

AN EXPERIMENTAL APPROACH OF CO₂ SEQUESTRATION IN GAS CONDENSATE RESERVOIRS

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ABSTRACT

This paper discusses an approach that relates primarily to the laboratory and modeling studies that precede compositional simulations and field pilot test of CO₂ sequestration in gas condensate reservoirs.

Depleted natural gas or gas condensate reservoirs are becoming important targets for CO₂ sequestration.

Although depleted below the dew point, CO₂ injection in the gas condensate reservoirs may allow enhanced gas recovery by reservoir re-pressurization or pressure maintenance.

The higher density of CO₂ relative to hydrocarbon gas means that CO₂ will tend to migrate downward. The larger viscosity of CO₂ ensures that displacement of hydrocarbon gas phase by CO₂ will be a displacement with a favorable mobility ratio. Furthermore, pressure diffusivity is typically several orders of magnitude larger than molecular diffusivity, making mixing by re-pressurization occur much faster than by molecular diffusion.

The phase behavior of CO₂/gas condensate system as a critical factor in determining the effectiveness of a reservoir to store CO₂ are reviewed in this paper along with its importance in tuning an accurate EOS model.

In addition to PVT experiments, a special core flood test design to determine the micro-scale conformance of the CO₂ displacement, identify CO₂ breakthrough characteristics at density and compositional level during re-pressurization process and evaluate the recovery performance is discussed.

INTRODUCTION

Laboratory studies performed by many researchers have shown that CO₂ injection is considered to be a very effective enhanced oil recovery (EOR) process for light and medium gravity reservoirs oils [1]. CO₂ is considered to be very effective at condensate recovery, too. Surface forces often render the condensate immobile and the only means to recover efficiently these hydrocarbons is through vaporization into a mobile phase.

Miscible displacement between oil and CO₂ is caused by the extraction of hydrocarbons from the oil into the CO₂ and by dissolution of CO₂ into the oil. Light and intermediate molecular weight hydrocarbon fractions are vaporized into the CO₂ front.

The miscibility between the oil and CO₂ eliminates interfacial tension, and lack of capillary forces could help recover, in theory, essentially all of the residual oil.

The efficiency of EOR depends on pressure and, thus, on reservoir depths. Greater miscibility has cost benefits associated with increased oil recovery [2].

Increased recoveries have been the driving force behind the use of CO₂. It is in this context that CO₂ sequestration remains an attractive option for the medium to longer term, particularly if the current trend of rising energy demand continues.

The accumulation and entrapment of a lean gas such as methane (CH₄) in the natural gas and gas/condensate reservoirs demonstrates the capability of these reservoirs for gas containment for long periods of time. By virtue of their proven records of gas production, depleted natural gas and gas condensate reservoirs have demonstrated to have both (i) the available volume, and (ii) the integrity of gas containment.

Less well recognized is the potential utility of CO₂ injection into natural gas and depleted gas/condensate reservoirs for the purpose of enhanced gas recovery by simple repressurization of the reservoir. The concept of enhanced gas recovery is important because it can partially offset the costs of CO₂ sequestration.

For CO₂ injection into gas/condensate fields, the important issues involve the effect of miscible mixing of the gases by dispersion, as a contribution of convection and molecular diffusion, in single phase flow as CO₂ displaces *in situ* gas. The large volume and large areal extent of gas reservoirs decrease the potential for mixing by dispersion over practical time scales [3].

CO₂ is denser and more viscous than hydrocarbon lean gas at all relevant conditions for gas reservoirs and that CO₂ will generally be supercritical in deep depleted reservoirs. The large density of CO₂ relative to lean gas, predominantly CH₄, means that CO₂ will tend to migrate downward relative to CH₄. The larger viscosity of CO₂ ensures that displacement of CH₄ by CO₂ will be a favorable mobility ratio displacement, with fewer tendencies for the gases to finger and intermix. Furthermore, pressure diffusivity is typically three-five orders of magnitude larger than molecular diffusivity, making repressurization occur much faster than mixing by molecular diffusion [4].

There are some disadvantages to CO₂ miscible displacement. CO₂ is expensive to transport and it is not always available. Poor sweep and gravity segregation can result in no production under certain conditions. Carbon dioxide containing moisture can be very corrosive; this will be a potential problem regardless of whether disposal is into oil or gas reservoirs [5].

EXPERIMENTAL DESIGN

Gas/Condensate and CO₂ Phase Behavior

The efficiency with which an injected CO₂ gas displaces a depleted gas condensate depends strongly on the phase behavior of mixtures of the gas with the liquid. As CO₂ gas is injected into reservoir rock containing gas/condensate and water, CO₂ is miscible at any pressure with hydrocarbon gas phase, components present in the gas may dissolve

in the condensate and to a much lesser extent in the water, while some components present in the condensate and some water transfer to the vapor phase.

The thermodynamic conditions required for dynamic miscibility of CO₂ and gas/condensate are best determined by miscibility PVT studies [6]. The P - x experiment is the most common PVT experiment for first-contact miscibility studies, which provides information on the gas injection fluid behavior as function of pressure at reservoir temperature. The P - x experiment was performed on the recombined fluid from the separator condensate samples and separator gas samples to a target dew point pressure and condensate-gas ratio. Several additions of CO₂ gas were used to investigate the phase behavior of mixture CO₂ and gas/condensate.

Prior to P - x experiments, a Constant Composition Expansion (CCE) and Constant Volume Depletion (CVD) of the recombined fluid, including determination of the dew point and liquid drop-out profile and other properties with pressure at reservoir temperature were performed.

CO₂ Core Flood Displacement

The core flood displacement apparatus consists of a core holder, injection system, an in-line densitometer, a sight cell, a production system and a data acquisition system. A back pressure regulator (BPR) is used to control the core outlet pressure at a set level, while allowing a constant flow rate of core production fluids into the separator. An overburden pressure is applied and maintained. Produced fluids at atmospheric pressure were routed to test tube, where the liquid is collected, while the gas production was monitored with gasometer. Compositional analyses of produced fluids were carried out using gas chromatography. A schematic of core flood system is shown in Figure 1.

Test air permeabilities and porosities were conducted on the individual core samples. All the core samples intended for core flow tests were initially saturated to 100% with the formation brine filtered to 0.5 micron. The core plugs were individually de-saturated to connate water saturations using a porous plate system. A composite core stack (3 ft in length and 1.5" in diameter) is mounted in a hydrostatic tri-axially loaded core holder.

After the assembly of the composite core stack, humidified nitrogen was displaced through the core stack in both directions at high rate to redistribute and minimize saturation discontinuities in the core stack. In this way, it is certain that the water was filling the smaller pores, while achieving the target connate water saturations.

The core and the injection fluids are pre-heated to the test temperature of 212 °F (373 K), while the core pressure is raised to initial test pressure of 4513 psia (31.12 MPa). The single phase gas condensate fluid was flowed through the composite stack until a stable flow was achieved and the endpoint permeability was calculated.

Keeping the overburden pressure 10015 psia (69.05 MPa), to simulate the depletion process in the reservoir and in order to deposit retrograde liquid in the pore system, a three stage constant volume depletion was performed in the core system. The pressure in

the core system was lowered in three pressure steps 3015 psig (20.79 MPa), 2015 psia (13.89 MPa) down to the current reservoir pressure of 1015 psia (7.00 MPa) and each time the system was allowed to equilibrate and the volume of gas produced at each stage was recorded.

The core system was then re-pressurized up to 1515 psia (10.45 MPa) by injecting CO₂. Keeping the backpressure at 1515 psia (10.45 MPa), CO₂ was injected at a constant flow rate through a motorized positive displacement pump and a piston cylinder connected to the core; injection pressure is the same as core pressure. The cumulative condensate production, gas production, water production, and differential pressure are monitored and recorded periodically. A series of compositional analyses of the effluent gas were performed to determine hydrocarbon gas recovery as a function of CO₂ contamination in the production stream and to identify the CO₂ breakthrough characteristics.

The gas flood with CO₂ was continued for approximately 3 pore volumes until the composition of the effluent gas was predominantly CO₂ and a stable flow was achieved.

At the conclusion of the test, the core was depressurized to atmospheric conditions. The core samples were then subjected to Dean-Stark extraction to measure in-situ residual fluid saturations to obtain material balance closure and to calculate the condensate recovery resulting from CO₂ injection.

Endpoint permeability data to nitrogen, single phase gas condensate fluid and CO₂ at respective pressures were evaluated and production and pressure history profiles were developed. In the endpoint permeability calculations, because no measured viscosity data available, the single phase gas viscosities were calculated using correlations [7].

EXPERIMENTAL RESULTS AND DISCUSSION

Gas/Condensate and CO₂ Phase Behavior

A single-stage separation test on the recombined fluid resulted in a condensate-gas ratio close to the target condensate gas ratio of 39.10 STB/MMscf and a dewpoint pressure close to the target dew point pressure of 3415 psia. Then, using a visual PVT cell, on the gas/condensate recombined fluid, a Constant Composition Expansion and a Constant Volume Depletion experiment were performed at reservoir temperature of 212 F (373.2 K). The recombined fluid exhibited a maximum liquid drop-out of 2.3 % of total volume from CCE experiment and a maximum liquid drop-out of 3.4 % of cell volume from CVD experiment.

In order to investigate the CO₂ gas/condensate behavior, a *P-x* experiment was performed on four different CO₂ gas/condensate mixtures with 20, 40, 60 and 80 mole % CO₂ additions, respectively. Each time a constant composition expansion was performed, the saturation pressure and the liquid dropout was measured. At 80 mole % CO₂ addition there was no retrograde liquid observed and the mixture was in single phase gas.

A summary of measured main PVT data is given in Table 1 and 2. The saturation

pressure profile and liquid drop-out with respect to CO₂ addition from CCE experiments are shown in Figure 2 and 3, while the results of liquid drop-out and the cumulative gas produced from CVD experiment are shown in Figure 4.

CO₂ Core Flood Displacement

The CO₂ core flood displacement was conducted on a core system 3 ft in length and 1.5” in diameter with an average porosity of 12 %, and harmonic average permeability to air of 0.12 mD. The average connate water saturation of the composite stack calculated based on measured individual core samples was 51 %.

The criteria for interpreting the CO₂ displacement have included the pressure differential profile, breakthrough, visual observation of core effluent, and the compositions of produced gases.

The main parameters measured from the core flood displacement are summarized in Table 3. The pressure differential was monitored continuously during the test and its profile with respect to CO₂ PV injected is given in Figure 5.

Due to vaporization mechanism developed during displacement, a significant amount of condensate was produced. The cumulative condensate produced and the produced condensate-gas ratios are shown in Figure 6 and 7, respectively.

During CO₂ displacement, at a much lesser extent a mass transfer between water and CO₂ occurs. The lower the reservoir pressure, the higher is the water content in CO₂/hydrocarbon gas phase [7]. This mechanism explains the water production with PV CO₂ injected. The results from water production are shown in Figure 8.

The mechanism of CO₂ displacement was also studied by experimentally determining the compositional changes that occur between CO₂ and in situ fluid during core flow testing. To determine the flowing wellstream analyses effluent fluids were analyzed using gas chromatography. A wellstream analysis was obtained at intervals of about 0.1 PV CO₂ injected. The results shown in Figure 9 and 10 illustrate the experimentally measured composition changes of the effluent during CO₂ displacement.

CONCLUSIONS

1. Properties of depleted gas/condensate reservoirs and of CO₂ are favorable for repressurization and enhanced gas recovery processes.
2. The measured compositional data can be used to calculate the experimental longitudinal dispersion coefficient during miscible displacement at given test conditions.
3. The experimental data can be used as a base for sensitivity case studies using a commercial compositional simulator to evaluate the feasibility of CO₂ sequestration in depleted gas/condensate reservoirs with enhanced gas recovery component.
4. Several important factors such as the core length, injection rate can have a great effect on the mechanism, stability and on the breakthrough and ultimate recoveries, which need further investigations and laboratory studies.

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0 mole % CO ₂		20 mole % CO ₂		40 mole % CO ₂		60 mole % CO ₂	
Pressure (psia)	Liq. Volume (% of Vtot)	Pressure (psia)	Liq. Volume (% of Vtot)	Pressure (psia)	Liq. Volume (% of Vtot)	Pressure (psia)	Liq. Volume (% of Vtot)
3417 *	0.00	2885	0.00	2321	0.00	1662	0.00
3015	1.56	2515	0.99	2015	0.49	1515	0.11
2515	2.27	2015	1.39	1515	0.69	1265	0.20
2015	2.22	1515	1.24	1265	0.63	1015	0.20
1515	1.77	1265	1.05	1015	0.52	765	0.16
1265	1.48	1015	0.84	765	0.38	515	0.09
1015	1.16	765	0.60	515	0.23		
765	0.83	515	0.36				
515	0.51						

* Saturation Pressure

Table 1. Summary of Constant Composition Expansion Data at 212 F (373.2 K)

Pressure (psia)	Gas Z-Factor (-)	Prod. Gas (% orig. mole)	Liq. Volume (% of Vcell)
3417 *	0.8684	0.00	0.00
3015	0.8635	11.01	1.76
2615	0.8633	22.46	2.71
2215	0.8681	34.28	3.19
1815	0.8783	46.30	3.39
1515	0.8895	55.35	3.40
1015	0.9156	70.23	3.28
765	0.9320	77.47	3.16
515	0.9507	84.53	3.01

* Saturation Pressure

Table 2. Summary of Constant Volume Depletion Data at 212 F (373.2 K)

CO2 Injected (PV)	Pressure Differential (psi)	Cum. Cond. Produced (cc)	Cum. Water Produced (cc)	Produced CGR (STB/MMscf)
0.00	345	0.00	0.00	0.00
0.18	370	0.00	0.00	0.00
0.28	390	0.00	0.00	0.00
0.46	422	0.00	0.00	0.00
0.55	447	0.00	0.00	0.00
0.66	464	0.00	0.00	0.00
0.77	475	0.00	0.00	0.00
0.85	485	0.00	0.00	0.00
0.95	475	0.02	0.00	1.95
1.13	453	0.13	0.07	5.03
1.62	433	0.27	0.25	12.95
2.23	399	0.38	0.50	27.83
2.96	382	0.48	0.80	5.45

Table 3. Summary of CO2 Core flood Displacement Data

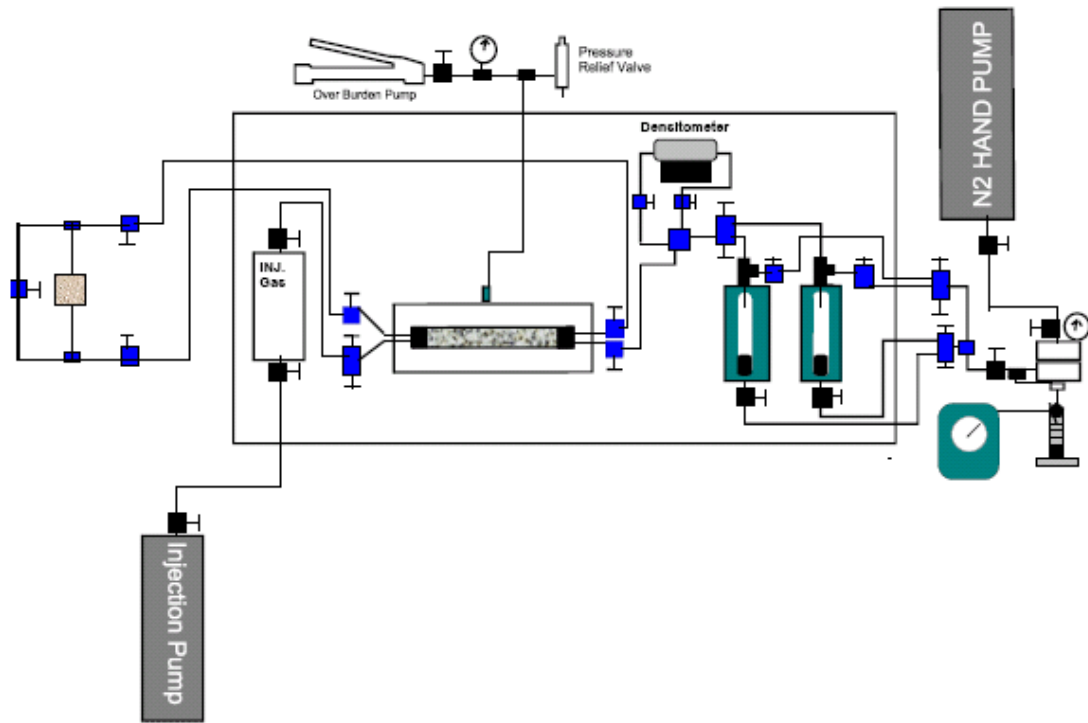


Figure 1. Enhanced Gas Recovery Core Flood System

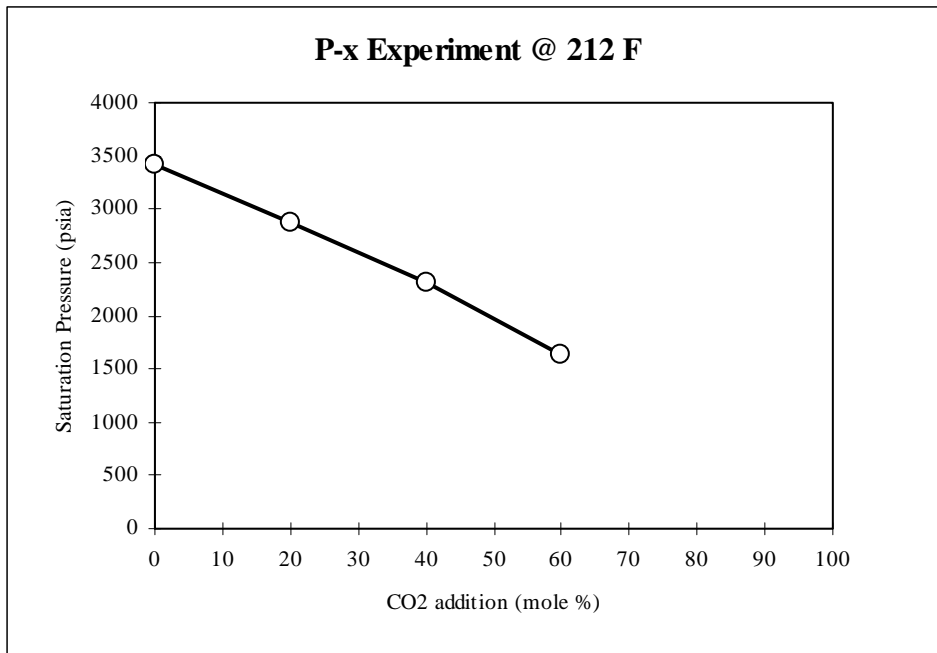


Figure 2. Saturation Pressure with CO2 addition

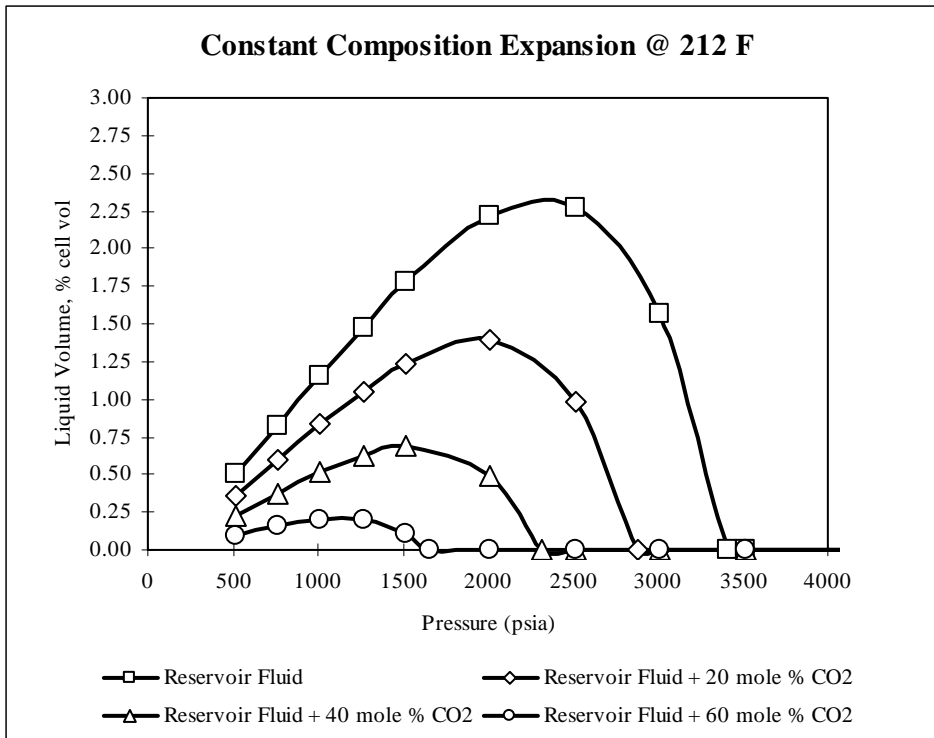


Figure 3. Liquid Drop-Out with CO2 Addition

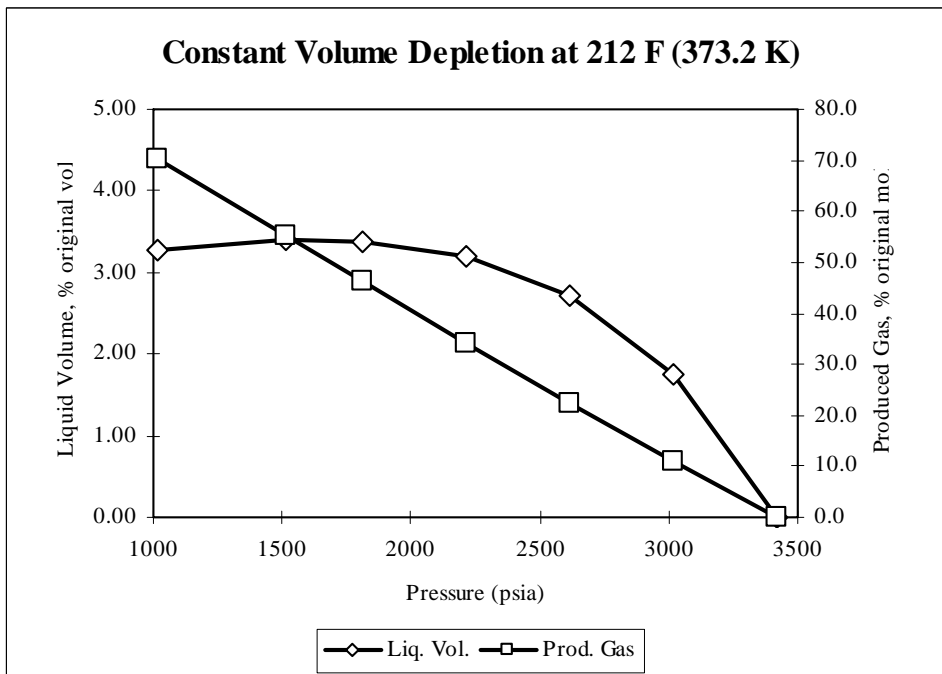


Figure 4. Liquid Drop-Out and Produced Gas during Constant Volume Depletion

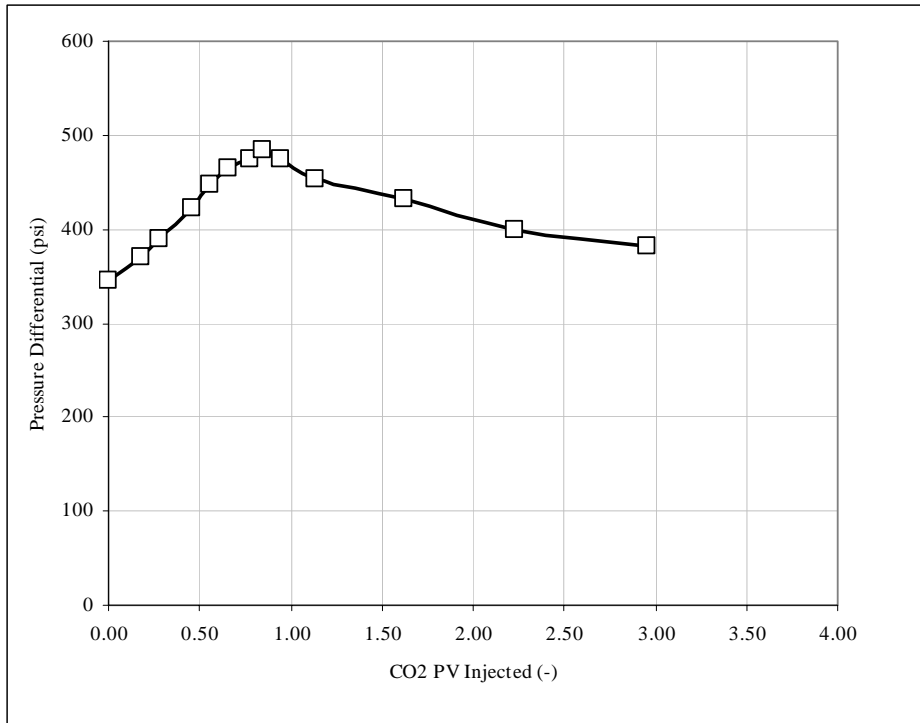


Figure 5. Pressure Profile with CO2 PV injected

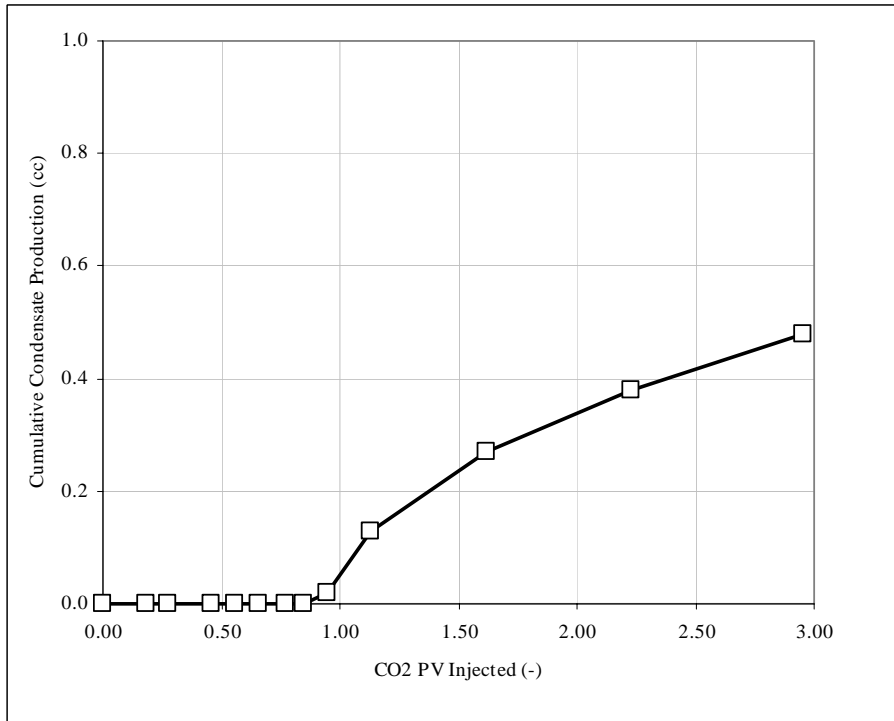


Figure 6. Cumulative Condensate Produced with CO2 PV injected

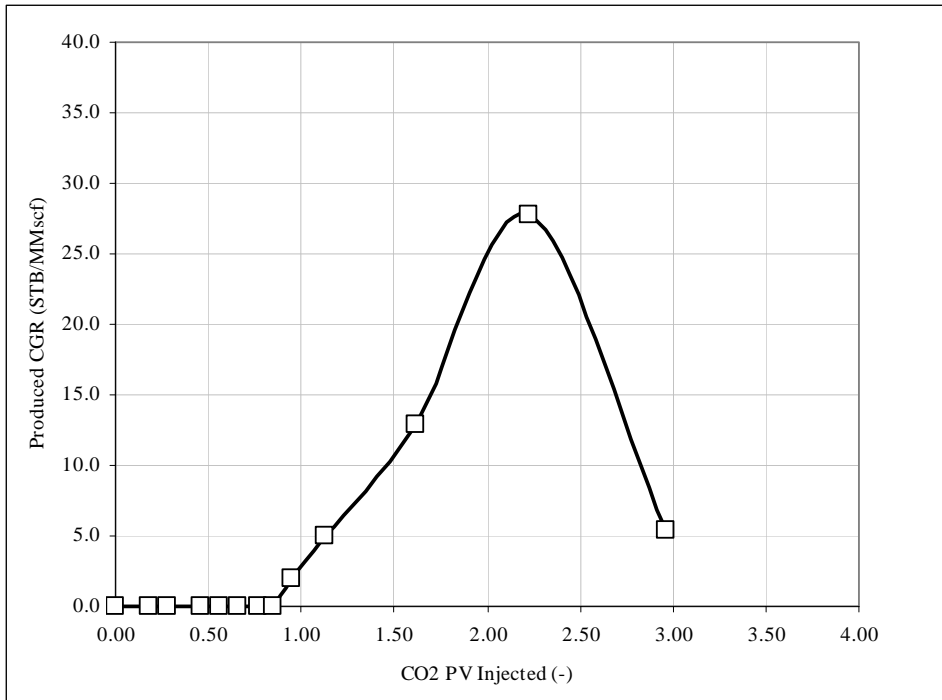


Figure 7. Produced Condensate-Gas Ratio with CO2 PV injected

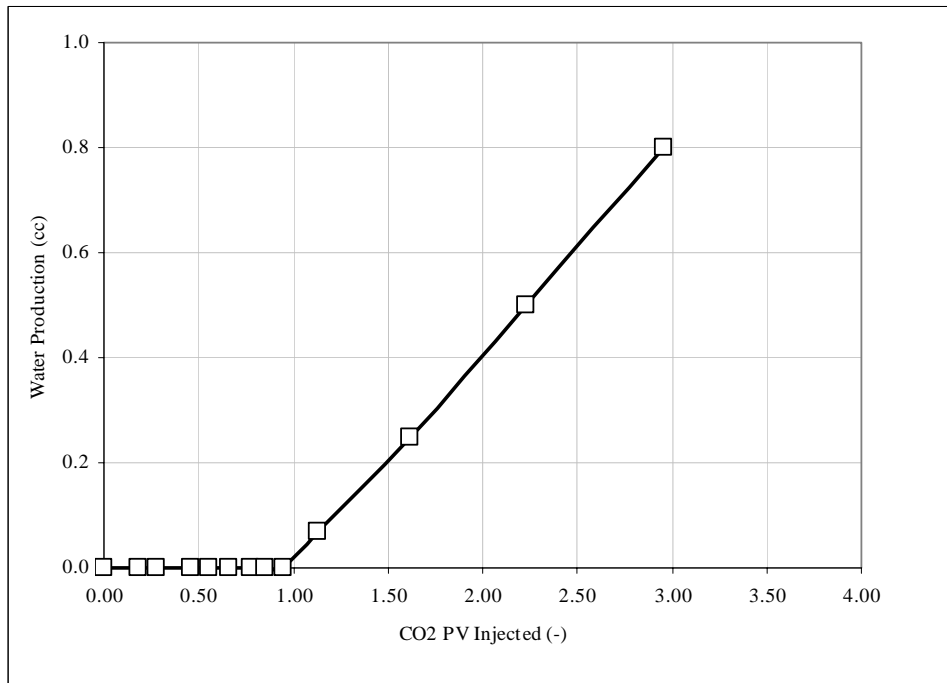


Figure 8. Cumulative Water Produced with CO2 PV injected

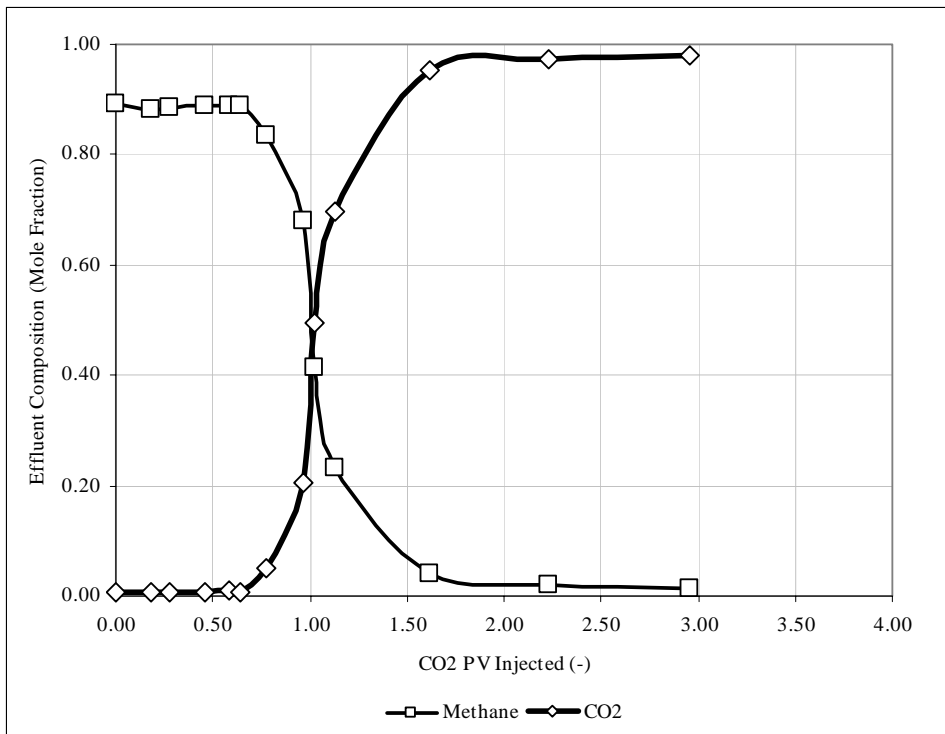


Figure 9. Effluent Compositional Profile (CH4, CO2) with CO2 PV injected

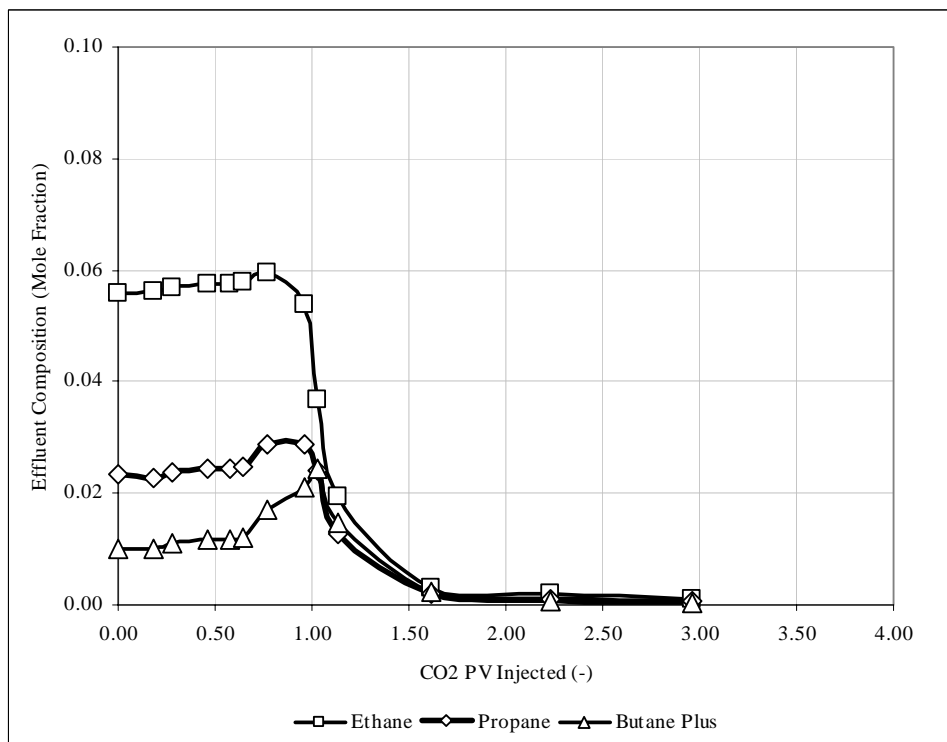


Figure 10. Effluent Compositional Profile (Intermediate HC) with CO2 injected