be shut in for a minimum of 36 hr while gauges are run and retrieved, exclusive of a pressure buildup period. The benefit of having BHP data continuously available at surface is that the data enable optimal operation of ESP. If the pumps are operated out of range, premature failures will occur. The workovers needed when these pumps fail often takes 7 days, and oil production is often deferred for considerably longer because of rig priorities. [6]

The pump's "apparent efficiency" is defined as the ratio of the actual head and the theoretical head. The flow-meter system computes this parameter in real time. The effect of any blockage around the suction ports or between them and the first-stage impeller is manifested as an apparent reduction in pump-head efficiency.

Well W - A11 is the prototype example of this situation. Having the intake pressure the Nodal Analysis follows at the pump intake as nodal analysis point (NAP). Fig. 6 shows the match to be far from reality (intersection apart from the operating point). Adjusting the head factor to 0.6 improved the match. This adjustment and the production rate test indicated there was a loss in pump head and that the ESP was functioning close to the upthrust boundaries. Fig. 7 illustrates the performance curves of the used pump.

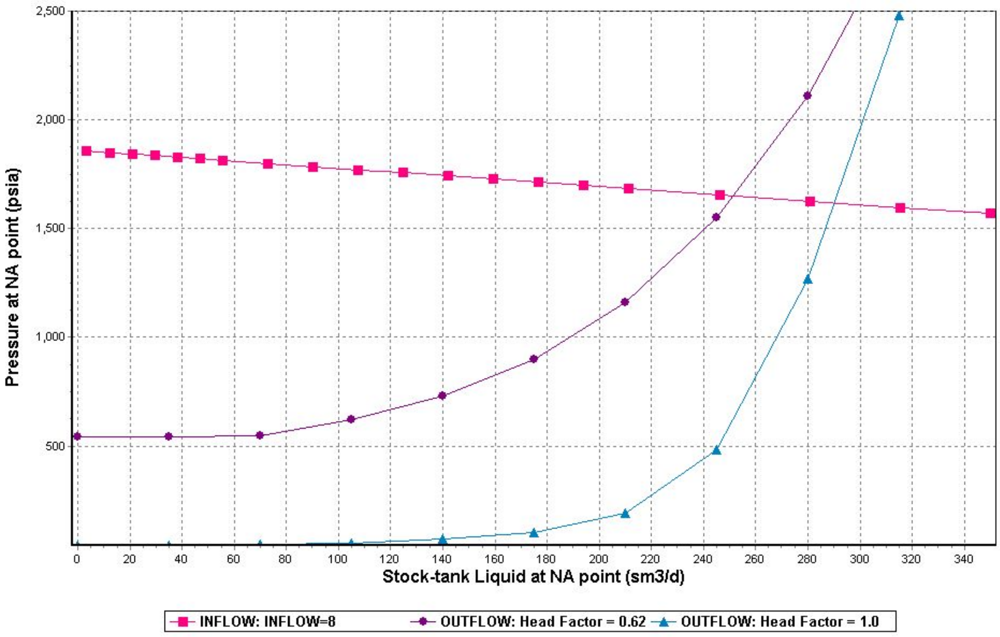

Fig. 6 - Inflow/Outflow Relationship at Different Productivity

Tubing Leak

Upward trends in BHP may be caused by pump stage wear in either upthrust or downthrust, diffusers spin, lost pump stages (a result of pump shaft shear, scale or solids deposits), and recycling of pumped fluids through a leak path below the top packer element (broken packer seals, leaking pipe connection, unseated adaptor tool plug, broken seals, washout in pump body).

Well W - 76 is obviously an example of a tubing leak. By the end of May 2001, the intake pressure had jumped to 1,300 psi (a more than 150-psi increase). This was accompanied by a decrease in the flow rate. A lack of change in salinity indicated there was no change in the reservoir conditions and the problem should be a borehole one. This case was interpreted as either intake plugging or tubing leak. There was no packer in the well, so the production loss from tubing to annulus extended the bottom of the hole, causing a rise in the P_{wf} and then decreasing the drawdown and the flow rate. Alternatively, scale plugging might lead to higher fluid static level and again higher P_{wf}. The well was shut in for inspection and a hole in the tubing was found 27 m above the pump.

Drawdown and PI

Analysis of pressure losses in the completion system, such as drawdown pressure between the reservoir and wellbore, completion skin, and tubing pressure losses provides information to optimize well production[7].

Considering the intake pressure and the static reservoir pressure, the reported PI in Well W - A11 was obviously wrong. When the static head exerted by the fluid column in the interval between the perforation and the pump intake was subtracted from the reservoir pressure the P_{wf}; was higher than expected, which indicated the drawdown was smaller than thought. When the actual production rate was substituted in the famous PI equation, the actual PI was found to be more than 600% higher than originally calculated.

Intake and Discharge Pressure

There are many benefits to recording simultaneously the intake and discharge pressure; e.g., pump performance degradation with gas and fluid viscosity, and multiphase pressure drop in the tubing in deviated wells with gas. Pump and tubing performance can be separated and the correct values can be assigned to each component for diagnosis and then design improvement. Issues in Well W - Z13 were actually resolved by running a Type-1 multisensor to measure the discharge pressure simultaneously with the other parameters.

It is worth to mention that the first Type 1 multisensor in Egypt was installed in September 2000 in Well W - Z13 to evaluate and solve the downhole problems that were requiring workovers every 3 months. In the first few hours of operation the sensor picked up a high ESP motor temperature (350 ^oF), and the pump was saved. Fig. 8 illustrates the effect of unreal reported data on well simulation using the multisensor data. The analyses and interpretation of multisensor data, using gradient traverse plot technique, determined an adjustment of productivity index value from 5 to 0.8 STB/D/psi and water cut from 31% to 17%. This match is shown in Fig. 9.

In addition, Well W - Z13 produces viscous crude with 21.7 ^{o}API gravity. The initially installed ESP had radial flow impellers, which are not appropriate for this crude, and there was a loss in the pump head as illustrated in Fig. 8. The pump was redesigned with mixed flow impellers to prevent the partial plugging of the small radial flow impellers.

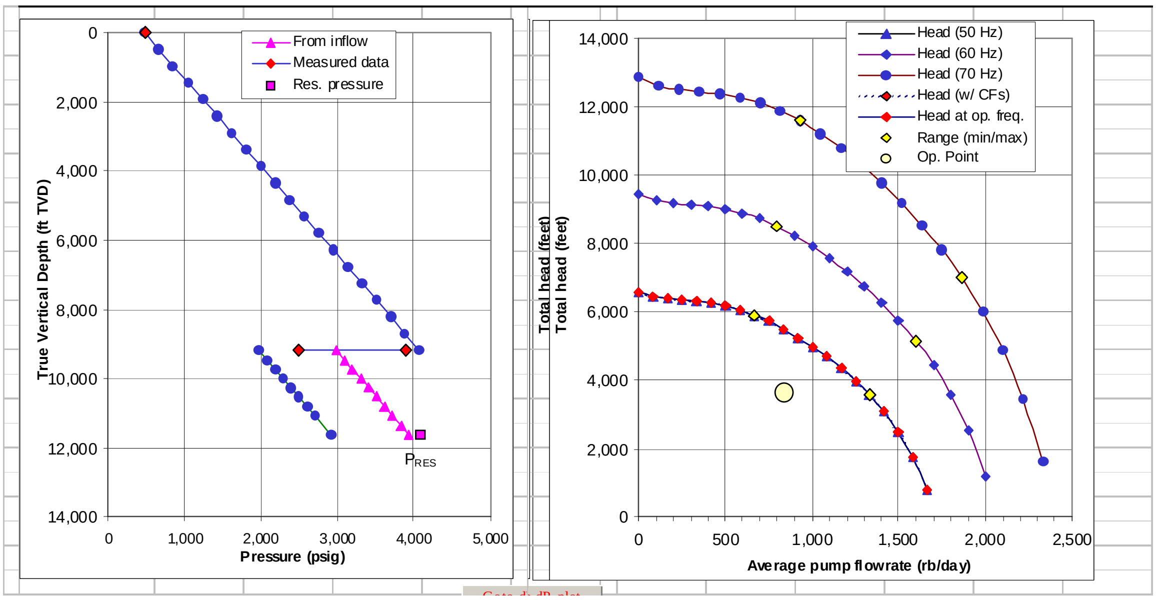

Fig. 8: Gradient Traverse Plot and Pump Performance Curves

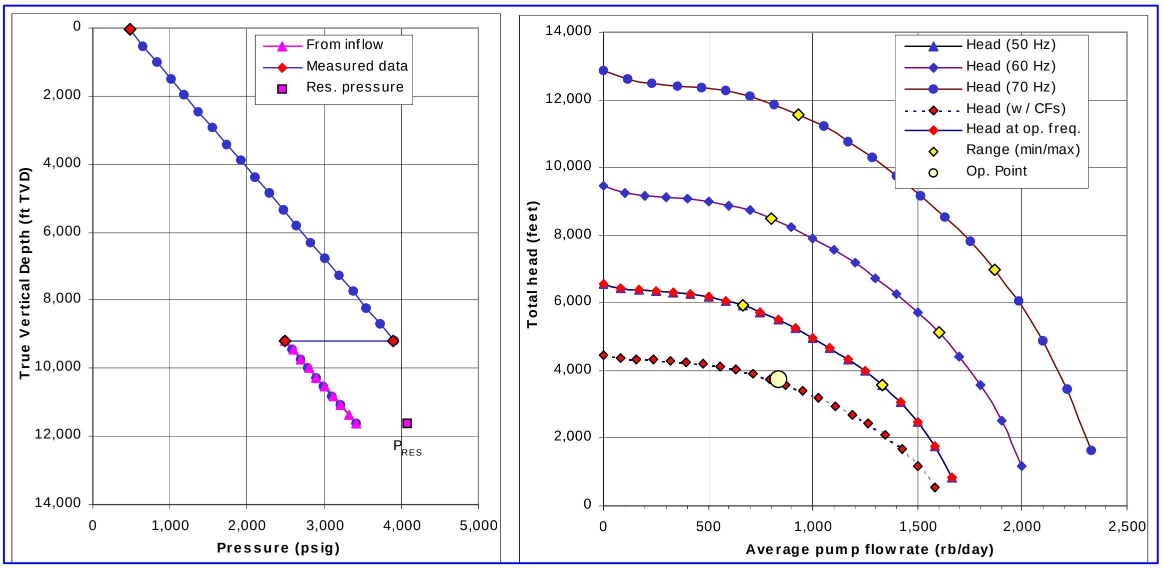

Fig. 9: Gradient Traverse Plot End Results of Well W - Z13 Simulation

CONCLUSIONS

1. Permanent bottomhole monitoring tools have achieved adequate resolution and reliability in wells with ESP's.
2. Well productivity and pump performance have been monitored directly with pressure- temperature gauges data. This monitoring has improved the operating efficiency of the pumps, enabling production targets to be achieved.
3. Reservoir management has been enhanced with data from downhole monitoring tools. Reservoir simulation models have benefited from improved reservoir description.

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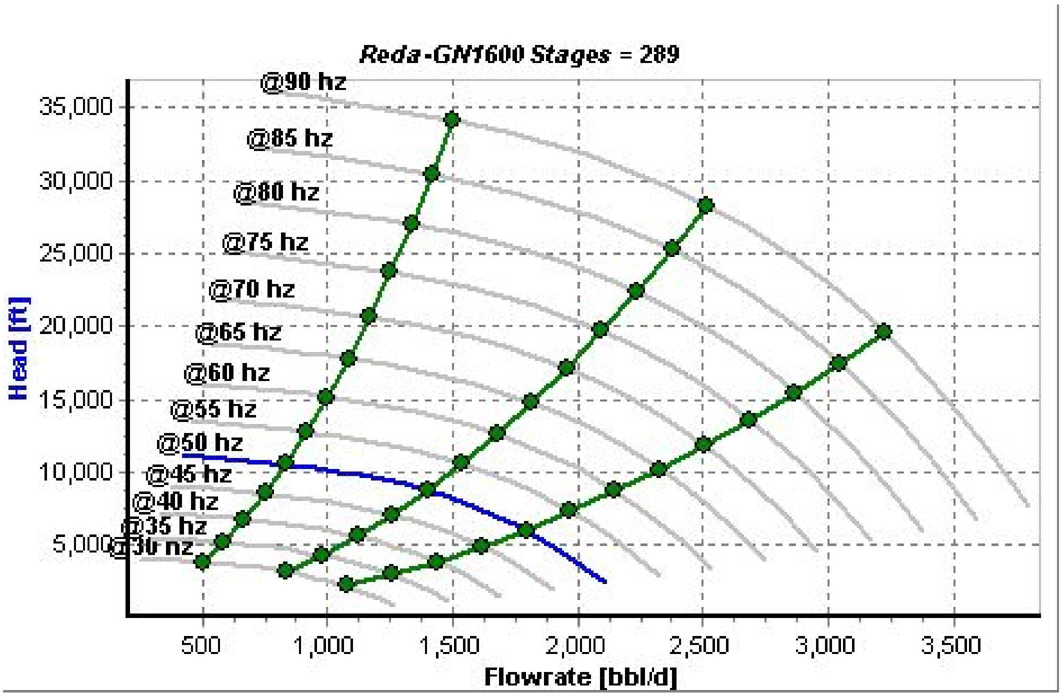

Fig. 7 – Well A-11 ESP Performance Curves