PREDICTING PRIMARY DEPLETION RECOVERY OF A GIANT LIGHT OIL CARBONATE RESERVOIR

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ABSTRACT

Predicting primary depletion recovery below the bubble point is a very difficult challenge, especially for carbonate reservoirs. Accurate predictions require sufficient laboratory data to cover the variability in response from the different rock types and laboratory procedures, and proper up-scaling of laboratory data to simulation grid scales.

Many recent studies have shown that laboratory derived gas oil relative permeability curves often depend on whether the tests were conducted using depletion drive or steady state methods. Though it may seem preferable to use depletion drive derived laboratory data for modeling solution gas drive recovery, these tests are complex and there is concern using data from tests conducted at pressure depletion rates much higher than that in the field. More significantly, such tests are expensive and it is not practical to conduct many depletion tests.

We used mercury injection, porosity, permeability, CT scans, and thin section data to classify the giant carbonate reservoir into different rock types. Steady state gas-oil relative permeability tests on plug samples were then conducted to span these rock types, and P10-50-90 curves developed. We also carried out steady state and reservoir condition multi-rate depletion on select whole cores. This data was used to apply a correction to the steady state plug data, and this typically lowered the gas relative permeability curves.

We next conducted numerous up-scaling studies using sector models extracted from the full field simulation model. These studies showed that areal up-scaling cause the core based critical gas saturation to be increased and the oil relative permeability to be decreased. Vertical up-scaling, including the presence of high permeability streaks to represent fractured zones, has not yet shown much impact on the laboratory derived curves.

INTRODUCTION

Accurate representation of gas oil relative permeability curves in simulation models is very important for prediction of oil recovery in solution gas drive reservoirs. However, conventional displacement type relative permeability experiments conducted at service laboratories do not mimic the physical processes that occur in a solution gas drive process. Solution gas drive experiments are rarely conducted as they are time consuming, expensive and are highly dependent on laboratory conditions such as depletion rates. The interpretation of these experiments is also difficult due to incomplete understanding of the physics of gas liberation and displacement; and because conventional simulators cannot handle non-equilibrium thermodynamic processes that may be present in such experiments. We will briefly discuss the current status of the experimental and theoretical work in understanding the physics of solution gas drive systems before outlining the methodology adopted in this work.

The mechanism of solution gas drive consists of three steps: gas nucleation, bubble growth and gas mobilization. Many authors have presented excellent reviews of these three mechanisms, for example Bauget and Lenormand [1] and Sheng et al., [2]. Many authors have shown higher critical gas saturations and lower gas permeabilities for solution gas drive experiments than external gas drive experiments [3-4]. Other authors have shown increased oil recovery with increasing solution gas-oil ratio [5]. One important experimental observation is the increase in the total oil recovery with higher pressure decline rates [6-8].

There is still some uncertainty in the theoretical understanding of solution gas drive mechanisms [1]. Two mechanisms have been proposed for the process of nucleation: thermodynamic models and models based on pre-existence of micro-bubbles [1]. It has been shown in the chemical engineering literature that experiments do not support the thermodynamic models, and that the pre-existing gas bubble model is more justified [9]. The preexisting bubble theory has been proposed for porous media by Tsimpanogiannis et al., [10] and Lenormand et al., [6]. The growth of these bubbles is controlled by such forces as diffusion, inertia, viscous forces, capillary forces, surface tension and supersaturation (difference of saturation pressure to actual pressure). Li et al., [11] have presented a theory for bubble growth using the pore network model and Lenormand et al., [12] have presented a bubble growth theory in a Darcy frame work. Lastly the gas can be mobilized either in a dispersed manner [2] or a continuous gas phase in which case the standard multiphase Darcy equations are applicable [12]. Conventional reservoir simulators do not incorporate all the equations governing the solution gas drive process. The common approach is to adjust key parameters such as critical gas saturation and relative permeability to match production data.

In this work we conducted solution gas drive experiments on two whole cores at two different depletion rates. We use the conventional approach of adjusting the critical gas saturation and the gas/oil relative permeabilities to fit the production obtained from these two experiments. We then compared these results with the standard steady state gas-oil experiments on the same whole cores. In addition we have also conducted areal and vertical upscaling with the solution gas drive derived relative permeability.

EXPERIMENTAL WORK

Sample Selection

Plug Tests

In order to address the geological variability of the reservoir, 33 plug samples were selected from 10 geologic regions. Sample selection spanned the high, moderate, and low K and ϕ ranges. Steady state gas-displacing-oil displacement tests were conducted on 20 samples, as the rest had permeabilities too low for steady state tests. Centrifuge gas-oil relative permeability tests were conducted on these low permeability samples. The summary of the plug sample properties is given in Table 1.

Table 1: Properties of some typical plug samples used in this study

Sample Number	Porosity	Perm (mD)	Region	Phi-K Range
1	7.71	1.43	1	M-M
2	3.49	0.02	2	VL-L
3	6.86	0.784	3	L-M
4	3.82	1.297	4	VL-M
5	8.4	0.96	5	M-M
6	6.23	0.437	6	L-L
7	8.8	0.095	7	M-L
8	4.89	0.008	8	L-VL
9	11.5	0.11	9	H-L
10	10.87	15.9	10	M-H

Whole Core Tests

The depletion tests were conducted on preserved whole core (10" long, 4" diameter) samples. One of the samples tested had very low permeability (0.08 md). This is an important rock to test as this particular carbonate reservoir has significant low permeability rock that is expected to produce oil on primary depletion, and conventional testing yields little useful information on such low quality rocks. Table 2 contains the geological description.

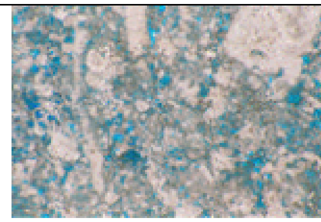
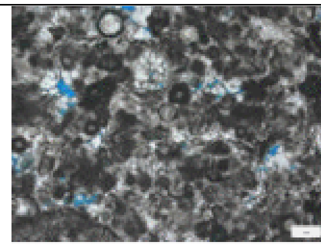
Sample	K md	ϕ	Rock Type	Thin Section
Sample # A	3.6	0.153	More packstone than grainstone. Smaller pores and smaller grains. Good solution-enhanced interparticle porosity; microporosity in peloids and matrix.	
Sample # B	0.08	0.095	This consolidated, micro fossil packed, limestone contains an inter granular pore system characterized by heterogeneously distributed micro pores. The majority of the rock volume is composed of microfossil tests which are cemented by authigenic calcite spar.	

Table 2: Description of core samples used in the study.

Steady State Relative Permeability Experiments

The appendix summarizes the procedures used for the standard steady state displacement tests on the plug samples. We observe that there is wide variability in the relative permeability measurements across regions as well as within the same region. Figure 1 shows the representative relative permeabilities for one given region for this particular reservoir which clearly shows the wide variability within a region. Similarly Figure 2 shows the low, medium and high gas-oil relative permeabilities for two representative regions of the reservoir.

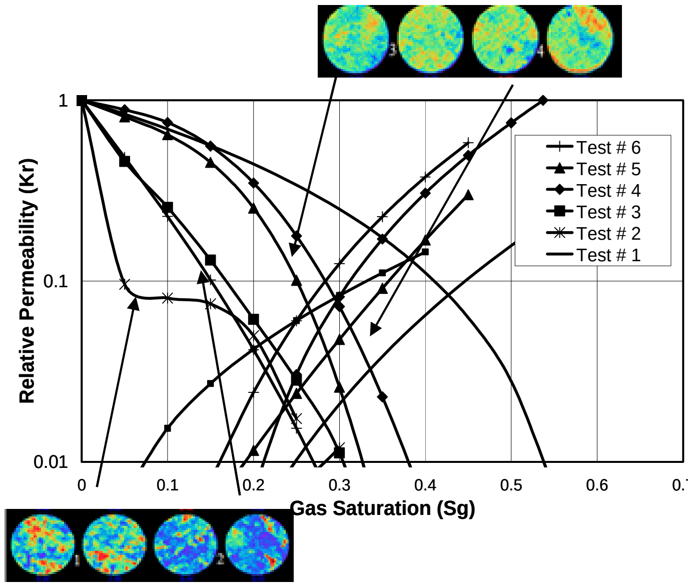


Figure 1: Gas-Oil relative permeability for various test samples in one particular region of the reservoir with corresponding CT scan images for the steady state experiments

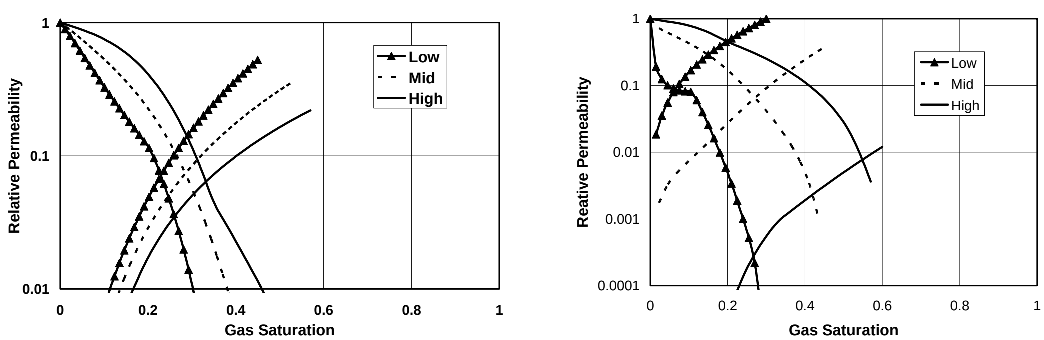


Figure 2: Low, medium, high gas-oil relative permeability sets for two representative regions of the reservoir

In addition to the standard steady state relative permeability experiments, we also conducted whole core steady state tests on two samples, Figure 3 shows the schematic of the experimental steady state setup. The sample preparation and the experimental procedure are similar to that outlined in the appendix.

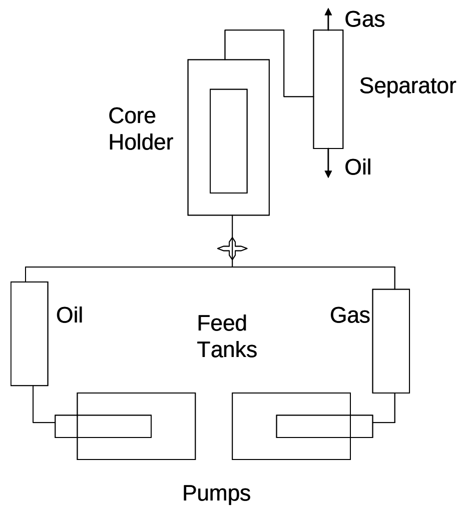


Figure 3: Schematic of the experimental steady state setup

Figure 4 shows the results of the steady state experiments conducted on the sample data set.

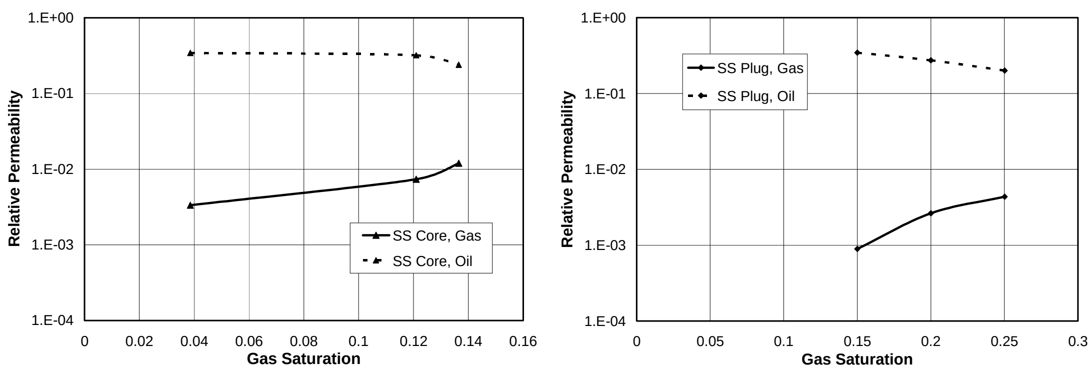


Figure 4: Steady state relative permeability data on the Sample # A whole core (a) and Sample # B whole core (b).

Depletion Experiments on Whole Cores

These experiments attempt to understand oil recovery potential below the bubble point. The primary outputs of these tests are gas-oil relative permeability curves, with critical gas saturation being a key parameter. There are many unresolved issues as to the best measurement method, especially when dealing with low permeability rocks and complex pore structures as discussed in the introduction. The ideal methodology calls for numerically modeling a series of depletion drive experiments conducted on large, uniform core samples. We were limited to a very small sample set. An important issue is the rate of pressure depletion as discussed in the introduction section. Laboratory experiments are necessarily conducted at depletion rates much quicker than in the field.

Figure 5 shows the schematic of the experimental depletion setup. The experiments consisted of saturating the preserved whole core with synthetic live oil at a pressure of at least 500 psi above the bubble point of 3650 psia. We used a process of alternating periods of flow and shut-in with frequent checks of effluent GOR to ensure that the core was fully saturated with the live oil. The pressure was then reduced at 250 psi/day and 150 psi/day for each experiment. The effluent fluids and pressures at the depleting end and the closed end were measured.

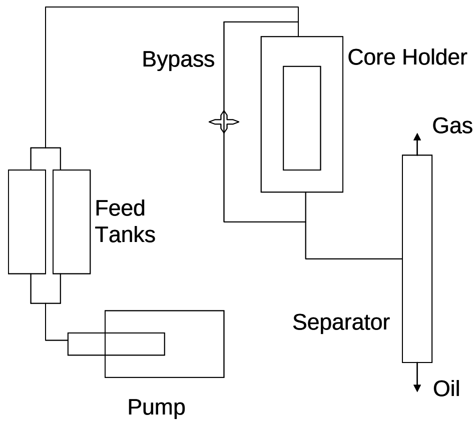


Figure 5: Schematic of the Experimental depletion setup

Figure 6a plots effluent cumulative gas and oil production as a function of the average pressure in the core Sample # A. The 150 psi/day depletion experiment recovered less oil than the 250 psi/day experiment, as it began at a lower initial pressure. Figure 6b plots the effluent cumulative gas and oil production as a function of the average pressure in the core for the 0.06 mD permeability core Sample # B. The average pressure in this case has been calculated as a linear average of the pressure between the inlet and the outlet of the core. We observe that the gas and oil production is not significantly effected by the difference in the depletion rate for the two rates considered here.

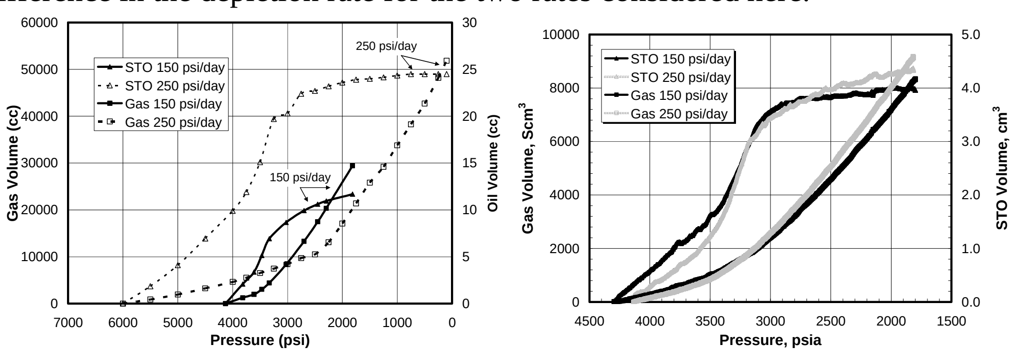


Figure 6: Cumulative oil and gas production for the 150 and 250 psi/day depletion experiments on Sample # A (a) and Sample # B (b).

Numerical Modeling of Depletion Experiments

The objective of numerical modeling is to obtain gas-oil relative permeability curves that can reproduce the observed experimental data. We used an in-house reservoir simulator with black-oil formulation for modeling the experiments. The depletion experiments are modeled by using a producing well at the outlet of the core. This well's target is the cumulative reservoir volume fluid produced during the experiment. Relative permeability is obtained by history matching surface cumulative oil and gas production and average core pressure.

Figure 7a shows the relative permeability curves that gave the best match to the 150 and the 250 psi/day experiments on core Sample # A. One very striking point is the gas relative permeabilities derived from the depletion experiments are an order of magnitude lower than those measured in the steady state experiments. Our findings are consistent with the extremely low gas relative permeabilities for solution gas drive systems observed by other workers [3, 4]. The non monotonic nature of the relative permeability curves might be attributed to the onset of different mechanisms in the core relating to depletion processes such as gas nucleation, bubble growth and gas mobilization as mentioned in Ref 1. Figure 7b shows the best match of the simulation results with the experimental data for the cumulative oil production. We have conducted various numerical sensitivity studies on the uniqueness of the fits that are obtained by matching the production data. We have found that the gas relative permeabilities we have obtained by matching the production profiles are quite unique. However, the oil relative permeabilities are not uniquely determined by this process as we do not obtain good quality pressure drop data across the core from these depletion experiments.

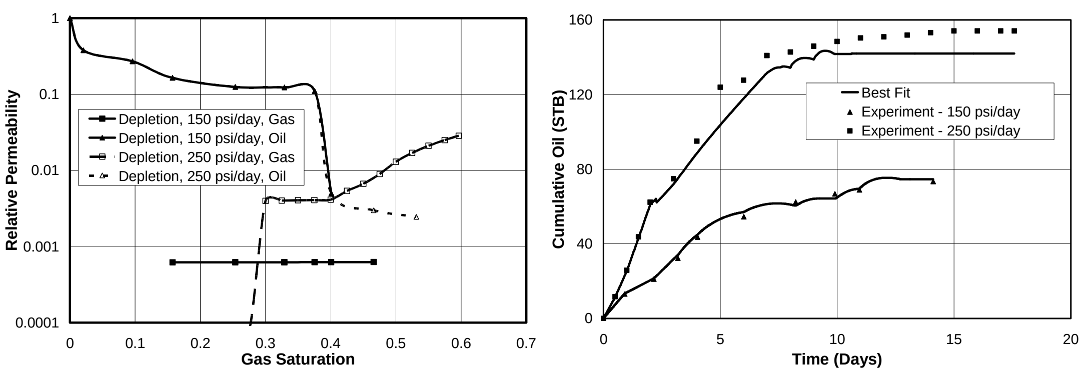


Figure 7: Best fit relative permeability curves for the 150 psi/day and 250 psi/day depletion experiments on core Sample # A(a) and comparison of numerical prediction (lines) to experimental data (points) on cumulative oil production for Sample # A (b).

Figure 8a shows the relative permeability curves that gave the best match for the 150 and 250 psi/day experiments on core Sample # B. Figure 8b shows the match of the simulation results with the experimental data for the cumulative oil production from the core. As discussed with the core Sample # A we observe that we get a good match for the cumulative oil production. As observed by other authors [3] the effect of pressure depletion rate on critical gas saturation and gas relative permeability is dependent on the importance of the mass transfer effects in the given pressure regime, the type of oil and the rock type among other factors.

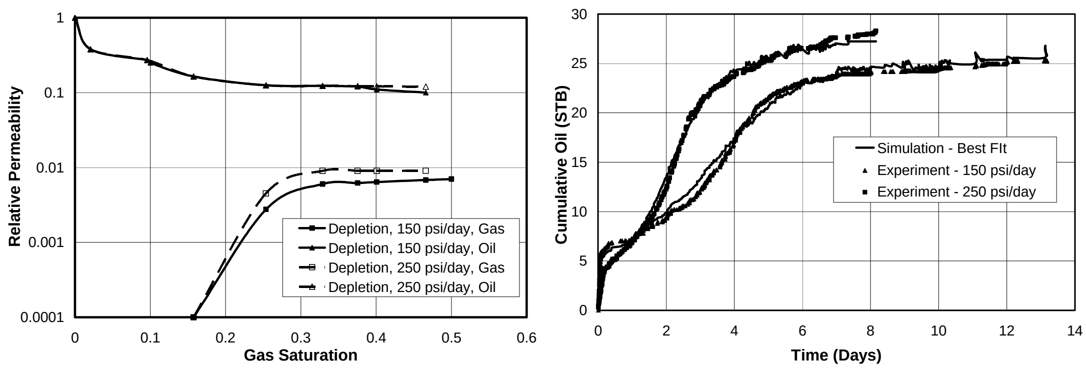


Figure 8: Best fit relative permeability curves for the 150 psi/day and 250 psi/day depletion experiments on core Sample # B (a) and comparison of numerical prediction (lines) to experimental data (points) on cumulative oil production for Sample # B (b).

UP-SCALING

We conducted up-scaling studies on a typical well of this reservoir. For the purpose of areal up-scaling a section of the reservoir is extracted from the coarse grid model. A radial model is then constructed which preserves the porosity, permeability, pore volume and the drainage area of the coarse grid. The direct use of relative permeability data measured from the steady state plug scale experiments shows a much earlier breakthrough in GOR for the coarse grid model than is seen in the actual fine grid model. We then adjust the critical gas saturation by increasing it to match the GOR as shown in Figure 9a. Once this adjustment is made the GOR in the coarse grid model matches with the GOR in the radial model along with the bottom hole pressure and the cumulative productions. We also conducted the up-scaling exercise with the depletion gas relative permeability curves. In this case when the oil relative permeability is lowered by almost a factor of 0.1 (Figure 9b) then we obtain a good match on the bottom hole pressures as well as on the cumulative productions. The two curves shown here were incorporated as the probabilistic end member cases in the uncertainty assessment of the full field performances.

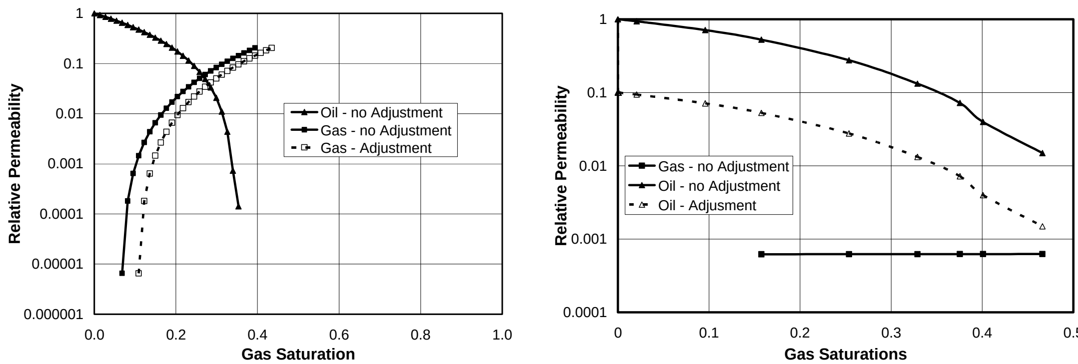


Figure 9: Gas-oil relative permeability correction for the steady-state (a) and the depletion curves (b) due to areal up-scaling.

We also conducted vertical up-scaling studies on a sector model of the well. In this case we observe that the GOR between the fine grid model and the coarse grid model are essentially the same even with introduction of different permeability streaks and different producing rates and there is no need to adjust the relative permeabilities between the fine grid and the coarse grid models.

CONCLUSIONS

1. Gas relative permeability is very low in depletion experiments.
2. It is not possible to determine oil relative permeability from the oil and gas production data.
3. Areal up-scaling has the effect of increasing critical gas saturation and lowers oil relative permeability. Vertical up-scaling has no effect on relative permeability.

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APPENDIX

The general test procedures followed for steady state experiments are given as follows:

1. Sample Preparation – The samples have been Soxhlet batch extracted using toluene to remove hydrocarbon and then flushed with methanol to remove any salts. The samples are then dried in a vacuum oven at 220 degrees F.
2. K_a & ϕ determinations - The samples are allowed to return to room temperature while in a desiccator. The grain volume is determined by Boyle’s law using Helium as the gas. The pore volume and permeability to air are determined at a net confining stresses of 800 & 3000 psi.
3. Establishment of S_{wi} not necessary because of very low values in reservoir and the samples have not been aged at reservoir conditions as ambient temperature tests have been conducted. We assume that the wettability has little impact [7] especially when operating in the bulk saturation space away from gravity drainage (Sorg).
4. The samples are then mounted in a linear scanner in a vertical orientation for the steady state tests to achieve gravity stability to gas. A dry base CT scan is then conducted.

5. The samples are then flushed with lab oil using back pressure to achieve 100 % oil saturated plug. Radioactively “tagged” Isopar-L which has a viscosity similar to kerosene (1.8 cp at ambient temperature) is used as the lab oil. The oil is always saturated with nitrogen.
6. The oil permeability is measured and a saturated base scan is obtained.

Fractional Flow rates and/or ΔP targets for testing. - The fractional flow rates will vary for each sample based on the individual sample’s permeability. A pore pressure of 3,000 psi is targeted. The flow rates are adjusted such that the pressure drop does not exceed 600 psi (20% of pore pressure).