

OVERVIEW



The topic of knowledge management has matured considerably over recent years, evolving from abstract discussion about the translation of raw data into useful information on to knowledge while presenting an exposé of the differences between explicit and tacit knowledge. These dialogues, more often than not, lacked cohesion as well as a clear impression of the effect on the industry's bottom line.

In reviewing the various papers for this year's feature, I have to remark about the superior quality and high degree of relevance of the various publications. One can witness a foundation of data acquisition and management in a continuum, which spans from the large volumes of data that comprise the static domain of the shared Earth model to the capacity to collect data on a continuous basis along the full profile of the wellbore. The latter is a clear demonstration of the great strides in technology made by the providers of data-gathering systems.

Until recently, many knowledge-management initiatives were hindered by an environment that was unable to make immediate and efficient use of all the data being acquired to benefit the operation of the asset. A mainstay in the downstream operation of refinery and pipeline systems, the upstream E&P industry has evolved slowly in accepting the value of real-time data. Clearly, we are now at an advanced stage of integration of technology and information that does, indeed, drive decision making on a continuous basis.

Coupling the advances described above with the ascribing of value to specific information provides added capability in making decisions that are bottom-line driven in an industry that depends increasingly on marginal assets as we focus on sustainability of current and future reserves. The papers featured this month provide an interesting wealth of information on the state of play of data-gathering technology, integration initiatives, operational deployment of digital oilfield environments, and the use of mentoring as a means of capturing and retaining knowledge. These are all excellent ingredients in a recipe for the continuing success of integrating knowledge management into mainstream E&P operations. **JPT**

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Knowledge Management and Training additional reading available at the SPE eLibrary: www.spe.org

SPE 106916

"From Sensors to Models to Visualization—Handling the Complex Data Flow" by Ø. Kolnes, SINTEF Petroleum Research, et al.

SPE 103287

"Sustained Competitive Advantage Through Structured Mentoring" by G. Arango, SPE, Hughes Christensen, et al.

SPE 108175

"Value-of-Information Applications in Unconventional Resource Plays" by Patrick E. Leach, Decision Strategies, et al.

Technology Integration in the Caspian

BP's Azerbaijan Strategic Performance Unit (ASPU) was developed to meet key challenges of operating within the Caspian region and to maximize business value. Key challenges include complex depletion plans; unconsolidated reservoirs; a difficult-to-drill overburden; and an integrated development, gathering, and export system. To meet these challenges, advanced seismic, intelligent completions, zonal-flow monitoring and control, and field of the future (FOF) technologies collectively address the business challenges.

Introduction

Integration is key for the Azerbaijan strategy, specifically the technology strategy. The assets and reservoirs are integrated in a variety of ways and designed to operate in an integrated way. This integration is essential to maximize reservoir recovery. As the strategy developed, increased integration could create additional opportunities for performance improvements.

Azerbaijan Assets

As shown in Fig. 1, the BP-operated assets center on development of two very large hydrocarbon reservoirs in the Caspian [the Azeri, Chirag, and Guneshli (ACG) oil fields and the Shah Deniz (SD) gas development], although it is fully expected that other assets will be added. In addition, BP operates two major pipelines through which these hydrocarbons are exported—the Baku-Tbilisi-Ceyhan (BTC) and the South



Fig. 1—BP's Azerbaijan interests.

Caucasus Pipeline (SCP), which originate at the Sangachal terminal, south of Baku. These pipelines are designed to take ACG and SD reserves to market with capacity to take oil and gas from other fields and operators. A fully redundant data network is in place linking all facilities with a high-bandwidth optical-fiber “ring-main” backed up by satellite data systems. Fig. 2 summarizes the ACG full-field development.

Technology Plan

The 5-year technology plan integrates all functional and asset-based activities across business areas supporting the ASPU. The strategy includes leadership in a few key areas, efficient deployment of technology in other areas, bias toward rapid application of proven technology, and healthy progression of options in selecting available technologies. This strategy has helped to focus and prioritize technologies.

The technology plan was developed in conjunction with field-depletion plans. The technology plan also was designed

to improve ultimate recovery. The current ACG-development plans recover approximately two-thirds of the potential. Obtaining maximum value requires sophisticated reservoir management and application of advanced technologies such as multilateral completions and other enhanced-oil-recovery technologies.

The integration effort addresses four immediate challenges in the ASPU.

- Drill through unstable overburden in wells with stepouts of up to 6 km from the platforms.
- Develop and manage production from a multireservoir system.
- Operate highly productive wells in reservoirs that are loosely consolidated and, hence, prone to sand production.
- Integrate and optimize a complex development, production, gathering, and export system.

Reservoir-Performance Management

Real-time reservoir-performance management tool kits can enable reservoir-performance decisions on the basis

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 106858, “Technology Integration in the Caspian,” by Ian Pannett and David Hodgson, BP plc, prepared for the 2007 SPE Digital Energy Conference and Exhibition, Houston, 11–12 April.

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt. The paper has not been peer reviewed.

of real-time field-surveillance data. By underpinning reservoir simulation with real-time surveillance data, the operator will be informed about the reservoir at any given time and will, therefore, be continually in a position to make optimal reservoir-performance decisions.

The key technology links of the tool kits are as follows.

- Reducing model cycle time by use of automated data handling and manipulation in preparing simulator input.
- Improving reservoir characterization by adopting data-analysis techniques to mine surveillance data for interwell reservoir insight.
- Automating traditional reservoir-performance techniques such as pressure-buildup analysis.

Life-of-Field Seismic. The aim is to provide a means of obtaining high-quality, repeatable, high-resolution, potentially on-demand seismic images of the reservoir to track fluid movement in the reservoir that is associated with production and injection. The seismic receivers are deployed permanently or semipermanently on the seabed and connected back to a recording system on a permanent facility instead of the conventional method of one-off seismic acquisition from boats. The ability to monitor fluid movements in the reservoir allows optimal depletion of the reserves, often through more-accurate management and/or placement of future wells.

Intelligent Completions. Intelligent completions have two main functions.

- Prevent sand from getting into the well—achieved by placing an expandable screen across the reservoir to hold back the sand particles.
- Enable flow control into and out of multiple reservoirs.

Flow control is achieved by placing valves inside the completion assembly such that the production or water-injection rate can be varied between the zones. Previously, it was necessary to drill a separate well into each reservoir. Intelligent completions provide the functionality of multiple wells from a single wellbore. Controlling the volume of water injected into and monitoring production from each reservoir will ensure maximum oil sweep of each reservoir and, hence, maximize recovery.

Zonal Flow Monitoring. Zonal flow monitoring uses distributed temperature sensing, in which optical fiber is used for

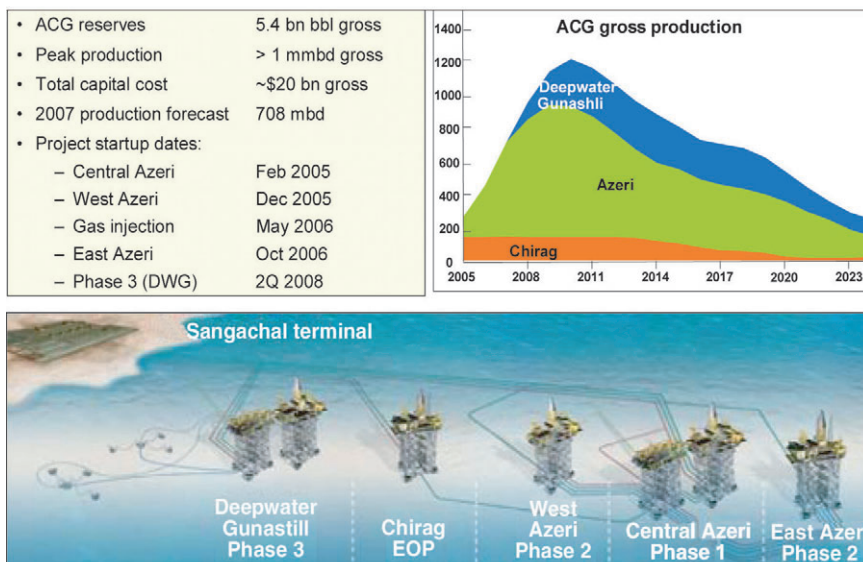


Fig. 2—ACG full-field development.

accurate temperature determination at any point along its length. This method helps to identify which section of the completion is producing the most fluid. Advanced fiber-optic sensor technology provides a means of obtaining real-time continuous down-hole temperature measurements that can be translated into zonal flow rates.

Remote Performance Management (RPM). RPM allows people from different disciplines, locations, and organizations to have access to the same real-time information, thus enabling collaboration to leverage expertise and improve decision making. RPM collects data from facilities and wells, which then are available through standard Web browsers to anyone who has valid access to the BP global network.

RPM includes several functions.

- Visualization enables users to view data in various forms (e.g., plant schematics, trends, and parallel-coordinate graphs).
- Task automation provides information such as online automatic calculation (e.g., rate and phase).
- Equipment-health monitoring compares real-time data with simplified models of pumps, compressors, and such to identify problems and deviation from design.
- Event detection and alerting provides automated alerts to key personnel on the basis of automatic interpretation of data.
- Report automation (e.g., provide operational information or valve-travel timing reports).

RPM supports the advanced collaboration environments (ACEs) being implemented to provide facilities that can be used to provide multidisciplinary support to remote locations.

Azeri Field Optimizer. The optimizer is an integrated dynamic computer simulation of the oil/gas processing plant on the facilities at the ACG field and the interconnecting pipelines, together with the Sangachal onshore terminal. It is designed to simulate the fluids processing through these facilities and is calibrated with real-time data from the instrumentation.

The optimizer can be used to maximize oil throughput by balancing plant processing and achieving the optimum gross throughput in the model, then making adjustments to the actual plant to obtain the same conditions. It also is used to simulate real-life events on the plant, thus allowing operators to respond optimally to likely upset conditions in the real plant. Currently, the optimizer is explicitly not a closed-loop simulation, requiring operator intervention to adjust the settings to represent the computer model settings.

ACEs. ACEs represent a combination of facilities, including display technology, rooms, digital infrastructure, and data systems, all of which enable collaborative working across different locations, disciplines, and companies. An example is an onshore operations center in which shore-based technical teams can work closely with offshore field teams,

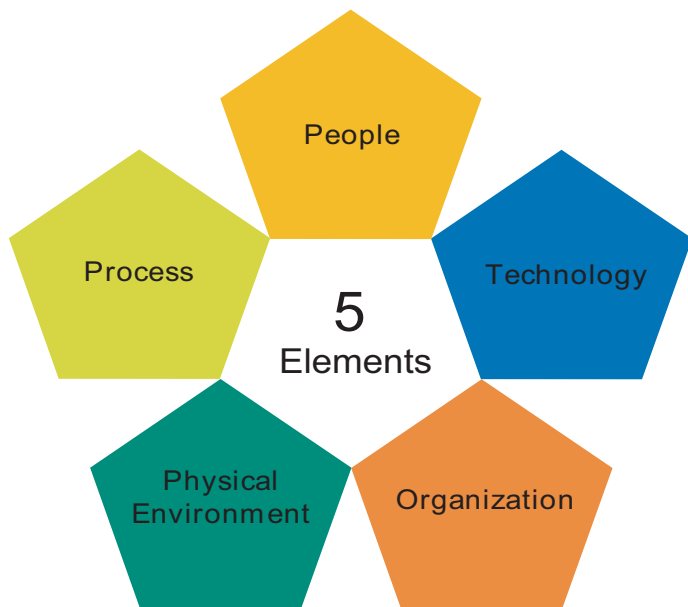


Fig. 3—Five-petal ACE model.

collaborating through video conferencing and simultaneous access to offshore data and systems. Thus, ACEs directly address the “more remote monitoring,” “more collaboration,” and, eventually, “more remote operation and control” aspects of the FOF.

While technology is a key enabler for collaboration, the real benefits stem from use of the technology to make better decisions more quickly. Much of the change required to deliver the collaborative capability and the business benefits will not be in the technology arena. Any asset or business unit embarking on an ACE project must consider the five key elements shown in **Fig. 3**. Collaboration may occur between people without necessarily having a particular room or facility in which to work, they may be in different offices around the world, using technical tools to support their work processes within a supportive organizational structure.

Technology Implementation

The value chain follows the flow of fluids from the reservoir through the wells, plant, pipelines, and export facilities to the point where the fluid (oil or gas) is sold. At every point in the chain, value can be added or destroyed. It is common to improve value at each point in the chain by optimizing performance of that point and repeating this process down the chain, thus leading to overall performance and value improvement.

In Azerbaijan, the aim is to bring these optimization technologies together—tempered by value identification and risk—to attain a degree of real-time performance improvement from reservoir to the point of sale. The Azeri-field optimizer is the first of these integrations.

The ASPU is at the beginning of the process of understanding and developing this technology integration. Work is ongoing in looking at the subsurface-model and tool linkages and in looking at the surface domain that includes offshore facilities, the terminal facilities, and all export routes. Early work indicates that integration is multidirectional and must consider many other factors that could affect the seamless development and deployment of an integration strategy.

Threats or Challenges to Integration. A specific effect to consider in Azerbaijan, which may not apply in other business units, is that of geographical administration. Although a single business unit, the ASPU operates in three countries—Azerbaijan, Georgia, and Turkey—which must be considered in assessing value-chain integration. This geographic dispersion requires consideration in the following business areas.

- Organizational responsibilities and accountabilities
- Differing contract strategies
- Commercial and legislative environments
- Differing technology advancement

- Hydrocarbon accounting and management
- Politics
- Time zones

Integration Maintenance. When analyzing detail and discussing model maintenance, updating of well and reservoir data through to export-tariff information, the model becomes complicated. The larger and more detailed the model, the more costly it will be to set up and maintain, and, thus, the less sustainable it becomes. Sustainability of associated tools and models that affect the success of integration is of great importance. Care must be taken early such that unreal expectations can be dealt with and the reality presented to the decision makers early in the process.

The ASPU is prepared to undertake an early-life-cycle evaluation of the process or processes being integrated. This work will identify gaps, the human/machine interface requirements for data, organizational capability, and frequency of interactions required for the integration to be a success. Additionally, the long-term sustainability of the optimization system needs to be addressed. This maintenance of integration must be built into the business case from inception, or there is a strong possibility of failure.

Role of ACEs. ACEs are the physical places where vertical integration occurs. This system is the catalyst for a change-management program. In Azerbaijan, the ACE strategy is coupled with the FOF strategy. It is recognized that both must be integrated and developed in unison.

An aspect of developing the ongoing ASPU ACE strategy is to understand how the ASPU will function as an organization in future and how it will evolve. The need for this understanding stems from the absolute need to ensure the way decisions will be made and how the business will be managed. Understanding the organization, or at least the vision, allows development of an integration strategy that can articulate the connectivity requirements within the ASPU. Integration and ACE strategy are not exclusive; each must consider the other. How an ACE is used in the future depends on the degree of desired integration. In Azerbaijan, the ACE strategy has targeted 2010.

JPT

Knowledge Management for Shared Earth Modeling

Shared Earth modeling is a process of integrating static (geological structures) and dynamic (hydrocarbon production) data collected from several disciplines to construct a model of a subsurface resource. A shared Earth model (SEM) should allow sharing and integrating data and knowledge related to data interpretation. People from different disciplines, with different technical skills, should be able to provide an SEM with specific technical knowledge concerning how to evolve a hydrocarbon prospect at the various stages of its life cycle.

Introduction

For knowledge-intensive organizations, the knowledge-management process involves complex interaction of many types of information and expertise that are processed and integrated progressively to produce value results. This work examined the possibility of developing an information-system environment for supporting the generation, codification, and dissemination of geological knowledge related to reservoir modeling for oil/gas exploration.

Preliminary Concepts

Knowledge management refers to planned and integrated strategies of

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 107152, "Knowledge Management for Shared Earth Modeling," by Laura Mastella, École des Mines de Paris and Universidade Federal do Rio Grande do Sul; Michel Perrin, École des Mines de Paris; Mara Abel, Universidade Federal do Rio Grande do Sul; and Jean-François Rainaud and Walid Touar, Institut Français du Pétrole, prepared for the 2007 SPE Europec Annual Conference and Exhibition, London, 11–14 June.

an organization to allocate and apply assets for knowledge value. These strategies include actions in seven areas: high-level management strategy; company culture and values; organizational structure; human-resources strategy; information system; results monitoring; and learning from companies, clients, government, universities, and others. Knowledge management is also necessary when a community of practice envisages distributing and sharing its knowledge in a homogeneous and organized manner. A community of practice is a group with a shared history and goals, which has, over time, negotiated meanings and shared norms, concepts, and ways of interacting about a particular domain of knowledge.

Knowledge Generation. Knowledge is a result of applying cognitive abilities of a person, team, scientific community, or company to solve a problem. Knowledge may be produced internally with the efforts of an organization, in which case knowledge needs only to be recorded and stored. Otherwise, knowledge must be purchased or selected from an external source. Knowledge generation is the result of actions such as internal development, external acquisition, technology transfer, and multidisciplinary codevelopment.

Knowledge Codification. Acquired knowledge must be codified so that it can be shared. Knowledge codification includes organizing, classifying, indexing, and storing knowledge. These actions are especially important in collecting new knowledge or retrieving dispersed existing knowledge, such as the corporate knowledge spread throughout the company or knowledge related to a complex process. The success of the codification stage depends on the efficiency of the chosen informa-

tion systems and knowledge-engineering strategies.

Knowledge Dissemination and Allocation. The third and fourth stages of the knowledge-management cycle are dissemination and allocation. Knowledge dissemination depends on human resources and on information-sharing strategies. The communication process is key for efficient knowledge transfer. Informal communication, information gatekeepers, work-shift systems, and training (supported by knowledge systems and computer-mediated communication intranets) are traditional forms of disseminating knowledge. Knowledge allocation deals with selecting and internalizing knowledge by company staff or people of a community of practice to improve the work process. Also, knowledge allocation is achieved by collecting knowledge regarding products and services, making them more valuable for the market.

SEM. This concept refers to the integrated work of constructing representations of subsurface resources. Ideally, SEM organizes the work of multidisciplinary teams in a community of practice around the construction of common Earth models. The cooperatively built model evolves as team members contribute data and interpretations about subsurface volumes as well as about knowledge embedded in the model and shared by everyone in the community. This task is not simple. To aggregate different models in a common environment, a common understanding is needed about how scientists and engineers of various disciplines make use of their respective expert knowledge.

Reservoir information should be integrated with the knowledge used to produce that information. The results of applying this knowledge to the data

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt. The paper has not been peer reviewed.

(i.e., the actual interpretation) also should be integrated. Items manipulated in the course of modeling should no longer be successive categories of data but actual geological objects to which experts should attach various properties successively according to interpretations. Moreover, these objects and properties should be described by use of a common language that will allow information to be accessed at each stage of the modeling chain by all involved in the modeling process.

Information Integration With Ontologies

An ontology is a formal explicit specification of a shared conceptualization. Ontological construction enables describing static knowledge by specifying which objects compose the domain and how the structure is organized. The three main architectures for information integration proposed in the literature are based on a unique ontology (which defines a global ontology to the semantic specification of the concepts of the domain), multiple ontologies (in which a semantic concept of each information source is described by its own ontology), and hybrid approaches (in which a semantic concept of each source is described locally, but ontologies are built with a shared global vocabulary).

Models and Representations for Reservoir Analysis

The construction of structural, stratigraphic, or reservoir models is essential for reservoir characterization. However, the concept of a model may have two meanings in the scientific field.

“Model” may refer to a class of structures sharing general characteristics. Such models should be called “models of theory,” such as sedimentary-deposition models or models of folds.

“Model” may refer to specific geological assemblages in which all relevant parameters have specific values. Such models should be called “models of representations.” An example is a block diagram representing a 3D geological assemblage.

This study is concerned with models of representations that correspond to reconstruction of geological assemblages from seismic and well data. The following 3D models were considered.

- Structural models consisting only of geological-surface assemblages

- Stratigraphic models corresponding to structural models complemented with stratified geological matter (or lithology)

- Reservoir models that were simplified stratigraphic models fit for hydrocarbon-migration calculation and for reservoir hydrocarbon-content estimation

There are two types of geological representations.

- Spatial representations corresponding to objects or assemblages embodied in the 3D space associated to defined spatial coordinates (e.g., a seismic cube, geological cross section, geological map, or 3D model)

- Logical representations dedicated mainly to showing the existing relationships between various objects to help visualize data or enable a better understanding by geologists

The full-length paper details key ideas for developing knowledge-driven modeling on the basis of a common ontology for externalizing and sharing knowledge.

Chronological Approach of Geological Knowledge

Geology provides support for many applications, and much effort has been dedicated to its description and codification. In more-specialized fields like petrology, codification is necessary for ensuring communication between practitioners. Therefore, geological surveys and oil companies have developed large nomenclatures.

Geological knowledge should be in three categories.

- Descriptive knowledge about the geological objects (e.g., rocks or surfaces) and their characteristics

- Geological-process knowledge, regarding the formation, deformation, and/or transformation of rock assemblages (geology being the physical science that studies the physical, chemical, or mechanical processes that affect rocks)

- Historical vision of how processes operated through geological time

Geological Objects in Earth Models

Other conventional representations of the geological subsurface, such as 3D Earth models, are an assemblage of geological objects. For instance, a structural Earth model is an assemblage of geological surfaces. Structural, stratigraphic, or reservoir Earth models also can be viewed as collections of closed volumes

limited by surfaces. Normally, they contain no significant voids. Each of these elementary volumes (geological blocks) normally comprises matter belonging to only one geological formation.

Blocks of geological matter are limited by surfaces (also called limits), such as sedimentary interfaces or faults. In the case of 3D Earth models, geological-limit assemblages are constructed first to obtain structural models that are populated further by petrophysical properties to obtain stratigraphic and reservoir models. Here, it is assumed that each defined surface of the model is the record of one defined geological event (considered instantaneous with respect to the geological time scale). Therefore, geological interpretation gives geological qualification (e.g., stratigraphic surface or fault) to surfaces entered into the model, and it implicitly or explicitly establishes a total or partial chronological order between the geological events to which they correspond.

Reservoir-Modeling Chain

From the modeling point of view, geological reservoirs are interpreted as assemblages of geological objects. A reservoir engineer will be interested in the mechanical or hydraulic properties of the various geological formations to compute realistic fluid migrations. Exploration managers will be concerned mainly with the amount of exploitable hydrocarbon reserves within the reservoir and with the quality of those reserves. Earth scientists may, as sedimentologists, focus their attention on sedimentary processes, and as petrologists, focus on the nature and origin of the various rocks. Structural geologists will focus on the various generations of folds, thrusts, and faults that can be identified. Geophysicists will concentrate on identifying which markers correspond to the limits of the reservoir and on defining velocity models for the rock layers.

Data. Raw data are related to a prospect, which corresponds to the spatial area of interest for the model and to the related subsurface. Seismic data, well data, and rock samples provide input for the model. Raw data are of three basic types.

- Seismic data [usually 3D data (seismic cubes)]

- Well logs corresponding to 1D data along drilling trajectories

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Modelers also take interpreted data into account that concern regional geology (e.g., a zone that may be much larger than the prospect) or that are related only to the prospect itself. These interpreted data may consist of literal information (texts in paper documents), 2D graphic documents such as geological maps or cross sections, or even 3D Earth models (e.g., former interpretations of the prospect).

Interpretations

Data can be considered for the model only if they are interpreted. For instance, structural and sequential analysis may be applied to seismic or to well data and will result in the identification of various geological objects (e.g., sedimentary formations, interfaces, or faults) linked by specific relationships.

Thin-section data interpreted by petrographers while identifying rock properties may be qualitative (lithology or petrofacies) or semiquantitative (e.g., granulometry). Experimental studies on rock samples may bring additional quantitative information (e.g., composition, porosity, relative permeability, resistivity, and acoustic velocity). However, interpretations related to one-time-test data can be considered for modeling only if they can be generalized to specific volumes or surfaces (such as a fault surface or a specific layer or formation).

Representations

Current modeling provides spatial representations corresponding to the various Earth models produced or to parts of those models (e.g., a given horizon, fault surface, or formation). Examples include geometric objects, surfaces, volumes, geological volumes, geological surfaces, and local properties, as well as structural, stratigraphic, and reservoir models.

Various types of graphical representations also are used in current models, such as stratigraphic columns. The knowledge editor used in this study can represent topological and chronological relationships between the various objects of a given model. Examples include knowledge, topological, and geological representations; fault-network arrangement; stratigraphic column; and geological-evolution scheme.

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Subsea-Data Management

This project will contribute toward making real-time reservoir-monitoring and other downhole data available everywhere on Statoil's network infrastructure. The goal is to resolve hurdles for implementing fiber-optic monitoring and data transmission from subsea developments. Focus is on detailed seabed-system solutions to create an open high-speed communication infrastructure, which fiber-optic technology enables. The project will develop interfaces with existing subsea systems that have only electrical low-bandwidth communication systems.

Introduction

In June 2005, Statoil requested technical and commercial proposals relating to the development of integrated fiber-optic systems (an integrated subsea communications system) and reliable downhole sensors.

There are two key project areas:

- Downhole-sensor (DHS) sand monitoring (identification and quantification), multiphase flowmeter (for intelligent-well applications), and distributed pressure and temperature measurements
- Integrated fiber-optic subsea system (IFOSS) containing subsea well-sensor interrogation solutions, a subsea-control system, a subsea telecommunica-

This article, written by Technology Editor Dennis Denney, contains highlights of paper OTC 18744, "Subsea-Data Management," by Brian Drakeley, SPE, Weatherford International, Svein Omdal, SPE, Statoil, and Sigurd Moe, SPE, FMC Technologies, prepared for the 2007 Offshore Technology Conference, Houston, 30 April–3 May.

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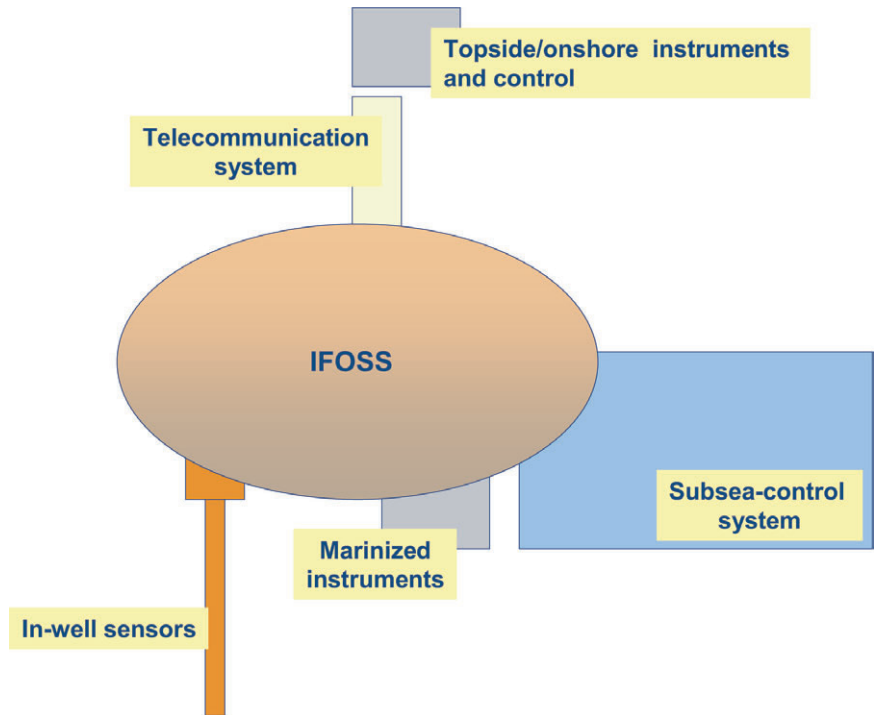


Fig. 1—Complete integrated system.

tion and transmission system, and an integrated fiber-optic system

Fig. 1 illustrates the scope of the project and how these key project areas fit into the total integrated system.

DHS Real-Time Reservoir Monitoring

Essentially, in-well monitoring systems are required that deliver high-quality measurements throughout the life of the well without the need for routine maintenance or intervention. With no downhole electronics in existing fiber-optic systems, sensing systems are intrinsically more reliable than electronics-based systems.

With increased demand for more data on reservoir and well performance, communication systems must

have that significantly improved signal performance, data density, and transmission distance, which leads to a fiber-optic solution.

Existing Downhole Fiber-Optic Sensors

Currently, there are four types of optical sensing systems.

Pressure/Temperature (P/T). Many P/T fiber-optic gauges have been installed and are very reliable.

Distributed Temperature Sensing (DTS). DTS systems are the most widely used fiber-optic sensing system. These systems provide a continuous temperature log of the well along the entire length of the fiber [e.g., a pro-

The full-length paper is available for purchase from the OTC Library: www.otcnet.org. The paper has not been peer reviewed.

duction (or injection) thermal profile of the well] and can be used to identify well problems; water, gas, and steam breakthrough; gas lift valve and system performance monitoring; and paraffin and hydrate formation monitoring. Measurement points are at 1-m intervals, and temperature resolution can be on the order of $\pm 0.1^\circ\text{C}$.

Flow. Downhole flowmeters reduce infrastructure, surface facilities, and the number of well tests, and they allocate production/injection from/to multiple zones. Traditionally, downhole flow and fraction meters have used intrusive mechanisms, such as venturi flowmeters, to produce pressure drops, but these mechanisms restrict access to the lower part of the completion. Such meters use electronic components downhole, thereby lacking the inherent reliability of optical systems.

An optical multiphase flowmeter is nonintrusive and measures multiphase flow inside the tubing at the point of the sensor. These sonic flowmeters make two primary measurements: the flow velocity and the mixture sound speed. The speed of sound through a mixture, which is proportional to the volumetric fractions of oil, water, and gas in the mixture, and the flow velocity yield the total flow rate. The sonic flowmeter is, by itself, a two-phase flowmeter with the capability of resolving the phase fraction of two phases along with the total and component flow rates. A full-bore nonintrusive design has no pressure loss. This type of flowmeter contains no downhole electronics or moving parts and has no nuclear sources. The robustness of the meter also allows performing workover, perforating, and hydraulic-fracturing operations with the flowmeter in place.

Seismic. The optical seismic system is designed specifically for permanent borehole seismic imaging and continuous passive monitoring, including microseismic monitoring. The optical seismic sensors are installed on production tubing or casing and contain no downhole electronics.

In-well seismic sensors also can monitor production away from the wellbore by, for example, monitoring microseismic activity related to remote fluid movement or formation compaction. Permanent seismic sensors also can monitor other production activities,

such as nearby drilling. In combination with pressure, temperature, flow, and phase-fraction monitoring and downhole flow control, in-well seismic sensing will help reservoir and production engineers manage and enhance reservoir production.

Sensors in Development

Sand Production. It is important to detect accurately both the presence of sand and the amount of sand produced to maximize oil/gas production. It also is important to be able to determine the producing zone from which sand is being produced. For intelligent-well applications, there is the additional requirement to ensure the continued reliable operation and sealing integrity of remotely operated interval-control valves in multizone wells. For sand control, two parameters are essential: sufficiently low detection limit and confidence in detecting sand at sudden onset (situations where no other methods can verify the measured rate). Development of this sensor will be based on some pre-existing flowmeter technology.

Multiphase Flow in Intelligent Wells.

For existing flowmeters in horizontal well sections, differential-pressure measurements across the pipe in the horizontal section are made. Production-logging tools may be able to provide an indication of the density. To determine density, it is necessary to measure the pressure drop across the flowmeter. This pressure drop can be determined by integrating measurements from two optical P/T gauges in the meter—one above and one below—providing there is sufficient vertical separation between the two P/T gauges.

In horizontal and deviated wells with inclination such that sufficient vertical separation is not available, it is necessary to use a differential-pressure gauge. Currently, such gauges are available as electronic, not optical.

For three-phase measurements, the use of a differential-pressure reading to provide gravimetric information will be evaluated and optimized.

Another key element is that current flowmeter instrumentation has physical dimensions and power-consumption requirements that render it impractical to deploy in a subsea pod. Part of the project is to produce a subsea instrumentation package.

Distributed Sensing. There are several distributed sensing systems at various stages of commercial availability. DTS systems are available commercially. Array-temperature-sensing (ATS) systems measure temperature at predetermined points within the fiber. The concept of a distributed-pressure-sensing (DPS) system was proved in the late 1990s, but is not widely used. Both DTS and DPS systems are distributed-backscattering techniques, and ATS is a quasidistributed fiber-Bragg-grating system.

Integration Into Completion Configurations

After determining the types of completion configurations that could be used by Statoil, an analysis was completed to determine the requirements for full integration for both new and retrofit applications. Requirements include the following.

- Feedthroughs (including production, annulus, and zone-isolation packers)
- Passing of expansion or compression units such as polished-bore receptacles
- Downhole splices and cable systems
- Subsea and in-well dry- and wet-connect systems
- Subsea packaging of optical interrogation systems
- Extended tieback applications

Reservoir Monitoring

Development of a fiber-optic-based permanently deployed 4D four-component ocean-bottom-seismic array system is ongoing. Subsea-data file sizes are measured in terabytes, a much larger scale than P/T, DTS, flow, and in-well seismic data files. Therefore, file size is a major driver for development of a next-generation subsea telecommunications infrastructure.

IFOSS

For data transmission, downhole- and subsea-instrumentation systems traditionally use infrastructure provided for subsea controls. These communication systems were designed to achieve long-distance transmission with copper cables, and protocols have been selected accordingly. The challenges of traditional systems have been to achieve high data speed and simple or no protocol conversions between

different systems and to allow system upgrades and expansions.

IFOSS activities challenge and complement current subsea communication topologies and technologies, and they address the following.

- Analog transmission of data measured with fiber-optic sensors
- Solutions for seabed conversion of optical measurements
- Capacity and flexibility of traditional subsea communication systems
- Retrofitting of high-speed communication in systems with only electrical cables in place
- Technology, features, and standards from the telecommunication industry

The target is to develop a seamless infrastructure for communication and control—reservoir to topside to shore.

Subsea Communication. A traditional configuration of a North Sea system uses the available copper-based power cables for signal transmission. Normally, four cable pairs are used; one cable pair is connected to the primary subsea electronics of the first subsea-control module and the redundant subsea electronics of the second subsea-control module. Such configurations ensure redundant backup in case of cable malfunction. Alternative configurations share communication of one pair with 12 or more subsea-control modules. Each module is addressed in sequence with a low communication speed (typically 1,200 to 9,600 bit/s), and the per-well throughput can become low.

Introduction of optical fibers affected the subsea-distribution architecture. Redundant routers convert optical communication into electrical signals. In subsea routers, an Internet-protocol network is used to communicate with the subsea-control modules and, in parallel, other subsea equipment.

Another option is one-to-one fiber connection with a redundant set of fibers to each subsea-control module. This system also features a network for communication between the subsea-control modules. It may, as in the Ormen Lange subsea system supplied to Hydro, feature backup for the fiber-optic communication with traditional electrical communication over the power line.

Well-Sensor-Interrogation Solutions. Alternative approaches for data trans-

mission, either available or under development, include the following.

- Subsea signal conversion (interrogation) and digital transmission
- Analog transmission of optical measurements
- Analog transmission of optical measurements in parallel with digital transmission to the rest of the subsea and downhole system

A suite of Bragg-grating-interrogation instrumentation systems has been developed for topside placement. With the increasing importance of subsea wells, and with the lack of a fiber-optic-based infrastructure in many fields, it is necessary to address subsea deployment of these instrumentation systems.

Solutions that maximize the interrogation length (length between sensors and instrument) for P/T, ATS, and other Bragg-grating-based sensors as well as flow and DTS instruments located topside or onshore will be developed. Focus will be on optimizing existing instrumentation and improving optical-fiber-network design. The use of passive optical-network components, optical amplifiers, and components from repeaterless telecommunication-transmission systems will be evaluated. The reliability of long-range subsea optical networks that use such components will be evaluated.

Subsea-Control System. Subsea production-control-system activities focus on challenges with future production controls, interface with existing and emerging fiber-optic instrumentation, and increasing functional requirements of the subsea infrastructure. Maturing and emerging subsea processing, gas compression, smart wells, and data mining will contribute to increased recovery in an integrated-operations environment. Also important is technology to enable retrofitting of optical and other high-speed instrumentation into existing fields where no fiber infrastructure is in place.

The first practical results of the work were demonstrated in January 2007, when a 1-Gbit/s subsea-communication system was demonstrated. This communication system is compatible with telecommunication-standard repeaters and may operate in parallel with transmission of analog data. The first planned use of the system is for the Tyrihans field. Flexibility is built into the system to allow retrofitting of elec-

trical actuators, a feature considered for the Gjøa field that will be developed with this technology.

Subsea Telecommunication and Transmission System. Technology from the telecommunication industry may be suited to solving some of these challenges of future subsea systems.

- Ultralong offset distances
- High transmission speeds
- Short lead times and use of standard cable products
- Availability of dedicated vessels for installation and repair

The last two points are especially important because the use of this technology will not load the already busy oilfield installation-vessel market and umbilical-manufacturer capacity. The direct-current-power system built into some of the telecommunication systems has a power capacity compatible with subsea and downhole controls and monitoring requirements.

Another focus is subsea-telecommunication systems with respect to the following.

- Data safety and security
- Cable-design requirements and recommendations
- Cable-network interfaces
- Mixed communication (i.e., analog and digital)
- Cable subsea-termination concept
- Marine-applicable components

The main focus of the project is on data safety and security. Various aspects are studied, including a system for providing and controlling remote access. Also, restrictions based on safety functions, available infrastructure, and version control of software are being addressed.

Conclusion

The selected focus areas will contribute to closing critical gaps. Subsea-data management will contribute automatic monitoring and a safe and reliable data-communication infrastructure. A modularized fiber-optic “plug and play” system design for which future functionality can be added into the system design will be developed.

The integrated-operation projects are essential to increase the reserves-replacement ratio, increase recovery rate, and reduce costs. It will improve total added value from existing fields and improve the long-term ability to secure new reserves.

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