

## URTeC: 1923960

# Coupled Geomechanics and Pore Confinement Effects for Modeling Unconventional Shale Reservoirs

Yi Xiong\*, Philip. H. Winterfeld, Yu-Shu Wu, Colorado School of Mines; Zhaoqin Huang, China University of Petroleum (East China)

Copyright 2014, Unconventional Resources Technology Conference (URTeC) DOI 10.15530/urtec-2014-1923960

This paper was prepared for presentation at the Unconventional Resources Technology Conference held in Denver, Colorado, USA, 25-27 August 2014.

The URTeC Technical Program Committee accepted this presentation on the basis of information contained in an abstract submitted by the author(s). The contents of this paper have not been reviewed by URTeC and URTeC does not warrant the accuracy, reliability, or timeliness of any information herein. All information is the responsibility of, and, is subject to corrections by the author(s). Any person or entity that relies on any information obtained from this paper does so at their own risk. The information herein does not necessarily reflect any position of URTeC. Any reproduction, distribution, or storage of any part of this paper without the written consent of URTeC is prohibited.

## Abstract

The pore sizes of shale and tight-rock formations are on the order of nanometers. The thermodynamic phase behavior of in-situ hydrocarbon mixtures in such small pores is significantly different from that of bulk fluids in the PVT cells mainly due to effect of large capillary pressure, which has been a subject of great interest for shale reservoir study. For example, it has been recognized that the critical pressure and temperature of reservoir fluids may change due to the pore spatial confinement, thus the phase envelop shifts for unconventional shale reservoirs. Those shifts of phase envelop could favor the productions of shale reservoirs, especially for tight oil systems because of suppressed bubble-point pressure leading to longer single phase production.

On the other hand, the pore sizes, especially the pore-throats, are subjected to change due to rock deformation induced by the fluid depletion. As the fluids are being produced from the pore space, the pore pressure will decrease; thus the effective stress on reservoir rock increase, resulting in the reduction of the pore and pore-throat sizes. This reduction on pore spaces affects again the fluid flow through impacts on the thermodynamic phase behaviors, as well as stress induced changes on porosity and permeability. Thus a coupled flow-geomechanics model including pore confining effects is in general necessary to examine the unconventional shale reservoir behavior.

In this paper, we present a multiphase multi-component reservoir model, fully coupling fluid flow, geomechanics and pore confining effects for shale reservoirs. This model is based on general mass conservation law for each component. The geomechanical model is derived from the elasticity theory extended to porous and non-isothermal media. The Peng-Robinson EOS-based flash calculation is used to analyze the large capillary pressure effects on shale reservoir phase behavior. This theoretical model can be readily discretized and implemented with control volume based numerical methods, and generally applied to both dew-point and bubble-point systems. Eventually it could improve the forecast accuracy for long-term production rate and recovery factors of unconventional reservoirs.

## Introduction

Ultra-tight and shale reservoirs are playing a significant part to oil and gas production of U.S. in recent years, thanks mainly to technological advances in horizontal drilling and multi-stage hydraulic fracturing. However, the reservoir fluid flow behaviors are still poorly understood due to the complexity of fluid properties in nano-size scales. Kuila and Prasad (2011) pointed out that shale matrix has predominantly micro-pores with less than 2 nm diameter to meso-pores with 2-50 nm diameters. Such small pores lead to significant interfacial curvature and capillary pressure between confined vapor and liquid phases. The researchers have been investigating the impacts of capillary pressure on fluid properties and phase behavior since 1970s in oil and gas industry. It was found that the dew-point and bubble-point pressure were same in the 30- to 40-US-mesh porous medium and in bulk volume (Sigmund et al., 1973), and concluded that capillary effects on vapor-liquid equilibrium (VLE) is negligible for conventional reservoirs. The recent studies on unconventional reservoirs, however, show that the effect of capillary pressure on

#### URTeC 1923960

reservoir phase behavior cannot be ignored (Du and Chu, 2012; Firincioglu et al., 2012; Pang et al., 2012; Nojabaei et al., 2013; Wang et al., 2013 ).

On the other hand, the reservoir rock properties such as pore size, porosity and permeabilities, are subjected to change due to rock deformation. Han et al. (2013) claimed that stress-dependency is more pronounced in low permeability rock than in conventional reservoir rock. They investigated a nano-Darcy permeability unconventional oil reservoir rock under triaxial stress conditions and concluded that the hydraulic and mechanical properties of unconventional rocks depend strongly on the loading and confining stress. Mokhtari et al. (2013) performed laboratory tests on Mancos Shale and Eagle Ford Shale excluding fractured samples, and found strong functions between effective stress and matrix porosity and permeability. The above tests on unconventional field by Chu et al. (2012), Honarpour et al. (2012), and Orangi et al. (2011). For example, Chu et al. (2012) claimed that the increased net confining stress has very large impact on pore-throat size rather than pore-size, therefore it results in the reduction of matrix permeability varies between 3 to 10 times and pore throat size within 20% to 60%, therefore significant increase of capillary pressure. Thus the effects of pore-confinement and geomechanics are interlinked in unconventional reservoirs. However, models with capability to couple both geomechanical and pore confining effects are rarely available.

In this paper we present a compositional reservoir model fully coupling geomechanical effects. The compositional model is formulated through mass conservation law for each component. The geomechanical equations are derived based on the classical theory of elasticity, extended to porous media in the form of mean normal stress as a function of pore pressure and temperature. The pore confinement effects are incorporated by including capillarity influence on vapor-liquid equilibrium (VLE). In the following sections, we firstly present a general multiphase multi-component model. Then the geomechanical model is derived by yielding an equation between stress, pore pressure, and reservoir temperature. After that the effects of capillary pressure on VLE and reservoir phase behavior are addressed. Finally we discuss how to implement this model with numerical methods in order to use it for fluid flow simulation of unconventional reservoirs.

#### Fluid Flow Model

The physical processes associated with multiphase multi-component fluid flow in unconventional shale reservoirs are governed by the fundamental mass conservation law. It is often represented mathematically by a set of partial differential or integral equations on the macroscopic level. Those mathematical equations are usually called governing equations, which are generally nonlinear as long as compressible or multiphase fluids are involved (Wu and Qin, 2009).

Let us consider three fluid phases, oil, gas and water in unconventional reservoirs, with each fluid phase consisting of a number of mass components. For example, methane ( $C_1$ ) accounts for about 0.37 molar fraction in Bakken oil (Nojabaei et al., 2013); it is also the main component of the gas phase after reservoir pressure depleted under bubble-point pressure. For a component within a representative elementary volume (REV) in the reservoir, a generalized conservation equation can be written as follows:

$$F^k + q^k = \frac{\partial M^k}{\partial t} \tag{1}$$

where superscript k is the index for the components,  $k = 1, ..., N_c$  with  $N_c$  being the total number of mass components in the reservoir system. F is the mass flux term; M is the accumulation term; q is an external source/sink term representing mass production or injection.

For multiphase fluid flow, the accumulation term is evaluated as

$$M^{k} = \phi \sum_{\beta} (\rho_{\beta} S_{\beta} X_{\beta}^{k})$$
<sup>(2)</sup>

where  $X_{\beta}^{k}$  is the mass fraction of component k in fluid phase  $\beta$ ;  $\rho_{\beta}$  and  $S_{\beta}$  are phase density and saturation;  $\phi$  is the reservoir porosity. The total mass of component k is the summation of mass of k in phase  $\beta = \text{oil}$ , gas and water.

The mass flow term is determined with similar way as accumulation term, where the total mass flow of component k is the summation of mass of k in the flow of each phase as

$$F^{k} = -\sum_{\beta} \nabla \cdot \left( \rho_{\beta} \mathbf{v}_{\beta} X_{\beta}^{k} \right) \tag{3}$$

where  $\mathbf{v}_{\beta}$  is a vector of the Darcy's velocity or volumetric flow, defined by Darcy's law to describe multiphase fluids flow as

$$\mathbf{v}_{\beta} = -\frac{kk_{r\beta}}{\mu_{\beta}} \left( \nabla P_{\beta} - \rho_{\beta} g \nabla z \right) \tag{4}$$

where  $P_{\beta}$ ,  $\mu_{\beta}$  and  $k_{r\beta}$  are pressure, viscosity and relative permeability of fluid phase  $\beta$  respectively; and g is the gravitational constant; z is the vertical coordinate; k is absolute permeability.

#### **Geomechanical Model**

The geomechanical equations in our model are based on the classical theory of poro-thermal-elastic system, and the equilibrium equation can be expressed as (Jaeger et al., 2007; Zoback, 2007)

$$S_{ij} - \left(\delta_{ij}\alpha P + 3\beta K\Delta T\right) = 2G\varepsilon_{ij} + \lambda\delta_{ij}\varepsilon_{\nu}$$
<sup>(5)</sup>

where *S* is the total stress and subscript *i*, *j* represent the direction of stress; it is normal stress if i = j otherwise it's shear stress;  $\delta_{ij}$  is Kronecker delta, given by  $\delta_{ij} = 1$  if i = j; and  $\delta_{ij} = 0$  if  $i \neq j$ ;  $\alpha$  is Biot's coefficient; *P* is the pore pressure;  $\Delta T$  is the temperature change to the reference temperature for a thermally unstrained state;  $\beta$  is linear thermal expansion coefficient; *K*, *G* and  $\lambda$  are mechanical properties of rock, representing bulk modulus, shear modulus and Lame's constant respectively.  $\varepsilon$  stands for strain;  $\varepsilon_v$  is volumetric strain evaluated as  $\varepsilon_v = \varepsilon_{xx} + \varepsilon_{yy} + \varepsilon_{zz}$ . In general, Equation (5) is the extended Hooke's law by including terms dependent on pore pressure and temperature.

Two other fundamental relations in the linear elasticity theory are the relationship between strain tensor and the displacement vector and the condition of static equilibrium as Equation (6) and (7)

$$\varepsilon_{ij} = \frac{1}{2} \left( \frac{\delta u_i}{\delta x_j} + \frac{\delta u_j}{\delta x_i} \right) \tag{6}$$

$$\nabla \cdot \overline{\overline{S}} + \overline{F_p} = 0 \tag{7}$$

where u is the displacement; S is stress tensor and F is body force vector.

Combine Equations (5), (6) and (7) to obtain the thermo-poro-elastic Navier's Equation

$$\nabla(\alpha P + 3\beta KT) + (\lambda + G)\nabla(\nabla \cdot \overline{u}) + G\nabla^2 \overline{u} + \overline{F}_b = 0$$
<sup>(8)</sup>

The above equation has two terms containing the displacement vector, and taking the divergence of it to result in the equation with only one term containing the divergence of the displacement vector as follows

$$\nabla \cdot \left[ \nabla (\alpha P + 3\beta KT) + (\lambda + 2G) \nabla (\nabla \cdot \overline{u}) + \overline{F}_b \right] = 0 \tag{9}$$

And the divergence of displacement vector  $\nabla \cdot \overline{u}$  is the volumetric strain  $\varepsilon_v$  as

$$\nabla \cdot \overline{u} = \frac{\partial u_x}{\partial x} + \frac{\partial u_y}{\partial y} + \frac{\partial u_z}{\partial z} = \varepsilon_{xx} + \varepsilon_{yy} + \varepsilon_{zz} = \varepsilon_v \tag{10}$$

The trace of the stress tensor is an invariant with the same value for any coordinate system. Thus Equation (5) gives the trace of Hooke's law for a thermo-poro-elastic medium as (Winterfeld and Wu, 2014),

$$S_m - (\alpha P + 3\beta K\Delta T) = \left(\lambda + \frac{2}{3}G\right)\varepsilon_v$$
(11)

Where  $S_m$  is the mean stress with relationship with normal stress  $S_m = \frac{S_{xx+}S_{yy+}S_{zz}}{3}$ , which corresponds to uniform confining stress in laboratory experiments (Zoback, 2007).

Finally combining Equations (9) (10) and (11) yields an equation relating mean stress, pore pressure, temperatures and body force:

$$\nabla \cdot \left[ \nabla (\alpha P + 3\beta KT) + \frac{\lambda + 2G}{\lambda + (2/3)G} \nabla (S_m - \alpha P - 3\beta K\Delta T) + \overline{F}_b \right] = 0$$
(12)

The coefficient of Equation (12) is related to the rock mechanical properties, and is only function of Poisson's ratio v. Thus the final governing equation for geomechanical model is therefore can be represented as following

$$\nabla \cdot \left[ \frac{3(1-\nu)}{(1+\nu)} \nabla S_m + \overline{F}_b - \frac{2(1-2\nu)}{(1+\nu)} \nabla (\alpha P + 3\beta KT) \right] = 0$$
(13)

Equation (13) and (11) are the governing equations in our geomechanical model, and mean stress  $S_m$  and volumetric strain  $\varepsilon_v$  are the geomechanical variables associated with those equations.

#### **Numerical Formulation**

The above multiphase multi-component fluid flow equations and geomechanical equations are readily discretized in time and space with numerical methods. We propose a control-volume based concept, an integral finite-difference method (Pruess, 1991) for space discretization. Time discretization is carried out using a backward, first-order, and fully implicit finite-difference scheme.



Figure 1: Space discretization and geometry data in the integral finite difference method (Pruess, 1991)

The residual form of discrete nonlinear equations for each component k (k=1,2, ..., Nc; Nc being total number of component) in node i (i=1,2, ...N; N being total number of nodes in the grid) at time step n+1 can be written in a general form as

$$R_i^{k,n+1} = \left(M_i^{k,n+1} - M_i^{k,n}\right) \frac{V_i}{\Delta t} - \sum_{j=\eta_i} flow_{ij}^{k,n+1} + Q_i^{k,n+1} = 0$$
(14)

Where *M* is the accumulation term as Equation (2),  $V_i$  is the volume of node *i*;  $\Delta t$  is the time step size;  $\eta_i$  contains the set of direct neighboring nodes *j* of node *i*; The flow term can be evaluated as Equation (3) and (4). *Q* donates the sink/source at node *i*.

The geomechanical governing equation can be discretized with similar method. Applying divergence theorem on Equation (13) to yield an integral form as

$$\int \left[\frac{3(1-\nu)}{(1+\nu)}\nabla S_m + \overline{F}_b - \frac{2(1-2\nu)}{(1+\nu)}\nabla(\alpha P + 3\beta KT)\right] \cdot \hat{n}d\Gamma = 0$$
(15)

where  $\hat{n}$  is a normal vector on surface element  $d\Gamma$ , which can be evaluated as a discrete sum of averages over surface segments as

$$\sum_{j=\eta_i} \left[ \frac{3(1-\nu)}{(1+\nu)} \frac{S_j - S_i}{d_{ij}} + \left( \overline{F}_b \cdot \hat{n} \right)_{ij} - \frac{2(1-2\nu)}{(1+\nu)} \left( \alpha \frac{P_j - P_i}{d_{ij}} + 3\beta K \frac{T_j - T_i}{d_{ij}} \right) \right] A_{ij} = 0$$
(16)

where  $d_{ij}$  and  $A_{ij}$  are the distance and area between node *i* and its neighboring nodes *j* respectively.

A set of non-linear discretized equations of Equation (14) for each component and Equation (16) for mean stress, can be solved with Newton-Raphson method.

#### **Capillarity Effects on VLE**

The capillary pressure in the ultra-tight rocks with nanometer pore throats could reach as high as 1,000 psi (Du and Chu, 2012). The large capillary pressure has significant effects on VLE in unconventional reservoirs, which cannot be ignored in tight and shale reservoir modeling. In this section the effects of capillary pressure on two-phase VLE is analyzed with fundamental principles of reservoir phase behaviors. In multi-component system under VLE, the chemical potential  $\mu$  of each component *i* throughout all the co-existing phases should be equal. This general requirement becomes a practical engineering tool if the chemical potential can be related to measurable or calculable quantities, such as fugacity *f* as follows.

$$\mu_i^L = \mu_i^V \quad or \quad f_i^L = f_i^V \qquad i = 1, 2, \dots N_c$$
 (17)

The practical way to get fugacity of each component is to evaluate the fugacity coefficient,  $\phi_i$ , which is defined as the ratio of fugacity to partial pressure of the corresponding phase by Equation (18).

$$\phi_i^L = \frac{f_i^L}{x_i P^L} \quad and \quad \phi_i^V = \frac{f_i^V}{y_i P^V} \tag{18}$$

where  $x_i$  and  $y_i$  are mole fraction of component *i* in liquid and vapor phase respectively;  $P^L$  and  $P^V$  are the pressure of corresponding fluid phase. The fugacity coefficient is related to pressure, temperature and volume by Equation (19) (Danesh, 1998)

$$ln\phi_{i} = \frac{1}{RT} \int_{V}^{\infty} \left[ \left( \frac{\partial P}{\partial n_{i}} \right)_{T,V,n_{j \neq i}} - RT/V \right] dV - lnZ$$
<sup>(19)</sup>

Where *R* is gas constant,  $n_i$  is the number of moles of component *i*; *V* is the total volume, and *Z* is the mixture compressibility factor. Equation (19) can be determined with the aid of an Equation of State (EOS), relating pressure, temperature, volume and compositions. For example, Equation (19) can be evaluated for liquid and vapor phase as follows using Ping-Robinson (P-R) EOS:

$$\ln \emptyset_{i} = \frac{b_{i}}{b} \left( Z - 1 \right) - \ln \left( Z - \frac{bP}{RT} \right) + \frac{a}{2\sqrt{2}RTb} \left( \frac{2\sum_{j=1}^{N_{c}} x_{j}a_{ij}}{a} - \frac{b_{i}}{b} \right) \cdot \ln \left( \frac{Z + \left( 1 - \sqrt{2} \right) \frac{bP}{RT}}{Z + \left( 1 + \sqrt{2} \right) \frac{bP}{RT}} \right)$$
(20)

where *a* and *b* are parameters defined by P-R EOS; they are functions of critical pressure, critical temperature, composition, acentric factor, binary interaction coefficient, etc. For each phase, Equation (20) can be calculated according to the phase pressure and mole fraction  $x_i$  within this phase.

Equilibrium ratio  $K_i = y_i / x_i$  for component *i* is usually used to solve Rachford-Rice (R-R) equation (Rachford Jr and Rice, 1952) for flash calculation.

$$\sum_{i=1}^{N_c} \frac{z_i (K_i - 1)}{\widetilde{N_L} + K_i (1 - \widetilde{N_L})} = 0$$
(21)

where  $\widetilde{N_L}$  is the mole fraction of liquid phase. And the initial guesses of *K* factors could be estimated from the Wilson's equation (Wilson, 1968):

$$K_i = \frac{P_{c_i}}{P} exp\left[5.37(1+\omega_i)\left(1-\frac{T_{c_i}}{T}\right)\right]$$
(22)

where  $\omega_i$  is the acentric factor of component *i*.

The initial guess of K factor are inputted in Rachford-Rice equation for flash calculation; and its outputs are used in Equation (20) to evaluate the fugacity coefficients, which are further used to update the K factor according to the relationships of Equation (17) and (18) by

$$K_i = \frac{y_i}{x_i} = \frac{P^L}{P^V} \frac{\phi_i^L}{\phi_i^V}$$
(23)

In conventional reservoirs simulation, the above relationship is usually treated with neglected capillary pressure by assuming  $K_i = \phi_i^L / \phi_i^V$ , which is not valid in unconventional system. The pressures of two phases are correlated by capillary pressure as

$$P^V = P^L + P_c \tag{24}$$

On the other hand, interfacial tension (IFT) is a function of composition and should be updated according to flash calculation results. Weinaug and Katz (1943) proposed a simple molar averaging for the parachor to calculate the IFT of compositional system as

$$\sigma^{\frac{1}{4}} = \sum_{i=1}^{N_c} P_{\sigma i} \left( x_i \rho_M^L - y_i \rho_M^V \right)$$
(25)

Based on above analysis and relationships, the VLE calculation including capillary pressure follows steps below:

- 1) Estimate initial *K* values with Equation (22);
- 2) Plug the *K* values into *R*-*R* equations (21);
- 3) Calculate fugacity coefficients with results of step (2) using Equation (20);
- 4) Calculate IFT with results of step (2) with Equation (25) and updated capillary pressure;
- 5) Update *K* values with Equation (23);

- 6) Check the convergence criteria by comparing updated *K* values and last step *K* values; If not converged, go back to step 2 with updated *K* values;
- 7) Repeat step (2) to (6) until *K* values are converged.

The above steps are outline as Figure 2; it includes above steps and also coupled geomechanics effects, which are discussed in the next section.



Figure 2: The VLE calculation process including geomechanical and pore confining effects

#### **Coupled Geomechanics and Pore Confinement Effects**

The stress-dependent properties of reservoir rock are subject to change during reservoir depletion. In this model we consider reservoir permeability and porosity are functions of effective stress. The researchers have been actively investigating the correlations between effective stress and rock properties for a variety of rock types. The shale rocks are intensively under laboratory investigation for the stress-dependent properties. In general, the relationship between stress and rock properties can be represented as

$$\sigma = S_m - \alpha P \tag{26}$$

$$k = k(\sigma) \tag{27}$$

$$\phi = \phi(\sigma) \tag{28}$$

$$V_b = V_b(\varepsilon_v) \tag{29}$$

where  $\sigma$  is the effective stress;  $\alpha$  is Biot coefficient; k and  $\phi$  are rock permeability and porosity respectively;  $V_b$  is the bulk volume with function of volumetric strain. The mean stress and volumetric strain are solved with numerical methods in our model, and the rock properties are dynamically updated accordingly.

Capillary pressure is another function related to stress, and it has a significant effect on the VLE calculation as analyzed above. Capillary pressure is usually determined by the well-known Young-Laplace equation:

$$P_c = \frac{2\sigma cos\theta}{r} \tag{30}$$

where  $\sigma$  is the IFT; *r* is the pore or pore-throat size; and  $\theta$  is the contact angle. Since it is difficult to build the direct relationship between pore space and the effective stress, the Leverett J-function approach (Leverett, 1941) as Equation (31) is used to obtain the capillary pressure based on measured reference capillary pressure, plus the results of current saturation, stress-dependent permeability and porosity, and IFT.

$$P_c(S) = \frac{J(S)\sigma cos\theta}{\sqrt{k/\phi}}$$
(31)

where S is the saturation of wetting phase;  $\sigma$  is the surface tension;  $\theta$  is the contact angle; k and  $\phi$  are permeability and porosity respectively. J(S) is the J function, which is a dimensionless number and used to correlate capillary pressure data for the reservoir rocks with same lithology.

Figure 2 illustrates the coupled process between pore confining (capillary pressure) and geomechanical effects. The conventional VLE calculations neglect the capillary effects by assume  $K_i = \phi_i^L / \phi_i^V$ , which is not valid in unconventional reservoirs. In our model the capillary pressure is included and subjected to change through J-function with stress-dependent permeability and porosity.

## **Results and Discussions**

In this section, we present an example to illustrate the stress and pore confinement impacts on the reservoir fluid phase behaviors. Especially for the bubble point system, like tight oil reservoirs, the bubble point pressure is suppressed due to the large capillary pressure. The accurate bubble point pressure is essential for estimation of reservoir performance and recovery factor. We take the Bakken oil as the example to calculate the bubble point pressure with capillary effects, specifically the increased capillary effects due to rock deformation.

We summarize the relationship between pore throat size and effective stress change, and the composition of Bakken oil from the published data (Chu et al., 2012; Wang et al., 2013; Nojabaei, 2013). Table 1 shows the pore-throat size as a function of effective stress change, and the corresponding estimated capillary pressure. Table 2 and 3 give the properties of Bakken oil composition, which are used in the P-R EOS for bubble point calculation. The Equation (32) is used to find the bubble point pressure through bisection search assuming the reservoir temperature is constant at 240 F.

$$\sum_{i=1}^{N_c} z_i K_i = 1$$
(32)

Table 1: Relationship of between	pore throat size/capillary	pressure and effective stress change f	for Bakken (Chu et al., 2012; '	Wang et al., 2013)
----------------------------------	----------------------------	--	---------------------------------	--------------------

Effective Stress Change (psi)	Pore Throat Size (nm)	Capillary Pressure(psi)
0	50	102.20
900	40	127.75
2000	30	170.33
4000	20	225.30
7000	10	511.00

## URTeC 1923960

Table 2: Bakken oil compositional data (Nojabaei et al., 2013)							
Component	Molar	Critical	Critical	Acentric	Molar		
	Fraction	Pressure (psi)	Temperature (R)	Factor	Weight		
C1	0.36736	655.02	335.336	0.0102	16.535		
C2	0.14885	721.99	549.969	0.1028	30.433		
C3	0.09334	615.76	665.97	0.152	44.097		
C4	0.05751	546.46	759.208	0.1894	58.124		
C5-C6	0.06406	461.29	875.479	0.2684	78.295		
C7-C12	0.15854	363.34	1053.25	0.4291	120.562		
C13-C21	0.0733	249.61	1332.095	0.7203	220.716		
C22-C80	0.03704	190.12	1844.491	1.0159	443.518		

Table 3:Binary interaction coefficients of Bakken oil composition

	C1	C2	C3	C4	C5-C6	C7-C12	C13-C21	C22-C80
C1	0	0.005	0.0035	0.0035	0.0037	0.0033	0.0033	0.0033
C2	0.005	0	0.0031	0.0031	0.0031	0.0026	0.0026	0.0026
C3	0.0035	0.0031	0	0	0	0	0	0
C4	0.0035	0.0031	0	0	0	0	0	0
C5-C6	0.0037	0.0031	0	0	0	0	0	0
C7-C12	0.0033	0.0026	0	0	0	0	0	0
C13-C21	0.0033	0.0026	0	0	0	0	0	0
C22-C80	0.0033	0.0026	0	0	0	0	0	0

Table 4: Calculated bubble point pressure with P-R EOS

Effective Stress	Pore Throat Size	Capillary Pressure	Bubble Point Pressure
Change (psi)	(nm)	(psi)	(psi)
Without pore	N/A	0	2793.7
confinement			
0	50	102.20	2520.8
900	40	127.75	2457.4
2000	30	170.33	2352.8
4000	20	225.30	2154.0
7000	10	511.00	1595.8



Figure 3: Calculated bubble point pressure for Bakken oil

#### URTeC 1923960

With above data as input, the bubble point pressures under pore confinement and stress effects are calculate as Table 4 and plotted in Figure 3. The bubble point pressure is constant to the change of effective stress without considering pore confinement as in the conventional reservoirs, as the dash line in Figure 3. However, the capillary pressure of nanometers pores of unconventional reservoir rocks suppresses the bubble point pressure; and the geomechanical effect due to increase of effective stress intensifies the suppression. For example, the bubble point pressure is about 2794 psi without including capillarity effect; the suppressed bubble point pressure is about 2521 psi with capillary pressure effect. The bubble point pressure keeps decreasing as the change of effective stress, which induces smaller pore throat size and larger capillary pressure. The final bubble point pressure could reach as low as 1596 psi with 7000 psi change of effective stress.

## Conclusions

In this paper we introduce a coupled geomechanics and pore confinement model for unconventional reservoir simulation. The geomechanical model is developed based on fundamental theory of elasticity extended to porous media, and a momentum conservation equation relating mean stress, pressure and temperature is derived. The pore confining effect is treated through incorporating large capillary pressure into the VLE calculation with Peng-Robinson EOS, and results in suppressed bubble point pressure. The increase of the effective stress further exaggerates the suppression effect. In addition, the time and space discretization is introduced so that our model could be readily implemented with numerical method. We take Bakken oil as the example to demonstrate the effects of capillary pressure and stress on fluid phase behavior in unconventional reservoirs. It confirmed that the geomechanical and pore confining processes may make a significant difference.

The effects of rock compaction and pore confinement are not constant during reservoir depletion because stress, pore pressure and rock properties keep changing. Those complex reservoir behaviors must be captured for accurate EUR (estimated ultimate recovery) estimation. For example, the calculated bubble point pressure without capillarity effect is much higher, which would result in underestimation for the single phase liquid production. Although the example presented is a tight oil reservoir, the theoretical model in this paper can be generally applied to both bubble-point (tight oil) and dew-point (gas condensate) systems for unconventional reservoirs.

## Acknowledgement

The authors would like to extend thanks to Energy Modeling Group (EMG) of Petroleum Engineering Department at Colorado School of Mines and Foundation CMG for the support and sponsor of this research.

### References

Chu, L., Ye, P., Harmawan, I.S., Du, L. and Shepard, L.R., 2012. Characterizing and Simulating the Nonstationariness and Nonlinearity in Unconventional Oil Reservoirs: Bakken Application, SPE Canadian Unconventional Resources Conference. Society of Petroleum Engineers.

Danesh, A., 1998. PVT and phase behaviour of petroleum reservoir fluids, 47. Elsevier.

Du, L. and Chu, L., 2012. Understanding Anomalous Phase Behavior in Unconventional Oil Reservoirs, SPE Canadian Unconventional Resources Conference. Society of Petroleum Engineers, Calgary, Canada.

Firincioglu, T., Ozkan, E. and Ozgen, C., 2012. Thermodynamics of Multiphase Flow in Unconventional Liquids-Rich Reservoirs, SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers.

Han, G., Gutierrez, M. and Schmitz, P., 2013. Stress-Dependent Flow Mechanical and Acoustic Properties for an Unconventional Oil Reservoir Rock, Unconventional Resources Technology Conference. Society of Petroleum Engineers.

Honarpour, M.M., Nagarajan, N., Orangi, A., Arasteh, F. and Yao, Z., 2012. Characterization of Critical Fluid, Rock & Rock-Fluid Properties Impact on Reservoir Performance of Liquid-Rich Shales, Paper SPE 158042 presented at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, pp. 8-10.

Jaeger, J.C., Cook, N.G. and Zimmerman, R., 2007. Fundamentals of rock mechanics. John Wiley & Sons.

Leverett, M., 1941. Capillary Behavior in Porous Solids. Transactions of the AIME, 142(01): 152-169.

Mokhtari, M., Alqahtani, A.A., Tutuncu, A.N. and Yin, X., 2013. Stress-Dependent Permeability Anisotropy and Wettability of Shale Resources, Unconventional Resources Technology Conference. Society of Petroleum Engineers.

Nojabaei, B., Johns, R.T. and Chu, L., 2013. Effect of Capillary Pressure on Fluid Density and Phase Behavior in Tight Rocks and Shales. SPE Reservoir Evaluation & Engineering, August: 281 - 289.

Orangi, A., Nagarajan, N.R., Honarpour, M.M. and Rosenzweig, J.J., 2011. Unconventional Shale Oil and Gas-Condensate Reservoir Production Impact of Rock Fluid and Hydraulic Fractures, SPE Hydraulic Fracturing Technology Conference. Society of Petroleum Engineers.

Pang, J., Zuo, J.Y., Zhang, D. and Du, L., Impact of Porous Media on Saturation Pressures of Gas and Oil in Tight Reservoirs. Society of Petroleum Engineers.

Pruess, K., 1991. TOUGH2: A general-purpose numerical simulator for multiphase fluid and heat flow, Lawrence Berkeley Lab., CA (United States).

Rachford Jr, H. and Rice, J., 1952. Procedure for use of electronic digital computers in calculating flash vaporization hydrocarbon equilibrium. Journal of Petroleum Technology, 4(10): 19-3.

Sigmund, P., Dranchuk, P., Morrow, N. and Purvis, R., 1973. Retrograde condensation in porous media. Society of Petroleum Engineers Journal, 13(02): 93-104.

Wang, Y., Yan, B. and Killough, J., 2013. Compositional Modeling of Tight Oil Using Dynamic Nanopore Properties, SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers.

Weinaug, C.F. and Katz, D.L., 1943. Surface tensions of methane-propane mixtures. Industrial & Engineering Chemistry, 35(2): 239-246.

Wilson, G.M., 1968. A modified Redlich-Kwong equation of state, application to general physical data calculations, 65th National AIChE Meeting, Cleveland, OH.

Wu, Y.-S. and Qin, G., 2009. A generalized numerical approach for modeling multiphase flow and transport in fractured porous media. Communications in Computational Physics, 6(1): 85.

Zoback, M.D., 2007. Reservoir geomechanics. Cambridge University Press.