IMPERIAL COLLEGE LONDON

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Impact of Compositional Grading and Component Lumping on Ultimate Recovery

By

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A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC.

September 2012

DECLARATION OF OWN WORK

I declare that this thesis

Impact of Compositional Grading and Component Lumping on Ultimate Recovery

Is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and or with appropriate acknowledgement given.

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Acknowledgements

I would like to thank BG Group for their continued support and for sponsoring me during my studies at Imperial College.

I am grateful to my BG colleagues, who have been generous in sharing their time and knowledge. In particular, I am grateful to Alex Assaf for his excellent advice and guidance throughout. I am also thankful to Hamidreza Razavi for his time and expertise and to Olorunsola Abdul for his assistance in software related matters.

Gratitude is extended to the professors and external lecturers that have helped me develop an understanding of Petroleum Engineering over the last year. My academic supervisors, Ann Muggeridge and Velisa Vesovic, are particularly thanked for their insight and advice during the course of this project.

I am most grateful for the continuous encouragement, support and understanding of my fiancé Simon. Thanks to my parents for their love and support.

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Impact of Compositional Grading and Component Lumping on Ultimate Recovery

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Abstract

Published studies comparing different compositional grading models do not assess their impact on recovery. Additionally, the limitations of available and widely used compositional grading models tend to be downplayed during routine application. Investigation of these limitations could provide insights as to the source of compositional grading as well as the potential for anomalous characteristics such as lateral variation within the reservoir. A large body of literature has examined the impact of component lumping on enhanced oil recovery for reservoirs with uniform composition but not on recovery for reservoirs with compositional grading.

This paper addresses the impact of component lumping and compositional grading on recovery from waterflood and from a secondary water alternating gas (WAG) injection scheme. The reservoir fluid analysed is a medium sweet oil of 27°API gravity and high concentrations of CO_2 and methane, which account for more than 55% of total composition. In the reservoir, the fluid is held at low temperatures (58°C) and high pressures (8,000 psia). This study demonstrates that reservoirs with strong compositional gradients should not be modelled assuming uniform composition, as a change in composition with depth can result in a change in mobility with depth and a varying sweep during secondary recovery. Furthermore, the change in composition with depth can affect the design of surface facilities. To address lumping, experimental data were used to tune an Equation of State (EOS) for a reservoir with observed compositional grading. The fluid was characterised using 22 components, considered to be the true fluid representation, and then lumped to 14, 10 and 8 components based on similar K values. The fluid models were run in a sector model assuming both uniform and compositional grading. Both saturation pressure and Minimum Miscibility Pressure (MMP) were observed to increase with lumping, without significantly impacting recoveries. As long as the lumped fluid models can successfully simulate the experimental data, in particular viscosities, the studied fluid can be lumped to eight components or three heavy pseudocomponents, irrespective of whether fluid composition is uniform with depth or whether compositional grading is modelled. This has led to a significant reduction in computational time. Field specific recommendations relate to gathering further fluid samples. More generally, the tuning of parameters in regression based compositional grading models should be constrained.

Introduction

Compositional grading, i.e. the variation of composition with depth, is most commonly considered to be caused by: i) gravity segregation, where the heavier components increase in concentration with depth and the lighter components decrease in concentration with depth (thus thicker reservoirs tend to exhibit greater compositional grading), ii) thermal diffusion induced by the geothermal gradient, and iii) molecular diffusion, which can take millions of years to reach equilibrium). Other, less commonly cited processes which may induce compositional variation include the differential migration of hydrocarbons from different source rocks, biodegradation, or the relative proportion of paraffins, napthenes and aromatics.

In terms of thermodynamic modelling of compositional grading, two EOS-based approaches have been reported in the literature. The first assumes that the fluid column is in equilibrium and considers only the impact of gravity, thereby ignoring heat flux arising from a temperature gradient. Sage and Lacey (1938) were the first to propose an analytical model to this effect, which was then refined and applied by Schulte (1980) in a case study. Although the models developed predicted compositional grading, the results did not match experimental data. Montel and Gouel (1985) were the first to present a robust fitting method to honour the experimental data in the model.

The second approach assumes that the fluid column is in a steady state and that compositional grading is controlled by both gravity and thermal effects. Høier and Whitson (2000) compared three published thermal models for compositional grading

and found that thermal diffusion generally counteracts gravity, thereby reducing compositional gradients. They do not explain how thermal diffusion coefficients were calculated or why thermal diffusion should counteract gravity. The key limitation of these models lies in their inability to correctly approximate thermal diffusion coefficients. The reliance upon an EOS model in both approaches may be a further source of error, as these models are non unique.

Galliero and Montel (2009) investigated the use of Molecular Dynamics (MD) simulation to understand the physical mechanisms and timelines governing component segregation and compared these with steady state models. They found that MD simulation corroborated the results from isothermal models but not always from non-isothermal models. They highlighted the need for caution when considering non-isothermal models. Our study investigates the steady state models.

Consideration of changes in composition with depth may impact recoverable reserves, particularly under miscible injection as the fluid may be miscible at certain depths but not miscible at others. One aim of this study is to quantify how compositional grading can affect field recovery. Previous studies have compared compositional grading models and compared their ability to predict compositional variation with depth.

In most reservoir simulations, black oil models can be used effectively, assuming there is no mass transfer between components. If mass transfer occurs, such as in miscible flooding, compositional models may be required. At each time step, a flash calculation determines the equilibrium ratio (the ratio of mole fraction in the vapour phase over the ratio of mole fraction in the liquid phase) of each component. Computational requirements increase exponentially with an increasing number of components. Hence, lumping, whereby multiple components are grouped into one pseudocomponent, is widely employed to build more manageable fluid models. A substantial body of literature exists detailing various lumping methodologies.

Lee et al. (1981) proposed a simple procedure based on grouping components with similar physicochemical properties. They plotted various properties (e.g., molecular weight, specific gravity) for each component against boiling point, grouping components that plotted similar slopes. The authors demonstrated the feasibility of describing the crude oil with just two fractions. However, pressures at which this methodology was tested (1,000 to 3,000 psia) no longer capture the known range of reservoir conditions. An alternative method was considered by Li et al. (1985) who proposed a lumping scheme based on similar equilibrium K values at operating pressures and temperature. This approach has been used in this study as it describes a fluid in terms of component volatility, a key factor in determining phase behaviour.

Danesh et al. (1992) proposed a grouping method which combines composition and molecular weight. The components were arranged in order of their normal boiling points and grouped in such a way that the mole fraction multiplied by the natural logarithm of the molecular weight of the pseudocomponents is similar. The authors showed that four to six components were sufficient to model gas injection processes.

Joergensen and Stenby (1995) compared twelve lumping procedures and concluded that the number of pseudocomponents was of more significance than the way in which they were grouped, and their conclusion was applied in this study. Wu and Batycky (1988) demonstrated the need to consider solvent/oil phase behaviour in the lumping process, as this influences the MMP and therefore recovery. Recent developments (Egwuenu et al. 2008) have shown that lumping can be improved and the number of pseudocomponents further reduced by including the MMP when tuning the EOS. However these studies only consider miscibility from a static perspective (at a single point in space and time). Rastegar et al. (2009) were the first to propose a grouping method which takes account of changes along the displacement path, lumping components with similar changes in K values along one dimensional slimtube simulation.

The methodologies and case studies above all considered reservoirs with uniform composition. An aim of this paper is to resolve the impact of lumping on reservoirs with vertical compositional grading.

The purpose of this paper is twofold: firstly, to understand the variability introduced by considering compositional grading and assess the need for its analysis; secondly, to assess the impact of lumping on a reservoir with compositional grading and determine the optimum number of pseudocomponents. This is a case study of an unusual fluid, 27°API gravity oil, over half of which is CO_2 and methane. The reservoir is cold at 58°C, with a pressure of 8,000 psia.

Methodology

The workflow followed in this study is shown in Fig. 1.

Vertical Compositional Grading

Nine bottomhole fluid samples available from two wells, A and B, indicated clear vertical compositional grading in the field (**Table 1**). CO_2 concentration decreases with depth, ranging from 16%-5%, whereas the heavy components (C_{7+}) increase in concentration with depth, ranging from 17% to 23%. Methane concentration does not appear to vary consistently with depth, but ranges from 48% to 57%. These samples were decontaminated prior to analysis and the degree of accuracy of each data point is unknown as these data were not supplied from the original analyses.

Four methods for modelling the fluid in this reservoir were then considered and compared;

<u>Case 1- Uniform composition</u>: Compositions were integrated over depth to derive an 'average' composition for the entire fluid column (Table 1). The DST sample is not equivalent to an average composition as it would underestimate the extent of

 CO_2 , and overestimate C_{7+} and therefore OIIP. The concentration of CO_2 is an important parameter in tuning an EOS. Ideally, a second EOS would be built using a sample with a higher concentration of CO_2 and compared against the current model to understand the range of uncertainty caused by the EOS.

<u>Case 2- Isothermal</u>: This model assumes that the fluid column is in equilibrium such that the difference in the chemical potential (μ) of the same component at two different depths is a function of the molecular weight of the component and the depth range.

 $\mu_i(h) - \mu_i(h^o) = M_i g(h - h^o)$,(1) This is actually a passive thermal model where the temperature change with depth is not taken into account. Høier and Whitson (2000) demonstrated, using case studies, that for normal temperature gradients passive thermal models replicate predictions from isothermal models. For simplicity, this model will be referred to as 'isothermal' in this study. This model allows only one sample to be used at a time. The shallowest sample (A-1) was used to predict composition with depth.

<u>Case 3- Non-isothermal</u>: This model assumes that the fluid column is at steady state, i.e., there is no component mass flux. In this case the difference in chemical potential of component 'i' (μ_i) at two different depths is a function of gravity and of the thermal diffusion coefficient of the component. The shallowest sample was used to predict composition with depth. The temperature gradient was 0.706 °C/ 100 ft. The thermal diffusion coefficients were approximated by internal enthalpies (Haase 1969).

 $\mu_i(h) - \mu_i(h^o) = M_i g(h - h^o) - M_i \left(\frac{H}{M} - \frac{H_i}{M_i}\right) \frac{\Delta T}{T},$ (2) For consistency, sample A-1 was again used to predict compositional change with depth.

<u>Case 4- Regression</u>: The available compositions were used in a regression that changes the thermal diffusion coefficient in a way that minimises the prediction error, i.e. the differences between the predicted and actual composition at a given depth. The PVT simulator "PVTsim" (Calsep 2011) requires that a sample is selected as an 'anchor' whereby this particular fluid composition is matched perfectly at the required depth.



Fig. 1 Workflow used in this study

Table 1 - Fluid samples showing change in composition with depth												
Well		А	А	A	А	B	A	В	В.	В	А	
Sample		1	2	3	4	5	6	7	8	9	DST	Average
Depth	ft	15,829	15,891	15,960	16,086	16,362	16,371	16,411	16,464	16,568	16,288	(Case I)
N ₂	%	0.51	0.51	0.51	0.44	0.59	0.52	0.82	0.00	0.00	0.34	0.35
CO_2	%	15.95	16.48	15.92	10.31	4.53	8.67	6.44	6.60	5.38	6.83	9.76
C ₁	%	50.07	49.41	49.49	50.31	56.85	47.85	54.16	52.58	52.68	51.96	51.85
C_2	%	6.61	6.43	5.84	6.08	7.66	6.72	7.25	7.04	7.67	7.67	7.33
C ₃	%	4.53	4.49	4.69	4.97	5.07	4.98	4.99	4.95	5.02	4.76	4.86
iC ₄	%	0.79	0.82	0.85	0.89	0.93	0.89	0.94	0.91	0.92	0.88	0.84
nC ₄	%	1.74	1.82	1.90	2.04	1.93	2.12	1.99	1.95	2.01	1.88	1.85
iC ₅	%	0.49	0.52	0.55	0.59	0.63	0.61	0.65	0.64	0.67	0.62	0.56
nC ₅	%	0.82	0.89	0.97	1.06	0.93	1.09	0.98	0.98	1.02	0.93	0.89
C_6	%	1.06	1.12	1.27	1.49	1.27	1.46	1.28	1.32	1.41	1.24	1.25
C ₇	%	1.25	1.32	1.38	1.64	1.42	1.69	1.46	1.61	1.67	1.46	1.44
C ₈	%	1.70	1.77	1.84	2.18	1.88	2.24	1.87	2.09	2.17	1.93	1.92
C ₉	%	1.43	1.48	1.53	1.79	1.55	1.87	1.55	1.75	1.81	1.61	1.61
C ₁₀	%	1.34	1.37	1.33	1.65	1.27	1.74	1.28	1.45	1.48	1.33	1.41
C ₁₁	%	1.17	1.17	1.17	1.46	1.09	1.38	1.12	1.27	1.30	1.14	1.26
C ₁₂	%	1.02	1.03	1.03	1.29	0.97	1.34	0.98	1.12	1.15	1.02	1.10
C ₁₃	%	0.89	0.90	0.91	1.15	0.85	1.19	0.87	1.00	1.02	1.03	0.98
C ₁₄	%	0.78	0.79	0.81	1.02	0.75	1.05	0.77	0.88	0.90	0.86	0.86
C ₁₅	%	0.68	0.68	0.71	0.91	0.66	0.92	0.68	0.78	0.80	0.83	0.77
C ₁₆	%	0.60	0.60	0.63	0.81	0.58	0.82	0.60	0.70	0.71	0.65	0.68
C ₁₇	%	0.53	0.52	0.57	0.73	0.51	0.70	0.54	0.63	0.59	0.57	0.58
C ₁₈	%	0.48	0.48	0.52	0.67	0.47	0.66	0.49	0.57	0.58	0.61	0.56
C ₁₉	%	0.44	0.43	0.48	0.62	0.44	0.61	0.45	0.53	0.54	0.53	0.52
C ₂₀₊	%	5.14	4.98	5.10	5.91	7.15	8.89	7.84	8.66	8.53	9.32	6.82

Fluid Characterisation

Prior to modelling the aforementioned four cases, an EOS model had to be built. A fluid sample obtained from a Drill Stem Test (DST) was used as the basis for EOS modelling (Table 1). There is no indication of a gas cap in the reservoir. It has a low API of 27° despite containing a very high proportion of methane (around 50%). Gas chromatography (GC) was used to obtain the molecular distribution for the sample to C₂₀.

Characterising a fluid's PVT behaviour involves determining the molar distribution of the plus fraction (in this case C_{20+}), defining the critical properties of the carbon number fractions and then lumping these into a more manageable number of pseudocomponents. The Pedersen methodology was used in this case study.

Initially, compositions were entered to the PVT simulator "PVTsim" (Calsep 2011) to C_{20+} . The fluid was then characterised to C_{80} , using the Peng-Robinson-Peneloux EOS (Jhaveri and Youngren, 1988), and the heavier components were lumped into twelve pseudocomponents, such that each pseudocomponent has a similar mass, following the methodology of Pedersen and Christensen (2006).

The EOS parameters were tuned such that the predicted PVT behaviour matched that obtained from a suite of experimental data (separator test, differential liberation, constant mass expansion, swelling test and slimtube test). The tuned parameters comprised the critical parameters (pressure, temperature and volume) and acentric factors of the C_{7+} components. The binary interaction parameters (BIPs) between the heavy pseudocomponents and CO₂, and between the heavy pseudocomponents and C_1 were also adjusted.

The problem of matching an EOS to a fluid data sample is an underconstrained inverse one, where multiple solutions may all equally match. The focus is therefore on limiting the number of parameters to be adjusted and the extent to which they can be modified (Pedersen and Christensen 2006). All modified parameters were altered by the same percentage for all carbon numbers so that monotonicity and physical dependency on molecular weight were preserved. Critical temperature and volume both increase with molecular weight and critical pressure and acentric factor decrease with molecular weight. The downward bend in the acentric factor for C_{60} - C_{80} assures a correct physical trend in the a-parameter of the EOS¹. In matching the EOS the number of unknowns was limited to six and the extent of tuning was restricted.

Table 2 presents the new critical parameters and acentric factors, as well as the percentages by which they were modified. The BIPs were increased from 0 to 0.03 for C_1 and the heavy components. The BIPs between CO_2 and the heavy components were not modified and were kept at 0.1.

¹ Personal communication with C.P. Rasmussen. June 2012. Calsep.

The following tolerances were considered acceptable for the various parameters during the matching process: 2% error for oil density, 3% error for formation volume factor, 5% error for oil viscosity, 10% error for solution gas oil ratio and 200 psi error for saturation pressure from the swelling test.

The deviations between simulated and differential liberation are shown in **Fig. 2**, where an under-saturated reservoir fluid is transferred into a PVT cell at reservoir temperatures, in this case 58°C. Here the differential liberation experiment includes the constant mass expansion in that the initial pressure of the PVT cell is reservoir pressure. The volume in the cell is then increased step by step and the pressure and volume are recorded. Matching these experiments ensures that the fluid model properties honour the experimental data as pressure changes, i.e. compressibility effects. Since the aim is to maintain reservoir pressure above the bubblepoint pressure, it is most important for properties to match above 5,980 psia. Oil density, Formation Volume Factor (FVF) and solution gas oil ratio match to within the stated tolerances.

Viscosities were calculated using the Lohrenz-Bray-Clark (LBC) correlation (Lohrenz et al., 1964), which expresses viscosities as a function of density. This relationship is based on the observation that, as long as the fluid is supercritical, there is a unique relationship between viscosity and density and that this relationship holds at all temperatures. This correlation is known to be questionable when predicting liquid viscosities, but is widely used in the industry and was the only one available for the purposes of this study. To match experimental data, the constants in the relationship were tuned (**Table 3**). Limits were placed on tuning these constants, in order to maintain as much accuracy as possible in the correlation, and consequently viscosities matched to within 10%. This is more than the 5% suggested in the tolerance table.

Matching the separator test honours the relative volumes of oil and gas expected to be produced from the reservoir at separator conditions. The separator density matched to within 1% and the gas oil ratio to within 3.7%. In a swelling test, the reservoir fluid is placed in a PVT cell at its saturation point and kept at reservoir temperature. A known volume of gas is then injected into the cell, increasing the volume and pressure. The composition of the injected gas is given in **Table 4**. Once the gas has been dissolved into the oil, the mixture is at its saturation point. Matching the swelling test honours the reservoir fluid behaviour when gas is injected during WAG. The saturation pressure, before any gas is injected, was matched very closely, to within 15 psi, and continues to match within 200 psi tolerance as gas is injected (**Fig. 3**). The critical point (where the saturation pressure changes from bubblepoint to dewpoint) was found by simulating the swelling test and matched the critical point range of the laboratory experiment (Fig. 3). The EOS that was built is considered a true representation of the fluid and will be used as a base case for further sensitivities.

Table 2- Tuning of critical parameters and acentric factor						le 3- Tur	ning of LBC	coefficients
							Post-tuning	adjustment
Component	I _c	P_{c}	ω	V _c				%
	°C	psia		(cm³/mol)		a ₁	1.03E-01	0.8
C-	000	,	0.04	400		a ₂	2.35E-02	0.6
	290	419	0.34	433		a_3	5.87E-02	0.2
C ₈	312	390	0.37	444		a ₄	-4.04E-02	-0.8
C ₉	337	356	0.42	482		a_5	9.21E-03	-1.3
C ₁₀ -C ₁₃	389	303	0.52	592	Tabl	e 4- Com	position of i	njection gas
C ₁₄ -C ₁₈	475	246	0.70	834		Compone	nt	Mol%
C ₁₉ -C ₂₂	546	217	0.86	1,093		N_2		0.53
C22-C27	610	202	0.97	1 356				11.43
	010	100	4.00	1,000		C ₁		67.18
C ₂₈ -C ₃₃	683	190	1.08	1,701		C_2		9.91
C ₃₄ -C ₃₉	759	182	1.15	2,093		C ₃		6.35
C ₄₀ -C ₄₇	842	176	1.15	2,561		iC ₄		1.03
C_{40} - C_{50}	954	170	1 02	3 242		nC₄		2.02
-40 -39	4.400	100	0.50	4,000		iC ₅		0.43
U ₆₀ -U ₈₀	1,123	166	0.52	4,363		nC₅		0.6
% tuning	4.9	2.0	0.3	-9.0		C ₆		0.52

Component Lumping

The equal K value method was used to lump the heavy fractions since the displacement process depends on the K value of the components (Orr, 2007). The base case fluid model was flashed to 58° C and 5,980 psi, reservoir temperature and saturation pressure. The resulting K values are shown in **Table 5.** Heavy components with similar K values were grouped together into 14, 10, 8 and 6 components (**Table 6**). The light components were lumped such that the liquid and vapour components were kept separate, in order to avoid de-lumping at a later stage, as well as ensuring that majority components in the injection gas were kept separate (CO₂ and C₁). N₂ accounts for less than 0.5% of the total composition and was therefore lumped with C₂.

The experiments were then simulated for each of the four lumped cases, the idea being that the models should match the experimental data with no further regression. Fig. 4 show that the 14, 10 and 8 component cases matched the oil density,

solution gas oil ratio, FVF and swelling test saturation pressures with no further tuning. For the six component case, a good match to the experimental data could not be achieved without extensive further tuning. For this case, all the heavy components had been lumped into one pseudocomponent. This increased the errors associated with the critical parameters and acentric factor of this pseudocomponent. The six component model was therefore discarded.

Oil viscosities for the 10 and 8 component cases were up to 30% higher than the experimental data (**Fig. 5**). The critical volumes for the heavy components were reduced by 4% such that viscosities for the 10 and 8 component cases matched the experimental data. The matching of viscosities is essential as it impacts fluid mobility within the reservoir.

Fig. 6 shows that the phase envelopes of the four models are very similar across all temperature and pressure ranges. They are identical within the expected operating ranges (shaded section), both in the reservoir and at the surface. The fluid models were therefore expected to show similar behaviours across the operating conditions.

Saturation pressures were observed to increase with lumping, by up to 100 psi in the eight component case (**Fig. 7**). The observed difference is unlikely to be significant, in that maintaining the reservoir pressure to within 100 psi is not practical.





Fig. 2: Match of differential liberation and constant mass expansion experiments

Table 5- K values					
Component	K value				
C ₇	0.36				
C ₈	0.32				
C ₉	0.29				
C_{10} - C_{13}	0.22				
C_{14} - C_{18}	0.11				
C_{19} - C_{22}	0.05				
C_{23} - C_{27}	0.02				
C_{28} - C_{33}	0.01				
C ₃₄ -C ₃₉	0.00				
C_{40} - C_{47}	0.00				
C ₄₈ -C ₅₉	0.00				
$C_{60} - C_{80}$	0.02				

Table 6 - Lumped fluid models							
14	10	8	6				
CO ₂	CO ₂	CO ₂	CO ₂				
C ₁	C ₁	C ₁	C ₁				
$C_2 - N_2$	$C_2 - N_2$	$C_2 - N_2$	$C_2 - N_2$				
C_3-C_4	C_3-C_4	C_3-C_4	$C_{3}-C_{4}$				
C_5-C_6	$C_{5}-C_{6}$	$C_{5}-C_{6}$	$C_{5}-C_{6}$				
C ₇	C ₇ -C ₉	C ₇ -C ₁₃	$C_7 - C_{80}$				
C ₈	C_{10} - C_{13}	C_{14} - C_{33}					
C ₉	C_{14} - C_{18}	C_{34} - C_{80}					
C_{10} - C_{13}	C_{19} - C_{33}						
C_{14} - C_{18}	C_{34} - C_{80}						
C_{19} - C_{22}							
$C_{23}-C_{33}$							
C ₃₄ -C ₅₉							
C_{60} - C_{80}							



Minimum Miscible Pressure (MMP)

The MMP is the minimum pressure at which an injected gas composition becomes multi-contact miscible with the reservoir oil. In a slimtube experiment, a long and narrow sandpack is initially saturated with oil at reservoir temperature and above bubblepoint pressure. Gas is then injected at constant pressure and the composition, recovery and density of the effluent are measured. The experimental MMP is compared to a simulated MMP for each of the fluid models created. This MMP can either be simulated numerically in a one-dimensional grid, first proposed by Metcalfe et al. (1972), or calculated using ternary diagrams generalized to multicomponent mixtures, proposed by Jensen and Michelsen (1990), using "PVTsim" (Calsep, 2011).

In the numerical simulation method, the recovery factor is simulated at a range of pressures. To eliminate the effect of numerical dispersion, or grid size, the numerical simulation was run for three grid sizes (10,000 cells, 5000 cells and 1000

cells). The recovery factors were then plotted against the inverse of the square root of the number of cells at each pressure and extrapolated to an infinite number of grid cells. Fig. 8 illustrates this procedure at two pressures. The derived dispersion free recoveries were then plotted against the pressures (Fig. 9). The MMP was determined by observing that there is a linear relationship between recovery factors and pressures and that this linear relationship changes once the MMP is reached. Below the MMP, recovery factors increase significantly with pressure as miscibility increases. Above the MMP, recovery factors stabilize.

The numerical and tie-line methods provide an MMP range of around 200 psi. In both methods, MMP was observed to increase as the number of components decreases (**Fig. 10**). Wu and Batycky (1988) also found that lumping based on similar mass overestimates the size of the two-phase region, presumably overestimating MMP and MME (Minimum Miscibility Enrichment).

Published data by Glasø (1985) and Firoozabadi and Aziz (1986) also found that simulated MMP was 5–15% lower than experimental data. In this case, it would be equivalent to an error of 300–1,000 psi. In fact, the numerically simulated MMP for the 22 component underestimates the true value by 40 psia while the tie line method underestimates MMP by 245 psia. Prior to lumping, numerical simulation appears to predict more accurate MMP values. As the number of components is reduced, the difference between the two methods is reduced.

The increase in MMP with lumping is more marked than the observed increase in saturation pressures. The MMP for the eight component model is about 400 psi higher than the experimental value. It is to be expected that recoveries from WAG may decrease in the eight component case, if the pressure cannot be maintained at the higher MMP. The theory was tested by running the fluid models on an existing sector model, simulating recovery processes using "Eclipse" (Schlumberger, 2011).





Fig. 7: Saturation pressure increases with lumping





Fig. 8: Determination of dispersion free recovery factors



Reservoir Simulation

The impact of lumping and of compositional grading was assessed by running the various fluid models through a sector model. The sector model is relatively fine with each grid cell representing an area of 210 by 210 ft and a total of 960,000 grid cells. The reservoir thickness is 1,500 ft (15,416–16,829 ft, all depths referred to in this study are true vertical depth subsea) and the OWC is assumed at 16,900 ft. Two development scenarios were considered: WAG, and water injection. Both cases assumed five injector wells laid out in a five spot pattern. In the WAG case, water and gas were injected for a period of six months each. The composition of the gas is given in Table 4. The plateau is set in the simulation to 100,000 stb/d and so the

Table 7- List of reservoir simulations carried out Composition vs depth Objective Number of components Development Scenario DST sample composition assumed throughout Investigate the impact of lumping assuming a the reservoir. This was the fluid sample on 22 14 10 and 8 Waterflood uniform composition and water flooding which the EOS was built. B. DST sample composition assumed throughout Investigate the impact of increasing saturation the reservoir. This was the fluid sample on 22, 14, 10 and 8 Depletion pressures with lumping which the EOS was built. Investigate the impact of lumping assuming a C. DST sample composition assumed throughout the reservoir. This was the fluid sample on 22, 14, 10 and 8 WAG uniform composition and WAG which the EOS was built. D. DST sample composition assumed throughout WAG but allowing Investigate the impact of increasing MMP with the reservoir. This was the fluid sample on 22, 14, 10 and 8 pressures to drop below lumping which the EOS was built. MMP DST sample composition assumed throughout 10 and 8 component Investigate the importance of viscosity tuning the reservoir. This was the fluid sample on models pre and post WAG and waterflooding which the EOS was built. viscosity tuning Compositional grading assumed using Investigate the choice of sample used to anchor 22, 14, 10 and 8 WAG and waterflooding regression based model the rearession G. Compositional grading assumed using Investigate the impact of lumping on recovery 22. 14. 10 and 8 WAG and waterflooding isothermal model assuming compositional grading H. Uniform average composition used as Investigate the errors associated with ignoring 22 WAG and waterflooding approximation of compositional grading compositional grading Compositional grading assumed using non-Investigate the uncertainty associated with 8 WAG and waterflooding

focus is on comparing total production rather than daily rates. Table 7 summarises the various simulations carried out and their objective.

Analysis and Discussion

isothermal model

Impact of Lumping on Recovery Assuming a Uniform Composition

The four fluid models (22, 14, 10 and 8 components) resulted in similar Oil Initially in Place (OIIP), varying from 1,080 to 1,100 million stb. The range was considered negligible. Neither did recovery factors change with lumping. In all cases WAG provided a 13% improvement in recovery over waterflooding, which only provided a total recovery of 31%. The largest deviation in terms of cumulative oil production was 5 million stb, which is insignificant when considered in the context of wider subsurface uncertainty. Furthermore the differences between the four cases in terms of cumulative water and gas production were similarly negligible (456-460 million stb of water and 2,440-2,500 billion scf of gas in the WAG case; 454-460 million stb of water and 419–432 billion sc f of gas in the waterflood case).

Since pressures are maintained above bubblepoint, the different fluid models show similar behaviour under waterflood, as they all replicate the same experimental data. The impact of the increase in saturation pressures caused by lumping was tested by running a depletion case, whereby pressures were allowed to drop to 4000 psia, well below the bubblepoint (Fig. 11). Lumping still does not appear to have a noticeable impact. However, since lumping increases MMP, it is to be expected that recovery factors should decrease with lumping in WAG.

Pressures, in the WAG case, were maintained above 7100 psia, above the highest MMP estimate. Thus all models should achieve miscibility leading to similar recoveries. The theory was tested by allowing the average field pressure to drop below 6,600 psi, i.e., below the MMP of every fluid model. Since the relationship between pressure and MMP is linear below the MMP, the expectation would be that recovery from the 8 component model would be lower than that from the 14 component model. However, despite a 400 psi difference in MMP, the recoveries were similar for the different models (Fig. 12). The results indicate that for this fluid system the focus on accurately matching MMP is misplaced and that, from a reservoir management perspective, there is a degree of cushioning in terms of the need to maintain pressures far above MMP.



Fig. 11: Lumping did not impact recovery from depletion despite the increase in saturation pressures with lumping (Simulation B)

Fig. 12: Lumping did not impact recovery from WAG despite the increase in MMP with lumping (Simulation D)



individual fluid samples

Viscosity Tuning

The impact of viscosity tuning on simulation results was also tested. Not tuning viscosities, for the 10 and 8 component cases, would have reduced recovery factors by one percentage point (14-16 million stb). This impact of viscosity was observed in both WAG and waterflooding cases. Furthermore, gas production in the WAG case would have been overestimated by 70-80 billion scf and water production in the water injection case would have been overestimated by 15-20 million stb.

Lumping the fluid to 8 components does not affect simulation results and reduces simulation time by 70% (7 hours), improving efficiency. The workflow highlights the potential benefit, in terms of time saving, of carrying out sensitivities on the number of components sufficient to replicate fluid behaviour. This may be particularly beneficial if, as stated by Newley and Merrill (1991), numerical dispersion actually decreases with lumping. This step is not considered standard practice in reservoir engineering. The optimum number of components to consider will vary with the specific fluid composition and operating conditions.

Compositional Grading Regression (Case 4)

The compositional grading module in "PVTsim" (Calsep, 2011) was used to model the variations of composition with depth. For consistency, the shallowest sample (A-1) was used as anchor. This is effectively a best-fit model, where the focus is on matching available data and not on describing a physical reality.

In effect, **Fig. 13** shows that the regressed C_{7+} increases with depth, and suddenly starts to decrease with depth below 16,200 ft. This behaviour is not physical and is due to the change in internal enthalpies required by the simulator, to accurately match the fluid sample compositions. The order of internal enthalpies is falsely manipulated leading to a non-physical change in saturation pressure with depth (**Fig. 14**) and implying that the extrapolated compositions, above and below sampled depths, are unlikely to be as accurate.



Compositions within the sampled depths should provide more accurate predictions. The DST sample, on which the EOS was built, was not used in the regression but was used to test prediction accuracy as a blind test. The predicted composition at the DST sample depth was used to simulate PVT experiments and compared against the laboratory data. Most of the predicted fluid properties match the actual laboratory data to within the previously specified tolerances. However, the model underestimates saturation pressures, prior to gas injection, by about 300 psi (**Fig. 15**). These deviations are due to a higher predicted CO₂, 8% rather than 5%, therefore a lower C₁ concentration, as compared to the actual fluid sample (**Fig. 16**). This might be a reflection of contamination of the fluid samples used in the regression, whereas the DST sample is not affected by contamination. The 300 psi increase in saturation pressures are likely to be so far above the saturation point that the discrepancy would have no impact in this reservoir model. The regression model does seem able to predict fluid composition within sampled depths with sufficient accuracy. The degree of error surrounding un-sampled depths can only be tested by collecting further samples from shallower and deeper zones and blind-testing them.

Choice of Sample to Anchor the Regression

A sensitivity analysis was carried out on the choice of anchor sample. For each lumped case, the two or three anchor samples that resulted in the best predictions in terms of matching the available data (generally the shallowest or deepest samples), were compared. Using different anchor points resulted in noticeable differences in terms of production (27 million stb in the WAG case and 18 million stb in waterflood) and a wide range of transitional gas-oil contacts (105 ft). The impact of anchoring is likely to be greater in cases with a clear gas-oil contact, as properties change suddenly on either side of the contact. The choice of anchor will change the forecasted gas-oil contact depth, thus impacting fluid behaviour and recovery.





Fig. 15: Regression model underestimates saturation pressure at DST depth by 300 psi



Impact of Lumping on Predictions of Compositional Grading

The actual effect of lumping components on predicted compositions with depth is negligible for the regressed model (Fig.16). This is expected as the aim of the model is to best match the available laboratory data. To assess the impact of lumping on predictions of vertical compositional grading, the isothermal model was used.

The difference in predicted composition between the lumped models increases away from the depth of the sample used in the prediction (15,830 ft). At greater depths, the eight component model underestimates C_{7+} and overestimates C_1 . At shallower depths, the eight component model overestimates C_{7+} and underestimates C_1 . Lumping slightly reduces the extent of compositional grading (**Fig. 17**). However, the differences are negligible such that the four models result in a narrow range of OIIP (981–992 million stb, oil production from WAG (452–456 million stb) and oil production from water injection (318–324 million stb). The range of water and gas production is similarly negligible (414–420 million stb of water and 2,630–2,670 billion scf of gas in the WAG case; 432–444 million stb of water and 531–549 billion scf of gas in the waterflood case). A thicker oil column might be expected to exhibit greater variation with lumping





Impact of Compositional Grading on Recovery

The 22 component fluid model was used to compare the average uniform composition, Case 1, against the regression-based model, Case 4. The OIIP from these two models is identical at 1,020 million stb, which is to be expected as the only difference between Case 1 and Case 4 is the distribution of the components with depth, rather than the hydrocarbon volumetrics. However, modelling compositional grading with depth lowers predicted recoveries from 47% to 44% in the WAG scenario and from 33% to 31% in the water injection scenario. This difference equates to a drop in estimated recoverable reserves of 28 million stb in the WAG case and of 22 million stb in the waterflood case. This is a large difference and may be critical to project economics. Assuming an oil price of \$100, a loss of 28 million stb in ten years time (at the end of plateau) amounts to a loss of revenue of \$742 mm (Net Present Value discounted by 15%). The impact would be greater for a shorter plateau.

The difference is explained by differential mobility in the compositional grading case, leading to a varying sweep of the reservoir. The shallower fluid is higher in CO_2 and has a lower viscosity compared to the fluid at deeper depths (Fig. 18). This

Greater care is required in choosing the anchor sample when considering a field with a gas cap or closer to its saturation point.

lower viscosity leads to improved mobility such that the oil is preferentially produced from the shallower layers (Fig. 19). This is likely to impact the preferred development scenario as the onus should be on improving the mobility of the deeper oil.

The differences in viscosity apply to both the WAG and water injection cases. The reason that there is no specific miscibility explanation for the difference in the WAG case is that reservoir pressures were maintained above MMP, despite a change in MMP with depth. MMP increases with depth to around 7,120 psia at 16,230 ft and then decreases. The MMP change with depth follows the change in C_{7+} with depth (Fig. 13), so higher C_{7+} results in a higher MMP. Reservoir pressures do not drop below 7,100 psia and so miscibility is always ensured.

Furthermore, in this case, ignoring compositional grading can lead to an under-design of CO_2 handling facilities. The uniform composition model underestimates CO_2 production by up to 12 MMscf/d in both the WAG and waterflood cases. This corresponds to an underestimation of 39% in the WAG case and of 20% in the waterflood case. Modelling fluid composition as uniform could therefore lead to a loss of production as rates become constrained by CO_2 handling facilities.



Fig. 18: Viscosity variation in uniform and compositional grading cases



Fig. 19: Oil saturation at the end of the simulation. Shallower oil is preferentially produced in the compositional grading case (WAG and waterflood)

Relative Effect of Gravity and Temperature

Both the gravity segregation process and the thermodiffusion process are controlled by the mass diffusion coefficient (de Groot and Mazur, 1984), hence the composition segregation in the non-isothermal case should follow the same behaviour as the composition segregation in the isothermal case. In effect, both models predict that the heavier components segregate at greater depths whereas lighter components segregate at shallower depths.

Høier and Whitson (2000) observed that thermal diffusion counteracts the effect of gravity and reduces compositional grading. In some cases, the impact was to remove compositional variation altogether. Ghorayeb et al. (2003) concluded that thermal diffusion can override gravity segregation, such that a dense fluid can lie above a lighter fluid.

In this study, however, the compositional grading predicted by the non-isothermal model is greater but in the same direction as that predicted by the isothermal model (**Fig. 20**). This implies that the effect of thermal diffusion on component segregation overrides that of gravity segregation. The previous studies focused on typical reservoir temperature ranges ($100 - 200^{\circ}$ C), but the effect of thermal diffusion may be modified and/or enhanced at lower temperatures. Høier and Whitson (2000) also stated that "compositional gradients decrease with increasing degree of undersaturation" which may mean that the thermal impact is lessened, relative to the gravitational impact, for a near saturated oil, even at cold reservoir temperatures.

The predictions of the models are dependent on the thermal diffusion coefficients used, the estimation of which is unsatisfactory (Gonzales-Bagnoli et al. 2003) as the current understanding of thermodiffusion in fluids in still limited (Artola et al. 2008; Wiegand 2004). To fully corroborate these results, an MD simulation, as performed by Galliero and Montel (2009), would need to be carried out. MD simulation follows the position of molecules through time and space and therefore does not depend on the EOS model or the method used to calculate thermal diffusion (Galliero and Montel 2008).

Fluid Not in Steady State

The compositions of C_{7+} predicted by the two steady state models capture the compositional variation observed in the data. However, both models predict similar CO₂ compositions, severely underestimating compositional grading as exhibited by the fluid samples (Fig. 20). Neither methodology predicts compositional variation with depth accurately in this instance. In particular, CO₂ is overestimated whereas C₁ is underestimated. The two main models for predicting compositional grading assume the reservoir is in steady state. The fluid column in this reservoir is therefore unlikely to have reached a steady state and as such components are still likely to be in flux. The extent of CO₂ compositional change has to be explained by an external element such as a source of CO₂ above the reservoir. The theoretical models can help identify instances where the system is not in steady state.

If there is ongoing charging, then the timescale of the phenomena causing the compositional grading needs to be assessed to understand whether compositional grading is likely to change significantly over the production timescale. MD simulation can be used to understand the time-dependence of compositional grading. Changes to compositional grading, due to molecular diffusion, take place on a geological timescale, over millions of years (Galliero and Montel 2009). In these instances, a best-fit model may be reasonable to represent the reservoir. However, compositional grading may be accelerated by changes in pressure resulting from production. If compositional grading is likely to change over production timescales it is of key importance that further work is done to identify the reasons and expected changes to fluid composition.

Potential for Lateral Compositional Grading

The predictions of compositional grading in the non-isothermal model using different fluid samples were compared. **Fig. 21** shows the predicted range of composition with depth. Predicting compositions from Well B samples shows more variability than predicting compositions from Well A samples, which could be due to varying degrees of contamination or decontamination. The predictions based on samples A-1 and B-5 were used to simulate the fluid at a depth of 16,180 ft. The two samples predict very different fluids, whereby one is 29°API and the other is 34°API (**Fig. 22**). These models result in a wide range of recoverable reserves, as demonstrated in **Fig. 23**, thus illustrating the uncertainty involved when using a small number of samples to predict recoverable reserves.

Samples 1, 2, 3, 4 and 6 originate from Well A and result in a tighter range of recoverable reserves; 417-433 million stb from WAG and 299–319 million stb from water injection. Samples 5, 7, 8 and 9 originate from Well B and result in a much wider range of recoverable reserves of 246–381 million stb from WAG and 170–259 million stb from water injection. It may be the case that Well B samples were more affected by contamination issues. Alternatively, the evident split between the two wells may highlight some degree of lateral variation across the field. This variation may be caused by areal molecular diffusion, if CO₂ is still charging, or by some degree of compartmentalisation or faulting. In any case, considering that the wells are 5 km apart, there may be a high degree of heterogeneity across the field, likely to severely impact recoverable reserves estimates.



Fig. 20: Non-isothermal model predicts greater compositional grading than the isothermal model



Fig. 22: Phase envelopes simulated at 16,180 ft, using two samples to predict composition based on a non-isothermal model



Fig. 21: Prediction of C₇₊ prediction with depth using individual samples (non-isothermal model)



Fig. 23: Range of OIIP and recoverable reserves estimates using different samples to predict compositional grading (non-isothermal model)

Conclusions

Published compositional grading models capture the effects of gravity and temperature gradient on component distribution, typically showing that heat flux counteracts the effect of gravity. This study shows that this need not be the case in cold reservoirs, where heat flux can lead to higher compositional grading than gravity alone.

Widely accepted models of compositional grading can only be applied accurately if the fluid column has reached steady state equilibrium, leaving many instances of compositional grading which cannot be captured. However, the disparities between compositional grading models and fluid sample data can help shed light on the occurrence of other processes affecting fluid compositions (e.g., multiple source horizons, compartmentalisation and biodegradation). Subsets of fluid sample data from differing locations within the reservoir may show variation during application of published models which can help identify instances of lateral compositional grading.

If the published models cannot accurately describe the reservoir, the best approach is to use as many compositions from fluid samples as possible and either regress or interpolate between them. Although the physical behaviour of the fluids may not be captured, it is the best approximation available at an early stage. A more thorough approach would require the use of MD simulation.

A uniform composition should not be used as an approximation for compositional grading as the changes in viscosity and mobility with depth are likely to lead to preferential production from the less viscous zones. A uniform composition may tend to overestimate recovery and give the appearance of a vertically stable sweep of the reservoir. It can also lead to design errors in surface handling facilities in reservoirs where CO_2 varies with depth.

Standard workflows in reservoir engineering promote careful attention to grid sensitivities in order to most effectively upscale the static model whilst retaining its rock properties and essential geological detail. This study demonstrates that careful attention should also be paid to the fluid model in terms of the number of components. The fluid samples that have been modelled can be lumped to just three pseudocomponents without affecting recoverable resources, whether assuming a uniform

composition or assuming a change in composition with depth. Thus, when different numbers of pseudocomponents are run as sensitivities early in the model build, it may become apparent that a lower number of components is sufficient to describe fluid behaviour effectively, which, in turn, may lead to significant efficiency gains in the modelling process. Lumping might be expected to have a greater impact on a thicker fluid column, whereby compositional variation is reduced by lumping.

Sensitivities run to model the effects of viscosity have demonstrated that this parameter can have a large impact on recovery factors. Accuracy can be achieved by tuning critical volumes to viscosities from laboratory measurements after both fluid characterisation and lumping stages. Without this step, different mobilities will impact recovery factors, which, in marginal field scenarios, may be critical.

Minimum Miscibility Pressure increases with lumping but the effects of this increase on recovery from WAG processes are negligible. In this study, there was no observed change to recovery factors despite a 400 psi difference in MMP, suggesting a degree of cushioning when considering this parameter in the workflow.

Recommendations for Further Study

Further subsurface investigation into the variation of CO_2 with depth is recommended. This might be achieved by undertaking MD simulation. The collection of shallower samples would also be useful in terms of improving the accuracy of composition at depths of less than 15,800 ft. To test the theory of lateral compositional variation, it is recommended that fluid samples are taken from future wells.

To identify potential changes in composition during the life of the field, it is recommended that fluid samples are also taken post production. If possible, further information regarding observed contamination and methods for decontamination should be provided alongside the samples. Alternatively, it is suggested that the latest generation of wireline fluid sampling tools is used to reduce sample contamination.

Building an EOS model to match available data is an underconstrained inverse problem whereby multiple EOS models may be equally valid. This study has been based on one EOS model, built around one fluid sample. To corroborate the model built, a different sample, ideally from the crest of the field such that it contains a higher degree of CO_2 , should be used to tune a new EOS. The difference in the models should provide a measure of uncertainty surrounding the fluid characterisation. It is recommended, if possible, that the composition of this sample is measured using True Boiling Point Distillation, to reduce errors in the molecular weights of the heavy components.

An investigation into the impact of lumping on compositional grading might be considered for a field with a thicker fluid column to confirm to what extent the observed decrease in compositional variation with lumping can be significant.

More generally, the importance of correctly modelling viscosity is a key result of this study. The industry is limited by the correlations available in the widely used software packages. It would be helpful if the software available provided for a wider range of viscosity modelling methods.

Finally, although more work remains to be done on estimating thermal diffusion coefficients, constraining the tuning of these during regression would improve the reliability of the regression based model.

Acknowledgements

This project was supported and funded by BG Group.

Nomenclature

$ ho_{oil}$	Oil density (g/cm^3)	ω	Acentric factor
g	Gravitational constant	P_{sat}	Saturation pressure (psi)
ĥ	Depth (ft)	P_{c}	Critical pressure (psi)
Hi	Internal enthalpy of component i	R_s	Solution gas oil ratio
M_i	Molecular weight of component i	Т	Temperature (°F)
μ_i	Chemical potential of component i	T_{c}	Critical temperature (°F)
μ_{oil}	Oil viscosity (cp)	ΔT	Change in temperature (°F)

SI Metric Conversion Factors

°API	141.5/(131.5+°API)	$= g/cm^3$
bbl	X 1.59 X 10 ⁻¹	= m ³
ср	X 1.0 X 10 ⁻³	= Pa.s
ft	X 3.048 X 10 ⁻¹	= m
°F	(°F-32)/1.8	= °C
psi	X 6.895	=kPa

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Appendix A: Literature Review

TableA-1: Key milestones related to compositional grading

Source/SPE Paper #	Year	Title	Authors	Contribution
Transactions of the AIME, (Dec. 1939), vol 132, 1	1938	Gravitational Concentration in Static Columns of Hydrocarbon Fluids	B.H. Sage, W.N. Lacey	First to analytically model compositional grading with depth.
9235	1980	Compositional Variations within a Hydrocarbon Column due to Gravity	A.M. Schulte	First to solve Gibb's equation using an EOS to model compositional grading with depth.
SPE 14410	1985	Prediction of Compositional Grading in a Reservoir Fluid Column	F. Montel, P.L. Gouel	First to present a fitting method to calculate composition variation with depth, improving results.
SPE 63085	2000	Compositional Grading- Theory and Practice	L., Høier, C.L., Whitson	First paper to compare published models of non- isothermal compositional grading.
SPE 121902	2009	Understanding Compositional Grading in Petroleum Reservoirs thanks to Molecular Simulations	G. Galliero, F. Montel	First to compare the predictions of compositional grading from MD simulation and from the steady state models

TableA-2: Key milestones related to characterisation and lumping

Source/SPE Paper #	Year	Title	Authors	Contribution
SPE Journal, (Oct. 1981), 535	1981	Experimental and Theoretical Studies on the Fluid Properties Required for Simulation of Thermal Processes	S.T. Lee, R. Jacoby, W.H. Chen, W.E. Culham	Demonstrated the feasibility of two fractions lumping within certain pressure and temperature ranges and proposed a simple lumping approach.
The Journal of Canadian Petroleum (Nov Dec. 1985), 29-36	1985	Phase Behaviour Computations for Reservoir Fluids: Effect of Pseudo-Components on Phase Diagrams and Simulation Results.	Li, Y.H., Nghiem, L.X., and Siu, A	Proposed a lumping method based on equal K values
SPERE, (Aug. 1988), 875-83	1988	Pseudocomponent characterization for Hydrocarbon Miscible Displacement	R. S., Wu, J.P., Batycky	Demonstrated that lumping greatly impacted solvent oil phase behaviour and suggested a method taking solvent/oil composition into account during EOS modelling.
SPERE, (Aug. 1992)	1992	A Grouping Method to Optimize Oil Description for Compositional Simulation of Gas Injection Processes	A., Danesh, D., Xu, A.C. Todd	Presents a grouping method, based on concentrations and molecular weights that optimize compositional description of the phase behaviour of miscible gas injection systems.
SPE 30789	1995	Optimization of pseudo-component selection for compositional studies of reservoir fluids	M., Joergensen, E.H., Stenby	Compared 12 lumping procedures and concluded that they were equally accurate. The impact of the number of pseudocomponents on the accuracy of the simulation was much more significant.
SPE 94034	2008	Improved Fluid Characterization for Miscible Gas Floods	A.M., Egwuenu, R.T., Johns, Y., Li	First to include MMP/MME in tuning of EOS demonstrating that the number of pseudocomponents can be reduced further.
SPE 119160	2009	A Flow Based Lumping Approach for Compositional Reservoir Simulation	R. Rastegar, K. Jessen	First to include displacement dynamics of gas injection in a lumping scheme.

Transactions of the AIME, (Dec. 1939), vol 132, 1

Gravitational Concentration in Static Columns of Hydrocarbon Fluids

Authors: Sage, B.H and Lacey, W.N.

<u>Contribution to the understanding of compositional grading:</u> First to analytically model compositional grading with depth

Objective of the paper:

Evaluate the change in composition with depth required to be at equilibrium in an iso-thermal system.

Methodology used:

For a system to be in equilibrium it is necessary that the chemical potential of each component be equal at each point in the system. The change in concentration of a component with height is described as a function of the molecular weight of that component, the average molecular weight and the partial molar volume. The methodology was evaluated for three fluids.

Conclusion reached:

Large variations in composition near the critical point were observed. The results are qualitatively correct but the variation in composition could not fully be explained by the suggested models. The authors believe that the results can be improved if temperature changes were also considered.

Comments:

The analytical approach assumes that the system behaviour is that of an ideal solution at all pressure and temperatures considered. This assumption is highly questionable for reservoir fluids and their conditions.

SPE 9235 (1980)

Compositional Variations within a Hydrocarbon Column due to Gravity

Authors: Schulte, A.M.

<u>Contribution to the understanding of compositional grading:</u> First to solve Gibb's equation using an EOS to model compositional grading with depth

Objective of the paper:

Use a practical, rather than analytical method, to solve for compositional grading with depth. Follow on study from Sage & Lacey where some of the more restrictive assumptions are relaxed.

Methodology used:

True chemical equilibrium is effectively achieved when chemical potential, calculated using an EOS, and gravity potential are constant throughout the column in an isothermal system.

 $\mu_i(h_2) - \mu_i(h_1) + m_i g(h_2 - h_1) = 0, \qquad (A-2)$

where

μ is the chemical potential of component ih is the heightm is the component's weightg is the gravitational constant.

The difference in chemical potential is obtained using an EOS. If the mole fraction and pressure are known at depth h_1 , they can be calculated for depth h_2 . The model was solved numerically for each component in the fluid. The results were presented for a number of hydrocarbon fluids.

Conclusion reached:

It is possible to predict compositional variation in a hydrocarbon system due to gravity by solving for chemical equilibrium using an EOS. The results are matched qualitatively but not accurately.

Further elements that increase composition grading were identified:

- Presence and quantity of aromatics
- Lower initial pressure

Comments:

The results could not be fully explained, possibly highlighting the need to model the impact of heat flux.

SPE 14410 (1985)

Prediction of Compositional Grading in a Reservoir Fluid Column

Authors: Montel, F. and Gouel, P.L.

<u>Contribution to the understanding of compositional grading:</u> First to present a fitting method to calculate composition with depth, improving results

Objective of the paper:

Present a new thermodynamic fitting method to estimate compositional variation with depth.

Methodology used:

It is assumed that the fluid system under investigation is in a stationary state, zero mass flux and that it is isothermal, so only the gravitational effect on compositional grading is considered.

Thermodynamic properties are simulated for two cases:

- Oil reservoir under gas injection
- Gas condensate

Conclusion reached:

Gravity impact increases with depth and with the molecular weight difference between components.

Large change in composition was observed when the fluid is near the critical point.

The results were not completely satisfactory due to sampling issues, non-optimum thermodynamic fitting (non unique solution) and not considering thermal diffusion.

Comments:

The analysis can be improved by improving the thermodynamic fitting and including temperature gradients.

SPE 63085 (2000)

Compositional Grading- Theory and Practice

Authors: Høier, L. and Whitson, C.L.

<u>Contribution to the understanding of compositional grading:</u> First to compare published models of non-isothermal compositional grading.

Objective of the paper:

Quantify the variation in composition and PVT properties with depth due to gravity, chemical and thermal forces and compare the published thermal models.

Methodology used:

The paper provides a review of the published thermal models and the way in which they estimate thermal diffusion coefficients. The Haase and Kempers models both express thermal diffusion coefficients as a function of enthalpies, whereas the Belery da Silva model expresses them as a function of viscosity and density.

Published case studies, representing a wide range of fluid systems, are used to compare predictions from the three models.

Conclusion reached:

The study concludes that gravitational forces result in greater compositional grading than thermal forces. In fact, thermal forces generally counteract gravitational forces. Near critical fluids may exhibit such large thermal diffusion, that composition becomes more or less constant with depth, as convection takes place.

The viscosity based model resulted in an increase in compositional grading due to thermal diffusion in oil like systems, away from the critical point. The model was declared to be less theoretically robust than the thermodynamic models.

For normal temperature gradients, predictions from a gravity based model are replicated by a thermal model from which the temperature gradient has been eliminated (passive thermal model).

The paper highlights the uncertainty surrounding using published models to predict compositional grading in reservoirs as the required simplifying assumptions are unlikely to hold in real case studies. Therefore, guidelines for using measured fluid sample data to initialise a simulation model are presented. It is suggested that linear interpolation is used between compositions at sampled depths. Two methods are suggested to capture the range of likely compositions at non sampled depths; extrapolated compositions. Based on the understanding that the effect of temperature counteracts that of gravity, the highest amount of compositional grading is predicted using an isothermal model, whereas the least amount of compositional grading is predicted using an isothermal model, whereas the least amount of compositional grading is predicted using an isothermal model, whereas the least amount of compositional grading is predicted using an isothermal model.

Comments:

The suggested methodologies for interpolation and extrapolation were not tested to ensure they could represent a physical reality. The authors do not explain how they derive the thermal diffusion coefficients or why the thermal impact should counteract that of gravity. Furthermore, the theoretical validation for ignoring the viscosity based model was not explicit.

SPE 121902 (2009)

Understanding Compositional Grading in Petroleum Reservoirs thanks to Molecular Simulations

Authors: Galliero, G. and Montel, F.

Contribution to the understanding of compositional grading:

First to compare the predictions of compositional grading from MD simulation and from the steady state models

Objective of the paper:

Investigate the underlying physics of the steady state compositional grading models and validate their results through molecular simulations.

Methodology used:

The authors applied classical MD simulations on model fluids to simulate the gravitational segregation and thermodiffusion. The fluids were composed of 2000-4000 molecules. The authors used in house built software. They used the same fluids to simulate compositional variation with depth, using the steady state models.

Conclusion reached:

The molecular simulation results are consistent with the isothermal models. The results of the non-isothermal models were not always consistent and the authors highlighted the need for care when considering these models. Particularly as non-isothermal models approximate thermal diffusion coefficients.

Additionally, MD simulation provided information on the time required for the fluid column to reach a steady state as well as the stability of the fluid distribution.

The MD simulation confirmed that thermodiffusion has a significant impact on concentration profiles. Furthermore, both isothermal and non-isothermal segregation were shown to be based on the mutual diffusion coefficient.

Comments:

The next steps may be to compare the accuracy of different models for estimating thermal diffusion coefficients.

SPE Journal, (Oct. 1981), 535

Experimental and Theoretical Studies on the Fluid Properties Required for Simulation of Thermal Processes

Authors: Lee, S. T., Jacoby, R. H., Chen, W. H. and Culham, W. E.

Contribution to the understanding of component lumping:

Demonstrated the feasibility lumping C_{7+} to two pseudocomponents within certain pressure and temperature ranges and proposed a simple lumping approach based on grouping components with similar physicochemical properties.

Objective of the paper:

Use experimental data to develop a correlation of BIPs for the heavy fractions. Investigate the feasibility of using two pseudocomponents to describe a reservoir fluid. Propose a lumping methodology based on similar physicochemical properties.

Methodology used:

Conduct experiments under various conditions to obtain the Vapour Liquid Equilibrium (VLE) and measure various fluid properties for a mixture of flue gas, water and crude oil.

The experimental results were used to develop a correlation of Binary Interaction Parameters (BIP) of crude oil fractions required for the Peng-Robinson EOS.

Proposed a simple lumping scheme where the component properties (specific gravity, molecular weight...etc) were plotted versus an independent variable, in this case the average boiling point. The weighted sum of the slopes was calculated and used to group fractions with similar values.

A six component fluid was compared to a two component fluid.

Conclusion reached:

It is feasible to lump a fluid to two pseudocomponents within certain pressure and temperature conditions.

Comments:

The lumping procedure suggested requires extensive laboratory data, which in many cases is not available. The known range of field reservoir pressures is much wider than that presented in this paper (1,000 to 3,000 psia).

JCPT (Nov.-Dec. 1985) 29-36

Phase Behaviour Computations for Reservoir Fluids: Effect of Pseudo-Components on Phase Diagrams and Simulation Results

Authors: Li, Y.H., Nghiem, L.X. and Siu, A.

Contribution to the understanding of component lumping

First to propose a lumping method based on the volatility of individual components. Components with similar K values are lumped together.

Objective of the paper:

Demonstrate the applicability of a K value based lumping scheme.

Methodology used:

K values are obtained from a flash calculation at expected operating pressure and temperature.

The lumping methodology was used for three fluid systems (reservoir oil with free gas, reservoir oil-CO2 system and a gas condensate) and was shown to replicate experimental results.

Reservoir simulations were carried out for a gas condensate lumped to 11, 9, 7, 6, 5 and 4 components. The 11 component case was considered the base case. All cases, except the 4 component case, yielded very similar simulation results. The 7 component fluid was considered the most efficient.

The four component case lumped C_4 - C_{10} and C_{11+} . The authors concluded that it is incorrect to lump the light and heavy components together.

Conclusion reached:

It is possible to describe a fluid accurately, for simulation purposes, by lumping it to 7 pseudocomponents. The lumping method based on equal K values is valid.

Comments:

The simulations were only run for the gas condensate and not for miscibility cases.

SPERE (Aug. 1988) 875-83

Pseudocomponent characterization for Hydrocarbon Miscible Displacement

Authors: Wu, R. S. and Batycky, J. P.

Contribution to the understanding of component lumping

Demonstrated that lumping may have a greater impact on the predicted solvent-oil phase behaviour than on the Gas Oil Ratio (GOR), and suggested a method of taking oil/solvent composition into account in EOS modelling.

Objective of the paper:

Investigate the impact of lumping on the prediction of phase behaviour of oil solvent compositions.

Methodology used:

Built a fluid model using 12 components, based on the Peng-Robinson EOS and matched the bubblepoint, GOR and atmospheric flash liquid and vapour compositions from experimental data.

The heavy components were lumped into one fraction and the light components were lumped into two, three or four fractions and compared against the 12 component model.

The ternary diagram phase envelopes were compared for various mixing rules, used to model the pseudocomponent properties (critical pressure, temperature, volume, acentric factor and interaction coefficients). It was concluded that molar weighting underestimates the size of the two phase region whereas molecular weight based mixing overestimates it. The authors demonstrated that a proportioning of both mixing rules improved the prediction of oil/solvent phase behaviour.

The above method was successfully applied to one condensate and three oil reservoirs, reducing the number of components required to four.

Conclusion reached:

Demonstrated that it is possible to select as few as four pseudocomponents and accurately characterise the oil properties as well as the behaviour of oil/solvent mixtures.

Proved that lumping methodology has the greatest influence on solvent/oil phase behaviour and the latter should be taken into account, via mixing rules. Lumping is also influenced by reservoir temperature.

Comments:

The amount of experimental data was limited and the vaporization data was poor and did not match. Furthermore, displacement dynamics are not considered.

SPERE, (August. 1992)

A Grouping Method to Optimize Oil Description for Compositional Simulation of Gas Injection Processes

Authors: Danesh, A., Xu, D. and Todd, A.C.

Contribution to the understanding of component lumping:

Presents a grouping method, based on concentrations and molecular weights, that optimizes compositional description of the progressive phase behaviour of miscible gas injection systems

Objective of the paper:

The authors recognised that the use of group properties, generated from the original reservoir fluid composition may be insufficient to model gas injection and they proposes a new grouping methodology and mixing rules such that forward and backward multi contact tests can be matched.

Methodology used:

Experiments designed to simulate the compositional variations during a gas injection process were carried out, which included single contact and equilibrium flash experiments as well as multiple forward and backward contact experiments, used to simulate the leading and trailing edge of gas-oil displacement.

The proposed grouping arranged the original fluid components in ascending order of normal boiling point and grouped such that the sum of composition times the natural logarithm of the molecular weight of each group are equal. The proposed grouping was tested for five mixtures.

Conclusion reached:

The proposed lumping methodology is an improvement on methods which only take molecular weight or composition into account and that four to six components is sufficient to model gas injection process.

Comments:

The leading and trailing edge of the composition are matched but not the middle of the displacement, which is believed to be where miscibility occurs in a condensing vaporizing gas drive.

SPE 30789 (1995)

Optimization of pseudo-component selection for compositional studies of reservoir fluids

Authors: Joergensen, M. and Stenby, E.H.

Contribution to the understanding of component lumping:

Compared 12 lumping procedures and concluded that they were equally accurate. The impact of the number of pseudocomponents on accuracy of simulation was much more significant.

Objective of the paper:

Compare 12 lumping procedures, three grouping methods and four property calculation methods, by simulating phase equilibria and PVT experiments for three synthetic fluids.

Methodology used:

The three lumping methodologies compared are:

- 1. Equal mole fractions
- 2. Equal weight fractions
- 3. Minimise the distance between the property of a pure components and the property of the pseudocomponent

The property calculation methods compared are:

- 1. Molar averaging
- 2. Weight averaging
- 3. Mixing rule based, temperature independent
- 4. Mixing rule based, temperature dependent

The resulting 12 lumping methodologies were applied to three synthetic fluids using the same EOS.

The methods were evaluated by comparing the phase envelopes, Constant Mass Expansion (CME) results and swelling tests simulated.

Conclusion reached:

None of the lumping procedures performed significantly better than the others.

The temperature independent property calculation method performed significantly worse.

The number of pseudocomponents greatly impacted the accuracy of the simulations and the optimum number of components was found to be around six to eight.

Comments:

The comparison is not exhaustive and there are many more lumping methodologies that can be compared. The synthetic fluid types mimic typical North Sea fluids. The study could be generalised by considering a wider range of fluid types and experiments.

SPE 94034 (2008)

Improved Fluid Characterization for Miscible Gas Floods

Authors: Egwuenu, A.M., Johns, R.T and Li, Y.

Contribution to the understanding of component lumping:

First to include MMP/MME in EOS modelling, demonstrating that displacement simulation can be improved and the number of pseudocomponents reduced, by considering solvent/oil behaviour.

Objective of the paper:

Present an improved reservoir fluid characterization for gas floods by taking solvent/oil behaviour into account. The standard method of tuning an EOS includes PVT experiments (Constant Volume Depletion, Constant Composition Expansion, Differential liberation and separator tests) but does not include solvent/oil interaction gathered through multi contact experiments, swelling and slimtube tests.

Methodology used:

- 1. PVT data is simulated using a 12 component EOS model (formation volume factor, solution GOR, saturation pressure, Liquid density and viscosity, relative volume and swollen volume). This data is synthetic.
- 2. Components are lumped to 12 components based on Newley and Merrill (1991) method which minimises the difference between the k-values of a component and that of the pseudocomponent to which it has been assigned.
- 3. The properties of the heavy fractions are tuned such that PVT data and then MMP/MME data match the simulations from the unlumped fluid model. Four tuned models are developed:
 - a. Tuned only to PVT data
 - b. Tuned to PVT data and swelling test
 - c. PVT and MME/MMP but not swelling test
 - d. Tuned to all three.
- 4. A one-dimensional simulation is run and the gas saturation profile of the non lumped fluid and the lumped fluid are compared.
- 5. The approach is demonstrated using two fluid displacement systems; enriched gas and CO₂.

Conclusion reached:

The models tuned to MMP/MME outperform the others, in which the MMP tends to be overestimated and the oil recovery underestimated. The sensitivity of the gas saturation profile to dispersion is reduced with lumping. Four to five pseudocomponents were sufficient to accurately model the displacement.

Comments:

Assumes a linear combination of the reservoir fluid and injection gas, which may not be accurate.

Light and heavy components were lumped together, assuming that delumping would not be an issue at a later stage. This is not necessarily the case. No appropriate delumping methodology was included in the study.

SPE 119160 (2009)

A Flow Based Lumping Approach for Compositional Reservoir Simulation

Authors: Rastegar, R. and Jessen, K.

Contribution to the understanding of component lumping:

First to include displacement dynamics, in the context of gas injection, in a lumping scheme. Traditional lumping approaches do not include any information regarding fluid flow.

Objective of the paper:

Demonstrate the benefit of including displacement dynamics in the selection of a lumping scheme and propose an automatic lumping methodology that improves the accuracy and efficiency of compositional reservoir simulation.

Methodology used:

A 15 component fluid description was generated by the approach of Pedersen et al. (1989) for use with the Soave Redlich-Kwong (SRK) EOS (Soave, 1972), which was then tuned to the available experimental data (standard PVT experiments, swelling test and slimtube displacement experiment).

Where i and j are two components and L is the length along the one-dimensional displacement path.

The properties of the lumped component are evaluated using the Leibovici et al. (1993) and the new EOS model is checked against experimental data. The steps are then repeated until the minimum number of lumped components is achieved while still maintaining accuracy.

The methodology was tested for two fluids, for a gas displacement and a CO_2 displacement case. The full description was compared to the lumped description and found to match the PVT experimental data and swelling test. Moderate differences were observed in the one-dimensional displacement simulation. The outputs of a synthetic 3D simulation were also matched.

Conclusion reached:

The results suggest that the proposed lumping scheme maintains good accuracy of the predicted PVT behaviour and displacement characteristics when the number of components is no less than seven.

Comments:

The number of components could be reduced further by tuning the lumped fluid to experimental data. The differences in MMP between the lumped and non lumped fluids could be investigated further, examining the causes and potential of these effects, as well as how they relate to numerical dispersion in reservoir simulation.

List of Other References- Appendix A

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Appendix B: PVT Experimental Data

Objective: This section presents a summary of the PVT experimental data used to characterise the fluid.

<u>Uncharacterized fluid sample:</u> The composition is defined to C_{20+} using gas chromatography. This method measures mass fraction but not molecular weight or density, unlike True Boiling Point Distillation. It is not as accurate as True Boiling Point Distillation.

Saturation pressure: At reservoir temperature, 58 °C, the saturation pressure is 5,980 psia.

<u>Separator test:</u> This experiment gives an indication of the relative volumes of oil and gas expected to be produced from a reservoir. The fluid is flashed at separator conditions. (Table B-1)

Table B-1: Separator test

Pressure	Temp	GOR	oil density
psia	С	mscf/bbl	g/cm3
14.65	40	1.37	
14.65	15.6		0.885

<u>Differential Liberation</u>: The under-saturated reservoir fluid is transferred into a PVT cell at reservoir temperatures. The volume in the cell is reduced step by step by moving the piston. At each step, the pressure and volume is recorded. At the saturation pressure, an infinitesimal amount of gas comes out of solution and is removed from the cell via a valve. The experiment continues until pressure reaches atmospheric pressure. (Table B- 2)

Table B- 2: Differential liberation experiment

Stage	Pressure	Oil FVF	Gas FVF	Rs	Oil density	Z factor	Gas gravity	Oil viscosity	Gas viscosity
#	psia		Bg	mscf/bbl	g/cm3	gas	air=1	ср	ср
1	9,260	1.573		1.40	0.7306			1.06	
2	8,549	1.583		1.40	0.7264			1.02	
3	7,838	1.593		1.40	0.7217			0.98	
4	7,126	1.604		1.40	0.7169			0.95	
5	6,415	1.615		1.40	0.7116			0.91	
6	5,980	1.624		1.40	0.708			0.88	
7	5,704	1.579	3.12E-03	1.31	0.7153	1.055	0.94	0.92	0.046
8	5,135	1.508	3.19E-03	1.14	0.7283	0.97	0.88	1.01	0.040
9	4,566	1.45	3.30E-03	1.01	0.7393	0.893	0.85	1.20	0.036
10	3,997	1.4	3.47E-03	0.88	0.7503	0.824	0.81	1.28	0.031
11	3,428	1.354	3.88E-03	0.76	0.7603	0.788	0.78	1.39	0.028
12	2,859	1.312	4.50E-03	0.65	0.77	0.763	0.75	1.52	0.024
13	2,290	1.271	5.73E-03	0.54	0.7811	0.779	0.72	1.71	0.019
14	1,721	1.228	7.88E-03	0.43	0.7936	0.805	0.72	2.00	0.016
15	1,152	1.184	1.24E-02	0.31	0.8078	0.85	0.73	2.49	0.014
16	584	1.138	2.59E-02	0.19	0.8231	0.898	0.77	3.39	0.013
17	15	1.032		0.00	0.8557		1.24	9.06	0.011

<u>Swelling Test:</u> The reservoir fluid is placed in a PVT cell at its saturation point and kept at reservoir temperature. Gas is injected into the cell, increasing the volume and pressure. Once the gas disappears, has been dissolved into the oil, the mixture is at its saturation point. (Table B- 3)

Stage	Mole % gas/ initial mol oil	Sat P	Swollen volume	Density
		psia		g/cm3
1	0	6,171	1.00	0.7084
2	12	6,770	1.06	0.6954
3	24	7,307	1.11	0.6839
4	54	8,418	1.25	0.6599
5	76	9,058	1.35	0.6455
6	120	10,006	1.55	0.6222
7	160	10,596	1.73	0.6054
8	190	10,918	1.87	0.5947

Table B- 3: Swelling test experiment

Appendix C: Pedersen Method of Characterization

Objective: This section presents the Pedersen fluid characterization method.

Pedersen et al. (1983, 1984) proposed an exponential relationship between composition and carbon number, for heavy components (carbon number greater than 6).

$$z_i = e^{(n-A)/B}$$
,.....(C-1)

where

 \boldsymbol{z}_i is the molar composition of component i

n is the highest carbon number considered

A and B are two coefficients found by applying a least squares fit to the measured molar distribution for the heavies (C_7 - C_{20}).

The density and molecular weight for each pseudocomponent are estimated (equations C.2 and C.3) and then used to calculate the critical properties and acentric factors using the following correlations (equations C.4-C.7) (Pedersen, 2007).

$\rho_N = C + DlnCN, \qquad (C-2)$
$M_N = 14C_N - 4, \dots$ (C-3)
$T_c = c_1 \rho + c_2 lnM + c_3 M + \frac{c_4}{M}, $ (C-4)
$lnP_c = d_1 + d_2\rho^{d_5} + \frac{d_3}{M} + \frac{d_4}{M^2}, \qquad (C-5)$
$m = e_1 + e_2 M + e_3 \rho + e_4 M^2, $ (C-6) $m = 0.37464 + 1.54226\omega - 0.26992 \omega^2, $ (C-7)
where
N is the carbon number
C and D are constants
T _c is critical temperature (K)
P_c is critical pressure (atm)
ω is the acentric factor
M is the molecular weight (g/mol) at atmospheric conditions

 ρ is density (g/cm³) at atmospheric conditions

c1, c2, c3, d1, d2, d3, e1, e2, and e3 are coefficients outlined in Table C-1 (Pedersen et al. 2002).

Table C-1: coefficients used to calculate T_c and P_c with PR-Peneloux EOS

Subindex/coefficient	1	2	3	4	5
С	7.34043x10	9.73562x10	6.18744x10 ⁻¹	-2.05932×10^3	-
d	7.28462x10 ⁻²	2.18811	$1.63910 \text{x} 10^2$	-4.04323×10^3	1⁄4
e	3.73765x10 ⁻¹	5.49269x10 ⁻³	1.17934x10 ⁻²	-4.93049x10 ⁻⁶	-

List of Other References- Appendix C

Pedersen, K.S., Thomassen, P., and Fredenslund, Aa. 1983. SRK-EOS calculation for crude oil. Fluid Phase Equilibira 14: 209-2018.

- Pedersen, K.S., Thomassen, P., and Fredenslund, Aa. 1984. Thermodynamics of petroleum mixtures containing heavy hydrocarbons. 1. Phase envelope calculations by use of the Soave-Redlich-Kwong equation of state. *Industrial and Engineering Chemistry Process Design and Development* **23**:163-170.
- Pedersen, K.S., Milter, J., and Sørensen, H. 2002. Cubic equations of state applied to HT/HP and highly aromatic fluids. Paper SPE 77385-MS presented at the SPE Annual Technical Conference and Exhibition, 29 September – 2 October, San Antonio, Texas. http://dx.doi.org/10.2118/77385-MS.

Appendix D: Peng-Robinson

Objective: This section presents the EOS used in the paper.

Peng-Robinson (1976) proposed the following equation of state

$$P = \frac{RT}{V-b} - \frac{a(T)}{V(V+b) + b(V-b)},$$
 (D-1)

where

$$a(T) = a_c \alpha(T),$$
 (D-2)

$$a_c = 0.45724 \frac{R^2 T_c^2}{P_c},$$
 (D-3)

$$b = \frac{0.07780RT_c}{P_c},$$
 (D-7)

A volume correction element, to improve liquid density accuracy, was added by Jhaveri and Youngren (1988) to the Peng-Robinson EOS to become P-R Peneloux EOS.

D —	RT	<i>a</i> (<i>T</i>)		n	8)
1 –	V-b	(V+c)(V+2c+b)+(b+c)(V-b)	(1	D-	0)

where:

c = volume shift or Peneloux parameter

Appendix E: LBC Viscosity Model

Objective: This section presents the LBC correlation for viscosity

The relationship between viscosity and density is given by the following correlation. This correlation is valid for supercritical fluids but known to incorporate errors in predicting liquid viscosities.

 $\left[(\eta - \eta^*)\xi + 10^{-4}\right]^{1/4} = a_1 + a_2\rho_r + a_3\rho_r^2 + a_4\rho_r^3 + a_5\rho_r^4, \dots (E-1)$

$$\xi = \frac{\left[\sum_{i=1}^{N} z_i T_{ci}\right]^{1/6}}{\left[\sum_{i=1}^{N} z_i M_i\right]^{1/2} \left[\sum_{i=1}^{N} z_i P_{ci}\right]^{2/3}},$$
 (E-2)

where:

 $\begin{array}{l} a_1 \text{ to } a_5 = \text{constants shown in Table E-1} \\ \rho_r = \rho/\rho_c \\ \rho_c = \text{critical density} \\ \eta = \text{viscosity} \\ \eta^* = \text{low pressure gas mixture viscosity} \\ z_i = \text{the mole fraction of component i} \\ T_{ci} = \text{critical temperature of component i} \\ M_i = \text{Molecular weight of component i} \end{array}$

 $P_{ci} = critical pressure of component i$

Table E-1: LBC model a coefficients

a ₁	1.02E-01
a_2	2.34E-02
a_3	5.85E-02
a_4	-4.08E-02
a_5	9.33E-03

Appendix F: EOS Tuning

Objective: This section presents the impact of tuning EOS parameters on fluid properties as well as the final EOS parameters





Fig. F-1: Impact of tuning on matching fluid properties

Table F-1 illustrates the separator test match

Table F-2 displays the EOS parameters post tuning. This model is considered to be the "true" fluid representation in the study.

Table F-1: Separator test match

		Experiment	Pre-tuning	Post-tuning	% error
GOR	mscf/bbl	1.37	1.44	1.42	3.7
Oil density	g/cm³	0.89	0.90	0.89	1

Table F-2: EOS model for the 22 component case

Component	Mol %	Mol wt	Crit T (°C)	Crit P (psia)	Acentric factor	Normal Tb (°C)	Crit V (cm ³ /mol)
N2	0.4	28	-147	492	0.04	-196	90
CO2	5.3	44	31	1,070	0.23	-79	94
C1	54.6	16	-83	667	0.01	-162	99
C2	7.4	30	32	708	0.10	-89	148
C3	4.8	44	97	616	0.15	-42	203
iC4	0.9	58	135	529	0.18	-12	263
nC4	1.9	58	152	551	0.19	0	255
iC5	0.6	72	187	491	0.23	28	306
nC5	0.9	72	196	489	0.25	36	304
C6	1.2	86	234	431	0.30	69	370
C7	1.5	96	290	419	0.34	92	433
C8	1.9	107	312	390	0.37	117	444
C9	1.6	121	337	356	0.42	142	482
C10-C13	4.4	153	389	303	0.52	197	592
C14-C18	3.4	218	475	246	0.70	280	834
C19-C22	1.9	282	546	217	0.86	344	1,093
C23-C27	1.9	344	610	202	0.97	397	1,356
C28-C33	1.6	421	683	190	1.08	450	1,701
C34-C39	1.2	505	759	182	1.15	496	2,093
C40-C47	1.1	601	842	176	1.15	543	2,561
C48-C59	0.9	736	954	170	1.02	602	3,242
C60-C80	0.7	948	1,123	166	0.52	681	4,363

Appendix G: Lumping

Objective: This section presents the EOS parameters for each lumped case

Table G-1: EOS parameters for 14 component model

Component	Mol %	Mol wt	Crit T (°C)	Crit P (psia)	Acentric factor	Normal Tb (°C)	Crit V (cm ³ /mol)
CO2	5.3	44	31	1,070	0.23	-79	94
C1	54.6	16	-83	667	0.01	-162	99
C2-N2	7.8	30	24	699	0.10	-93	145
C3-C4	7.5	49	118	585	0.17	-26	227
C5-C6	2.8	78	213	461	0.27	50	337
C7	1.5	96	290	419	0.34	92	428
C8	1.9	107	312	390	0.37	117	439
C9	1.6	121	337	356	0.42	142	476
C10-C13	4.4	153	389	303	0.52	197	584
C14-C18	3.4	218	475	246	0.70	280	824
C19-C22	1.9	282	546	217	0.86	344	1,080
C23-C33	3.5	380	648	196	1.03	424	1,516
C34-C59	3.1	604	856	176	1.10	549	2,623
C60-C80	0.7	948	1,123	166	0.52	681	4,310

Table G-2: EOS parameters for 10 component model

Component	Mol %	Mol wt	Crit T (°C)	Crit P (psia)	Acentric factor	Normal Tb (°C)	Crit V (cm³/mol)	% change V_c
CO2	5.3	44	31	1,070	0.23	-79	94	0%
C1	54.6	16	-83	667	0.01	-162	99	0%
C2-N2	7.8	30	24	699	0.10	-93	145	0%
C3-C4	7.5	49	118	585	0.17	-26	227	0%
C5-C6	2.8	78	213	461	0.27	50	337	0%
C7-C9	5.0	108	315	386	0.38	119	438	-4%
C10-C13	4.4	153	389	303	0.52	197	570	-4%
C14-C18	3.4	218	475	246	0.70	280	803	-4%
C19-C33	5.4	345	619	202	0.98	401	1,355	-4%
C34-C80	3.8	663	922	173	0.96	582	2,963	-4%

Table G-3: EOS parameters for 8 component model

Component	Mol %	Mol wt	Crit T (°C)	Crit P (psia)	Acentric factor	Normal Tb (°C)	Crit V (cm ³ /mol)	% change V_c
CO2	5.3	44	31	74	0.23	-79	94	0%
C1	54.6	16	-83	46	0.01	-162	99	0%
C2-N2	7.8	30	24	48	0.10	-93	145	0%
C3-C4	7.5	49	118	40	0.17	-26	227	0%
C5-C6	2.8	78	213	32	0.27	50	337	0%
C7-C13	9.5	129	356	23	0.46	162	511	-4%
C14-C33	8.8	296	578	15	0.90	366	1,199	-4%
C34-C80	3.8	663	922	12	0.96	582	2,965	-4%

Appendix H: Sector Model and Development Scenarios

Objective: This section presents the sector model used and the two development scenarios considered



Fig. H-1: Sector model representing oil saturation

Table H-1: Development scenarios

	Waterflood	WAG
# producers	13	13
# injectors	5	5
Plateau (stb/d)	100,000	100,000
Max water (stb/d)	400,000	400,000
Waterinjected (stb/d)	120,000	120,000
Gas injected (MMscf/d)	0	900

Appendix I: Simulation Results

Objective: This section presents the various simulation results.

Tables I-1 to I-7 present the results of the various simulations considered in this study.

Table I-1: Results of simulations A and C

	# components	22	14	10	8
	OIIP (million stb)	1,090	1,080	1,090	1,100
0	Oil Production (million stb)	479	474	475	483
MAC	Gas Production (billion scf)	2,470	2,500	2,470	2,440
	Water Production (million stb)	456	460	463	462
pod	Oil Production (million stb)	338	333	337	340
aterfic	Gas Production (billion scf)	432	426	427	419
Ma	Water Production (million stb)	454	460	457	458

Table I-2: Results of simulation B

# components	22	14	10	8
OIIP (million stb)	1,090	1,080	1,090	1,100
Oil Production (million stb)	130	126	130	130
Gas Production (billion scf)	290	289	289	285
Water Production (million stb)	2	2	2	2

Table I-3: Results of simulation D

# components	22	14	10	8
OIIP (million stb)	1,090	1,080	1,090	1,100
Oil Production (million stb)	468	461	464	470
Gas Production (billion scf)	2,420	2,460	2,430	2,420
Water Production (million stb)	474	479	481	482

Table I-4: Results of simulation E

		pre tuning		post tuning	
	# components	10	8	10	8
	OIIP (million stb)	981	992	981	992
VAG	Oil Production (million stb)	461	468	475	483
	Gas Production (billion scf)	2,540	2,520	2,470	2,440
1	Water Production (million stb)	476	477	463	462
poq	Oil Production (million stb)	322	324	337	340
aterflo	Gas Production (billion scf)	410	401	427	419
W	Water Production (million stb)	477	479	457	458

# components		22		14			10		8	
Anchor sample	A-1	A-2	A-1	B-8	B-9	A-1	B-8	A-1	A-2	
GOC (ft)	15,672	15,767	15,669	15,662	15,669	15,662	15,711	15,669	15,767	
OIIP (million stb)	1,020	977	1,020	1,020	1,020	1,010	1,000	1,020	982	
Oil production from WAG (million stb)	449	434	447	456	451	447	444	449	429	
Oil production from waterflood (billion scf)	313	301	311	316	310	318	313	319	302	

Table I-5: Results from simulation F

Table I-6: Results from simulation G

	# components	22	14	10	8
	OIIP (million stb)	985	982	981	992
(1)	Oil Production (million stb)	456	453	452	456
NAC	Gas Production (billion scf)	2,660	2,670	2,650	2,630
1	Water Production (million stb)	414	417	420	420
poc	Oil Production (million stb)	322	318	321	324
aterflo	Gas Production (billion scf)	548	547	549	531
Wa	Water Production (million stb)	432	435	433	444

Table I-7: Results of simulation H

		Uniform (case 1)	Regression (case 4)
	# components	22	22
	OIIP (million stb)	1,020	1,020
(1)	Oil Production (million stb)	477	449
VAC	Gas Production (billion scf)	2,530	2,630
1	Water Production (million stb)	429	428
poc	Oil Production (million stb)	335	313
Iterflo	Gas Production (billion scf)	512	534
Wa	Water Production (million stb)	427	436

Appendix J: Lumping Reduces Computation Time

Objective: This section presents the reduction in computation time resulting from lumping components (Fig. J-1).



Fig. J-1: Lumping improves computing efficiency

Appendix K: Tuning of Internal Enthalpies

<u>Objective</u>: This section presents the tuning of internal enthalpies utilized by the "PVTsim" (Calsep, 2011) software such that the composition of the fluid samples is matched.

Internal enthalpies are used to approximate thermal diffusion coefficients. They are changed such that the predicted compositions match the fluid sample compositions entered into the software. The tuning of this parameter is an artificial method of best fitting available data and does not consider physical reality.

Fig. K-1 illustrates the tuning of reference enthalpies required to match the fluid sample data.



Fig. K-1: Tuning of reference enthalpies

Appendix L: Blind Test at DST Depth

<u>Objective</u>: This section presents the blind test carried out to quality check the regression compositional grading model, within sampled depths (Fig L-1.a, Fig L-1.b, Fig L-1.c, Fig L-1.d and Fig L-1.d).





Fig. L-1: Blind test

Appendix M: MMP Change with Depth

Objective: This section presents the estimated change in MMP with depth

Since there was little variation in MMP estimation from the numerical simulation and the tie line method, only the latter was used in this instance. Fig M-1 shows the change in MMP with depth, which follows in the change in C_{7+} with depth.



Fig. M-1: Change in MMP with depth (regression based compositional grading)

Appendix N: Uniform Composition Underestimates CO2 Production

<u>Objective</u>: This section presents the differences in CO_2 production resulting from uniform composition and from compositional grading.

In both WAG and waterflood, taking account of compositional grading results in higher considerably higher CO_2 production (Fig. N-1 and Fig. N-2).

In the compositional grading case, the spike in CO_2 production corresponds to the production of resident CO_2 , which can be observed in both the WAG and waterflood cases. This is due to the fact that the oil richest in CO_2 is preferentially produced as it has greater mobility.



Fig. N-1: CO₂ production from WAG

CO2 production (Waterflood)



Fig. N-2: CO₂ production from waterflood