

Impact of Thermal Maturity of Shale on Well Production Performance – A Physical Simulation of Primary Production Stage in the Duvernay

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Summary

Most unconventional wells typically exhibit limited oil production during the primary production stage, primarily due to ultralow permeability of the rock matrix and immaturity of the organic matter. To understand the key factors responsible for this limitation and identify candidate sweet spots for drilling, we conduct physical simulations of the primary production stage in the laboratory. In this study, Duvernay shale samples undergo a single-cycle methane injection process to simulate the primary production stage. We utilize a visualization cell to explore oil-recovery mechanisms under representative reservoir conditions. We soak oil-saturated core plugs with methane at 4,150 psig and a reservoir temperature of 90°C to restore initial reservoir conditions. After equilibrium, we deplete the cell pressure at a controlled rate to simulate the primary production stage. Using two shale samples with different thermal maturity levels, our results demonstrate that methane diffuses into both cores during the soaking; however, it dissolves in oil only in the mature shale sample, resulting in a live oil with a solution gas-oil ratio of 932 SCF/STB. During the primary production stage, we observe significant oil production under the solution-gas drive mechanism from the mature shale, while the immature shale exhibits negligible oil production. Natural fractures enhance gas penetration into the core, contributing to increased oil production in the primary production stage. Ultimately, the mature shale sample exhibits an oil recovery factor of 25.6% of original oil-in-place after the primary production stage, a remarkable contrast to 1.5% recovery observed in the immature shale. This difference is attributed to the immaturity of the organic matter, insufficient original oil-in-place, and absence of connected oil-wet pore network in the immature shale sample, confirmed by wettability evaluation and rock-eval pyrolysis data.

Theory / Method / Workflow

We use two rock samples extracted from two different wells in the Duvernay Formation (**Figure 1**). Du-1 and Duv-2 are immature and mature shale samples, respectively. We conduct the primary production experiments using a state-of-the-art HPHT visualization cell. We use pure methane as soaking fluid at set pressure of 4,150 psig. The viewing window of the cell enables us to observe the real-time gas-oil interactions during the experiments. Each experiment consists of five main steps:

- **Cell and Gas Preparation:** The visualization cell needs to be tested for leakage using the same type of gas and under the same operating conditions as the main test. After the leakage test, we place the oil-saturated rock sample inside the visualization cell and vacuum the cell for a short period. Note that the cell and rock sample are already heated up to the set temperature of 90°C during the leakage test and rock saturation steps. Meanwhile, the gas sample is discharged from the gas cylinder into a transfer vessel and is heated up to the required temperature.

- **Gas Injection:** We use a pulse-free water pump to compress and inject the pre-heated gas into the visualization cell. The cell pressure builds up rapidly due to the initial pressure of the gas in the transfer vessel and then pressure is gradually increased to the set pressure of 4,150 psig. The entire injection period lasts for less than 30 minutes.
- **Restoring Initial Reservoir Conditions (Soaking):** After reaching the set pressure, the injection valve is closed, and the cell is isolated. This step is designed for sufficient gas penetration into the core and subsequent dissolution in oil. This procedure helps to prepare live oil in the pore space of the rock samples. The cell pressure and temperature are recorded in 10-seconds increments during the entire soaking period. The soaking period lasts for 180 hours in this study to allow sufficient time for gas transport into the rock.
- **Primary Production (Depletion):** At the end of the soaking, we use a back-pressure regulator (BPR) for a controlled rate of production similar to choke in field operations. We connect the production port of the visualization cell to the BPR and decrease the cell pressure at a controlled rate down to atmospheric pressure. The depletion period lasts for approximately 2 hours in this study.
- **Oil Recovery Calculation:** Finally, we remove the rock sample from the visualization cell and measure its weight to calculate the oil recovery factor of primary production stage.

Note that during the entire experiment, the cell temperature is maintained at 90°C to avoid temperature fluctuations in pressure responses. Besides, a high-resolution camera records the gas-oil interactions and oil production during the entire experiment.

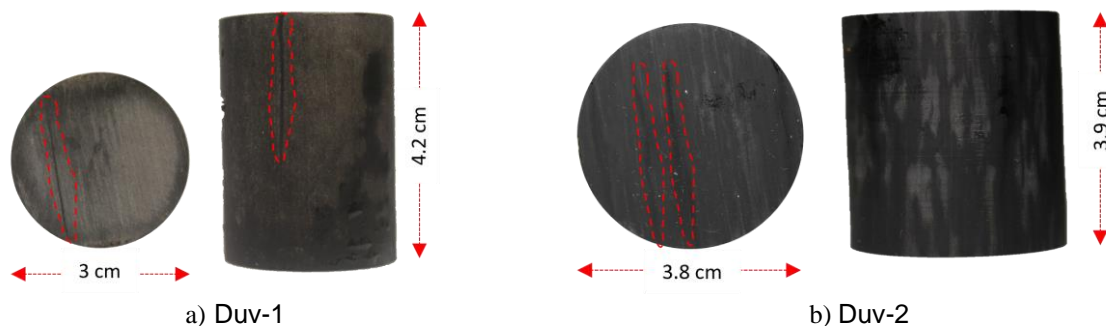


Figure 1. Photos of the preserved Duvernay rock samples used in this study. The red dashed regions denote the presence of natural fractures in the rock samples.

Results, Observations, Conclusions

After reaching the set pressure, we observe a gradual decline in cell pressure in both experiments (**Figure 2**). As gas penetrates into the core plug through the open end-face, the cell pressure decreases [1,2]. The total pressure drop (ΔP) after 180 hours of soaking is 340 and 140 psig for Duv-1 and Duv-2 samples, respectively. This indicates that more mole of gas is transported into the pore space of Duv-1 sample. However, this is because gas penetration into depleted pores of Duv-1 is easier than its penetration into non-depleted pores of Duv-2 sample. The solution gas-oil ratio at the end of soaking for the mature Duv-2 shale sample is 930 SCF/STB, which is comparable to the gas-oil ratio reported at field site (1,340 SCF/STB).

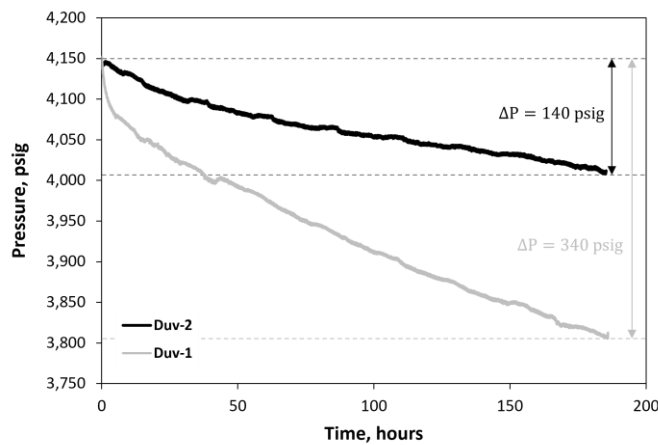


Figure 2. The recorded pressure data during the soaking stage. The black and gray curves represent the pressure profiles for Duv-2 and Duv-1 samples, respectively. The black and gray arrows indicate the total pressure drop during the soaking process for Duv-2 and Duv-1 samples, respectively.

After 180 hours of soaking, we decrease the cell pressure using the depletion strategy illustrated in **Figure 3**. This is a hybrid depletion scheme with a fast depletion of 100 psi/min down to 1,100 psig followed by a slow depletion of 20 psi/min down to atmospheric pressure. We implement the same strategy for both experiments; therefore, the pressure profiles are completely parallel in **Figure 3**. Since the cell pressure at the end of soaking is higher in Duv-2 test compared to Duv-1 test (**Figure 2**), the depletion pressure profile of Duv-2 test starts at a higher pressure.

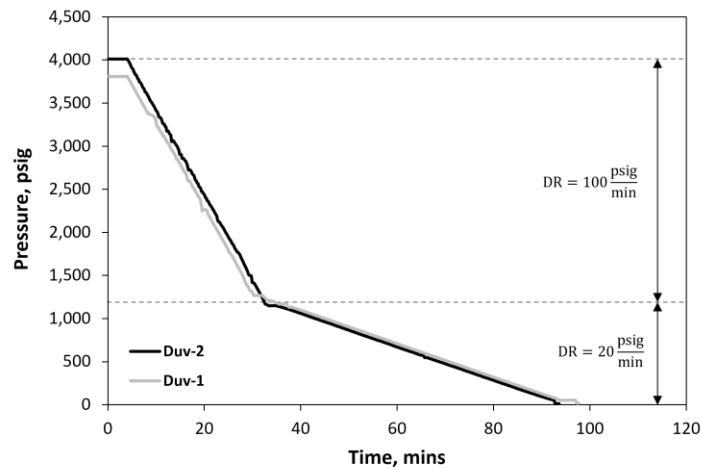


Figure 3. The recorded pressure data during the primary production stage. The black and gray solid curves represent the pressure profiles for Duv-2 and Duv-1 samples, respectively. The depletion rates during the early and late stages are marked by black arrows.

We analyze the snapshots of the open end-face of the core at specific time intervals for both Duv-1 and Duv-2 samples (**Figure 4**). During the entire depletion stage, the snapshots do not indicate any oil production through the open end-face of Duv-1 sample (**Figure 4.a**).

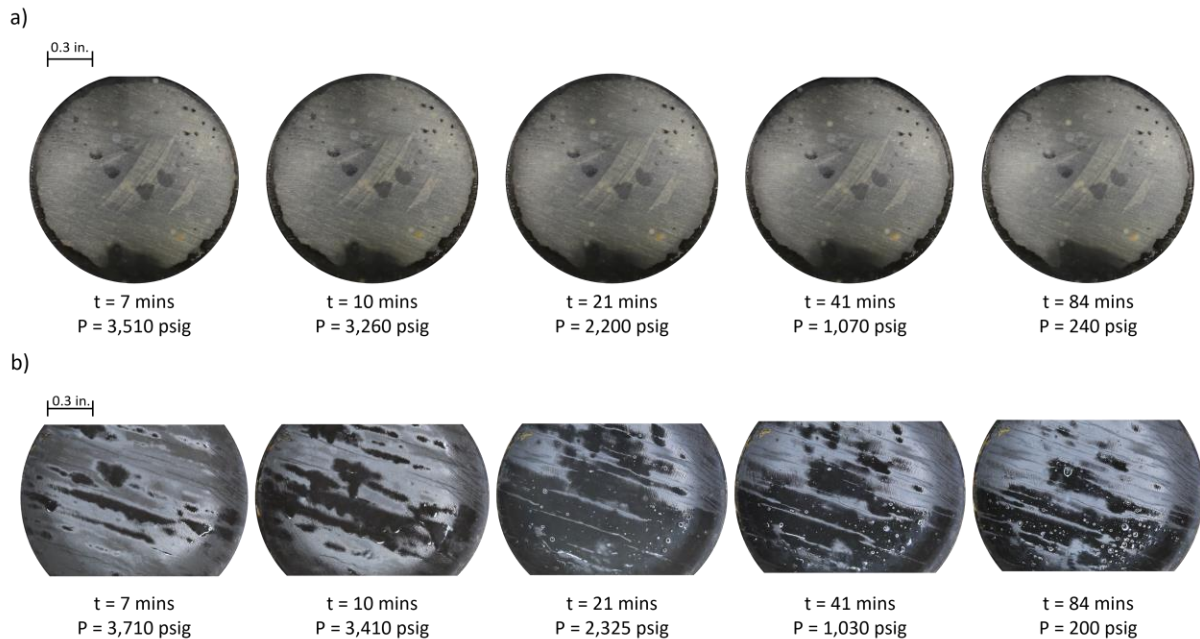


Figure 4. The snapshots of the open end-face of the core plug during the primary production stage for a) Duv-1 and b) Duv-2 samples. The corresponding pressure and temperature is indicated for each snapshot.

From Duv-2 sample, after 7 minutes of depletion, when the cell pressure is reduced to 3,710 psig, oil production starts along the natural fractures of the core. The surface of the core becomes more wet by oil by continuous depletion down to 2,325 psig at $t = 21$ minutes and then starts drying down to atmospheric pressure. Once the cell pressure is decreased, the dissolved gas evolves out of the oil and increases the pore pressure. Accordingly, the pore pressure becomes higher than the cell pressure and creates a pressure gradient from pore to cell for oil and gas production. The evolved gas moves towards the open end-face of the core and pushes and drags the oil with itself and results in oil production. This mechanism is commonly called solution-gas drive and is identified as the dominant mechanism for oil production based on the observations in this study [1–3].

After depleting the cell pressure, we estimate the RF_{oil} using material balance. The results indicate an RF_{oil} of 1.5 and 25.6% for Duv-1 and Duv-2 samples, respectively. Consistent with the results of visualization experiments, the extent of oil recovery is significantly higher from Duv-2 sample. This corresponds to the higher OOIP, pronounced solution-gas drive mechanism, abundance of natural fractures, and higher maturity of organic material in Duv-2 shale sample.

Novel/Additive Information

Although Duvernay possesses the requirements for a successful unconventional reservoir, the industry faces challenges in identifying its sweet spots. Many drilled wells encounter issues such

as low fracturing fluid recovery, incompatibility of chemical additives with reservoir fluids, and minimal oil recovery. This study attempts to physically simulate the primary production stage in Duvernay with shale samples with different thermal maturity levels. By analyzing the results of this study, we aim to identify the candidate Duvernay wells for implementing EOR operations. The visualization data assists in determining the associated oil-recovery mechanisms under in-situ reservoir conditions.

Acknowledgements

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