GAS-CONDENSATE CORE FLOODING EXPERIENCE FOR URENGOYSKOYE GAS-CONDENSATE FIELD

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ABSTRACT
Production from gas-condensate reservoirs below the dewpoint of the reservoir fluids leads to the accumulation of the liquid hydrocarbon phase (condensate) in the near-wellbore region of the reservoir and causes deterioration of the well productivity—so called condensate blockage [2]. Condensate blockage results from fluid and formation interaction in the near-wellbore region. The main goal of our research was to experimentally study multiphase gas-condensate flow at regimes typical for near-wellbore zones of production wells producing from the Achimov formation of the Urengoyskoye gas-condensate field (western Siberia, Russian Federation).

In the course of preparing the flooding experiments, a full-featured pressure-volume-temperature (PVT) study of live gas-condensate fluid sampled from the Achimov formation field was performed. Due to limitations of the core flooding facility in handling high-pressure, high-temperature conditions, a model gas-condensate fluid was prepared to match, at laboratory pressure-temperature (PT) conditions (150 bar, 70^0C), phase viscosity, bulk density, and interfacial tension (IFT) measured on the live fluid at downhole PT conditions (350–500 bar, 110^0C). A reservoir model consisting of three cores with 19.6% porosity and 17.5 mD permeability was prepared for the core-flooding experiment. A commercially available core flooding system was adapted to handle the measurements of relative phase permeability for the live fluids at elevated PT conditions (150 bar, 70^0C). Phase permeability and non-Darcy coefficients were measured for artificial gas condensate fluid at different flow rates and condensate saturations.

The main results of the study include: development of a methodology for preparing the model gas condensate fluid to enable core flooding experiments at PT conditions different from downhole conditions; a methodology was implemented for 2-phase core flooding experiments using live fluids with separate injections of the fluid phases at elevated PT conditions; non-Darcy (inertial) flow coefficients were measured for the gas phase at different immobile condensate saturations; and phase permeability curves were obtained for 2-phase gas-condensate flows at different flow rates.

INTRODUCTION
The Urengoyskoye natural oil, gas, and condensate field in the western Siberian basin is the largest gas field in Russia and also one of the largest onshore deposits in the world.

The recoverable reserves have been estimated at around 7 trillion m^3 of natural gas. The deposit was discovered in the 1960s and systematic development and production was initiated in 1977. Most of the gas is produced from the Lower Cretaceous Achimov formation at depths ranging from 3,150–3,800 m. The Achimov formation is characterized by elevated temperatures (> 100°C) and abnormally high-formation pressures (> 500 bar), and consists of moderately porous but quite low-permeable sandstone. From a geological aspect, this horizon in which both gas and oil are to be found evolved around 140 million years ago. This geological formation is very common in western Siberia and can be found in many fields.

Complex physical processes occurring in the reservoir and the huge field size place it on the level of poorly studied objects. The low permeability of the Achimov formation causes high depression while producing; therefore, a significant amount of the condensate drops out in the near-wellbore region. For optimal field development planning and enhancing gas/condensate production and recovery, there is clearly a need for obtaining phase permeability experimental data at reservoir pressure and temperature (PT) conditions because they are key components in the reservoir modeling of rich gas-condensate fields.

In the years 2009–2011, there was a joint R&D project between the Schlumberger Moscow Research Centre (SMR) and Gazprom's R&D Institute TyumenNIIgiprogas (TNGG) aimed at studying gas-condensate flow in the Achimov formation of the Urengoyskoye field. The project goal was to perform a direct laboratory measurement of phase permeabilities for a dual-phase gas-condensate flow in the presence of residual water in the pore space at reservoir conditions in the vicinity of a wellbore. The project plans called for performing a series of gas-condensate core flooding experiments in both Darcy (low-rate) and non-Darcy (high-rate) flow regimes. The experimental program consisted of three stages: analysis of the available core material and preparation of the reservoir model; preparation of the fluids; core flooding experiments.

RESULTS

Reservoir model preparation

A collection of 36 core plugs (cylinder ø30×30 mm) of Achimov sandstone was prepared by TNGG team and then studied in the SMR. All of the samples were taken from a Urengoyskoye oil-gas-condensate field well at a depths ranging from 3676–3750 m of horizon Ach4. The entire collection of cores has been thoroughly studied by means of petrographic analysis of thin sections, capillary pressure curves, and irreducible water saturation by the porous plate technique, formation resistivity factor, resistivity index, and qualitative and quantitative analysis of X-ray microCT images (porosity, structural parameters). Laboratory results led to the definite conclusion that the Achimov sandstone, as a clinoform deposit, exhibits unusual properties and is not easy to investigate. Core porosity varied over the range of 15–20%. Permeability measurements performed by steady-state and pressure falloff methods provided sample permeability values of less than 30 mD.

Before performing the analysis, all of the cores were cleaned by Soxhlet's extraction apparatus and dried. Porosity and gas permeability were experimentally measured for all 36 samples and the results are shown in **Figure 1**. Nine groups were arbitrarily identified from the crossplot and three samples from Group 1 with high porosity and permeability were selected for gas-condensate core flooding experiments.

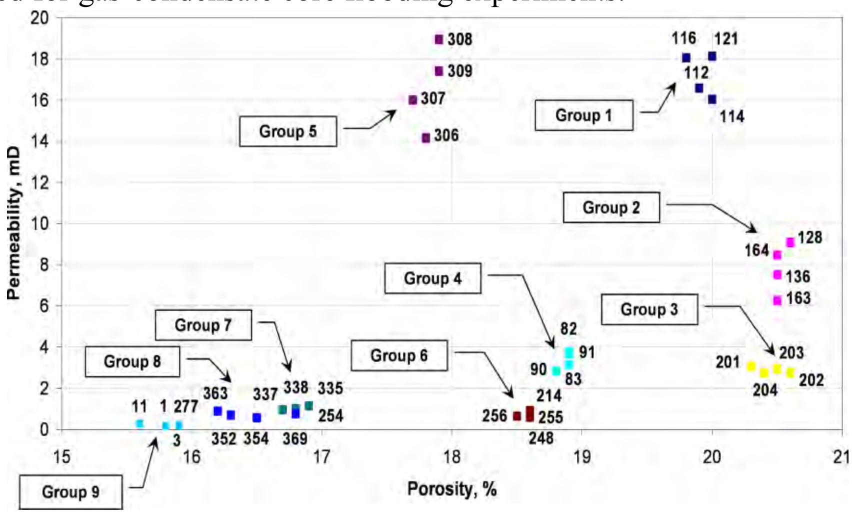

Figure 1. *Porosity versus gas permeability (Klinkenberg corrected) crossplot for the 36 core plugs of the Achimov sandstone.*

Fluid model preparation

Due to limitations of available core flooding facilities, PT conditions of the experiment were reduced to 150 bar and 70^0C (laboratory PT conditions) from 500 to 600 bar and 110ºC. A model fluid that could simulate the laboratory condition's behavior of the reservoir fluid at original conditions was prepared. Because non-Darcy flows of 2-phase fluid were studied, conditions of equality of phase, viscosity, density and IFT were used to qualify similarity of the fluids. Preparing model fluids as alkanes mixtures or alkanes and aromatic 1-methylnaphtalene mixtures, although simple and allows for generating arbitrary amounts of the fluid with controlled properties (see **Table 1**) was proven to be impossible. It was observed that mixtures of saturated alkanes were unable to reproduce the condensate properties and 1-methylnaphtalen was determined to be forming a 2-phase mixture while mixed with hexane and cetane, even under laboratory conditions. The complex composition of the condensate was considered to be the main reason of the failures for the models based on the saturated alkanes mixture; therefore, a mixture of the methane and stable condensate—debutanized natural gas liquid—was used. Low variability in the composition of the stable condensate during production allowed for obtaining an amount of the liquid sufficient for the experimental program. Using simulations based on the fluid model developed by TNGG, it was determined that the composition of the model fluid was key in providing the best model properties fit at laboratory conditions to the reservoir fluid properties at reservoir conditions (**Table 1**). Simulation results were validated by the laboratory measurements (see **Fig. 2**).

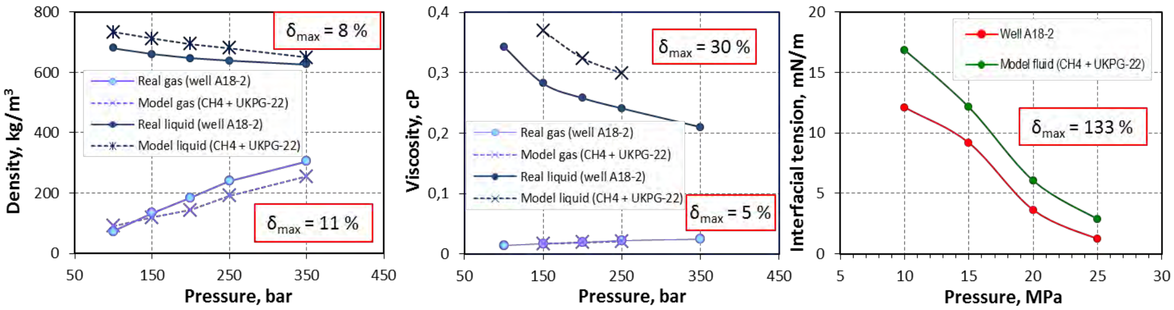

Figure 2. *Measured phase, density, viscosity, and IFT for the Achimov reservoir fluid (real fluid) and model gas condensate (CH4+UKPG-22)*

Table 1. Composition of model fluids

Component	**Aggregate state @ SC***	**Mass fraction, %**	**Component**	**Aggregate state @ SC***	**Mass fraction, %**
Model 1			Model 2		
methane (C_1H_4)	gas	70.04	methane (C_1H_4)	gas	70.00
hexane (n-C_6H_{14})	liquid	17.95	hexane (n-C_6H_{14})	liquid	18.00
cetane (n-$C_{16}H_{34}$)	liquid	4.00	icosane (n-$C_{20}H_{42}$)	liquid	12.00
1-methylnaphthalene (1-$C_{11}H_{10}$)	liquid	8.01	Model 3		
			methane (C_1H_4)	gas	60.00
*SC – standard conditions			stable condensate (UKPG-22)	liquid	40.00

Core flooding experiment

Before the flooding experiments with gas and condensate, a series of single-phase flow experiments with gaseous nitrogen was performed to test the core flooding setup and study the influence of residual water on both permeability and non-Darcy (inertial) flow coefficient. For performing flooding experiments at non-Darcy regimes, the setup was equipped with a high-flow rate pump unit (250-cc/min maximum flow rate) for gas injection.

Core flooding experiments were performed on a composite core consisting of three core plugs with 19.6% average porosity and 17.5 mD gas permeability. Initially, the gas flow experiment was performed on dry cores. In the next step of the experiment, the cores were saturated with brine and irreducible saturation (S_{wi} = 35.5 – 35.9 %) was established in the centrifuge followed by repeating the flow experiment. A gas humidifier was installed in the system to prevent water evaporation. Experimental results are presented in **Figure 3**. Both sets of experimental data could be approximated by straight lines given by Cornell-Katz equation. Intersection of the trend lines with the Y-axis provides $1/K_{eff}$ (K_{eff} - effective permeability) and the slopes of the lines are inertial coefficient. As shown in **Figure 3**, gas permeability was insensitive to S_{wi} but inertial coefficient increased by 23% from $\beta = 2.76 \cdot 10^7 cm^{-1}$ to $3.40 \cdot 10^7 cm^{-1}$ due to presence of irreducible water.

After testing with nitrogen, experiments with gas-condensate mixtures began. Initially, single-phase flow of the model gas phase at different flow rates, 3, 6, 12, 24, 48, and 96 cc/min (S_{oil} = 0 %) was studied. The next step consisted of single-phase flow of the model gas at the same flow rates at immovable condensate saturation. To set immobile condensate saturation, 1, 2, and 3 cc of condensate was injected into the core.

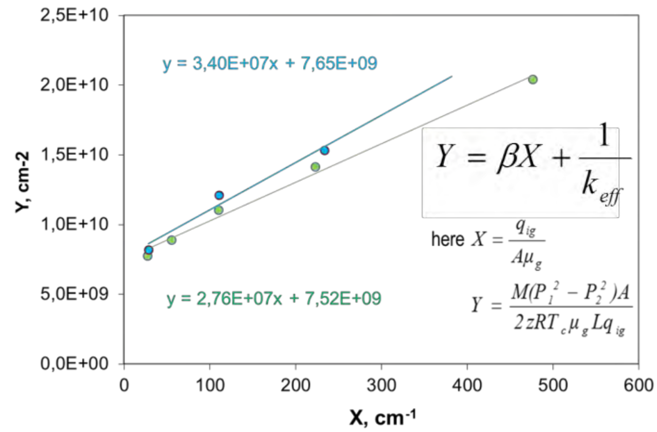

Figure 3. *Calculation of non-Darcy flow coefficient (β) using the Cornell-Katz equation [1]. Green and blue circles correspond to dry cores and cores with irreducible water, respectively.*

Saturation of the core in both phases during the experiment was estimated by mass balance, assuming absence of phase transition in the core (confirmed by PVT analysis data). The amount of produced gas and condensate was estimated by using a slightly modified acoustic separator. The increase of inertial coefficient and decrease of permeability shown in **Figure 4** are caused by an increase of condensate saturation in the porous space; nevertheless, quantitative estimation of β at higher values of S_{oil} should be performed with caution.

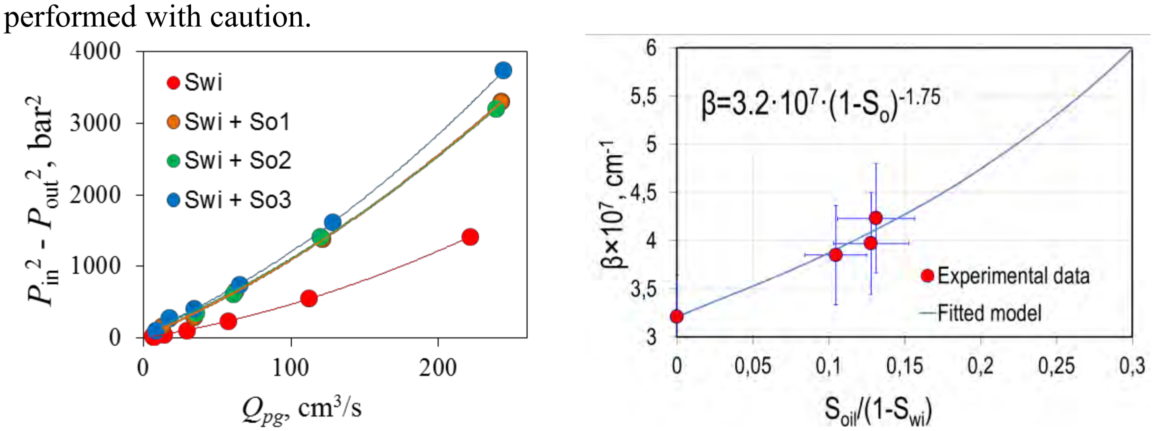

Figure 4. *Influence of immovable condensate saturation on pressure drop (left) and coefficient vs*. saturation β (right).

The last stage of the experiment was the 2-phase flow. Model gas and condensate were simultaneously injected in the core at different total flow rates (6, 12, 24, 48, and 96 cm^3/min) and at different condensate fractions in the flow (5, 15, and 30%). The experiment was completed with a single-phase model condensate injection at a flow rate of 6 cc/min. Relative phase permeabilities were calculated at each step of the experiment for each flow rate and are summarized in **Figure 5**.

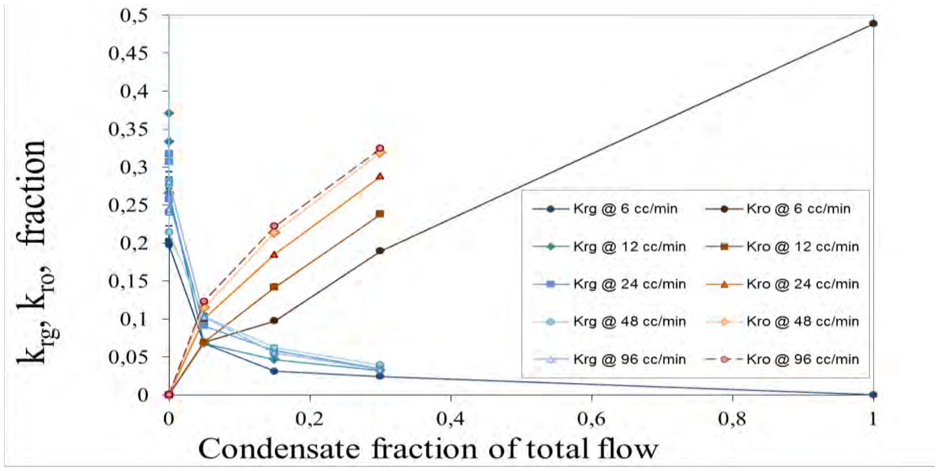

Figure 5. Relative phase permeability at different flow rates vs. condensate fraction in total flow.

SUMMARY AND CONCLUSIONS

It was observed that a model based on a mixture of the saturated alkanes could not simultaneously reproduce phase, viscosity, density, and IFT. A method for preparing the model gas condensate from debutanized condensate and methane was developed to enable core flooding at PT conditions that was different from downhole conditions.

A procedure for 2-phase core flooding experiments with live fluids with separate injections of the fluid phases at elevated PT conditions was implemented and adapted for high-flow rate gas-condensate core flooding experiments. The procedure was used to perform core flooding experiments with Achimov formation cores.

Non-Darcy flow regimes were studied for single-phase gas (nitrogen) flow. The presence of irreducible water in the pore space caused an inertial coefficient increase and had insignificant influence on gas permeability.

Phase permeability curves were obtained for 2-phase gas-condensate flows for different flow rates. Non-Darcy (inertial) flow coefficients were measured for gas and condensate phase at irreducible water and at different condensate saturation (immobile and mobile).

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