

# Field Development Projects



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We all are aware of, and have been affected by, the large swing in oil prices over the past 4 years. I have asserted the importance of evaluation and management of uncertainties when planning the development of a new field or even when revisiting options for mature fields. Higher oil prices may reduce financial risks temporarily for a certain project; however, the complex decisions involved in field development, as well as the many variables to be dealt with, will make almost every project extremely risky. Ultimately, decisions taken in earlier stages, when uncertainties abound, are among the main factors that will determine the level of success of a project.

Higher prices may improve the results, eventually, of a project that otherwise would be considered a failure, but the fact is, among the various uncertainties in our business, oil price is paramount. With that in mind, we should give utmost attention in management of uncertainties existing in other factors related to field development, ranging from well drilling to reservoir characteristics. Many in our industry agree, which can be seen by new approaches and recent development of various creative and exciting risk-management tools. Our featured papers this month have some wonderful examples.

On a personal note, I would like to mention that after 5 years of writing this column, initially for Subsea Completion and later for Field Development, in October 2008, I will replace Ed May as Chairperson of the JPT Editorial Committee. Ed did a fantastic job of chairing over the last 4 years, and I will do my best to follow his steps, maintaining JPT's status as the primary publication in our industry. I must thank all of you for your constant encouragement and so many thought-provoking emails. Please feel free to continue writing to me. Thank you. **JPT**

## Field Development Projects additional reading available at the SPE eLibrary: [www.spe.org](http://www.spe.org)

**SPE 108891** • "Using Geomechanics To Optimize Field-Development Strategy of Deep Gas Reservoir in Saudi Arabia" by Mahbub S. Ahmed, SPE, Saudi Aramco, et al. See JPT April 2008, page 78.

**SPE 113831** • "The Benefits of Integrated Asset Modeling: Lesson Learned From Field Cases" by M. Rotondi, Eni, et al.

**SPE 113554** • "Selecting an Optimal Field-Development Strategy for the Vankor Oil Field Using an Integrated-Asset-Modeling Approach" by D.A. Antonenko, OJSC Rosneft Oil Company, et al.

## Additional reading available at OnePetro: [www.onepetro.org](http://www.onepetro.org)

**OTC 19254** • "An Overview of the Roncador Field Development, a Case in Petrobras Deepwater Production" by E. Bordieri, Petrobras, et al.

# Probabilistic Field Development in the Presence of Uncertainty

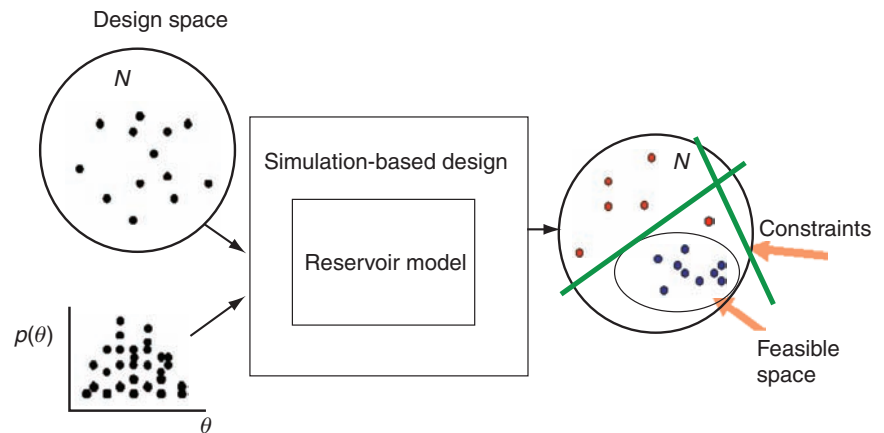
Field developments are characterized by high levels of uncertainty and dynamic interconnected decisions having complex value descriptions. A unified fully Bayesian design-optimization methodology helps with the complexity of decision making in field development. The proposed scheme can be customized with respect to the decision components: the metrics chosen, objective function, and associated uncertainties.

## Introduction

Various methods are used in decision making in the oil industry. Methods include worst-case/best-case scenarios, tornado graphs, Boston grid, expected net present value, decision trees, Monte Carlo simulation, and real options. These methods have different degrees of complexity and specific theoretical assumptions. For example, the decision-tree technique is a standard tool, but it is affected by important limitations. The number of decisions considered complicates the tree very quickly, especially when the decision tree is used to represent the whole-project design over time. Also, because decision trees provide only the maximum expected net present value of a project, they do not offer

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**Fig. 1—Simulation-based design algorithm in which the reservoir model is treated as a completed black box.  $N$ =set of designs,  $\theta$ =parameter,  $p(\theta)$ =probabilistic model.**

a way to quantify the volatility of the estimate.

Some decision-making methods model the decision process only partially. Monte Carlo simulation, for example, is a formal probabilistic technique in which different types of knowledge can be combined and uncertainty can be propagated. Various problems characterize the application. For example, correlation between uncertain variables can be modeled with Monte Carlo simulation, but it requires complicated mathematical algorithms. Monte Carlo simulation is not suitable for incorporating management flexibility or analyzing the value added by new available information.

Overall, current decision-making methods do not integrate the ability to represent uncertain factors efficiently, their contribution to uncertainty propagation and their correlation effect, or the possibility of managing flexibility in the presence of project irreversibility and proactive information gathering. The decision-making approach presented in this

paper aims to overcome such limitations by providing a way of framing and designing decisions and objectives that can be used in a variety of contexts, from the design of experiments to exploratory wells to a company's portfolio.

## Unifying Optimal Design

Bayes' theorem represents a natural way of dealing with uncertainty. It can be used as a basis to revise the degree of belief in a given system definition by incorporating newly acquired information as it becomes available. Bayes' theorem has been gradually adopted for uncertainty analysis of even very complex systems (e.g., physical, economical, and financial), particularly with recent developments in Bayesian computational algorithms. Its basic principle can be applied to estimate, predict, and evaluate model reliability and determine the optimal design. Also, it has been demonstrated that several optimization and estimation methods (e.g., least squares, Kalman filter, kriging, and maximum likelihood) can be

For a limited time, the full-length paper is available free to SPE members at [www.spe.org/jpt](http://www.spe.org/jpt).

derived directly from Bayes' theorem. In the same manner, system designs such as experimental design, portfolio optimization, real options, and sequential dynamics can be restated in Bayesian terms by use of the unifying Bayesian optimal-design formulation.

### General Formulation

Selection of an optimal design (e.g., portfolio of shares, oil drilling, and options to take) involves the ability to determine the best opportunity for generating the most satisfactory system output. A system design must be chosen from a set of designs on the basis of its payoff function defining, with respect to the observed data, the insight provided by the data over the system parameters and defining a terminal decision from some set of data whether to abandon the design or continue with its deployment. Uncertainty also affects the choice of a design because it affects the data being observed as well as the system parameters. The full-length paper details the formulation.

### Field-Deployment Example

This example determines the optimal valve setting for a 2D reservoir characterized only by uncertainty in permeability. Valve settings varied between completely open and completely closed in discrete steps (i.e., 0=completely closed valve; 1=completely open valve; and 0.25, 0.5, and 0.75 represent discrete intermediate steps). Three equally probable permeability realizations were considered. In place of a commercial reservoir simulator, a 2D black-oil model was used and simplifications were made. First, no cost function was assumed to represent any loss resulting from decisions to use controlled well valves. Second, no data were collected during the operation of the well, and, therefore, no information could be used to learn more about the geological scenarios or the performance of the design (i.e., no learning power of the design). The result of the design was measured in terms of cumulative oil produced as a function of the geological uncertainty. The combination of deterministic optimization and uncertainty analysis could provide misleading conclusions. The optimal value found may be optimum over a small portion of the search space (e.g., local optimum), such that it may be

optimal for only one scenario. The general formulation detailed in the full-length paper provides the probabilistic optimization that fully incorporates uncertainty and yields results that are probabilistically meaningful. In particular, the general formulation also remains valid in case the assumptions are relaxed (i.e., introduction of a cost function, definition of a terminal decision, or value of the data observed). For example, if the valve setting is updated at specific time periods, the uncertainty optimization becomes a problem of identifying the optimal sequence of valve settings. The utility function becomes a mixed function that globally optimizes the sequence over the simulation period. In addition, the Bayesian framing of the smart-well-deployment design can include a dynamic evaluation of the geological uncertainty in the optimization along with well measurements that are recorded progressively and used to update the uncertainty.

With this analysis, the setting that provides the average maximum oil production is identified along with its probability of occurring. In the example case, the magnitude of the production is higher in the deterministic-optimization case; however, its probability of occurring is lower. It must be emphasized that by use of the proposed decision method, it is possible to determine which valve setting should be used to obtain the highest averaged production, thus providing valuable information for designers and decision makers.

### Solution Algorithm: Simulation-Based Design

In the example, because of its simplicity, a simple discrete sampling was used. However, for more-realistic examples, the formulation requires the solution of a multidimensional integral, which may be computationally prohibitive. Markov-chain Monte Carlo methods make the solution of the multidimensional Bayesian integral possible.

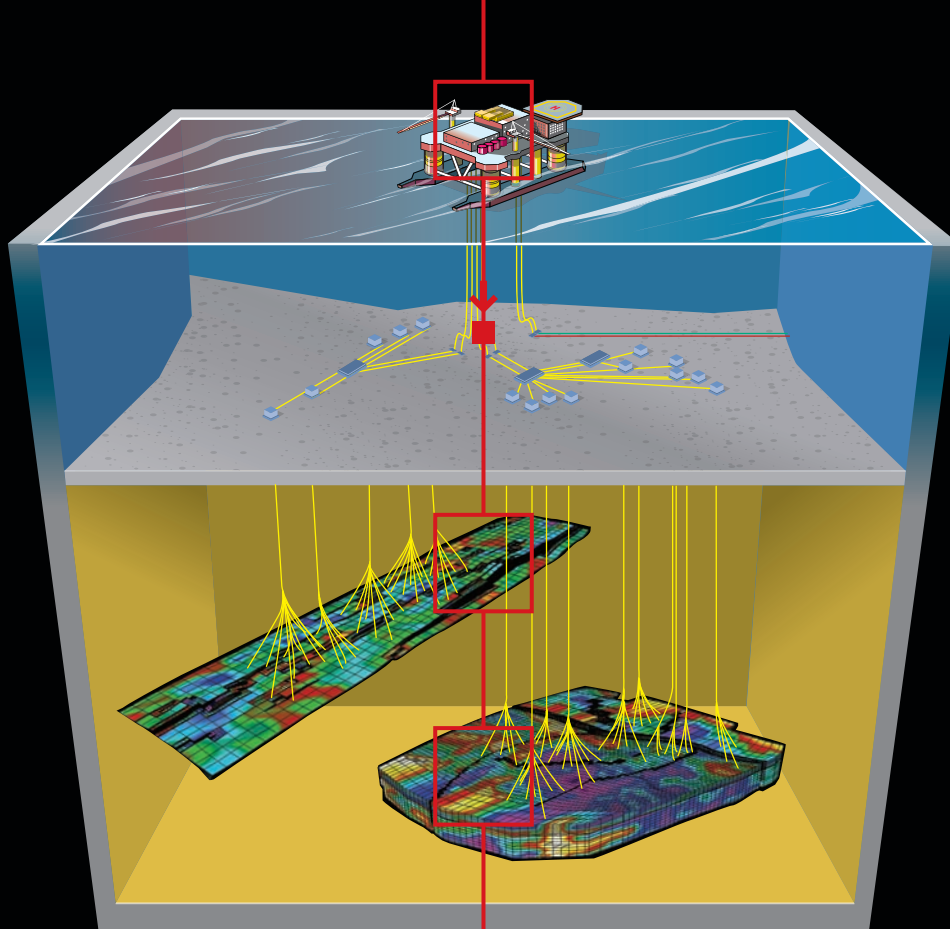
Markov-chain Monte Carlo simulation consists of a stochastic process in which the current state is a function of the previous state. The state space is represented by the input-parameter space from which the joint-probability distribution is sampled. It has been demonstrated that by running suf-

ficiently long chains, it is possible to obtain a sample of points from the state space representing the feasible set of designs defined by Eq. 1, and satisfying Eqs. 5 and 6, of the full-length paper. The most important Markov-chain Monte Carlo methods are Gibbs sampling and Metropolis-Hastings. In this paper, the optimal design computation was carried out with an algorithm that extends the Metropolis-Hastings method.

Assuming no terminal decision and making the probability model more explicit, the output will be a sample of designs and the corresponding values of the expected utility. The mode of those expected-utility values will represent the optimal design. The convergence of the algorithm can be measured and tested with a set of diagnosis criteria. The advantage of this algorithm is that it aims to explore those parts of the search space that are more probabilistically feasible, showing a greater rate of convergence than a classical Monte Carlo simulation. Differing from other optimization methods (i.e., adjoint methods), the physical model of the system is treated simply as a black box without requiring a change of the underlying mathematics (**Fig. 1**).

### Conclusions

Field-development-design optimization, in presence of uncertainty, must provide an optimal design for which the description is probabilistically valid and realistically feasible. Deterministic methodologies followed by a subsequent uncertainty analysis do not provide a correct and supportive analysis because they fail to explore the search space properly. The proposed Bayesian design optimization offers probabilistically meaningful solutions, and its formulation consists of a unified decision-making framework extendable to a variety of design-optimization problems (e.g., portfolio optimization, design of experiments, option-pricing evaluation). This property permits use of a consistent methodology during the field life, independent of specific characteristics of the decision problem under consideration, which provides consistency throughout the value analysis of the field and a common evaluation basis for comparison of different decisions. **JPT**



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## Roncador Field Development: Reservoir Aspects and Well-Development Strategy

Roncador, a giant field in the deepwater Campos basin, was discovered in 1996. Field development involves an 111-km<sup>2</sup> area and water depths from 1500 to 1900 m, with significant oil in place, different types of oil, and variations in geological characteristics. The development strategy comprises four modules. The first module, Module-1A, will produce reservoirs in the hanging wall of a large normal-fault structure. Modules-2, -3, and -4, will produce reservoirs in the footwall block. This paper presents key aspects of the reservoirs, drainage modeling and design, and the strategy for project implementation to overcome major reservoir uncertainties, such as fluid type, connectivity, and net-pay thickness.

### Introduction

The Roncador deepwater oil field is approximately 125 km from the coast of São Tomé Cape, Rio de Janeiro State, Brazil (Fig. 1). Reservoir depths range from 2900 to 3600 m below sea level. Roncador reservoirs are high-quality Cretaceous-age siliciclastic reservoirs with average porosity of 25% and average absolute permeability of 800 md. The field is divided into two large blocks separated by a major normal fault (Fig. 2), with oil gravity varying from 18 to 22°API in

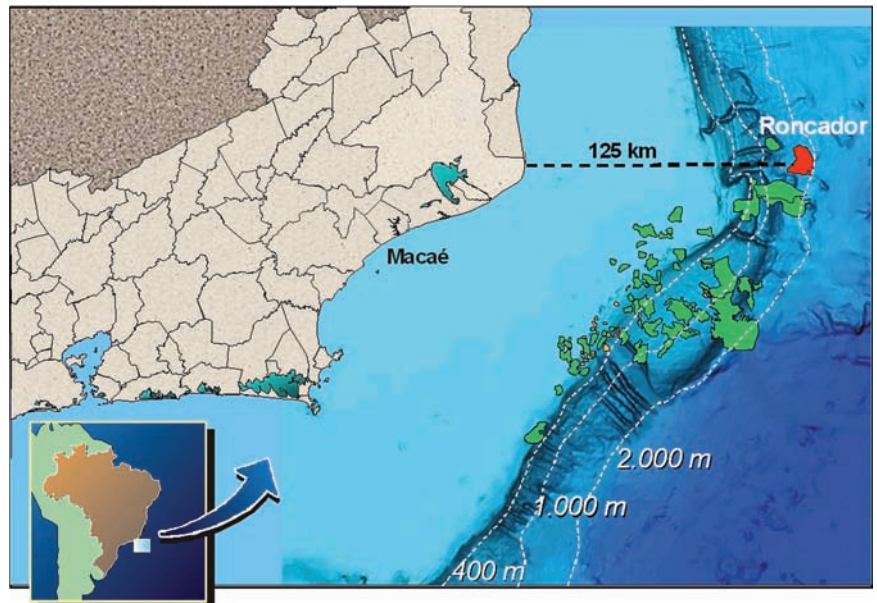


Fig. 1—Roncador field location offshore Brazil.

the footwall block and 28 to 30°API in hanging-wall block. The field resource volume is approximately 7.5 billion bbl. Estimated total recovery is 3.7 billion bbl of oil equivalent, with proven reserves of 3.0 billion bbl of oil equivalent.

Module-1 started production in May 2000 through semisubmersible platform P-36. Unfortunately, in March 2001, P-36 sank. Module-1 was renamed Module-1A and was divided in two phases. Phase-1 production started at the end of 2002 with floating production, storage, and offloading (FPSO) vessel *Brasil*. Phase 2 of Module-1A (P-52) and Module-2 (P-54), both with 180,000 BOPD capacity, started production at the end of 2007. Peak production of approximately 450,000 BOPD will occur by 2013, when all Modules (-1A, -2, -3, and -4) will be on production.

The newest drilling and completion technologies were used to achieve the project goals: field development by constructing good-quality wells with low price in the short term. Technologies and other well-construction strategies that contributed to success in the Roncador development are detailed in the full-length paper.

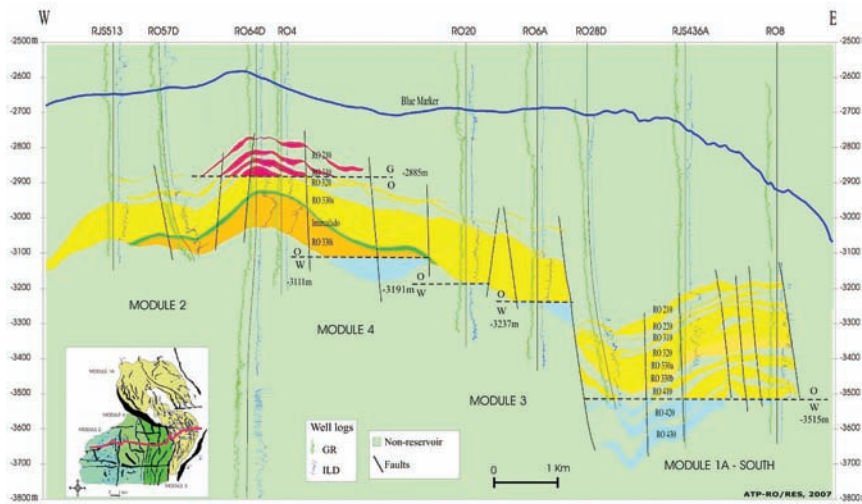
### Seismic, Geology, and Reservoir-Engineering Aspects

**Seismic.** The first 3D-seismic data encompassing Roncador field were acquired in 1992, but the acquisition parameters and processing routine were not sufficient for reservoir-characterization purposes. Two additional acquisitions occurred in 1999 and 2000, but did not cover the entire field. Specific reservoir-characterization 3D-seismic data covering all the Roncador reservoir area were pur-

*This article, written by Technology Editor Dennis Denney, contains highlights of paper OTC 19296, "Roncador Field Development: Reservoir Aspects and Well-Development Strategy," by L. Cysne and M.K. Mihaguti, Petrobras, prepared for the 2008 Offshore Technology Conference, Houston, 5–8 May. The paper has not been peer reviewed.*

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**Fig. 2—West/east structural geological section: footwall/hanging wall.**

chased. Also, during 2005, seismic data were acquired with four-component 3D ocean-bottom cable in a water depth of 1800 m.

The new seismic data improved interpretation of the main geological features significantly, as shown in **Fig. 3**. Seismic attributes were used extensively in geological modeling and to estimate petrophysical properties (e.g., porosity, permeability, and net-/gross-pay ratio) and geological facies.

**Geology.** The Roncador field has a normal-fault system (maximum 200-m throw), separating the field into two blocks, hanging-wall block (Module-1A area) and footwall block (Modules-2, -3, and -4). The traps are both structural and stratigraphic. Many oil/water contacts were identified in the reservoirs, but only one gas cap occurs, in the footwall block.

Reservoirs are turbidite sandstones of Maastrichtian age, dominantly massive, interbedded with shales and marls, exhibiting good porosity (24 to 30%) and permeability (400 to 5,000 md). Fluid distribution in Roncador reservoirs is complex. Light oil (28°API) saturates the deepest reservoirs in the hanging-wall block, and heavy oil (18°API) saturates the lowest reservoirs in the footwall block. There is clear evidence of originally sealing faults generating many compartments. To understand the fault-sealing characteristics and their effect on compartmentalization, geomechanical studies were conducted that confirmed the

main direction of sealing faults and pressure limits to fault reactivation.

**Geological Modeling.** Two geological and simulation models were generated, one for the footwall block and another for the hanging-wall block. The geological model was developed by integrating seismic surfaces and fault planes, seismic attributes, well-log and core-analysis data, depositional and stratigraphic models, and production data (e.g., pressures and fluid types). The use of a computational platform that was compatible with seismic interpretation and reservoir simulation was very important, resulting in rapid implementation and revision. Fast update of the geological and flow models during field development was required to support decisions related to drilling and well relocation and to prepare economic analyses and reserves estimates.

Seismic geomorphologic analyses of amplitude and impedance maps, seismic sections between wells, and proportional slices of seismic attributes enabled interpretation of the main heterogeneities and were entered into the geological and flow models. The most important heterogeneities were related to compartmentalization by faults and turbidity-body pinchout at the outer parts of the footwall-block reservoirs.

**Reservoir-Flow-Simulation Model.** Reservoir simulation was used to set up and adjust the Roncador field-

development plan and to estimate final recovery and production profiles. A commercial black-oil 3D three-phase numerical simulator with corner-point geometry was used. Multiphase flow along wells, lines, and risers was coupled to the simulation model. Gas lift optimization also was considered.

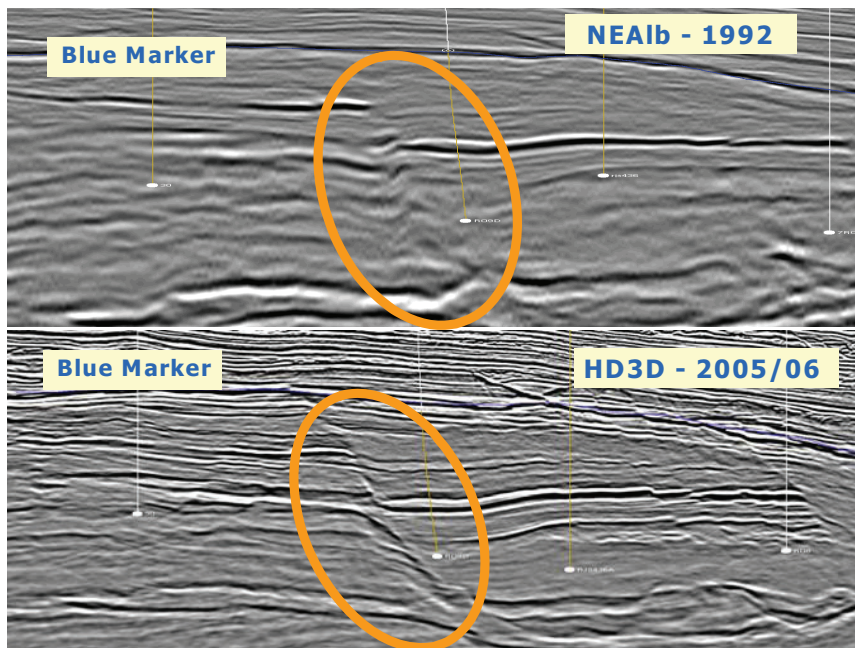
The simulation model was built from an overall reservoir framework, defined mainly from the 3D-seismic data and geological interpretations. The fault framework was used to model main geological heterogeneities. This feature was very important during the history-matching process. To maintain predominant flow directions, stratigraphic layering (proportional) was used in high-quality sandstones and structural layering (parallel to top) was used in lower-quality sandstones.

Well-productivity and -injectivity indices for the simulation model were estimated on the basis of analytical correlations and empirical corrections that were based on measured values. High calculated values of the indices were aligned with the maximum measured value to maintain a most-probable scenario in the project.

Relative permeabilities used in the simulation models were well defined on the basis of a vast core-analysis collection. After an initially inconclusive relative permeability study, specific cores were obtained from two new wells to resolve uncertainties about residual-oil saturation.

**Reservoir-Development Strategy.** Definition of each phase or module was based on compartmentalization, type of fluid in each compartment, and water depth. The lighter oil in the hanging-wall block was highest priority because of higher oil value; therefore, it was the first module of Roncador. Module-2 area was chosen because of its shallower water depth and less-corrosive fluids than the other areas, despite having heavier oil. Module-3 area received higher priority over the Module-4 area because of its lighter oil (22°API vs. 19°API, respectively).

The volume of oil in place, well productivity, long-term production behavior, and compartmentalization were confirmed with pilot production systems in each module area. This strategy reduced the risks of the projects significantly.



**Fig. 3—Comparison of 1992 and 2005 seismic acquisitions.**

The Module-1 pilot system confirmed technically the production viability in ultradeep water. Also, it confirmed viability of multiple-frac-pack technology, expected productivity, volume of oil in place, and hydraulic communication between all layers and blocks.

Two pilot systems in Module-2 confirmed the viability of large-bore/long-horizontal-extension-well technology, expected productivity, volume of oil in place, and hydraulic communication between all layers and blocks.

The pilot system in Module-3 confirmed expected productivity and injectivity, volume of oil in place, and hydraulic communication between the two main blocks.

Module-4 is an extension of Module-2 and, therefore, did not have a pilot system.

Several internal and external studies revealed that scale deposition in production wells and facilities could result from seawater injection and its interaction with formation water. To avoid such problems, sulfate-removal units were installed on all platforms of Roncador field.

All producing wells were equipped with downhole pressure gauges. These continuous downhole-pressure and -temperature data provide accurate information for performance monitoring, gas lift optimization, and reservoir management.

Another important strategy was to test all wells immediately after completion. This strategy enabled substantial improvements in adjusting and refining well placement in the reservoir. Also, this strategy reduced project uncertainty with better knowledge of variables such as effective reservoir permeability, well distance from reservoir barriers, well-productivity or injectivity index, and oil-production potential. Well-damage removal before first oil production has enabled avoiding additional rig expenses from mobilization and demobilization. After each well test, the new information was checked and the numerical flow model was updated.

#### Well Construction

A multidisciplinary approach in planning, geosteering, evaluation of pilot and horizontal wells, and incorporation of new technologies was a major factor for success. In Module-2, long horizontal wells (1,000-m horizontal extension) were planned and drilled extensively by use of seismic interpretations. Multidisciplinary 3D visualization for planning and real-time drilling monitoring was very important to reduce risks in well drilling. 3D visualization was very useful for predicting shallow hydrocarbon sandstones and for increasing optimization in well-trajectory planning. The use of logging-

while-drilling tools and specific software to support real-time planning and geosteering enabled real-time monitoring and decisions, reducing well re-drilling and improving horizontal-well net-pay penetration.

Pilot wells were drilled before the horizontal wells. This procedure enabled depth corrections in reservoir tops and bottoms and corrections in the planned well trajectory. After completion, all horizontal production and injection wells were tested, allowing full evaluation of the reservoir. As a result, many improvements in the next well-location plan could be implemented.

All this effort in planning, geosteering, and well evaluation resulted in better well placement, high horizontal-well net-pay penetration, improved well-production or injection index, reduced well re-drilling, and, consequently, an increase in project outcomes.

#### Conclusion

A 3D-seismic-acquisition program for reservoir characterization was very important for successful project planning and implementation. Also, conventional and special-purpose processing of seismic data enabled several interpretations of reservoir heterogeneities, allowing a complete geological view of the reservoir. Seismic attributes were an important tool to improve geological modeling.

The use of a computational platform that was compatible with seismic interpretation, geological modeling, and flow simulation resulted in fast update of the geological and flow models as required for planning field development (i.e., decisions related to drilling and well relocation) and for preparing economic analyses and reserves estimates.

For directional drilling, the use of rotary-steerable systems and pressure-while-drilling tools was mandatory for operational success in well construction. The frac-pack technique was very effective in Module-1, maintaining the original well-productivity index.

Development of a washpipe-free frac-pack assembly and improved frac-pack operation was essential for multiple selective wells in Module-1. Long gravel-pack completions in horizontal wells were effective to produce reservoirs with medium permeability and high-viscosity oil (e.g., 18°API oil of Roncador Module-2). **JPT**

## Troll West Oil Field—A Giant Gas Field Becomes the Largest Oil Field on the Norwegian Continental Shelf

The Troll West oil field has been developed with more than 110 horizontal sub-sea wells including 53 multilateral (ML) wells. The thin oil rim was developed through extensive use of multilateral drilling and wells containing up to 7 horizontal branches. The process of drilling the ML wells and the benefit/risk evaluation for the ML process are discussed.

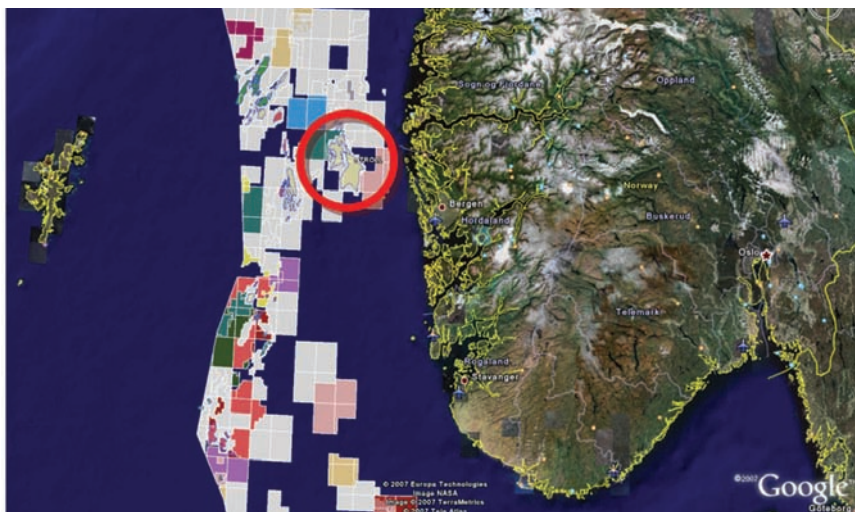
### Introduction

The Troll field is offshore Norway on the Norwegian Continental Shelf (NCS) in 300-m water depth, as shown in **Fig. 1**. The field was discovered in 1979 and covers an area of 750 km<sup>2</sup>. Drilling of the production wells began in 1994, and production began September 1995. Oil production to September 2007 was 188.3×10<sup>6</sup> m<sup>3</sup> of oil, all from horizontal wells. The 250 horizontal sections have drilled 900 000 m, including 560 000 m of reservoir section.

### Field Description and Challenges

Gas and oil are found mainly in the Sognefjord formation and in the underlying Fensfjord formation. The oil in the Troll West is from a 22- to 26-m thick oil column under a small gas cap. In the Troll West gas province, there is a 12- to 14-m-thick oil column and a gas column up to 200 m thick. The Troll reservoir sands are of two distinct types, with

*This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 112616, "Troll West Oilfield Development—How a Giant Gas Field Became the Largest Oil Field in the NCS Through Innovative Field and Technology Development," by Richard Dyve Jones, StatoilHydro, and Erland Saeverhagen, SPE, Arve K. Thorsen, SPE, and Sveinung Gard, SPE, Inteq, prepared for the 2008 IADC/SPE Drilling Conference, Orlando, Florida, 4–6 March. The paper has not been peer reviewed.*



**Fig. 1—Troll field is on the NCS.**

large grading between. The C sand is a clean coarse sandstone, with permeability ranging from 1 to more than 10 darcies. The M sand is micaceous, with a finer grain size than the C sand, and, in general, has permeabilities in the range of 1 to 100 md. The sorting in this sand is poorer than in the C sand; therefore, the permeability is less.

**Recovery Strategy.** Oil production is through long horizontal wells drilled just above the oil/water contact (OWC) in the thin oil zone. The main recovery strategy is pressure depletion, but with simultaneous expansion of the gas cap above and the water zone below the oil. In the Troll West oil province, some of the gas produced has been injected back into the reservoir to optimize the oil production. One important aspect is to recover the oil quickly, because less oil can be extracted when the pressure declines in Troll East. Therefore, limits were placed on gas extraction from Troll East.

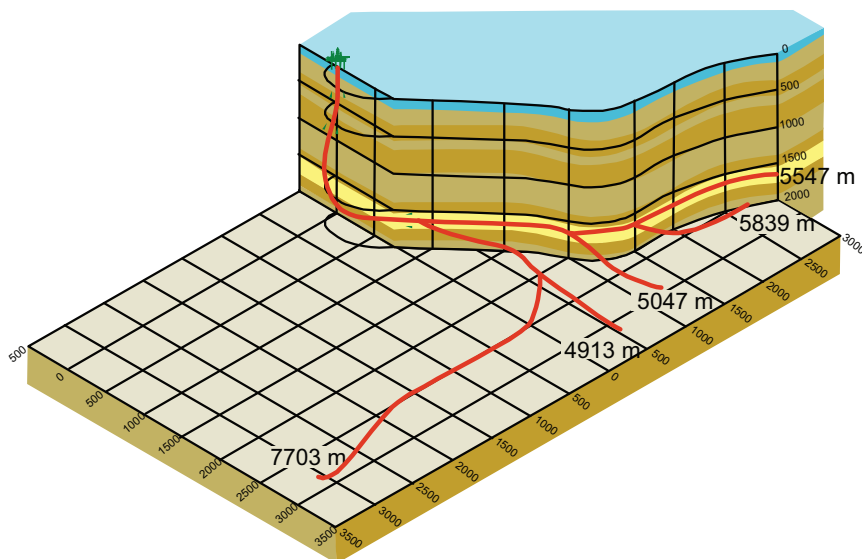
**Main Drilling and Logging Challenges.** Initially, the main concern was

gas coning from the gas cap above the oil column. Several methods were initiated to ensure drilling horizontal wells within acceptable tolerances. The development of 3D rotary-steerable systems (RSSs) and logging-while-drilling (LWD) technologies, together with an enhanced understanding of the drilling environment, led to high production rates. The logging challenges were to acquire high-quality logs along several thousands of meters of reservoir in a harsh drilling environment.

### Drilling, Measurement-While-Drilling (MWD), and LWD Service

From early 1990, the development pace of new technology for the Troll field resulted in many technological breakthroughs, including the instrumented motor, 3D-rotary-closed-loop-steerable (RCLS) system, and RCLS system with an integrated positive-displacement motor (PDM). However, the most important achievement was the increased precision in well placement and horizontally drilled sections.

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**Fig. 2—Schematic of the longest well on Troll, including several openhole laterals.**

**Instrumented PDM.** In 1992, before contract award for drilling on the Troll West oil province, it was decided to fund further development and building of the instrumented-PDM concept. Technical breakthroughs included the following.

- Highly precise “gun-barrel drilling” of the PDM stator housing. A hole through the stator housing allowed electrical cable to be run between the sensor sub and the rest of the MWD suite.
- A combined multifrequency-resistivity/gamma ray tool was developed.
- A near-bit inclination sensor was placed in the navigation assembly 5 m from the bit and was merged with the motor section.

### 3D-RCLS System or 3D RSS

A large improvement in drilling was achieved with the use of a 3D-RCLS system, after steering control by sliding the instrumented motor became almost impossible with a conventional drillstring. Sinusoidal and helical buckling was common with the drillstring while sliding, but drilling progress could continue with rotational drilling. To extend reservoir sections and further optimize well placement in the reservoir, the RCLS system was used to deliver the required extension of horizontal sections, allowing for more-accurate placement of the sections in sands with the highest production.

**Precision Well Placement.** With the 3D-RSS bottomhole assemblies (BHAs),

the true-vertical-depth window was reduced from  $\pm 1$  m to  $\pm 0.5$  m, and then further reduced to  $\pm 0.3$  m with the third-generation 3D-RSS BHA. Therefore, no drilling in sliding mode was required.

**LWD Services.** The LWD comprised gamma ray, resistivity, and density/neutron-porosity tools. At first, single gamma measurements were used, ignoring different layers. The analyses improved with the ability to transmit high-side and low-side gamma ray data in real-time. Although it was a time-consuming procedure the first year, it provided vital information when making flat turns to optimize well trajectory. Later, the gamma measurement became fully azimuthal in real time, and both image logs and sectored-gamma measurements are available in real time, improving the structural interpretation and allowing for real-time verification of the model and adjustment of the wellbore trajectory.

**Resistivity Measurements.** Because the wells were drilled at a set distance above the OWC in the best sands, a fixed resistivity value was determined to indicate the correct position, so steering on resistivity was used. Using the resistivity as the main steering criterion requires highly accurate resistivity measurements. In clean thick sandstones with uniform properties, the resistivity value will be constant over some lateral distance. When the rock

properties change, the logging responses must accommodate those changes.

The interpretation of resistivity is most important to understand the distance to the OWC, and to derive the true resistivity of the area being drilled. High focus on the resistivity accuracy and resistivity interpretation is maintained in the Troll field. Other logging systems detailed in the full-length paper include the gamma ray, resistivity, and density/neutron-porosity data; wellbore images; acoustic LWD measurements; formation-pressure and mobility measurements; and azimuthal-propagation resistivity data.

### Integrated Working Operations

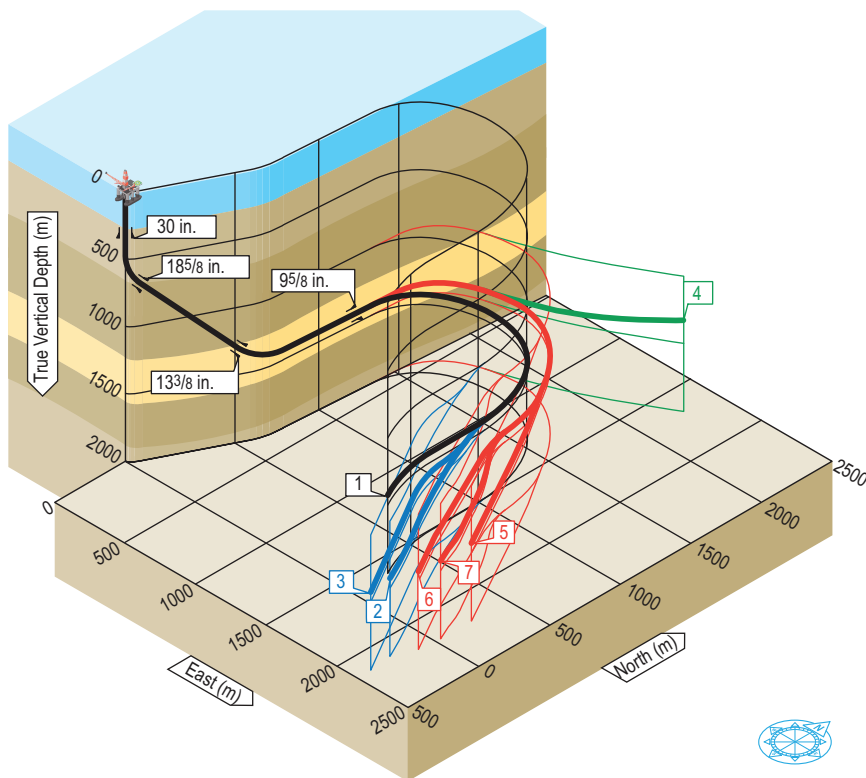
Working processes were developed to use new technology. One key element when assessing integrated and real-time operations from locations other than the rig site was to develop attractive working conditions and give responsibility and demanding work tasks to the onshore personnel. The success of the integrated operations on Troll has taken the process further, and increased focus has been placed on more-complex and -demanding integrated operations.

### Drilling-Optimization Development

Landing in small targets in the reservoir is necessary for optimal placement of the multilateral junctions. The reservoir formations drill easily and range from loose, almost-unconsolidated sandstones to very hard calcite-cemented stringers. The harder zones are scattered in the field and sometimes very hard to map. The drilling rate in such formations can change instantaneously from 100 m/h to  $<1$  m/h, significantly affecting drill-bit life and well placement and possibly the BHA and drillstring.

### Task Force 1 and 2, Troll Performance Group, and Total System Approach

After a few years of using the 3D-RSS drilling systems, two task-force work groups, called Troll Task Force 1 and Troll Task Force 2 (TTF1 and TTF2, respectively), were initiated. TTF1 was established to determine and identify the drilling challenges in the reservoir sections with respect to the new method of drilling. TTF1 gathered and analyzed the results and lessons learned from the drilling with respect to TTF2. In the second phase, the BHA design and the drillbit design and use were



**Fig. 3—Schematic of the first seven-leg well on Troll; five legs were drilled as openhole laterals.**

studied in detail, and appropriate drilling practices were established.

Shortly after TTF1 and TTF2 were dissolved, a decline in performance was experienced, possibly because of the change in operational focus. TTF1 and TTF2 decided that the service provider should take ownership of and responsibility for total drilling-system performance. This was done through a new work process, implementing multidisciplinary personnel across the service-provider divisions in the Troll Service-Provider Group late in 2002.

A downhole drilling-dynamics and diagnosis tool provides the drillers, directional drillers, drilling supervisors, and optimization engineers a more active role in the drilling process through a better understanding of the complex drilling environment.

A work process called Total System Approach evolved. Close cooperation between service-provider and operator personnel and drilling departments was crucial. Close collaboration in this process led to better common understanding of the Troll-field drilling challenges by all parties, and it led to design and use of application-specific BHAs and application-specific drilling practices and procedures.

### Drilling Fluids

Several initiatives were taken to match drilling fluids to the increased wellbore complexity. One significant objective is to drill the wells with lightweight fluids. Before 2003, reservoir sections were drilled with water-based mud having a specific gravity (SG) of approximately 1.25. This value posed a potential problem as the reservoir-section lengthened leading to well-hydraulic problems. In 2003, a much lighter mud was introduced. The lighter drilling fluids were vital for horizontal sections up to the current longest reservoir section of 5500 m. Currently, wells usually are drilled with 1.12-SG mud, which facilitates drilling and maximizing production in the less-permeable M sands in the field.

### ML Technology

The first ML well was drilled in Troll in 1997. Now, all wells are drilled as MLs, and the number of legs on each well has increased. The first ML wells were single-junction wells, with one main bore and one sidetrack through the premilled window. The next step was wells with up to three predrilled windows, yielding four completed lateral legs. A study has shown that, so far on

the Troll field, no well or wellbore has been lost with ML solutions. ML wells are considered a proven concept in the Troll field. ML wells have boosted production significantly.

### Openhole Sidetracks

Openhole sidetracking began in 2003, and has increased the drainage area further. By use of a ramp as support, a groove was reamed on the low side to kick off the lateral. The whole process usually required 8 to 16 hours, depending on the drillability of the formation in the sidetrack region. Later, the use of ramps was discontinued. Continuous geosteering enabled selecting an optimal point for sidetracking. Sidetracking flat horizontal areas, or even downhill, is possible. The main wellbores usually are left open, with no completion or screens installed. At the time this paper was written, none of the laterals seem to have collapsed, and seismic data have shown the drainage to function properly from those open laterals. Because of these experiences, the simplicity, and the low cost of these openhole sidetracks, this method is a standard part of well planning for the Troll field. A total of 41 openhole sidetracks have been carried out flawlessly on Troll (Figs. 2 and 3), and the method is used in several other fields.

### Future Technology Needs

The Troll field has a large amount of unrecovered oil reserves. Further technology development is necessary to realize the drainage potential economically. A dynamic process is in place, and further enhancements and developments are being implemented or planned in the near future. A thorough understanding of the goals for the Troll development is needed to tailor the technology development toward the direct needs. These goals can be achieved through the following.

- Real-time network and competence use; true enhanced integrated operations
- More and better proactive well placement
- Integrated work processes
- Drilling and completion efficiency
- New-technology development
- Global competence use
- Improved seismic imaging
- Direct hydrocarbon-indicator technologies
- Confident lithology and fluid prediction

**JPT**

## Offshore Atlantic Canada—Regional Overview

An overview is presented of current and planned offshore exploration, development, and production activity off the east coast of Canada. Petroleum-related research is taking place and is being applied to offshore development and production.

### Introduction

Atlantic Canada is the eastern region of Canada that comprises four provinces: New Brunswick, Prince Edward Island, Nova Scotia, and Newfoundland and Labrador. Current activity offshore Nova Scotia and Newfoundland and Labrador, is shown in **Fig. 1**. Four offshore fields are in production, and agreements with governments are being finalized for development of a fifth field. The area is a high-cost, high-risk environment with challenges presented by harsh weather conditions, remote drilling locations, and limited infrastructure. Much of the region is relatively unexplored and considered frontier area. Research, development, and new technologies have been key in advancing the industry.

The Newfoundland and Labrador offshore area has three fields in production: Hibernia, Terra Nova, and White Rose. Resource estimates on the Hibernia and White Rose fields have been revised as a result of positive drilling results in nearby satellite fields, and plans are

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**Fig. 1—Map of the Newfoundland and Labrador and the Nova Scotia offshore areas.**

under way to develop the additional resources.

Offshore Nova Scotia was the site of Canada's first offshore oil field, Cohasset Panuke. Production began in 1992, and the field ceased production in 1999. There is one offshore natural-gas field in production offshore Nova Scotia—the Sable Offshore Energy Project. Development of a second gas field, Deep Panuke, was sanctioned in October 2007 and is expected to reach production in 2010. Only a small amount of offshore petroleum-exploration activity has taken place offshore Prince Edward Island, with no significant discoveries.

### Offshore Production

**Nova Scotia.** The Sable Offshore Energy Project is 250 km from Halifax, Nova Scotia, and began production on 31 December 1999. The project deliv-

ered more than 500 MMcf/D of natural gas in the early years of production, decreasing to 375 MMcf/D in 2006. A compression platform was built in 2006–07 that returned production to 400 to 500 MMcf/D in 2007. Production is expected to continue at this level throughout 2008 and then begin to decline. Production is from five separate fields. The most recent public declaration of project reserves, January 2004, estimated the recoverable gas at 1.4 Tcf.

Nova Scotia's next field developed, Deep Panuke, received project sanction in October 2007. The project is expected to deliver 200 to 300 MMcf/D of natural gas to markets in Canada and the US. Recoverable sales-gas reserves are estimated to be between 390 and 892 Bcf, with a mean estimate of 632 Bcf. The mean production profile indicates a life of approximately 13 years, starting in

The full-length paper is available for purchase at OnePetro: [www.onepetro.org](http://www.onepetro.org).

late 2010. A 176 km pipeline will bring gas ashore from Deep Panuke, connecting with the Maritimes and Northeast Pipeline onshore pipeline at a tie-in point near Goldboro, Nova Scotia. The project also includes a mobile offshore production unit and subsea infrastructure.

**Newfoundland and Labrador.** The Newfoundland and Labrador offshore area produces more than 300,000 BOPD, representing 11.4% of Canada's total crude-oil production. There is an estimated 2.7 billion BO, 10.2 Tcf of natural gas, and 478 bbl of natural-gas liquids discovered offshore Newfoundland and Labrador. The natural gas is not yet being produced commercially.

Newfoundland and Labrador's first offshore oil field, Hibernia, began production in 1997, although it was discovered almost 20 years earlier. The offshore production facility is a concrete-gravity-base structure. It is estimated that Hibernia contains more than 1.4 billion BO and 1.794 Tcf of gas. In 2007, the production level was 140,000 BOPD (gross average). Positive drilling results in southern areas of the Hibernia reservoir were announced in 2006, and development-plan approval is being sought.

The second offshore oil field, Terra Nova, was discovered in 1984, with first oil produced in January 2002. The Terra Nova project uses a floating production, storage, and offloading (FPSO) system. Recoverable reserves are estimated at 354 million BO and 0.45 Tcf of gas. Average production in 2007 was 116,000 BOPD.

White Rose was discovered in 1984 and began production in December 2005. Similar to Terra Nova, the offshore production facility is an FPSO. White Rose is estimated to contain 283 million BO and 2.7 Tcf of gas. Three satellite fields containing a combined 214 million BO were discovered later, and a framework agreement to expand the project to include the satellite fields has been reached with governments.

Newfoundland and Labrador's next potential development project, Hebron, was discovered in 1981. Project owners are negotiating formal binding agreements with government to bring this field into production. Hebron is estimated to contain 581 million bbl of heavy oil.

#### **Future Exploration and Potential**

**Newfoundland and Labrador.** Exploration wells are expected to be drilled

in 2008 in the offshore Jeanne D'Arc basin, the site of Newfoundland and Labrador's three currently producing projects. Small-field tie-backs to the current production facilities in this basin are possible, with 46 significant fields already discovered in the basin. There are 32 active exploration licences in the area, with at least one seismic program to be conducted in the basin in 2008.

The Laurentian basin, south of the island of Newfoundland, is an area of interest for future exploration. The basin is relatively unexplored because the region was under a boundary-dispute moratorium until recently. Similar to the other basins, the Laurentian basin is a harsh and high-risk environment but is unique in that it is an iceberg-free zone. Two seismic programs were conducted in the basin in 2005. Exploratory drilling is being considered for 2009.

The Orphan basin, 390 km northeast of St. John's, will have exploration activity in the near future. The exploration well was spudded in August 2006 and was completed in April 2007. No results have been released. The well is in 2338 m of water. A second well could be drilled in 2008-09, pending rig availability and owner/regulatory approval.

There are technical and economic challenges associated with developing natural gas in these areas, including the harsh offshore environment, distance from consumers, and lack of infrastructure to transport natural gas. Nonetheless, interest in the Labrador offshore area, which had high levels of exploration activity in the late 1970s and early 1980s, seems to be rising.

**Nova Scotia.** The Government of Nova Scotia estimates that its offshore area contains in excess of 40 Tcf of gas over an area of more than 400 000 km<sup>2</sup>. The area is attractive because it is within 1000 km of northeastern US. The area comprises three main basins: the Scotian basin, a portion of the Sydney basin, and the Orpheus basin. No exploration activity took place offshore Nova Scotia in 2007. A lack of exploration success in recent years has led to reconsidering geological assumptions about the area. Nova Scotia has invested heavily in research to learn more about the geology of the area.

#### **Research and Development**

Atlantic Canada's research-and-development community is an integral part of oil and gas development in the region.

Offshore activities in these areas require innovative technologies to meet challenges of the harsh marine environment and distance to market. Many research-and-development organizations, post-secondary educational institutions, and oil and gas supply and service companies and producers are involved in research and development.

#### **Regulatory Environment**

Two offshore petroleum boards were established in 1985 to administer relevant provisions of the legislation governing the offshore area. The Canada/Newfoundland and Labrador Offshore Petroleum Board and the Canada/Nova Scotia Offshore Petroleum Board are federal/provincial authorities responsible for managing the petroleum resources in the Newfoundland and Labrador and the Nova Scotia offshore areas, respectively. Members of the boards are appointed by the provincial and federal governments, and the boards report to those two governments.

Board responsibilities include the sale of interest in lands; issuing exploration licences, approvals, and authorizations related to exploration activities; and declaring significant and commercial discoveries. The boards also have the responsibility to approve industrial-benefits plans and to monitor and evaluate health, safety, and environmental programs. The boards mostly operate autonomously in making decisions, but some decisions are subject to approval by federal and provincial energy ministers. These decisions may include such matters as development-plan approvals, extraordinary powers such as directing an interest holder to drill a well, and rights issuance.

The Governments of Newfoundland and Labrador and of Nova Scotia set policy direction for the provinces related to oil and gas development. The Government of Canada also has a role in regulating the offshore petroleum industry in Atlantic Canada. Various pieces of legislation must be adhered to by petroleum companies working in the offshore environment in eastern Canada. This legislation is aimed primarily at protection of the environment and includes legislation governing environmental assessments, protection for species at risk, and ocean discharge. Other federally regulated areas include safety-related legislation as it pertains to marine safety of personnel and vessels. **JPT**