Optimizing Production from Reservoir to Process Plant

A digital revolution is taking place in oil and gas fields. Field management has already been transformed by more data, rapid evaluation and better control. The next step change is now underway. New workflow software integrates asset simulations from the reservoir to the process plant and results in better economic outcomes.
Producing oil and gas is not easy or cheap. Whether production takes place in remote onshore environments or in deep water, costs are high. As increased cost converges with dwindling supply, energy producers are seeking to squeeze every drop from current assets and optimize design of new facilities. A key factor in this efficiency push is the increasing use of intelligent digital, or so-called “smart,” technology.

Digital technology continues to grow in sophistication and now pervades most activities in oil and gas fields. Technologies such as remote measurement and map-based visualization of key parameters in producing fields have become routine. These technologies first appeared in the 1980s, and their application has accelerated in the past 15 years (above). Although several acronyms have emerged for the marriage of digital technology and the oil field, “intelligent field” is one that captures the essence. Use of digital technology by oil and gas producers is not limited to operational or field data. They are now using the data to optimize asset management and design future facilities.

Digital technology evolution. During the past 25 years, computing and oilfield digital technology have evolved along similar paths. The first desktop computers were focused on simple calculations and graphics, while early application of digital technology in oil and gas fields brought advancements in automation, data-gathering systems and metering. During the 1990s, computers were developed to handle increasingly complex graphics and calculations. Digital capability in oil and gas fields accelerated in 2000 with more complex metering and automation for single locations. After 2000, both computing capability and digital technology migration to oil and gas fields have gained momentum. Desktop computers now boast dual- and quad-core processors as well as fast wireless networking. Networking capability has enabled field operators to carry out system-wide tasks that may involve multiple locations. (http://www.intel.com/technology/mooreslaw/index.htm (accessed October 26, 2007)). (See references 1 and 2 for SPE and OTC paper citations.)

new. What is new and part of the intelligent field vision is linking different technologies to accomplish a system-wide task (see “The Big Picture: Integrated Asset Management,” page 34).

The payoff for implementation of the intelligent field is large. This technology is predicted to increase world oil recovery by 20 billion m$^3$ [125 billion bbl] over the next five to ten years. Although some components of the intelligent field will take time to fully mature, others are being put into practice now. An example of new technology that can produce real benefits is integrated asset modeling. It links traditional tools such as ECLIPSE reservoir simulation software with other well-known production system models to arrive at an end-to-end solution. Integrated asset modeling can be used to improve production from existing fields or during front-end design for improvements to new fields.

The focus of this article is the application of integrated asset modeling—how it works and how it is being applied to solve production challenges. Case studies from Mexico, offshore India, the North Sea and the USA illustrate various aspects of intelligent field application. Before discussing the details of integrated asset modeling, we examine traditional methods for field planning.

**Traditional Methods**

In 2006, the oil and gas industry spent about 3% of total revenues on information technology—US $2 billion on hardware, software and services. This information technology package comprises individual simulators for the reservoir, piping network, process facilities and economics. These simulators have made significant advances in accuracy and reliability over the years. Complex reservoirs are more easily modeled, multiphase flow is simulated, and performance of important equipment such as compressors can be optimized.

Although the simulators work well when applied to individual field components, problems arise when they are applied in a serial manner to perform a full-field analysis. Data are often passed between individual assets and disciplines by spreadsheets and interaction effects are absent (above). A change in any one of the field components has cascading impacts on upstream and downstream results, and reflecting this properly requires substantial intervention in the modeling steps. In some cases, this intervention may be impractical, if not impossible.

There are two significant problems with applying traditional methods to field planning. First, all simulations downstream of the reservoir model are static—they represent only one point in time during the life of the asset. The work involved in setting up these models must be redone to analyze any other point in time. Secondly, the traditional method fails to take into account the dynamic nature of field development planning. For example, the production rate of an existing well may change when new wells are drilled in the area—undermining the original plan. In addition, events such as compressor changes, or implementation of various secondary-recovery...
programs executed later will likely invalidate the initial data exchanges between simulation models. These compromises in traditional full-field analysis can lead to a host of problems including unnecessary drilling and oversized or undersized facilities.

A solution to these deficiencies in full-field simulation is emerging as part of the intelligent field. There is a shift from historical serial workflows to real-time dynamic processes that fully account for feed-forward and feedback effects. A key characteristic of the intelligent field is the ability to extend use of one discipline’s boundary conditions into another discipline across the entire field. The use of real-time dynamic processing to model the impact of interrelated events, both historical and projected, paves the way for a prediction of field performance that adapts to a changing operations environment. This concept is at the heart of integrated asset modeling.

A Quiet Revolution
Integrated asset modeling is an evolutionary extension of a well-known technique called NODAL production system analysis. This process has been used to study complex, interacting systems such as pipeline networks, electrical circuits and oil production. The procedure entails selection of a reference point, or node, to divide the system. In an oil- or gas-producing system, a node might be in one of several locations—common points are the bottom of the well and the wellhead. Components upstream of the node are termed the inflow section, while those downstream are the outflow section. For instance, perforations located upstream of the wellhead node would be part of the inflow section, while a pipeline to the process plant would be part of the outflow section.

Regardless of the node’s location, two boundary conditions must be satisfied. Flow into the node must equal flow out of the node, and only one pressure can exist at a node. Pressure and flow-rate curves are generated for node inflow and node outflow. The intersection of the curves defines the solution to the problem by yielding a flow rate and a pressure that satisfy both inflow and outflow constraints.7

Extension of NODAL analysis from single wells to more complex systems is not new. In 1971, a pioneering proposal demonstrated how reservoir and surface models could be linked to arrive at a solution for a gas field-gathering system, and other proposals have followed.8 What is new and different is the arrival of commercial software that links separate models for reservoirs, piping, process facilities and production economics to achieve an optimized solution. These offerings are not multiple simulators en cascaded in a single package but rather are computational frameworks that link simulators across assets, computing environments and locations.

The connection framework approach to asset modeling is illustrated by the Avocet Integrated Asset Modeler production software. This integration software provides an end-to-end solution that links the reservoir (ECLIPSE reservoir simulation software), well and surface infrastructure (PIPIESIM production system analysis software) and process facilities (HYSYS process simulation software) into a single production-management environment.9 In addition to these commercial simulators, specialists can contribute models specific to their discipline or proprietary models specific to their company and let the results propagate throughout the model. The Avocet software supports implementation strategies that allow experts in separate locations to collaborate. The model framework residing on one computer can direct and interact with reservoir, pipeline, process and economic applications residing on remote computers. The interface allows the user to graphically link individual models and view the results as the procedure steps toward the optimal solution (below).

This approach provides a step-wise iterative solution to predicting the lifetime performance of a field. Similar to NODAL analysis, two iterative calculations are performed for each time step at a node point using existing boundary conditions. One set of calculations determines the rates and pressures achievable within the reservoir. The other calculation determines the rates and pressures within the facilities network. Both iterative calculations are repeated until the

Avocet Integrated Asset Modeler interface. Each of the individual simulations in the Avocet software can be integrated into a flow diagram that represents the total integrated asset model. Displays of combined results from all of the simulations are available in either graphical or tabular forms.


Winter 2007/2008
Coupling and network balancing. The default network-balancing scheme in the Avocet simulator is the chord-slope method. In this algorithm, the well simulator uses the well pressure limit \( P_1 \) as the starting guess to obtain a corresponding flow rate \( Q_1 \). The rate \( Q_1 \) is passed to the piping simulator to calculate a pressure, \( P_2 \) corresponding to that flow rate. The pressure \( P_2 \) is passed to the reservoir simulator to obtain the outflow rate \( Q_2 \) for that pressure. The chord between these two points provides the productivity index (PI), which is passed to the piping network simulator. The piping simulator uses this PI value to obtain Point 4. This iterative process is repeated until convergence within a specified tolerance is achieved at Point 6. At Point 6, pressure and flow rate are consistent between the reservoir and surface piping network and the system is balanced, ready for the next time step. Chord-slope coupling is highly iterative and may not be appropriate for all production systems. The Avocet software includes several other choices for coupling and network balancing.

Reservoirs with different compositional models. In some asset modeling simulations, it may be necessary to connect several reservoirs with differing compositional models. Consider the case in which three different reservoirs are connected to a single surface network. Reservoir A uses a compositional model with \( N_1 \) components, Reservoir B uses a compositional model with \( N_2 \) components, and Reservoir C uses a black-oil model with three components. Each of these reservoirs is connected to a controller where compositional conversion takes place to a final set of \( K \) components used by the surface network. For example, when a flow rate is queried from one of the reservoirs, it is converted by the controller into the surface network’s set of \( K \) components. Likewise, when a flow rate is sent from the surface network to any of the reservoirs, it will be converted into that reservoir model’s specific set of components.

Flow rates and pressures match throughout the coupled system (left). The asset simulator then takes another time step and repeats the procedure, alternating in this way until the desired field life is reached. At each time step, system constraints are propagated upstream and downstream between the models and their respective simulators. Although Avocet software develops solutions using this general approach, the final combination of simulators will depend on the complexity and nature of the problem under consideration.

The most rigorous location for coupling at a node point is at the bottom of a well, and, for most systems, coupling at the bottom will also require the most computing time. As the coupling point moves to the wellhead and into the other parts of the network, computational time generally decreases. Bottomhole coupling may not be practical or possible for analysis of highly complex fields, and the coupling point may need to be moved toward the surface.

In addition to coupling location, choice of compositional constraints will also affect the simulator’s computing time and convergence. For reservoirs where the effects of fluid composition on flow characteristics are not critical, a three-component model known as the ECLIPSE Blackoil finite-difference simulation may be appropriate. This model assumes the reservoir has oil, gas and water in a three-phase system. A four-component system can also be considered for modeling a reservoir when injected fluids are miscible with reservoir hydrocarbons.

For complex hydrocarbon systems, explicit compositional simulation is also available. Explicit compositional simulation may be the right option when an equation of state is required to describe reservoir fluid behavior changes with depth. This model may be the best choice for systems involving condensates, volatile crude oils, heavy oils, gas injection and secondary recovery. There is enough flexibility in the simulations to allow multiple reservoirs with different component models to be connected to a surface network (left). All of these choices plus other constraints will determine how the Avocet software is set up to solve a given problem.

Once the model has been properly configured, it offers a clear path for end-to-end field optimization. Feed-forward and feedback effects are handled by driving the model to a converged solution. Open architecture eliminates software-version issues, while the ability to communicate with remote computers enables cross-disciplinary collaboration and optimal use of computing hardware. All these factors taken together allow...
operators to efficiently respond to production challenges. For example, one of the most cost-effective ways to add production from an existing field is by optimization through integrated asset modeling.

**New Life for an Old Field**

Much of the world’s oil and gas comes from a multitude of onshore fields that have been producing for decades. A good example of this kind of asset is the San Manuel complex operated by PEMEX. Located in rugged, hilly terrain about 160 km [100 mi] south of Villahermosa, Mexico, this system was built more than 25 years ago and produces more than 7.9 million m³/d [279 MMcf/d] of gas and 2,080 m³/d [13,100 bbl/d] of crude oil. The complex has six process facilities that gather oil and gas from about 65 producing wells.

In recent years, several problems developed at San Manuel that concerned PEMEX. This system was originally designed for much higher rates than current production, and formation of gas condensates in the main gas pipelines became a persistent problem as the system aged. Because of the irregularity of the topography, high gas temperature and low gas velocities in the gas transfer lines, condensates tend to accumulate in the lower areas of the pipelines, forming unstable slugs. These slugs generate upstream backpressure, reducing production rates and forcing PEMEX to run pigs frequently in some branches to clean the lines and restore production.¹³

In response to these problems, PEMEX and Schlumberger implemented an integrated asset model approach to understand and improve performance for the entire San Manuel asset—active wells, process facilities and associated pipelines. The Avocet Integrated Asset Modeler was used to integrate individual well, pipeline and process simulators into a single environment.¹⁴

Simulation results are only as good as the data they use, and in the case of a complex network like San Manuel, a large amount of data was required to set up the simulations. The first task of the joint team was to develop a database for the well, pipeline and process facilities. Data collected included well-production results, pressure and temperature at the manifolds and compression facilities plus available fluid properties. In addition, it was necessary to obtain data on the San Manuel infrastructure such as pipeline diameters, geographical positions and topographic profiles.

Using these data, the team set up individual simulations for the entire San Manuel complex—65 wells, eight pipeline networks and six process facilities.¹⁵ These simulators were integrated into one framework for dynamic coupling using the Avocet software. Results from the simulation models were checked against actual field measurements at several points in the complex. On average, predicted versus measured oil rate showed a variation of 5.9%, while the corresponding variation in gas rate showed a 1.6% deviation.¹⁶

Satisfied that the simulations were giving good results, the team developed a variety of optimization alternatives to reduce costs, debottleneck facilities and increase oil and gas production. These opportunities were ranked based on their potential production increase benefit, cost reduction and implementation cost. The most promising ideas were simulated using the Avocet software to develop locations for targeted opportunities.¹⁷ Results from the dynamic simulation of the San Manuel complex yielded a specific list of opportunities that could be put into practice with available resources and no additional investment (above).

The bottom line for PEMEX has been an immediate US $600,000 per year operating cost savings accompanied by increased oil and gas production estimated to be worth US $35 million a year.¹⁸ These savings were realized by specific

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¹³ Coupling at the bottom of a well allows the respective simulators to handle the part of the problem that they are specifically designed for. For example, reservoir simulators are designed for flow through porous media, while wellbore and network simulators are designed for flow through pipe.

¹⁴ In general, flow requirements feed forward and pressure constraints feed back.

¹⁵ In this context, open architecture refers to the ability to communicate and direct remote computers. This allows the most current version of an individual simulation program to be included in the framework regardless of where that simulator is located.

¹⁶ At San Manuel, pigging has involved up to 42 runs per year in some lines.

¹⁷ Morales et al, reference 2.

¹⁸ Reservoirs and wells were modeled using the ECLIPSE reservoir simulator, pipelines were modeled using the PIPESIM simulator, and process facilities were modeled using the HYSYS process simulator.

¹⁹ More accurate data were available for gas rates than liquid rates.

²⁰ The iterative bidirectional solution in Avocet software ensured that pressure and flow-balance constraints were being met for the entire San Manuel complex. A converged solution was achieved for each alternative.

changes in the way the San Manuel complex is operated. By bypassing two high-pressure separators and one intermediate-pressure separation facility, backpressure was reduced by 3.3 MPa [479 psi] at one manifold and 0.2 MPa [30 psi] at another. These changes yielded an additional 240 m³/d [1,500 bbl/d] of oil and 143,000 m³/d [5 MMcf/d] of gas. Another important improvement confirmed by the simulation was the need for dewpoint control with corresponding liquid cooling and recovery on one of the gas pipelines. By lowering the temperature to 20°C [68°F] and recovering the liquids before they entered the pipeline, PEMEX estimated that they could recover an additional 210 m³/d [1,320 bbl/d] of condensate and reduce the number of pig runs by 90%.

Now that the integrated asset model is available for the San Manuel complex, PEMEX production engineers are using it to make decisions about daily operations and for planning additional improvements to the field. Potential changes to be analyzed include new wells, production-decline analysis for current wells and impact of further changes to the surface infrastructure.

Use of integrated asset modeling in the San Manuel field is a good example of extension of NODAL analysis from a single well to a field of 65 wells. The next case study involves a much greater number of wells.

Integrating a Massive Asset
Discovered in 1974, the Mumbai High field, operated by Indian Oil and Natural Gas Corporation (ONGC), is located near India’s continental shelf (below). Oil and gas are produced by 690 wells and pressure is maintained by 200 water-injection wells. Current production from Mumbai High is about 40,000 m³/d [250,000 bbl/d] of oil and 430,000 m³/d [15.2 MMcf/d] of gas. Processing complexes separate the bulk fluids into crude oil, gas and water; and the oil is sent to an onshore terminal along with part of the gas. The remaining gas is used for gas lift operations on about 80% of the oil-producing wells.

Efficient management and optimization of large mature fields in the decline phase are always challenging and Mumbai High is no exception. That level of challenge is increased given that this field produces more than 40% of India’s total crude-oil output, and ONGC has set a goal of not only arresting decline but boosting production. Meeting these goals also required the operator to move far beyond the single-branch NODAL analysis practiced in the past.

One of ONGC’s primary goals has been to optimize its gas lift operations. Although prior engineering work toward this objective was regularly carried out on a well-by-well basis, that work never delivered the expected production gains for the field. In gas-lifted fields where a portion of the produced gas is returned for lift, interaction effects cannot be captured by single-well analysis. The operator realized that the integrated asset model approach based on the entire field would capture all the network-interaction effects and ultimately lead to better decisions and increased production at reduced cost.

With these goals in mind and assistance from Schlumberger, a “reservoir to terminal” integrated asset model concept was developed along with a phased project plan for implementation. ONGC’s goal for the first phase of the three-phase project was to develop a production model integrated with the network for the entire Mumbai High field. Subsequent phases would add network optimization, integration with the ECLIPSE reservoir model and real-time simulation.

The goal set for the first-phase integrated-production model was ambitious—develop a rigorous, multiphase-flow, black-oil simulation. The model considered all the Mumbai High facilities including wells, platforms, piping, process vessels, gas lift delivery, water injection and connections to the onshore terminal. The modeling framework chosen for the integrated production model was PIPESIM well and network analysis software.

Like the PEMEX experience discussed earlier, the first task for the Mumbai High project was data gathering—a daunting task for a field containing nearly 900 wells and their associated facilities. ONGC made three critical decisions.
early in the data-gathering effort. First, since the field is in a dynamic environment, they chose a cutoff date for data instead of trying to hit a moving target. Secondly, ONGC trained people extensively to ensure that workflows were properly structured for speed and efficiency. Finally, ONGC developed consistency checks for datasets to ensure quality and accuracy.

During the data-gathering effort, a vast amount of production data was obtained for the Mumbai High field ranging from well-location maps and pressure-volume-temperature data to the production-test history and downhole equipment details for each well. Before integration of individual wells into the network model could be initiated, it was necessary to develop calibration data for the field. The stand-alone model for each well type was calibrated to the latest production-test data. With the data gathered and well models built and calibrated, work on the network model could start.

The integrated network model constructed in PIPESIM software by ONGC included all wells, risers, pipelines and process equipment. The model was built using a six-layer architecture (right). The last step in the model-building process was history-matching the model predictions of pressure, temperature and rates with actual production data. History-matching for the entire model was carried out at the process complex level and at the wellhead platform level. During this process of model-building, calibration and validation, ONGC engineers found more than 350 potential opportunities to improve production for the Mumbai High field. These opportunities were in various areas from gas lift optimization, to locating high-backpressure bottlenecks, to identifying wells showing inconsistent rate trends.

Now that the building and testing work is complete, ONGC is using the first-phase model for debottlenecking studies and networked gas lift optimization to increase production in the second phase. Their findings indicate a 475-m³/d [3,000-bbl/d] oil production increase and a 40% decrease in the required lift gas. A major reduction of injection gas has two important benefits. First, there is greater operational stability, controllability and predictability to the production and gas-injection operations because of higher reserve compressor power. This allows better gas lift coverage in distant wellhead platforms. Secondly, gas lift injection reduction means more gas is available for export and sale. Further optimization work using the first-phase integrated production model is ongoing.

Although ONGC has only begun to explore the possibilities for the integrated production network model for Mumbai High, the company is already looking at the second phase. In the second phase of this project, Avoet software will be used to couple the ECLIPSE reservoir simulator to the PIPESIM simulation built in the first phase. The results from this phase of the project will be used to optimize production, improve decision making and look at plans for field redevelopment. The third and final phase of the project envisions real-time simulation and optimization. The model developed in this final phase will use automated updating from supervisory control and data acquisition (SCADA) systems and other databases. This model will be used to do time-step planning studies with integrated reservoir-surface models.

One of the important lessons that ONGC learned was that improved workflows and collaboration between the field and the office were critical for success of the Mumbai High asset-modeling project. Integrated asset modeling is part of a technology wave that is changing not only what operators do, but also how they do it. A good example of this approach is now taking place at StatoilHydro.

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A Window on the Future

In 2006, Statoil, now StatoilHydro, and Schlumberger embarked on a joint R&D collaboration project as part of Statoil’s subsea-increased-oil-recovery (SIOR) program. This project envisioned having a set of consistent, integrated models for subsurface and topside as a basis for future real-time optimization. Goals of the project are to develop tools and work processes to optimize reservoir performance, well production and process facilities on a day-to-day basis over the life of the field. These goals have been translated into a demonstration project now taking place at StatoilHydro’s Snorre-B asset.

The Snorre field is located in the northwestern part of the field, is a subsea development with two production and two injection platforms tied back to a semisubmersible drilling, process and accommodation platform. Snorre-B produces from the Lunde reservoir, a complex structure with varying qualities and many barriers to flow. This reservoir is characterized by long horizontal wells and limited access for intervention.

Although work on the Snorre-B demonstration project is still ongoing, it is enlightening to follow the development of an improved WAG flood methodology. Shifting from largely manual tools and workflows to a system capable of real-time optimization on an actual producing system is a complex undertaking and worthy of examination.

The initial activity for the team was identification of relevant components of the WAG cycle optimization by using a SIPOC analysis. Results from this analysis showed that optimization of the WAG cycle required four components—a simplified reservoir model, well and reservoir control, a field performance analyzer and an integrated asset model.

The simplified reservoir model provides zonal-pressure estimation and short-term production forecasts in combination with well models. Well and reservoir control establishes choke positions for stable production and allows quick adjustments in case of process-equipment failure. The field performance analyzer guides analysis and subsequent action for the WAG cycle. Finally, the Avocet Integrated Asset Modeler is the optimization software. Control parameters for the Avocet software are rate and time for injection of water and gas, while production is constrained by erosional velocity at the choke and by bottomhole flowing pressure. The integrated asset modeling software outputs a two-year oil-production forecast for each well and a two-year reservoir-pressure forecast.

StatoilHydro has linked all these individual components together with a supervisory workflow automation module. Automation allows the individual components to act in concert to perform four distinct tasks for the WAG cycle at Snorre-B—optimization, analysis, production monitoring and tuning (next page).

Control and connection of the Snorre-B WAG workflows during development and testing use technology that integrates loosely coupled processes within and between locations in a Web-based environment. Some of these calculations


26. SIPOC is a tool used to identify all the elements of a complex process by considering sources (S), inputs (I), process (P), output (O) and customer (C).
Snorre-B water-alternating-gas demonstration workflows. The supervisory automation module executes four primary workflows, three of which are illustrated. The optimization workflow (top) handles long-term planning for the asset. Using a simplified reservoir model as a proxy, the optimizer develops a production forecast and injection rates, which feed into the integrated asset modeler to develop a solution for the surface facility network. From this, ECLIPSE reservoir simulation software validates the proposed solution and the new forecast is sent back to the workflow automation. The analysis workflow (middle) is the core offline evaluation component and is triggered by an out-of-range target or constraint. Predefined instructions based on the triggering event speed up the analysis, which may require a new execution of the integrated asset modeler. The production monitoring workflow (bottom) is updated the most frequently. If any key performance indicator is out of limit, an alarm is triggered and the analysis workflow described above begins. Alternatively, if all indicators are in range, production monitoring will complete calculations and send reservoir-pressure and well-rate estimates to the tuning workflow for choke control (not shown). This loop sets choke positions so that production and injection targets may be met. (Adapted from Sagli et al, reference 2.)
and transactions may run weeks or months—not just minutes or hours. Connections that emphasize data integrity and security between application and location are paramount. Connection between the various processes was uniquely handled on two levels—between applications and between locations. The communication protocol between applications uses PRODML, a standard E&P industry interface for data exchange. The communications architecture connecting Norwegian locations and centers in four other worldwide locations allowed remote access to the demonstration results and production data (below).

Although workflow automation for WAG optimization at Snorre-B is still under development, StatoilHydro is already realizing benefits from the work. First, integration of current users into the development and demonstration ensures that their accumulated experience is embedded in the streamlined workflow. Secondly, a simplified reservoir model was developed that provides results in minutes rather than hours—a necessity when including the model in the optimization loop. Finally, increased use of automation in production monitoring is an important milestone. Alarms are triggered appropriately, and the combination of monitoring and subsequent analysis results in faster turnaround times for unexpected situations. Avocet software, incorporated into a corrective and supervisory workflow, is playing a key role in delivering all these benefits.

**Toward the Intelligent Field**

Although the technology to obtain and transmit data in real time has been available for a few years, the oil industry has been slow in adoption. As the appreciation of increased recovery has spread, its absorption rate in the field is improving. This is also aided by real-time options that are simultaneously growing in capability and shrinking in cost. For example, BP has coined the name “Field of the Future” for the intelligent field and is taking steps to turn the company’s vision into a reality. BP has combined integrated asset modeling with a visual, map-based environment at their Arkoma Red Oak West field.

BP North American Gas operates this field near Wilburton in southeastern Oklahoma, USA. This field contains about 800 gas wells and 400 km [250 mi] of piping in an area 32 km [20 mi] long by 10 km [6 mi] wide. This asset also has seven compression stations and more than 70 portable wellhead compressors. In the past, optimizing fields like Red Oak West meant

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27. For more on PRODML www.prodml.org (accessed September 10, 2007).
laboriously examining large amounts of data for hundreds of wells from many sources. As a part of their Field of the Future initiative, BP has successfully brought this field to the forefront of the intelligent field. A SCADA system was merged with Avocet Integrated Asset Modeler to provide full-field optimization and map-based visualization.

The online integrated asset model at Red Oak West can run in either a real-time tracking mode to monitor current operations or in an offline mode to evaluate alternative production strategies. In addition to online modeling, BP has developed a tool for visualizing Red Oak West data called “MAPS” that has provided BP engineers with a map tool to see performance for a large field (above). Such an environment enables engineers to quickly identify wells that are producing below their potential and locate operational problems such as liquids accumulation or equipment failure.

Although production improvement was the key aspect of the program, BP found other important benefits. Integrity management was improved by using visual indicators and animation to view pipelines for corrosion, erosion and fluid velocities. BP has discovered that the MAPS tool is not confined to monitoring only well and pipeline performance and integrity variables. It can also track personnel and equipment for field activities such as maintenance, drilling or emergency evacuation.

Although there are many drivers in the push toward the intelligent field, operators most likely will be motivated by decreased cost and improved production. Significant increases in the value of projects will give operators the greatest push toward the technologies that define the landscape of the intelligent field (below left). Integrated asset modeling occupies a key position in this terrain.

Integrated asset modeling is part of a paradigm shift to digital technology that is changing the face of oil and gas fields. Starting as a ripple 25 years ago, this shift has gathered momentum and is now a wave. At the core of integrated asset modeling and all of the associated technologies that make up the intelligent field are information integration and communication. The old serial work processes are disappearing and being replaced by elements of a new paradigm—one that seamlessly integrates information between disciplines and communicates that information across geographical boundaries. The technologies that are part of this paradigm tend to break down barriers and promote collaboration—they are proactive rather than reactive. Integrated asset modeling will occupy a key position in the intelligent field as the industry moves toward optimization in real time. –DA