Precise Wettability Characterization of Carbonate Rocks to Evaluate Oil Recovery Using Surfactant-based Nanofluids

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Supporting Information

Details of all the coreflood experiments of this study, including the core parameters, experimental conditions, oil recovery and pressure drop history-match, and relative permeability curves.

Table 1. Initial parameters for waterflood using brine (2 wt.% NaCl) at 500 psi and 72 ˚F.

Core name:	Indiana Limestone-10 (12X2)	
Porosity:	18.14	%
Abs. Perm:	23.59	md
Pore Volume	112	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Injection rate	2	cc/min
Oil Recovery	20.43	%

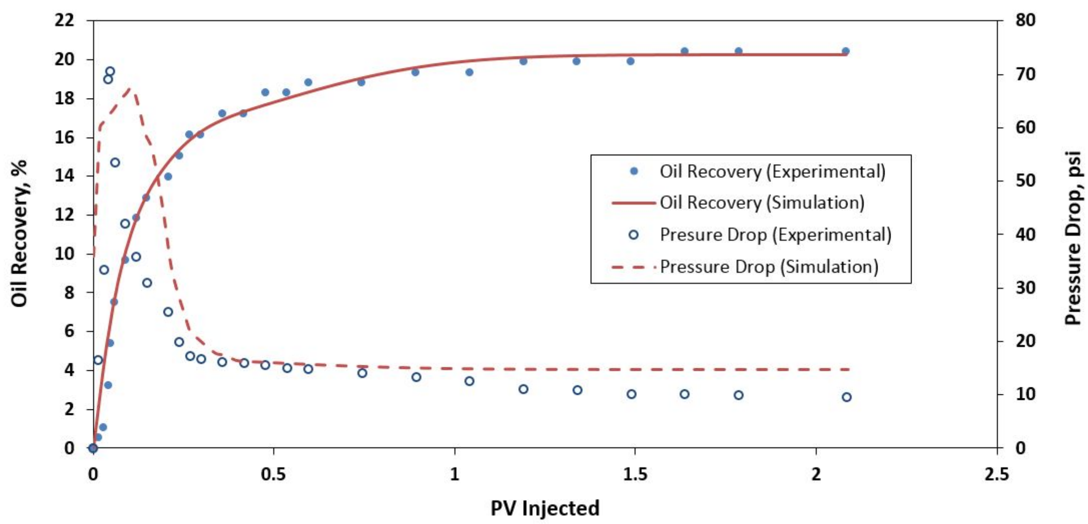

Figure 1. History match of oil recovery and pressure drop for waterflood (2 wt.% NaCl) at 500 psi and 72 ˚F.

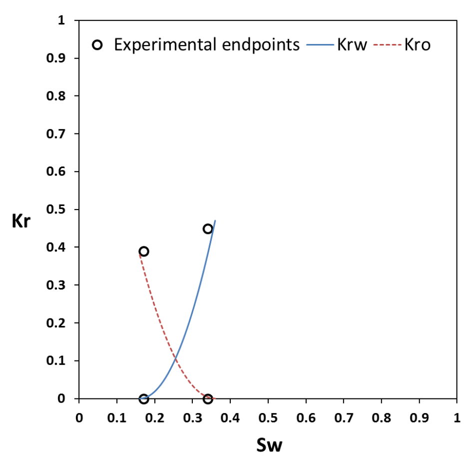

Figure 2. Relative permeability curves for waterflood (2 wt.% NaCl) at 500 psi and 72 ˚F.

Table 2. Initial parameters for coreflood using surfactant (ALF 13S, 2000 ppm) at 500 psi and 72 ˚F.

Core name:	Indiana Limestone-15 (12X2)	
Porosity:	16.03	%
Abs. Perm:	26.24	md
Pore Volume	99	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Surfactant	ALF 13S (2000 ppm)	
Injection rate	2	cc/min
Oil Recovery	20.73	%

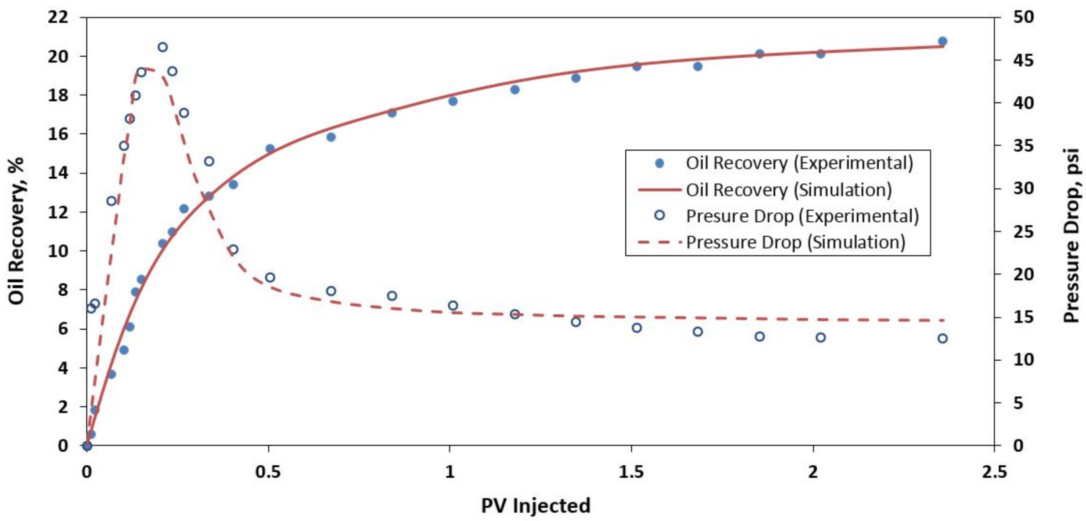

Figure 3. History match of oil recovery and pressure drop using surfactant (ALF 13S, 2000 ppm) at 500 psi and 72 ˚F.

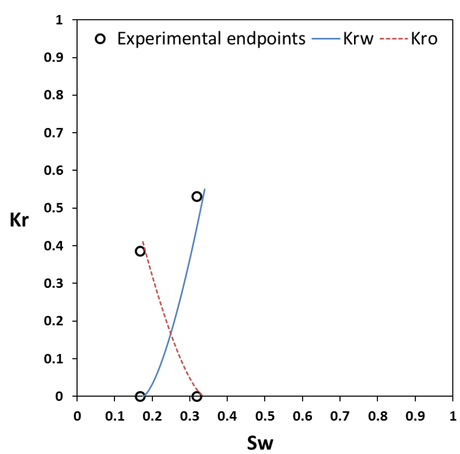

Figure 4. Relative permeability curves for coreflood using surfactant (ALF 13S, 2000 ppm) at 500 psi and 72 ˚F.

Table 3. Initial parameters for coreflood using brine-based nanofluid (0.4 wt.% NP in 2% NaCl) at 500 psi and 72 ˚F.

Core name:	Indiana Limestone-14 (12X2)	
Porosity:	14.73	%
Abs. Perm:	18.59	md
Pore Volume	91	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Nanofluid (brine-based)	0.4 wt.% NP	
Injection rate	2	cc/min
Oil Recovery	30.51	%

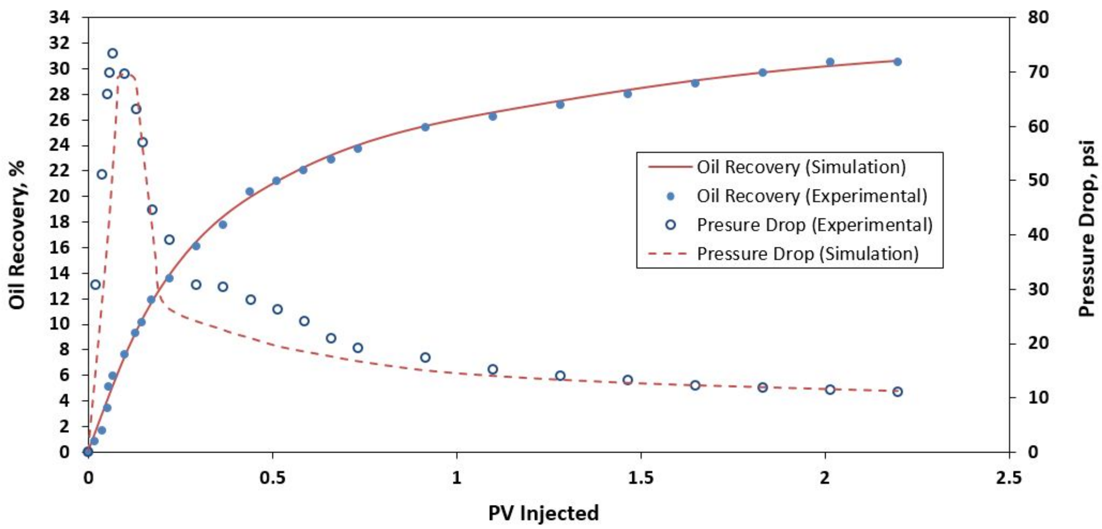

Figure 5. History match of oil recovery and pressure drop using brine-based nanofluid (0.4 wt.% NP in 2% NaCl) at 500 psi and 72 ˚F.

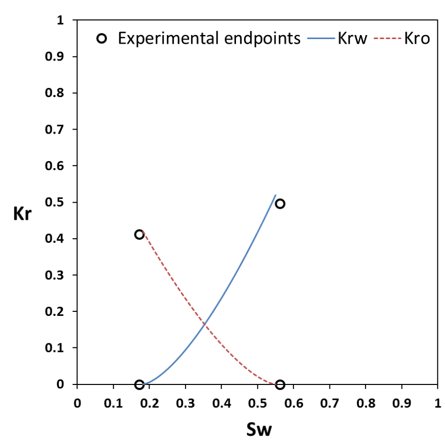

Figure 6. Relative permeability curves for coreflood using brine-based nanofluid (0.4 wt.% NP in 2% NaCl) at 500 psi and 72 ˚F.

Table 4. Initial parameters for coreflood using surfactant-based nanofluid (0.4 wt.% NP + ALF 13S, 2000 ppm) at 500 psi and 72 ˚F.

Core name:	Indiana Limestone-16 (12X2)	
Porosity:	16.52	%
Abs. Perm:	8.49	md
Pore Volume	102	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Nanofluid (surfactant-based)	0.4 wt.% NP + ALF 13S (2000 ppm)	
Injection rate	2	cc/min
Oil Recovery	57.33	%

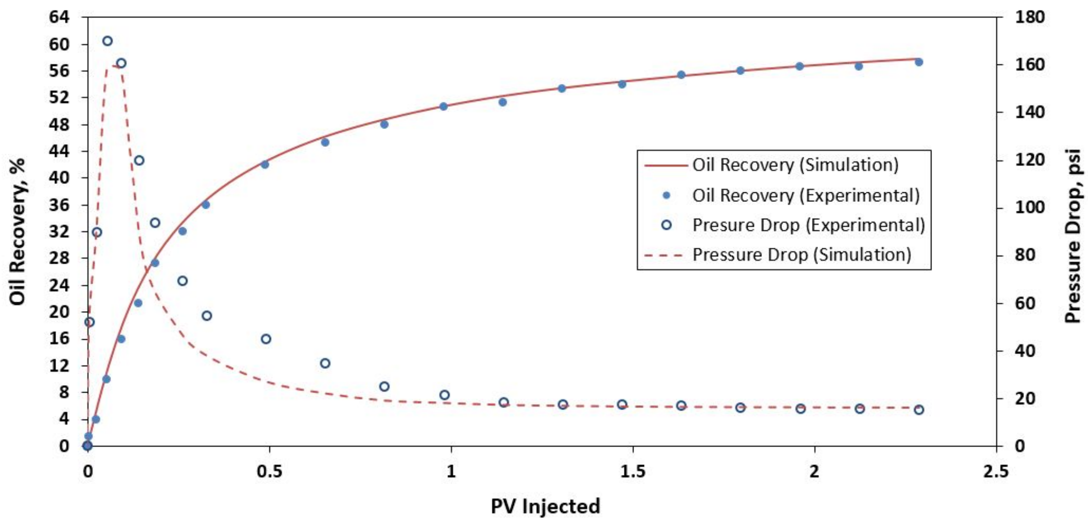

Figure 7. History match of oil recovery and pressure drop using surfactant-based nanofluid (0.4 wt.% NP + ALF 13S, 2000 ppm) at 500 psi and 72.

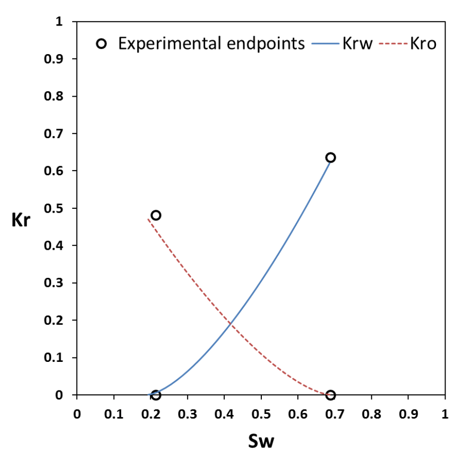

Figure 8. Relative permeability curves for coreflood using surfactant-based nanofluid (0.4 wt.% NP + ALF 13S, 2000 ppm) at 500 psi and 72 ˚F.

Table 5. Initial parameters for coreflood using surfactant-based nanofluid (0.4 wt.% NP + ALF 13S, 1000 ppm) at 500 psi and 72 ˚F.

Core name:	Indiana Limestone-17 (12X2)	
Porosity:	17.17	%
Abs. Perm:	15.81	md
Pore Volume	106	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Nanofluid (surfactant-based)	0.4 wt.% NP + ALF 13S (1000 ppm)	
Injection rate	2	cc/min
Oil Recovery	52.63	%

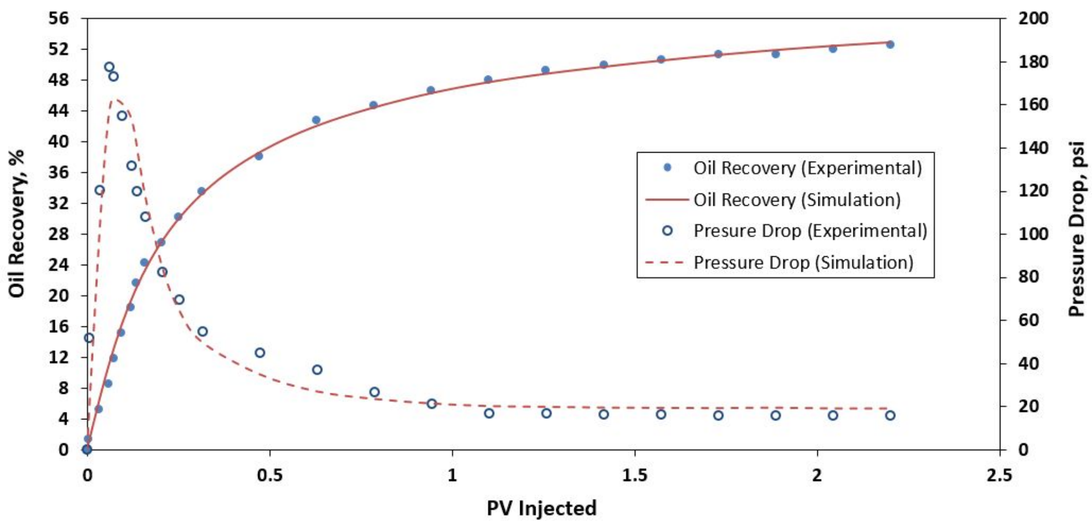

Figure 9. History match of oil recovery and pressure drop using surfactant-based nanofluid (0.4 wt.% NP + ALF 13S, 1000 ppm) at 500 psi and 72.

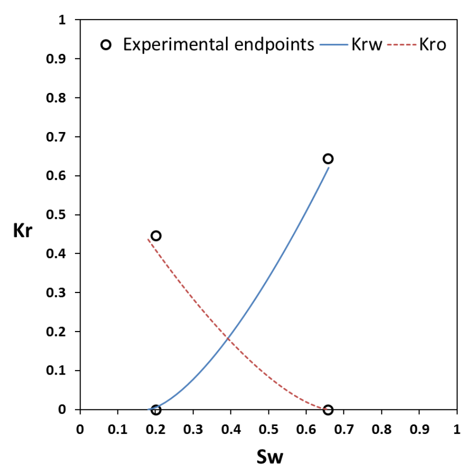

Figure 10. Relative permeability curves for coreflood using surfactant-based nanofluid (0.4 wt.% NP + ALF 13S, 1000 ppm) at 500 psi and 72 ˚F.

Table 6. Initial parameters for coreflood using surfactant (ALF 9S, 2000 ppm) at 500 psi and 72 ˚F.

Core name:	Indiana Limestone-X (12X2)	
Porosity:	16.36	%
Abs. Perm:	17.95	md
Pore Volume	101	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Surfactant	ALF 9S (2000 ppm)	
Injection rate	2	cc/min
Oil Recovery	48.19	%

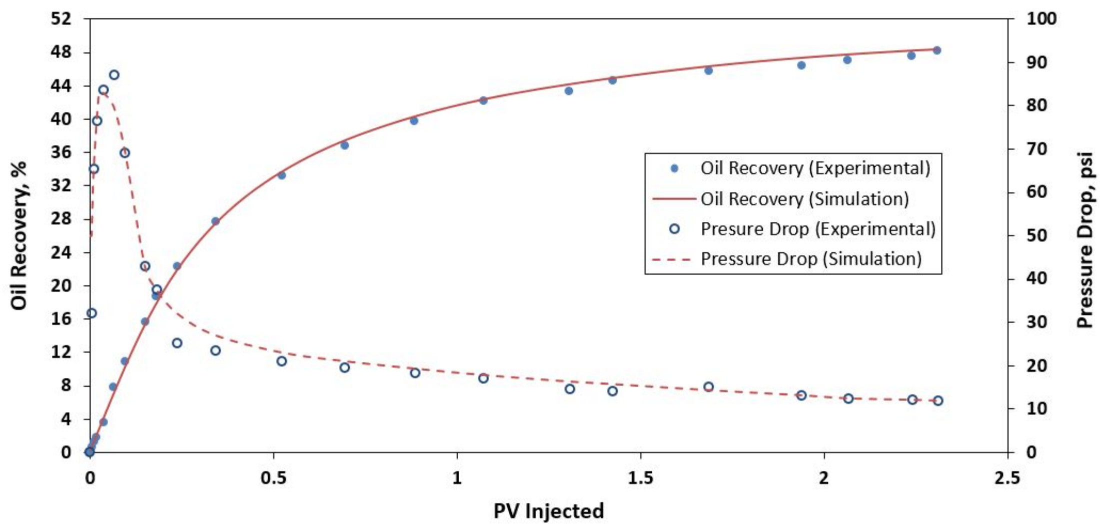

Figure 11. History match of oil recovery and pressure drop using surfactant (ALF 9S, 2000 ppm) at 500 psi and 72 ˚F.

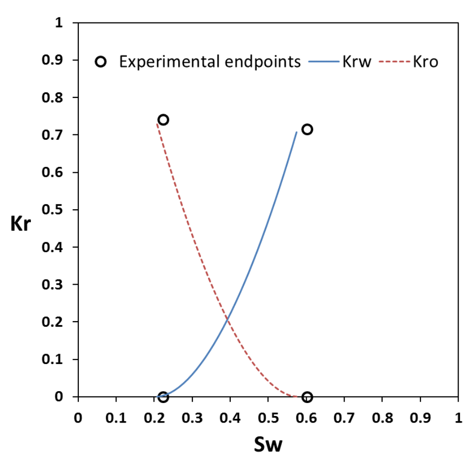

Figure 12. Relative permeability curves for coreflood using surfactant (ALF 9S, 2000 ppm) at 500 psi and 72 ˚F.

Table 7. Initial parameters for coreflood using surfactant-based nanofluid (0.4 wt.% NP+ALF 9S, 2000 ppm) at 500 psi and 72 ˚F.

Core name:	Indiana Limestone-X (12X2)	
Porosity:	16.36	%
Abs. Perm:	17.95	md
Pore Volume	101	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Nanofluid (surfactant-based)	0.4 wt.% NP + ALF 9S (2000 ppm)	
Injection rate	2	cc/min
Oil Recovery	92.68	%

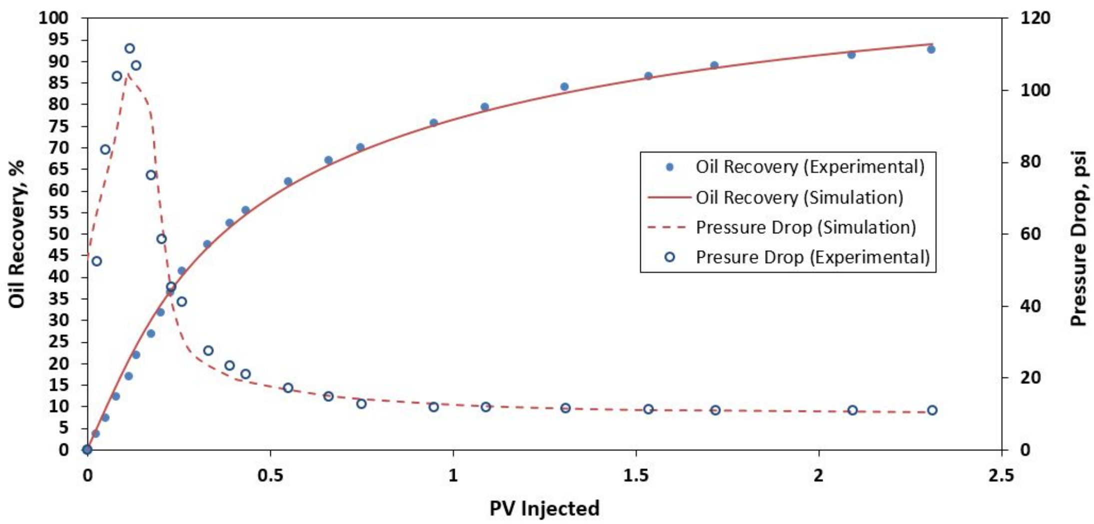

Figure 13. History match of oil recovery and pressure drop using surfactant-based nanofluid (0.4 wt.% NP+ALF 9S, 2000 ppm) at 500 psi and 72 ˚F.

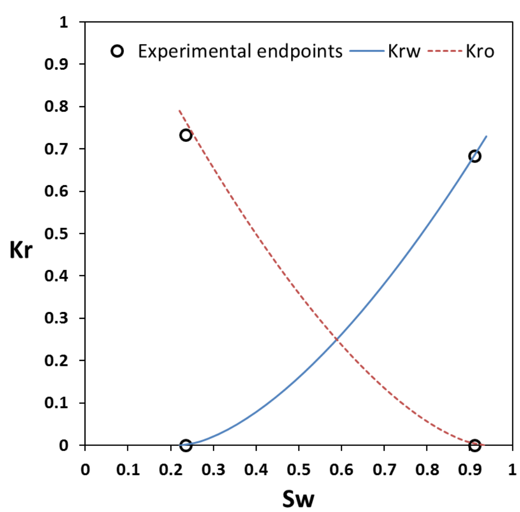

Figure 14. Relative permeability curves for coreflood using surfactant-based nanofluid (0.4 wt.% NP+ALF 9S, 2000 ppm) at 500 psi and 72 ˚F.

Table 8. Initial parameters for coreflood using surfactant-based nanofluid (0.4 wt.% NP+ALF 9S, 1000 ppm) at 500 psi and 72 ˚F.

Core name:	Indiana Limestone-X (12X2)	
Porosity:	16.36	%
Abs. Perm:	17.95	md
Pore Volume	101	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Nanofluid (surfactant-based)	0.4 wt.% NP + ALF 9S (1000 ppm)	
Injection rate	2	cc/min
Oil Recovery	86.25	%

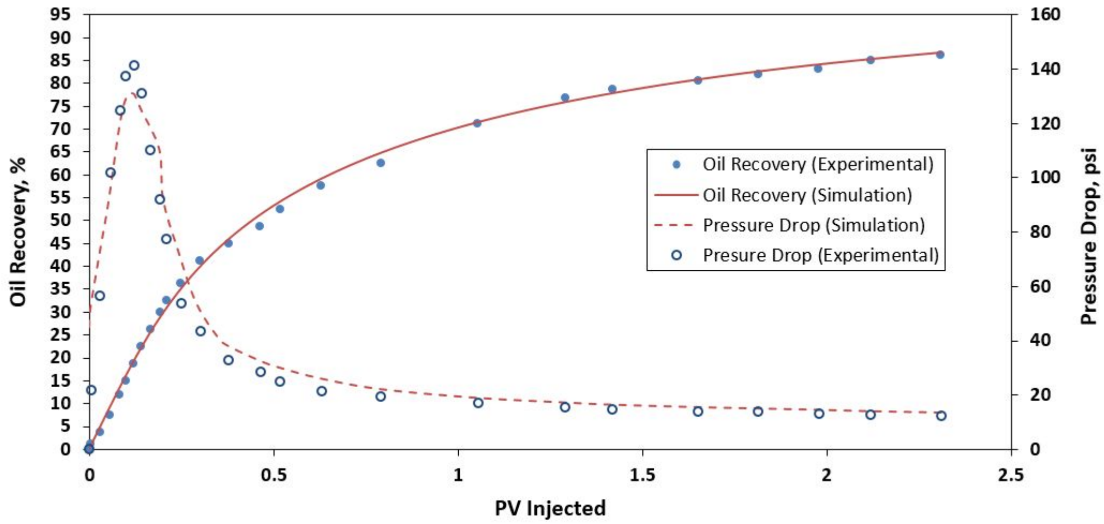

Figure 15. History match of oil recovery and pressure drop using surfactant-based nanofluid (0.4 wt.% NP+ALF 9S, 1000 ppm) at 500 psi and 72 ˚F.

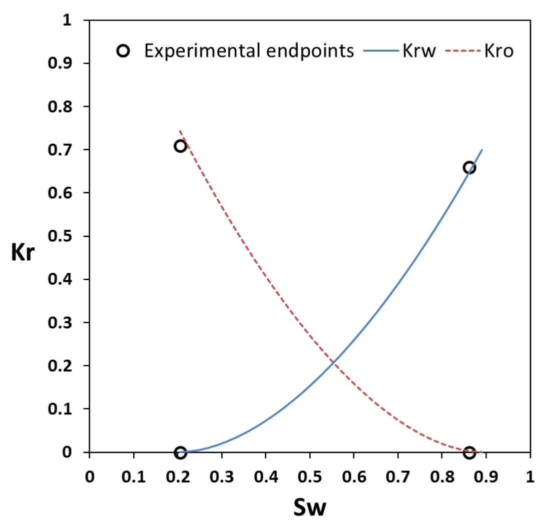

Figure 16. Relative permeability curves for coreflood using surfactant-based nanofluid (0.4 wt.% NP+ALF 9S, 1000 ppm) at 500 psi and 72 ˚F.

Table 9. Initial parameters for waterflood using brine (2 wt.% NaCl) at reservoir conditions (700 psi & 150 ˚F).

Core name:	Indiana Limestone-12 (12X2)	
Porosity:	16.35	%
Abs. Perm:	14.87	md
Pore Volume	101	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Injection rate	2	cc/min
Oil Recovery	17.5	%

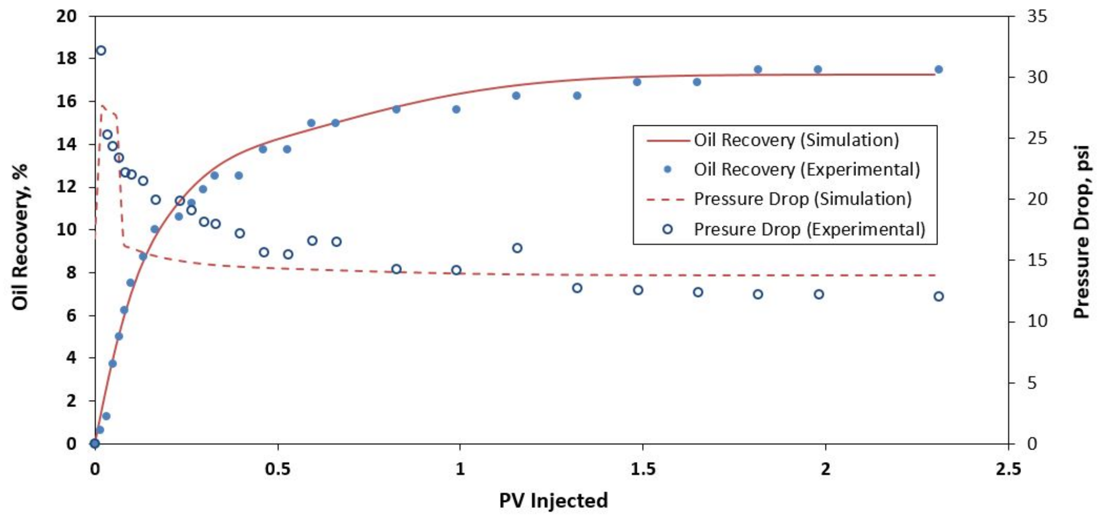

Figure 17. History match of oil recovery and pressure drop for waterflood (2 wt.% NaCl) at reservoir conditions.

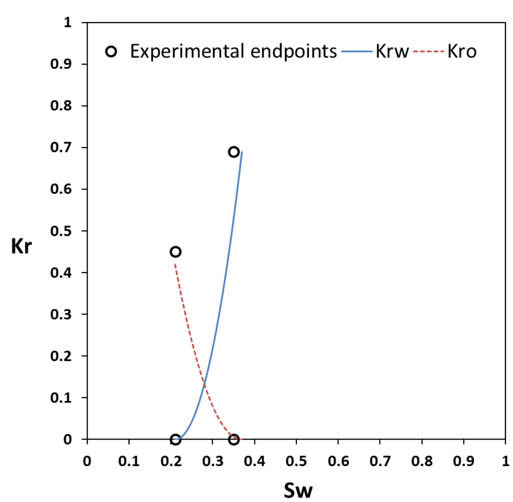

Figure 18. Relative permeability curves for waterflood (2 wt.% NaCl) at reservoir conditions (700 psi & 150 ˚F).

Table 10. Initial parameters for coreflood using surfactant (SOL 938, 2000 ppm) at reservoir conditions (700 psi & 150 ˚F).

Core name:	Indiana Limestone-18 (12X2)	
Porosity:	15.71	%
Abs. Perm:	24.92	md
Pore Volume	97	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Surfactant	SOL 938 (2000 ppm)	
Injection rate	2	cc/min
Oil Recovery	21.52	%

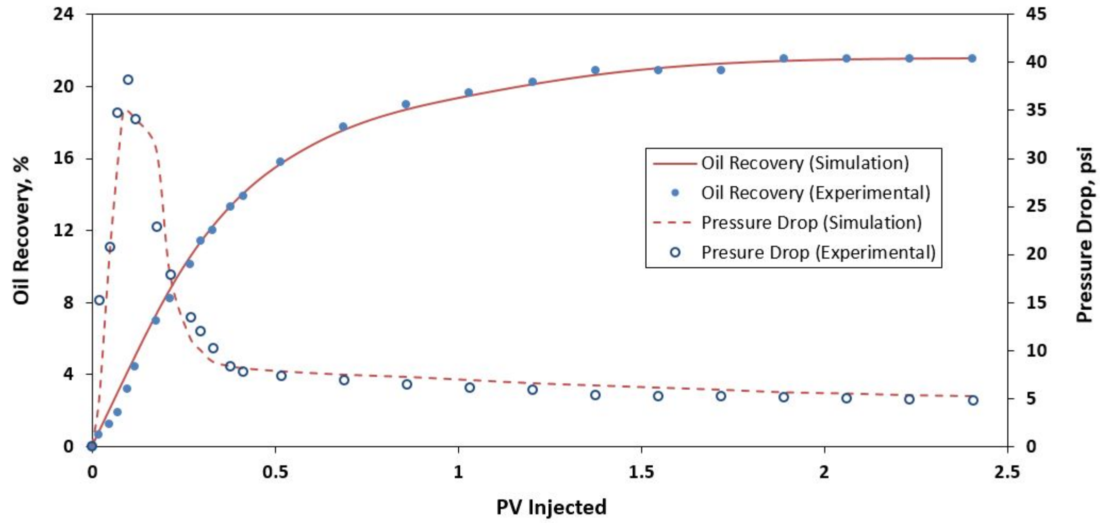

Figure 19. History match of oil recovery and pressure drop using surfactant (SOL 938, 2000 ppm) at reservoir conditions (700 psi & 150 ˚F).

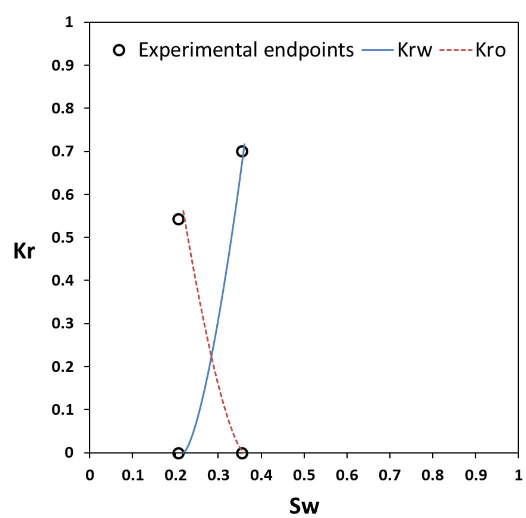

Figure 20. Relative permeability curves for coreflood using surfactant (SOL 938, 2000 ppm) at reservoir conditions (700 psi & 150 ˚F).

Table 11. Initial parameters for coreflood using brine-based nanofluid (0.4 wt.% NP in 2% NaCl) at reservoir conditions (700 psi & 150 ˚F).

Core name:	Indiana Limestone-19 (12X2)	
Porosity:	17.00	%
Abs. Perm:	31.29	md
Pore Volume	105	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Nanofluid (brine-based)	0.4 wt.% NP	
Injection rate	2	cc/min
Oil Recovery	28.57	%

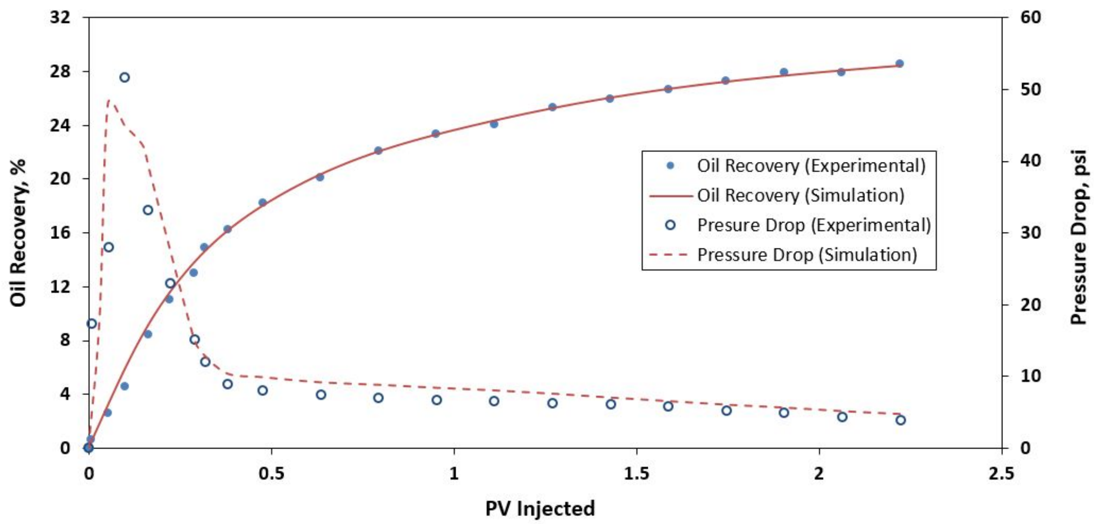

Figure 21. History match of oil recovery and pressure drop using brine-based nanofluid (0.4 wt.% NP in 2% NaCl) at reservoir conditions (700 psi & 150 ˚F).

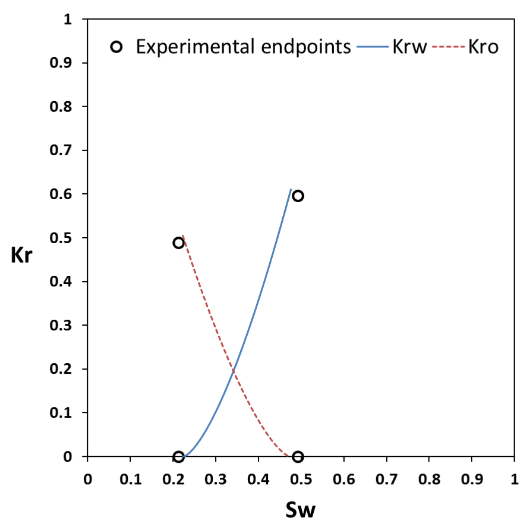

Figure 22. Relative permeability curves for coreflood using brine-based nanofluid ((0.4 wt.% NP in 2% NaCl) at reservoir conditions (700 psi & 150 ˚F).

Table 12. Initial parameters for coreflood using surfactant-based nanofluid (0.4 wt.% NP + SOL 938, 2000 ppm) at reservoir conditions (700 psi & 150 ˚F).

Core name:	Indiana Limestone-20 (12X2)	
Porosity:	15.06	%
Abs. Perm:	49.70	md
Pore Volume	93	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Nanofluid (surfactant-based)	0.4 wt.% NP + SOL 938 (2000 ppm)	
Injection rate	2	cc/min
Oil Recovery	51.56	%

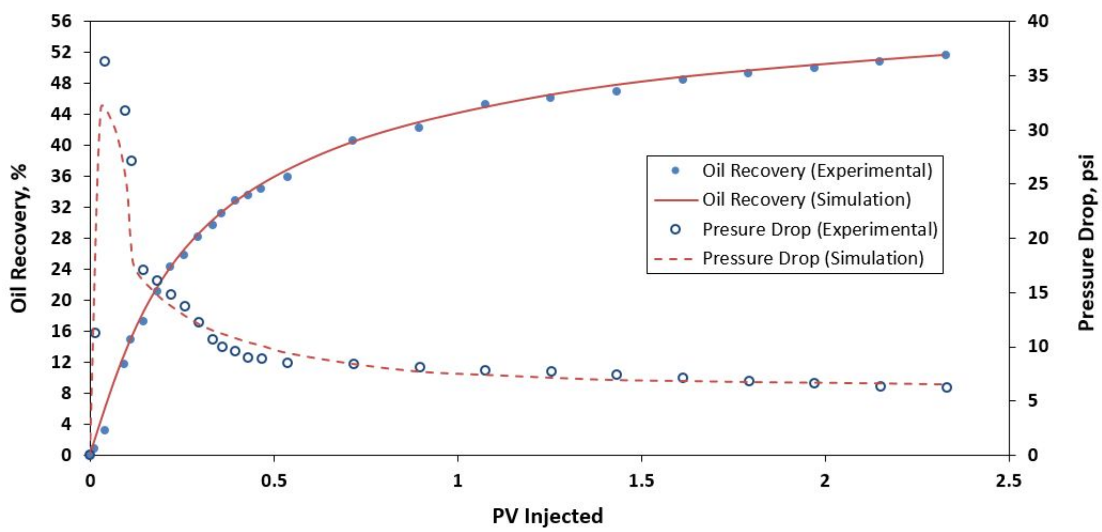

Figure 23. History match of oil recovery and pressure drop using surfactant-based nanofluid (0.4 wt.% NP + SOL 938, 2000 ppm) at reservoir conditions (700 psi & 150 ˚F).

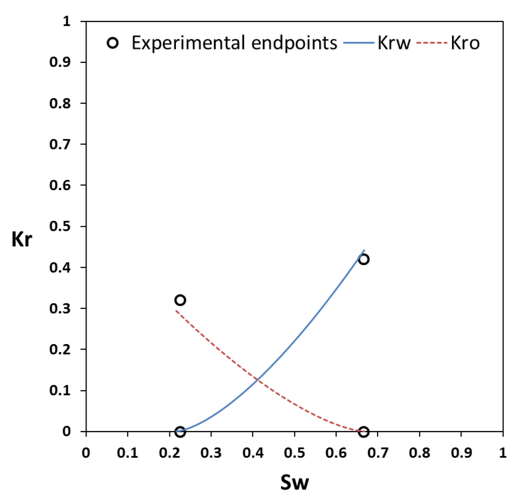

Figure 24. Relative permeability curves for coreflood using surfactant-based nanofluid (0.4 wt.% NP + SOL 938, 2000 ppm) at reservoir conditions (700 psi & 150 ˚F).

Table 13. Initial parameters for coreflood using surfactant-based nanofluid (0.4 wt.% NP + SOL 938, 1000 ppm) at reservoir conditions (700 psi & 150 ˚F).

Core name:	Indiana Limestone-21 (12X2)	
Porosity:	17.17	%
Abs. Perm:	62.77	md
Pore Volume	106	cc
Oil	Yates crude oil	
Brine (NaCl)	2%	wt
Nanofluid (surfactant-based)	0.4 wt.% NP + SOL 938 (1000 ppm)	
Injection rate	2	cc/min
Oil Recovery	45.07	%

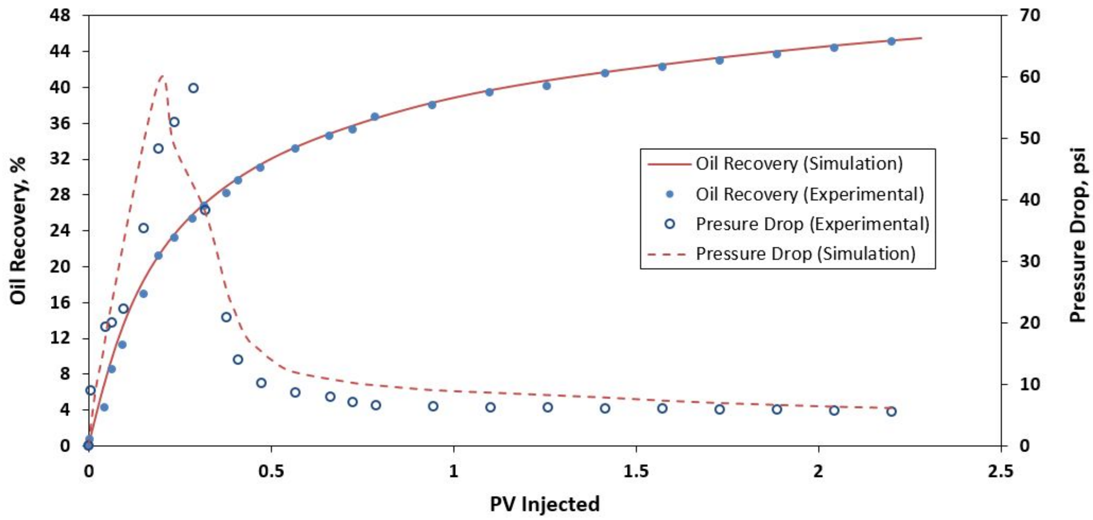

Figure 25. History match of oil recovery and pressure drop using surfactant-based nanofluid (0.4 wt.% NP + SOL 938, 1000 ppm) at reservoir conditions (700 psi & 150 ˚F).

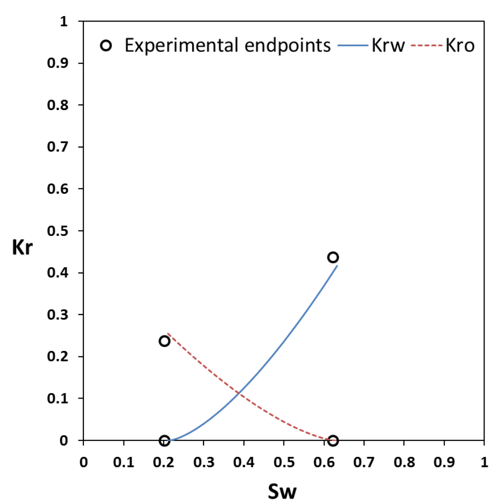

Figure 26. Relative permeability curves for coreflood using surfactant-based nanofluid (0.4 wt.% NP + SOL 938, 1000 ppm) at reservoir conditions (700 psi & 150 ˚F).