The key to successful development planning is the building of earth models integrating all relevant subsurface data and predicting reservoir performance in the presence of uncertainties.

The development of Bonga Field is presented as an example of integrated subsurface modeling of complex, deep-water channel reservoirs in which geophysical techniques are highlighted. Three main static reservoir parameters were modeled in detail: net sand distribution, subseismic channel architecture, and reservoir connectivity.

Proprietary probabilistic, model-based seismic inversion has provided excellent predictions of net sand thickness in development wells in the main reservoir, adding confidence to the in-place oil volume assessment. However, because of limits to seismic resolution, all potentially relevant sand and mud beds cannot be visualized from (inverted) seismic data alone. Consequently, subseismic channel architectures have been deterministically placed in the static models based on analog and well data and guided by seismic attributes. Connectivity is especially important because pressure support and sweep from water injection wells is crucial to productivity from these near-hydropres- sured reservoirs. Reservoir connectivity is defined as a function of horizontal and vertical permeability, and transmissibility barriers. Analysis of seismic equal-amplitude surfaces is a way seismic can potentially help indicate areas of relatively better or worse connectivity. Each reservoir is simulated multiple times using scenarios based on all combinations of the above parameters. Highly amalgamated channels are less impacted by connectivity variation than less well amalgamated channels. Reservoir simulation models have been transferred to synthetic seismic models and demonstrate the potential value of time-lapse (4D) seismic. Other “in-field opportunity” reservoirs have been identified in addition to the main reservoirs, and might add to production in the future.

Exploration history. Bonga Field is currently under development 120 km offshore the southwestern coast of Nigeria, in water depths of 3100-3800 ft (Figure 1). It is in Block OML 118, formerly OPL 212, and operated on behalf of the Nigerian National Petroleum Corporation by Shell Nigeria Exploration and Production Company (55%) in partnership with Esso Exploration and Production Nigeria (Deepwater) (20%), Nigeria Agip Exploration (12.5%), and Elf Petroleum Nigeria (12.5%).

A 3D seismic survey containing 1814 km² of full fold data was acquired in 1993. The Bonga-1 discovery well, drilled and tested between September 1995 and January 1996, encountered oil in a series of turbidite sands of Upper to Middle Miocene age. Four main oil-bearing reservoirs (690, 702, 710/740, and 803 reservoirs), occurring between 6000 and 10 500 ft subsea, contained significant net oil pay (Figure 2).

During appraisal, production tests were conducted in the 690 reservoir in Bonga-3ST1; the 702 and 803 reservoirs were tested in Bonga-1 and Bonga-2ST3. Bonga-2ST3 and Bonga-3ST1 produced oil at rates greater than 10 000 b/d. A feasibility study from January to December 1997 was followed by a field development plan leading to project sanction by the end of 1999. Development drilling of 14 production and water injection wells is now ongoing along with construction of production facilities. First oil production is expected by the end of 2003 to early 2004.

Crude evacuation from the field is planned through a subsea manifold/wellhead and flowline/riser system connected to a floating production, storage, and offloading system (FPSO). The FPSO will have a processing capability of 225 000 b/d with a storage capability of 2 million bbls, making it one of the largest FPSOs in the world. The water injection capacity is some 300 000 bbls of water per day with 170 million standard ft³/d gas handling capacity. The gas produced will be sent via pipeline to the Nigerian Liquefied Natural Gas plant at Bonny.
The Bonga structure is a south-plunging anticline cored toward the north as the mud diapir is approached. The are present at the crest of the structure, and are more prevalent toward the north as the mud diapir is approached. The mobile shale forms a diapiric structure (Figure 3).

The largest reservoir is the 702 sand. A seismic amplitude map draped on a 3D structure surface of the 702 sand illustrates some general aspects of the Bonga accumulation. The Bonga sands are unconsolidated and interpreted to have relatively weak aquifer support. In addition, because of high drilling costs in this deepwater setting, the field is planned with relatively little appraisal drilling, and the development well spacing is also sparse (averaging 1-2 km between injection and production wells).

The principal subsurface challenges in these types of reservoirs are: understanding the distribution of thick, high-quality reservoir sands, and understanding the reservoir connectivity and sweep efficiency between injection and production wells. These parameters impact assessment of oil-in-place, recoverable volumes, and, in combination with structural configuration, directly influence well count and location. Figure 4 simply illustrates the development concept for Bonga with reference to the entire network. Continuity through the waterflood system, from injection well, through the reservoir and production well, and through the subsea network is key for maximizing reserves capture. If the injection system or the reservoir communication is less than adequate, the production wells can quickly draw the reservoir pressure down below bubble point, releasing potentially large quantities of free gas into the reservoir and wellbore (Leonard et al., 2000). Secondary gas caps could form and gas production rates could be higher than expected, potentially restricting the oil production rate due to facility constraints on gas processing.

Because we have limited appraisal well data and had no dynamic performance data except for short-term (less than three days duration) well tests, we needed to account for a great deal of uncertainty in the field development plan. A multiple scenario approach was developed to account for possible variability in a number of subsurface parameters. This paper will focus mainly on uncertainties in the static description of the reservoir.

Characterization of channel reservoir examples. Two types of channel reservoirs will be contrasted here—loosely amalgamated systems and highly amalgamated systems (Figure 5). Loosely amalgamated systems such as the 690 sand have relatively discontinuous seismic loops, abrupt thickness changes, sinuous-to-meandering map patterns, and a high shale has been active since at least the early Miocene, and we interpret sand deposition to have been impacted by this growing structure. The switch-off of the high seismic amplitude conforms to structure downdip—indicating the inferred oil-water contact. However, in other areas, high amplitudes do not conform to the same structure contour or to faults, indicating the lateral edges of the accumulation are controlled by stratigraphic sand pinches. Dim shoestring-like channels interrupt the seismic amplitude continuity of the 702 sand. We interpret these as mud-filled channels where sand has largely been eroded away. Integrated analysis of seismic, cores, logs, and image logs indicate most Bonga sands comprise channelized turbidites.

The sand and oil quality of these reservoirs is high. The overall crude quality in the Bonga Field is good with an average in-situ viscosity less than 1 cP and an average API gravity of 30° (Varley, 1999). The porosity range is 20-37%. Cores show the sand is unconsolidated with Darcy-scale permeability.

**Subsurface challenges and modeling approach.** Bonga reservoirs are undersaturated, but close to bubble point. Because high permeability will support high production rates, high-rate water injection is planned from start-up, to provide pressure support and to sweep additional volumes not captured by depletion. Bonga Field for the most part is interpreted to have relatively weak aquifer support. In addition, because of high drilling costs in this deepwater setting, the field is planned with relatively little appraisal drilling, and the development well spacing is also sparse (averaging 1-2 km between injection and production wells).

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**Geophysical and geologic setting.** The 1993 seismic data were reprocessed by Shell in-house in 2000 using full prestack multiple elimination and extended FSI migration. The result was a dramatic increase in both vertical and lateral resolution, which made it possible to interpret some individual channel bodies. This seismic is the basis for all current modeling. Recently another 3D seismic survey over the whole block was reacquired and processed by CGG as a baseline for future 4D monitor surveys.

Figures 2 and 3 show the seismic expression of the Bonga accumulation. The Bonga sands are unconsolidated and acoustically soft with rising AVO when oil-filled. They are essentially seismically invisible when brine-filled. Seismic amplitude maps show areas of generally thicker net oil pay. The largest reservoir is the 702 sand. A seismic amplitude map draped on a 3D structure surface of the 702 sand illustrates some general aspects of the Bonga accumulation (Figure 3).

The Bonga structure is a south-plunging anticline cored by mobile shale. This mobile shale forms a diapiric structure and pierces the seabed north of the field. Normal faults are present at the crest of the structure, and are more prevalent toward the north as the mud diapir is approached. The

**Figure 3.** Bonga 702 seismic amplitude displayed on 3D structure map. Note faults at crest of structure and mud-filled channels cutting out the high amplitude areas.

**Figure 4.** High-rate waterflood system sensitivities. See text for discussion.
The proportion of thinly bedded to laminated intervals. Highly amalgamated systems such as the 702 sand have more consistent loop character, broader areas of consistent high amplitude, and blocky, massive sands with relatively few thin-bedded intervals. The degree to which different individual channels are amalgamated is important for determining the degree of connectivity in the reservoir.

Bonga well penetrations indicate that high-amplitude channel axes comprise mostly massive, amalgamated sands. Areas outside of channel axes can be either thin, high net-to-gross sands, or thinly laminated sands (Figure 6). Tops of channel deposits can also be thin-bedded, indicating channel abandonment deposits, resulting in a “fining-up” log profile. These facies relationships are confirmed by core data (Figure 7) and have been commonly seen in submarine channel deposits in outcrops (Campion et al., 1999).

Because the seismic data are high quality, we have attempted to maximize the information gained from seismic as input to reservoir models. At the same time, we know from outcrop modeling studies that it is impossible from seismic alone to resolve all the variability and heterogeneity in turbidite channel reservoirs, where average bed thickness is less than 1 m. Therefore we also perform a geologic “infill” step where deterministic or stochastic channel bodies and facies associations are placed into the model at a subsurface scale.

The principal parameters varied for constructing the static models include:

- net sand thickness, the main contribution to volumetric variation;
- subseismic reservoir architecture, including number and orientation of channel bodies and facies;
- “connectivity,” here defined as a combination of horizontal permeability, vertical permeability, and transmissibility barriers.

Figure 5. Seismic amplitude maps (a and b), traverses, and well logs (c and d) of 690 and 702 reservoir sands. The 690 seismic expression appears more disconnected than that of the 702 sand. Note also the log expression of the 702 sand is highly amalgamated compared to the 690 sand, which has significantly lower sand percent, and thinly interbedded sands and muds at the top of the interval. We infer the 702 sand has less reservoir connectivity risk than the 690 sand, as illustrated in block models (e and f).

Figure 6. Seismic cross-section through 690 and 702 sands showing seismic and log character of channel axis, margin, abandonment, and overbank facies (black logs are gamma ray, blue logs are resistivity). Note the discontinuity implied by the wet 690 sand at a higher elevation than oil-bearing 690 sands. All oil-bearing 690 and 702 sands penetrated to date are on the same oil pressure gradient. Bold black lines indicate channel bases.

Figure 7. (a) Thinly laminated sands and muds common in channel abandonment, margin, and overbank facies. (b) Laminated sands found in abandonment, margin, and overbank facies, and less commonly in channel axis. (c) Highly amalgamated sands found commonly in channel axis. Red arrow indicates amalgamated bed boundary.
All aspects of the characterization process are iterative and linked, both on the human side through integrated team involvement and ownership for each step in the work flow process, and through integrated software (Figure 8). The process is described more fully below, with special emphasis on the geophysical methods.

Net sand prediction using model-based, probabilistic seismic inversion. At Bonga, the key uncertainty for estimation of in-place volumes is the net sand thickness distribution. Porosity variation within a reservoir unit is small, although there is a general trend where deeper reservoir levels have slightly lower porosity. Likewise variation in oil saturation is small. However, variation in reservoir thickness and sand percent is large. Areas of high seismic amplitudes generally have thicker intervals of oil-bearing sand but, in detail, the correlation between seismic attributes and net sand thickness is not strong, because the seismic tuning thickness is similar to the average reservoir thickness (approximately 15-20 m).

Probabilistic seismic inversion was used to provide a better estimate of net sand distribution, and also to quantify the range of uncertainty (Figures 9-10). The proprietary inversion technique works on a layer-based model where all model input and output data are represented as grids. The inversion combines in a consistent manner the prior petrophysical and geologic information with seismic data. Prior probability density functions (PPDFs) for reservoir parameters such as layer thickness, porosity, net-to-gross, and fluid saturations are cast into a prior model. The PPDFs are obtained from well and geologic data by defining the mean and standard deviation for each. Using this prior information, the program then generates numerous subsurface models that match the actual seismic data within the limits set by the noise that is derived from the seismic data. In this process it was crucial to take the full stack response into account. The inversion is probabilistic in that these realizations are statistical samples from the posterior distribution, which includes the prior petrophysical and geologic information as well as the seismic data. In actual practice, the output from the program consists, for each seismic trace location, of a posterior pdf for each relevant parameter (e.g., thickness, net-to-gross, sand porosity) based on a user-defined number of accepted models. Finally, the posterior PPDF from each trace location are used to construct expectation values and uncertainty measures of the inverted reservoir parameters of interest (Leguijt, 2001).

Figures 9-10 show the results of the inversion for the 702 reservoir which was done before drilling eight development wells through the 702 sand in 2000, using six previous exploration and appraisal penetrations as calibration. The wells
We estimated the typical channel width from seismic amplitude maps at reservoir level, and the channel depths by the thickness of interpreted channel storeys seen in core and logs. We also compared the widths and depths to outcrop data sets and well-imaged channels shallower in the section. The aspect ratio of channel width to thickness is approximately 20 in our reservoir levels. These are similar to those in our shallow analogs and previous outcrop studies (Clark and Pickering, 1997), giving confidence to our dimensional estimates. Clues from seismic attribute maps such as crescent-shaped map patterns helped place channels. Higher concentrations of channels were placed in areas of thick net sand. 3D body checking using seismic amplitude cut-offs, and detailed loop shape mapping were used where possible to constrain the channels. Several realizations of channel density, orientation, and amalgamation for each reservoir were tested in simulation models, with the two scenarios having the most difference in performance being selected to take through the entire modeling process.

**Connectivity modeling.** To limit the number of simulation runs, we combined variability in horizontal permeability, vertical permeability, and transmissibility barriers into low, mid, and high scenarios of “reservoir connectivity.” A discussion of the details of permeability assignment is outside the scope of this paper. However, the biggest single influence on connectivity was the transmissibility barriers placed into the model. These represent both the faults and the stratigraphic barriers, for example mud-filled channels or channel margin shale drapes, that may interrupt lateral reservoir continuity.

Seismic equal-amplitude surfaces (isosurfaces) were used in conjunction with amplitude and semblance (similar to coherence) maps to identify faults and potential stratigraphic discontinuities. The isosurfaces could be extracted at different amplitude cutoffs to give a graduated indication of which portions of the reservoir were more consistently connected (Figure 12). Transmissibility barriers for all scenarios were placed between areas that were disconnected even under relaxed amplitude thresholds. Baffles with variable transmissibility were placed between areas that became disconnected at tighter thresholds. These baffles might have transmissibility factors that are very low to zero in low connectivity scenarios, and higher in medium to high connectivity scenarios.

**Multiple realization modeling to quantify uncertainty.** For each of the four main reservoirs, two final reservoir architectures, three oil-in-place scenarios, and three connectivity scenarios were evaluated through final reservoir simulation. All potential combinations were simulated, resulting in 18 simulation runs per reservoir and 72 for the field. The scenarios were simulated using the same well placement, which was optimized on the mid case. The output profiles for the multiple scenarios for the four reservoirs were analyzed using Monte-Carlo simulation to determine combined field P85-P50-P15 cases. These three cases were input to an integrated flowline and surface facility network model to understand possible operational constraints.

Table 1 shows relative impacts of the geologic parameters for the 690 and 702 reservoirs.

The most dramatic impact is that of connectivity on the 690 reservoir. The wide range in potential recovery for the 690 sand reflects our uncertainty in the connectivity and productivity of that reservoir, as noted earlier. Perhaps surprising is the relatively low impact of different reservoir infill architectures. We interpret that this is because the flow property variation assigned to those architectures is incorpo-
rated into the “connectivity” parameter, leaving geometry as the only variable in the architecture scenarios.

The results in Table 1 incompletely capture the additional effect of dependencies. For example, our assignment of horizontal and vertical permeability is partly dependent on facies and sand percent. Therefore low volume cases having lower average sand percent can also have lower connectivity. Likewise, high volume cases, in addition to having higher sand percent and potential connectivity, also have access in some reservoirs to wider drainage areas. A comprehensive discussion of these factors is beyond the scope of this paper, but these variable dependencies are the reason why we carry out simulations on the full range of combinations, and do not, for example, only investigate variations from the mid case. Numerous additional reservoir engineering sensitivities were in fact investigated parametrically by their deviation from the mid case. These included relative permeability, aquifer strength, horizontal versus vertical wells, and others.

Managing uncertainty in the future—4D seismic. Given the wide range of potential outcomes prior to start-up, significant consideration has been given to understanding potential intervention strategies. All production wells have downhole pressure sensors, and the development drilling is phased over nine years, with 14 of 37 wells available at field start-up. Ten of the first oil wells are in the 702 reservoir, which we interpret to have the least uncertainty. Each of the other three main reservoirs has at least one well at first oil, to get some early production information.

In addition we plan to use repeat seismic surveys (4D seismic) to understand reservoir sweep through time. The value of 4D seismic in heterogeneous turbidite channel reservoirs has been shown by Altan (2001) and Leonard (2000) for the Schiehallion and Forties fields, UKCS.

Preliminary time-lapse seismic feasibility studies at Bonga show a strong seismic amplitude changes resulting from changing water saturation during production (Figure 13). Saturation and pressure changes predicted from the simulation models were converted to an elastic earth model via rock property trends using proprietary software. The result showed that oil-filled reservoirs, which appear as bright low impedance reflectors on seismic, become almost invisible when swept by the aquifer. High, mid, and low scenarios were simulated to quantify the uncertainty. From this evidence, judgments as to the most appropriate time to acquire repeat surveys can be made in conjunction with the schedule for planned development drilling.

It is recognized that the likely outcome will be different from existing models; however, a multiscenario approach to 4D seismic simulation facilitates a better understanding of both reservoir issues in time and the planning of monitor surveys. The plan currently consists of a reshoot of the existing 3D seismic to establish a base line and three repeat surveys at intervals of 18 months to 2 years after the start of production in late 2003-early 2004.

Other in-field opportunities. In addition to the four main

Table 1. The relative impacts of the geologic parameters for the 690 and 702 reservoirs

<table>
<thead>
<tr>
<th>Reservoir Parameter</th>
<th>702 Oil in place</th>
<th>702 Architecture</th>
<th>702 Connectivity</th>
<th>690 Oil in place</th>
<th>690 Architecture</th>
<th>690 Connectivity</th>
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Figure 12. Illustration of seismic isosurfaces at different amplitude cutoffs to show different potential drainage areas. The underlying map shows the 702 amplitude. The four patches colored from north to south (pink, green, purple, and dark blue) show major drainage areas of the 702 sand, separated by faults and mud-filled channels. The light blue overlay shows isosurfaces at a tighter cutoff indicating smaller connected amplitude areas. The red wells are production wells, blue are water injection wells, and black are exploration and appraisal wells.

Figure 13. 4D seismic predicted response from simulation models. (a) and (b) are net oil thickness maps from reservoir simulation at beginning of production and after 2 years. (c) and (d) are predicted seismic amplitude maps (synthetic) corresponding to those simulation models.
reservoirs currently in the development plan, numerous other reservoirs exist in and around Bonga that may be tied in to the development in the future. These other reservoirs have been identified with increasing levels of refinement over recent years. Geophysical identification techniques have included traditional horizon mapping, voxel volume analysis, AVO analysis, and most recently simultaneous sparse-spike inversion. In 2001, five of nine development wells were deepened or sidetracked to specifically appraise these potential reservoirs, which were found to be oil-bearing as indicated in Figure 14. Visualizing these and other potential reservoirs on the Bonga structure shows the complex nature of the turbidite channel deposition over time (Figure 15).

In addition, the challenges of development planning for a labyrinth of reservoirs are apparent. The Bonga development is currently planned with future growth in mind. Some spare well slots are available in the existing subsea layout, and the system can also be expanded further in the future.

This flexibility will provide opportunity to mitigate downside scenarios by bringing in other reservoirs, and may also allow the production plateau to be extended.


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