WIERTNICTWO NAFTA GAZ • TOM 25 • ZESZYT 2 • 2008

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MAXIMIZING OF CONDENSATE RECOVERY RATIO IN KARACHAGANAK USING METHOD OF CYCLING PROCESS

1. GENERAL INFORMATION

Karachaganak is located in the northwest region of Kazakhstan and it is one of the world's largest oil and gas condensate fields. Covering an area of over 280 square kilometers, it holds more than 1,200 million tones of oil and condensate and over 1.35 trillion cubic meters of gas. The expansion of the field has involved an investment of over $ 4.3 billion and it is currently the biggest internationally funded project in Kazakhstan. The field development is being overseen by four international partners – British company BG Group and Eni of Italy, each with a 32.5 percent interest, Chevron of the USA with 20 percent, and LUKOIL of Russia with 15 per cent. They came together to form Karachaganak Petroleum Operating B.V. (KPO). The operations of KPO are regulated by the Final Production Sharing Agreement that was signed in 1997 by the government of the Republic of Kazakhstan and the KPO partners. Under the agreement, KPO will operate the Karachaganak facilities through to 2038.

Karachaganak production originates deep underground in reservoir approximately 5,000 meters deep. The reservoir contains a vast quantity of oil, condensate, and gas all embedded in a porous rock structure. These hydrocarbons are layered much like a cake with the oil near the bottom of the reservoir in a thin layer, the condensate in a thicker layer on top of the oil and then the gas in the thickest layer at the top of the reservoir. These hydrocarbons are produced through well bores from the deep formations up to the surface. At these depths the earths crust exerts high pressures and as a result the hydrocarbons are literally squeezed out of the rock formations and are under very high pressure, which allows them to flow easily to the surface. On reaching the surface the individual wells flow both oil and gas to manifolds, which combine the production and provide this feedstock to one of three modern efficient plants in the Karachaganak field.

Upon entering one of the process plants the oil and gas is initially separated into a gas stream and an oil stream. This separation can be achieved through both a gravity method

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and through temperature reduction of the fluids. Individual wells can also be directed to a test separator. This regular testing is needed to measure the rates at which a well is producing oil and gas, to determine whether it is producing any water, and to measure the pressure at which it is producing. All of these measurements enable the engineers to optimize the production from the field.

First gas reinjection into the Karachaganak reservoir took place on 2 July 2003, and first production from the new facilities entered the connecting pipeline to Atyrau on 15 July 2003. Further phases of development are expected to follow, to increase liquids production, subject to the development of a market for the substantial additional gas volumes that would be produced.

2. CONDENSATE RECOVERY FACTOR

Gas-condensate reservoirs exhibit complex phase and flow behaviors due to the appearance of condensate banking in the near-well region. A good understanding of how the condensate accumulation influences the productivity and the composition configuration in the liquid phase is very important to optimize the producing strategy, to reduce the impact of condensate banking, and to improve the ultimate gas recovery. Different producing strategies have been compared, and the optimum producing sequences are suggested for maximum condensate recovery.

3. WATER FLOODING

Gas condensate reservoirs are usually produced by primary depletion. This technique is normally an efficient means of producing the gaseous hydrocarbon components but can be very inefficient in producing the more valuable liquid components which are left in the reservoir in a condensed liquid phase. The recovery efficiency of the liquid components decreases with increasing richness of the gas condensate, making for a large IOR target in some reservoirs. The usual approach to improving liquids recovery is to recycle produced gas through the reservoir. However, this technique may not be economically attractive when there is the possibility of immediate gas sales because of the discounting applied to the gas value when sales are delayed. An alternative means of improving liquid recovery is to keep the reservoir pressure above the dew-point for a period by injecting water. Depending on reservoir characteristics, water injection may be continued throughout field life or the reservoir may be pressure depleted after a period of injection. Special relative permeability data, describing the mobilization of water flood trapped gas by expansion, are necessary for the latter case.

4. GAS CYCLING OR GAS RE-INJECTION

Gas reinjection is the reinjection of natural gas into an underground reservoir, typically one already containing both natural gas and crude oil, in order to increase the pressure within the reservoir and thus induce the flow of crude oil. After the crude has been pumped out, the natural gas is once again recovered. Since many of the wells found around the world contain heavy crude, this process increases their production. The basic difference between light crude and heavy crude is its viscosity and pumpability - the lighter the crude the easier it is to pump. Recovery of hydrocarbons in a well is generally limited to 50% (heavy crudes) and 75-80% (light crudes). Recycling of natural gas or other inert gases causes the pressure to rise in the well, thus causing more gas molecules to dissolve in the oil lowering its viscosity and thereby increasing the well's output. Air is not suitable for repressuring wells because it tends to cause deterioration of the oil, thus carbon dioxide or natural gas is used to repressure the well. The term «gas-reinjection» is also sometimes referred to as repressuring the term being used only to imply that the pressure inside the well is being increased to aid recovery.

The objective of the cycling in gas condensate reservoir is to maintain pressure close to the dew point and recover more wet gas with a maximum condensate yield. The problem is that during the life of the reservoir, breakthrough appears and the condensate yield decreases in some wells located close to the gas injectors. For a gas condensate reservoir with an active aquifer, the problem is twofold since care should be taken to avoid water and gas breakthrough. Condensate reservoirs are complicated as pressure drop provokes condensate dropout in the reservoir. Using PVT calculations based on the Peng–Robinson model or other models, authors have shown that after a pressure decrease of a few bars, dropout occurred, and about 10% of the condensate would be lost in the reservoir. Compositional simulation models characterize reservoir performance using the equation of state. Emphasizing the importance of the maximum recovery of condensate without condensation in the reservoir, the present work discusses the effect of gas cycling. This is not economically justified after a certain period of time, unless there is a need to stock lean gas in the reservoir.

5. KARACHAGANAK GAS INJECTION PROJECT – YEAR END 2004

Gas injection commenced on the 2nd July 2003. Approximately 185 MCM of gas was injected into the field before the gas injection facilities were shut down on the 31st October 2003 for facility modifications.

KPO re-started the sour gas injection from Unit 2 on May 19, 2004. During this period, the gas injection start-up sequence included individual well Step Rate tests and area wide Pulse Test. This activity was planned in the time available between the start-up sequence of Unit 2 and the start-up of the gas plant at KPC. At this time Unit 2 production was on restricted production to Unit 3 for feed forward to either Orenburg and/or KPC Train A.

Currently, there are 13 active injectors. Well 325 has been withdrawn as a potential injector due to poor reservoir development in Object 2. There are 4 main injection trunklines servicing these wells. A diagram of the injection well and distribution system is shown in Figure 1.

The main objective of the Step Rate Tests was to accurately measure the injection capacity of the wells. The main objective of the pulse test is to estimate the reservoir connectivity and transmissibility patterns of the Unit 2 injection area (pulse between gas injectors and producers). With limited need for U2 production during this time period (23 May to 1 July), the producers in the pulse test area could be shut-in to eliminate any background noise or interference with specific pulse measurements. During this testing program, Step Rate tests were completed on 5 injectors; wells 107, 126, 163, 207 and 702d. Pulse tests were performed using 6 injectors; wells 163, 207, 700, 702d, 707 and 715. Long term memory pressure gauges were set in 13 offset producers to measure pulse response. A field diagram of the pulse testing program, including well locations for the pulse injectors and monitoring producers is shown in Figure 2. Results of the step rate tests have provided excellent data to update our individual well models. Table 1 shows the current well injection capacity rates at the maximum allowable operating limits.

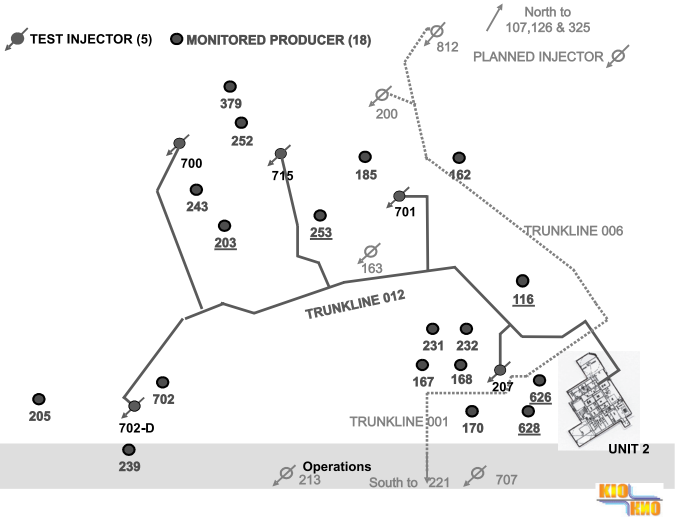

Fig. 1. Injection Line 012 – Network Schematic

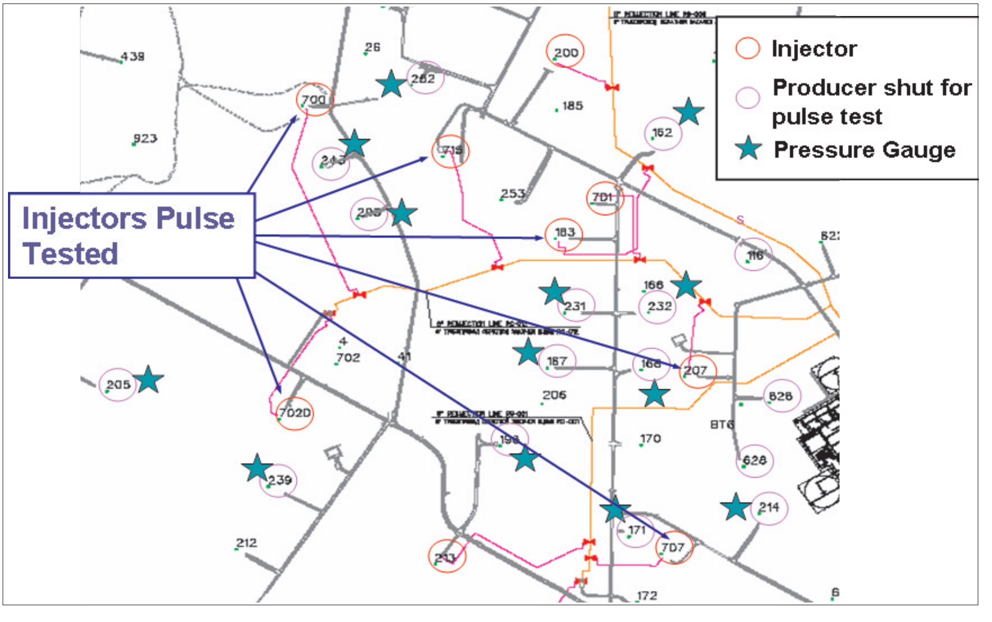

Fig. 2. Pulse Test Program Schematic

Table 1

Gas Injection Status at End of 2004

Well No	Flowline No	Max. Allowable Injection Operating Pressure (Barg) (Note 1)	Casing Test Pressure Barg	Estimated Max Injection Rate MM m^3/D C&N Matched (Note 7)	Comments
207	012	430	450	1.1	Well available. Injection step rate test completed June 04
700	012	365	390	1.5	Well available. Injection step rate test completed Q3 2003
701	012	425	450	1.4	Well available. Injection step rate test completed Q3 2003
702d	012	430	450	1.9	Well available. Injection step rate test completed Q3 2003
715	012	425	450	1.3	Well available. Injection step rate test completed Q3 2003
213	001	425	450	1.0	Well under investigation for tree growth. Injection step rate test completed Q3 2003
221	001	425	450	0.6	Well available
707	001	425	450	1.8	Well available. Injection step rate test completed Q3 2003
163	006	425	450	1.8	Well available. Injection step rate test completed June 04
200	006	425	450	0.5	Well available
812	006	430	450	1.5	Well available. Injection step rate test completed June 04
107	024	430	450	1.8	Well available. Injection step rate test completed June 04
126	024	430	447	2.1	Well available. Injection step rate test completed June 04
325	024	530	550	0	Well withdrawn from injection well stock
Total Trunk line Daily Well Injection Capacity MMSm^3/day – 100% Availability				18.4	Including well 213
TOTAL Annual Well Injection Capacity BSM3/Y – 100% Availability				6.7	Including well 213

cling of natural gas or other inert gases causes the pressure to rise in the well, thus causing more gas molecules to dissolve in the oil lowering its viscosity and thereby increasing the well's output. Nowadays gas-reinjection are used in Karachaganak for maximum condensate recovery and may be continued throughout field life.

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