

Measurement of Z-Factors for Carbon Dioxide Sequestration

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Abstract

Due to concerns about global climate change, carbon dioxide gases from natural and industrial sources are more and more re-injected into depleted gas reservoirs. The PVT laboratory at Texas Tech University has undertaken a comprehensive study on compressibility factor (Z-factor) of hydrocarbon (HC) gas at various amount of CO₂. For the sole purpose of the measured Z-factor data, three temperatures of 100°F, 160°F and 220°F and pressures ranges from 50 psia to 5000 psia are selected as representative of the depleted gas reservoirs (DGRs). In order to analyze the various phase behavior to be encountered in gas reservoirs (dry gas, wet gas and retrograde gas), the median gas compositions for dry, wet and retrograde gases are specified by gas type. The gas types are categorized by representative compositional analysis for the three types of gas reservoirs (dry gas, wet gas and retrograde gas). The measurements of z-factors for CO₂-hydrocarbon mixtures in varying proportions and at the three specified temperatures for various pressures are performed on the median gas compositions of the type gases. The results of the Z-factor measurements of CO₂-hydrocarbon mixtures are used to interpret the expected phase behavior to be encountered in the geologic storage of CO₂ in gas reservoirs. Also, the Z-factor measurements of CO₂-retrograde gas mixtures are used to quality the benefits of enhanced gas and condensate recovery in gas reservoirs.

Introduction

Carbon dioxide (CO₂) gas has been used for enhanced oil recovery through miscible and immiscible displacement of oil at high pressures and moderate temperatures since the earlier 1970. Recently, research is being directed for the use of carbon dioxide in the oil refining through supercritical extraction of hydrocarbons.¹ Current activities are to find ways for geologic storage of CO₂ in oil or gas reservoirs.² Although one laboratory measurement of CO₂-hydrocarbon mixture in the limited ranges of temperatures and pressures used in this project has been reported in Venezuela (Rojas-Requena, 1992),³ this paper presents experimental measurements of Z-factors for CO₂-hydrocarbon mixtures at three specified temperatures and pressures ranging from 50 psia to 5000 psia. The results of the experimental Z-factors are used to quantify economic benefits (such as enhanced oil recovery (EOR) and enhanced condensate vaporization) of geologic storage of CO₂ in gas reservoir.

Procedure for Z-factor Determination

The compressibility factor, or Z-factor, is determined by manipulating the Real Gas Law and assuming that reservoir gas will behaves as an ideal gas at ambient pressure and temperature (McCain, 1990, page 106).

The Real Gas Law is defined as follows:

$$PV = ZnRT \dots\dots\dots (1)$$

For a constant composition system, the product of pressure and volume is constant, thus

$$\frac{P_1V_1}{P_2V_2} = \frac{Z_1nRT_1}{Z_2nRT_2} \dots\dots\dots (2)$$

Where the subscripts are:

1. Condition in the cell
2. Ambient condition

Solving for the ratio of compressibility factors:

$$\frac{Z_1}{Z_2} = \frac{P_1V_1T_2}{P_2V_2T_1} \dots\dots\dots (3)$$

At ambient pressure and temperature all gases are assumed to behave like an Ideal Gas, so that its compressibility factor is unity. Substituting Z2 with 1 result in the primary formula for this study:

$$Z_1 = \frac{P_1V_1T_2}{P_2V_2T_1} \dots\dots\dots (4)$$

Where:

- P_1 cell pressure
- V_1 volume of gas released from the cell
- T_1 cell temperature
- P_2 ambient pressure
- V_2 volume of gas at ambient pressure and temperature
- T_2 ambient temperature

Pressure and temperature are in absolute units.

Hydrocarbon Type Gas Samples

The first part of the study is identifying major components of reservoir gas and the range of compositions for each of the categories of the gas reservoirs (i.e., dry gas, wet gas, and retrograde gas).

The gas compositions are obtained from published SPE papers, Petroleum Engineering Journals, Gas Information System (GASIS) and PVT analyses. The major components of gas reservoir are identified as nitrogen, carbon dioxide, methane, ethane, propane, n-butane, n-pentane, hexane, and heptane-plus ($N_2, CO_2, C_1, C_2, C_3, nC_4, nC_5, C_6, C_7^+$). Non-hydrocarbon components are removed and the hydrocarbon components are normalized to 1.0 mole. These compositions are analyzed to find the median composition for each of the categories of gas reservoirs, and a means of identifying the Gas Type from the composition is established. Tables containing the normalized median compositions for each category of gas reservoirs are constructed. The median compositions are derived from 131 dry gas, 12 wet gas, and 11 retrograde gas samples. A sample of the normalized median composition for gas reservoir is shown in Table 1.

Table 1 – Normalized Median Composition

	C ₁	C ₂	C ₃	C ₄	C ₅	C ₆	C ₇ ⁺	Total Mol %
Dry Gas	96.61	2.67	0.51	0.21	0.00	0.00	0.00	100.00
Wet Gas	90.03	4.75	2.03	1.03	0.42	0.35	1.40	100.00
Retrograde Gas	73.09	8.57	4.53	3.40	1.89	1.64	6.88	100.00

Table 1 shows that dry gas reservoir is mainly C₁, whereas wet and retrograde gas reservoirs have appreciable amount of heptanes-plus fractions (C₇⁺). Anticipating sequestration of CO₂ in depleted gas reservoirs (DGRs) to vary based on the phase behavior of the mixture of the CO₂ and the resident hydrocarbon gases and liquids, the Z-factor measurements are based on each gas types.

The gas compositions of Table 1 are the compositions of the initial or discovery gas reservoirs. By definition there are no phase changes in the reservoir for dry and wet gases; consequently, the median dry and wet gas compositions are also the compositions of the respective gases at depleted reservoir conditions. This is not the case for retrograde gas, which undergoes a phase change at reservoir conditions. As such, the composition of the retrograde gas' liquid and vapor phases varies with pressure. Three depleted pressures of 50, 250 and 500 psia are used as a range to define the depleted gas reservoir pressure, which is also the initial sequestration pressure. These three gases are labeled as retrograde gases A, B and C for the gases at 50, 250 and 500 psia, respectively, and their respective compositions are show in Table 2.

Table 2 – Normalized Median Composition of Retrograde Gas at Depleted Pressure

	C ₁	C ₂	C ₃	C ₄	C ₅	C ₆	C ₁₀	Total Mol %
Retrograde Gas A (50 psia)	24.77	5.27	5.41	7.71	6.67	7.34	42.82	100.00
Retrograde Gas B (250 psia)	39.05	6.99	5.82	6.83	5.25	5.49	30.57	100.00
Retrograde Gas C (500 psia)	50.78	7.92	5.64	5.75	4.05	4.07	21.76	100.00

To ensure the broadest applicability of the lab data to CO₂ sequestration in gas reservoirs, gas compositions are required for as many sources as possible so that a representative average composition of dry, wet and retrograde gases could be established. Therefore, a specific gas reservoir could be selected or fabricated in the laboratory that is close to the median composition found from data collected for each gas type. As broadest applications into gas reservoirs are required, a specific gas reservoir study is not mandated. Consequently, the 154 gas compositions found in the literature and private sources could be categorized by gas types: dry, wet, and retrograde. Median gas types are calculated for each gas type in order to have gas compositions that are not unique to specific gas reservoir. A plot

is made that identify regions type gases (dry, wet, and retrograde gasses) based on their compositions. Several plots were made to find the combination of compositions that would provide the greatest distinction of the gas type and thus yields unique gas-type identification.

The final plot (see Figure 1) is the sum of the mole fraction of the butane, propane, pentane, hexane and heptane divided by the mole fraction methane (y-axis) versus mole fraction of ethane divided by mole fraction of methane (x-axis). Figure 1 is the basis for gas samples specification ordered for the experimental work on CO₂-hydrocarbon mixtures.

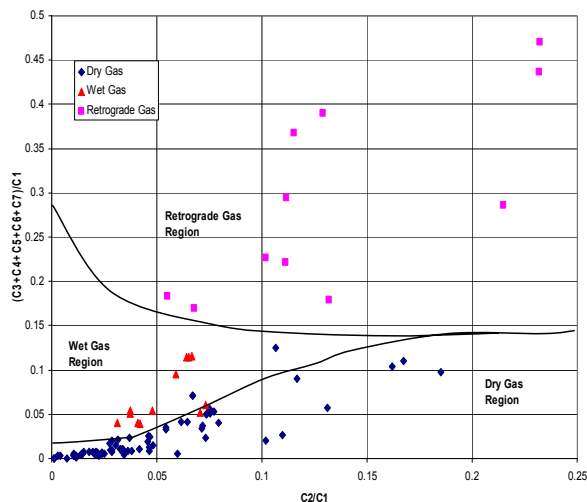


Figure 1 – TTU Gas Identification Chart based on hydrocarbon composition of C₁ – C₇₊

Experimental Gas Samples

To ensure repeatability of the Z-factor measurements for each gas type, pre-mixed gas with the median composition of each gas type that has been shown in Table 1 were ordered from a commercial analytical-gas vendor. Two more procedure were implemented to ensure sample consistency:

1. Single-phase sample loading from the gas bottle to the PVT cell must be performed all the time. To ensure single-phase loading each bottle has to be heated to above its cricondenthem temperature plus 15°F.
2. To prevent sample segregation in the bottle due to molecular weight difference of each component, the bottle must be heated in a non-uniform form. The lower part of the bottle is heated at 200°F while the top part is heated at the cricondenthem temperature plus 15°F. The much hotter lower part of the bottle will make the sample gas lighter than the upper part, and thus created a continuous convection upward that ensures no sample segregation occurs.

As the median retrograde gas has a cricondenthem temperature much higher than the safety limit of the sample bottle to ensure single-phase loading, the median retrograde gas sample must be loaded in two steps. The step one is to load the liquid part of the heptane-plus, in the form of liquid decane to the PVT cell. Then the second step is to load the pre-

mixed median retrograde gas but without the heptane-plus part. Then an overnight mixing was done in the cell at the target temperature of 100°F, 160°F, and 220°F.

Ruska PVT Equipment

This research project uses equipment commercially available from Chandler Engineering Products (previously Ruska) Model 2370 Mercury-Free PVT Oven, and the produced gas is measured with the Model 2331 Gasometer and Model 2353 Separator. Measurement automation and remote monitoring is performed by in-house developed LabVIEW-based software running on an off-the-shelf computer in-house.

To ensure a leak-free system, a special compound that is compatible with high concentration of CO₂ has been utilized. This special compound is called V1238-95, a fluorocarbon material (FKM) product of Parker Hannifin.

To prevent the premature destruction of seals in the system, due to the absorbed gas and/or CO₂ that suddenly expands when the system pressure is dropped, a measure similar to deep sea divers do to prevent a syndrome called “*bends*” has been implemented. This method calls for a waiting period until the system stabilized, for at least 15 minutes, after a volume expansion of maximum 1.5 times the initial volume has been performed. During this waiting time all absorbed gas will have sufficient time to diffuse out from the seal material safely.

Laboratory Measurement Results

Great effort has been spent during the measurement in the lab to minimize measurement error. These efforts comprised of repeating each measurement six times and rejecting the outlier data before the averaging, running the system against known gas to detect any system drifts between HC sample runs, and letting the system stays overnight to ensure a completely stabilized system before each sample run.

Figures 2 to 4 shows CO₂ compressibility factor measured in the lab compared to published data by Sage and Lacey (1955), and Burton Corblin (1990). The plot shows a very good match between lab results and the two published data sets that confirm equipment and methodology. At pressure less than 100 psia, the measured data deviates slightly (less than 10% absolute error) compared to the two published data sets.

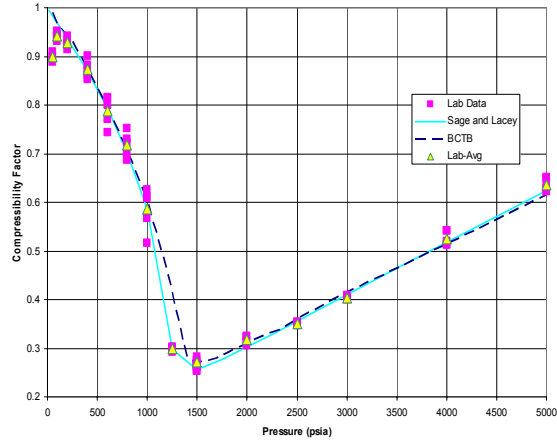


Figure 2 – Benchmark TTU CO₂ Measurements at 100°F to Sage and Lacy (1955) and Burton Corblin Technical Bulletin (1990)

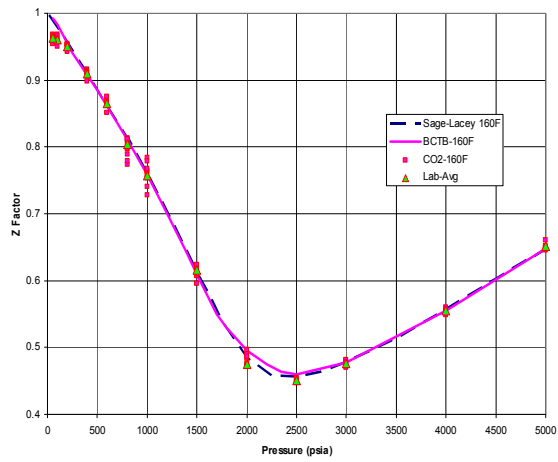


Figure 3 – Benchmark TTU CO₂ Measurements at 160°F to Sage and Lacy (1955) and Burton Corblin Technical Bulletin (1990)

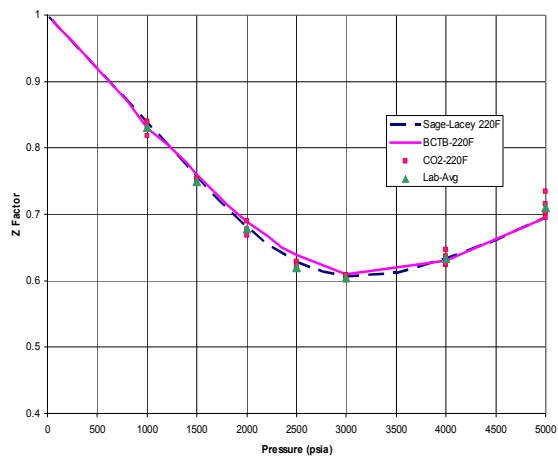


Figure 4 – Benchmark TTU CO₂ Measurements at 220°F to Sage and Lacy (1955) and Burton Corblin Technical Bulletin (1990)

The smoothed compressibility factors of dry gas samples from laboratory measurement are shown in Figure 5 to 7 and Table 3 to 5. Each table shows the actual lab result, and the smoothed data are listed next to the lab measurements. Figure 5 shows the compressibility factor of various median dry gas and carbon dioxide composition at 100°F. Also shown on the plot is the compressibility factor of pure carbon dioxide gas. As can be observed from the plot, a consistent progression in the increasing amount of carbon dioxide gas in the median dry gas mixture is shown. The result of the compressibility factor at 160°F is shown in Figure 6. The plot shows a consistent trend as a function of increasing carbon dioxide content. Figure 7 shows the compressibility factor of various dry gas and carbon dioxide mixture at 220°F. This plot shows a correct trend as a function of the amount of carbon dioxide in the mixture.

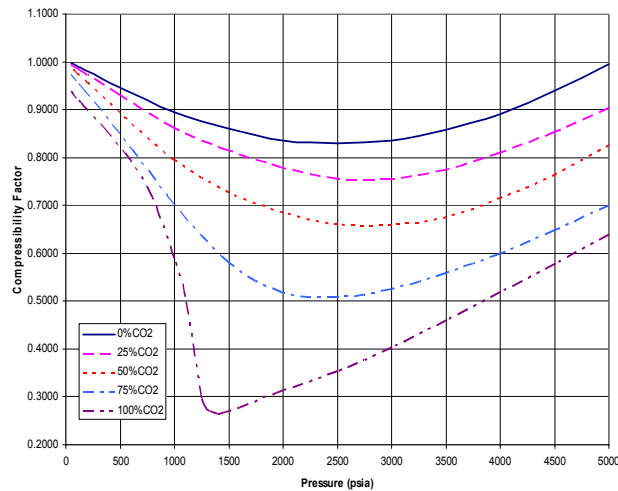


Figure 5 - Median Dry Gas and CO₂ Mixture at 100°F

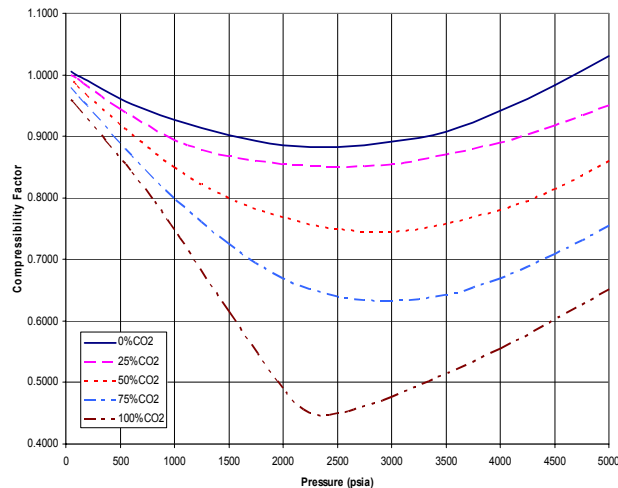


Figure 6 - Median Dry Gas and CO₂ Mixture at 160°F

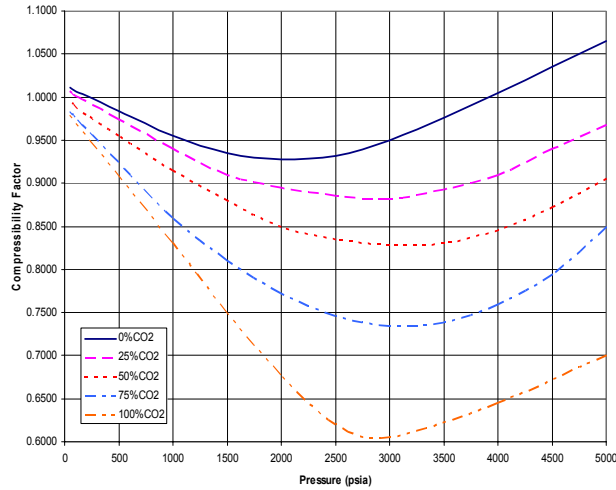


Figure 7 - Median Dry Gas and CO₂ Mixture at 220°F

Table 3 - Compressibility Factor of Median Dry Gas and CO₂ Mixture at 100°F

Pressure psia	0% CO ₂		25% CO ₂		50% CO ₂		75% CO ₂	
	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab
5000	0.9950	0.9947	0.9040	0.8981	0.8260	0.8227	0.7000	0.7538
4500	0.9400		0.8550		0.7650		0.6500	
4000	0.8900	0.8918	0.8100	0.8023	0.7150	0.7161	0.6000	0.6584
3500	0.8580		0.7750		0.6750		0.5600	
3000	0.8350	0.8382	0.7550	0.7382	0.6590	0.6452	0.5250	0.5327
2500	0.8300	0.8253	0.7560	0.7297	0.6600	0.6278	0.5090	0.5166
2000	0.8360	0.8596	0.7780	0.8251	0.6850	0.6932	0.5180	0.5045
1500	0.8600	0.8603	0.8150	0.8486	0.7275	0.7293	0.5800	0.5866
1000	0.8950	0.9024	0.8630	0.8985	0.7950	0.8149	0.7050	0.7485
500	0.9450	0.9473	0.9300	0.9325	0.8950	0.9073	0.8500	0.8747
200	0.9800	0.9908	0.9720	0.9807	0.9580	0.9500	0.9350	0.9669
100	0.9910	1.0050	0.9870	0.9937	0.9780	0.9715	0.9620	0.9875
50	0.9970	1.0146	0.9940	0.9958	0.9900	0.9815	0.9750	1.0051

Table 4 - Compressibility Factor of Median Dry Gas and CO₂ Mixture at 160°F

Pressure psia	0% CO ₂		25% CO ₂		50% CO ₂		75% CO ₂	
	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab
5000	1.0300	0.9968	0.9500	0.9449	0.8600	0.8625	0.7550	0.7535
4500	0.9830		0.9175		0.8150		0.7100	
4000	0.9420	0.9309	0.8900	0.8874	0.7800	0.7814	0.6700	0.6737
3500	0.9070		0.8700		0.7580		0.6420	
3000	0.8912	0.8918	0.8550	0.8584	0.7450	0.7487	0.6325	0.6333
2500	0.8828	0.8879	0.8500	0.8532	0.7500	0.7530	0.6400	0.6320
2000	0.8855	0.8830	0.8550	0.8527	0.7680	0.7764	0.6700	0.6787
1500	0.9014	0.8379	0.8680	0.8734	0.8000	0.8093	0.7250	0.7414
1000	0.9275	0.8617	0.8950	0.8942	0.8500	0.8737	0.8000	0.8095
500	0.9609	0.9011	0.9450	0.9439	0.9200	0.9330	0.8900	0.8872
200	0.9900	0.9230	0.9810	0.9785	0.9670	0.9655	0.9500	0.9686
100	0.9996	0.9489	0.9945	1.0226	0.9840	0.9903	0.9700	0.9868
50	1.0050	0.9868	1.0000	1.0189	0.9930	0.9598	0.9800	1.0208

Table 5 - Compressibility Factor of Median Dry Gas and CO₂ Mixture at 220°F

Pressure psia	0% CO ₂		25% CO ₂		50% CO ₂		75% CO ₂	
	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab
5000	1.0650	1.0638	0.9675	0.9648	0.9050	0.9027	0.8500	0.8481
4500	1.0350		0.9400		0.8725		0.7950	
4000	1.0050	1.0152	0.9100	0.9134	0.8450	0.8477	0.7600	0.7517
3500	0.9760		0.8930		0.8300		0.7390	
3000	0.9500	0.9467	0.8825	0.8789	0.8280	0.8249	0.7340	0.7325
2500	0.9320	0.9288	0.8850	0.8883	0.8350	0.8308	0.7460	0.7470
2000	0.9280	0.9148	0.8950	0.8997	0.8500	0.8576	0.7720	0.7715
1500	0.9350	0.9293	0.9100	0.9224	0.8800	0.8862	0.8100	0.8008
1000	0.9550	0.9486	0.9400	0.9425	0.9150	0.9151	0.8600	0.8632
500	0.9840	0.9878	0.9740	0.9683	0.9550	0.9505	0.9250	0.9198
200	1.0013	1.0141	0.9950	0.9894	0.9800	0.9672	0.9640	0.9173
100	1.0075	0.9762	1.0022	0.9669	0.9900	0.9703	0.9770	0.8737
50	1.0110	0.9657	1.0070	0.9768	0.9960	0.9796	0.9840	0.7603

Because wet gas sample generate liquid in the separator at temperature lower than 145°F, there is no plot of compressibility factor at 100°F. The compressibility factors at 160°F and 220°F are shown in Figures 8-9.

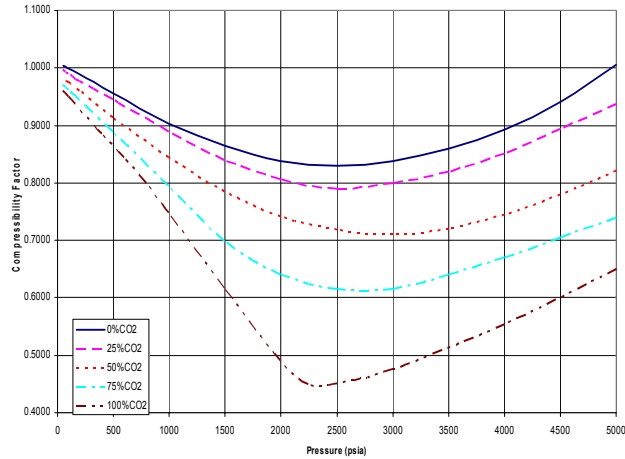


Figure 8 - Median Wet Gas and CO₂ Mixture at 160°F

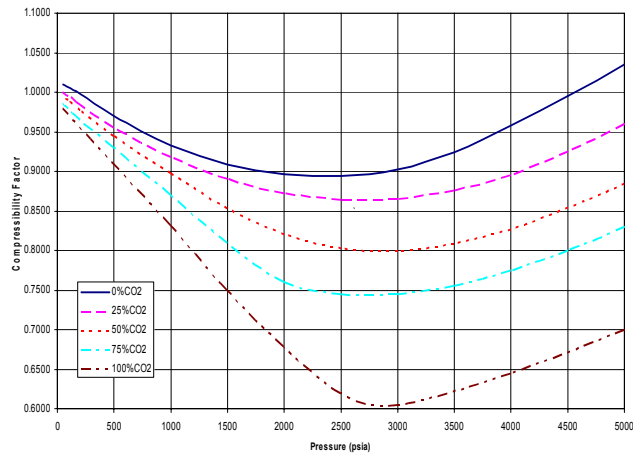


Figure 9 - Median Wet Gas and CO₂ Mixture at 220°F

Compressibility factor of various wet gas with carbon dioxide at 160°F shows a consistent trend as a function of the amount of carbon dioxide. At 220°F, the compressibility factor also shows the expected trend as a function of the amount of carbon dioxide. Tables 6 and 7 shows the compressibility factor of various wet gas with carbon dioxide in numerical format

Table 6 - Compressibility Factor of Median Wet Gas and CO₂ Mixture at 160°F

Pressure psia	0% CO ₂		25% CO ₂		50% CO ₂		75% CO ₂	
	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab
5000	1.0050	1.0046	0.9380	0.9368	0.8210	0.8224	0.7400	0.8386
4500	0.9400		0.8950		0.7800		0.7050	
4000	0.8920	0.8928	0.8510	0.8517	0.7450	0.7479	0.6700	0.7296
3500	0.8600		0.8200		0.7200		0.6400	0.7296
3000	0.8380	0.8557	0.8000	0.7938	0.7100	0.7108	0.6150	0.6237
2500	0.8290	0.8284	0.7900	0.7880	0.7180	0.7140	0.6150	0.6041
2000	0.8380	0.8434	0.8070	0.8023	0.7410	0.7375	0.6400	0.6514
1500	0.8650	0.8634	0.8400	0.8388	0.7850	0.7829	0.6980	0.7244
1000	0.9030	0.9050	0.8900	0.8869	0.8450	0.8504	0.7950	0.8952
500	0.9560	0.9608	0.9450	0.9536	0.9150	0.9116	0.8900	0.9439
200	0.9890	0.9849	0.9780	0.9830	0.9610	0.9692	0.9440	1.0891
100	0.9990	0.9891	0.9900	0.9919	0.9760	0.9801	0.9620	1.1870
50	1.0040	0.9896	0.9970	1.1588	0.9830	0.9772	0.9700	1.2069

Table 7 - Compressibility Factor of Median Wet Gas and CO₂ Mixture at 220°F

Pressure psia	0% CO ₂		25% CO ₂		50% CO ₂		75% CO ₂	
	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab
5000	1.0350	1.0365	0.9600	0.9605	0.8840	0.8838	0.8300	0.9190
4500	0.9950		0.9250		0.8540		0.8000	
4000	0.9575	0.9420	0.8950	0.8948	0.8265	0.8336	0.7750	0.8457
3500	0.9240		0.8760		0.8080		0.7550	
3000	0.9030	0.9106	0.8650	0.8632	0.7990	0.7977	0.7450	0.8223
2500	0.8940	0.8913	0.8640	0.8616	0.8030	0.8015	0.7450	0.8194
2000	0.8960	0.8948	0.8725	0.8714	0.8210	0.8261	0.7600	0.8056
1500	0.9090	0.9208	0.8900	0.8817	0.8530	0.8438	0.8100	0.8410
1000	0.9320	0.9211	0.9175	0.9148	0.8975	0.9120	0.8700	0.9863
500	0.9700	0.9688	0.9560	0.9644	0.9450	0.9631	0.9300	1.0686
200	0.9970	0.9753	0.9840	0.9902	0.9770	0.9854	0.9650	0.9701
100	1.0060	0.9855	0.9950	0.9709	0.9900	1.0044	0.9800	0.9680
50	1.0100	0.9864	0.9996	0.9574	0.9950	0.9936	0.9870	0.9983

As the retrograde gas is expected to have a fraction of the volume as liquid at certain pressure and temperatures, the compressibility factor measurement was done using two different methods and the result is merged together. For pressures above the dew-point pressure, the constant composition expansion (CCE) method was utilized whereby the cell is kept closed, and system pressure is gradually increased and the respective cell volume is recorded. For pressures below the dew-point pressure the constant volume depletion (CVD) method was utilized. This method mimics the actual condition in the reservoir during depletion process as the reservoir volume stays constant and the liquid precipitation stays in the pore space of the reservoir rock.

The dew-point pressure of median retrograde gas is 3400 psia, and drops to 1300 psia after CO₂ has been injected. Figures 10, 11, and 12 shows the compressibility factor of median retrograde gas and depleted retrograde gas after CO₂ has been mixed at temperatures of 100°F, 160°F, and 190°F. Tables 8, 9, and 10 show the result in numeric format, respectively. Owing to the equipment failures as a result of premature seal degradation at high temperatures, there is no result for cell temperature of 220°F.

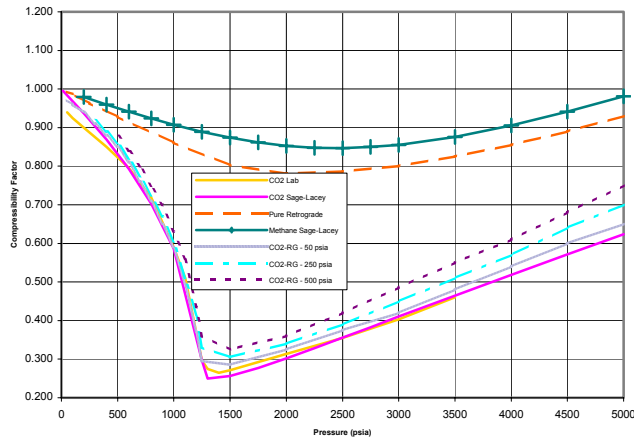


Figure 10 – Retrograde and Depleted Retrograde Gas and CO₂ Mixture at 100°F

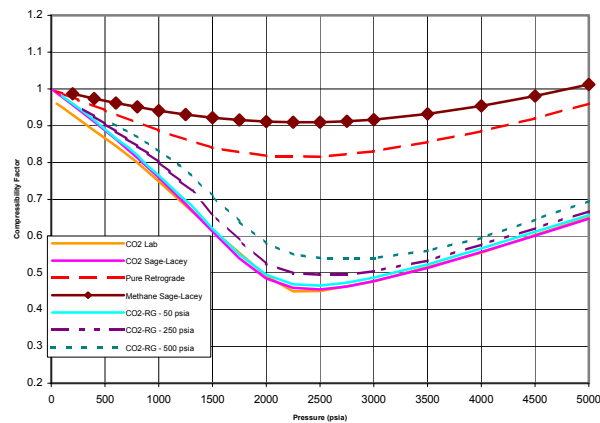


Figure 11 – Retrograde and Depleted Retrograde Gas and CO₂ Mixture at 160°F

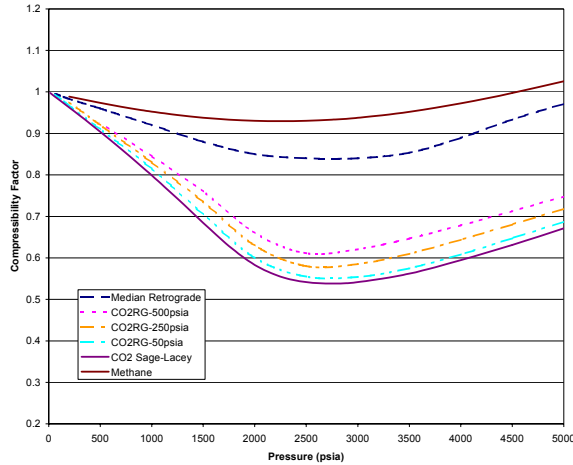


Figure 12 – Retrograde and Depleted Retrograde Gas and CO₂ Mixture at 190°F

Table 8 - Compressibility Factor of Median Retrograde Gas and Depleted Retrograde Gas + CO₂ Mixture at 100°F

Median Retrograde			Depleted Median Retrograde Sample						
Pressure	Smoothed	Lab	Pressure	50 psia		250 psia		500 psia	
				Smoothed	Lab	Smoothed	Lab	Smoothed	Lab
5000	0.93	0.935	5000	0.6500	0.6540	0.7000	0.6900	0.7500	0.7600
4500	0.89		4500	0.6000		0.6400		0.6800	
4000	0.855	0.845	4000	0.5400	0.5340	0.5700	0.5800	0.6100	0.6050
3500	0.825		3500	0.4800		0.5100		0.5500	
3000	0.8	0.79	3000	0.4200	0.4100	0.4500	0.4400	0.4850	0.4800
2500	0.786		2500	0.3750		0.3900		0.4200	
2000	0.7808	0.785	2000	0.3250	0.3300	0.3400	0.3200	0.3600	0.3500
1500	0.8027		1500	0.2850	0.2900	0.3050	0.3000	0.3250	0.3200
1000	0.8605	0.86	1250	0.2950		0.3300		0.3600	
500	0.9283	0.92	1200	0.3700		0.4150		0.4350	
250	0.9627		1100	0.4940		0.5100		0.5600	
100	0.9867	0.98	1000	0.5900	0.6000	0.6050	0.5900	0.6300	0.6200
50	0.993		900	0.6500		0.6700		0.7000	
			800	0.7100		0.7250		0.7500	
			700	0.7600		0.7750		0.8000	
			600	0.8100		0.8200		0.8400	
			500	0.8500	0.8400	0.8600	0.8700	0.8800	0.8600
			400	0.8800		0.8900			
			300	0.9100		0.9200	0.9100		
			200	0.9400	0.9300				
			100	0.9600	0.9500				
			50	0.9700					

Table 9 - Compressibility Factor of Median Retrograde Gas and Depleted Retrograde Gas + CO₂ Mixture at 160°F

Median Retrograde Gas			Pressure	Depleted Retrograde + CO ₂					
P	Smooth	Lab		50 psia		250 psia		500 psia	
			Smoothed	Lab	Smoothed	Lab	Smoothed	Lab	
5000	0.96	0.95	5000	0.6572	0.64	0.6672	0.656	0.695	0.7
4500	0.92		4500	0.6115		0.6215		0.645	
4000	0.885	0.88	4000	0.5667	0.55	0.5767	0.58	0.595	0.6
3500	0.855		3500	0.5232		0.5332		0.56	
3000	0.83	0.84	3000	0.4872	0.49	0.505	0.51	0.54	0.55
2500	0.815		2750	0.4732		0.495		0.54	
2000	0.8177	0.82	2500	0.4654	0.47	0.495		0.54	
1500	0.84		2250	0.469		0.499		0.55	
1000	0.8871	0.89	2000	0.495	0.5	0.525	0.53	0.58	0.57
500	0.9427	0.95	1750	0.5498		0.59		0.64	
250	0.97		1500	0.62	0.61	0.66		0.71	0.715
100	0.9874	0.99	1300	0.685		0.725		0.765	
50	0.994		1200	0.71		0.75		0.79	
			1100	0.737		0.775		0.81	
			1000	0.765	0.75	0.801	0.8	0.83	0.83
			900	0.79		0.825		0.85	
			800	0.82		0.845		0.868	
			700	0.845		0.865		0.885	
			600	0.865		0.885		0.9	
			500	0.89	0.88	0.905	0.9	0.915	0.92
			400	0.915		0.926			
			300	0.938		0.945			
			200	0.96					
			100	0.981	0.97				

Table 10 - Compressibility Factor of Median Retrograde Gas and Depleted Retrograde Gas + CO₂ Mixture at 190°F

Median Retrograde			Depleted Median Retrograde Sample + CO ₂					
			50 Psia		250 psia		500 Psia	
Pressure	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab	Smoothed	Lab
5000	0.971	0.97	0.6874	0.68	0.7184	0.72	0.748	0.75
4500	0.9335		0.6475		0.6806		0.7126	
4000	0.889	0.89	0.6084	0.62	0.6439	0.65	0.6784	0.68
3500	0.8534		0.575		0.61		0.6467	
3000	0.84	0.83	0.554	0.57	0.585	0.59	0.6209	0.63
2500	0.84		0.555		0.58		0.611	
2000	0.85	0.84	0.6	0.58	0.63	0.64	0.66	0.67
1500	0.88		0.705		0.735		0.76	
1000	0.92	0.92	0.815	0.8	0.83	0.82	0.845	0.85
500	0.96	0.955	0.91		0.92		0.9251	0.92
200	0.983		0.967	0.96	0.975	0.98		
100	0.992	0.99	0.986	0.99				
50	0.996		0.994					

Benefits of Geologic CO₂ Storage

One side benefit of CO₂ sequestration is the additional production of hydrocarbon gasses due to re-vaporization of retrograde condensate in the reservoir.

Figure 13 shows the amount of re-vaporized liquid, in percent of original condensate volume, as a function of temperature and depletion pressure. As it can be seen on the plot, the amount of condensate that is re-vaporized range from as low as 5.7 percent to as high as 35 percent. Stated in different ways, as much as one-third of the condensate liquid in a depleted reservoir can be produced as gas after CO₂ is sequestered. Table 11 shows the complete result in tabular format.

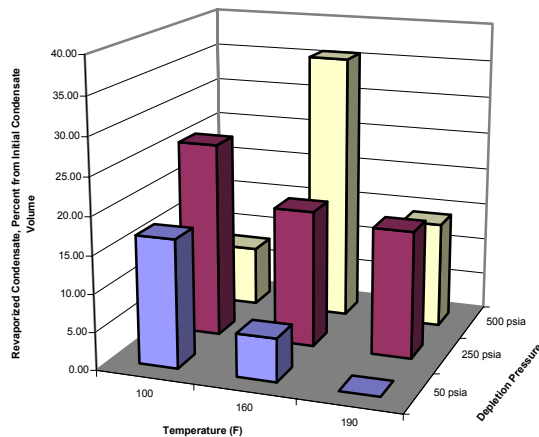


Figure 13 - Revaporized Condensate as a Function of Pressure and Depletion Pressure

Table 11- Revaporized Condensate

Temp (°F)	Condensate Volume at Depleted Pressure (cc)						Condensate Re-vaporized (%)		
	Median Retrograde			CO ₂ +RG			at Depleted Pressure		
	50 psia	250 psia	500 psia	50 psia	250 psia	500 psia	50 psia	250 psia	500 psia
100	19.85	19.59	18.39	18.26	14.53	17.69	16.93	25.85	7.98
160	11.93	14.41	19.85	11.25	11.79	12.77	5.70	18.18	35.67
190	No Data	18.19	19.10	No Data	15.12	15.12	No Data	16.88	14.14

Conclusions

This research uses laboratory measured Z-factor of CO₂-hydrocarbon mixture to analyze phase behavior, enhanced gas and enhanced condensate recovery for CO₂ storage in depleted gas reservoirs. The laboratory measured CO₂ compressibility factor (or Z-factor) is much lower than hydrocarbon gas mixtures at the specified temperatures and pressures. Therefore, that offers the opportunity to store larger surface volumes of CO₂ than hydrocarbon gases. Five times the storage is possible depending on pressure, temperature and hydrocarbon gas composition

Storage of CO₂ increases if the CO₂/HC gas mixture compressibility (Z-factor) is low. Furthermore, if a liquid condensate occupies the reservoir pore space and the addition of CO₂ vaporizes the liquid, then additional pore space is acquired for CO₂ storage.

Nomenclature

- P_1 = cell pressure, psia
- V_1 = volume of gas released from the cell, cc
- T_1 = cell temperature, °R
- P_2 = ambient pressure, psia
- V_2 = volume of gas at ambient pressure and temperature, cc
- T_2 = ambient temperature, °R
- n = number of moles of the system
- Z = compressibility factor
- DGR = Depleted Gas Reservoir
- HC = Hydrocarbon
- CVD = Constant Volume Depletion
- CCE = Constant Composition Expansion

Subscripts

- 1 = Initial condition
- 2 = Final condition

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