

## Clair Field: Development of a Waterflooded Fractured Reservoir

Clair is the largest naturally fractured reservoir developed in the U.K. Recovery is by waterflood. Its 28-year appraisal period reflects the high reservoir complexity, relatively poor-quality conventional-seismic image, and uncertain effect of the conductive fractures. Clair is not predrilled, and the preferred well locations and design will change.

### Introduction

Clair is a naturally fractured Devonian sandstone reservoir with a 1,970-ft reservoir interval containing 23°API oil 47 miles west of Shetland in 500 ft of water. Clair was discovered in 1977 and appraised by a series of vertical wells with disappointing rates. Field potential finally was demonstrated by the drilling of high-angle appraisal wells 206/8-9z and 206/8-10z, culminating in an extended well test (EWT) of 206/8-10z in 1996, which produced 500,000 STB of oil and demonstrated communication with a minimum of 500 million STB. The EWT led to sanction of the Clair Phase 1 development in 2001 and first oil in February 2005.

The Clair Phase 1 development comprises the core, graben, and horst fault blocks (Fig. 1) believed to contain approximately 1.5 million STB of oil. Appraisal of the remaining areas of the field is continuing and may lead to subsequent development phases. Phase 1 is a single fixed-platform development. The field will be developed by drilling

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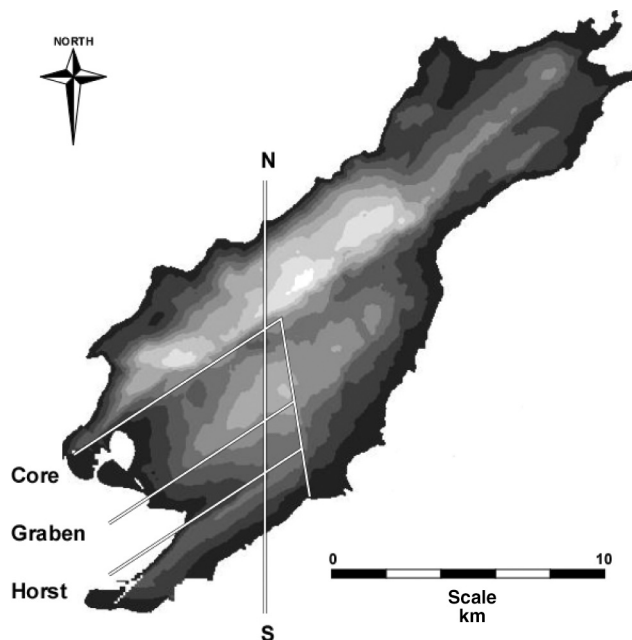


Fig. 1—Clair Phase 1 area.

22 additional wells over a 3-year period. The principal recovery mechanism is waterflood, with a planned ratio of approximately 2 producers per injector.

Matrix permeability averages approximately 30 md, and oil viscosity is 3.5 cp at reservoir conditions. Recovery strategy begins with development of the more productive relatively high-permeability fluvial sands of Unit V in the large core segment and proceeds with development of the interbedded lake-margin fluvial sands of Unit VI on the basis of learning from Unit V wells. Drilling in the smaller and less appraised graben and horst blocks proceeds in parallel with the later core development.

**Natural-Fracture Description.** The controlling feature of reservoir development in Clair is the system of natural fractures. Core and image logs demonstrate widespread granulation seams, conductive fractures, and cemented frac-

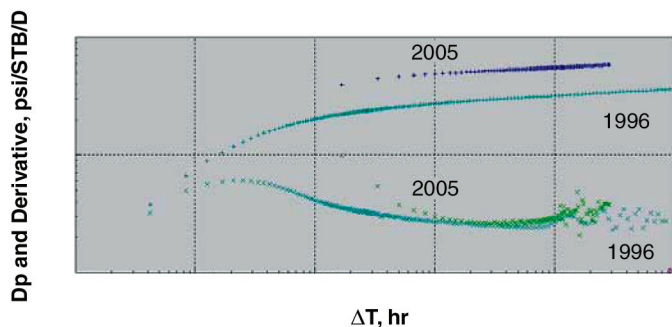
tures. Use of seismic techniques to distinguish conductive from nonconductive faults and fractures is a key methodology in Clair reservoir description.

To describe the possible fracture distributions, and to allow their incorporation into reservoir models, a number of scenarios have been generated. In these scenarios, stochastic distributions of conductive faults or joints have been generated with use of conditioning to seismic data, and these have been upscaled into fracture permeability arrays for incorporation into dynamic reservoir models.

### Fracture Influence on Development.

The fractures are a key component of permeability but do not account for a significant fraction of the pore volume. A comparison of permeability-thickness product,  $kh$ , from core and log data with  $kh$  from dynamic-drillstem-test and EWT data indicates a fracture

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



**Fig. 2—Pressure-derivative plots in 1996 and 2005.**

contribution to permeability that may range from zero to more than 80%. The fracture contribution defines the basic well design as a high-angle well sufficiently long to intersect several conductive-fracture zones. The relatively high matrix permeability, together with the possibility of high fracture spacing in many areas, does not allow Clair to be seen as a dual-porosity reservoir.

### Uncertainty Management in Clair

The underpinning process for uncertainty management for Clair is the concept of a plan/do/measure/learn/plan (PDMLP) loop. In this instance, the “plan” is the reservoir-development plan, including the well sequence and, in particular, individual-well plans. The “do” is the drilling sequence and individual-well delivery as well as the production-management actions; the “measure” is the data acquisition, both static and dynamic; and the “learn” is the understanding of the reservoir response, derived from the data and model environment, that allows return to a revised “plan.”

Choices for the early drilling sequence demonstrate this in practice. To achieve a fast production ramp-up, the early wells need to be high-rate, lower-risk producers. These criteria are best fulfilled with long horizontal wells targeted at Unit V in the core area. Good well options are the tieback of the EWT well, which has proven potential, and long horizontal wells that target fractures and matrix. Subsequent producers represent a step change in risk, being either shorter infill wells or wells targeted at the graben or horst or Unit VI and, thus, having lower production potential. Because the Clair Phase 1 reservoir is normally pressured with no initial gas cap, reservoir energy is limited and water injection is required early in production life to maintain reservoir pressure. The initial drilling

sequence needs to balance the timing of producers with injectors for production support. Cumulative recovery on Clair is linked directly to cumulative water injection. Cumulative-recovery optimization needs to start early in field life.

In considering the learning derived from the initial wells, there are seven major areas of uncertainty that can be addressed; acquiring data to reduce the uncertainty in these areas will result in more-optimum well placement. These seven identified areas are: fracture and matrix controls on well productivity, waterflood sweep efficiency, controls on injectivity, compartmentalization, vertical connectivity, and structural uncertainty.

To extend the fracture- and matrix-productivity data from drilled locations to future targets requires the integration, or calibration, of structural style and seismic response with well, pressure, core, log, and production data. As an example, an integrated core data set to be acquired in the first drilled producer and injector is a key milestone for learning about productivity and injectivity. Connectivity and compartmentalization uncertainty is best addressed by post-production pressure data; the timing of pressure-data acquisition from offset locations as they are drilled can be optimized.

### Data Acquisition and Learning

The initial-development well-planning sequence was derived from flow-simulation models conditioned by static information from 15 exploration and appraisal wells (most in a single limited area) and matched to limited primary-production data from the 206/8-10z EWT. As development matures and decision points in the drilling sequence are met, it is necessary to feed the PDMLP loop with an appropriately augmented set of static and dynamic performance data. These allow previous predictions to be

tested and inconsistent models to be discarded from the range of outcomes considered. They also aid identification of well-intervention opportunities in the event that performance deviates significantly from expectation.

Static-data acquisition includes conventional openhole formation-evaluation logs in conjunction with image logs, dipole sonic, nuclear magnetic resonance, formation-pressure surveys, and core. From a dynamic perspective, the initial focus is on the reservoir pressure response, and all wells (including injectors) will be equipped with permanent downhole pressure and temperature gauges. Baseline pressure-transient tests also are programmed within the first weeks of each well’s production or injection history to determine effective  $kh$  and skin. These will support diagnosis of subsequent well performance, verify whether or not drilling processes are nondamaging, and help determine the influence of the natural-fracture system on productivity and injectivity. To complement baseline well tests, production-logging campaigns are planned to provide information on flow profile along the reservoir section and identify relative contribution of matrix and fractures.

Interference tests will be conducted between producers and injectors to allow tuning of different reservoir models and narrow uncertainty regarding breakthrough and water-cut increase. Chemical tracers also will be added to each injector, helping to determine injection patterns and potentially yielding information regarding degree of imbibition from fractures to matrix.

Finally, routine production testing combined with fluid sampling and compositional analysis will be conducted for each well, establishing actual vs. predicted performance in oil production, gas/oil ratio, and water cut. These will help constrain the range of plausible models and reduce uncertainty in predicted performance of remaining wells.

### The First 3 Months

Clair has been operating with the single producer 206/8-10z during the first 3 months of production. Until data become available from the second well (CP-22), the opportunities for reservoir-uncertainty reduction are limited, but substantial value already has been derived from the surveillance program. First production by use of the fixed Clair platform was achieved by the tieback of

Well 206/8-10z, which was originally drilled, tested, and suspended in 1996. Operations to re-enter and complete the well progressed largely as planned, but the final suspension barrier, a pump-open plug (POP) set in the original completion tail pipe, could not be recovered on slickline. The POP was left in place and the tailpipe perforated above it.

The well was brought on line on 23 February 2005. After a short (45-minute) flow period to displace tubing contents and confirm reservoir fluids, the well was shut in to conduct a pressure-buildup (PBU) survey. The objective was to determine the extent to which reservoir pressure had recovered since the 1996 EWT.

The analysis gave a remaining depletion of 5 psi, with an error bar of  $\pm 5$  psi because of the large vertical interval between the gauge and the reservoir, and minor uncertainty in the wellbore-fluid density. This contrasts with the depletion of 55 psi measured 1 month after the EWT in the 206/8-9y sidetrack close to 206/8-10z. It suggests communication with an oil-plus-water volume of approximately 10 billion bbl over the

10-year period since the EWT. Such a large volume requires either a larger-than-expected volume of the core aquifer or communication through the aquifer with other fault blocks.

Choke position was gradually opened to 100% with expectations of matching the final flow of approximately 18,500 STB/D achieved in the 1996 EWT. However, with the valve wide open, only 12,500 STB/D could be achieved at a 246-psi wellhead flowing pressure. A plant trip on 28 February 2005 provided the opportunity to interpret PBU data acquired by the downhole gauge and compare the response to that seen during the EWT. **Fig. 2** shows the 1996 and 2005 pressure-derivative curves for Well 206/8-10z. A horizontal-well type curve fitted to the 2005 data gave identical  $kh$  and other parameters compared with the 1996 interpretation, with the exception of the skin factor. To achieve a match, the skin factor had to be increased substantially. It was not possible to achieve a match by reducing the well length. It was concluded that all intervals contributing in 1996 were still doing so in 2005

and that the apparent high skin was the result of a partial blockage beneath the gauge and within the wellbore.

In addition to the downhole restriction, an insert designed to protect the choke valve body against erosion was identified as restricting the flow potential of the well. A shut-in was planned for 8 March to remove the insert. Removal of the insert added approximately 1,000 STB/D. The most likely source of the restriction was poor communication through single-phase perforations on the low side of the old-completion tail pipe. Engineering work was pursued to develop an oriented tubing punch, allowing an additional set of zero-phase holes to be shot at approximately 90° offset to the first. The job was completed at the beginning of May and added an additional 2,000 STB/D.

Interpretation of permanent-downhole-gauge data was instrumental in both interventions, aiding early diagnosis of lower-than-anticipated production, helping to verify tubing and surface-network flow models, and increasing confidence in predicted incremental oil.

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