Challenges of Waterflooding in a Deepwater Environment

The waterflood study team for the deepwater Ursa/Princess field evaluated various challenges affecting the surface and subsurface aspects of the development plan. The design for an optimum injection rate was a bottom-up process from the reservoir to the top-side injection facilities. Reservoir-sweep efficiency and reservoir-pressure distribution dictated injection-well designs and injection-pump sizing. Subsurface risks, such as reservoir souring and hydrate formation, dictated material selection and completion design.

Introduction

Ursa and Princess fields are 100 miles south-southeast of the Mississippi River mouth in the Gulf of Mexico (GOM) Mars basin. The Ursa field was discovered in 1990 and has been producing since 1999. The Princess field was discovered in 2000 and has been producing since December 2003 through a subsea tieback to Ursa. The fields have common main reservoirs (the Yellow) and are in pressure communication.

Because of limited tension-leg-platform (TLP) well availability, high cost of subsea wells, and the limitations of the subsea system to handle large water cuts, the waterflood will use relatively few injectors. The proposed base plan has four water injectors: two into Princess and two into Ursa. Producing wells will include three Princess subsea wells and four Ursa TLP wells.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper OTC 18523, "Challenges for Waterflooding in a Deepwater Environment," by ***Azhar Alkindi,*** SPE, Shell; ***Robert Prince-Wright,*** Riskbytes; and ***Wesley Moore,*** SPE, ***John Walsh, Lee Morgenthaler,*** *and* ***Cor Kuijvenhoven,*** SPE, *Shell, prepared for the 2007 Offshore Technology Conference, Houston, 30 April–3 May.*

High injection rates are required to replace voidage and maintain reservoir pressure above bubblepoint. Initial injection rates per well (annual average) of 30,000 to 40,000 BWPD are required.

Because the original operating health, safety, and environmental (HSE) case for the asset did not include the potential threat of reservoir souring after seawater injection, well-casing and -tubular materials have limited resistance to sulfide stress corrosion cracking (SSCC). This resulted in the need to recomplete the Ursa TLP direct-vertical-access (DVA) wells with qualified tubing. Princess producers already have C100 sour-resistant casing and will not require tubing change out.

Injection Wells

The number of wells was optimized during a number of vital reviews. Sweep efficiency and return on investment were the main optimization criteria for the required total water-injection rate per day. Approximately 50% of the total project capital expenditure is related to drilling and well completion. Because economics is the dominating decision criterion for injector number, optimizing the fine details of the well bottomhole locations, well geometry, and well-completion designs retains prime importance.

Well Geometry. The 12,000-acre reservoir is to have four subsea injectors with at least 120,000 BWPD of combined annual average injection capacity. Having decided on the number of wells, ensuring the total required pore volume (PV) of water calls for optimized drilling and completion designs for those injectors. The dynamically preferred subsurface locations have been selected on the basis of careful analysis of the seismic signals, ensuring sand development and communication to producers. The wells are to intersect the reservoir in a straight vertical geometry to simplify the fracture design and maximize its chance of success.

Seawater-Injection Management

If water specifications are not met throughout the life of the waterflood, various problems can occur, including oxygen corrosion, biofouling, microbial-induced corrosion, SSCC, injectivity problems, reservoir souring, and barite scaling. The risks from souring and scaling resulted in elimination of raw-seawater flooding as an option. Finding the right solutions during concept selection and detailed design required multidisciplinary teams. This ensured appropriate materials, chemical treatment, and water conditioning within the constraints imposed by project schedules and economics.

Solids, particulates, dissolved salts, and oxygen make seawater a difficult and corrosive environment for the top-side facilities, the wells, and the formation. The intake for each dedicated seawater-lift caisson was at a point approximately 90 ft below the keel. Information provided by a university indicated that at this depth, there is minimal contamination and organic matter and that the water properties are relatively uniform.

Fouling by macro- and microorganisms is prevented at the intake by a screen and by injection of hypochlorite just below the pump suction. The intention is to add sufficient hypochlorite to maintain a chloride residual of 0.5 to 1.0 ppm upstream of the sulfate-removal membranes. Biocide is injected as far upstream as possible in the surface equipment to prevent the formation of biofilms that cause fouling and corrosion.

The full-length paper is available for purchase at the OTC Library: ***www.otcnet.org****. The paper has not been peer reviewed.*

Typically, batch biocide treatments are initiated once per week with a kill concentration determined by laboratory studies (typical range is 100 to 250 ppm, active for 2 to 4 hours). The biocide regimen will be optimized by on-site monitoring of bacterial cell counts.

The seawater is passed through strainers and cartridge filters to remove larger particles from the seawater ahead of the sulfate-removal unit (SRU). The SRU membranes are specifically designed to reject sulfate ions by use of a porous material with a negatively charged surface. The net effect is low-sulfate, nanofiltered permeate having very low solids content. Given the use of corrosion-resistant alloys (CRAs) for the surface facilities, high-density-polyethylene-lined injection flowlines, and either CRA- or glass-reinforced-epoxy-lined injection strings, there is little corrosion downstream of the membranes. The risks of plugging the injection wells, or fracturing out of zone, are minimal.

The sulfate-removal technology is based on crossflow filtration membranes. The membrane skid is installed downstream of the deoxygenation unit and upstream of the high-pressure injection pumps. A single pass through the membranes produces permeate with approximately 25 mg/L of sulfate but rejects 50% of the water. Part of the reject stream is recycled to optimize the ratio of water lifted by the caissons to water available for injection. Recycling results in a design specification of less than 45 ppm of SO_4^{-2} over the warrantied life of the membranes. Environmental assessments have shown that the sulfate-rich reject stream can be discharged back into the GOM without harm.

The specified design life for the SRU is 20 years, and the system availability is 80% or better. Additionally, the SRU must be on line from the start of seawater injection and continue throughout the life of the waterflood project. The membranes are sensitive to fouling and require periodic cleaning to maintain sulfate-removal performance.

The seawater is deoxygenated by use of two independent processes: nitrogen stripping to achieve an O_2 content less than or equal to 20 ppb and scavenging by use of bisulphite.

Oxygen-scavenger residual is desirable to ensure that safe oxygen levels are maintained during minor excursions in the efficiency of the deoxygenation unit. Sodium metabisulfite was selected and will be delivered continuously. The only exception is during the weekly batch nonoxidizing-biocide treatment. Because of the preferential reaction of the two products, oxygen scavenger must be discontinued during this time. A typical, recommended treatment range for oxygen scavenger is 20 to 22 ppm per ppm O_2 in the stream to be scavenged.

Souring

Natl. Assn. of Corrosion Engineers (NACE) MR0175 defines sour fluids as those having a hydrogen sulfide (H_2S) partial pressure greater than 0.05 psi. The reservoir fluids are defined as sour if the partial pressure in any flow stream exceeds 0.05 psi, or the sales-gas H_2S concentration exceeds 4 ppm.

Seawater contains active anaerobic organisms, including sulfate-reducing bacteria (SRB). When micronutrients, organic carbon, and sulfate concentrations are present above certain thresholds and the temperature falls within ranges typically found in the natural environment, a system can support SRB growth and maintenance resulting in the reduction of sulfate to H_2S.

The H_2S yield can be limited by controlling the mass of organic carbon or the mass of sulfate. The Ursa and Princess reservoir fluids contain significant concentrations of dissolved organics and negligible quantities of sulfate. The most robust means for controlling the H_2S yield in the event the reservoir is inoculated with SRB is to remove as much sulfate as practical from the seawater. The team examined whether the combined effect of oil adsorption and rock/water interactions would result in the biogenic H_2S being sequestered in the reservoir.

Souring Evaluation. The biggest challenge for the waterflood project was to predict the likelihood of souring and to develop methods for mitigating the threat. The first step was to assess the conditions under which souring is likely to occur and the potential timing and severity of H_2S breakthrough at the producers. A reservoir dynamic-simulation model was set up specifically to investigate these aspects.

First seawater and then first H_2S production predictions are made on the basis of this model. The model has a tracer for the seawater, so first seawater production is clearly distinguished from aquifer water.

The second stage of the analysis was to conduct laboratory studies in which Ursa Yellow core plugs were exposed to synthetic SRU permeate in which the entire sulfate fraction had been converted to sulfide. The purpose of these tests was to provide empirical evidence that Yellow reservoir rock has adequate scavenging capacity to sequester any biogenic H_2S produced in the injection system or reservoir.

HSE Case for Souring-Threat Control

The Ursa DVA wells have P110 and CY-P110 casing and 13Cr tubing. Both materials failed qualification testing for 20 ppm H_2S at bubblepoint pressure, which means there is a credible risk that H_2S levels at the producers may exceed the material qualifications. The Hazards and Effects Management System uses "barrier" counting as a means to demonstrate that threats are controlled adequately. The development team examined options to protect the wells from environmental cracking. The conventional solution is to use NACE or qualified casing and tubing; however, the cost and risk associated with replacing the DVA-well casing and subsea well tubing were not considered to be economically viable. Therefore, the team proposed a barrier strategy based on the following.

1. Confirmed injection of desulfated seawater containing less than 45 mg/L of sulfate.
2. Monitoring and response (for seawater breakthrough and H_2S).
3. Recompletion of the DVA wells with qualified materials.

Results from the static and core-flow tests, combined with the effects of oil adsorption evident in the reservoir dynamic-simulation model, show the reservoir can adsorb the H_2S created by several PVs of desulfated seawater. Field production data from assets using SRU technology support this case because none of the initially sweet reservoirs have soured and those that contained native H_2S have not become more sour after desulfated-seawater injection. The plan is to measure the H_2S content in each wellstream by use of a combination of online and manual methods to confirm the SRU is preventing reservoir souring. If H_2S is detected, then the HSE case requires that the well be shut in and a reassessment of the HSE case completed. JPT