Multiphase Pump Recovers More Oil in a Mature Carbonate Reservoir

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Abstract

A field test for a multiphase pump (MPP) was conducted in Abqaiq field, a mature carbonate reservoir in Saudi Arabia. Test results showed that large quantities of oil, water, and gas mixtures could be pumped over long distances without separating gas from the liquids. The helico-axial MPP successfully lowered backpressure, revived dead wells, and was able to transport as much as 75,000 B/D total fluid to a separation plant 10 km away. From test startup (8 June 2001) until 1 June 2002, the pump logged 5,160 operational hours (215 days). Economic payout was achieved rapidly, with up to 12,000 B/D of incremental oil production. The technology offers an attractive alternative to constructing expensive gas/oil separation plants in remote areas. This paper presents a summary of the field test.

Introduction

Multiphase pumps[1,2] are modified liquid pumps that are capable of pumping various combinations of oil, water, gas, and minor amounts of sand in the same pipeline without separation. MPPs are most commonly used to add energy to unprocessed fluids for transportation to central processing facilities a long distance downstream. A reduction, consolidation, or elimination of the production infrastructure, such as separation equipment and offshore platforms, also can be achieved. In this way, marginal fields in hostile environments can be developed more economically. In mature fields, MPPs have potential to reduce the backpressure on producing wells, leading to an increase in production rate and recovery efficiency. There also is an environmental advantage of MPP application: the possibility to reduce gas emission and flaring.

Field and Reservoir

The Abqaiq field, shown in **Fig. 1,** is one of the oldest in Saudi Arabia. It is approximately 37 miles long and 6 miles wide. It has been on production since 1946. The light crude is produced from the Arab D carbonate formation at an average depth of 6,500 ft and an average pay thickness of 240 ft. More than 50% of the initial oil in place has been produced with the support of peripheral water injection, its natural aquifer, and, between 1954 and 1974, partial gas injection. The average reservoir permeability is approximately 400 md with tighter zones at the top and the bottom. The average reservoir porosity is approximately 20%.

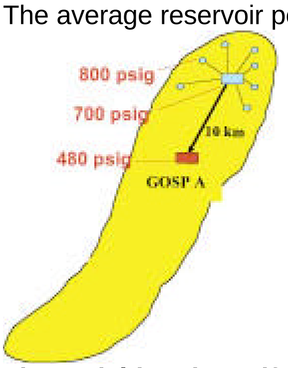

Fig. 1-Field and manifold location map.

The reservoir crude is 36°API gravity, with an average solution gas/oil ratio of 860 scf/STB at the saturation pressure of 2,560 psi. The original reservoir pressure was 3,400 psi at 6,500 ft subsea. The reservoir is maintained above the bubblepoint pressure. Original oil formation volume factor was 1.53, and the average oil viscosity is approximately 0.4 cp. Sulfur content of the mixture is 1.4 wt%, and the gas contains 3.7 mol% of H_2S. No solids production is reported. Average well productivity index is more than 100 B/(D-psi). Producing-well water cut varies from 0 to 80% throughout the field.

Test Location

The test location was chosen in the North Nose of the field (Fig. 1). There is a production manifold in this part of the field 18.6 miles from the engineering offices. The North Nose remote manifold **(Figs. 1 and 2)** is 6.2 miles from the nearest gas/oil separation plant (GOSP). Fourteen oil-production wells are connected to the manifold, 12 of which are not capable of flowing into the production line because of high trunkline pressure and high producing water cuts, greater than 70%. The main objective of the MPP is to reduce the backpressure on the dead wells and restore their production.

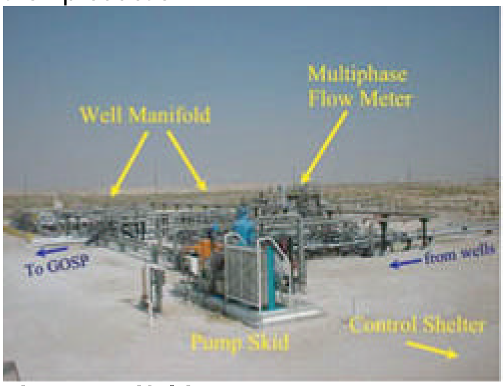

Fig. 2-Manifold.

The manifold was originally constructed to divert wells from the production line to a well-test line. The pump was installed in a manner to allow a combination of wells to be placed on pump suction header selectively. The pump discharge header is connected to a 16-in. production trunkline and to a 10-in. test line, which flows to a conventional test separator at the GOSP. A multiphase flowmeter was installed at the manifold upstream of the MPP to allow testing of individual wells, combined wells, or total pump discharge.

Reservoir Conditions and Well Performance at the Test Location

Fig. 3 shows an east/west vertical cross section showing the water saturation in the test location. On average, 30 to 40 ft of oil column stays at the top of the water. The thickness of the oil column varies with location. Most of the wells are completed vertically except one multilateral discussed later in the paper. The current pressure distribution within the same area is shown in **Fig. 4.** A relatively lower area exists in the crest where most of the manifold wells are connected. Similarly, rock permeability distribution is given in **Fig. 5.** A high-permeability pocket is in the crestal area where a horizontal well, later converted to a dual-lateral well, was completed.

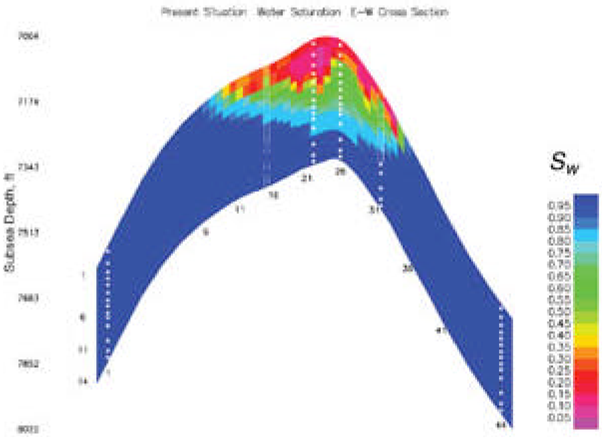

Fig. 3-Fluid-saturation distribution in the test location.

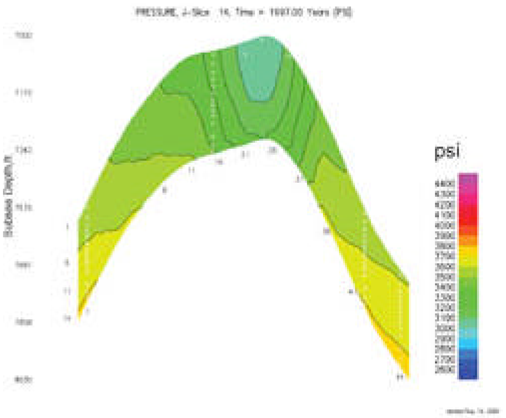

Fig. 4-Pressure distribution in the test location.

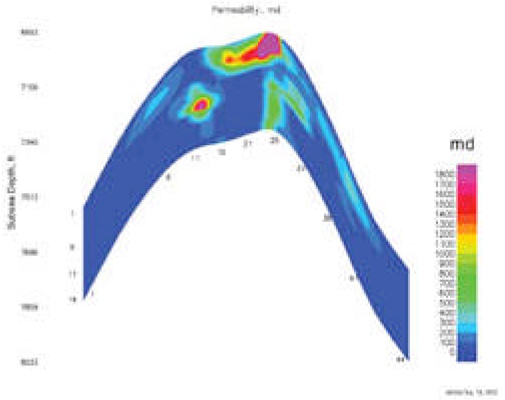

Fig. 5-Permeability distribution at the test location.

A typical well pressure and water cut starting from 1985 are shown in **Fig. 6** for demonstration purposes. Although there is enough reservoir pressure to sustain flow, high water cut, which increases the weight of the production column, and the long distances (6.2 to 9.3 miles) that the wells would have to flow, end up killing the wells. Therefore, 12 wells, which were producing at rates with 70 to 75% water cut, were unable to sustain production against the high trunkline pressure of 750 psi. These wells were shut in and classified as dead wells.

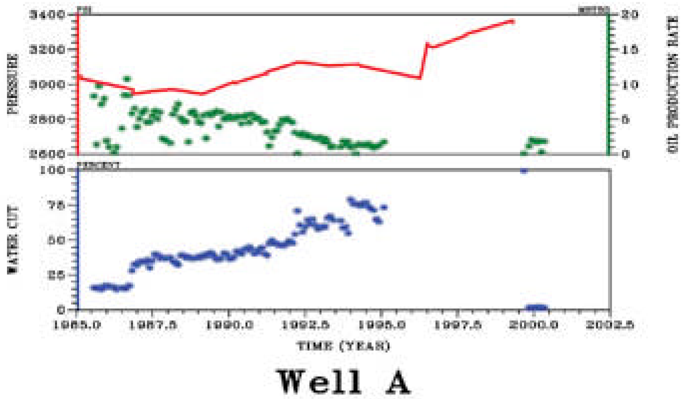

Fig. 6-Typical well performance in the test location.

Multiphase Pump

The Sulzer helico-axial pump[3] is a rotodynamic turbine machine capable of handling a mixture of oil, water, and gas containing H2S, CO2, and a certain amount of solids. The MPP package is mounted on a horizontal skid **(Fig. 7).**

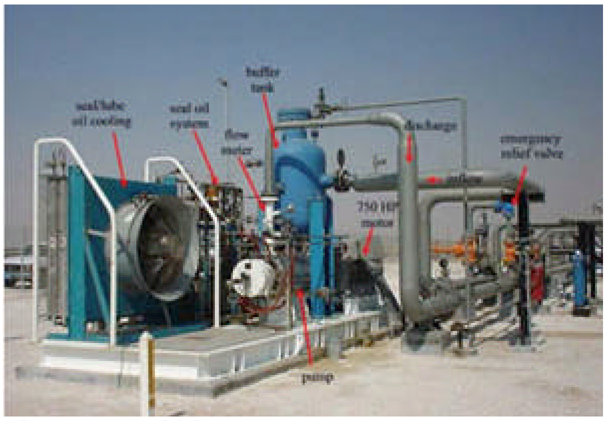

Fig. 7-MPP skid.

The pump is equipped with a variable-frequency driver (VFD) inside a temperature-controlled shelter. The VFD provides optimum control and operational flexibility to adjust the pump output to suit the changes in production conditions and requirements. The pump's operational design parameters are as follows: differential pressure: 200 to 300 psi; suction pressure: 400 to 500 psi; discharge pressure: 650 to 750 psi; total flow rate: 25,000 to 75,000 B/D; average gas-volume factor: 60%; average water cut: 50%; speed: 2,000 to 3,600 rev/min; and shaft power (rating): 750 HP (560 kW).

The pump has a process control system with a user-friendly interface that allows the operator to set and maintain certain production requirements. The main pump process data are available on a PC screen within the site control shelter. All process data are stored in this PC unit. Graphs of pump-performance operational parameters vs. time can be generated easily.

Field Testing

The trial testing of the MPP was initiated in June 2001 **(Fig. 8).** From the pump startup in June 2001 through 1 June 2002 (preparation time of this paper), the pump logged 5,160 operational hours (215 days). Since February 2002, after a major mechanical repair, the pump has had an operational availability of 95%. Two major failures were observed and fixed: replacement of the mechanical seals, caused by excessive seal oil leak, and failure of the thrust-bearing system. Several minor trips occurred because of a high process temperature caused by gas slugs (5- to 10-minute periods) entering the pump. Because of the low heat capacity of the gas, the gas slugs did not efficiently remove the heat generated by the pump. These difficulties were overcome in time.

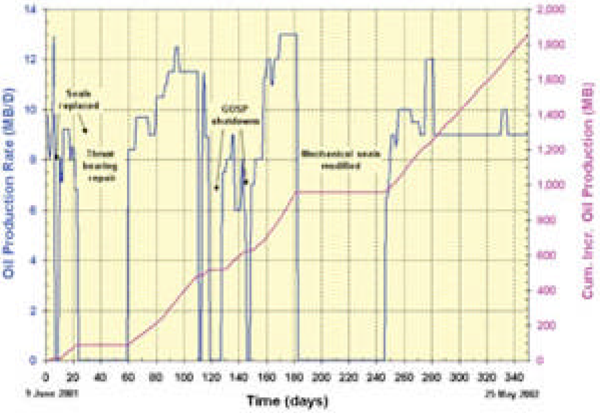

Fig. 8-Operating history of the MPP: June 2001 to May 2002.

At initial startup, two free-flowing (live) wells were placed on pump suction. Flow through the pump averaged 9,800 B/D of oil, 10,900 B/D of water, and 9.5 MMscf/D of gas. The total actual condition production rate (liquid plus gas) was 60,000 B/D. The next step in the trial testing was to remove the strongest live well and replace it with "dead wells," which were unable to flow against the normal manifold pressure of 700 psig. Wells on pump suction were increased gradually to one live well and six dead wells. Pump speed was increased to 3,400 rev/min. At this speed, production rates reached 12,500 B/D of oil, 12,000 B/D of water, and 10.0 MMscf/D of gas. Actual total flow through the pump was 75,000 B/D with a gas fraction of 60%. Incremental oil production was 8,800 B/D. Increasing the pump speed to its maximum of 3,600 rev/min was not possible because the torque limit of the pump was reached at 3,400 rev/min. At the 3,400-rev/min speed, the design differential pressure of 300 psi across the pump was achieved.

Eventually, the live well was removed from pump suction. Thus, all production was from dead wells. Various combinations of dead wells were placed on pump suction to expose the pump over a variety of operating conditions. Up to eight dead wells at a time were placed on pump suction, producing up to 9,000 B/D of incremental oil. Cumulative incremental oil production by use of the pump, from startup through 25 May 2002, exceeded 1.8 million bbl (Fig. 8), and payout was achieved several times over. The oil-production rate and cumulative oil recovered during the above period of time (11 months) are shown in Fig. 8.

Pump Hydraulic Performance

The pump characteristics and the daily production rates for this period can be summarized as follows: pump speed: 3,300 rev/min; power : 480 kW; gas-volume factor: 60%; oil rate: 12,000 STB/D; water rate: 12,000 B/D; gas rate: 10.5 MMscf/D; average hydraulic efficiency: 40%; total actual flow rate: 25,000 to 75,000 B/D. The pump hydraulic performance also was analyzed using different relationships between pump speed, differential pressure, and total fluid rate. These relationships are shown in **Fig. 9.**

Fig. 9-MPP performance.

Revival of a Dual-Lateral Well

A horizontal well was drilled in Zone 2 in 1996 **(Fig. 10),** which watered out and died shortly after completion because of a behind-casing communication with a water-bearing formation above. The well was recompleted horizontally in Arab D, Zone 1, which is above Zone 2. This zone is approximately 25 ft thick and underlain by 10 ft of tight zone. The 10-ft barrier practically seals the zones and does not allow pressure support to Zone 1, which is unswept by water and has low porosity. Consequently, the well died after a short time of production because of the lack of the pressure support. The well was connected to the MPP, and it produced at a rate of 3,000 STB/D with 4% water cut.

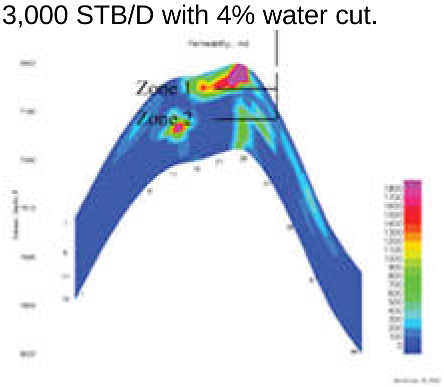

Fig. 10-Permeability distribution at the test location and schematic of the multilateral well.

Conclusions

- A field test of the first MPP in a mature carbonate reservoir in Saudi Arabia showed that this technology can be used to pump three-phase fluids at long distances without separating the gas and to revive dead wells.

- Wells responded to reduced backpressure, incremental oil production is estimated at 2,000,000 STB, and payout was achieved several times over since startup.

- The pump is capable of accommodating a broad range of operating conditions. The VFD was required equipment for the application.

- Power consumption was economical, with a power cost of U.S. $0.03/bbl of oil.

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