SPE Workshop: Evolution of Flow Assurance – Learnings from the Past and Navigating Future Challenges

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The Persistent Challenge of Asphaltene Precipitation in CO_2-EOR and Novel Surfactant-Based Solutions

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01 Flow Assurance from Reservoir to Wellbore -- *asphaltene precipitation*

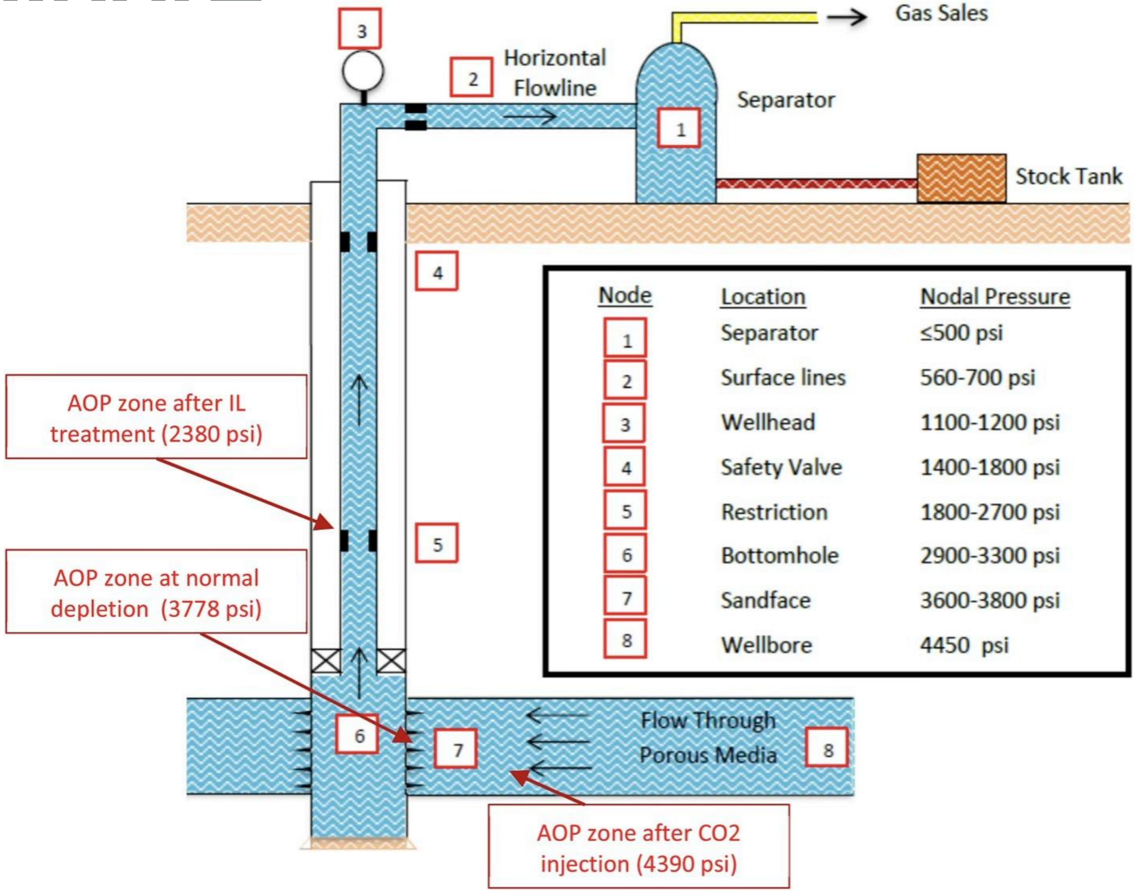
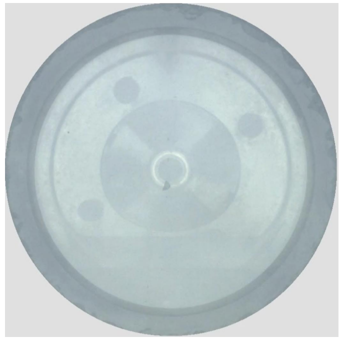


Fig 1. A schematic diagram of a conventional oil well in the target reservoir, showing the relationship between the range of nodal pressures and the onset pressure （AOP） for asphaltene precipitation (from Bisweswar Ghosha,Journal of Petroleum Science and Engineering 180 (2019) 1046–1057.)

01 Reservoir -- *Original Asphaltene Precipitation*



30°C/60MPa, GOR4000
Fig. 2a

60℃/100MPa, 42hr
Fig. 2b

Fig. 2e

60℃/100MPa, 69hr
Fig. 2c

100℃/100MPa, 22hr
Fig. 2d

Fig. 2f
180℃/180MPa, inside the PVT cell

PVT Experimental Data showing
Original Asphaltene Precipitation

A simulation experiment was conducted using an ultra-deep oil sample from the Junggar Basin to investigate phase evolution in oil reservoirs. The experiment successfully reproduced the characteristic process of "low-pressure charging and high-pressure accumulation" commonly observed in reservoir systems.

Figures 2a–2d depict the reservoir's response to cyclic temperature and pressure variations, clearly highlighting the occurrence of solid-phase precipitation. High-resolution images of the solid deposits formed within the reactor after the experiment are presented in Figures 2e and 2f. The simulated oil had a density of 0.8171 g/cm³ and an asphaltene content of 1.0714%.

01 Reservoir -- *Original Asphaltene Precipitation*

Table1. Experiment data of oil volume

Time (min)	Oil Volume (ml)	Volume change (%)	T (℃)	P (Mpa)
0	24.366	0%	30	60
40	18.246	-25%	60	60
55	16.789	-31%	60	60
100	15.157	-38%	60	100
1060	3.357	-86%	60	100
1330	2.808	-88%	60	100
1390	2.681	-89%	60	100
1450	2.364	-90%	60	100
1510	2.034	-92%	60	100
1570	1.611	-93%	60	100
2500	1.296	-95%	60	100
6100	1.142	-95%	60	100
8020	0.704	-97%	100	100
9520	Cannot Be Measured	No data	100	110

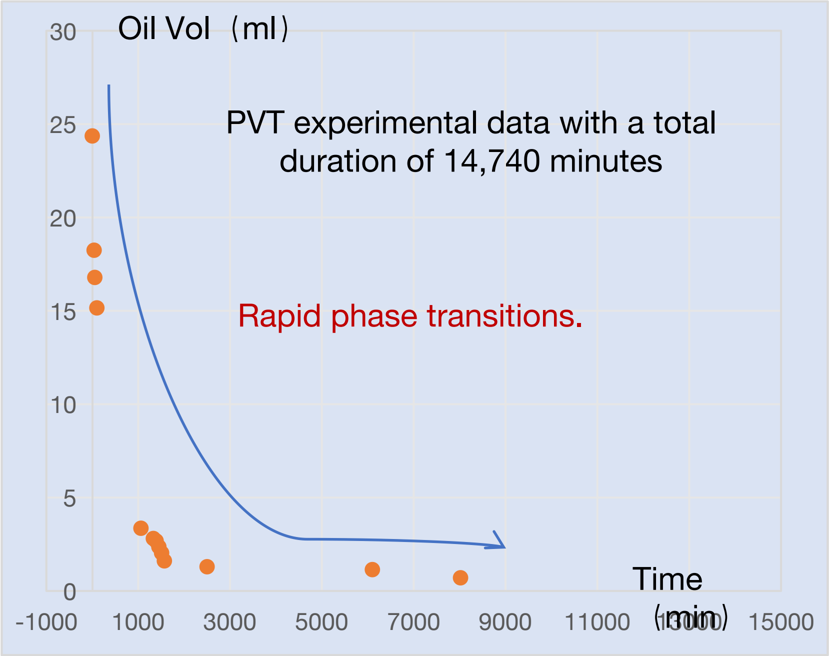


Fig.3 Graph of Oil Volume vs. Time

Pressure is the primary influencing factor

01 Reservoir -- *Artificial process of asphaltene precipitation*

CO2 - Enhanced Oil Recovery

Table2. Slimtube Analysis of black oil at Reservoir Conditions
40MPa and 50°C, immiscible flood

SARA Analysis of MB6330 Oil	**Before CO_2 Flooding （injection fluid）**			**After CO_2 Flooding （wash fluid）**		
	Test 1 %	Test 2 %	Average %	Test 1 %	Test 2 %	Average %
Asphaltenes	1.1294	1.2421	1.1858	30.7743	34.455	32.6147
Resins	3.7649	3.7432	3.7541	35.0997	39.3618	37.2308
Aromatic Hydrocarbons	6.0938	6.8383	6.4661	12.2348	8.1102	10.1725
Saturated Hydrocarbons	89.012	88.1765	88.5943	21.8912	18.073	19.9821

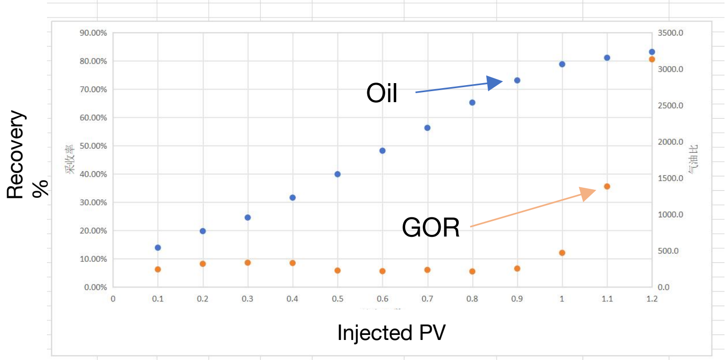


Fig.4 Slimtube apparatus and testing data

01 Wellbore

Monitoring Asphaltene Precipitation via Near-Infrared Solid Detection Technology

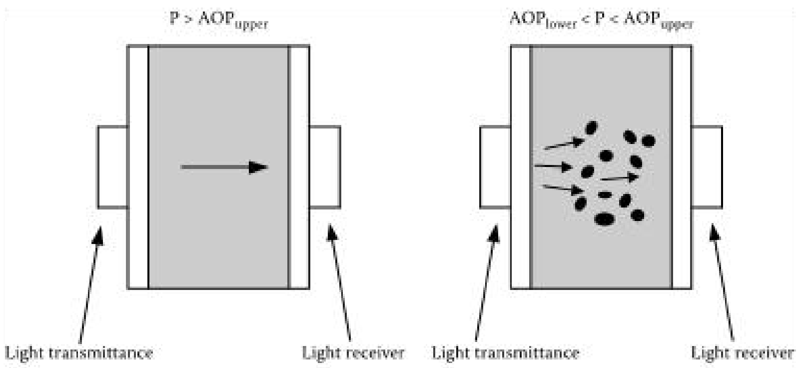


Fig.5 Principle of NIRSDS

* NIRSDS - Near Infrared Solid Detection System

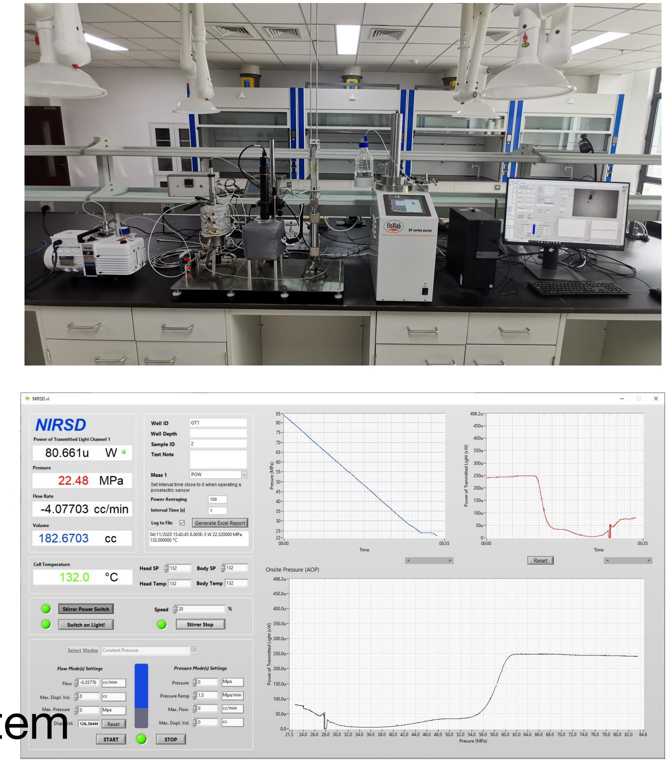


Fig. 6. Experimental apparatus for asphaltene precipitation detection using NIRSDS

Features：

- **Pressure: 100 MPa, 200 MPa optional**
- **Temperature: 150°C - 180°C**
- **Volume: 50 ml - 100 ml**
- **Pressure Accuracy: 0.01% Fs**
- **Temperature Accuracy: 0.1°C**
- **Near-Infrared (NIR) Detection**

01 Wellbore AOP and APE

Monitoring Asphaltene Precipitation via Near-Infrared Solid Detection Technology

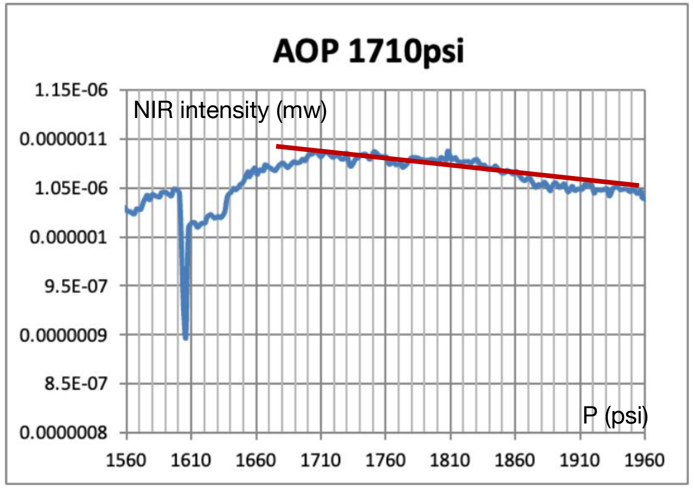


Fig. 7a AOP detection

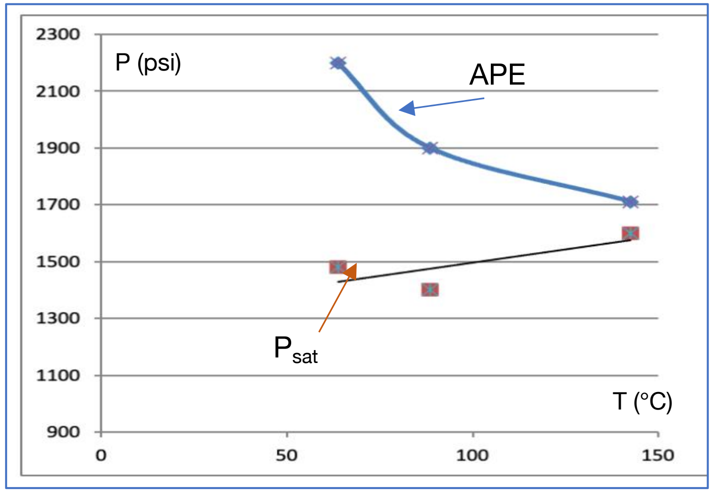


Fig. 7b Asphaltene precipitation envelope

Table 3. AOP and BP data

Temperature (℃)	AOP (psi)	BP (psi)
142.5	1710	1600
88.4	1900	1400
63.7	2200	1480

Note: The downhole sample was sourced from the Tarim Basin, and asphaltene deposits were found in the wellbore.

Fig. 7 By the requirements, AOP and APE were detected using the NIRSDS system

* NIRSDS - Near Infrared Solid Detection System

02 Reservoir

-- Integrating CO_2-EOR Technologies to Mitigate Asphaltene Precipitation

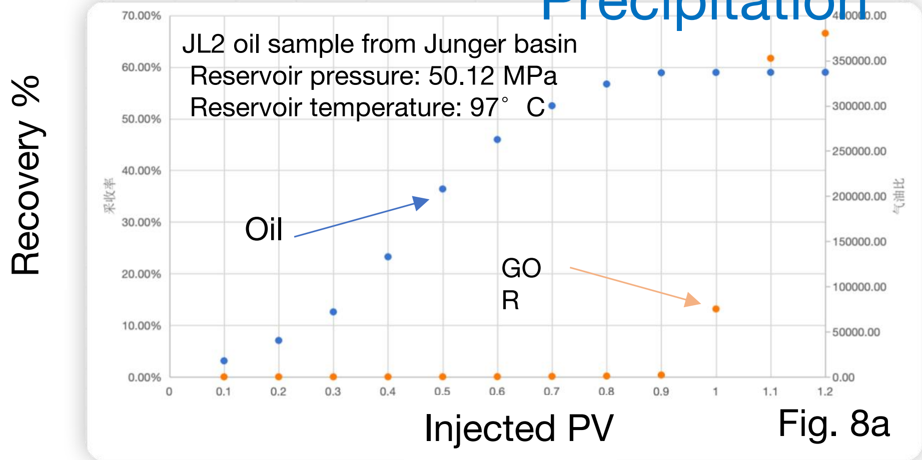


Fig. 8a

Fig. 8. Effect of various chemical additives—including oil-based and water-based amphiphilic surfactants—on CO_2 injection into oil. These additives significantly enhanced oil recovery (EOR) and increased CO_2 solubility. (8a) without chemical additive, (8b) with 5% oil-based chemical additive, and (8c) with 30% water-based chemical additive.

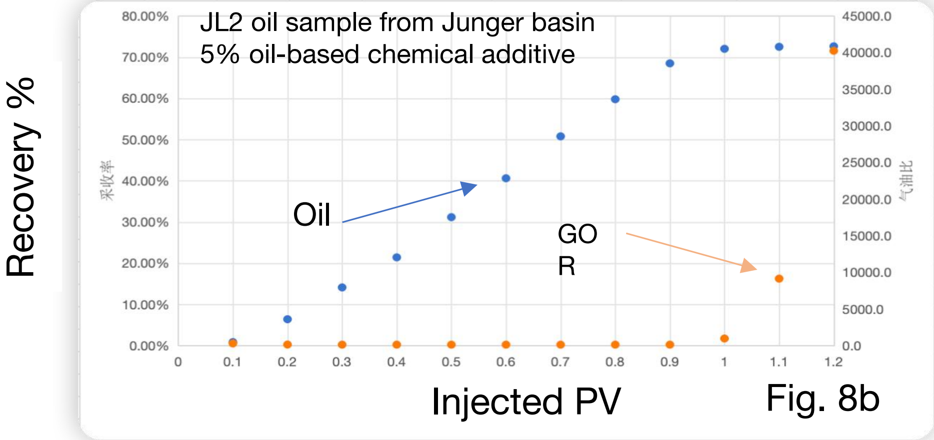


Fig. 8b

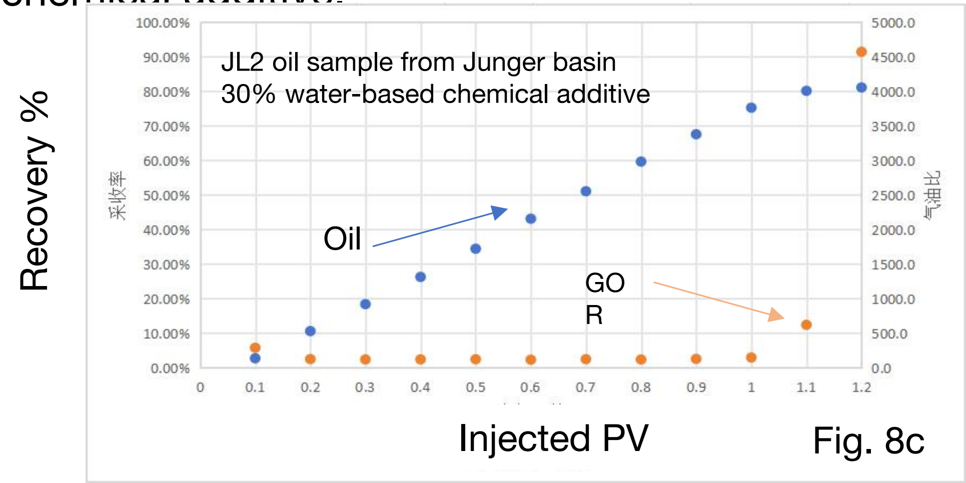


Fig. 8c

Slimtube analysis

02 Reservoir

-- Integrating CO_2-EOR Technologies to Mitigate Asphaltene Precipitation

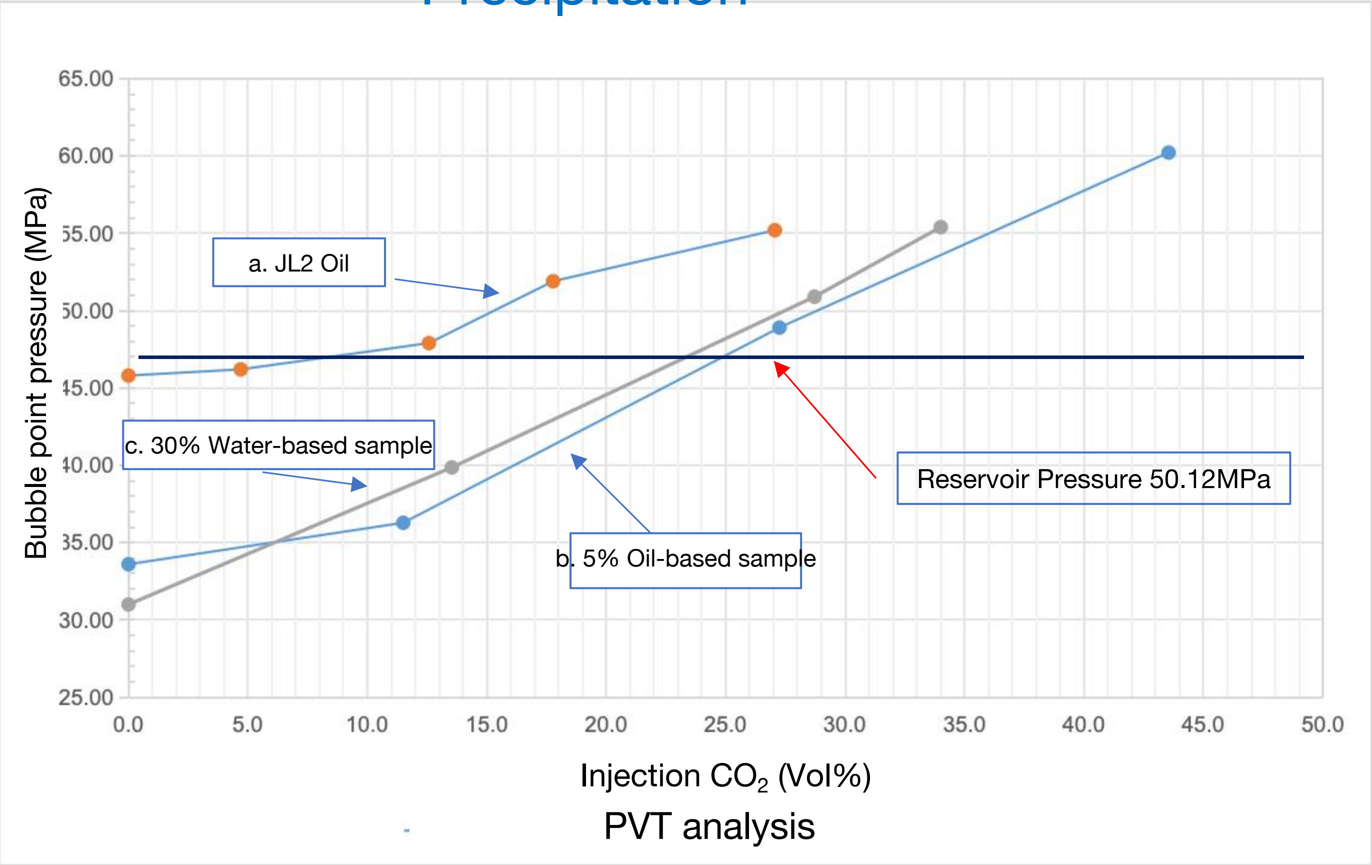


Fig. 9

Fig. 9. The effect of chemical additives-comprising oil-based and water-based amphiphilic surfactants - on CO_2 injection into oil. The additives notably reduce bubble point pressure and improve CO_2 solubility. (a) without chemical additive, (b) with 5% oil-based chemical additive, and (c) with 30% water-based chemical additive.

02 Reservoir

-- Integrating CO_2-EOR Technologies to Mitigate Asphaltene Precipitation

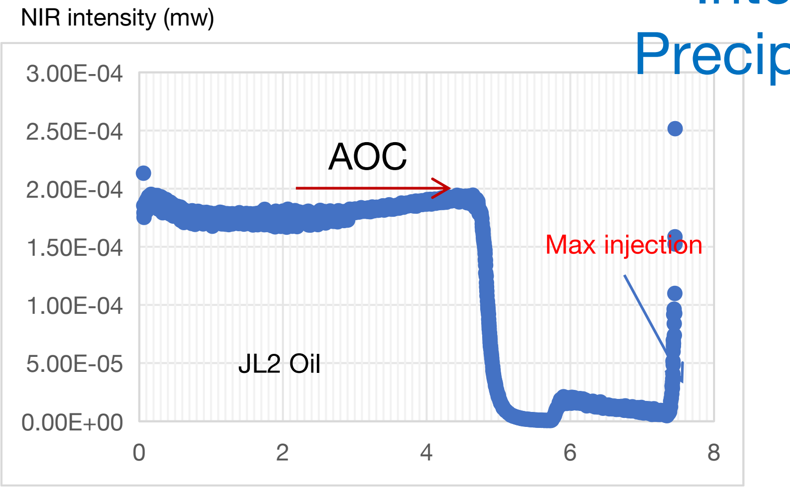


Fig. 10a

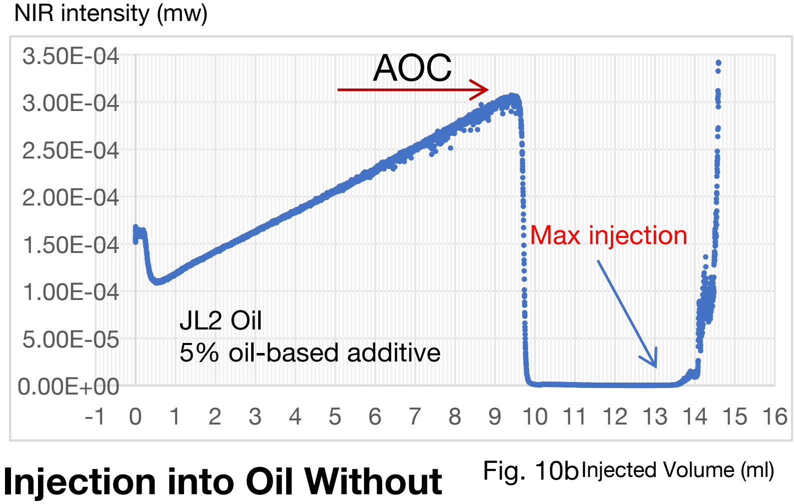


Fig. 10b

Fig. 10. Continuous CO_2 injection under reservoir conditions (97 °C /7267psi) at a flow rate of 0.1 mL/min: (10a) without chemical additive, (10b) with 5% oil-based chemical additive, and (10c) with 30% water-based chemical additive.

Table 4. Data Comparison of Continuous CO_2 Injection into Oil Without and With Chemical Additives

JL2 Oil	Reservoir P psi	Oil vol ml	Injection CO2 vol ml	Injected Vol %	Max Injection Vol ml	Max Vol %
Without chemical additive	7267psi	33.89	4.65	12.07	7.35	17.82
5% oil—based additive	7267psi	30.09	9.50	24.00	13.50	30.97
30% water—based additive	7267psi	30.24	8.60	22.14	10.10	25.04

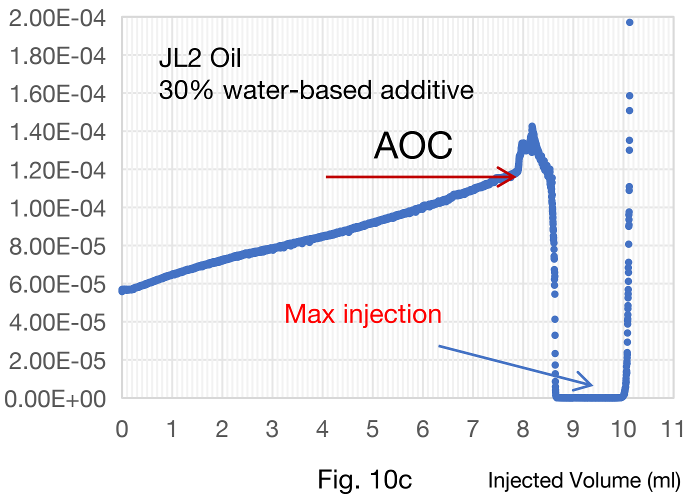


Fig. 10c

*AOC (Asphaltene Onset Concentration)

02 Reservoir

-- Integrating CO_2-EOR Technologies to Mitigate Asphaltene Precipitation

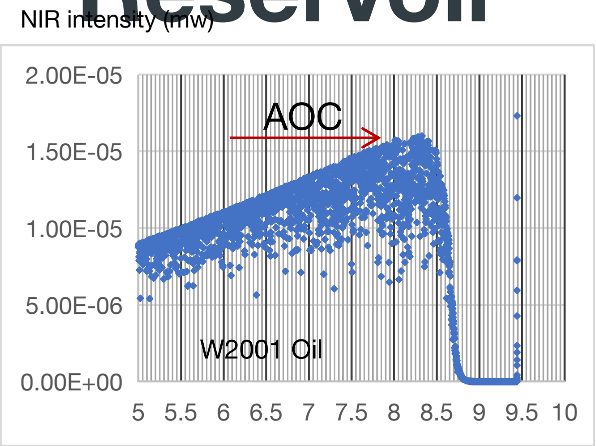


Fig. 11a

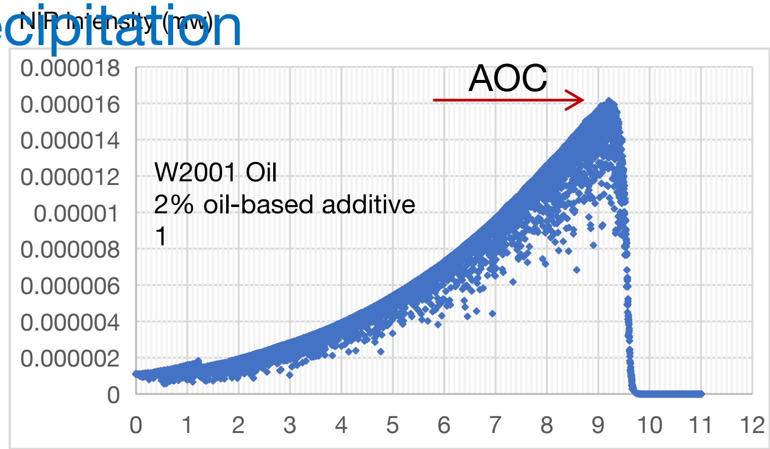


Fig. 11b

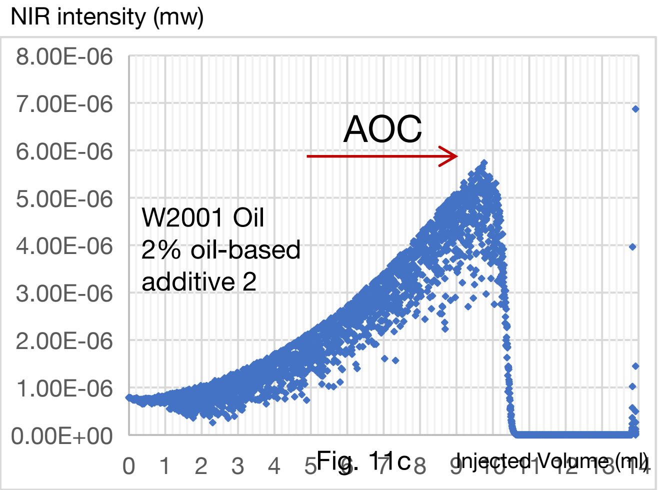


Fig. 11c

Table 5. Data Comparison of Continuous CO_2 Injection into Oil Without and With Oil-based Chemical Additives

No	Sample	CO2 injection	CO_2 solubility
1	Live oil W2001	8.35ml （27.33%）	9.45ml （30.93%）
2	Live oil W2001 2% YT02 chemical additive 1	9.2ml （30.56%）	9.87ml （32.8%）
3	Live oil W2001 2% Wax inhibitor and viscosity reducer additive 2	9.7599ml （32.47%）	13.92ml （46.3%）

Fig. 11. Continuous CO_2 injection under reservoir conditions (44.7°C / 2320 psi)at a flow rate of 0.1 mL/min: (a) without chemical additive, (b) with 2% YT oil-based chemical additive, and (c) with 2% different oil-based chemical additive.

*AOC (Asphaltene Onset Concentration)

02 Reservoir

-- Integrating CO_2-EOR Technologies to Mitigate Asphaltene Precipitation

JL2 Tank Oil | JL2 Tank Oil with 5% oil-based additive | JL2 Tank Oil with 30% water-based additive

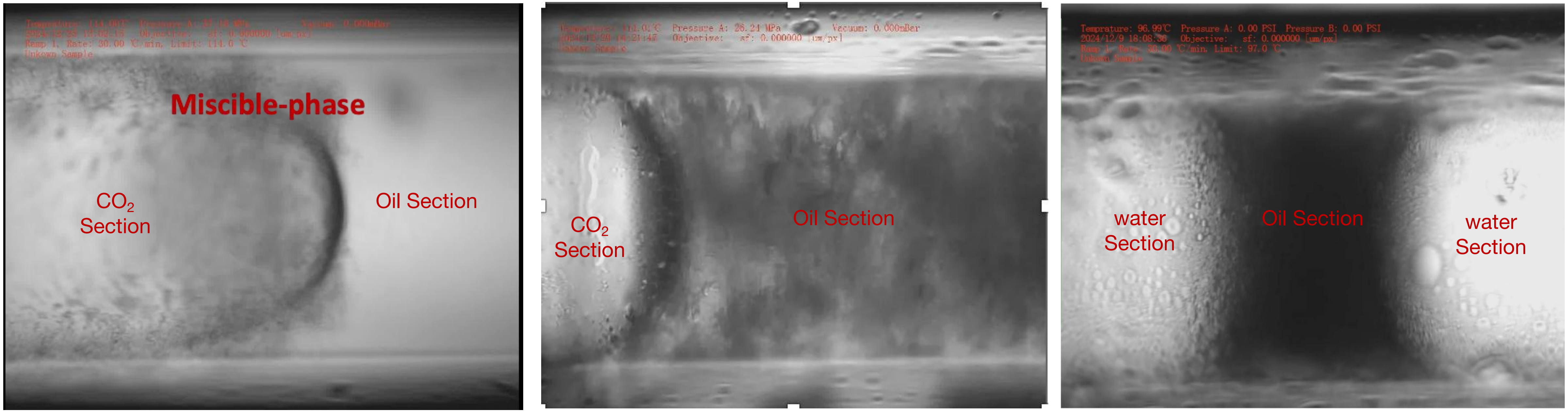


Fig. 12a | Fig. 12b | Fig. 12c

Fig. 12. Interaction between CO_2 and oil under reservoir temperature and pressure observed using the IRHPOC Raman microscope: (a) without chemical additive, (b) with 5% oil-based chemical additive, and (c) with 30% water-based chemical additive.

03 Future Strategies and Recommendations

- ✓ When addressing asphaltene precipitation, it is crucial to identify where the issue originates, from the reservoir to the wellbore.
- ✓ In CO_2-enhanced oil recovery (CO_2-EOR), asphaltene precipitation typically begins in the reservoir and extends into the wellbore. To mitigate this challenge, new strategies can be explored, such as integrating CO_2-EOR technologies specifically designed to minimize asphaltene precipitation.
- ✓ Our studies indicate that a combination of WAG (Water-Alternating-Gas) injection with water-based chemical additives is significantly more effective than WAG alone.

Thank you all for your attention. I hope this sharing has provided you with some inspiration and enjoyment.