Tahiti: Development-Strategy Assessment

The Tahiti field in the deepwater Gulf of Mexico (GOM) is a three-way anticlinal structure trapped against salt. The discovery well was drilled in 2002, and two appraisal wells were drilled soon afterward. Because of significant uncertainties remaining after appraisal, probabilistic methods were used to assess development alternatives. A classical experimental-design method was applied, and reasonable reservoir-simulation models were designed and validated. The proposed workflow enhances use of experimental design by combining the technique with response-surface methods and rational engineering judgement.

Introduction

Tahiti field is in more than 4,000 ft of water in the Green Canyon area of the GOM, approximately 190 miles southwest of New Orleans. The field was discovered in April 2002 with the drilling of Well GC 640-1. Results from the exploratory well indicated the presence of high-quality reservoir sand with more than 400 ft of total net pay distributed in three main Miocene turbidite sheet sands at depths ranging from 24,000 to 27,000 ft true vertical depth. In 2003, two appraisal wells were drilled simultaneously. One of the appraisals encountered more than 1,000 ft of net pay in high-quality sandstones, confirming one of the most significant net-pay accumulations in the history of the deepwater GOM. The field will be developed in phases. The first development phase was sanctioned in August 2005 by Tahiti joint-venture partners Chevron, Statoil, and Shell at a cost of more than U.S. $1.8 billion. Total capital costs for the project are anticipated to be approximately U.S. $3.5 billion. The field is expected to come on line in mid-2008. Because of significant uncertainties, probabilistic methods were used to assess development alternatives during Phases 2 and 3 of Chevron's project-management process. The main purpose of this study, part of Phase 3 (Develop Preferred Alternatives), was to assess a mature predevelopment strategy.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 100656, "Tahiti: Development-Strategy Assessment Using Design-of-Experiments and Response-Surface Methods," by ***P.E. Carreras,*** *SPE,* ***S.E. Turner,*** *SPE, and* ***G. Wilkinson,*** *SPE, Chevron, prepared for the 2006 SPE Western Regional/AAPG Pacific Section/GSA Cordilleran Section Joint Meeting, Anchorage, 8–10 May.*

Reservoir Description

The Tahiti prospect was identified by use of advanced subsalt 3D-seismic imaging technology, along with geologic-data interpretation to identify the presence of reservoir-sand development, hydrocarbon charge, and migration into a geologic trap. The trap tested by the discovery well is a three-way anticlinal closure truncated against a salt feeder/weld system buried beneath an 11,000-ft-thick subsalt canopy **(Fig. 1).** On the basis of seismic data and appraisal wells, the trap is estimated to extend approximately 5 miles in a north-to-south direction and 1.5 miles in a west-to-east direction. Main reservoirs are Lower to Middle Miocene.

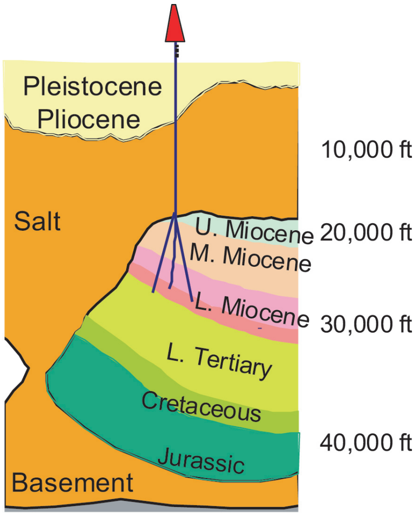

Fig. 1—Trap and salt canopy.

DOE Methodology

Design of experiments (DOE) is a methodology that reduces the number of reservoir-simulation runs that must be generated to develop equations for response variables. The response variables usually are economics parameters such as oil recovery or net present value (NPV). DOE provides not only a systematic framework for unbiased decisions but also technical continuity to the study. The understanding of field dynamics increases as the project evolves. The DOE workflow applied in this study comprises nine steps.

Step 1—Identify Uncertainties. A thorough analysis of some uncontrollable uncertainties was performed in a previous paper. A new set of Earth models was developed as part of Tahiti Phase 3 work. The static DOE study results were used to select five Earth models for the dynamic DOE study.

Reservoir anisotropy, rock compaction and dilation, fluid characterization, skin factor, and well pressure drawdown were identified as having minor effects in project economics during Phase 2 work. Accordingly, these factors were modeled with midvalues in this study.

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Step 2—DOE Reservoir-Simulation Runs. The experiments were modeled by use of full-field reservoir simulation. Many test predictions were run to determine near-optimum well counts for the low, middle, and high Earth models.

Reservoir Model. The reservoir model is limited to the west by the saltface location and to the east by the aquifer. The fine-scale Earth model that contained more than 3.5 million cells (182×193×101 cells) was scaled up to form a coarse grid with 280,529 cells (53×69×67 cells) to improve run-time efficiency. Vertical coarsening was implemented for the top and the bottom reservoirs. The intermediate reservoir comprised only four fine layers that were kept in the coarse grid. The shale between consecutive reservoirs was captured with a separate layer.

All reservoirs contain a highly undersaturated crude oil; consequently, a black-oil reservoir-simulation option was used. As in Phase 2, primary depletion and waterflood were evaluated as possible development scenarios.

Individual-well flow tables for 5^1/2-in. tubing were used to model flow from the reservoir to the surface. Flow tables were included to accurately model fluid deliverability late in the life of the reservoir. Predictions were run for 20 years with no field-level economic limits.

First Round of DOE Runs. Plackett-Burman (PB) is a two-level design that attempts to estimate linear effects or the constant rate of increase or decrease of the response variable as the uncertainty parameters increase from low to high. The PB matrix was generated for nine uncertainty parameters. A center-point run that combines midvalues of all uncertainty parameters was performed to estimate the curvature of the response surface.

A Pareto chart was used to rank the effect of each reservoir uncertainty. The uncertainty parameters that affect the response variables with a 95% level of confidence were selected for further analysis.

Step 3—Rank Uncertainties. The effect of uncertainty parameters on the response variables can be visualized with the normalized Pareto chart. As expected, for a new field development like Tahiti, the Earth model and the location of the water/oil contact (WOC) have the most important effect on oil recovery. Other influential variables are field compartmentalization, pore-volume compressibility, and aquifer support. Pore-volume compressibility emerges as the main effect when the field is developed with primary depletion.

Step 4—Generate Response Surface. Use of a multiple linear regression to model the response surface is common practice in DOE. The technique uses the least-squares method and other standard statistical testing to quantify the relationship between the input variables and the output response.

Step 5—Identify P10, P50, and P90 Values of Response Variable. The probabilistic distribution functions of the response variables are obtained by assigning either discrete or continuous density-distribution functions to the uncertainties and applying Monte Carlo sampling on the polynomial model. P10, P50, and P90 oil recoveries and discounted oil recoveries were obtained from the cumulative distribution function. Commonly, PB and D-optimal design (DOD) estimates of P10, P50, and P90 values of the response variable differ slightly. DOD gives the most precise estimate of the response variable.

Step 6—Generate P10, P50, and P90 Reservoir-Simulation Models. Reservoir-simulation models and well counts were developed that mimic oil recovery and discounted oil recovery simultaneously for primary depletion and waterflood. The reasonable option was to use low, middle, and high Earth models to match corresponding P10, P50, and P90 oil recoveries.

Two steps were required to develop representative P10, P50, and P90 reservoir-simulation models. First, the location of the WOCs was modified to match P10, P50, and P90 original-oil-in-place (OOIP) values. Second, by modifying the statistically most significant parameters, the simulation results were fine-tuned to match P10, P50, and P90 oil-recovery figures.

Step 7—Assess Development Alternatives. Tahiti field-development planning was framed in Phase 2. However, the permanent team strategy is to add value to the decision-making process by optimizing the future capital investments and general economics of the project. Consequently, it was deemed necessary to re-evaluate field-development alternatives in Phase 3.

The preferred development strategy assumes commingled production. A phased development is planned to reduce the risk of overdrilling. On the basis of the expected time to first oil and drilling times, the decision was made to have six wells available before first oil. Low, middle, and high well counts consisted of seven producers/two injectors, nine producers/three injectors, and 14 producers/four injectors, respectively.

Surveillance data from the initial development wells will be collected for approximately 1 year before any further development decisions. The number and timing of additional producers or water injectors will depend on production performance and further reservoir assessment. In addition, each well requires approximately 6 months to drill and complete. On the basis of the current interpretation of faulting and OOIP distribution, the water injectors probably will target the southern portion of the field.

Step 8—Make Second Round of DOE Reservoir-Simulation Runs. The development plan was examined by performing a second round of DOE runs with uncontrollable uncertainties and decisions as factors. The critical uncontrollable uncertainties from the first round of DOE runs were consolidated into three factors: OOIP, reservoir energy, and faulting. OOIP groups the Earth model and the WOC location (i.e., the pessimistic Earth model was grouped with the pessimistic WOC). Project decisions such as well count and producer and injector timing were included in the design as well. The most convenient way to estimate the necessity of injection was to carry on independent designs for primary depletion and waterflood.

In this set of experimental runs, a coupled reservoir/wellbore/surface network simulation was implemented for the dynamic modeling of producer/facility behavior. The network included two subsea production manifolds. All production arrived topside by import risers from the center well of the spar hull. Total production from the field was limited by the processing capacity. Injection was modeled with individual-well flow tables.

Step 9—Use Response Surface To Explore Multiple Scenarios. Response surfaces for oil recovery and NPV were determined for the second set of DOE runs. NPV was selected as the financial yardstick and computed with the Tahiti Decision Analysis economic model.

OOIP (Earth model and WOC) and faulting affect oil recovery and NPV the most. The uncertainty in reservoir potential and in compartmentalization will not be reduced significantly until production data are acquired.

The effect of the number of producers on oil recovery is ranked in third place. The negative effect of drilling fewer producers is especially noticeable. However, the number of producers is ranked as having a meaningless effect on NPV. The conclusion is that drilling more producers would increase the final oil recovery, but the production would come late in field life with negligible economic effect.

The effect of energy (pore-volume compressibility and aquifer support) on NPV is ranked in third place. Waterflooding costs affect project economics. Again, in this case, the necessity of waterflood will be resolved when production data are acquired.

Finally, the polynomial response models were used to explore multiple scenarios by varying decisions across the whole range of uncontrollable uncertainties. On the basis of experience, the polynomial models stimulate question-and-answer discussions and contribute to a better understanding of the main project uncertainties.

Because of the high cost of Tahiti wells, well-count optimization is a critical success factor. Full field development will require seven to 14 producers and a maximum of three injectors. DOE, using an unconstrained and a constrained scenario, consistently identified nine producers and three injectors as the preferred development strategy, providing robustness to the decision. However, because well production rates computed by reservoir simulation were optimistic compared with analogies, the technical recommendation was to include 13 producers and three injectors in the base case well count.

Summary and Conclusions

The main purpose of this study was to assess a mature predevelopment strategy for Tahiti field. The classical experimental-design method was applied, and reasonable P10, P50, and P90 reservoir-simulation models were designed. Next, a second round of DOE runs with uncontrollable uncertainties and decisions as factors was performed on the development plan with the goal of validating that the previously selected models reasonably represented P10, P50, and P90 oil recoveries and NPV after including decisions in the design. The validation worked out properly, reinforcing confidence in the model selection. Finally, the polynomial response models were used to explore multiple scenarios by varying decisions across the whole range of uncontrollable uncertainties. JPT