The Big Picture: Integrated Asset Management

Reservoirs, wellbores, gathering lines and processing facilities are complex, dynamic systems, and changes in any one parameter can resonate throughout. With the advent of downhole and surface sensors and instrumentation for optimizing system performance, operators are faced with processing and managing enormous streams of data produced by these systems. Just as other industries are growing adept at handling and responding to critical data in real time, so too are E&P companies, which are now implementing new workflows in processing, analysis and information sharing to achieve their goals.

Wellbore sensors produce a great deal of data, but instrumented production systems generate data at even more astounding rates. Sensors placed downhole, mounted on wellheads, along flowlines or inside process equipment transmit a relentless stream of digits. Operators receive real-time, episodic, discrete or streaming field data and extract temperature, pressure, flow rate or other measurements to ascertain the status of downhole and surface systems linked to their assets. Every measurement and piece of data is intended to make operators better informed, and help them make quicker decisions that will improve recovery factors, increase reserves and ultimately increase the value of their assets.

E&P companies are striving to adopt new ways of managing and processing their operational information. Achieving this end can be challenging. The sheer volume of data produced by instrumented systems may be overwhelming, and the slightest delay in routing all these data to the right departments, computer models and personnel may prevent operators from realizing the full value of their data.

Software that conditions and manages the data is readily available. Engineers can securely access key operational data, and can choose from a variety of programs to evaluate and model performance at the reservoir, pump, wellhead, pipeline or refinery (see “Optimizing Production from Reservoir to Process Plant,” page 18). The data management and processing challenge, therefore, does not arise from lack of data or software capabilities.

To get the best performance from a field, how does an asset team find the key measurements that will indicate when reservoir or component performance is declining? In large fields that often involve hundreds of wells, an engineer might have to sort through thousands of datasets to evaluate asset performance. E&P companies are realizing that their personnel can spend inordinate amounts of time simply looking for the right data and conditioning the data for acceptance into modeling programs—before...
ΔP_1 = PR – P_{wfs}
ΔP_2 = P_{wfs} – P_{wf}
ΔP_3 = P_{USV} – P_{DSV}
ΔP_4 = P_{wf} – P_{tf}
ΔP_5 = P_{tf} – P_{DSC}
ΔP_6 = P_{DSC} – PR_{B}
ΔP_7 = PR_{B} – P_{sep}
ΔP_8 = P_{sep} – P_{CD}
ΔP_9 = P_{sep} – P_{PD}
ΔP_{10} = P_{CD} – P_{GD}
ΔP_{11} = P_{PD} – P_{LD}
finally getting to evaluate the data. The challenge, then, lies in moving validated sensor data to the right programs or models that evaluate the entire system—from reservoir to distribution lines—and doing it all in time to make the best decision.

Other industries, such as medicine and aviation, have come to excel in processing and evaluating constant streams of data. In hospitals and air-traffic control centers, crucial decisions are made following rapid analysis of constantly changing data. Doctors, nurses and medical technicians carry out surveillance and evaluation of patient ailments, with automated systems performing electronic triage of their wards. Air-traffic controllers receive a variety of inputs that enable them to regulate the spacing between aircraft, and they receive alerts when a plane encroaches on the airspace of another. In each case, datastreams are converted into visual displays and audio cues that enable specially trained experts to immediately ascertain the status of their systems. Visualization is key to interpretation of their data, and is critical for responding quickly to rapidly changing situations.

In the oil field, visual displays are becoming increasingly important for managing the development and production of reserves. These tools provide a common focal point for collaboration and discussions to help individuals understand the implications of data and information that might lie outside of their discipline. As focal points, they are also gathering places that move individuals out of their ‘silos’ of expertise, promoting cross-functional integration into asset teams that carry out collaborative analysis of the data. Asset teams are coming to depend on these displays for assimilating large volumes of data and making informed decisions about rapidly changing production systems.  

One approach to making timely, informed decisions combines visual displays with automated surveillance and management of data by exception. Basically, a green-yellow-red-light system is used to screen sensor data (next page). Green measurements indicate that a component or system is performing within specified limits and requires no action or further attention. Yellow is an alert, meaning the sensor measurement is approaching upper or lower bounds. Red is an alarm, indicating that the component has been shut down because sensor measurements fall outside of specified ranges. A yellow alert is one key to asset management that helps operators avoid deferred production. Operators take proactive measures on yellow alerts, and are reactive to red alarms.

Who sets the bounds for the system alarms? This is an area where knowledge capture is important. The operating limits may be set according to several criteria, such as previous performance history, goals set forth in the business plan, or various model predictions. Once alarm limits are specified, asset teams charged with optimizing production from hundreds of wells need only respond to a handful of yellow or red lights that signify readings approaching or falling outside of preestablished limits. This frees operations and engineering personnel to focus on more urgent matters that require analysis and prompt resolution.

Reservoir performance optimization incorporates a variety of workflows that allow asset managers to move from data acquisition and analysis to action. At this level, experts analyze the data and account for certain operating constraints to improve production. For example, by analyzing the frequency curve of an electric submersible pump (ESP), a surveillance engineer might determine that increasing electrical power will increase production, while decreasing vibration and reducing wear on the pump. However, such decisions to increase power should be weighed against other operational constraints specific to the well or field, such as the risk of increased sand production, the cost of electricity or the cost of handling increases in produced water.

These matters often affect several departments within the production organization, and optimal response usually requires input from each department, to avoid working at cross-purposes. Otherwise, actions taken to improve performance in one area may adversely impact another. This article describes the drive to integrate real-time and episodic measurements, automated workflows and analytical models to optimize performance throughout the life span of a reservoir. A case study from Brazil describes the process that one operator used to achieve this goal.

Challenges and Capabilities

Mounting challenges in replacing reserves through new discoveries are prompting oil and gas companies to focus attention on optimizing production of proven reserves from existing assets. Renewed efforts to boost reservoir recovery, coupled with a brighter economic outlook for operators, have encouraged E&P companies to invest in measures to increase production. Many companies are turning to downhole and surface sensor technology, combined with impressive advances in data access, computing power, analytical capabilities, visualization and automation, to heighten awareness of operations and enhance the decision-making abilities of asset managers. Such improvements have raised expectations for boosting asset performance and for extracting the most from every prospect. These advanced technologies are changing the way in which E&P companies work, and their benefits can be measured against key business indicators:

- Increases in recovery: Analysis and prediction of changing reservoir conditions may spur preemptive actions that enable asset teams to extend production and surpass original production targets. As conditions change over time, these analyses may also identify additional recoverable reserves.

- Increases in efficiency: Workflows that detect impending equipment problems or improve the efficiency of production equipment can protect assets and reduce wear, repair costs and operating expenses. Automated workflows can also boost human efficiency, allowing operators to focus less on mundane tasks and more on decision quality. Other workflows may result in better facility utilization.

- Increases in safety: Governmental regulations hold operators accountable for the integrity of their product stream, from reservoir to refinery. Real-time monitoring may reduce the risk of equipment malfunctions or system downtime, along with ensuing penalties that may result from flaring, leaks or spills. Furthermore, real-time monitoring and remote command capabilities may reduce the number of personnel needed at a wellsites, thereby decreasing exposure to risks inherent in well-site operations and associated travels.

- Decreases in downtime and lost production: Continuous production monitoring is vital for detecting the onset of production problems. Production-monitoring data can indicate gradual trends such as increasing skin factor or premature water breakthrough; episodic events, such as equipment failure, can also be quickly detected.
Decreases in operating costs: Through early detection and trend analysis of changing reservoir and operating parameters, asset managers are better able to schedule remedial actions such as workover and servicing of equipment, or facility upgrades. This helps operators allocate resources to areas where they will be most cost-effective.

Other contributions from automated oil fields and advanced workflows show potential for paying dividends related to future corporate success. The retirement of experienced personnel resulting from the anticipated “big crew change” will affect the manner in which companies and asset teams handle daily workloads. While this sophisticated technology will be instrumental in managing assets with limited personnel resources, it will also play a major role in knowledge capture.

The systematic collection and management of knowledge will be useful in bridging the gap between experienced personnel and those who are new to an organization. New personnel will be able to track the history of an entire production system, along with changes to its key parameters over time. Then they can review the team’s response to those changes and learn from resulting outcomes. Furthermore, with much of an asset team’s expertise concentrated at a central monitoring and support facility, a small group of highly experienced experts can mentor less experienced staff spread across remote locations, reducing risk and accelerating training.
The BlueField intelligent asset integration service has been developed to help E&P companies obtain the most from their investment in instrumented or intelligent technologies. This customized, broad-based, multidisciplinary approach to production optimization links downhole and surface instrumentation, integrated asset models and automated workflows (above). It provides asset managers with the information they need to respond to changes in their reservoirs, wells and processing systems. In addition, the BlueField system encourages petrotechnical personnel to share expertise, providing a collaborative environment backed by data acquisition, transmission, storage, modeling and visualization systems.

From Data to Decision
To get the most from their instrumented oil fields and personnel, operators use a variety of processes, or workflows, to acquire, condition, screen and analyze data—often from hundreds or thousands of locations throughout a field. Other workflows have been developed to flag systems or components that are performing outside acceptable limits, to diagnose problems and recommend corrective actions to optimize production throughout the asset. An open architecture design permits integration with the client’s own hardware and software systems. (Adapted from Unneland and Hauser, reference 2.)

The workflow for an intelligent field typically contains a number of primary routines that may, in turn, be divided into smaller, more intricate subprocesses (next page, top left). To move an asset team from data to decision, most workflows will follow the general steps described below.

Data acquisition, transmission, management and validation—A network of downhole and surface sensors, previously installed by the operator, obtains measurements at constant, periodic or episodic rates. These data are typically acquired by the operator’s supervisory control and data acquisition (SCADA) system, which transmits data from the field to the operator’s office. There, the data are conditioned and validated prior to evaluation (see “An Automated Approach to Data Quality Management,” page 40).

Surveillance—This is the problem-detection phase, during which asset surveillance engineers monitor the status of operations in real time. This task requires rapid access to data, as well as the capability to visualize it.
During this phase, validated data are, in many cases, automatically evaluated against preset limits in the surveillance system. Before values exceed preset limits, the detection system activates alerts to notify operators that performance is trending beyond standard limits. These surveillance systems usually monitor both historical and model-based conditions. Alerts are generated either when data values differ from historical values—as might be computed from a five-day moving average—or when they deviate from model-based values, such as those predicted by pressure-decline curves.

**Problem analysis**—Measurements of performance are compared against historical performance trends, business plans, or reservoir and facility models, using tools such as ECLIPSE reservoir simulation software, PIPESIM production system analysis software or Avocet Integrated Asset Modeler.

**Solution selection and decision**—Monitoring data are coupled with expert numerical modeling and decision-making applications, then reviewed by multidisciplinary asset teams, who reexamine model results from various production scenarios, and then decide upon the optimal course of action. Results are captured in a knowledge base for future exploitation.

Workflows vary in scope, from field development planning or waterflood optimization to sand management and ESP performance optimization (below). For example, most production scenarios require maintenance and close scrutiny of drawdown pressures. A general drawdown-monitoring workflow might be structured along these lines:

- Pressure and temperature data acquired continuously by a downhole pressure gauge are transmitted in streaming mode to the receiving system.

![Typical oilfield workflow. A system of automated routines and subroutines acquires, conditions and analyzes field data in time for asset managers to respond to changing operational conditions.](image)

![Workflows for asset management. Separate workflows for data conditioning, well performance and reservoir performance show the interactions between various processes, in which output from one workflow serves as input for those that follow.](image)
An Automated Approach to Data Quality Management

As additional instrumented oil fields come on line, operators are finding the return on their investment in sensors and instrumentation can be measured, in part, by the quality of the data the new technology generates. Just as the asset teams manage completion systems and production facilities, so too must they manage their data.

Like all physical assets, data require maintenance over time. Raw data will degrade when errors are introduced—typically through human intervention, as when data are manually entered into spreadsheets or various processing routines used for decision making. Data errors are easily generated; a misplaced decimal, typographical error or erroneous map datum can relegate well data to a new geographical province, redraw the boundary of a field, change the structure of a productive horizon or alter a completion strategy.

The information technology industry has devised a systematic methodology to address oilfield data quality and validation issues. Using data quality management (DQM) automated software, operators can evaluate, correct and synchronize their datasets. One such line of DQM software has been developed by InnerLogix, a Schlumberger company. Its DQM portfolio includes tools for interactive and automated assessment, and for improvement and exchange of data between multivendor datastores and multiple data repositories.

The DQM methodology relies on six basic criteria, or measurement categories, to evaluate data quality:

• Validity: do the data make sense, honor science and corporate standards?
• Completeness: does the client have all of the required data?
• Uniqueness: are there duplicate items in the same datastore?
• Consistency: do the attributes of each item agree between data sources?
• Audit: has an item been modified, added or deleted?
• Data changes: have any attributes of an item been modified?

These measurement categories translate into business rules for assessing the data.

The InnerLogix QCPro software suite enables users to create customized rules that are incorporated into statistical assessments of data quality. Users can create business rules that have varying degrees of complexity.

For example, they can develop rules to ensure that deviation surveys contain a minimum number of points, with each point increasing in measured depth. They might want to identify duplicate data for items such as well headers, log curves and marker picks, then remove duplicates from the datastore. Users can also develop geographic rules to verify that a surface location falls within a field, block or country boundary. Other rules have been developed to confirm that data are consistent between datastores, thus ensuring that everyone works with identical data.

After assessing the data, QCPro software allows users to create and edit rules to correct...
defective data. The verified data can then be synchronized throughout the client's various databases. The creation of automatic correction rules must reflect the science underlying E&P practices, processes, standards and workflows. These correction rules generally involve copying, calculating or modifying a set of attributes or data items. QCPro software has the capability to dynamically identify the optimum source from which to reference attribute values during the correction process.

The final phase of the DQM process involves identifying data quality lapses before low-quality data are allowed to enter the system. This phase is instrumental in minimizing errors that can creep into a dataset during ongoing interpretation. Without a viable DQM process, these errors can be perpetuated by automatically or blindly overwriting data into project datastores. For example, a wellbore deviation survey may be loaded into a project database with the assumption that the survey was oriented to true north rather than grid north. QCPro software would automatically detect this error and prevent its propagation, thereby reducing team frustration and time wasted on reworking the data.

Identifying aberrations in data is important, but having the ability to automatically correct them is essential. Utilizing user-defined business rules in combination with the results of assessment runs, QCPro software ensures that only the highest quality data are synchronized into project and corporate datastores. With repeated use, the QCPro suite can systematically eliminate defects and propagate high-quality data throughout an asset's applications.

- The surveillance engineer and other users view the pressure and temperature data in streaming mode.
- The pressure data are smoothed by removing spikes and obvious errors, and by averaging over a predefined time interval.
- Additionally, the running maximum and running minimum values for pressure are calculated for each hour. These running averages are reset at the end of each hour.
- The running maximum, minimum and average of the pressure data are also calculated for the day. The running averages are reset at 24:00:00 each day.
- Static reservoir pressure ($P_r$) in the vicinity of the wellbore is estimated using material-balance models or numerical simulations, then entered at predefined intervals, typically every 48 to 72 hours. On occasion, previously estimated $P_r$ values are reestimated; in this case, other previously estimated values must be updated.
- Drawdown pressures are calculated by subtracting the gauge pressure ($P_w$) from the static reservoir pressure ($P_r$).
- Limiting values for gauge pressure are calculated or estimated and entered at predefined intervals, typically 48 to 72 hours. The sources are bubblepoint limits, sand-management limits and drawdown limits. Bubblepoint limits are absolute limits for the bottomhole pressure; sand-management limits are functions of the static reservoir pressure; and drawdown limits are a fixed offset from the static reservoir pressure. Occasionally, these limits are recomputed, and the previous values must be updated.
- Drawdown surveillance is performed each hour by comparing the hourly average, running maxima, running minima and running averages to the appropriate limiting values for gauge pressure.
- Automatic yellow alerts are generated whenever the gauge pressure is within a defined variance from the limit value.
- A surveillance engineer analyzes these alerts and sets a validation condition for each alert, based on knowledge of field behavior. These validation conditions typically range from "no action required," to "monitor closely," or "action recommended." The engineer may also enter supplementary comments.
- An asset manager views a list of wells for which automatic alerts have been generated, along with the validation status and the surveillance engineer's comments.
- If complex or unusual problems are discovered, a team of experts may convene for a quick root-cause analysis.
- Remedial action is taken, based on the supporting analysis.

**Change Management**

By evaluating the impact of enabling technologies on traditional asset-management work practices, and then implementing selective workflow changes, E&P companies can achieve significant improvements in asset performance. Orchestration of these changes is an important part of any BlueField transformation.

It is human nature to resist the new and the different. Change is often uncomfortable and sometimes risky. Before undertaking change, people generally need to recognize significant personal benefit arising from a new course of action. This tendency carries over into organizations as well. If not motivated by personal benefit, individuals at all levels in an organization may directly resist change or indirectly slow its progress.

A comprehensive change-management plan is central to the success of large, technology-enabled transformation projects. From the outset, it must be acknowledged that change issues will arise while undertaking BlueField projects, because these projects often involve significant alterations to the status quo. Transformations of asset performance through a combination of new technology, new skills and new work practices will require employees to adjust long-standing work habits and workflows. Management must be prepared to deal with the potential resistance to change.

Over the decades, change management has evolved into a management science. Leading academic institutions, such as the Harvard Business School, have published research and case studies on the effective application of change-management principles to the workplace. Based on these principles, Schlumberger business consulting experts have developed a

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transformational change-management approach for BlueField projects (above).

Before this process is implemented, the current state of the organization should be assessed with respect to each of the six major steps. Based on the results of the assessment, a comprehensive change-management plan is created. Early involvement of key players, a clearly defined picture of the asset and a detailed vision for operational improvement will lead to effective changes within the scope of asset operations and management.

Road Map to Intelligence

The drive toward the intelligent oil field has been aided by a convergence of technological improvements, without which instrumentation, much less intelligence, would have been impossible. Chief among these developments is miniaturization. Impressive reductions in size, cost and power consumption have broadened the transfer of smart devices and technologies to the oil field, allowing deployment of real-time sensors and instrumentation throughout the asset. These improvements have extended into the realm of communications, providing vital links between sensors at the sandface and asset-management offices around the world. At the same time, computing power, software and visualization capabilities have continually improved, helping engineers and geoscientists make sense of the data that streams in from the field. The convergence of these technologies has been essential for improving the performance, and extending the productive life, of oil and gas fields around the world.

Integrating these diverse technologies requires a carefully formulated plan. The BlueField development and implementation process follows a series of steps, which can be broadly grouped into six phases (below).

Preassessment phase—Initial steps involve meetings to ascertain general problems and client needs and goals. Based on this information, the BlueField team develops a customized BlueField Road Map to outline the steps associated with the proposed project—from the assessment and implementation phases, through to continuous monitoring and improvement.

Assessment phase—Based on the specially developed BlueField Road Map, the team conducts onsite assessment sessions and workshops. In addition to documenting current capabilities and practices, the team and client assess operational problems, risks and opportunities that might be realized. These sessions are vital for mapping out links between critical activities, the data associated with these processes and the workflows that support each activity. This comprehensive assessment evaluates sensors and instrumentation; data-transmission and bandwidth capacities; data management and validation procedures; production surveillance capabilities; third-party and in-house processing software; and field production issues, such as sanding or high water cut. One major goal at this stage is documenting key performance indicators (KPIs) and current performance baselines. These
baselines will serve as a reference for post-implementation performance assessment.

BlueField teams also work with the client to move from current workflows to desired workflows. During this stage, the teams assist the client in establishing project goals relevant to the operational environment and ensure that desired outcomes are explicitly defined. Then they examine performance gaps in technology, collaborative practices and decision quality that would impede the achievement of those outcomes. Highly detailed project requirement statements based on this input define critical aspects that the project must improve upon. The client and BlueField team set project-management timelines to ensure that critical milestones are met in a timely manner. They also devise change-management and implementation strategies to ensure acceptance and utilization of BlueField workflows and technology.

Design phase—With a clear understanding of critical processes, data requirements and current workflows, the project teams will determine which workflows can be streamlined or automated. Using requirement statements and associated workflow maps, the BlueField team develops a design and project-implementation plan, which is submitted for client review and approval. These requirement statements and workflows form the basis for technical specifications that stipulate which technical or engineering components will be used in the project, and how they will interact in workflows or processes needed to achieve previously defined outcomes. The team devises links between existing client technology and new technologies. During this phase, project-management practices are reviewed to ensure successful implementation of the BlueField Road Map.

Construction phase—Previously defined requirements and specifications drive the construction and customization of project components and processes. A variety of construction tasks will take place concurrently:

- developing automated surveillance workflows
- developing automated data management and validation workflows
- developing links to accommodate existing hardware and software retained by the client
- developing and integrating analytical tools to work in conjunction with third-party programs and programs developed in-house by the client
- developing operational workflows in response to specific issues, such as sanding or flow-assurance problems
- constructing a collaboration and coordination center.

Components and workflows are also tested during this phase to confirm that the desired outcome will be achieved as intended. This testing usually takes place in a laboratory environment to prevent onsite disruption of client operations.

Implementation phase—Field teams install or modify sensors, instrumentation and data-transmission capabilities. Workflows and technologies previously tested in a laboratory setting are moved to the client’s work environment for installation and further testing. Pilot-test results are measured and compared with assessment-phase performance baselines to quantify improvements in efficiency, cycle time, decision quality or cost savings.

Continuous monitoring and improvement phase—Postinstallation performance must be measured against the established baseline. Petrotechnical personnel and tools identify processes that may require adjustments to obtain better results. Other improvements may be identified during this process, which can then be tied back to the design, construction and implementation phases. Finally, changes to the existing organizational structure may be made to provide the most efficient ongoing support for the new ways of working.

An example from Brazil highlights the efforts required to develop and implement intelligent and automated workflows for improving production in an offshore field.

Pioneers in Brazil
As Brazil's largest oil province, the Campos basin is home to several major offshore discoveries, including Carapeba field. This field is located in approximately 85 m [280 ft] of water in the northern part of the basin (below). Discovered by Petróleo Brasileiro SA (Petrobras) in 1982, Carapeba field primarily produces from two upper Cretaceous turbidite sandstones, with additional production from Eocene sands.

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a mature field, Carapeba production is hosted by three platforms that support 41 oil wells and six water injectors. Except for two wells equipped with wet trees, each producer in this field is equipped with dry trees and ESPs. Carapeba field has played a leading role in two important pilot projects carried out by Petrobras. In 1994, Petrobras installed an ESP in the RJS-221 well, a vertical well located in 86 m [282 ft] of water at Carapeba field—marking the world's first installation of an ESP in a subsea well. Having gained extensive ESP experience with wells drilled in shallow waters, Petrobras conducted this pilot project to test the viability of ESP technology in subsea applications with the expectation that this experience would lead them to substantially greater water depths.

In 2006, Petrobras selected Carapeba field for another pilot project. With much of the downhole and surface infrastructure already in place, Petrobras recognized that Carapeba field would make a good setting in which to demonstrate and evaluate the integration of intelligent technologies. The field's three productive intervals afforded a good opportunity to test intelligent completion equipment. ESPs had been installed in each producer—18 were equipped with variable-speed drives that allowed operators to remotely adjust power settings. Some of these pumps were monitored by Phoenix artificial lift downhole monitoring systems. Importantly, dry-tree completions for each well would ease access and reduce the complexity of installing intelligent completion equipment or conducting downhole interventions. This undertaking marked the first of five such projects designed to test and qualify the best technology, options and suppliers for optimizing asset production and efficiency.

Through installation and integration of intelligent technologies, Petrobras sought to improve reservoir sweep efficiency and boost the field's recovery factor. In addition to validating technologies and processes to manage their fields, Petrobras management defined key objectives for this pilot project:

- Production optimization: Achieve a 15% increase in production by monitoring downhole sensors.
- Production efficiency: Achieve a 1% increase in production efficiency through additional hardware upgrades installed on the platform.
- Recovery factor: Realize a 0.2% increase in recovery factor through improved regulation of injection water to increase sweep efficiency and through optimization of flow using intelligent completions in five to ten wells.

The project began in June 2006. Schlumberger conducted a site assessment and workshop involving all disciplines associated with the Carapeba asset. The site assessment generated a comprehensive catalog covering the general layout of the field and platforms; asset business organization; computer network architecture; fiber-optic communications; ESPs, downhole sensors and equipment; water-injection systems; multiphase fluid processing; electrical power distribution; well testing; well intervention; process automation; platform staffing and work rotation; reservoir evaluation; management-level information systems; intelligent completions; health, safety and environment; and flow assurance. At the workshop, representatives from each discipline outlined critical work processes and defined the current state of the processes they controlled. During later workshop sessions, they refined their vision of the desired outcome for those work processes. The workshop and onsite assessment were instrumental in identifying impediments to desired outcomes. Throughout these sessions, planning teams focused on processes, rather than on particular products or technologies.

Based on the workshop, Petrobras created more than 50 requirement statements, which helped define the scope of work and guide the selection of appropriate products and technologies for achieving the desired end state. Petrobras managers then conducted a value analysis to prioritize the requirement statements with respect to their complexity, cost and ultimate impact on business performance. Having mapped the state of current and desired work processes, Petrobras and Schlumberger project teams used the requirement statements to guide the development of a project design and implementation plan for management approval. Once plans were approved, the work process maps served as templates for developing automated workflows.

The overall plan for Carapeba called for a system to provide acquisition, transmission and storage of real-time streaming and episodic data, along with integrated models of the asset's reservoir, wellbores and surface facilities. It also required a portal platform to integrate information from production operations and geotechnical and financial systems. This portal platform provided an information hub for the entire asset. Using data and information from these resources, multidisciplinary asset management teams would work in a collaborative environment to plan, monitor, control and optimize operational processes.

Implementation of this project required extensive coordination and teamwork between the numerous technical domains within Petrobras and Schlumberger. To integrate the various downhole and surface systems, Schlumberger assembled teams with expertise in project management, business consulting, petrotechnical evaluation, reservoir completion, production engineering, software design, information management, downhole sensors and oilfield instrumentation. Clearly, this was a mammoth, multidisciplinary, multidimensional project.

Throughout the planning, construction and implementation phases, business consulting experts from Schlumberger helped Petrobras develop and carry out change-management strategies to engage Carapeba asset personnel, and align their efforts toward stated goals. These experts were also instrumental in defining business and operational KPIs for this asset, as

11. Wells offshore may be produced through either wet trees or dry trees. Designed for deepwater fields, wet-tree wells typically produce through flowlines to a common subsea manifold, which is connected to the platform by a riser. Most wet trees are fitted with flow control valves and pressure and temperature sensors, which are located at or beneath the seafloor, and which are optimized to preclude well-intervention operations. The well-intervention costs for deepwater wet-tree completions are so great that these wells are designed with the expectation that physical intervention will not occur. Dry trees, in contrast, each have a subsea wellhead connected to a riser, with a tubing hanger and surface tree mounted at the platform. They are typically designed to produce to compliant towers, spars and tension-leg platforms, from which well-intervention operations are simpler and less expensive. In recent years, dry-tree capabilities have evolved, allowing their installation in deeper waters.


13. During this pilot test, the 150-hp REDA pump operated at 2,000 bbl/d [318 m3/d] for 34 months.


well as determining how these indicators would be measured and benchmarked.

Installation and coordination of these technologies culminated in development of a custom-designed collaboration facility, designated by Petrobras as GeDIg (Gerenciamento Digital Integrado), a center for digitally integrated management. This collaboration facility brings together specialists from throughout the organization to share expertise and provide a better understanding of the engineering and economic impacts of various field-development decisions that are required to manage the Carapeba asset (above). Similar facilities were installed at two Carapeba platforms to improve communication and collaboration between offshore and onshore personnel.

Schlumberger equipped Petrobras with required systems and software for asset management, along with a fully customized DecisionPoint Web workflow portal for enhanced visualization and management of KPIs. The GeDIg facility features an ergonomically designed collaboration room, divided into surveillance, diagnosis and planning areas, along with a separate crisis room. Concepts inspired by space-flight control centers and the medical industry were incorporated into the facility design to improve decision support and decision control.

Although slated for commissioning in July of 2008, this project achieved an early completion, and the entire project was inaugurated in September 2007. Experience gained on the Carapeba GeDIg project led to expansion of this concept to other fields. A similar project for Petrobras is nearing completion at Marlim field, in the deeper waters of the Campos basin.

Carapeba Workflows

A number of workflows were developed in conjunction with the Carapeba project. In this section, we will review some of the improvements that are helping Petrobras manage the asset efficiently.

*Diagnosing ESP and productivity problems*—To prevent unforeseen interruptions in production, the Carapeba artificial lift team must be attentive to any change in operating conditions that might signal the earliest stage of a production problem. Diagnosing potential difficulties required team members to scrutinize large volumes of real-time streaming data. Team members spent much of their time sifting through mostly routine data points to find anomalies that would point to the onset of troubles downhole. Petrobras recognized that automating the data-sifting routine would free more time for engineering solutions to current problems and for preventing future difficulties.

The Schlumberger BlueField team established a surveillance and diagnostics system to ease the data burden on the artificial lift team. The system aggregates real-time streaming data from surface and downhole sensors, along with reservoir information and daily production data. These data can be coupled with simulation models of any well in the field. The new system monitors surface and downhole sensors, and automatically flags any deviations
from established setpoints, allowing the team to quickly identify and respond to potential malfunctions (below).

A key problem identified by Petrobras was a potential for high volumes of sand production, which could damage Carapeba production equipment and force costly shutdowns for maintenance. To avoid sanding complications, all wells at Carapeba must produce above bubblepoint pressure \( (P_b) \) at the pump intake with a maximum drawdown pressure of 50 kg/cm\(^2\) [710 psi or 4.9 MPa] in front of perforations. Various KPIs were instituted to evaluate well performance, such as calculated productivity index (PI), bottomhole pressure (BHP) and total liquids flow volume \( (Q_b) \) versus time. Other workflows were developed to help the operator quickly recognize when optimal production constraints were being violated:

- warnings for wells producing below bubblepoint pressure, where \( \text{BHP} < P_b \) at the intake pump
- real-time maps of BHP and temperature versus depth
- ESP efficiency plots that compare the calculated real-time pump head and flow rate against theoretical curves
- pump health checks to monitor ESP head efficiency versus time.

Monitoring ESP parameters against preset operating conditions. The Carapeba surveillance team can use an interactive control screen (main screen, shown in the original Portuguese, background) to access wellbore diagrams and performance parameters in great detail. Artificial lift engineers can examine each well that produces to a given platform to monitor ESP performance, including downhole pressure, temperature, electrical amperage, estimated flow rate, and the most recent production and well-test data. Clicking on a particular well, such as the one highlighted (blue) opens a dropdown selection of options leading to additional detail on the ESP. One of these, the real-time indicator window (inset, left), lets the engineer study numerous parameters such as wellhead pressure and temperature, choke size, electrical current and frequency at the variable-speed drive, intake pressure, outlet pressure and motor vibration. Here, the display of electrical current (red) and wellhead temperature (black) shows similar trends where temperature drops as power is shut off to the pump. By clicking on the pump display, the engineer can summon an up-to-the-minute reading of temperature and electrical current (inset, right). (Adapted from Henz et al, reference 14.)
These KPIs are based primarily on input provided by Phoenix artificial lift downhole monitoring systems. For wells that did not have Phoenix sensors, performance was calibrated using surface well-test data. This surveillance and analysis workflow has proved vital for optimizing pump performance, extending mean time between failures and boosting production.

Downtime analysis—In this workflow, data from current and previous well failures and downtime events at Carapeba are analyzed and categorized, and each such instance is prioritized on the GeDig operations portal display (above). Asset teams use a DecisionPoint display to analyze failure trends and forecast intervention activities. Ensuing variances from forecasted production rates are identified on a display that enables managers at GeDig to prioritize and schedule critical resources for remediation.

Integrated modeling capability—Improving performance of the entire asset, rather than that of individual wells, is key to extending field life and optimizing its production. Simulation models are vital for forecasting the performance of the asset. Rather than running separate simulations to characterize performance of the reservoir, well, gathering network and processing facility, Petrobras wanted the capability to see how adjustments to any particular component would affect the rest of the system during various production scenarios.

Recognizing that Carapeba asset managers had been well served by their own in-house modeling systems, which had been built by...
several different vendors, Schlumberger installed the Avocet Integrated Asset Modeler. This system was used to coordinate results from one model and distribute them to others throughout the system. The Avocet modeler also accepted spreadsheets as proxy model inputs and allowed the economic analysis of different development scenarios.

Executive overview—An executive overview of the asset combines business views with operations views to highlight key variances from the plan. For Petrobras management, this overview ensures that all work processes lead toward overall objectives. Managers can quickly assess the impact of various operations throughout the asset by examining a DecisionPoint software portal that displays overviews of the field operation. Should they need to delve deeper into a wellbore problem, the schematics for each well are easily accessible. The asset surveillance view unites important status information on ESP operations, oil and gas separation, power generation and other critical processes and have immediate access to component-level schematics and information when needed. For instance, asset managers can see that, of the Carapeba wells produced through the PCP-1 and 3 platforms, eight are either shut in or abandoned (red pump icons, PCP-1/3, upper left). (Adapted from Henz et al, reference 14.)

Implementing Intelligence for the Future

Breakthroughs in one technology often give rise to advances in another. Recent advances in completion, sensor, communications and computing technologies are helping the industry achieve its vision of implementing the intelligent oil field. However, intelligence is largely a tool for fine-tuning component performance in response to constantly changing system conditions. To achieve the promise of optimal performance from their assets, E&P companies must integrate their advanced technologies, coupling detailed wellsite data with quick-analysis capabilities that reflect the impact of a decision as it resonates throughout the entire system—from reservoir to gathering line.

Those companies that succeed in integrating their assets must have a clear strategy to guide the analysis of processes they need to modify. The ensuing changes can be difficult to implement, much less accept. But the companies that succeed in these efforts will be rewarded with a system in which validated data and customized workflows serve to improve the quality of decision making as they continually optimize their production. — MV