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Application of numerical modeling of a gas condensate recovery using gas cycling

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ABSTRACT

The two most popular methods for extracting gas condensate from reservoirs are the gas cycle and natural depletion. The first method is the quickest and least expensive, but it also produces a significant amount of stagnant liquid drop-out that is lost during the recovery process. Gas cycling, which maintains the same pressure while re-evaporating the condensed oil, boosts liquid recovery. Yet, reservoir heterogeneities and money problems may make implementation more challenging. Pressure maintenance has been opposed in favor of water injection. In order to assess the latter method's viability, this thesis compares its efficacy to that of the gas cycle and natural depletion. An Equation of State (EOS)-based multi-phase, multi-component compositional technique was used to accomplish this. It was important to make changes to lower the cost of simulation and raise the physical realism of the projections before executing full scale recovery calculations. In order to reduce the amount of elements that describe hydrocarbon fluids, regression-based EOS software was created. The findings of the present study imply that even three components might be adequate to preserve the thermodynamic consistency of the predictions. By solving the pressure equation with a powerful algorithm, the cost of simulation might be decreased. In the prior investigation, several sparsity conserving techniques were used and conventional direct approaches were investigated. To deal with the drainage and imbibition cycles that happen during water injection, a relative permeability hysteresis methodology was also integrated into the procedure. According to the findings, recovery forecasts may be off in the absence of the hysteresis effect. To determine how sensitive the process of water injection was to different fluid and rock parameters, the approach was then applied to a variety of representative reservoir simulations. The effectiveness of the suggested approach was also compared to that of more widely used ones.

Keywords: Cycling, gas, condensate, recovery, modeling

1. INTRODUCTION

The liquid condenses from the gas in a gas-condensate reservoir when the well's bottom-hole pressure (BHP) drops below the dew point pressure. In addition to losing precious liquid with heavier constituents near the wellbore, the dropped-out liquid also causes an obstruction that reduces well deliverability. Retrograde condensation's impact on decreased well deliverability has been carefully examined for decades (El-Banbi et al., 2000). Fevang and Whitson, (1996) demonstrated that an accurate pseudo pressure approach can be used to determine the loss in well deliverability of gas-condensate wells. Gas cycling is a significant way of pressure maintenance in optimizing hydrocarbon recovery and energy-development. The loss in well deliverability will be underestimated if rate is calculated using the conventional technique (mobilities measured at grid block pressure). The validity and precision of the pseudo pressure approach for multilayer systems with considerable permeability and gas-condensate composition heterogeneity were further confirmed by Singh and Whitson, (2010). Condensate-banking phenomenon was modeled by Tran et al., (2015) using both pseudo pressure and local grid refinement, which was then applied to horizontal and hydraulic fracturing design. The condensate banking will be lessened thanks to pressure maintenance when gas-condensate reservoirs are beneath a bottom natural aquifer or water influx. In the past, researchers have examined the impact of water incursion on gas and retrograde condensate reserves (Ayyalasomayajula et al., 2005; Ali, 2014; Roussennac, 2001; Izuma and Nwosu, 2014; Ogolo et al., 2014). The eventual gas and oil recoveries in a gas-condensate reservoir might dramatically rise depending on the size and durability of the aquifer (Ali, 2014). Unchecked water production, however, can destroy gas wells, leaving a sizable amount of gas in the reservoir. In gas reservoirs with bottom water drive, reservoir characteristics including vertical permeability, aquifer size, non-Darcy flow effect, density of perforation and flow behind casing have a significant impact on water coning and water output. Both Cartesian and radial models have been used in earlier studies to simulate the effects of condensate banking or water ingress on gas condensate reservoirs. To the authors' knowledge, however, there is no workflow for creating a benchmarked simulation model for a gas-condensate reservoir. In this research, a process for developing a benchmarked model for a gas-condensate reservoir subject to bottom water intrusion is provided. Subsequently, a thorough analysis of the effects of reservoir and water aquifer parameters on the eventual recoveries of gas-condensate reservoirs was conducted. A typical gas-condensate reservoir's pressure at the time of discovery may have been above or very near the critical pressure. There is only one type of gas available for now. The bottom whole pressure in a flowing well falls below the fluid's dew point as production rises, however and a liquid hydrocarbon phase form. In gas condensate reservoirs, retrograde condensation occurs when the pressure drops below the dew point pressure. Small recoveries result from capillary trapping or leaving behind of the liquid dropout due to the limited relative permeability. By injecting gas to raise the reservoir pressure above the dew point pressure, retrograde condensation can be prevented. Dry hydrocarbon gases work best for injection due to their physical properties. But dry gas is pricey and re-injection isn't always an option. Nitrogen is a viable choice since it is widely available, reasonably priced and has good injection properties (safe, non-corrosive, environment-friendly). In a similar line, the major issue faced since the discovery of gas condensate resources has been to maximize the liquid recovery from those reservoirs. Spontaneous depletion and various forms of gas cycling are the main recovery methods employed for this purpose (Moradi et al., 2020). As soon as the pressure drops below the dew point, a liquid phase occurs; hence the liquid recoveries obtained by natural depletion are typically poor. Usually, this quantity is insufficient to fully saturate the oil, therefore it is lost. Together with these production issues, depletion can also result in substantial fluctuations in the loading of liquid and gas plants over the course of a project's life and a deterioration in the deliver abilities of producing wells because of condensate building close to well bores. This approach may still be viable in spite of all of these drawbacks, particularly for condensates with low liquid yield or reservoirs with extreme heterogeneities that impede injection. The quickest recovery mechanism, with significant initial capital flows, is depletion. Gas cycling is a method for increasing liquid recoveries that involves separating surface-produced condensate gas from the liquid phase and reintroducing it. The reservoir pressure is occasionally maintained by purchasing additional make-up gas. The cycle procedure starts when the dry gas flow passes through and the condensate content of the production stream drops below the economic threshold. Following this, the reservoir is naturally exhausted. This system's widespread use since the 1900s and high microscopic displacement efficiency (up to 80–90 percent) serve as its primary justifications for use. Despite the mechanism's enticing features, its performance is affected by the reservoir's degree of stratification and continuity, gravity override and operational conditions. The most notable is that early cessation of gas cycle may be required due to premature gas breakthrough, which has been documented in numerous papers. The t economics will be important in selecting a production method. Since there has been a significant growth in gas consumption over the past ten years, natural gas prices have virtually caught up to those of crude oil. Any gasoline price hike might be painful. Because to the low liquid recoveries in natural depletion and the problems with gas cycling, the current research was initiated to investigate alternative ways for increasing recovery from gas condensate reservoirs. Nitrogen injection, CO2 injection or even air injection has been proposed as potential solutions in several researches. Water injection followed by blow down has been suggested as a recovery approach by Sun and Hu, 2003. This dissertation compares the performance of water injection to more conventional methods like natural depletion and the gas cycle while also conducting a theoretical investigation into the application of the technique to gas condensate reservoirs.

Gas condensate reservoir

Gas condensate production can be thought of as a step between oil and gas production. A small amount of liquid is condensed in surface separators based on the GOR from the majority of gas condensate production. The ancient names for the fluid, distillate and oil, are still used occasionally. Gas condensate reservoirs can be broadly categorized as those that generate stock tank liquids with gravities greater than 45 °API that are light colored or colorless.

There are reserves for both wet gas and retrograde condensate. Both kinds of reservoirs' fluid begin their lives in a single-phase state. Retrograde reservoirs differ in that liquid can form there. Most known gas condensate reservoirs are located between the temperatures of 200 and 400 degrees Fahrenheit and pressures of 3000 to 6000 psi. This leads to a number of circumstances that could alter the physical behavior of the gas condensate deposit, along with a wide range of compositional ranges.

Recovery from Gas Condensate Reservoirs

Once the original hydrocarbon in situ has been computed, the recovery of the gas and condensate may be determined. These recoveries will be based on a predetermined abandonment pressure. As soon as the pressure in the reservoir drops below the dew point, liquid will start to leak out and most of it won't be retrieved. This drop-out causes a decrease in the surface composition of heavy hydrocarbons when the reservoir is exhausted. A recovery by depletion estimate must be established before the viability of maintaining pressure using a specific method can be assessed. Five single-phase reservoir fluids' characteristics and make-up. Lean or dry gas is often indicated by GOR > 100,000 scf/bbl, however this value is not set in stone.

Volatile oil sits in the center of black oil and gas condensate (sometimes called wet gas). High GORs are thought to be a reliable predictor of the general composition of a reservoir fluid since they show low pentane plus compositions. There is a general rising tendency in GOR as pressure in black oil, volatile oil and gas condensate reservoirs decreases because of the reservoir mechanism that restricts the flow of oil and gas to the wellbore. An increase in GOR can be found in two-phase reservoirs, depending on the reservoir circumstances. The downward coning of gas from the underlying gas cap may happen when a well is built in the oil zone and the oil and gas zones are only a few feet apart, raising GOR.

Due to the shortcomings of the inverted black oil models, which were discussed in the previous section, a compositional technique is used to mimic the production mechanisms of the gas condensate reservoir. The main causes of the com positional simulation's high cost were also discussed. For the sake of brevity, these criteria can be classified as follows to better reflect the problem areas of this investigation: Areas of generic compositional simulation problem: Costs include the linearized equations' solution, the PVT representation of hydrocarbon fluids, the acceleration of the entire process and the problem with numerical diffusion (or dispersion). Problem areas specific to water injection include: efficient use of the EOS. By correctly defining the relative permeability's, demonstrated the accuracy of my predictions. As a result, a mathematical model was created for the recovery of gas condensate utilizing gas recycling. This research aims to provide a thermodynamic diffusion model-based mathematical model of dry gas movement. This mathematical model was used to examine how dry gas was distributed within the condensate gas resource.

To fulfill the study's objective, the following goals were used: To investigate the lean gas recycling into the reservoir to enhance condensate recovery minimizing the appearance of a reservoir condensate at reservoir conditions so that the associated loss of surface condensate and impairment in gas production around the wellbore region can be avoided.

To identify the key variables that influence productivity of a gas condensate reservoir under a gas recycling

To develop a numerical model

Determine effects of relative permeability and critical condensate saturation on gas condensate recovery.

2. METHODOLOGY

Although using compositional models is more expensive than using classic black oil models, they provide the most accurate simulation of the processes involved in recovering gas condensate from reservoirs. There is hence a considerable motivation to research and consider methods for enhancing their effectiveness, numerical accuracy and predictability. Both the mathematical model and the approach to solving it will be discussed. The following section will cover methods such as proper linearization of the flow equations, local saturation iterations to fix consistency issues with saturation calculations, optimization of EOS usage, solution of concurrent linear algebraic equations, and other advancements like the creation of a regression-based EOS program and handling of relative permeability. These methods will be used to examine the reliability and accuracy of process simulations for recovering gas condensate.

Depending on how the partial differential equations describing the flow of fluid in porous media are solved, compositional simulators can be categorized into the following groups:

IMPES, Completely Implicit (Implicit Pressure, Explicit Saturation)

The cost of the fully implicit model described extremely high, making its use impractical for large domains with numerous components. It also requires the simultaneous solution of at least N + 1 finite difference equations (N being the number of components) at any given point in the reservoir domain.

Just the pressure equation must be simultaneously solved by IMPES simulators. As a result, conducting economically viable reservoir-scale modeling experiments is possible.

The accuracy of compositional simulator predictions is strongly influenced by the technique employed to calculate the thermodynamic characteristics of the reservoir fluid and EOS-based simulators appear to be the most usual in compositional research in this regard. To accomplish the goal of the study, a multi-component, multi-phase and multi-dimensional IMPES simulation approach based on Equation of State (EOS) is being used.

Model of Mathematical

Be aware that the reservoir under discussion contains N and M components. Applying a molar balance and Darcy's Law to a single component yields the generalized for-m of balance equations below;

$$\nabla\left[\sum_{m}^{M} C_{mn}\left(\frac{kkrm}{\text{Ų}\, m}\xi_m\right)\ \nabla\ \Phi_m\right]+$$

$$\left\{\sum C_{mn}\,\xi\ \ _{m\ qm}\right\}\delta_{(\times)}=\frac{\partial}{\partial t}\ \emptyset\left[Z_n\sum_m^M \xi_m\, S_m\right] \qquad 1$$

Where C_mn= mole fraction of component n in phase m,

k = absolute permeability

krm = relative permeability to phase m

Ųm = viscosity of phase m

ξ_m = molar density of phase m

Φ_m= flow potential of phase m

qm = source or sink for mth phase

Zn = overall mole fraction of component n

Sm = saturation of phase m

δ_ ((×)) = Dirac delta function, production or injection at cell x: (x) = 1

no ^{11} ^{11} ^{11} ^{11} ^{11} ^{11}: (x) = 0

$\underset{\sim}{\nabla}$ = Del operator which is defined as

$$\left(\frac{\partial}{\partial\times}i+\frac{\partial}{\partial y}j+\frac{\partial}{\partial t}k\right) \qquad 1.1$$

Constraint Equations are

$$\sum_m C_{mn}=1 \quad for\ m=!,\ldots.,M\ (i,e.\ for\ all\ \ phases) \qquad 1.2$$

$$\sum_n Z_n=1 \qquad \ldots.1.3$$

$$Z_n=1\sum_n\sum_m C_{mn}V_m \qquad \ldots\ldots.1.4$$

$$\sum_n \quad V_m=1 \qquad \ldots\ldots\ldots 1.5$$

$$V_m=\frac{\xi\ \ _m S_n}{\sum_m^M \xi\ \ _m S_m} \qquad \ldots\ldots\ldots 1.6$$

$$P_c=P^{nwp}\ \ -P^{wp} \qquad \ldots\ldots\ldots.1.7$$

$$V\ \Phi_m=\nabla\ \ P_m-\text{Ɣ}_m\quad \nabla\quad 0 \qquad \ldots\ldots\ldots..1.8$$

$$\sum_m^M S_m=1.0 \qquad \ldots\ldots 1.9$$

Procedural steps

The developed numerical procedure is divided into two phases; Initialization Phase-In this phase, input data relating to reservoir dimensions and geometry, reservoir type (i.e., oil, gas or oil with gas cap), rock and fluid properties are processed to yield initial reservoir pressure, saturation, composition and so on for each grid block. Prediction Phase-where reservoir performance calculations are performed time step by time step using prescribed reservoir production data

Methods for Improving the Procedure's Efficiency and Accuracy

The techniques developed to improve the numerical efficiency and accuracy of the com positional procedure will be discussed in this section. The following is how the discussion will proceed:

(i) Dimensionless density function treatment
(ii) Local Saturation Iterations
(iii) EOS usage optimization
(iv) Simultaneous equation solution
(v) Other enhancements

Dimension Density Function Treatment

The dimensionless density function used to formulate the IMPES pressure equation is given in Equation 3.1 and 3.2

$$\propto (Po)^{k+1} = \left[\frac{\xi w\ (1-Sw)}{\sum_m^{M-1} \xi m\ \ Sm}\right] \qquad 3.1$$

This expression clearly shows that it is a strong function of both pressure and saturations. In the literature a similar function is used with the exception that the molar density in the $\propto$ equation is replaced by bw (water formation volume factor). They used finite difference approximation to the derivative of $\propto (Po)$as follows:

$$\left(\frac{\partial \propto (Po)^k}{\partial Po}\right) = \frac{\propto (Po)^k - \propto (Po)^{k-1}}{Po^k - Po^{k-1}} \qquad --- \ 3.2$$

This method works well if a good initial estimate of is provided. Severe convergence problems can arise if this initial estimate causes the solution of Equation 3.23 to deviate from the exact solution. This is especially true for gas condensate problems, in which the liquid phase condenses as pressure falls below the dew point. This finite difference approach to estimate the pressure derivative of <*x* initially arose with the use of the convergence pressure concepts for the phase equilibrium calculations. This method may result in inconsistencies in the calculation of various fluid properties.

Because equation of state calculation provides a consistent approach to estimating these properties, an analytic derivative of the dimensionless density equation can be derived. The Amoco-Redlich-Kwong EOS will be used as an example here to obtain the desired derivatives.

Thus, the derivative of Equation 3.5 is as follows:

$$\frac{\partial \propto (Po)}{\partial P} = \left(\sum_m^{M-1} Sm\right) \frac{\left[\left(\sum_m^{M-1} \xi m\ \ Sm\right)\frac{\partial \xi\ w}{\partial P} - w\ \left(\sum_m^{M-1}\ Sm \frac{\partial \xi\ m}{\partial P}\right)\right]}{\left[\sum_m^{M-1} \xi\ m\ \ Sm\right]^2} \qquad ---3.3$$

Term $\frac{\partial \xi\ m}{\partial P}$ is calculated using a cubic EOS, and once determined, it is possible to solve Equation 3.3. The following expression defines a phase's molar density.

$$\xi m\ = \frac{P}{Zm\ \ RT} \ --- \qquad 3.4$$

The derivative of Equation 3.23a will then be

$$\frac{\partial \xi\ m}{\partial P} = \frac{1}{Zm\ \ RT}\left[1 - \frac{P}{Zm}\frac{\partial Zm}{\partial P}\right] \qquad --- \quad 3.5$$

Amoco-Redlich-Kwong EOS in cubic form is

$$Zm^{\ 3} - (1 - Bm)Zm^{\ 2} + \ (Am - 3Bm^{\ 2} - 2Bm)Zn - (AmBm - Bm^2 - Bm^{\ 3}) = \ 0 \qquad ---3.6$$

And the total derivative is:

$$dZm = \frac{\partial Zm}{\partial Am}dAm = \frac{\partial Zm}{\partial Bm}\ \ dBm \qquad --- \quad 3.7$$

The derivative w.r. to pressure will then be

$$\frac{\partial Zm}{\partial P} = \frac{\partial Zm}{\partial Am}\frac{\partial Am}{\partial P} + \frac{\partial Zm}{\partial Bm}\frac{\partial Bm}{\partial P} \qquad --- \quad 3.8$$

Where

$$\frac{\partial Zm}{\partial Bm} = \frac{Am + Zm \quad (2Bm + 1)}{3Zm^{2} - 2Zm + (Am - Bm^{2} - Bm)} \qquad --- \qquad 3.9$$

$$\frac{\partial Zm}{\partial Am} = \frac{Zm \quad Bm}{3Zm^{2} - 2\ Zm + (Am - 3Bm^{2} - 2Bm)} \qquad --- \qquad 3.10$$

Similar forms can also be derived for other Equations of State. When a tight convergence tolerance is required, this approach has the disadvantage of slow convergence. For example, in a gas cycling process simulation in gas condensate recovery studies in a 200-grid block domain, the pressure equation required approximately 15 iterations to converge to the desired tolerance. This contrasts negatively with the number of iterations required by the Lal, (2003) scheme for the same problem.

The following procedure is used to reap the benefits of both of the aforementioned approaches.

(i) use analytical derivative calculations as an initial guess, (ii) switch to finite's difference approach, If with the caveat that if this approach leads to non-monotonic convergence, revert to using analytical derivative calculations.

Analytic derivatives

This method was used throughout this research and resulted in significant gains. For example, for the same problem as above, the maximum number of iterations required was 4 (when the average reservoir pressure reached the dew point of the reservoir fluid), while the average number of iterations per time step was less than.

Iteration of Saturation

If the number of iterations in a Newtonian iteration procedure reaches infinity, the residuals of the pressure equation become zero. In practice, iterations must terminate as soon as the residuals meet certain tolerance limits. As a result, under three phase flow conditions, for example, the sum of the phase saturations may not add up to unity, resulting in severe material balance errors. In practice, M-l phase saturations are typically calculated using Equations 3.9 and 3.10, with the Mth phase saturation obtained by subtracting the sum of (M - 1) saturations from unity. As a result, the calculated saturations are now inconsistent with the pressure field. In cases where the saturation of one phase is very small, such as in gas condensate studies, this type of approach can be very unsatisfactory. In the numerical procedure, the following technique is used to overcome this problem.

$$Let\ \Delta S\ be = \textstyle\sum_{m}^{M} Sm - 1 \qquad 4.0$$

EOS Usage Optimization

The compositions of the hydrocarbon fluid remain essentially the same in the case of water injection because the reservoir pressure is kept above the dew point and there exists a single hydrocarbon phase that is in gaseous form. To reduce the cost of simulation under these conditions, the following simplification is possible.

(i) Because the displacement process is isothermal and the fluid compositions are constant, the molar gas densities depend only on pressure and can be calculated without resorting to full equation of state calculations. They can be found in look-up tables or by using a cubic equation solver. The latter method is chosen for the smoothness of the calculations.

(ii) Because an oil phase does not exist above dew point, there is no need to calculate oil molar densities. Also, oil phase transmissibility can be removed from the pressure equation, reducing it to a two-phase (gas/water) case.

(iii) The number of moles of each component in the hydrocarbon phase is calculated using standard procedure.

$$V_R \emptyset^{k+1}(1 - Sw^{k+1}) Ƶn^{k+1} \qquad --- \qquad 4.1$$

Where $Ƶn^{k+1}$is obtained using Equation 3.16. In this case there is no need to use Equation 3.16 since overall component mole fractions remain the same. Thus, the cost of simulation is further reduced.

Solution of the Simultaneous Equations

As the number of grid blocks raises, the cost of doing overall equilibrium computations increases linearly while the cost of solving linear equations rises exponentially. As a result, effective solution methods are particularly desirable for reducing calculation costs in extensive domain research. The characteristics of the coefficient matrix play a significant role in determining the kind of solution (direct or iterative). Iterative methods perform well when the coefficient matrix exhibits a high diagonal dominance.

According to Equation 3.10, the diagonal dominance is governed by the term C7 and large positive values of this parameter are favourable to iterative approaches. However, Op is impacted by density gradients and negative density gradients can develop, leading in the loss of diagonal dominance. Usually, mass conservation flow equations are in this situation. A mole conservation form of the equations is less likely to yield a negative molar density gradient since adding more moles to a grid block is typically related with adding pressure. Negative density gradients could still increase in a simulation of a gas condensate reservoir, though. There can be no general assurance of the diagonal dominance of the pressure equations, as also note.

The employment of iterative approaches in com positional simulators (apart from semi-direct, semi-iterative techniques like preconditioned variants of Conjugate Gradient Techniques) becomes troublesome when the general as symmetry of the coefficient matrix is taken into consideration (Jamiolahmady et al., 2000). In one particular gas condensate depletion simulation research, for instance, it took over 200 iterations to solve the pressure equation using the SIP iterative solver for a domain of 100 grid blocks. This research's primary objective was to determine whether it would be possible to use effective sparse matrix solution techniques and matrix ordering approaches to solve reservoir problems of this kind.

Both the mathematics challenge of efficient solution and the petroleum engineering problem of gas condensate investigations were not pursued due to the research limited resources and overall time frame.

3. DISCUSSION

Vapour Liquid Equilibria and Equation of State (EOS)

The principles of vapour-liquid equilibrium (VLE) were defined by Gibbs, who said that a vapour and a liquid are in equilibrium if their pressure, temperature and chemical potentials are equal. Chemical potential is the shift in a system's overall free energy caused by a change in the quantity of one particular component while the pressure, temperature and quantities of other components stay constant. Gibbs also described the Phase Rule of a system. As a result, the number of coexisting phases and degrees of freedom (the number of independent properties that must be defined) necessary to fix all other properties are determined.

The formula is as follows:

$$F = N + 2 - M \qquad 4.2$$

Where N stands for the number of components, M for the number of phases and F for the number of degrees of freedom. According to the phase rule, a single component system can have a maximum of three phases under equilibrium conditions. Chemical potential, however, is a challenging thermodynamic term with no clear explanation. In order to represent chemical potential proposed the alternative quantity of fugacity. Because each component's fugacity in an ideal gas mixture equals its partial pressure, fugacity can be regarded of as a thermodynamic pressure. It can be viewed as partial pressure that has been adjusted for non-ideal behavior in real mixtures. Using these definitions, it is clear that each component's fugacity in the current phases must be equal under equilibrium conditions.

The following is an analytical equation that defines fugacity:

$$f = P \ \exp\left[-\frac{1}{RT}\int_{0}^{P}\left(\frac{RT}{P} - Vl\right)\, dP\right] \qquad --- 4.3$$

R = gas constant, T = absolute temperature, P = total pressure and V = molar volume.

When utilizing the fugacity equation, determining the molar volume VI is a substantial task. In complicated systems, the challenge is even greater. The logical and widely used method for achieving this goal is Equation of State, with precision and validity (especially for complicated mixes) being crucial. In the sections of this article that follow, the use of the Equation of State in VLE calculations for two-phase systems will be covered first. The application to three-phase equilibrium calculations and the method's general drawbacks will be discussed after some numerical experiments are presented. To increase the predictive power of EOS and lower the cost of computations for compositional simulation, the theory and some application outcomes of the Regression Based EOS technique will be presented. The explanation that follows will only cover equations of state with two parameters. When accurate compositional computations are necessary, more complicated equations are both feasible and valuable. The two parameter equations offer an acceptable trade-off between complexity and accuracy in the current study, since the compositional calculation is only a small portion of the entire computational technique and are probably as exact as the typically available data would justify.

Equation of State (EOS)

Background

PV = nRT is the basic equation for ideal gas. However, no real gases obey this law over a wide range of pressure and temperature. In order to accurately reflect the thermodynamic behavior of real gases, some adjustments are necessary. In order to do this, Vander Waals put out the first substantial revision, which prompted a number of additional initiatives to increase the generality of Equations of State. This method's success can be ascribed to its astounding mathematical simplicity (Jamiolahmady et al., 2000), which is achieved despite creating a variety of physical parameters necessary for processor calculations and the calculation of transport phenomena. The EOS forms that have been reported in the literature as of Vander Waals' time range from straightforward formulas with one or two additional coefficients to complex forms with up to more than 50 constants. More complicated equations have been utilized for high precision work, including and its derivatives (BWRS, SHBWR, Onje BWR, etc.), Stobridge (Fevang and Whitson, 1996) and the virial (polynomial) form with the 17th power in volume.

The exact representation of PVT data and the computation of basic thermodynamic parameters are well suited for these lengthy and difficult equations, but more intricate thermodynamic calculations are often outside their scope. Predicting "vapour pressure, Latent heat of vapourization, mixture behavior and activity coefficients of mixture components or multi component vapour-liquid equilibrium ratios requires tedious manipulation and excessive computer storage in lengthy iterative calculations that tax even the most modern electronic machines”.

The employment of these forms becomes unaffordable in the case of reservoir modeling, where EOS is called thousands of times. The shorter variants of EOS, the majority of which are stated in cubic form, are attractive due to their mathematical simplicity (Du et al., 2004). None of these closed forms can be considered to be valid over a very broad range of conditions because they are all truncations of the virial EOS (with coefficients given varied thermodynamic dependency on physical parameters). To date, numerous initiatives to enhance these simpler forms have been made. Generalized formulations were proposed by El-Banbi and Mccain, (2000) and Chen et al., (1995), but they were found to be insufficient for accurate PVT property estimates. Despite its shortcomings, Martin's generalised EOS provides a valuable insight into the form required for accuracy:

$$P = \frac{RT}{V} - \frac{\propto (T)}{(V+\beta)(V+\ )} + \frac{\delta(T)}{V(V+\beta)(V+\gamma)} \qquad ---4.3$$

Where V = volume/mass, T = absolute temperature, R = gas constant, $\propto, \delta, \gamma, \beta$ = constants and P = pressure.

With suitable constant and temperature function values, most of the simpler Equations of State can be derived from this form

Cubic EOS

Whatever the cubic EOS forms, the source on which they are based is typical and has at least three graphs: A P-V plot, a P-T plot, and a P-Z plot. The method for obtaining the EOS and calculating its parameters is most frequently explained using the first plot. Vander Waals calculated his EOS by fitting an equation to a critical isotherm, which displays a P-V plot of a one-component system.

$$P = \frac{RT}{V-b} - \frac{a}{V*V} \qquad --- \qquad 4.4$$

The following are the main criteria that must be met:

$$\left(\frac{\partial P}{\partial V}\right)_{Tc,Vc} = 0 \ \ (Minimum) \qquad --- \qquad 4.5$$

$$\left(\frac{\partial^2 P}{\partial V^2}\right)_{Tc,\ \ Vc} = 0 \ \ (Inflection\ Point) \qquad --- \qquad 4.6$$

They are also referred to as Vander Waals conditions. On the other hand, the fit "constants" (a) and (b) in Equation 4.3 heavily depend on molecular size and are insufficient at high pressures and temperatures. Fussell put forth one of the most current EOS, which has been shown to be accurate in terms of fit and liquid density predictions and whose constants are easy to compute.

Here is the suggested format:

$$P = \frac{RT}{V-b} - \frac{a(T)}{V(V+b)} \qquad --- \qquad 4.7$$

Sometimes when we describe Z = PV/RT, A = aP/R 2T2 and B = bP/RT, we get the cubic form:

$$Z^3 - (1-B)Z^2 + (A - 3B^2 - 2B)Z - (AB - B^2 - B^3) = 0 \qquad ---4.8$$

At severe situations, the Peng-Robinson Equation of State must satisfy either Vander Waal's conditions to obtain the values of "a" and "b" or a simple method is to form a cubic Z equation whose three roots are equal at the critical point.

$$(Z - Zc)^3 = 0 \qquad ---4.9$$

$$Z^3 - 3ZcZ^2 + 3Zc^2\,Z - Zc^3 = 0.0 \qquad ---5.0$$

If we compare Equation 4.9 and 5.0

$$1 - B \ = \ 3Zc \qquad --- \quad 5.1$$

$$A - 3B^2 - 2B = 3Zc^2 \qquad --- \quad 5.2$$

$$AB - B^2 - B^3 = 3Zc^2 \qquad 5.3$$

The final sets of equations are:

$$Zc^3 - 3Zc^2\ \ B - 2B^3 - B^2 = 0.0 \qquad ---5.4$$

$$B = 1. -3Zc$$

Which have three roots, two of which are complex? The third and useful root is

$$Zc = 0.3074 \qquad 5.5$$

At the critical point, therefore:

$$a = \Omega \;\; a \;\; \frac{R^2 Tc^2}{Pc} \qquad ---4.15 \qquad b = \Omega \;\; b \;\; \frac{RTc}{Pc} \qquad ---5.6$$

Where $\Omega\, a = 0.4572$ and $\Omega\, b = 0.07780$.

Temperatures well above critical point necessitate special consideration and it is a general rule to regard "b" as temperature independent, whereas "a" is a strong function of temperature. a(T) is written as:

$$a(T) = a(Tc) \propto \qquad ---5.7$$

Where at $T = Tc, \propto = 1$.

Soave defines $\propto$ as

$$\propto^{1/2} = 1 + m \;\; \left(1 - Tri^{1/2}\right) \qquad ---5.8$$

Which is obtained by plotting $\propto$ against Tri yielding a straight line with a component-dependent slope mi. Roussennac, (2001) define mi as a function of the centric factor (w), and a plot of mi versus WI yields the following straight line:

$$m_i = 0.37464 + 1.5226 \;\; w_i - 0.26992 \;\; w_i^2 \qquad ---5.9$$

Equations 4.1 and 4.6 are then used to calculate the fugacity equation. For a single component, the resulting form is:

$$f = P\, e^{Z-1}[\frac{1}{(Z-B)\left(\frac{Z+2.414B}{Z-0.414B}\right)^{\left(\frac{A}{2.82}B\right)}}] \qquad ---5.10$$

EOS is logically extended to mixtures through the use of mixing rules, which are recipes that relate mixture parameters to (i) composition, (ii) pure component parameters and possibly (iii) additional parameters intended to characterize interactions between unlike molecular species is a general quadratic mixing rule.

$$\pi = \sum_i \sum_j X_i\, X_j\, \pi_{i\,j} \qquad ---5.11$$

Where if $i = j, \pi_{i\,j} = \pi_{i\,i} = \pi_i$ which is the parameter for the pure substance. Generally accepted forms of mixing rules to define EOS parameters are: -

$$b = \sum_j X_i\, b_i \qquad ---5.12$$

$$a = \sum_i \sum_j (1.k_{i\,j}) \;\; X_i\, X_j\, a_i^{1/2} a_j^{1/2} \qquad ---5.13$$

$k_{i\,j}$, which is term ed a binary interaction parameter, has a profound effect in determining (a) and by which the calculations may be reduced to finding the best estimate of it defined as

$$k_{i\,j} = 0 \quad if\ i = j$$
$$k_{i\,j} > 0 \;\; if\ i\ \neq j$$
$$< 0$$

For pure hydrocarbons, $k_{i\,j}$is usually quite small (less than 0.1) but for non-hydrocarbon and hydrocarbon binary values are much greater. The EOS types used in this research are P-R EOS, S-R-K EOS and A-R-K.

Criticism: This section presents the origin of cubic EOS, its characteristics and its application to mixtures. The circumstances under which a specific EOS will be correct are not generally known "a priori," making it difficult to select an EOS for a given purpose or set of data. The following variables affect precision:

(i) Binary interaction parameters, (ii) kia and Q.b values, (iii) The data base containing the critical properties and a centric factor of pure components forming the mixture. All of these factors are embodied in the "a" and "b" parameters of EOS, which affect the degree of fit to the critical isotherm. If the accuracy of this fit is to be ensured, a wise choice for representing "a" and "b" must be made.

VLE Calculations

As was already said, the main objective of every VLE computation is to meet the requirements listed below. The temperature and pressure in both stages must be equal. Component I must have an equal fugacity in each of the current phases. First, a two-phase situation will be explored in order to understand how an EOS can be applied to a VLE. For equilibrium, the following constraining equations must be satisfied.

$$V + L = 1 \qquad --- \quad 5.14$$

$$\mathrm{x}_i L + y_i V = z_i \qquad ---5.15$$

$$k_i = y_i/\mathrm{x}_i \qquad ---5.16$$

Where, Equation 4.24 is an overall material balance that states that the number of moles in liquid (L) and number of moles in vapour (V) must add up to unity. The overall mole fraction of component 'i1 in the fluid (zi) is equal to L moles of liquid of mole fraction xi and 'V' moles of vapour of mole fraction 'y I according to Equation 4.25a. The following restrictive equation can be deduced from these definitions:

$$\sum \mathrm{x}_i = \sum \mathrm{y}_i = 1 \qquad ---5.17$$

These equations show that zi is known and xi, yi, V and L are unknown and that if there are n components, there are 2n + 2 unknowns with n + 2 equations. The equations are highly nonlinear and undetermined.

Ki is defined in Equation 4.25b as the equilibrium ratio that varies with temperature, pressure and composition and is also equal to:

$$k_i = \emptyset_l/\emptyset_l \qquad ----------- \quad -5.18$$

Where $\emptyset = f_i/p\mathrm{x}_i$

The first and most common method for solving this system of equations is Successive Substitution (SS), which is discussed now.

Successive Substitution

This technique is especially designed for VLE calculation which proceeds as follows.

Step 1: Estimate K-values
Step 2: Calculate composition of each phase
Step 3: Calculate fugacities
Step 4: Adjust K values using vapour-liquid fugacity ratio
Step 5: Check if the change in K values falls within the specified tolerance. If not, go to Step 2.

The initial estimate of K-values affects the convergence process and thus a reliable guess is necessary. Ahmed proposed a form which relates reduced pressure, temperature and a centric factor to K as follows:

$$\mathrm{k}_i = \exp\left[5.37(1+\mathrm{w}_i)(1-1/Tr_i)\right]/Pr_i \qquad ---5.19$$

In case of failure due to the first estimates, there are several remedies existing in the literature. These either alter Ki estimation or force the system into the two-phase condition at the beginning of the calculations. To calculate the composition s of Step 2 the following equation is used:

$$F = \sum \mathrm{x}_i = \sum \mathrm{y}_i = \sum \frac{\mathrm{z}_i(1-\mathrm{k}_i)}{L+\mathrm{k}_i(1-L)} \qquad ---5.20$$

Fluids close to the critical area and the saturation point exhibit gradual convergence during sequential substitution. Using Powell's hybrid algorithm with SS offers a more dependable method of solving this problem. The particulars of this tactic are detailed. For nonlinear optimization, there are widely used but highly sophisticated library techniques, however if these routines are utilized carelessly, the results could quickly become physically unsuitable. It is strongly encouraged to employ SS whenever it is practical. In circumstances where this method looks pricey, it is advisable to give the computations a physically sound trend using SS to guarantee the accuracy of the overall predictions before applying any complex optimization tools.

Constrained optimization approaches, however expensive in recurring calculations like reservoir modeling, can prevent a process from converging to a physically nonsensical result. In situations where many minimums exist, there is no guarantee that the global minimum will be met.

Numerical Experiments

The P-R, S-R-K and A-R-K equations of state are included in the numerical procedure for two phase VLE calculations developed for the purposes of this study and the solution of nonlinear equations is accomplished by using either the SS, SS + Powell's or Powell's scheme alone. The following numerical experiments have been created to demonstrate this PVT package's capability to forecast gas condensate reservoir performance:

Comparison of SS, SS + Powell and Powell
Kaybob Gas Condensate Study,
W-M-E Data Study,
Constant Volume Depletion versus Constant Composition
Expansion Study

Assessment of Phase Equilibrium

Every petroleum reservoir contains water, therefore the effectiveness of natural gas dissolution in reservoir brines may determine how successfully surface flow streams are processed with water. For example, at 5000 psia and 160°F, 0.28 percent CH4 dissolves in water. However, under reservoir circumstances, the quantity of natural gas that dissolves are often considered to be small and not taken into account when assessing the performance of the reservoir. An exception would be a CO2 rich gas with a very high CO2 solubility in water. For instance, at a pressure of 4000 psia, one barrel of water may dissolve up to 160 SCF of CO2 and water can also expand by up to 1%. The PVT characteristics of gas condensate fluids are also greatly influenced by the fluids' CO2 level. In order to calculate the magnitude of these changes, VLE calculations were performed on five different gas condensate fluid data from the literature (Lal, 2003).

Three Phase EOS PVT Procedure

The prediction of three phase equilibrium composition garnered a lot of interest when there were no experimental data to rely on. To anticipate three phase equilibrium, Peng and Robinson used their EOS (Moradi et al., 2010) whereas employed S-R-K. Whitson used a modified version of Henry's Law to calculate the solute fugacities in the aqueous phase. Henry's Law approach was used, but the former authors failed to take into consideration the changes in k-values that occurred during the thermodynamic equilibrium process. In one of the more recent investigations both PR EOS and EOS were utilized to forecast the phase behavior of systems including water (1993).

However, the absence of appropriate experimental data on gas solubilities in brines has limited the use of theoretical hydrocarbon - CO2 - water investigations. Since there are currently two methods available, they can be categorized into two groups: I Computing the total fugacity using EOS and (ii) Determining the component fugacities of the aqueous phase using Henry's Law and EOS.

Two distinct numerical processes were developed for the current study program based on these two approaches. We'll discuss how to improve the procedure and apply Henry's Law see equation 6.0 to 6.1

$$F1 = \sum \frac{\mathrm{z}_i(1-\mathrm{ko}_i)}{io(1-\mathrm{ko}_i) + Lw\left(\frac{\mathrm{ko}_i}{\mathrm{kw}_i} - \mathrm{ko}_i\right) + \mathrm{ko}_i} = 0.0 \qquad ---6.0$$

$$F2 = \sum \frac{\mathrm{z}_i}{io(1-\mathrm{ko}_i) + Lw\left(\frac{\mathrm{ko}_i}{\mathrm{kw}_i} - \mathrm{ko}_i\right) + \mathrm{ko}_i} = 0.0 \qquad ---6.1$$

These formulae are derived by using component and overall material balances which are

$$\mathrm{xo}_i \;\; Lo + \mathrm{xw}_i\, Lw + V = \mathrm{z}_i \qquad ---6.2$$

$$Lo + Lw + V = 1.0 \qquad ---6.3$$

$$Koi = \frac{\mathrm{y}_i}{\mathrm{xo}_i};\ \mathrm{kw}_i = \frac{\mathrm{y}_i}{\mathrm{xw}_i} \qquad ---6.4$$

Where x0j is the mole ratio of component I in the rich liquid phase
x wj = mole fractionation of component I in a water-rich liquid phase
yj = the mole fraction of component I in the vapour phase.
Oil, water and gas, respectively, make up the overall mole fractions of Lo, Lw and V.
Koi, Kwi = Oil and water distribution coefficients.

As long as "good" initial estimates of Koi and Kwi are provided, the equations 4.31 and 4.32 can be solved using the Newton-Raphson method. Peng and Robinson use the following formula to provide a preliminary estimate for Kwi:

$$\mathrm{kw}_i = 10^n \left(\frac{Pri}{Tri}\right) \qquad ---6.5$$

Where Pri and Tri are reduced pressure and temperature, and n is a large integer to represent the law of gas solubility in the water phase. To Gao et al., (2012) Wilson's equation is applied. These two formulas, however, may not always produce physically viable solutions since the convergence must be forced to the regions that satisfy the constraints because the problem is fundamentally a restricted minimization.

$$g = 1 - (Lo + Lw + V) = 00 < Lo < 1$$
$$0 < V < 10 < Lw < 1 ----6.6$$

This is usually an expensive numerical procedure. Because it is trustworthy and appropriate for reservoir simulation due to large computing savings, the "principle of optimality" may be implemented to speed up the procedure. As a result, the following strategy is selected and used:

$$V_N + L_{ON} = 1 \qquad ---6.7$$

Where

$$V_N = V/[1-Lw];\ L_{ON} = Lo/[1-Lw]$$

$$V_n y_i + L_{ON} X_{oi} + CL\, X_{wi} = Ƶni \qquad ---6.8$$

Where

$$Cl = \frac{Lw}{1-Lw} \qquad Zni = \frac{Zl}{1-Lw}$$

If we assume Lw to be constant at the beginning, the function to be solved will be reduced to the form

$$F_1 = \frac{Zn\,(1-Ka)}{Lo_N(1-Ko_i) + Ko_i(1+\frac{Cl}{Kw_i})} \qquad ---6.9$$

$$and\ \ {Lo_N}^{k+1} = {Lo_N}^{k} - \frac{F_1(Lo^k)}{F'}(Lo^k) \qquad ---6.10$$

A pseudo-two-phase case of the issue is created

$$F_2 = 1 - \frac{Zi - Vyi - Lo\ Xoi}{Lw} ---6.11$$

And

$$Lw^{k+1} = Lw^k - F_2(Lw^k)/F_2(Lw^k) \qquad ---6.22$$

The "Lo N" calculation is then repeated until the values of Lo, Lw and V agree within a preset tolerance between repetitions. Henry's Law fails to take full advantage of EOS and is therefore inaccurate thermodynamically.

Adjusting calculations to experimental data is a good way to calculate fugacity while avoiding the complexity (and potential errors) of the whole Equation of State method. The following steps were taken in this experiment to identify component fugacities in the water phase:

According to fugacity and Henry's constant (hi) are related in the manner given below.

$$f_i = {H_i}^S \mathrm{x}_i \exp\left(\frac{{V^L}_i(P-Pw^S)}{RT}\right) \qquad ---6.33$$

The partial molar volume is given by, where Xi is the mole fraction of component I in a liquid phase with high water content, Pws is the saturation pressure, R is the gas constant, T is the absolute temperature. The total pressure is P. Partial molar volume is calculated using the formula shown below;

$$Pc_i {V^L}_i / R\,Tc_i = 0.095 + 2.35\,(TPc_i/C11\ Tc_i) \qquad ---6.34$$

Where C 11 is the cohesive energy for water which is defined as

$$C11 = (1 - hw^S - Pw^S Vw^S + RT)/Vw^S \qquad ---6.35$$

P_(w^s) can either be obtained from steam the following formula c

$$Pw^S = Pc_i B_k(B) \qquad ---6.36$$

To calculate the molar volume of the saturated liquid, Vws, empirical formulae given in Steam

The equilibrium calculation process is then continued in the same manner as VLE until the following equilibrium conditions are met:

$$f_{oi} = f_{wi} = f_{vi}\ for\ all\ i$$
$$T_o = T_w = T_v = T$$
$$P_o = P_w = P_v = P$$

Further improvements to the method are developed in relation to the predictions of the viscosity and density of the aqueous phase. This is because reservoir water isn't pure, and the presence of salt reduces the solubility of gases in water. In order to make the predictions seem more plausible, it is crucial to consider the influence of salt content. These impacts are gathered from the literature and sent to the numerical procedure as a data base. Equilibrium is attained using the updated gas solubilities, which are adjusted based on the water's salt concentration in ppm. Moreover, the viscosity of water is automatically calculated using the formulas given in steam tables.

Numerical Experiments

The capacity of the approaches described in this part to predict outcomes is only shown in a small number of numerical experiments due to the overall lack of experimental data. It's interesting to see how well the forecasts from the two methodologies match in one of the case studies. In the case of the solubility of CO2 at 25°C and 6856.4 KPa, Henry's Law predicted 0.022 while found 0.02156, whereas the full usage of an EOS projected it to be 0.02150 moles in the aqueous phase. At 30 0°F and 350 psia, the experimental value of water dissolved in liquid phase with a high hydrocarbon content is stated as 0.036.

This method employing P-R EOS predicts 0.03513 as opposed to the 0.0075 anticipated and the 0.0350 predicted. When the distribution coefficients from this study and those from are compared, with the exception of the water component, the distribution coefficients from the two studies are fairly similar. Moreover, the Kw values for hydrocarbon components increase as the molecular size increases. This is the justification for not accounting for natural gas solubility when determining reservoir forecast.

The predictions are extended at varied temperatures and pressures to observe the phase distribution compares the results of the research to those that Erbar gave in a typical condensation curve. The purpose of this experiment is to investigate how CO_2 solubility affects fluid properties. Because there are no experimental data available, the results can only be evaluated qualitatively. By using an interval halving technique to determine the equivalent number of H_2O moles, water saturation is fixed at 20%. It is assumed that the salinity is 40,000 ppm. The fluid is above the phase's dew point at 4,200 psia and 267°F and the feed is: And the amount of CO_2 condensed in the aqueous phase is 3.42%. The documentation of other fluid properties is given (Table 1).

Table 1 Result of Three Phase Flash Equilibrium Studies

	Oil	Gas	Water	
Molecular Weight	64.42	31.35	18.08	
Density (lb/cft)	40.33	19.06	GO.70	
Mole Rates (Fraction)	0.000	0.420	0.580	
Phase Volumes (%)	0.0	80	20	
Viscosity	0.128	0.035	Pure	0.210
			Salinity corrected	0.265
			C02 + Valor	0.264

Tuning of an Equation of State

The term "tuning" defines the strategies used to increase EOS's predictions in comparison to a given collection of experimental data. The following elements—or a combination of both—lead to the requirement for tuning: insufficient experimental data and problems with the EOS.

In order to improve forecasts, this section will look into the reasons of these problems and offer viable solutions. Reviewing the component characterizations in EOS is the first step toward accomplishing this.

Regression Based EOS PVT Approach

The cost of Equation of State calculations is directly influenced by the number of components needed. In a reservoir simulation of the compositional kind, the Equation of State calculations must be repeated several times at each block and time step. For reservoir instances other than the simplest (or economically limited ones), complete compositional simulation utilizing extended fluid analysis becomes time- and cost-prohibitive. A technique that will maintain thermodynamic consistency while using the fewest number of representational components or "pseudo components," must be created. To minimize the number of components, it is important to pseudo-synthesize both the heavy fractions and the pure components. This composition must then be validated using EOS results that are consistent with the experimental data.

He and colleagues (1996) outline a trial-and-error methodology where a phase diagram is initially generated using a small number of pseudo components and then this number is progressively increased until there is a reasonable level of agreement between experimental data and predictions. A large amount of experimental data is required for the procedure. According to Jamiolahmady et al., (2000), the reservoir fluid's constituent parts were combined using a statistical approach. Their strategy is based on the finding that phase saturations pre dominate reservoir simulations because they have a major impact on phase mobility. As a result, it is recommended that reservoir components be grouped together to lessen the inaccuracies in phase saturation forecasts.

In previous study classifies components according to similarities among a few traits identified through chromatographic analysis. Another prerequisite for this strategy is the availability of comprehensive experimental property data for 150 components. Coats recently presented a very methodical solution to the problem by employing a regression method to force EOS predictions to concur with experimental evidence. Due to the possible advantages, this strategy is applied in this research coupled with enhancements to boost productivity. Many fluid properties are covered by the numerical results that have been provided. The Regression Based EOS strategy basically requires reducing the value of an objective function made up of a number of variables, maybe with some variable value restrictions, in order to solve an optimization problem.

EOS equations are nonlinear; hence the problem is classed as a nonlinear regression problem. The following paragraph will go over the variables of regression, the formulation of the objective function, its properties and the specifics of the numerical technique.

(i) Variables of Regression: In the EOS investigations, the projected values are referred to as dependent parameters. They include, among other things, densities, liquid dropouts, enthalpies and saturation pressures. These characteristics are calculated from the critical properties, molecular weights, centric factors, standard conditions densities and binary interaction parameters of the relevant components. In order to get a reasonable level of agreement between the experimental values and the predictions given the experimental values of the dependent parameters, it is necessary to change the independent parameters is employed in this work to fill in the knowledge gaps for the heavy ends.

According to previous studies components (Tc, Pc, Mwt, p and w) are pseudoized and their properties are determined using Kay's Mixing Rules. Binary interaction parameters, a and b values, have been selected as the movable independent parameters. At this point, the parameters' flexibility needs to be clarified. Binary interaction parameters for the heavy fractions are generally acknowledged as movable parameters, despite disagreement over a and b. Driving the EOS to the critical hysteresis loop yields these parameters, if we were to discuss the derivation of an EOS. Therefore, the values of a and b should be distinct. In contrast, a counterargument put forth by Nasiri-Ghiri et al., (2015) claims that in actuality, a, a, n and d, can be considered to be temperature-dependent functions of their respective components for a given component I at a given temperature T below the critical so that the saturated liquid density and component vapour pressure are exactly matched.

Gas Condensate Reservoirs' Use of Relative Permeability Characteristics

Preamble

This article takes into consideration the specification of relative permeability’s for studies on the recovery of gas condensate from reservoirs. The section that follows explains potential saturation histories that might persist in gas condensate reservoirs. These saturation histories serve as the foundation for the second portion, which focuses on the specification of relative permeability. End results and relative permeability’s for two- and three-phase systems are discussed in this context. Further section of this article contains the numerical experiments. The topic of the final section is the determination of relative permeability for various phases of mechanisms for extracting gas condensate.

Saturation Histories in Gas Condensate Reservoir

Setting relative permeability in gas condensate reservoirs requires an understanding of the saturation histories that may occur throughout each recovery step. The saturation histories in the case of two-phase flow are well known, including those in natural depletion and gas cycling at connate water saturations. When water injection and blow down are coupled, three phases are likely to exist, making the fluctuations in saturation much more difficult. Experimental data don't make the case any clearer and collecting such data would be difficult. It is both possible and necessary to approach the relative permeability problem theoretically in the current context. The accuracy of the estimated and assigned relative permeability values is one of the factors that contribute to the performance of the water injection.

First, saturation histories that are likely to occur will be looked for in completely three-phase situations. Since water, oil and gas are all mobile, there are 27 different combinations of saturation histories, but only 13 of these are truly conceivable. This is because none of the three phases can change at the same time and the third saturation will also be constant if two of the saturations are (steady-state). In order to illustrate the probable saturation histories of water injection followed by blow down in gas condensate reservoirs. Water breakthrough and associated coning are also displayed. C* stands for zero levels of oil saturation. Thus, the following are the possible saturation histories: When the water phase progresses, the gas phase diminishes in the early water injection process of I C * D. (the letters are ordered to follow water-oil-gas sequence). In the subsequent portions, it is CC*C. Water injection in the middle: In the area of the injection well, a residual hydrocarbon saturation has been developed that matches to C C *C. At the propagating flood front, there will be a transition between both scenarios, with the C C * C replacing the I C * D, which will then replace the C C * C. The case CID will appear if the pressure at the production site drops below the dew point. In the regions where the water pattern is preserved, the process is breakthrough, being CC*C. Due to the large absolute permeability of the bottom, injected water preferentially moves through the lower layers more quickly and eventually reaches the well bore, where it may form a water cone. In this case, IC*D and IID are possible results.

4. CONCLUSIONS AND RECOMMENDATIONS

A general-purpose Equation of State PVT Software was created with an emphasis on the characterization of the heavy components because it is essential to accurately depict the PVT behavior of gas condensate fluids in compositional research. The code was incorporated into the composing process. To decrease the strain brought on by employing the equations in compositional processes, it is imperative to design an efficient and reliable solution approach for the highly nonlinear and underdetermined set of equations of the EOS. These are the findings of this investigation in this area: Solutions that are physically unreasonable could be produced by unconstrained minimization techniques alone. Confined, although reduction strategies might be able to prevent this, the additional cost of the computations renders this tactic ineffective in repeated EOS calculations. In order to avoid this, Successive Substitution (SS) should be used wherever possible. If this approach demonstrates delayed convergence, using SS initially will set the calculations on a convergent course. Any succeeding effective approach will hasten the convergence to a physically workable answer. The created EOS approach is validated using a wide range of experimental data sets. Although though the Constant Volume Depletion (CVD) test is substantially more expensive than the Constant Composition Expansion (CCE) test, the investigation's surprising conclusion was that the fluid's intense features remain true for both tests.

Three-Phase, EOS Studies

The degree to which CO2 dissolved in water was examined, along with how this impacted the gas condensate's PVT behavior. It was discovered that the amount of CO2 in the hydrocarbon phase influenced the gas density, liquid dropout and dew point pressure, with a rise in CO2 content having the opposite effects. These findings led to the development of a three-phase (Water-Oil-Gas) EOS PVT Program that computed water phase fugacities using Henry's Law.

Regressions based EOS PVT Program

Regression-based EOS PVT Software is created in order to match the chosen EOS to the supplied experimental data with the least amount of components. This is so because the number of components utilized to define the hydrocarbon fluid strongly correlates with the cost of the com positional operation. Following this examination, the following conclusions were discovered:

The regression technique's multi-variable nonlinear minimization method's convergence rate and objective function's shape are closely correlated. It is found that the least squares formulation yields the fastest convergence rate. In order to accelerate the search for the minimum, a technique is also used to combine random search, pattern search and Metric Method and Non-Linear Least Square minimization techniques. This strategy is discussed in the following section.

The bare minimum experimental quantities required to fully explain the hydrocarbon PVT behavior are the saturation pressure, densities at saturation pressure and liquid dropout curve. Generally, a methane-heavy% binary interaction parameter and omega values acting as the independent parameters of the regression technique are used to create an adequate match. The 30% reduction in simulation costs for the same accuracy exemplifies the advantages of this regression approach.

Numerical Improvements

The following areas underwent modifications in order to increase compositional technique accuracy as well as speed:

(i) Convergence Acceleration: In order to determine the derivatives of the fluid property, a technique is used to linearize the equations resulting from the combination of EOS and Finite Difference. This expedites the iterative Newtonian pressure determination process. When compared to the effectiveness of the previously reported methods, this led to a reduction in the number of iterations by half.

(ii) Saturation Iteration: The calculations of the overall material balance of the numerical technique depend on the tolerance limit provided for the pressure iteration and occasionally there may be substantial material imbalance owing to early termination of the iteration process. As described in subsequent parts of the article

(iii) A local grid iteration process is used to update the pressures without altering the previously estimated fluxes at the block faces in order to ensure consistency in the saturation forecasts and material balances. The coefficient matrices of the simulation approach frequently have weak diagonal dominance or even ill-conditioning, which makes it difficult for traditional iterative methods like SIP, ADIP, LS O R and al. to converge (preconditioned conjugate).

Relative Permeability and Hysteresis

One of the most important aspects of the current investigation was the definition of relative permeability for the water injection technique, especially during the blow down stage. In three phase flow conditions, there are thirteen possible saturation histories that can occur, thus it's important to pick the right relative permeability. An algorithm that extends the two-phase history dependent relative permeability prediction techniques currently available in the literature to three-phase was developed using a Stone type approach. The method can predict changes in the relative permeability of three-phase oil by tracking changes in saturation histories without thorough experimental data, the entire major imbibition curves and residual gas saturations relative permeability of intermediate imbibition. Simulation experiments integrating this model have shown how important it is to choose the appropriate relative permeability for recovery estimations. In one of the numerical trials, it is claimed that the use of drainage data for an imbibition process could result in hydrocarbon recoveries being up to 35% overstated.

Areal studies

Natural Depletion

The numerical findings of this study support the hypothesis that this mechanism's performance degrades as gas condensate richness rises. For instance, for the identical reservoir domain, NS1 reduces the 34% liquid recovery that would have been attained in the Kaybob research to 28.5%. When compared to gas cycling and water injection, this recovery method is less effective in both situations since the liquid recovery that can be achieved is so minimal.

Water Injection

A favorable mobility ratio is produced when condensate gas is substituted with water, stabilizing the injection process. The performance of well water injection is influenced by the following factors: condensate richness, blow down timing and residual gas saturation. The research's findings are as follows: Richness of condensate gas: One of the noteworthy results is that the richness of the gas condensate has a beneficial effect on the efficiency of the water injection mechanism. The oil recoveries from Kaybob and NS1, which in the latter case reveal an additional 6% oil production, serve as an illustration of this fact. Moreover, hydrocarbon recoveries from the NS1 case study show that for the same PV of fluid injection, water injection performs just slightly better than gas cycling.

Blowdown Timing

The performance of water injection can be improved by increasing the volume of water to be injected or by delaying blow down; the restriction is the formation of a water cut. The Kaybob Fluid Research shows that increasing the volume of water injection from 0.3 he PV to 0.4 he PV results in an extra oil recovery of 7020 STB. The additional recovery for NS1 is 14930 STB. Residual gas saturation, one of the key water injection variables, has a direct impact on the process' economics. At higher residual gas saturation levels, hydrocarbon recovery is reduced. The trapped gas saturation affects both the amount of water that can be injected before water breakthrough and the loss of liquid components. For instance, the maximum he PV water injection is about 0.4 for trapped gas saturation of 35 percentages, whereas it may increase to 0.6 PV for trapped gas saturation of 20 percentages. The oil recovery might increase from 48 percentages to 61 percentages. The necessity of experimental confirmation of the residual gas saturation for each unique reservoir is highlighted by this discovery.

Cross-sectional Studies

Stratification and gravity factors are taken into account in this section of the research to conduct a more realistic evaluation. The absolute permeability distribution of the condensate fluid NS1 exhibits rapid variations and a ratio of 2700 between the largest and smallest absolute permeability. The efficiency of each recovery mechanism is as follows:

Gas cycling

The permeability distribution of the injected solutes has a significant impact on the system's performance. If permeability decreases with depth, the system performs particularly poorly because the injected dry gas preferentially moves to the upper layer, leading to an early breakthrough from the reservoir's top. On the other hand, permeability that grows with depth make an excellent foundation for gas cycling since gravity has a beneficial impact on the vertical sweep efficiency of injected gas. The oil recovery rates are 49% for the unfavorable permeability distribution and 63% for the favorable situation.

Natural Depletion

Although it performs poorly in terms of recovery, reservoir heterogeneities often have no impact on this. Water Injection: Because it is equally impacted by reservoir heterogeneities, this process requires a thorough reservoir engineering investigation before to usage.

The subsequent parametric investigations are completed:

-Modifying the distribution of absolute permeability,

-Blow down time,

-Change the remaining Gas Saturation,

Below is a summary of how the parametric study affected permeability distribution and reservoir dip: The presence of a high permeability streak, which results in fingering of the injected water in the high permeability zone, is what leads to the development of coning and early project termination. The downward increase in absolute permeability would prevent the application of water injection due to water seeping through in the deeper layers. An absolute permeability distribution, whose permeability decrease with depth, is appropriate for water injection. The preferential advance through the top, high permeability layers is lessened by gravity and dip effects.

Blow down Timing

A 35% trapped gas saturation and an upward-sloping permeability distribution was used for the testing in this section. Oil is recovered more effectively when water input is increased. For instance, water injections at 0.3 and 0.5 he PV led to recoveries of 8970.5 and 11005.5 STB, respectively.

Water injection is obviously impossible in the presence of high residual gas saturations due to substantial losses in gas condensate, only as a recovery mechanism. Due to the early entry of injected water into the well bore, considerable coning may occur as a deterrent. In the numerical experiments in this thesis, it is demonstrated that the recovery for a 20% residual gas saturation is approximately 7400 STB (or 47% more) than that obtained from a 50% residual gas saturation, while the difference between 20% and 35% residual gas saturation is 500 STB for the same, he PV of water injection.

Suggestions for Further Work

Regression-based EOS PVT Approach improvement

Although this method significantly reduced costs, additional study is still required, notably for simulations of gas cycle. Because to excessive pseudoisation, the low concentration heavy components cannot be precisely traced. In surface separator calculations, a detailed analysis based on precise heavy fractions is often not possible. As a result, it is suggested that you do the following research: A technique for dissecting the surface stream's pseudoized component representation into its individual portions, allowing for extended gas analysis for surface process calculations, will improve the predictions made by gas cycling models.

More accurate state equations

In contemporary industrial applications, it is common practice to employ a cubic Equation of State. The pros and cons of this method are discussed in a later section of this article. The flaws highlight the demand for improved EOS iterations.

Further research is required in order to improve heavy fraction characterization, identify various hydrocarbon phases, estimate component liquid density, predict polar/non-polar system properties and finally, comprehend the nature of molecular attraction and repulsion. There are limitations on the accuracy of any two-parameter Vander Waals type equation of state in various circumstances.

Equations of enhanced states

Today's industrial applications frequently use a cubic Equation of State. The advantages and disadvantages of this technique are discussed in this article. The flaws highlight the need for better EOS substitutes. Improved heavy fraction characterization, a method to identify multiple hydrocarbon phases, better component liquid density predictions, better property predictions of polar/non-polar systems and last but not least, better understanding of the nature of molecular attraction and repulsion are all areas that require additional study. Any state equation of the Vander Waals type with two parameters has constraints on its correctness in a variety of situations.

The difficulty of conducting three-phase relative permeability experiments has led to the widespread adoption of analytical models like Stone type probabilistic techniques, as is the case in the current study. All of these tactics, unfortunately, have been demonstrated to be useless by low oil saturation levels; investigations on gas condensate recovery must take this into account. Experimental two-phase relative permeability needs more investigation (gas-oil in the presence of water). In light of the improved experimental data, the current analytical techniques can be further enhanced. It's also intriguing to consider how the relative permeability of the rocks is affected by their wettability. This analysis only considers strongly water-wet systems, which is a reasonable assumption for gas condensate reservoirs. The influence of CO2's solubility in the aqueous phase on condensate and gas recovery

This article examines the importance of CO2's solubility. It has been shown to have a major impact on how PVT properties of hydrocarbon fluids behave. The resolution of this problem is not covered by the focus of this work, which is limited to circumstances where the aqueous phase is inert. However, the design of the modeling equations allows for the general case in which more than two liquid phases may be present and the three-phase EOS PVT program that is included takes into account CO2 solubility in water. To assess the effects of CO2's solubility in water on the overall hydrocarbon recovery, it is advised that simulation research be carried out specifically for water injection.

Investigation of alternative gas condensate recovery methods

Just natural depletion, gas cycling and water injection are the subject of this study. However, due to financial constraints and reservoir heterogeneities, there may be situations where neither injection strategy is feasible. The default production technique under these circumstances is natural depletion, which has a poor liquid recovery performance. Nitrogen, carbon dioxide or even air infusion are potential substitute recovery techniques. Nitrogen is often readily available on site from air by utilizing cryogenic separation. The effects of nitrogen miscibility with condensate gas on the PVT characteristics of the reservoir fluid, the requirement to confirm nitrogen's displacement efficiency because it is more viscous than, say, methane, the unique economic constraints and combined injections, such as nitrogen injection followed by water, are all elements that need to be researched in order to assess nitrogen injection.

It appears like a simple process to introduce air. Air and nitrogen will react similarly of their fundamental similarities. Yet, it is vital to consider the possibility of corrosion and combustion in the production facilities in order to utilize this choice.

Effects of CO2's solubility in aqueous phase on gas condensate recovery

A thorough analysis is needed to understand the physical processes that occur around production wells in gas condensate reservoirs and how they affect the well productivity. The following problems could occur: Due to the constant flow of condensate-rich gas to the wellbore and to noticeably higher-pressure reductions in the area of the well bore, the liquid phase develops earlier and to a greater extent than other areas of the reservoir. Non-equilibrium condensation, which can increase the volume of liquid produced, can be brought on by sudden drops in pressure. Standard displacement procedures typically yield values that are less than the critical oil saturation for gas condensate reservoirs. The creation and mobilization of this liquid phase would consequently result in a decrease in the system's overall mobility as compared to single phase flow. This has an effect on the production of wells.

Another problem that reduces the well's productivity is the mechanical skin, which is brought on by formation damage from plugging, clay hydration, compaction and partial completion effects. This may increase the visibility of liquid dropout. Consequences of non-Darcy flow. To examine these issues, a radial well model that can mimic the coning behavior that could happen during water injection is needed. High levels of implicitness are frequently needed when choosing a method to solve flow equations; as a result, totally implicit or adaptive implicit strategies may be necessary.

Ethical issues

Not applicable.

Informed consent

Not applicable.

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Conflict of Interest

The author declares that there are no conflicts of interests.

Data and materials availability

All data associated with this study are present in the paper.

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