Connecting with the reservoir

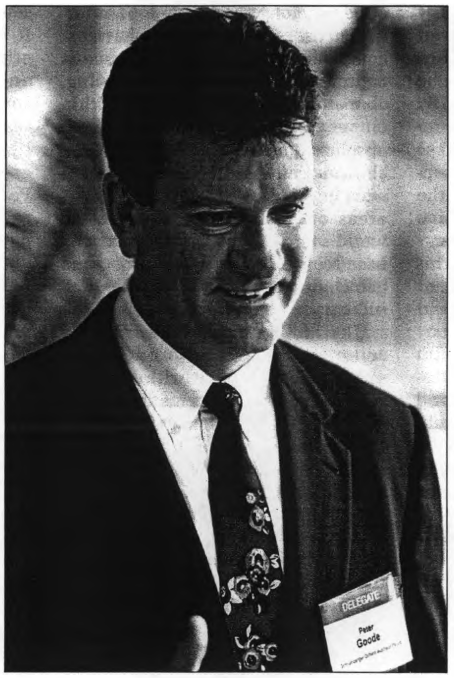
I want to highlight some of the tools and technologies, I believe, will shape the oil field of the future. Specifically, I contend that we need to challenge the industry to raise the level of completion and artificial lift technology. We must do this if we are to realise the industry's ultimate vision: real-time optimisation of reservoir performance.

I like to refer to this vision as connecting with the reservoir.

The industry has always had financial pressures to reduce finding and producing costs, increase recoverable reserves and maximise asset value.

Oil and gas companies must cost-effectively discover and develop new reservoirs, while simultaneously increasing recovery from existing ones, targetting 50% and beyond. This is a monumental task. The challenges we face are made more difficult considering that new plays will be concentrated in deepwater and remote areas where costs and risks are high, and field development is complex. The process of recovery depends on many services and technologies. The design, deployment and long-term operation of subsurface equipment, linked to surface facilities and models, will be fundamental.

Throughout my career, in a variety of positions, I have seen first-hand how development and application of technology can make a huge difference in both the short-term profitability and long-term economic viability of oil and gas production. The key is efficient and effective exploitation of these technologies, based on a systems approach customised to fit the particular requirements of each asset.



Peter Goode, President—Well Completions and Productivity, Schlumberger Oilfield Services

CHALLENGES AND OPPORTUNITIES

It is estimated that approximately 65% of the world's oil that has been discovered is still in the ground. At an oil price of US$45 per barrel, this is equivalent to US$65 trillion dollars, or 40 years of production at current consumption rates.

A significant portion of this incremental value can be captured using permanent well surveillance and inflow control—connecting with the reservoir—to provide the increased knowledge on how the reservoir is responding to the depletion strategy. As dynamic control of completions continues to progress it will become increasingly necessary to recognise the interdependence of systems, in particular instrumented, functional completions and artificial lift equipment.

Some in the industry speculate that finding larger, more productive reservoirs is the answer to satisfying future demand. This is simply not the case. While new reservoirs will certainly contribute, and benefit significantly from new technology, alone they will be insufficient. We must revisit existing fields more aggressively using today's technology advances.

In the mid-1960s, the average discovery was around 200 million barrels. Today, the average size has dwindled to about 50 million barrels. Fields are also becoming harder and more expensive to locate. These include subtle stratigraphic traps and deepwater prospects, many of which are found in remote basins far from a existing infrastructure, a situation that increases development costs, substantially.

By focussing on the vast potential of increased recovery from existing reservoirs—where structures are generally well defined and ample data reservoir data typically exists—we can eliminate many of the risks and costs of finding and developing new hydrocarbon supplies.

Despite any consumption anomalies that may occur in the short term, the global demand for oil will increase substantially in the next 10 years, outstripping supply unless the industry adopts a more aggressive approach to improving recovery.

Pivotal to improving recovery will be making better decisions through-

> Our poor experience with using large volumes of data in our industry is slowing the uptake of new technology that can offer significant benefits.

out field life. Such decisions can only be based on having accurate and current information, from both wells and facilities. However, today's experience with such data is a barrier. If gathered at all, data are usually incomplete and often remains unverified and, therefore, unused.

Experts estimate that, as an industry, we waste roughly 25%—or approximately US$30 billion—of our annual upstream expenditures.

Providing timely access to integrated, reliable, verified data, information and knowledge is crucial to the effective decision-making that will ensure optimal exploitation of an asset.

Our poor experience with using large volumes of data in our industry is slowing the uptake of new technology that can offer significant benefits. The barriers grow when we confront changing our established work processes aso that we can move to the necessary level of interdisciplinary integration.

NEW DEVELOPMENT

What part will emerging completion and production technology play in achieving these recovery improvement goals? The typical cash flow curve for a new field highlights this.

The initial phase is a period of capital outlay, which typically involves finding, delineating and developing the prospect. This may take years or even decades. The more rapid the development, the sooner revenue is generated and the greater the return on investment.

The second period is when oil starts flowing and a revenue stream is established. Eventually, the break-even point is exceeded, and the project becomes profitable and cashflow positive.

As the revenue stream continues to grow, expenses usually decrease as the asset depreciates and production efficiencies are realised.

Later, oil production declines, water production increases and workover and maintenance costs increase. Finally, the field reaches its economic limit: the point where expense exceeds revenue and cash flow stops.

The industry has long focussed on extending the economic lifetime of fields beyond that achievable with natural energy drive through such methods as installing artificial lift. This extends beyond what would have normally been the field abandonment point. In the future, it will become imperative to find novel ways to extend this region even further. This is the basic challenge faced by many operators every day.

There is an increasing industry trend to install artificial lift or provide pressure support earlier in the life of a field to accelerate production. This is a good plan, but implies a need for measurement and optimisation to realise maximum value from the investment. An accelerated production profile contributes significantly to the financial performance of a field. For example, the incremental cost to add artificial-lift is usually insignificant relative to the overall expenditures required to find, develop and complete the reservoir. This acceleration of cash flow early in the life of a project, achieved through application of fit-for-purpose completion technology, can substantially improve net present value, NPV, and return on investment, ROI.

MITIGATING RISK

I am well aware of the concerns that many of you have and the potential risks associated with using controllable completions and the early installation of artificial lift systems, in particular in environments where intervention costs are high. Eliminating, or at least mitigating, this risk relies on significant investments in research and engineering specifically targetted at systems, instrumentation and equipment reliability.

Future field developments will rely heavily on systems designed with reliability and total system cost as the key drivers, not component reliability and cost as is often the case today. We will also need to actively manage all interfaces between the component technology and the total production system. I firmly believe that the industry has the technological capability today to substantially reduce the risk of failure while, at the same time, significantly improve the total efficiency of production systems.

For example, recent developments in the application of subsurface fibre optic sensors will demonstrate how new technologies can create a paradigm shift in the reliability of permanently installed subsurface sensors.

OPTIMISE PRODUCTION RECOVERY

Through production optimisation based on evolving completion and information technology, operators can realise incremental cash flow beyond that planned at project inception. This will mean incremental recovery and higher returns. These improvements in recoverable oil will result from improving the drainage pattern of a field or the sweep of a water, steam or CO_2 flood. Advanced completion components together with improved subsurface monitoring will play a crucial role in achieving this incremental recovery. These completions are available today.

OPTIMISED RECOVERY

Let's look at an example of the opportunities afforded by such systems. Here we see a typical flood pattern from a horizontal well being produced with a pump that creates a pressure sink or drainage point in the reservoir. The heel of the well cones in water, and drainage is impaired. If, however, the capability exists to model, monitor and control specific reservoir drainage points, a more efficient reservoir sweep results.

In our now extensive experience in production logging of horizontal wells, this is often not the case, highlighting

the need for making better use of the tools now at our disposal.

ACTUAL TEST IN RESERVOIR ROCK

This theory has been tested in actual reservoir rock. Controlling drainage can be a critical tool for optimising hydrocarbon recovery. These experiments helped to validate a series of models, but more importantly they provided a visual understanding of the mechanisms actually occurring in the reservoir, reflecting the demonstrable need for real-time control of well flowrates and pressures.

The full potential is only realised if this approach is extended beyond individual wells to encompass a comprehensive, field-wide application based on real-time reservoir monitoring, data acquisition and analysis, enlightened decision-making and remotely actuated control systems.

INTELLIGENT CONTROL IN A DUAL DATERAL USING A SUBMERSIBLE PUMPING SYSTEM

This type of technology has been successfully tested at BP's Wytch Farm field in southern England. The M-15 well was unable to drain the reservoir effectively, due to cementing problems. Two laterals were drilled, to the north and south of the original borehole. The northern lateral drains a portion of the reservoir that is faulted. It was suspected that the faults could induce comunication with the underlying aquifer, yielding a faster increase in water-cut. The southern lateral is in a more competent part of the reservoir and was, therefore, planned for an openhole completion.

The objectives were:

- to evaluate the interaction of the two laterals when jointly put into production;
- to allow individual testing of each branch;
- to control the production of water independently from each lateral; and
- to avoid excessive pressure draw-down at the level of the junction of the southern lateral to prevent hole collapse.

A downhole pump was installed along with flow- control for the two zones, controlling production from the northern and southern laterals. A reservoir model of the well and near-well region was used to evaluate several production scenarios. The highest well performance was observed when production from the two laterals was co-mingled and a control strategy was used from the onset of production. Higher water flowrates in the northern lateral represented the main control issue, since it affected total oil production.

RES2000 FIELD EXPERIMENT

The need for well bore sand control is increasing rapidly within the industry. Particularly in wells with long horizontal sections drilled in deep-water environments. An additional problem with many of these wells is the early influx of water. It often occurs at a point early enough in field development that understanding where the water is coming from can have significant value in the placement of subsequent development wells and production management decisions. Not to mention the value of controlling it once it arrives in a particular well.

This follows the axiom that the best water management strategy is the one that leaves the water in the reservoir.

To advance this, Schlumberger undertook a field project with the ultimate objective being to manage, in real time, the water entry into a horizontal well completed using an open-hole gravel pack.

The project included:

- having all data available in real time, web delivered, to allow expert collaboration and participation in all phases of the well construction and subsequent production;
- real time geo-steering in a thin oil column;
- real time geo-steering of an 800 ft horizontal well into an 8 foot oil column;
- segmentation of the well into three producing zones using inflatable packers;
- control of the fluid entry into each zone using electric flow control valves run with pressure gauges on each side of the valve;
- gravel packing on two of the three producing zones;
- combining sand face fibre optic distributed temperature with deep reading resistivity measurements; and
- allow remote and automatic control of production based on the acquired reservoir surveillance and production data.

> **The need for well bore sand control is increasing rapidly within the industry. Particularly in wells with long horizontal sections drilled in deep-water environments.**

Following the successful installation in Q3 2001, and initial monitoring and control system testing, the well is now producing and a variety of controlled experiments are being performed. The extent of the instrumentation and control in this well represents a step beyond what would be considered an acceptable risk by many operators today. However, within it there are incremental steps; the monitored sand face, high-resolution wellbore inflow control, and fibre optic monitoring, that offer immediate, significant value, both in terms of production improvement and reservoir characterisation.

REAL-TIME OPTIMISATION OF RESERVOIR PERFORMANCE

The use of real-time information and knowledge to control production in the previous examples illustrates the power of optimising well performance and the multifold potential if extended to the entire field development.

How can this be achieved?

I believe that the industry must fully commit to a closed-loop process that both optimises well and field

productivity and, ultimately, reservoir performance—all in real time. A collection of best-in-class solutions spanning reservoir characterisation, development planning, field implementation and reservoir monitoring and control will be required, directed at a common goal—maximising the financial return from an asset. The methodology is applicable for cradle-to-grave optimisation of a new field—from the first seismic survey through to decommissioning or extension of the economic lifetime, productivity and recovery of an existing field.

Enhancing the financial performance of an asset involves a full spectrum of oilfield experience and disciplines—extending from geologists, geophysicists, drilling engineers, production engineers and reservoir engineers, to financial planners and support personnel.

There is an outer loop to the process that represents the macroscopic phases of discovery, initial development and large-scale surveillance, like time-lapse 4D and multi-component seismic, history-matching of full field simulation models and field-wide pressure surveys. This loop has a cycle time of many months, and often years. Full-field production optimisation extends the field's economic lifetime—the section of the cash flow curve identified earlier in which artificial lift can play a key role.

Integral to this vision is a common requirement for subsurface sensors to monitor real-time events within the well bore. The new generation of sensors utilising fibre optic technology will provide the nervous system to the living reservoir model of the future. Over time, full-field production optimisation will be applied more aggressively, and will become more automated. Here, reservoir and field data—inclusive of production, seismic and borehole measurements and data acquired from sensor arrays placed throughout the reservoir—will be used to continuously modify the reservoir model and enable effective decision-making, improving production potential. System changes typically occur over months or years but result in the optimum reserve recovery from the asset.

Enhancing the financial performance of an asset involves a full spectrum of oilfield experience and disciplines—extending from geologists, geophysicists, drilling engineers, production engineers and reservoir engineers, to financial planners and support personnel.

Within the outer loop resides an inner, or production, loop. This loop represents the daily decisions and resulting actions that must be taken to keep the asset operating at peak performance. Success depends on, for example, efforts directed at increasing a submersible pumping system's operational efficiency and, thus, increasing the oil rate and reducing operating expenses.

The typical feedback loop is hours or days, and incremental improvements are realised quickly. Surveillance data is high-rate, like bottomhole flowing pressures, flowrates and wellhead pressures, and must be gathered, analysed, interpreted and acted upon in relevant real time—the timeframe required for successful decision-making.

There is a common mis-perception that these technology advances, in particular in permanent surveillance, are beneficial primarily in ultimate recovery and reservoir characterisation. This is simply not the case.

Often there is also immediate production improvement resulting in cash flow and reserves capture.

It may be through better well clean-up, knowledge based control in early life production, or better use of episodic measurements, for example well tests combined with the permanent surveillance, and appropriate action.

Reservoir characterisation, modelling and monitoring integrated with day-to-day wellbore control steps provides the road map for achieving the increased recovery factors the industry so desperately needs.

OPTIMISATION DOMAIN

The domain where both the short-term and long-term processes are deployed can be broken down into several distinct, but highly related, elements.

First is the reservoir, where the hydrocarbons reside, providing the primary source for value generation.

Second is the wellbore, which must be constructed to optimally access hydrocarbons and placed to ensure efficient, cost-effective recovery.

Next is the production system and handling facilities, which must process and transport the hydrocarbons to the point of sale.

Finally, but certainly not least important, is the field monitoring and telemetry system. It is crucial that the team responsible for asset optimisation have access to accurate, real-time information about field performance and the capability to implement actions and required solutions following analysis of acquired data.

It is a necessary requirement that this entire domain be seen as a single system. Each link is vital to the success of the process. Break or ignore any link and value is lost.

REALTIME CONTROL

The biggest challenge in moving the industry forward—but also a major opportunity—is to rapidly and effectively migrate to full implementation of realtime oilfield management.

For oil companies to achieve dramatic increases in recovery requires advances in reservoir monitoring and control, the fourth stage of the optimisation process.

Here, a variety of sensors, located within the completion or within the reservoir itself, monitor lift system parameters, well flowrates, changing phase composition and advancing fluid fronts. The downhole information will be relayed to surface collecting points and on by satellite to the oil company office for analysis. Systems data will be relayed to the service provider monitoring the system.

Engineering and financial implications of the reservoir's current performance will be evaluated using state-of-the-art reservoir models and communication systems that allow control signals to be relayed back to the reservoir.

This capability enables well zones to be opened or closed, fine-tuning the reservoir to maximise production, optimise the artificial lift system life and increase recoverable reserves.

As this capability develops, we will see convergence of the various workflows involved in the process to where modelling the entire production domain and the decisions required for optimal operation will be performed in realtime. This will require not only a new generation of sensor and controller technology for data acquisition, but also development of faster, more integrated numerical models and lower-cost, highly efficient data transmission systems.

THE SCHLUMBERGER APPROACH

How can oilfield service suppliers help the industry achieve these goals?

Schlumberger's approach has five key elements: First, we have created a responsive, fully enabled, cross-disciplinary organisation—focussed on the needs of local oil company asset management teams—which with the goal of providing fit-for-purpose solutions to complex field problems.

Second, we have equipped this organisation with the world's largest private intranet—connecting 75,000 users at over 1,000 sites in more than 100 countries augmented with the latest information technology and web-enabled tools.

Third, we are building a knowledge-sharing culture where technical communities of practice interact and exchange information to deliver global experience, expertise and best practice to clients anywhere, rather than just the know-how embodied in a few local individuals.

Fourth, we have established several centres of excellence, staffed with regional expertise, that are focussing on the specific needs of a given oil-

> **State-of-the-art information technology and communication tools allow user-friendly interchange and access to validated information, knowledge repositories and training aids—all within the framework of a responsive infrastructure.**

producing area.

Finally, through the use of the internet, our intranet and knowledge-sharing communities, we are connecting technology centres to the field to facilitate quick and efficient solution of operational problems.

I'll discuss the last area in greater detail.

Our initiative that facilitates greater technical collaboration and immediate problem solving is called InTouch. InTouch provides timely, direct information exchange between experts at worldwide technology centres and field personnel. The goal is to "apply everywhere what we learn anywhere."

State-of-the-art information technology and communication tools allow user-friendly interchange and access to validated information, knowledge repositories and training aids—all within the framework of a responsive infrastructure.

This allows a global knowledge base and best practices to be available anytime to field personnel, thereby leveraging the vast expertise of the technology centres and the extensive operational know-how of the field. This streamlines communications and speeds the solution of field problems.

The key components of the InTouch system include:

- An intranet with high bandwidth and global coverage.
- A standardised computer platform across all users.
- A single portal into the company's technical resource base.
- A validated knowledge repository;
- Interactive training and distance learning.
- Evergreen, online documentation.
- 24/7 access to technical experts across the spectrum of our business.

A single-standardised notebook computer functions as a fully supported knowledge platform. The platform accesses global helpdesks via the intranet. Currently, more than 30,000 field users are equipped with this integrated, mobile office, pre-loaded with the latest technical and business applications, including current operations and design software for various specialised completions, for example intelligent wells and artificial lift systems.

InTouchSupport.com, the heart of the system, is the sole interface for information exchange between the technology centres and the field. It provides one-stop technical support from centres of expertise 24 hours a day, 7 days a week, and helps create an efficient organisation where technical communities of practice interact, share and use what they know.

Through a global network of specialised, multi-disciplinary experts, we are capturing, classifying and disseminating best practices, lessons learned and fit-for-purpose solutions vital to worldwide field operations.

With InTouchSupport, employees can access a validated knowledge repository to seek existing solutions. If a field engineer cannot find an answer to a client problem online and has exhausted local resources, he or she can immediately contact an InTouch helpdesk engineer who either solves the problem directly or assembles a problem-solving team at a technology centre. Fast, accurate answers are transmitted directly to the originator in the field. The solution, following validation, is then placed in the online knowledge base for access by other field personnel.

A key component of InTouch is interactive training and distance learning—using an intranet to deliver instructor-based training directly to the end-user's location. We have created an unparalleled online learning environment for the professional development of employees and to support rapid deployment of new technology. Multiple sites can be connected simultaneously with an

expert anywhere in the world, delivering first class training. Online capabilities also afford efficient information updates. The intent is to complement traditional classroom instruction and hands on training, not to fully replace it.

InTouch also contains a single source of evergreen, online documentation providing a vehicle for effective distribution of, and access to, materials in both electronic and physical form. Documents are modular and conform to a single standard. Users are automatically notified of updates and revisions. Easy-to-use search-and-browse functions increase productivity.

Let me give you an example of how this works in practice. In a remote location in Indonesia, an operational procedure had been developed for starting stuck submersible pumping systems, following a power shut down. The procedure saved the operator significant intervention costs. The success of the local solution prompted the field service engineer to generate a best practice summary and post it to the InTouch repository. Months later, a field engineer in Venezuela used the solution developed in Indonesia to start stuck pumps, saving the cost of a workover.

This local application of global lessons learned was communicated between two individuals who never had the opportunity to share experience in the past.

InTouch is just one element in helping to foster better internal communication and technical collaboration.

CONCLUSIONS

In conclusion, our industry faces many profound challenges. This is not new to us. What is new is that we can't depend primarily on newly discovered fields as the answer to satisfying future demand. Instead, the route to lower unit cost, increased production rates and higher recovery factors will hinge on a concerted effort targetted at both new and existing reservoirs that can add decades in production capacity if we cost-effectively unlock their potential.

Connecting with your reservoir—physically, remotely, and intellectually. with your reservoir.

Mr **Peter Goode**, President—Well Completions and Productivity, Schlumberger Oilfield Services, delivered this address to the 42nd APPEA Conference in Adelaide on Wednesday, 24 April 2002.