RESERVOIR SIMULATOR FOR IMPROVED RECOVERY OF COALBED METHANE (ICBM) PART I: MODEL FORMULATION AND COMPARISON

By: **Ego Syahrial**
Technological Assessor at "LEMIGAS" R & D Centre for Oil and Gas Technology
Jl. Ciledug Raya, Kav. 109, Cipulir, Kebayoran Lama, P.O. Box 1089/JKT, Jakarta Selatan 12230 INDONESIA
First Registered on 13 October 2009; Received after Corection on 19 November 2009
Publication Approval on: 22 December 2009

ABSTRACT

Sequestration of CO_2 in deep unmined coal seams is currently under development for improved recovery of coalbed methane (ICBM) as well as permanent storage of CO_2. Recent studies have shown that CO_2 displaces methane by adsorbing more readily onto the coal matrix compared to other greenhouse gases, and could therefore contribute towards reducing global warming. In order to carry out a more accurate assessment of the potential of ICBM and CO_2 sequestration, field based numerical simulations are required. Existing simulators for primary CBM (coalbed methane) recovery cannot be applied since the process of CO_2 injection in partially desorbed coalbeds is highly complex and not fully understood. The principal challenges encountered in numerical modelling of ICBM/CO_2 sequestration processes which need to be solved include: (1) two-phase flow, (2) multiple gas components, (3) impact of coal matrix swelling and shrinkage on permeability, and (4) mixed gas sorption. The objective of this part I of this two-part paper series is to develop a two-phase, multi-component CH_4-CO_2 simulator for use in the assessment of CO_2-ICBM recovery and CO_2 sequestration potential of coal seams. The developed formulation was tested and compared to model the improved coalbed methane (ICBM) recovery with pure CO_2 injection using a published data.

Key words: adsorption, desorption, improved recovery of coalbed methane (ICBM), CO_2 sequestration

I. INTRODUCTION

Sequestration of CO_2 in deep unmined coal seams is currently under development for improved recovery of coalbed methane (ICBM) as well as permanent storage of CO_2. Recent studies have shown that CO_2 displaces methane by adsorbing more readily onto the coal matrix compared to other greenhouse gases, and could therefore contribute towards reducing global warming. In order to carry out a more accurate assessment of the potential of ICBM and CO_2 sequestration, field based numerical simulations are required. Existing simulators for primary CBM (coalbed methane) recovery cannot be applied since the process of CO_2 injection in partially desorbed coalbeds is highly complex and not fully understood. The principal challenges encountered in numerical modelling of ICBM/CO_2 sequestration processes which need to be solved include: (1) two-phase flow, (2) multiple gas components, (3) impact of coal matrix swelling and shrinkage on permeability, and (4) mixed gas sorption.

This part I of this two-part paper series describes the development of a compositional simulator for improved recovery of coalbed methane and CO_2 sequestration. The new features that describe the complex process of CO_2 injection are implemented here. The developed formulation was tested and compared to model the improved coalbed methane (ICBM) recovery with pure CO_2 injection using a published data.

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 32. NO. 3, DECEMBER 2009 : 169 - 178

II. MODEL FORMULATION

Flow Equations

In brief, this simulator employs three main equations, gas, component and water equations:

$$\nabla\cdot\left[\left(\frac{[k]k_{rg}}{\mu_g}\xi_g\right)\nabla\Phi_g\right]+q_d+q_g=\frac{\partial}{\partial t}\left[\left(\phi\ S_g\ \xi_g\right)\right] \qquad (1)$$

$$\nabla\cdot\left[y_i\left(\frac{[k]k_{rg}}{\mu_g}\xi_g\right)\nabla\Phi_g\right]+q_{di}+q_{gi}=\frac{\partial}{\partial t}\left[\left(y_i\ \phi\ S_g\ \xi_g\right)\right] \qquad (2)$$

$$\nabla\cdot\left[\left(\frac{[k]k_{rw}}{\mu_w}\xi_w\right)\nabla\Phi_w\right]+q_w=\frac{\partial}{\partial t}\left[\left(\phi\ S_w\ \xi_w\right)\right] \qquad (3)$$

where:

k = absolute coal permeability (*mD*),

k_{rg} = relative permeability to gas phase (*frac.*),

k_{rw} = relative permeability to water phase (*frac.*),

μ_g = gas viscosity (*cp*),

μ_w = water viscosity (*cp*),

ξ_g = gas molar density (*lb-mole/cuft*),

ξ_w = water molar density (*lb-mole/cuft*),

ϕ = porosity (*frac.*),

S_g = gas saturation *(frac.),*

y_i = mole fraction of component *i* (*frac.*)

S_w = water saturation *(frac.),*

q_d = gas desorption rate (*lb-mole/day*),

q_{di} = gas desorption rate for component *i* (*lb-mole/day*),

q_g = gas production or injection rate (*lb-mole/day*),

q_{gi} = gas production or injection rate for component *i* (*lb-mole/day*),

q_w = water production (*lb-mole/day*),

$\nabla\Phi_g$ = gas phase potential (*psia*),

$\nabla\Phi_w$ = water phase potential (*psia*),

These equations are highly non-linear, therefore, numerical methods are required. By linearising them by the use of the *Newton Raphson* approximation and by discretising them with finite difference scheme, the system of equations can be written into a matrix form, and can be described by this following equation (they are in the fully-implicit form):

$$A^k\ \delta x^{k+1}=b^k \qquad (4)$$

where:

A = Block hepta-diagonal Jacobian matrix containing the coefficients of the left-hand side of equations (1), (2) and (3).

b = Vector containing the right-hand side of equations (1), (2) and (3).

$$\delta x=\left[\delta p_g\ ,\ \delta S_w\ ,\ \delta y_i\ \right]$$

So, in general, number of equations to be solved in each iteration can be described as:

No. Equation = [No. Phases + (No. Component-1)] x No. Media x No. Gridblock

Equation of State (EOS)

The model formulation utilizes an Equations of State (*EOS*) for gas mixtures property calculations, such as, gas molar density and its derivatives (Reynold, *et.al.*, 1990). The *EOS* in this simulator is used to replace gas *PVT* table that usually used for single gas component system. In single gas component, the gas property is only a function of pressure and the gas composition is always assumed to be constant. As we will deal with a multi-component system, the composition of each component will be varied from one to another point in the reservoir (especially in the location of injection wells) and the gas property will be a function of both pressure and gas composition. The *EOS* has been designed to provide a consistent source for determining composition and property of real gases at various ranges of pressure and temperatures.

The *EOS* is incorporated in both initialization and simulation parts of the simulator. In this work, we use a generalized Equations of State which upon selection of appropriate parameters, can be used to represent any of two Equations of State commonly employed in the oil industry; that is, the Peng-Robinson (*PR*) and Soave-Redlich-Kwong (*SRK*) Equations of State. The generalized *EOS* can be written in terms of compressibility factor (Z_m) to yield the following

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 32. NO. 3, DECEMBER 2009 : 169 - 178

cubic equation (for *PR EOS*):

$$Z_m^3-(1-B_m)Z_m^2+(A_m-2B_m-3B_m^2)Z_m-(A_mB_m-B_m^2-B_m^3)=0 \quad (5)$$

Eq. (5) can be solved analytically for a maximum of three real roots, where the largest root is vapor compressibility factor, and two remaining roots are without physical significance. Gas molar density and its derivatives are determined using following equations:

$$\xi_g = \frac{p}{Z_m R T} \quad (6)$$

$$\frac{\partial \xi_g}{\partial p} = \frac{1}{Z_m R T}\left\{1 - \frac{p}{Z_m}\frac{\partial Z_m}{\partial p}\right\} \quad (7)$$

Desorption Term

Sorption isotherm equation is used to define the relationship between the flow in the matrix system (where flow is controlled by concentration gradients) and the flow in the cleat system (where flow is controlled by pressure gradients). The calculation of diffusion/sorption term (q_d) in this simulator is based on the pseudo steady-state model (King *et al.*, 1986). This model allows it to be included as an extra rate term in the flow equations, hence, it simplifies the calculation and computer storage requirements. Total gas desorption from matrix system to the cleat system can be written as follows:

$$q_d = \sum_i^{NC} q_{di} \quad (8)$$

where, q_{di} of each component is calculated by:

$$q_{di} = -s\frac{dV_{ii}}{dt} \quad (9)$$

and

$$\frac{dV_{ii}}{dt} = -\frac{1}{\tau_{Qi}}\left[V_{ii} - V_{Ei}\right] \quad (10)$$

where:

s = shape factor (*dimensionless*),

t = time step (*days*),

V_{ii} = volume of gas adsorbed (component *i*) per-unit volume of the reservoir (*lbmol/ton*),

τ_{Qi} = diffusion constant of component *i* (days),

V_{Ei} = volume of gas adsorbed (component *i*) per-unit volume of the reservoir in equilibrium at gas pressure p_g (*lbmol/ton*), and defined by the extended Langmuir isotherm.

II. MODEL COMPARISONS

The developed formulation described in the previous section was tested and compared to model the improved coalbed methane (ICBM) recovery with pure CO_2 injection. Data used for this comparison study is taken from a published paper (*Law. D.H.-S., van der Meer, L.G.H. and Gunter, W.D., 2002)*. In the published paper, there are five simulators participated in the comparison study, they are: (1) GEM, Canada; (2) ECLIPSE, UK; (3) COMET 2, USA; (4) SIMED II, Australia; and (5) GCOMP, USA. In this study, results from our simulator (LEMIGAS, Indonesia) will be included in this comparison study (Syahrial, 2005).

The CBM simulators that participate in this comparison study must have the following basic features:

- Darcy flow of gas and water in the natural fracture system;
- Adsorption/desorption of two different gas components (*i.e.*, CH_4+CO_2) at the coal surface;
- instantaneously gas flow (*i.e.*, diffusion) between the coal matrix and the natural facture system;
- no coal matrix shrinkage/swelling due to gas desorption/adsorption;

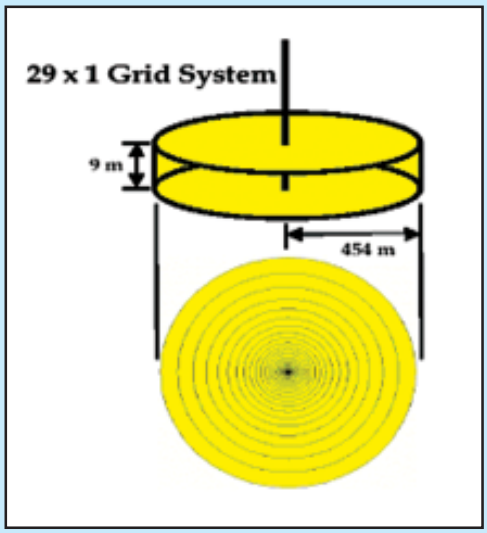

Figure 1
Schematic diagram of radial grid system used in problem set 1

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 32. NO. 3, DECEMBER 2009 : 169 - 178

- no compaction/dilation of natural fracture system due to stresses; and
- no non-isothermal adsorption due to difference in temperatures between the coalbed and the injected CO_2.

There are two problems set selected for this comparison: the first problem set deals with a single well test with CO_2 injection (see Figure 1) and the second problem set deals with ICBM recovery process with CO_2 injection in an inverted five-spot pattern (see Figure 2). A complete description of the two problem sets is given in Appendixes A, B and C. The coalbed characteristics are the same for both problem sets. The problems selected for comparison are intended to exercise many of the features of CBM simulators that are practical and theoretical interest and to identify areas of improvement for modeling of the ICBM process.

IV. RESULTS

Problem Set 1

Figure 3 shows a comparison of a well bottom-hole pressure as a function of time indicating the four operating stages of the single well test: (1) CO_2 injection stage; (2) pressure falloff stage; (3) gas production stage; and (4) pressure buildup stage. It can be seen that during injection period, the bottom-hole pressure increases above the original pressure, but it is still below maximum pressure (15,000 kPa) that can damage the reservoir. Then, during shut-in period for 45 days, the bottom-hole pressure decreases to the level of about 8000 kPa. The last period of 62.5 days, the bottom-hole pressure will reach to the level before the well was produced.

Figure 4 shows comparison of CH_4/CO_2 production rates as function of time. During the gas production stage (60 – 120 days), the injected CO_2 near the well is produced first with high rate. This can be understood since CO_2 is a strongly absorbable gas, so once it penetrates to the few grid blocks around the well, it remains on those blocks with high concentration. This high rate period is short and CO_2 production rate declines rapidly as CO_2 around the well is depleted which corresponds to the decline of the production CO_2 composition. On the other hand, CH_4 production rate remains rather constant throughout the gas production stage. This similar situation can be also described by production gas compositions for

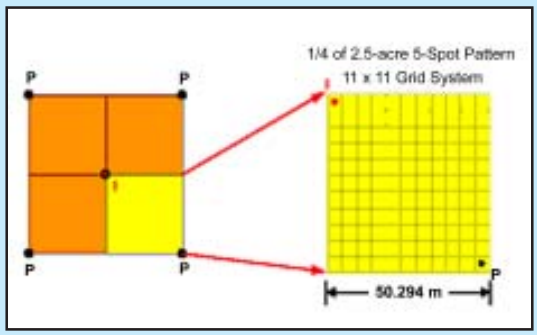

Figure 2
Schematic diagram of rectangular grid system used in problem set 2

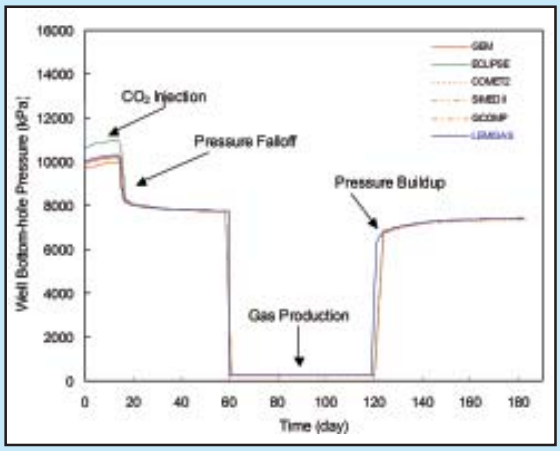

Figure 3
Problem set 1 – well bottom-hole pressure

CH_4/CO_2 as function of time as shown in Figure 5.

This single well test is a typical standard test that normally taken in conventional oil and gas wells during discovery and development stages. The test is carried out by observing the bottom-hole pressure as a function of time and it is used to determine reservoir characteristics, such as: average reservoir pressure; drainage area; well productivity; reservoir permeability and skin factor. However, as coalbed reservoir always has low porosity and permeability, time required for the well to reach transient period *(i.e.*, period when reservoir characteristics can be determined) is longer than that required for conventional sandstone reservoirs. It is believed that pressure responses during the test will be affected by well-bore

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 32. NO. 3, DECEMBER 2009 : 169 - 178

storage effects. This simulator can give rough estimate time for how long a well should be produced or shut-in for reaching the transient period.

Problem Set 2

Figure 6 shows comparison of CH_4 production rates for the primary CBM and CO_2-ICBM recovery processes as functions of time indicating the enhancement of CH_4 production due to CO_2 injection. In general, the enhancement of CH_4 production remains until CO_2 breakthrough occurs at the producer after approximately 60 days (this approximate breakthrough time can be clearly viewed from Figure 8). During the initial primary CBM, the typical "*negative decline*" in CH_4 production rate due to "pumped-out" of water is not observed in this case because of presence of an initial gas saturation of 0.408. On the other hand, the initial decline of CH_4 production rate in CO_2-ICBM recovery process is due to mobile water is being displaced from the injector to the producer.

It is appropriate to mention here that we are asked

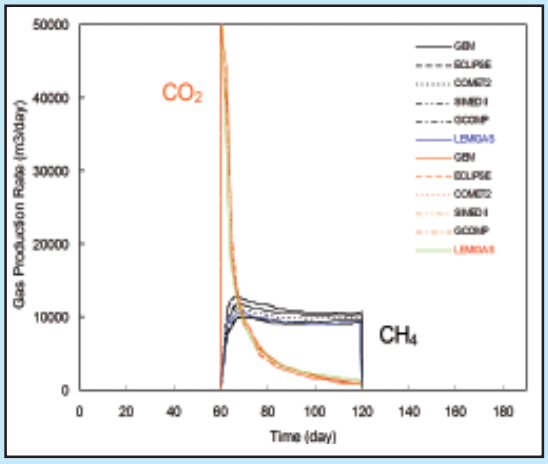

Figure 4
Problem set 1 – CH_4 and CO_2 production rates

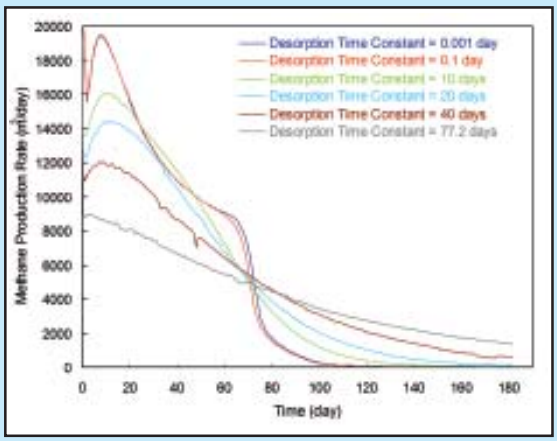

Figure 6
Problem set 2 – CH_4 production rate for primary CBM and CO_2-ICBM recovery processes for full 5-spot pattern

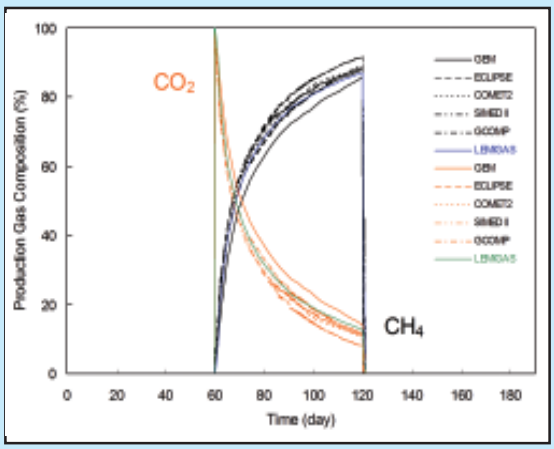

Figure 5
Problem Set 1 – Production gas compositions for CH_4 and CO_2

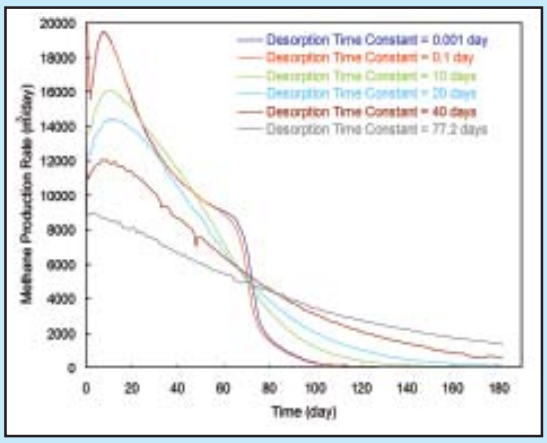

Figure 7
Problem set 2 – Effect of desorption time constant to the CH_4 production rate

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 32. NO. 3, DECEMBER 2009 : 169 - 178

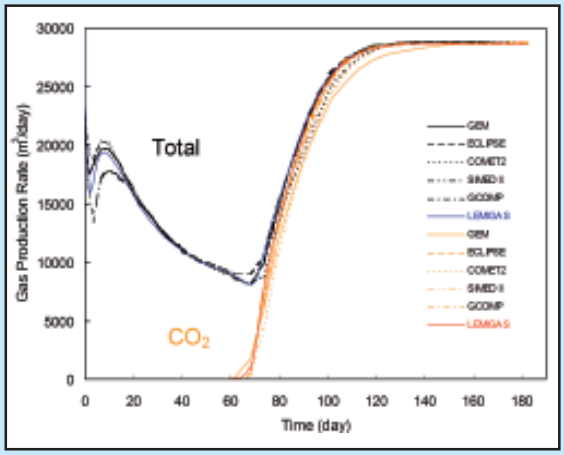

Figure 8
Problem set 2 – CO_2 and total gas production rates for full 5-spot pattern

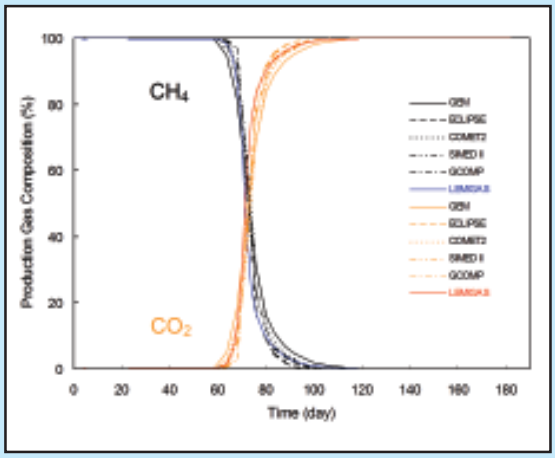

Figure 10
Problem set 2 – Production gas compositions for CH_4 and CO_2

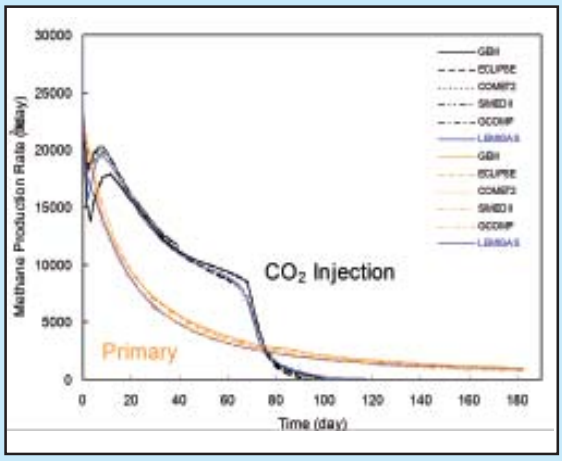

Figure 9
Problem set 2 – Injection bottom-hole pressure

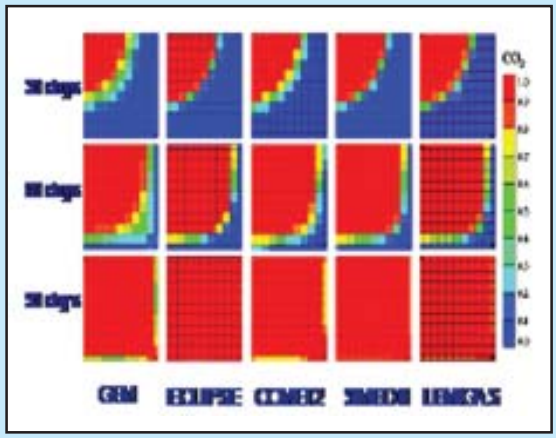

Figure 11
Problem set 2 – CO_2 distributions as CO_2 mole fraction in gas phase in natural fracture system

to run the problems set by mimicking instantaneously gas diffusion between the coal matrix and the natural fracture system . To do this, we do sensitivity studies by running the model with different desorption time constants. This can be understood since not all simulators participated in the comparison study implement desorption term as an extra term in their formulations, instead, some of them just mimicking the gas diffusion by assumption that desorbed gas could be described as the dissolved gas in matrix. This assumptions is being used in ECLIPSE and COMET 2 simulators. Our simulator, however, implementing the rate of desorbed gas by non-equilibrium pseudo-steady state formulation, where the gas diffusion is strongly affected by the desorption time constant. Therefore, we do sensitivity studies for obtaining the desorption time constant that really represent instantaneously gas diffusion between the coal matrix and the natural fracture system. We found that t_{Qi} = 0.1 day is quite appropriate to represent the cases. Figure 7 shows effect desorption time constant to the enhancement of CH_4 production due to CO_2 injection. There-

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 32. NO. 3, DECEMBER 2009 : 169 - 178

fore throughout this study we use t_{Qi} = 0.1 day as desorption time constant.

Figure 8 shows comparisons of CO_2/total gas production rates as function of time. It can be seen that all simulators predict an initial decline of total gas production rate (*i.e.*, mainly CH_4 production rate) at the beginning of CO_2 injection. This period of declined gas production rate is short (*i.e.*, our simulator predict 2.1 days) and mainly due to relative permeability effects. This can be described that shortly after CO_2 injection, mobile water in coalbed is displaced from the injector towards the producer that reduces gas relative permeability around the producer. After majority of the mobile water is produced, the gas relative permeability around the producer increases which corresponds to the increase in CH_4 production rate. After reaching the minimum decline, the CH_4 production rate increases again and reaches a maximum value after approximately 8.1 days.

Figure 9 shows comparisons of injection bottomhole pressure as functions of time. Under the condition of constant CO_2 injection rate, injection bottomhole pressure declines initially as mobile water is being displaced around the injector and gas injectivity increases. After the decline, the injection bottom-hole remains rather constant until CO_2 breakthrough at the producer after approximately 60 days, then the injection pressure gradually increases. This is because after CO_2 breakthrough, the injected CO_2 channels through towards the producer with only very little being adsorbed at the coal surface (*i.e.*, acting as a weakly adsorbable gas). In general, under the condition of constant injection rate, injection pressure for a weakly adsorbable gas (*e.g.*, N_2) is higher than that for a strongly adsorbable gas (*e.g.*, CO_2).

Figure 10 shows a comparison of production gas compositions for CH_4/CO_2 as a function of time. After CO_2 breakthrough occurs at the producer after approximately 60 days production, CH_4 composition decreases sharply as the production rate of CO_2 increases. This indicates great sweep efficiency in the 5-spot pattern for CO_2 injection, as there is little CH_4 left to produce.

And, finally Figure 11 shows a comparison of CO_2 distribution as the CO_2 mole fraction in the gas phase in the natural fracture system after 30, 60 and 90 days. The contour plots represent a ¼ of the 5-spot pattern with injector located at the upper left-hand corner and the producer located at the lower right-hand corner. It can be seen here that the CO_2 distribution confirms the good sweep efficiency with CO_2 injection.

V. CONCLUSIONS

We agree with the published paper said that in general, there is very good agreement between the results from the different simulators. The differences between the predictions from different simulators may result for a variety of reasons:

- possible different initialization procedure (*e.g.*, initial gas in-place),
- possible slightly different *PVT* properties for pure gas used,
- possible different dual porosity approach in the simulators,
- handling of wells (*e.g.*, ¼ well in 5-spot pattern),
- tolerance of the convergence of iterations; and
- selection of numerical control parameters.

The first two simple problem sets can be used as baseline for different CBM simulators when they participate in the comparison of more complex test problems. At this time the comparison study on more complex test problems is ongoing and our CBM simulator (LEMIGAS) is participating in that comparison study. The second part of this paper series will discuss impact of matrix shrinkage/swelling on the production performance on primary and improved coalbed methane (ICBM) recovery with pure CO_2 injection.

REFERENCES

1. Reynolds, A.C., Guehria, F.M., and Thompson, L.G.,: "A Robust Algorithm for Determining Hydrocarbon PVT Properties Using a generalized EOS". SPE Paper 21588, presented at the International Technical Meeting, Calgary, June 1990.
2. King, G.R., Ertekin, T., and Schwerer, F.C.: "Numerical Simulation of the Transient Behavior of Coal Seam Degasification Wells," SPEFE (April 1986) pp. 165-183.
3. David H.-S. Law, L.G.H. (Bert) van der Meer, and W.D. (Bill) Gunter: "Numerical Simulator Comparison Study for Enhanced Coalbed Methane Recovery Processes, Part I: Pure Carbon Injection," SPE Paper 75669, presented at the

SPE Gas Technology Symposium held in Calgary, Alberta, Canada, 30 April-2 May 2002.

4. Syahrial E: "Coalbed Methane Simulator Development for Improved Recovery of Coalbed Methane and CO2 Sequestration", paper SPE 93160, presented in the 2005 SPE Asia Pacific Oil and Gas Conference and Exhibition in Jakarta, Indonesia, 5-7 April 2005.ˇ

APPENDIX A
COALBED CHARACTERISTICS

Coalbed Properties	SI Units	Field Units
Coal seam thickness	9 m	29.527 ft
Top of coal seam	1253.6 m	4112.8 ft
Absolute permeability of natural fracture	3.65 mD	3.65 mD
Porosity of natural fracture system	0.001	0.001
Effective coalbed compressibility	$1.45\acute{}10^{-7}$ kPa^{-1}	$1.0\acute{}10^{-6}$ psia^{-1}
Initial Reservoir Conditions		
Temperature	45°C	113°F
Pressure (assumed uniform from top to bottom)	7650 kPa	1109.5 psia
Gas saturation (100% CH_4)	0.408	0.408
Water saturation	0.592	0.592
Water Properties at 45°C (113°F)		
Density	990 kg/m^3	61.8 lb/ft^3
Viscosity	0.607 cp	0.607 cp
Compressibility	$5.8\acute{}10^{-7}$ kPa^{-1}	$4.0\acute{}10^{-6}$ psia^{-1}
Pure Gas Adsorption Isotherm at 45°C (113°F) Average in-situ coal density	1434 kg/m^3	89.5 lb/ft^3
Average in-situ moisture content (by wt.), wwe	0.0672	0.0672
Average in-situ ash content (by wt.), wa	0.156	0.156

The dry, ash-free isotherm parameters shown in Table A-1 is used to estimate the in-situ storage capacity as a function of pressure, ash content, and in-situ moisture content using the Langmuir relationship:

$$G_s = G_{sL}\left[1 - (w_a + w_{we})\right]\frac{p}{p + p_L} \qquad \text{(A-1)}$$

where:

G_s : gas storage capacity

G_{sL} : dry, ash-free Langmuir storage capacity

w_a : ash content, weight fraction

w_{we} : equilibrium moisture content, weight fraction

p : pressure

p_L : Langmuir pressure

The individual component isotherm parameters used to compute storage capacity when multiple gas species are present. The computation is based upon extended Langmuir isotherm theory. The extended Langmuir isotherm relationship is listed as following:

$$G_{si} = G_{sLi}\left[1 - (w_a + w_{we})\right]\frac{\frac{p\,y_i}{p_{Li}}}{1 + p\sum_{j=1}^{nc}\frac{y_j}{p_{Lj}}} \qquad \text{(A-2)}$$

where:

G_{si} : multi-component storage capacity of component *i*, in-situ basis

G_{sLi} : single component Langmuir storage capacity of component *i*, dry, ash-free basis

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 32. NO. 3, DECEMBER 2009 : 169 - 178

p_{Li} or p_{Lj}: single component Langmuir pressure of component *i* or *j*

y_i or y_j : mole fraction of component *i* or *j* in the free gas (vapor) phase

nc : number of components

p : pressure of the free gas phase

Relative Permeability Data

The relative permeability relationship shown in Table A-2 is based upon the relationship published by Gash. No effect of temperature or hysteresis on the relative permeability is considered and the capillary pressures are assumed to be zero.

APPENDIX B
PROBLEM SET 1

Problem Set 1: Single Well CO_2 Injection Test

Grid System

- Cylindrical (r-q-z) grid system = 29´1´1 (Figure 1)
- Area = 160 acres
- Radius = 454 m (1,489.5 ft)
- r-direction = Table B-1
- q-direction = Dq = 360°
- z-direction = Dz = 9 m (29.5 ft)

Operating Conditions

- Well location : (*i* =1, *j* =1, *k* =1)
- Well radius (2 7/8" well) = 0.0365 m (0.11975 ft)
- Well skin factor = 0
- 15-day CO_2 injection period (0 - 15 days) :
  - CO_2 injection rate (full well) = 28,316.82 sm^3/d ($1´10^6$ scf/d)
  - Maximum bottom-hole pressure = 15,000 kPa (2,175.6 psia)
- 45-day shut-in period (15 - 60 days) :
  - Well shut-in for pressure falloff
- 60-day production period (60 – 120 days) :
  - Maximum gas production rate (full well) = 100,000 sm^3/d ($3.5315´10^6$ scf/d)
  - Minimum bottom-hole pressure = 275 kPa (39.883 psia)
- 62.5-day shut-in period (120 – 182.5 days) :
  - Well shut-in for pressure buildup

APPENDIX C – PROBLEM SET 2

Problem Set 2a : 5-Spot Primary CBM Recovery Process

Grid System

- Rectangular (x-y-z) grid system = 11´11´1 (Figure 2)
- Area = ¼ of a 2.5 acres pattern
- Pattern half width = 50.294 m (165 ft)
- x and y-direction = Table C-1
- z-direction = Dz = 9 m (29.5 ft)

Table A-1
Dry, ash-free Langmuir isotherm parameters

	Methane		Carbon Dioxide		Nitrogen	
Langmuir Pressure	kPa	psia	kPa	psia	kPa	psia
P_L	4688.5	680	1903	276	27241	3951
Dry, Ash-Free Langmuir	m^3/kg	scf/ton	m^3/kg	scf/ton	m^3/kg	scf/ton
Volume, G_{SL}	0.0152	486	0.0310	993.8	0.0150	482

Table A-2
Relative permeability relationship

S_w	k_{rw}	k_{rg}	S_w	k_{rw}	k_{rg}
1.000	10.000	0.0000	0.500	0.0880	0.2160
0.975	0.8140	0.0035	0.450	0.0670	0.2530
0.950	0.7310	0.0070	0.400	0.0490	0.2950
0.900	0.6010	0.0180	0.350	0.0350	0.3420
0.850	0.4900	0.0330	0.300	0.0240	0.4010
0.800	0.3920	0.0510	0.250	0.0150	0.4660
0.750	0.3120	0.0700	0.200	0.0070	0.5370
0.700	0.2510	0.0900	0.150	0.0020	0.6270
0.650	0.2000	0.1180	0.100	0.0013	0.7200
0.600	0.1540	0.1470	0.050	0.0006	0.8350
0.550	0.1160	0.1800	0.000	0.0000	10.000

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 32. NO. 3, DECEMBER 2009 : 169 - 178

Table B-1
Radial grid system used for Problem Set 1

i	Δr		r	
	(m)	(ft)	(m)	(ft)
1	0.9110	29.888	0.9110	29.888
2	11.600	38.058	20.710	67.946
3	13.456	44.147	34.166	112.093
4	15.609	51.211	49.775	163.303
5	18.106	59.403	67.881	222.706
6	21.003	68.907	88.884	291.614
7	24.364	79.934	113.248	371.548
8	28.262	92.723	141.510	464.271
9	32.784	107.559	174.294	571.830
10	38.030	124.770	212.324	696.601
11	44.114	144.731	256.438	841.332
12	51.173	167.890	307.611	1.009.222
13	59.360	194.751	366.971	1.203.973
14	68.858	225.912	435.829	1.429.885
15	79.875	262.057	515.704	1.691.942
16	92.655	303.986	608.359	1.995.928
17	107.480	352.625	715.839	2.348.553
18	124.677	409.045	840.516	2.757.598
19	144.625	474.491	985.141	3.232.090
20	167.765	550.410	1.152.906	3.782.500
21	194.608	638.478	1.347.514	4.420.977
22	225.745	740.633	1.573.259	5.161.611
23	261.864	859.134	1.835.123	6.020.744
24	303.763	996.598	2.138.886	7.017.342
25	352.364	1.156.050	2.491.250	8.173.392
26	408.742	1.341.017	2.899.992	9.514.409
27	474.141	1.555.581	3.374.133	11.069.990
28	550.005	1.804.478	3.924.138	12.874.468
29	614.972	2.017.625	4.539.110	14.892.093

Operating Conditions

- Well locations :
  - Production well : (i=11, j=11, k=1)
- Well radius (2 7/8" well) = 0.0365 m (0.11975 ft)
- Well skin factor = 0
- 182.5-day continuous gas production period (0 – 182.5 days) :
  - Maximum gas production rate (full well) = 100,000 m^3/d (3.5315´10^6 scf/d)
  - Minimum bottom-hole pressure = 275 kPa (39.885 psia).

Table C-1
Rectangular grid system used for Problem Set 2

i or j	Δx or Δy		x or y	
	(m)	(ft)	(m)	(ft)
1	2.500	8.20	2.500	8.20
2	5.000	16.40	7.500	24.60
3	5.000	16.40	12.500	41.00
4	5.000	16.40	17.500	57.40
5	5.000	16.40	22.500	73.80
6	5.294	17.37	27.794	91.17
7	5.000	16.40	32.794	107.57
8	5.000	16.40	37.794	123.97
9	5.000	16.40	42.794	140.37
10	5.000	16.40	47.794	156.77
11	2.500	8.20	50.294	164.97

Problem Set 2b : 5-Spot CO_2 – ICBM Recovery Process

Grid System

- Same as Problem Set 2a.

Operating Conditions

- Well locations :
  - Injection well : (i=1, j=1, k=1)
  - Production well : (i=11, j=11, k=1)
- Well radius (2 7/8" well) = 0.0365 m (0.11975 ft)
- Well skin factor = 0
- 182.5-day continuous CO_2 injection/production period (0 – 182.5 days) :
  - CO_2 injection rate (full well) = 28,316.82 sm^3/d (1´10^6 scf/d)
  - Maximum bottom-hole pressure = 15,000 kPa (2,175.6 psia)
  - Maximum gas production rate (full well) = 100,000 m^3/d (3.5315´10^6 scf/d)
  - Minimum bottom-hole pressure = 275 kPa (39.885 psia).