SPE 116007

Development and Use of High Density Fracturing Fluid in Deep Water Gulf of Mexico Frac and Packs

L. Rivas, G. Navaira, and B. Bourgeois, SPE, Chevron, B. Waltman, P. Lord and T. Goosen, SPE, Halliburton

This paper was prepared for presentation at the 2008 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA, 21–24 September 2008.

Abstract

In the Gulf of Mexico, there has been an increase in the number of wells drilled to depths greater than 20,000 ft with bottomhole pressures exceeding 20,000 psi. These deeper wells present drilling and completion challenges to the industry. Two of these challenges include fracture stimulation for low permeability formations and frac and pack sand control completions for higher permeability formations. A conventional 1.0 to 1.04 SG fracturing fluid would result in a surface treating pressure greater than 15,000 psi due to the high fracture gradient and friction pressures. In the offshore marine environment, 15,000 psi pressure is the current limit of the flexible treatment line that transmits fluid from the stimulation equipment on the marine vessel to the wellhead on the rig.

To solve this limitation, a borate-crosslinked high-density fracturing (HDF) fluid with up to 1.38 SG was developed to harnesses the power of gravity and reduce the amount of surface treating pressure required to achieve adequate bottomhole fracturing pressure without exceeding the safety limits of the surface equipment. In numerous wells, a minimum of 20% reduction in surface treating pressure compared to a treatment with a 1.04 SG fracturing fluid was recorded.

This paper summarizes the well conditions, extensive fluid qualification testing, procedures, and selected job results along with final completion performance indicators.

The HDF fluid enables treatment of these deep offshore wells by lowering surface treating pressure. Conventional 15,000 psi equipment was able to be used, less horsepower was required, and a safer work environment was created.

Introduction

The Tahiti Field underlies the Gulf of Mexico in the Green Canyon area (**Fig. 1**) where water depths range from 4,000 to 4,300 ft, is operated by Chevron USA. Total and Statoil are partners with Chevron in the project.

The discovery well was drilled in 2002 in the Green Canyon in block 640, approximately 190 miles southwest of New Orleans. Total depth was in excess of 28,000 ft using the drillship "Discoverer Deep Seas." The initial evaluation indicated approximately 400 ft of net pay in the high-quality reservoir sand that was encountered.

Subsequent appraisal drilling over the next two years resulted in confirmation of the size of the Tahiti Field and its status as one of the most significant net pay accumulations in the history of the Gulf of Mexico. The discovery well was re-entered in 2004 and a well test was carried out to verify deliverability, dynamic well data, and reservoir properties. A stacked frac pack in the Miocene M21A and M21B sands was planned for the well test. The Tahiti M21A sand averages 60 to 80 ft thick and the M21B sand averages 120 to 150 ft thick. Permeability ranges from 600 to 800 mD. However, the TCP guns for the lower interval fired prematurely while across the upper interval, and the decision was made to perforate the lower interval and complete both intervals with a single, high-rate frac pack. At the time, at a depth in excess of 25,800 ft, it was the deepest successful well test and frac pack completion ever carried out in the Gulf of Mexico. This fact was made more significant by the high pressure environment. The HDF fluid described in this paper was a key component of the successful Tahiti well test. The well test results led to the development of the Tahiti Field, which began in February of 2006.

While planning the Tahiti well test, several factors influenced the decision to develop a suitable HDF fluid that would minimize surface treating pressures and allow the frac job to be pumped below the 14,000 psi limit. Uncertainty regarding Miocene pay sand frac gradients, and required treating rates, coupled with high friction losses in the treating string led to the desire to find a HDF fluid that would allow the fracs to be pumped at 40 to 45 bbl/min while staying within surface treating pressure limitations. In that way, the full range of treating uncertainties could be handled successfully the day the job was carried out.