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ESPs and Intelligent Completions

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Abstract

The value of intelligent well completions combined with ESPs comes from the capability to restrict or exclude production from specific zones experiencing water or gas breakthrough. This technology may be applied to horizontal wells, multilateral wells, wells that produce from commingled reservoirs, or wells that exploit layered, compartmentalized, or heterogeneous reservoirs. The control of production and water and/or gas breakthrough permits more efficient operation of the downhole pump, and improves ultimate hydrocarbon recovery. This paper presents the benefits of synergy, technologies available, and the issues that must be considered when combining intelligent wells with ESPs. A theoretical example is presented that illustrates the economic benefits of combining the two technologies, and it is followed by an offshore case history that puts theory to practice.

Introduction

Intelligent well completion technology enables the oil and gas operator to actively monitor and selectively modify the zones from which hydrocarbons are produced, while on-stream and without intervention. As such, intelligent well completions are a powerful complementary technology to the evolving capabilities of electric submersible pump (ESP) artificial lift.

Zonal flow control is made possible through remotely controlled hydraulic, electric, or electro-hydraulically actuated inflow control valves in conjunction with purpose-built feed-through isolation and production packers. Permanently installed instrumentation that includes pressure, temperature and flow gauges can monitor the condition and contribution from each segregated zone and can transmit this data to the petroleum professional in real time. This instrumentation can be based on electronic or fibre-optic technologies.

Application of ESP artificial lift to intelligent well completions requires special considerations, including the capability to disengage from the intelligent well completion downhole to change pumps while maintaining well control and minimizing formation damage through shut-in at the sand-face. Hydraulic wet-connects allow the downhole completion equipment to be re-integrated with the intelligent well control system at surface once the ESP is back in place.

Objectives of Intelligent Well Flow Control

An intelligent well completion is a system capable of collecting, transmitting and analysing completion, production, and reservoir data, and taking action to better control well and production processes. The value of the intelligent well technologies comes from their capability to actively modify the well zonal completions and performance through flow control, and to monitor the response and performance of the zones through real time downhole data acquisition, thereby maximising the value of the asset.

The oil and gas industry has only begun to scratch the surface when it comes to realizing the potential of intelligent well technology to contribute to efficiency and productivity. Beyond the attraction of interventionless completions in the high cost arena of subsea and deep water wells, intelligent well technology can deliver improved hydrocarbon production and reserve recovery with fewer wells. Intelligent well technology can improve the efficiency of water floods and gas floods in heterogeneous or multi-layered reservoirs when applied to injection wells, production wells, or both. The production and reservoir data acquired with downhole sensors can improve the understanding of reservoir behaviour, and assist in the appropriate selection of in-fill drill locations and well designs. Intelligent well technology can enable a single well to do the job of several wells, whether through controlled commingling of zones, monitoring and control of multiple laterals, or even allowing the well to take on multiple simultaneous functions – injection well, observation well or production well.

Finally, intelligent well technology allows the operator to monitor aspects of wellbore mechanical integrity, or the environmental conditions under which the completion is operating, and to modify the operating conditions to maintain them within an acceptable integrity operating envelope.[1]

Elements of Intelligent Wells

The industry generally recognises the definition of an intelligent completion, as described at the 2001 SPE Forum in St. Maxime, France, as one in which "control of inflow (or injection) takes place downhole *at the reservoir*, with no physical intervention, with or without active monitoring."

To realize this, the following elements are generally required:

Flow Control Devices. Most current downhole flow control devices are based on or derived from sliding sleeve or ball-valve technologies. Flow control may be binary (on/off), discrete positioning (a number of preset fixed positions), or infinitely variable. The motive force for these systems may be provided by hydraulic or electric systems.

Current-generation hydraulically operated flow control devices have evolved to be more reliable, more resistant to erosion, provide greater flow control, and generate greater opening and closing forces.

Feedthrough Isolation Packers. To realize individual zone control, each zone must be isolated from each other by packers incorporating feedthrough systems for control, communication, and power cables.

Control, Communication and Power Cables. Current intelligent well technology requires one or more conduits to transmit power and data to downhole monitoring and control devices. These may be hydraulic control lines, electric power and data conductors, or fibre optic lines. Optical fibres may be installed in a dedicated armoured (control) line, or may share a control line with a hydraulic line. Electronic and electrical systems may be integrated with an ESP power/data transmission cable. For additional protection and ease of deployment, multiple lines are usually encapsulated and may be armoured. New technologies for intelligent wells are being developed to eliminate the communication and power cable – i.e., "the cableless well".

Downhole Sensors. A variety of downhole sensors are available to monitor well-flow performance parameters from each zone of interest. Several single-point electronic quartz crystal pressure and temperature sensors may be multiplexed on a single electric conductor, thus allowing very accurate measurements at several zones. Optical fibres are now widely used for distributed temperature surveys throughout the length of a wellbore and provide temperature measurements for each meter of the well. Single-point fibre-optic pressure transducers are now available, and multi-point or distributed fibre optic pressure sensing is being developed. Downhole flow meters are available based on Venturi systems, or pressure drop correlations across flow control devices. New generation flow meters based on passive optical fibre acoustic sensing are being developed. Other new technologies under development are water cut sensors, fluid density meters, micro-seismic arrays, formation resistivity arrays, and downhole chemical analysis sensors.

Surface Data Acquisition and Control. With multiple downhole sensors providing "real-time" production data, the volume of data acquired can be overwhelming. Systems are required to acquire, validate, filter, and store the data. Processing tools are required to examine and analyse the data to gain insight into the performance of the well and the reservoir. In combination with the knowledge gained from the analysis, predictive models can assist in the generation of process-control decisions to optimize production from a well and asset.

ESPs and Intelligent Completions – Synergy and Benefits

Current ESP technology shares many of the attributes for monitoring and control typical to intelligent well completions. ESP sensor technology provides the capability to monitor well inflow parameters such as fluid pressure and temperature at the pump intake; pump performance parameters such as pressure, temperature, and flow rate at the discharge; and motor diagnostic parameters such as vibration, current leakage and motor temperature. ESP control technology provides the capability of changing the speed of the motor and the pump to match pump performance to well inflow conditions, thereby optimizing lift energy consumption, maximizing well productivity, and reducing wear and tear on the artificial lift equipment.

Intelligent well monitoring and control technology augments the capabilities of the ESP systems by providing the capability to balance production from multiple zones, restrict or shut in zones with high water or gas production, and selectively test zones to monitor reservoir performance. Intelligent well technology can be used in the following applications:

- wells exploiting multiple zones or commingling multiple reservoirs
- horizontal wells exploiting reservoirs with a high degree of anisotropy
- multilateral wells to control flow from individual branches
- wells using downhole oil/water separation and disposal.

The following benefits can be realized by applying intelligent well technology to ESP installations:

- more energy generated by the ESP is dedicated to lifting oil rather than water;
- greater drawdown on oil producing zones can be achieved;
- wear-and-tear due to slugging and inclusion of gas is reduced;
- ESP size may be tailored (reduced) to better match oil lifting requirements;
- size of downhole ESP gas separator and gas handling equipment can be reduced; and,

- the well can be shut-in at the sand face while pulling the ESP to surface, thus maintaining well control and minimizing formation damage

These benefits result in more oil production, recovery of more reserves, and the reduction of lifting costs for the asset.

Issues Specific to Applying Intelligent Wells

When considering combining ESP and intelligent well technology, several key issues must be considered in a total system context to ensure the appropriate design, installation and operation of the "Smart ESP" well.

Wellhead Penetrations. The real estate available for electrical power conductors, instrument cables, hydraulic control lines, and fibre optic cables passing through the wellhead is limited. Solutions to this problem can come from multiplexing the function of some of the conduits, such as pumping the optical fibre down the hydraulic control line, or combining intelligent well electrical power and data transmission with ESP cabling. Alternatively, the intelligent well cables can be strapped to the outside of a production liner to surface.

Intelligent Well Cable Disconnects. Intelligent well components are generally installed for an extensive mission profile, perhaps for the full life cycle of the well. ESP equipment generally has a more limited life-time, and requires (relatively frequent) change-out throughout the life of the well. If the ESP is deployed on the same production conduit on which the intelligent well cabling is conveyed, then downhole wet disconnects must be provided for intelligent component hydraulic control lines and electric conductors. Hydraulic wet connects allow the downhole completion equipment to be re-integrated with the intelligent well control system at surface, once the ESP is back in place. This issue may be avoided by conveying the intelligent well cables on the outside of a production liner or deploying the ESP on a cable or coiled tubing.

Flow Scenarios, ESP Sizing and Speed Control The key to the successful marriage of intelligent well technology with ESP technology is an understanding of the mission profile for the completion design – that is, what range of inflow/outflow conditions are expected for the life of the intelligent well completion and for the typical run life of the ESP. In particular, the artificial lift system must have adequate turn-down capability to cope with the closing in of one or more zones. This can be accomplished by selecting the appropriate pump design and variable speed control system for the most likely productivity scenarios given the probable selective inflow operating options. A detailed operating philosophy must also be described to ensure that the system is operated within its design envelope.

Communication and Control Systems Interface and Integration. Maximum value of the synergy between intelligent wells and ESP technology will be realized with the full integration of the communication and control systems, and development of related petroleum engineering tools as well as production optimization software. Several companies are developing these technologies with the ultimate aim to provide "real-time" optimization of not only a single well's hydrocarbon productivity, but also the productivity and recovery efficiency of an entire asset.

A Theoretical Example

In practical terms, how can intelligent well technology work with ESP technology to improve well productivity? **Fig. 1** illustrates a hypothetical horizontal production well, which penetrates three hydraulically isolated layers of a multi-layer reservoir. The uppermost layer of the reservoir is at a depth of approximately 6000 ft TVD, and the horizontal wellbore penetrates each layer at a shallow angle, such that 1500 ft of the total 2500 ft of measured horizontal wellbore is connected to each of the three layers equally (500 ft each). Each layer has equal gross fluid productivity, with the top layer producing at 2% water cut, the middle layer at 12% water cut and the lower layer at 30% water cut.

Fig. 2 represents the inflow and outflow performance of the well. Without artificial lift, the well is capable of producing 3200 BOPD gross fluid with a water cut of 15.3%, as illustrated by *point A* at the intersection of the tubing performance curve and IPR1. By adding an ESP with 35 stages, using 180 hp, approximately 1000 psi of additional drawdown can be imposed on the well. As a result, the gross rate increases to 7475 BOPD with a water cut of 14.5%, as illustrated by *point B*.

If we then assume that water breakthrough occurs in the lowermost zone through water flooding or an active aquifer, such that the lowermost zone water cut increases to 95%, the well performance slips to a gross rate of 7250 BOPD with a water cut of 35.7% (*point C*). This results in net oil production of 4662 BOPD.

With the intelligent well capability to shut-in the lowermost zone, the performance of the well drops to IPR2 from IPR1, and the operating point moves to D from C. The result is a drop in gross rate to 5850 BOPD with a water cut of 7.4%, but with a net oil production of 5417 BOPD, *an increase of 755 BOPD.* In addition, processing and disposing of more than 2000 bbls of water per day is eliminated, and ESP power use is reduced by 10%. With intelligent well technology, this can be accomplished without intervention.

Putting Theory to Practice

The previous hypothetical example illustrates the benefits of intelligent well technology, but includes a number of assumptions, which are simplifications compared to the real world, particularly with regard to the IPR performance. How does this translate into practice?

BHP's Douglas Well D17 is a successful example of the application and benefits of real-time monitoring and inflow control at the reservoir in a well produced with the assistance of an ESP.

D17 Background. The Douglas Field is a shallow, low pressure, under-saturated oil reservoir situated offshore in the Liverpool Bay area of the East Irish Sea west of Great Britain (**Fig. 3**). The Triassic sandstone reservoir lies at depths between approximately 2,250- and 3,000-ft. TVD. The reservoir is made up of a number of geological facies; i.e., aeolian dune, aeolian sandstone, sandy sabka, fluvial channel, partial fluvial and mudstone and consists of a number of distinct zones with varying reservoir qualities. The oil producers are all completed with ESPs that provide the necessary artificial lift to obtain economic production rates. Table 1 shows the reservoir characteristics at the D17 location, which are similar to other wells in the Douglas field.

Water Production Performance. The Douglas Field is produced under a combination of natural aquifer support and water injection to maintain reservoir pressures and manage oil sweep efficiency. Trends in produced fluid water cut are very similar in all wells with the timing of water breakthrough and the current level of watercut being a function of the well's structural elevation and the cumulative oil produced. Over six years into the producing life of the field, water cuts have reached in excess of 80% in some wells. Limitations on handling water at surface have resulted in the need for downhole water management to maximize oil production, optimize oil recovery and add project value.

Understanding and confirmation of the water breakthrough mechanism was essential to develop a business case for downhole water management. Production logging indicated that the majority of the water production is originating in either Zone 1A or Zone 1C - little or no water is being produced from Zone 2.

Fig. 4 is a representative production log showing where the water is entering a typical Douglas well. The data shows that any water management scheme must be capable of isolating water production from the middle or upper reservoir intervals, while allowing continued production from the other zones. Based on these studies and data, the completion for the D17 well was designed to allow selective isolation of the major reservoir zones, and also, to allow zones to be returned to production.

D17 Completion Design.

The D17 completion was designed with the following objectives in mind:

- Provide capability to shut off water to optimize production from both individual Douglas wells and the total field.
- Reduce well intervention costs.
- Provide distributed temperature survey (DTS) data to monitor watercut development in each reservoir zone and to eliminate interventions associated with PLTs.
- Allow replacement of the DTS optical fiber without significant intervention.
- Allow the upper ESP completion to be serviced while leaving the lower completion in place.

Based on production logging results, water shut off capabilities were focused on isolation of each of the major producing intervals; i.e., Zone 1A, Zone 1C, and Zone 2.

Water shut off benefits field production optimization by:

1. Offsetting water production with increased oil production at each well where the oil production is constrained by limitations of the ESPs.
2. Maximizing net oil production within the constraints of the Douglas field processing facility gross liquid handling limits or water handling limits by closing off the highest watercut intervals.

The capability to reopen closed zones at a later date is of value as watercut progressively increases in other zones or other wells. In addition, production water-cut performance has indicated that gravity separation occurs in the reservoir during long periods of shut-in. This phenomenon suggests that there might be an added benefit from cycling high water producing intervals.

Based on the objectives and functionality described, BHP chose the D17 well to demonstrate the capability of the DTS system and intelligent well technology to identify and control downhole water production.[2,3,4,5] The D17 multizone completion, as depicted by the schematic in **Fig. 5**, is designed with isolation packers between each zone and remotely actuated interval control valves to shut off production from high watercut intervals. For the purpose of servicing the ESP, the upper completion can be separated from the lower completion by means of an On/Off disconnect sub.

D17 Performance. The D17 completion was successfully installed in December, 2000 with the exception that the DTS system could not be fully deployed.[5] As a result, it was not possible to use the DTS to fully monitor zonal watercut development as originally planned.

Initial well performance is shown in **Fig. 6**. After one year of production watercuts reached 82%. In line with other wells in the field, zone 1A was suspected of producing at the highest watercut, so the interval control valve was closed to isolate zone 1A. The operation was safe, quick and trouble free, and resulted in less than 4 hours lost production. **Table 2** compares the production rates before and after closure, clearly demonstrating the increased production rate achieved by closure of the interval control valve.

Figs. 7 and **8** compare the lift curves and inflow performance of the well before and after closure of the interval control valve. The consequence of this action is demonstrated in **Table 2**. Inflow performance was reduced due to the elimination of production from zone 1A. However, the reduction in watercut due to closure of the interval control valve ***increased oil production by approximately 1200 STB/D***. The pump operating frequency was reduced from 60Hz to 50Hz to ensure that the pump inlet pressure remained above the bubble point pressure with the reduced inflow performance

Fig. 9 compares the performance of the well before and after the closure of the interval control valve. The watercut stabilized at 70-72% compared to 79-82% before the sleeve was closed.

Water samples are regularly analyzed to monitor well performance. Before closure of the sleeve, the produced water density indicated production was mainly from a zone where injected seawater had broken through. Following closure of the sleeve, the produced water density increased, indicating production of formation water with no injected seawater. This change in water density clearly demonstrates that the closing of the interval control valve has modified the inflow profile so that previously poorly swept zones are now being effectively drained.

The closure of the interval control valve also resulted in an increase in reserves, as illustrated by the decline curve plot in **Fig. 10**. The shift in the curve indicates that use of smart well technology on D17 is expected to increase reserves by at least 700,000 STB (from 3.2 to 3.9 MMSTB). There will probably be further gains from water shutoffs achieved through closing the other interval control valves, as well as the future benefit of re-opening the upper sleeve once gravity segregation has reduced the interval watercut.

Business Case for D17 smart well. The original business case for the installation of smart well technology in D17 assumed that at least one water shutoff would be required during the field life. The estimated incremental cost of installing the smart well completion in D17 was \$335k and this was primarily justified by the elimination of a conventional zonal isolation intervention costing \$335k to \$770k.

Given the well performance following the interval control valve operation, the 700,000 STB additional reserves and incremental oil rates (400 to 1200 STB/D) easily justified the additional \$335k expenditure. The performance of Douglas well D17 clearly demonstrates the technical and economic benefit of intelligent well technologies in combination with ESPs.

Conclusions

It has been shown that the application of ESP artificial lift to intelligent well completions requires special considerations and that significant up-front engineering is required to integrate the two technologies.

The benefits of improved rate and recovery can be quantitatively identified on a case by case basis by modelling the system (reservoir and well) performance prior to installation.

The design of the integrated package must take into consideration the required capability to disengage from the intelligent well completion downhole (e.g., to change pumps) while maintaining well control and minimizing formation damage through shut-in at the sand-face. Hydraulic wet-connects allow the downhole completion equipment to be re-integrated with the intelligent well control system at surface once the ESP is back in place.

Installation in the field must account for the operational complexities of multiple control and monitoring lines, and installation procedures should be co-ordinated between the different service providers.

The methodology for operation of the well should be planned in advance of commissioning. In order to ensure that improvements in operating efficiency may be made real-time over the producing life of the well, field personnel and engineers should be trained in assimilation of the data and operation of the well.

Douglas well D17 has demonstrated the application of smart well technology to improve production and reserves. The project was a success due to:

1. Proper understanding of the reservoir architecture to allow the objectives of a smart well to be clearly defined,
2. Development of a sound business case for the use of smart well technology and selection of an appropriate smart well solution, and,
3. Successful deployment of surface actuated inflow control valves and a DTS system.

The advantages of the smart well technology in D17 are clearly demonstrated by:

- Incremental oil rates of 400 to 1200 STB/D,
- Modified inflow profiles to improve reservoir sweep efficiency, evidenced by a change in produced water properties, and,
- An estimated 700,000 STB of additional reserves.

Acknowledgements

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SI Metric Conversion Factors

in	x 2.54*E + 01	= mm
ft	x 3.048*E - 01	= m
hp	x 7.460 43*E – 01	= kW
psi	x 6.894 757*E + 00	= kPa

*Conversion factor is exact

Table 1

Zone	Geological Facies	AH Thickness (ft)	TV Thickness (ft)	Average Porosity (%)	Permeability (mD)	Reservoir Quality
IA	Aeolian sandstone	127	56	18.1	100 - 5000	Excellent
IB	Thinly inter-bedded fluvial	34	16	12.2	10 - 500	Fair
IC	Aeolian sandstone	102	51	15.0	100 - 2000	Excellent
II	Fluvial deposits	163	91	14.4	50 - 1000	Fair
III	Aeolian sandstone	Below OWC. Not targeted by D17				Excellent

Table 2

	Immediately Before Closing	Immediately After Closing	One Month After Closing
Pump Frequency	60 Hz	50 Hz	52 Hz
Liquid Rate	14841 b/d	9993 b/d	11870 b/d
Watercut	79%	57%	70%
Oil Rate	3117 b/d	4297 b/d	3561 b/d
Incremental Oil		**1180 b/d**	**444 b/d**
Produced Water Density	1.087 g/cc (Mainly injected Sea Water)	1.177 g/cc (Formation Water)	1.176 g/cc (Formation Water)

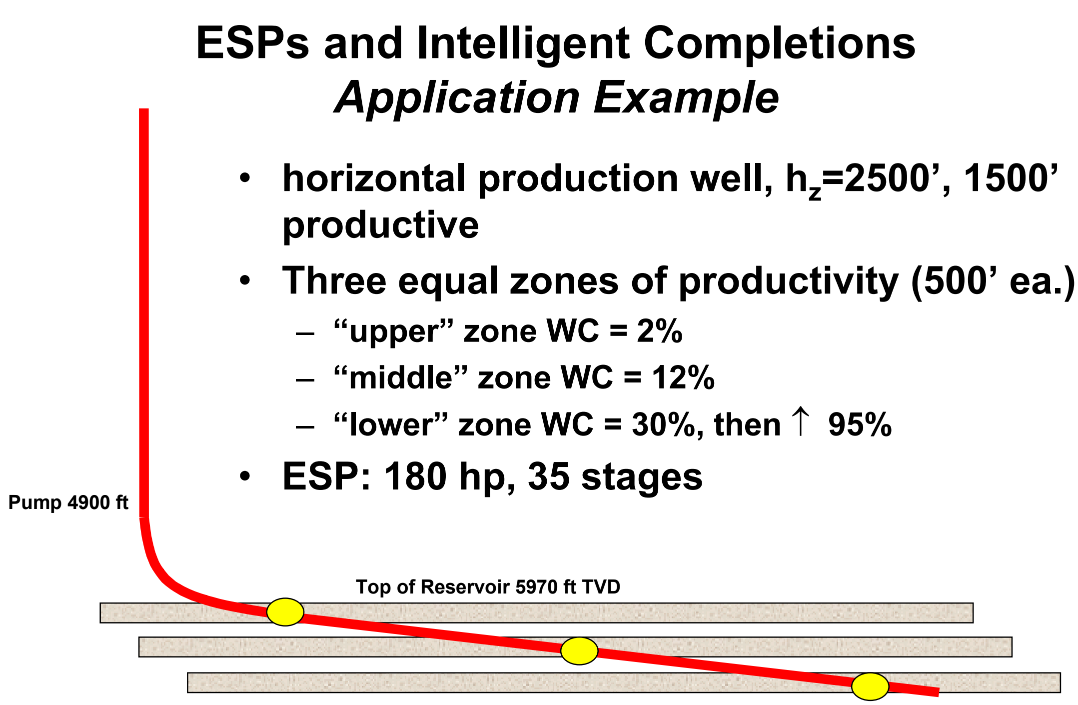


Fig. 1 — Hypothetical Horizontal Production Well That Penetrates 3 Layers.

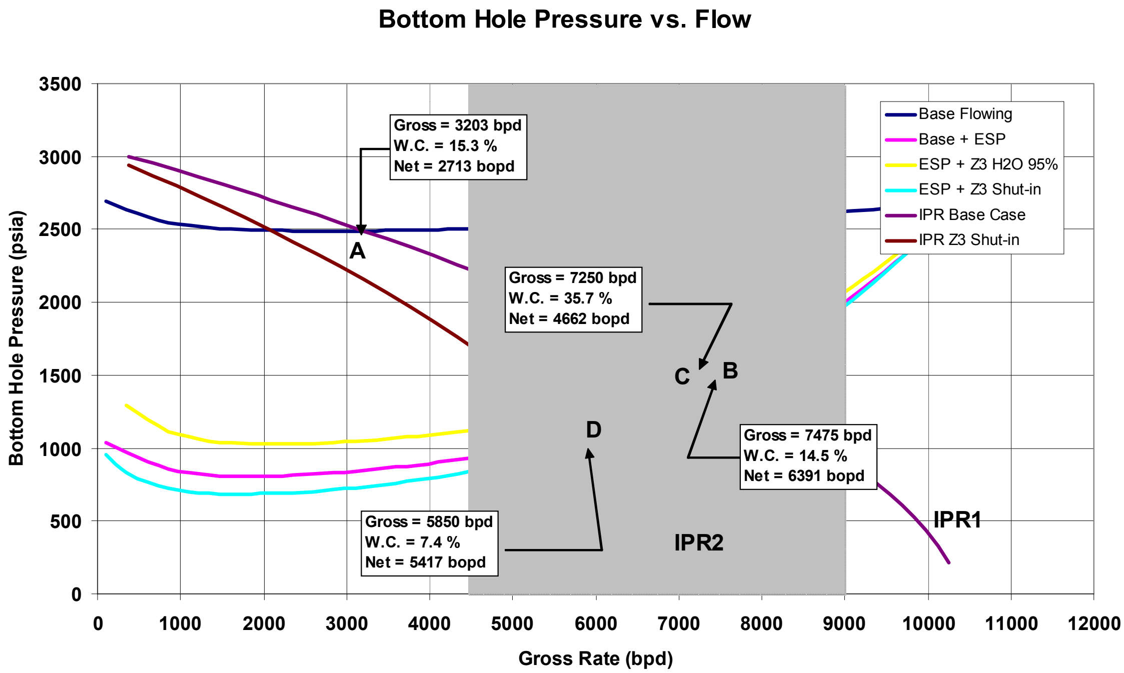
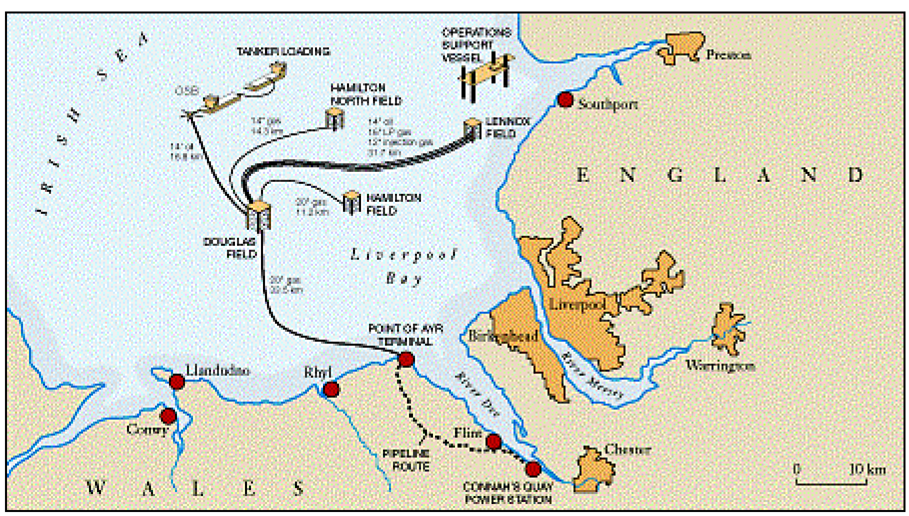


Fig. 2 — Inflow and Outflow Performance



BHP's Liverpool Bay development incorporates drilling and production facilities, a mobile support vessel, oil storage barge, subsea pipelines, gas terminal and export gas pipeline, and onshore base—all in the full view of the local community.

Fig. 3 — Location of the Douglas Field

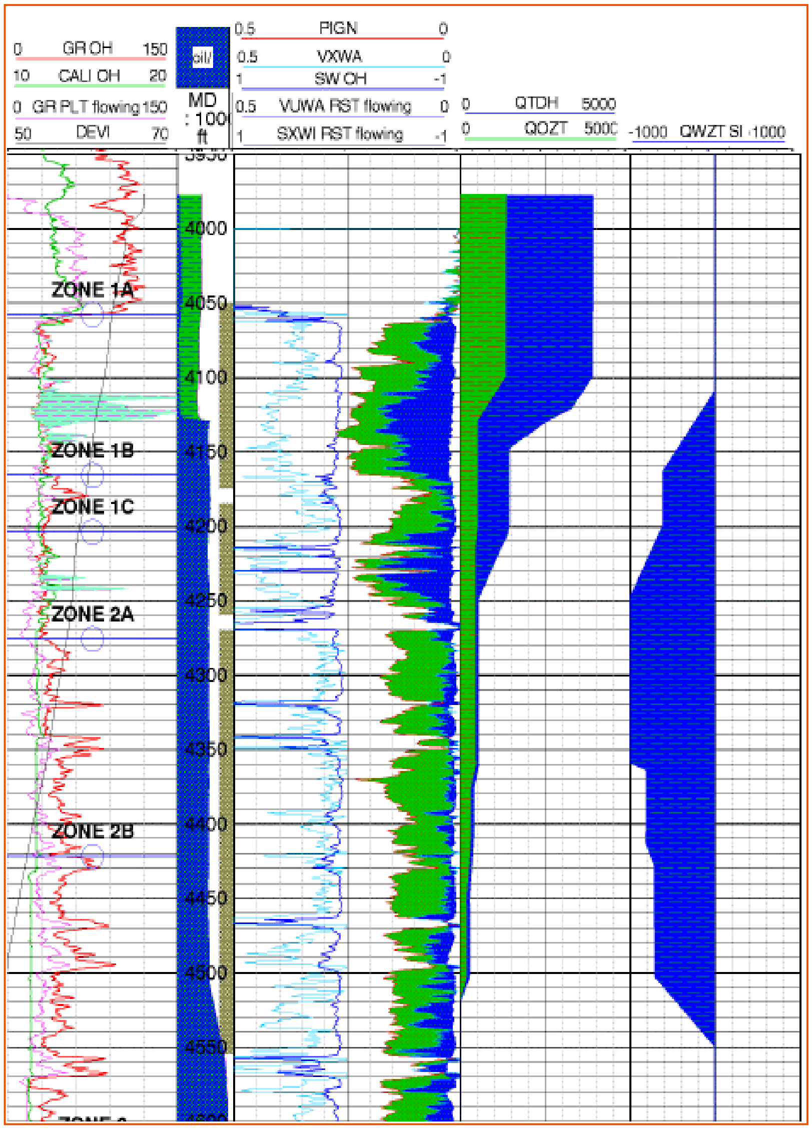
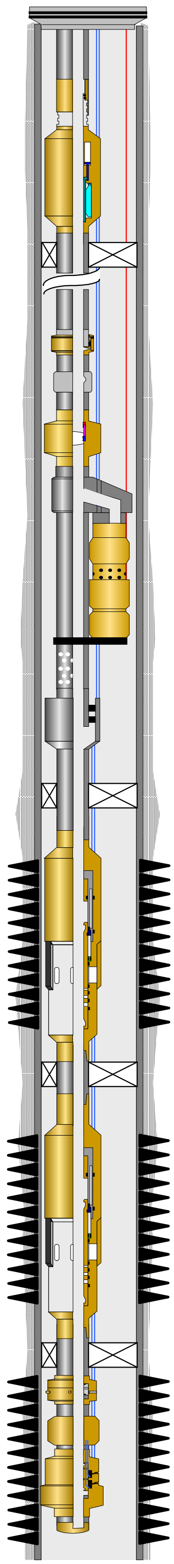


Fig. 4 — Representative Production Log Showing Water Entry Locations.



Description	Depth
Hanger	
Adjustable Union	15
TRSSV	600
Packer	4550
4 ½” Tubing	
Adjustable Spacer	
Nipple	
FBIV	
Auto Y-Tool	4700
ESP / Bypass	
Motor Base Support For Tubing	4800
Perforated Pup Joint	
On / Off Disconnect	
Retrievable Packer	5050
Hydraulically Operated Interval Control Valve	
Retrievable Packer	5250
Hydraulically Operated Interval Control Valve	
Retrievable Packer	5350
Mechanical Sliding Sleeve	5600
C.I.T	5600
D.T.A.S	5700
Bullnose	
9 5/8" Casing	6200

Fig. 5 — The D17 Multizone Completion

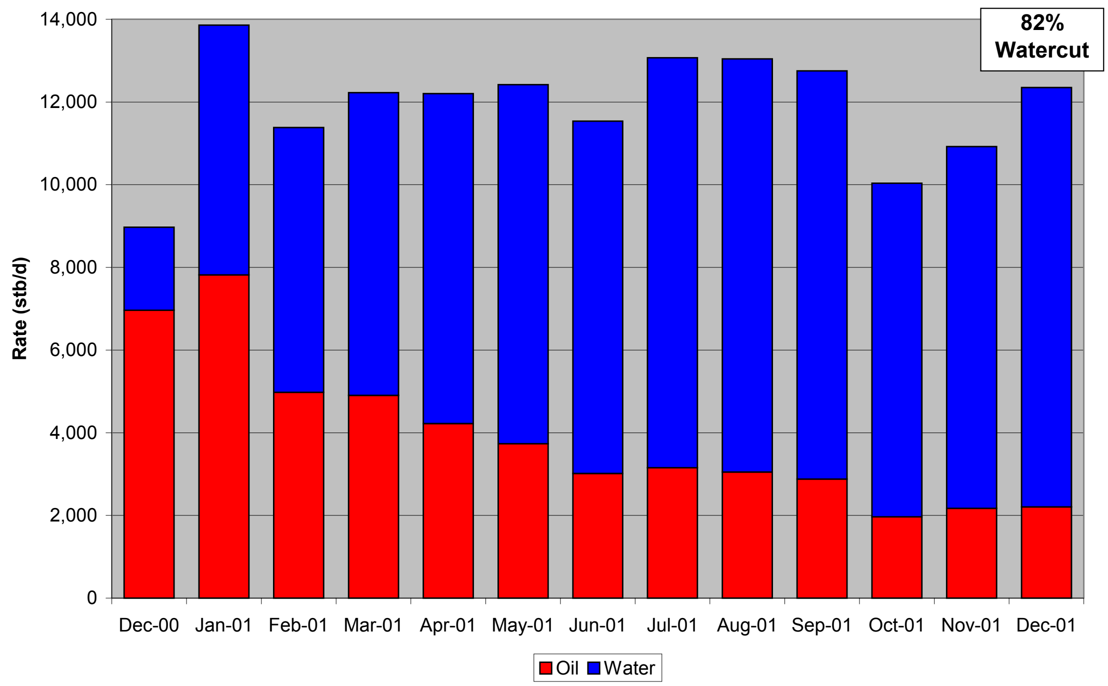


Fig. 6 — Initial Well Performance

Frequency	**=**	**60 Hz**
Gross rate	**=**	**14841 b/d**
Water cut	**=**	**79 %**
Net oil rate	**=**	**3117 b/d**

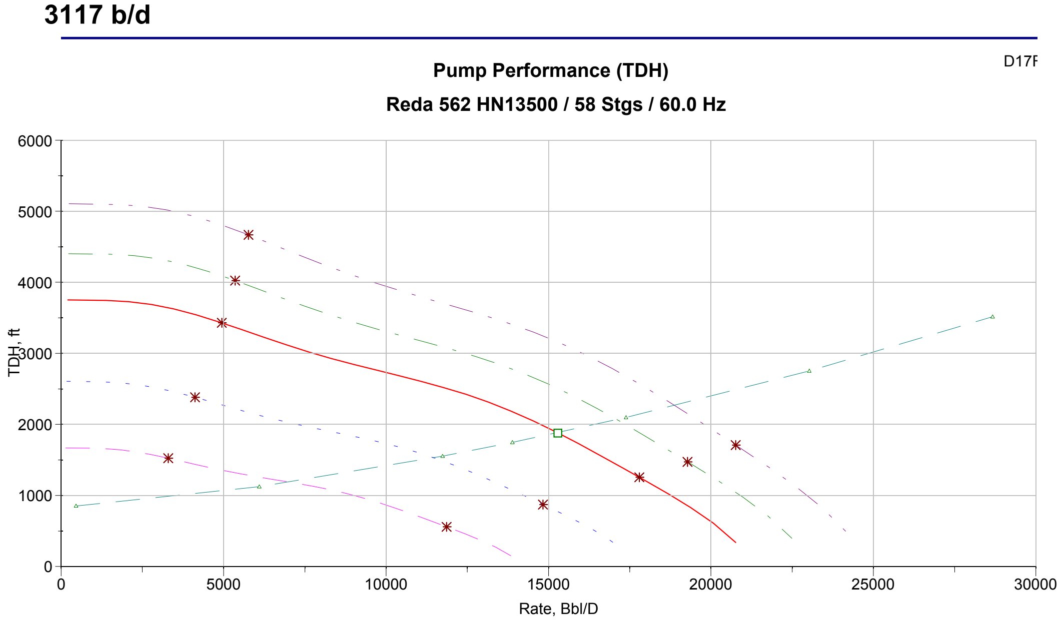


Fig. 7 — Lift Curves and Inflow Performance of the Well Before Closure

Frequency = 50 Hz
Gross rate = 9993 b/d
Water cut = 57 %
Net oil rate = 4297 b/d

Incremental oil gain ca. 1200 b/d

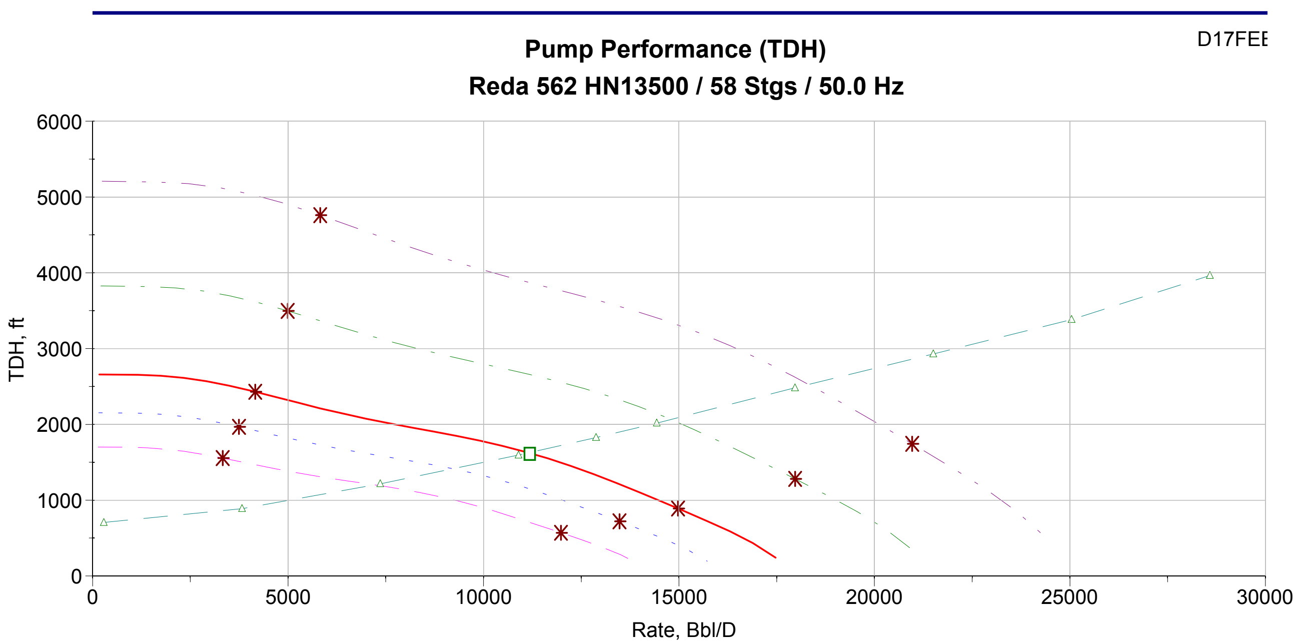


Figure 8 – After water Shut Off

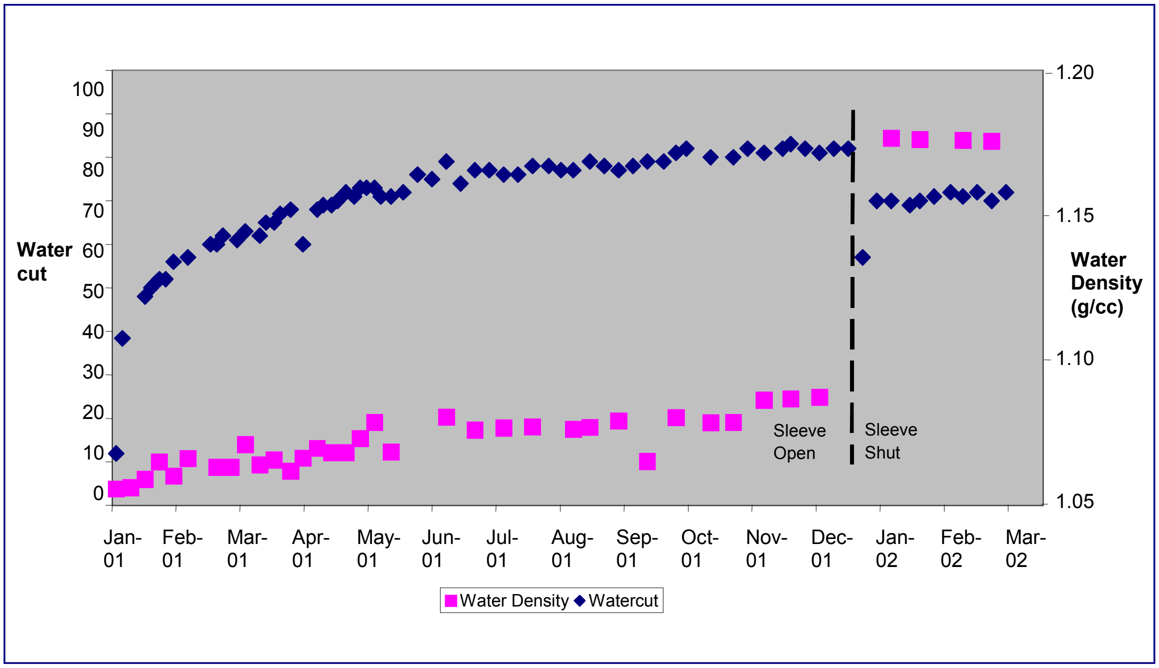


Fig. 9 — Performance of Well Before and After the Closure of the Interval Control Valve

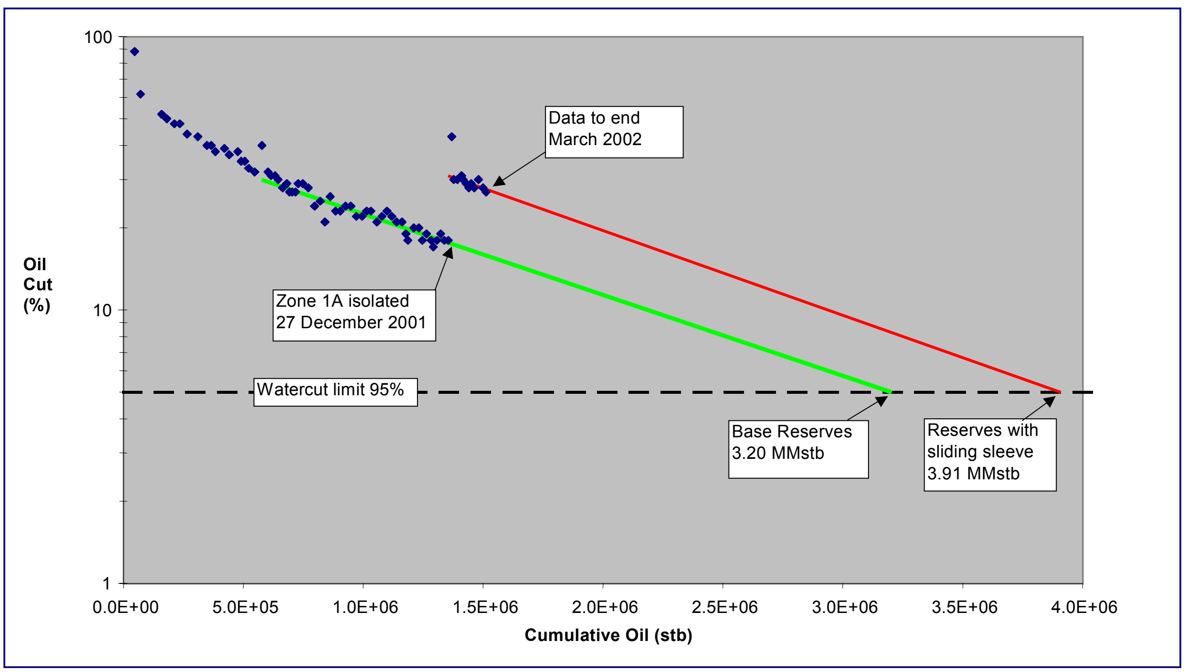


Fig. 10 — Plot Showing Increase of Reserves After Closure of the Interval Control Valve