Gas Condensate PVT –
What's Really Important and Why?

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ABSTRACT

This paper gives a review of the key PVT data dictating recovery and well performance of gas condensate reservoirs. The importance of specific PVT data are put in the context of their importance to specific mechanisms of recovery and flow behavior. Phase behavior important to gas cycling projects is also covered. Modeling gas condensate reservoir fluid systems with an equation of state is discussed, as is EOS modeling of complex fluid systems with strongly varying compositions and PVT properties.

INTRODUCTION

It could be argued that the engineering of a gas condensate field is 80% traditional "gas" engineering, and 20% "extra" engineering. The numbers could be 90/10 or 70/30 – but the majority of engineering of any gas condensate field is *always* the same as the engineering of a gas reservoir without condensate.

The main difference between a gas condensate field and a "dry" gas field is the additional income derived from surface condensate production. Condensate production evolves from *produced reservoir gas* (= *produced "wet gas"* = *produced wellstream*) as the wellstream is processed at the surface. The production of reservoir gas can, for the most part, be handled with traditional gas engineering tools.

From an engineering point of view, the two "extra" issues which must be addressed in a gas condensate reservoir are:

- How the condensate "yield" will vary during the life of a reservoir, and
- How two-phase gas/oil flow "near" the wellbore affects *gas* productivity.

Both of these issues are strongly related to the PVT properties of the fluid system (though productivity is more affected by relative permeability effects).

PVT properties important to the engineering of all gas condensate reservoirs includes:

- Z-factor
- Gas viscosity

and a few "extra" properties needed to handle the "condensate" part of a gas-condensate reservoir:

- Compositional (C_{7+}) variation with pressure
- Oil viscosity and liquid dropout

Dewpoint pressure is implicitly defined by the pressure dependence of compositional variation. As discussed below, the dewpoint is less importance than is commonly thought.

The PVT properties listed above are particularly important to reservoirs produced by pressure depletion. For gas condensate reservoirs undergoing gas cycling it may also be important to quantify phase behavior (vaporization, condensation, and near-critical miscibility) which develops in gas cycling *below the dewpoint*.

Compositional grading in gas condensate reservoirs may be important to the design of well placement, estimation of in-place surface volumes, reserves, and prediction of fluid communication vertically (between geologic layers) and areally (between fault blocks). Prediction of a potential underlying oil is often required in discovery wells which are drilled upstructure and encounter only gas which is near-saturated. Here, accurate sampling and PVT modeling are paramount.

A PVT model[a] should describe accurately the key phase, volumetric, and viscosity behavior dictating the key processes affecting rate-time performance and ultimate recoveries of surface gas and oil. Unfortunately, a PVT model may not be capable of accurately describing *all* PVT properties with equal accuracy. EOS models often have difficulty matching retrograde phenomena (compositional variation of gas, and liquid dropout), particularly when the system is near-critical, or only small amounts of condensation occur just below the dewpoint ("tail-like" retrograde behavior). Oil

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[a] We define a PVT (pressure-volume-temperature) model to include the EOS (equation of state) model describing phase and volumetric behavior, together with the viscosity model (e.g. the Lorentz-Bray-Clark[1] or Pedersen et al.[2]); the viscosity model is not formally linked with the EOS model but makes use of EOS-calculated density.

viscosities are also difficult to predict for reservoir condensates, and measured oil viscosities are not usually available for tuning the viscosity model.

Consequently, it is important to determine which PVT properties are most important to the accurate engineering of reservoir and well performance for a given field development. Different fields require different degrees of accuracy for different PVT properties, dependent on field development strategy (depletion vs. gas cycling), low or high permeability, saturated or highly undersaturated, geography (offshore vs. onshore), and the number of wells available for delineation and development.

Consider the following examples.

Example 1. A small offshore "satellite" reservoir with high permeability (kh=4,000 md-m), initially undersaturated by 400 bar, and with a test yield of 300 STB/MMscf.

Example 2. A large offshore deep-water reservoir with moderate permeability (kh=1000 md-m), initially saturated or near-saturated (?), large structural relief, and a test yield of 80 STB/MMscf. A single (and very expensive) discovery well has been drilled.

Example 3. An onshore "old" undeveloped gas cap with well-defined initial volume (by production oil wells and pressure history), uncertain initial composition (estimated initial yield of 120 STB/MMscf), partially depleted due to long-term production of underlying oil, and low permeability (kh=300 md-m).

These three examples require significantly different emphasis in the treatment of PVT data. Why? The reason lies in a coupling of the reservoir and well performance with PVT properties. Every gas condensate reservoir provides a new example with a different set of conditions requiring different emphasis on which PVT data are important.

This paper will attempt to explain when and why various PVT properties are important to the development of a particular gas condensate field.

PVT EXPERIMENTS

Constant Composition (Mass) Expansion Test

The constant composition expansion (CCE) test, sometimes referred to as a constant-mass expansion test, is used to measure dewpoint pressure, single-phase gas Z-factors, and oil relative volume below the dewpoint ("liquid dropout curve"). A sample of reservoir fluid is charged in a visual PVT cell and brought to reservoir temperature and a pressure sufficiently high to ensure single-phase conditions. Pressure is lowered by increasing cell volume until a liquid phase is visually detected (through a glass window). Total cell volume and liquid volume are monitored from the initial reservoir pressure down to a low pressure (dictated by cell and sample size).

Constant Volume Depletion Test
The constant volume depletion (CVD) test is an extremely important laboratory test which monitors the phase and volumetric changes of a reservoir gas sample (at reservoir temperature) as the pressure drops below the dewpoint and equilibrium gas phase is removed. *The CVD test simulates closely the actual behavior of a gas condensate reservoir undergoing pressure depletion*, and results from the lab measurements can be used directly to quantify recoveries of surface gas and condensate as a function of pressure below the dewpoint. Combined with single-phase Z-factors from the CCE test, a complete prediction of depletion behavior (recoveries and liquid-yield variation) can be accurately predicted from initial pressure to abandonment.

The CVD test involves stepwise lowering the pressure below the dewpoint, with an associated increase in cell volume. After equilibration at each pressure, enough equilibrium gas is removed from the top of the cell to bring the cell back to the original volume occupied at the dewpoint. The amount of gas removed, its composition and Z-factor, and the remaining oil volume in the cell are measured and reported. A "two-phase" Z-factor is also reported for use with the "gas" material balance (see discussion below).

Accurate measurement of the removed gas composition is very important to the prediction of condensate recovery and liquid-yield variation – much more important than accurate measurement of retrograde oil volumes. Special laboratory procedures should be followed to ensure accurate CVD compositional measurements (e.g. appropriate heating of tubing used to remove equilibrium gas from the cell). Measurement of the final low-pressure condensate composition allows an important "backward" material balance check.[b]

INITIAL FLUIDS IN PLACE AND DEPLETION RECOVERIES

Gas Z-factor
Muz Standing would be happy to hear that the Z-factor is (still) the only PVT property which *always* needs accurate determination in a gas condensate reservoir (as in a "dry" gas reservoir). The reason is (1) to get an accurate and consistent estimate of the initial gas (and condensate) in place, and (2) to accurately predict the gas (and condensate) recovery as a function of pressure during depletion drive.[c]

Single-phase gas Z-factors are measured experimentally at reservoir temperature and pressures from the initial reservoir pressure to the dewpoint. These data are

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[b] The backward material-balance check is made by starting with the final condensate composition and amount (using the reported final oil relative volume and properties), adding incrementally the removed gas from each CVD step, and ending up with a check of the original fluid composition. This check is insensitive to oil relative volume (except the final value), a big advantage over the traditional "forward" material balance which is extremely sensitive to all relative oil volumes and, consequently, can not be used for leaner gas condensates.

[c] It also is important to quantify recovery by depletion for a reservoir which is to be gas cycled, because the evaluation of economics will always involve comparison of the gas cycling project with depletion drive.

reported as part of the constant composition expansion test. Z-factors used in the material balance equation *below the dewpoint* are "back-calculated" from data in the constant volume depletion test. These so-called *two-phase Z-factors* are "pseudo" (not-physical) properties which should only be used in the traditional gas material balance equation.

It is not commonly recognized that condensate recovery is strongly related to the recovery of gas. Gas Z-factors dictate gas *and oil* recoveries during depletion (together with the amount of water expansion and influx), because recoveries are proportional to (Z_i/Z) – i.e. the term $[1 - (Z_i/Z)(p/p_i)]$. In fact, at average reservoir pressures above the dewpoint, condensate recovery "exactly" equals the gas recovery. Consequently, condensate recoveries are strongly dependent on accurate description of gas-phase Z-factors (both above and below the dewpoint).

As an example for a high-pressure reservoir, a +5% error in Z_i and a –5% error in Z at the dewpoint will result in (a) a +5% error in initial gas and initial condensate in place, and (b) a +5 to +10 *recovery-%* error in recovery of gas and condensate at the dewpoint.

Compositional (C_{7+}) Variation During Depletion

As mentioned earlier, the distinguishing characteristic of a gas condensate field is the added value from condensate production, in addition to gas. Surface condensate is, for practical purposes, the C_{7+} content[d] of the produced wellstream. This simplification makes the treatment of many engineering calculations easier to understand without loosing engineering accuracy.

The condensate rate profile is easy to convert into an economic profile, and engineers can readily relate the two. But how can we readily forecast the condensate rate profile for a gas condensate reservoir?

For a *surface gas*-rate production profile $q_g(t)$, the profile of oil rate versus time is given (approximately) by

$$q_o(t) \cong q_g(t) \cdot \frac{(y_{7+})_{CVD}}{1-(y_{7+})_{CVD}} \cdot \frac{1}{(C_{og})_{CVD}} \quad\text{.. (1)}$$

$$C_{og} = \frac{R\, T_{sc}}{P_{sc}} \cdot \frac{\rho_o}{M_o} \quad\text{.. (2)}$$

where $(\rho_o / M_o) = (\rho_{7+}/M_{7+})_{CVD}$. Time dependence of CVD properties must be correlated with cumulative wet-gas volumes produced,

$$G_{pw} = \int q_w dt \quad\text{... (3)}$$

where

$$q_w = q_g + q_o C_{og} \quad\text{.. (4)}$$

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[d] The simplification of surface condensate being "essentially" C_{7+} is a subjective choice. One could easily have chosen C_{6+} or C_{5+} without any change in our comments.

Given the $q_w(t)$ profile and $G_{pw}(t)$, this can be translated into cumulative wellstream produced from the CVD test, $(n_p/n_d)_{CVD}$,

$$(n_p/n_d) = G_{pw}/G_w - [1 - (p/z)_d/(p/z)_i] \; ; \; p \leq p_d \quad \text{........................} \quad (5)$$

where all CVD properties = initial gas properties for $p > p_d$. C_{og} represents the surface gas equivalent of one surface oil volume.

Equations for converting CVD results to approximate surface product recoveries, including the depletion recovery from initial to dewpoint pressure are:

$$RF_{gD} = \left(1 - \frac{(p/Z)_d}{(p/Z)_i}\right) + \frac{(p/Z)_d}{(p/Z)_i} \cdot \sum_{k=1}^{N}\left(\frac{\Delta n_p}{n_d}\right)_k \cdot \frac{(1 + r_{si} \cdot C_{og})}{(1 + r_{sk} \cdot C_{og})} \quad \text{...........................} \quad (6)$$

$$RF_{oD} = \left(1 - \frac{(p/Z)_d}{(p/Z)_i}\right) + \frac{(p/Z)_d}{(p/Z)_i} \cdot \sum_{k=1}^{N}\left(\frac{\Delta n_p}{n_d}\right)_k \cdot \frac{(1/r_{si} + C_{og})}{(1/r_{sk} + C_{og})} \quad \text{...........................} \quad (7)$$

$$r_s \cong \frac{z_{7+}}{1 - z_{7+}} \cdot \frac{1}{C_{og}} \quad \text{..} \quad (8)$$

A simple spreadsheet calculation using these equations allows quick translation of laboratory CVD data to important engineering and commercial quantification of in-place surface volumes, reserves, and production forecasts. **Fig. 1** and **Table 1** shows an example calculation using Eqs. 6-8 for a rich-gas condensate.

Compositional Variation with Depth
Numerous field case histories have shown that composition varies with depth in petroleum reservoirs. Component "segregation" due to gravitational forces is usually given as the physical explanation for the variation in composition. A theoretical model for such variation was already defined by Gibbs in the late 1800's for an isothermal system under the influence of a constant force field such as gravity. The result of gravitational segregation is that a gas condensate gets richer at greater depths, with increasing C_{7+} mole fraction (and dewpoint pressure)[3].

Not all fields show compositional gradients with depth as predicted by the isothermal model. Some fields show practically no gradient over large depths, such as the Cupiagua field in Columbia[4] where a near-critical gas condensate with more-or-less constant composition is found over an interval of some 2000 m. Some *oil* fields have gradients larger than predicted by the isothermal model. Høier[5,6] made comprehensive calculations using a number of thermal diffusion models which indicate that thermal gradients typically *reduce* compositional gradients in gas condensate fluids, while for oils a thermal gradient may cause either a reduction or an increase in compositional gradients.

Our concern with compositional gradients in gas condensates will be limited to three topics: (1) assessing the effect of a gradient on in-place surface volumes, (2) assessing the prediction of a gas-oil contact using a theoretical gradient model, and (3) the impact of compositional gradients on depletion (and cycling) recoveries.

Variation in C_{7+} composition with depth will obviously affect the calculation of initial surface condensate in place, compared with a calculation based on a constant composition. Depending on the "location" of the sample used in the constant-composition model, either smaller or larger initial condensate volumes in place can result when compared with a gradient model[e].

The gradient model will typically give an "optimistic" in-place sensitivity when the gas condensate reference sample is upstructure. If the reference gas sample is downstructure then the gradient model will provide a "pessimistic" in-place sensitivity. For reservoirs with limited control of fluid variation with depth, we recommend using the "in-situ representative" samples available, linear interpolation between these samples, and for sensitivities use both (a) the gradient model for extrapolation beyond the samples and (b) a constant-composition extrapolation.

Another interesting feature of *near-saturated* reservoirs with compositional gradients is that the *recoverable condensate volumes by depletion* are insensitive to whether the model is initialized with or without a compositional gradient. This lack of sensitivity[f] will not be apparent if comparisons are made using *recovery factors* (because initial volumes in place can be quite different for the two models of compositional initialization).

A gradient model may also predict a transition from gas to oil which can dramatically affect the initial oil in place volumes (see discussion below). However, a *predicted GOC* from an upstructure gas sample is, at best, a "possibility". Results of predicted "oil zones" from gas samples should only be used for sensitivity analysis of a new discovery, or in a reservoir where additional delineation wells are not planned.

Dewpoint Pressure

Strictly speaking the dewpoint pressure is the pressure where an incipient liquid phase condenses from a gas phase. Practically, the dewpoint marks the pressure where (1) reservoir gas phase composition changes and becomes leaner, and (2) condensate accumulation starts in the reservoir. These two changes can have a profound effect on reservoir and well performance – or, they may have little impact. The importance of the *actual dewpoint pressure* will vary from reservoir to reservoir, but in most situations accurate dewpoint determination is *not important*.

Why? First, in the context of compositional variation with pressure (and associated variation of condensate yield with pressure) accurate determination of the thermodynamic dewpoint pressure is *not* of particular importance. In fact, we don't need to know the "specific" dewpoint at all as long as the variation of composition (C_{7+} content) with pressure is well defined "near" the thermodynamic dewpoint.

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[e] The gradient model requires that a composition be specified at a reference depth with a reference pressure and temperature.

[f] This behavior is readily understood in a black-oil model using a solution oil-gas ratio $r_s(p)$ function. The initial variation of r_s (and dewpoint) with depth is short-lived when reservoir pressure drops below the dewpoint, as r_s of the equilibrium gas through the reservoir becomes (more-or-less) constant at the average reservoir pressure. Because only reservoir gas flows into wells, the producing OGR will reflect the equilibrium r_s at average reservoir pressure, which becomes independent of depth when $p_R < p_d$.

Second, when the bottomhole flowing pressure (BHFP) drops below the dewpoint and two phases start flowing near the wellbore, gas relative permeability drops and well *productivity* drops. However, as long as BHFP is "anywhere near" the dewpoint the well will have *excess deliverability* – i.e. we simply reduce the BHFP to produce more gas (even though the well *productivity* is lower).

Only when the BHFP reaches a minimum value (dictated by some delivery-pressure constraint) will the well no longer be able to deliver the desired rate. At this point, well productivity *is* important. However, this occurs at a BH flowing pressure much lower than the dewpoint. A typical minimum BHFP might be 50-150 bara, while dewpoint pressures are typically 250-400 bara. Whether the BHFP drops below the dewpoint at 400 or 350 bara has little impact on what the well will (or won't) produce when BHFP reaches a minimum constraint of 100 bara.

Another (less common) need for dewpoint pressure is when an underlying saturated oil zone *may exist* and a PVT model is used to predict the existence and location of the gas-oil contact (GOC). In this case, the PVT model dewpoint should be tuned precisely to an accurately measured dewpoint pressure. It is not uncommon that a predicted GOC may vary 10's of meters per bar of uncertainty in the (PVT-model) dewpoint pressure. Thus an accurate description of the dewpoint pressure will have an impact on the prediction of initial oil and gas in place, placement of delineation wells, and potential field development strategy. In this situation, accurate dewpoint measurement and equally-accurate modeling of the measured dewpoint should be given due attention.

On the other hand, if accurate treatment of the dewpoint pressure is *not* required (for estimating a GOC), then we recommend using little if any weighting of the measured dewpoint pressure when tuning the PVT model. Instead, priority should be given to matching the variation of C_{7+} with pressure in the removed gas from a constant volume depletion test.

CONDENSATE BLOCKAGE

When BHFP drops below the dewpoint and two-phase gas/oil flow stabilizes in the near-wellbore region, relative permeability to gas (the primary flowing phase) may drop dramatically and the well deliverability is lowered accordingly. Saturations in the near-wellbore region can reach 40-60%, with gas permeability reductions of 0.05-0.2.

Flow in the near-wellbore region reaches a steady-state condition in a relatively short time after the BHFP drops below the dewpoint. Flow theory shows that the produced wellstream mixture is constant throughout the "steady-state" region, meaning that if we "captured" the flowing mixture at any point within this region, its composition would be the same as the producing wellstream mixture.[g]

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[g] The flowing mixture composition at some point within the steady-state region will not equal to the overall composition occupying the pore volume ("in-situ" composition) at that point, as the in-situ composition will vary throughout the steady-state region.

Permeability reduction in the near-wellbore (steady-state) region is particularly important because most of the pressure drop will be greatest in this region. A relative permeability reduction of 0.1 in the first 10 meters from the wellbore will have significantly greater impact than a k_{rg} reduction of 0.1 at a 10-m radial interval some 100 m away from the wellbore.

The relative permeability ratio k_{rg}/k_{ro} in the steady-state (SS) region is given by

$$k_{rg}/k_{ro} = (1/V_{ro} - 1)(\mu_g/\mu_o) \dotfill (9)$$

where $V_{ro} = V_o/V_t$ is the CCE oil relative volume of the produced wellstream at any pressure within the SS region. The pressure in the SS region ranges from the BHFP to the dewpoint pressure of the produced wellstream, and most deliverability loss occurs nearest the wellbore where pressures are closer to the BHFP.

Given the k_{rg}/k_{ro} ratio throughout the SS region from Eq. 9, the relative permeability to gas k_{rg} can be found directly from the relative permeability relationship. That is, $k_{rg}(S) = k_{rg}(k_{rg}/k_{ro}(S))$. Fevang and Whitson[7] have shown that the k_{rg}/k_{ro} ratio in the SS region does not vary more than about one order of magnitude throughout the life of a reservoir. With regard to uncertainties in PVT properties, and the need to measure (or predict) their values for accurate description of condensate blockage, we can conclude that oil viscosity should be given highest priority because it has the largest uncertainty both experimentally and in predictions. **Fig. 2** shows the effect on k_{rg} caused by a $\pm20\%$ error in V_{ro} for values of V_{ro} ranging from 0.5 for a near-critical condensate to 0.005 for a very lean condensate (using $\mu_g/\mu_o = 0.02/0.2 = 0.1$ and a typical Corey relative permeability relation).

Oil Viscosity
As discussed above, oil viscosity is important in the proper modeling of "condensate blockage" – i.e. the two-phase gas/oil flow effect on gas relative permeability in the region around the wellbore. Oil viscosity is usually low for reservoir condensates, ranging from 0.1 to 1 cp in the near-wellbore region.[h] Measurement of condensate viscosities is not made in routine laboratory tests, and it may be difficult to obtain measurements for lean condensates (where volumes of condensate are small). Viscosity correlations are typically unreliable for predicting low oil viscosities, and some approach is needed to ensure accurate and consistent modeling of this important property.

We recommend that the oil viscosity model be tuned to measured viscosities of a separator condensate sample[i] at reservoir temperature and pressures in the range of 100-400 bara. More "appropriate" condensate viscosity measurements can be designed (at greater expense), but having oil viscosity data from a separator oil

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[h] The viscosity of condensate flowing in the near-wellbore region *throughout depletion*, and particularly when a well goes on decline, will remain fairly constant at a value close to the condensate viscosity of the original reservoir fluid in the pressure range 100-200 bara. This viscosity is typically lower than the viscosity of condensate from a CVD test in the same pressure range, where the difference may be as much as a factor of 2-3.

[i] This idea was suggested by Dr. Jeff Creek, Chevron Oil Company, ca. 1997.

sample to tune the viscosity correlation should ensure reasonably accurate oil viscosity predictions of the condensate actually flowing in the near-wellbore region when bottomhole flowing pressures drop below the dewpoint.

Gas Viscosity

Gas viscosity for most systems will vary from 0.02 to 0.03 cp for all pressure conditions. For near-critical gas condensates and high-pressure gases the viscosity may initially be 0.05 cp, but in most of the near-wellbore region experiencing significant pressure losses the viscosity will be in the lower range of 0.02-0.03 cp. Consequently, the absolute value of viscosity does not vary greatly for a given gas, or from gas to gas system. Viscosity correlations are fairly reliable at predicting accurate gas viscosities, within 5-10% in most cases.

What *is* important with respect to gas viscosities is that consistent viscosities be used in all engineering applications – e.g. well test interpretation, well performance design, reservoir simulation, tubing calculations, pipeline calculations, etc. It is not uncommon that a 15-25% difference in gas viscosities may result using different correlations (by different engineering disciplines). This may result in similar inaccuracies in well performance calculations, even where all flow is single-phase gas!

Oil Relative Volume (Liquid Dropout Curve)

The oil relative volume or "liquid dropout curve" is perhaps the most familiar property to engineers working with gas condensate fields. The *maximum liquid dropout*[j] is often used as a subjective measure to characterize the richness or leanness of a gas condensate fluid system (perhaps even more common than the liquid yield itself!).

Two definitions of oil relative volume V_{ro} are used,

$$V_{ro} = V_o / V_d \quad\dotfill\quad (10)$$

$$V_{ro} = V_o / V_t = V_o / (V_o+V_g) \quad\dotfill\quad (11)$$

It is important to differentiate between the two definitions. The first and most common definition is oil volume relative to the dewpoint volume, where this gives a *direct* measure of the actual volume of oil condensed. The second and more important definition (for engineering purposes) is oil volume relative to total gas+oil volume, where the change in this V_{ro} depends on two effects – the change in oil volume itself and the change in total volume, $V_{ro}(p) = V_o(p)/V_t(p)$. This latter definition is more important because it enters directly in the condensate blockage problem, and at lower pressures (<250 bara) where condensate blockage is particularly important, the change in total volume $V_t(p)$ due to gas expansion becomes even more important than the change in oil volume.

Ironically, *the liquid dropout curve has little direct impact on reservoir and well performance*. Only the CCE liquid dropout $V_{ro}=V_o/V_t$ of a reservoir gas at "lower" pressures has a (second-order) effect on the modeling of condensate blockage. The

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[j] The maximum liquid dropout often occurs at a pressure near 150-250 bara (though higher for near-critical systems), and is approximately correlated to the minimum in equilibrium K-values ($K_i=y_i/x_i$) of heavier components (C_{5+}).

"average" oil saturation in a gas condensate reservoir during depletion, given approximately by the CVD experiment, is seldom important.

Interestingly, the magnitude of maximum liquid dropout does not determine whether condensate blockage will or will not be a problem for a given reservoir. It only has a second-order effect on the relative degree of severity. For example, one reservoir with 35% maximum liquid dropout may have a condensate blockage effect which has no importance to well deliverability, while another reservoir with 2% maximum liquid dropout may have condensate blockage causing a dramatic well deliverability loss.

The importance of condensate blockage on well performance is dictated by the relative importance of "reservoir" pressure losses compared to "pipe" (tubing+flowline) pressure losses. For a high-kh (kh=10 000 md-m) rich condensate well the blockage skin may be +30 with a resulting additional pressure loss of only 3 bar, where tubing pressure losses are 300 bar due to high deliverable rates. A lower-kh (kh=500 md-m) lean condensate well may have a blockage skin of +15 with a resulting additional pressure loss of 150 bar, where tubing+flowline pressure losses are 150 bar. Clearly the lean condensate well has a more severe condensate blockage problem than the rich high-kh well.

GAS CYCLING

Traditional gas cycling with full pressure maintenance is almost completely unaffected by PVT properties. The gas-gas displacement process is fully miscible, independent of the injection gas, so only the viscosity ratio of the two gases enters into the displacement performance. For practical purposes, reservoir heterogeneities (and mainly layering) dominate recovery performance of a gas cycling project – almost totally for full-pressure maintenance cycling, but also if the reservoir is cycled below the dewpoint.

As indicated by Coats[8] and others, gas cycling projects below the dewpoint are also affected by the vaporization characteristics of displacement gas on the retrograde condensate. For most gas cycling projects the injection gas is fairly lean and recovery efficiency of the reservoir retrograde condensate depends mostly on vaporization.

If injection gas is rich in intermediate components C_2-C_5 and gas cycling occurs below the (original) dewpoint, an efficient condensing/vaporizing mechanism can develop and, in some cases, develop full miscibility with the gas+condensate reservoir system. This mechanism is described by Høier and Whitson[6].

Gas Cycling Recovery Efficiency in Swept Zone
Let us look at the recovery mechanisms in a gas cycling project in the volume of the reservoir swept by injection gas – the "microscopic" or "pore-level" recovery. At a given time and position in the swept zone, the pressure is either above or below its original dewpoint when the injection gas front arrives.

If above the dewpoint, a gas-gas miscible displacement will yield 100% recovery of the *current* condensate in place. A miscible displacement is guaranteed,

independent of the injection gas used, even though the injected gas may be first-contact "immiscible" with the original reservoir gas. Miscibility develops by a simple vaporizing mechanism.

If reservoir pressure is below the dewpoint when the displacement front arrives, ultimate recovery of condensate is dictated by two processes: (1) gas-gas miscible displacement of the reservoir gas, and (2) partial vaporization of the retrograde condensate. The condensate recovery by gas-gas miscible displacement is 100% *of the condensate in solution in the reservoir gas at the time the front arrives*. The recovery efficiency of retrograde condensate by vaporization (E_v) increases gradually as increasing volumes of injection gas sweep this point in the reservoir.

We will try to discuss the two mechanisms of condensate recovery for a reservoir undergoing cycling below the dewpoint. Before the gas front arrives, (1) the amount of "condensate in place" in the gas-filled pores continuously decreases below the dewpoint; and (2) the "cumulative retrograde condensate" in the oil-filled pores continuously increases at decreasing pressures.

After the gas front arrives, (1) the gas-gas miscible displacement has a 100% efficiency *of the condensate remaining in solution in the reservoir gas*; and (2) the recovery efficiency of retrograde condensate by vaporization (E_v) rises quickly but then flattens quickly after the front passes. This behavior of E_v is due to the preferential vaporization of "light" C_{7+} first, leaving behind a heavier condensate which is less efficiently (more slowly) vaporized. The more volumes of injection gas passing over the condensate, the less efficient vaporization becomes. Even if pressure continues to decline, new condensation will not occur because the gas behind the front is lean and has little dissolved condensate.

Accurate prediction of the changing vaporization efficiency requires (1) an accurate description of the C_{7+} molar distribution of the condensate, and (2) the K-values of C_{7+} components as a function of pressure and overall composition. Because total condensate recovery efficiency in the swept region may be dependent on an accurate description of the component-by-component vaporization process, effort should be made to obtain compositional data which describes the vaporization process. Extra effort should also be given towards fitting these *compositional* data with the EOS model. However, it is worthwhile to first evaluate the potential for recovery by vaporization of retrograde condensate below the dewpoint prior to obtaining extensive (and expensive) laboratory data of the type described above.

Evaluating Gas Cycling Potential

Defining the "target" of condensate recovery by gas cycling is important to economic evaluation and field development strategy. The following definitions are useful for defining the target of gas cycling:

1. RF_{oD} is, as previously discussed (Eq. 7), the condensate recovery by pressure depletion to some reservoir pressure – e.g. the end of production p_{end}, or at the pressure of gas cycling p_{cycle}.

2. RF_{oM} is the recovery of condensate which would be expected at the end of cycling due to gas-gas miscible displacement with 100% sweep efficiency

(E_s=100%); it is assumed the gas cycling occurs at a constant pressure $p_{cycling}$ above or below the original dewpoint.

3. RF_{oV} (=100 – RF_{oM}) is the recovery of condensate which would be expected at the end of cycling due to vaporization of retrograde condensate with 100% sweep efficiency (E_s=100%); it is assumed the gas cycling occurs at a constant pressure $p_{cycling}$ below the initial dewpoint. Note, RF_{oV} = 100% for gas cycling above the initial dewpoint.

4. RF_{oDx} is the extra condensate recovery from pressure depletion of the reservoir volume *not swept* by injection gas during cycling, (depletion from $p_{cycling}$ to p_{end}). Note, $RF_{oDx} = RF_{oD}(p_{cycling}) – RF_{oD}(p_{end})$.

5. RF_{oult} is the ultimate condensate recovery due to (a) depletion prior to cycling, (b) cycling, and (c) depletion after cycling. For $p_{cycling} > p_d$,

$$RF_{oult} = RF_{oD} + E_S \cdot RF_{oM} + (1 - E_S) \cdot RF_{oDx} \quad\text{.. (12)}$$

while for $p_{cycling} < p_d$,

$$RF_{oult} = RF_{oD} + E_S \cdot (RF_{oM} + E_V \cdot RF_{oV}) + (1 - E_S) \cdot RF_{oDx} \quad\text{.. (13)}$$

where E_S defines the final areal-times-vertical sweep efficiency at the end of cycling, and E_V defines the final efficiency of vaporized retrograde condensate (for $p_{cycling}$ below the dewpoint).

What components of the ultimate recovery are strongly dependent on PVT properties?

We already have defined the dependence of RF_{oD} on PVT properties (Eq. 7), where Z-factors and variation of C_{7+} in the CVD produced gas phase determine RF_{oD}. It is also easy to show that RF_{oM} is given exclusively by data in the CCE and CVD tests, as is RF_{oV} (= 100 – RF_{oM}).

The only other PVT-dependent parameter is E_V, which (as mentioned earlier) is determined by (1) the C_{7+} molar distribution of retrograde condensate, and (2) the K-values of C_{7+} components as a function of pressure and overall composition. However, E_V is only important for cycling below the dewpoint, and often the contribution of vaporization to overall condensate recovery is relatively small.

Fig. 3 shows recovery of condensate versus pressure for a high-pressure offshore gas condensate field. Initial pressure is 900 bara, and dewpoint is 400 bara. The calculations are based only on CCE and CVD data, as shown in **Table 2**. The lower curve gives $RF_{oD}(p)$, the recovery due to pressure depletion. The upper curve gives $RF_{oM}(p)$, the recovery due to gas-gas miscible displacement with 100% sweep efficiency but with no vaporization of retrograde condensate.

In this high-pressure reservoir, the additional recovery due to gas cycling will not be realized until late into the life of the field, as pressure approaches the dewpoint and

recovery is about 30%. In terms of net present value, and depending on when the investment for compressors etc. are required, cycling does not appear attractive.

For the same reservoir but initially saturated at the dewpoint of 400 bara, additional condensate recovery by gas cycling is more attractive, as shown in **Fig. 4**. Here the rapid decline in producing liquid yields will have a pronounced affect on project economy, while successful cycling (high sweep efficiency E_S) can provide prolonged initial liquid yields and higher ultimate recovery. For this case, net present value is more positive to a cycling project.

In summary, most of the primary evaluation for potential of gas cycling can be quantified by CVD and CCE data. Vaporization effects are often less significant than commonly thought, an observation which follows from the calculation of recovery factors RF_{oD} and RF_{oM} based on CVD and CCE data. When vaporization recovery (RF_{oV}) is important, special multi-contact vaporization tests should be conducted and fit with the PVT model, where variation of C_{7+} in the equilibrium gas is the most important data.

Combined Condensing/Vaporizing Mechanism

Historically it has been assumed that any gas cycling project in a gas condensate reservoir was miscible only by the vaporizing gas drive mechanism. Consequently, the MMP has always been assumed equal to the dewpoint pressure. Cycling projects where reservoir pressure drops below the dewpoint were considered "inferior" because only partial vaporization of the retrograde condensate could be expected. For most separator injection gases these traditional assumptions are valid. However, Høier and Whitson[6] show that miscible displacement of gas condensates (by the condensing/vaporizing mechanism) can be obtained at pressures far below the dewpoint for continuous or slug injection of gas enriched with components C_2-C_5.

Whether a below-dewpoint miscible displacement can develop in a gas condensate depends on (1) pressure, (2) composition of the injection gas, (3) composition of the retrograde condensate ahead of the front, and (4) physical dispersion or fingering (for slug injection). Although the same conditions also apply for enriched-gas miscible displacement of an oil reservoir, conditions (3) and (4) are particularly important for gas condensates.

The most likely candidate for enriched-gas miscible gas cycling below the dewpoint would be rich or near-critical condensates where injection gas is not available in sufficient quantities to maintain reservoir pressure.

"REPRESENTATIVE" SAMPLES

Before a field development starts, the primary goal of sampling is to obtain "representative" samples of the fluids found in the reservoir at initial conditions. It may be difficult to obtain a representative sample because of two-phase flow effects near the wellbore. This occurs when a well is produced with a flowing bottomhole pressures below the saturation pressure of the reservoir fluids. It is also commonly thought that "bad" fluid samples result if gas coning or oil coning occurs during sampling.

The most representative insitu samples are usually obtained when the reservoir fluid is single phase at the point of sampling, be it bottomhole or at the surface. Even this condition, however, may not ensure representative sampling. And, as shown by Fevang and Whitson[9], samples obtained during gas coning in an oil well can provide accurate insitu representative samples if a proper laboratory procedure is followed.

Because reservoir fluid composition can vary areally, between fault blocks, and as a function of depth, we are actually interested in obtaining a sample of reservoir fluid that is representative of the volume being drained by the well during the test. Unfortunately, the concept of a "representative" sample is usually *a sample that correctly reflects the composition of reservoir fluid at the depth or depths being tested*.

If we suspect or know that a sample is not "representative" (according to this definition), then we tend to do nothing with the sample. Or we question the validity of the PVT analysis done on the "unrepresentative" sample, and consequently don't include the measured data when developing the PVT model.

We strongly recommend against using this definition of "representivity." First of all, it is a definition that costs our industry in terms of wasted money and time, and lost opportunity. An important point to keep in mind is that:

> *Any fluid sample that produces from a reservoir is automatically representative of that reservoir. After all, the sample is produced from the reservoir!*

The final EOS fluid characterization of a field should match all (accurate) PVT measurements of all (uncontaminated) samples produced from the reservoir, independent of whether the samples are representative of insitu compositions.

Accuracy of PVT Data ≠ Insitu Representivity of Sample

Accurate PVT measurements can be made on both representative and unrepresentative samples. Inaccurate PVT measurements can also be made on both types of samples; bad PVT data should be ignored.

Furthermore, an EOS fluid characterization is used to predict compositional changes during depletion which represent a much greater variation than the compositional differences shown by "representative" and "unrepresentative" samples.

Another misconception in "representative" fluid sampling of gas condensates is that it is difficult to obtain insitu-representative samples in saturated gas condensate reservoirs (with underlying oil). The exact opposite is true! Fevang and Whitson[9] have shown that if a gas condensate is initially saturated and in contact with an underlying oil zone, then a near-perfect insitu-representative sample can be obtained (at the gas-oil contact) – independent of whether the reservoir gas and reservoir oil samples collected are insitu-representative.

In summary, all "uncontaminated" samples collected from a reservoir are *reservoir representative* and, accordingly, should be described accurately by the PVT model. *Insitu-representative* samples may be difficult to obtain. But even when collected, they may not represent more than a "local" volume of the reservoir, where significant variations in fluid composition exist vertically and areally away from the point of sampling.

EOS MODELING

To make EOS calculations, the minimum required input are (1) molar composition, and (2) molecular weight and specific gravity of the heaviest fraction (usually C_{7+} or C_{10+}). With this minimum information, an EOS can calculate practically any phase and volumetric property of the mixture - e.g.,

- · Bubblepoint or dewpoint pressure at a specified temperature
- · Pressure-temperature phase envelope
- · Densities and compressibilities of oil and gas phases
- · Separator gas-oil ratio and surface gravities
- · Depletion PVT experiments
- · Multicontact gas injection experiments

Splitting the Plus Fraction
Usually, three to five C_{7+} fractions (or 2 to 3 C_{10+} fractions) should be used. The Whitson et al.[10] splitting/characterization procedure is recommended for the Peng-Robinson EOS. The Pedersen et al.[11] method is recommended for the Soave-Redlich-Kwong EOS, where each plus fraction has equal mass fraction.

When true boiling point distillation data are available, these data should be used directly, or to define parameters in the splitting model. TBP data can be used, for example, to define the molar distribution parameters α and η in the gamma distribution model, and constants in the specific gravity correlation.

Tuning the EOS Model
If measured PVT data are available, and they have been checked for accuracy[k], the EOS characterization can be modified to improve the predictions of measured data. Manual adjustments of EOS parameters such as binary interaction parameters (BIPs) and heavy component critical properties can be used, though this approach is time consuming (and often frustrating). Nonlinear regression can be used to mathematically minimize the difference between EOS predictions and measured PVT data. A critical aspect of the "tuning" procedure is to properly weigh individual data (and data types) based on the importance of individual data to reservoir and well performance.

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[k] Material balance methods are often useful for checking consistency of depletion experiments (CVD and DLE). The material balance starts at the final stage of the experiment, with known amounts and compositions. Removed gas is then added back from each depletion stage, arriving at the initial fluid. Comparison with the initial composition gives a direct measure of consistency. Another approach is to start the material balance with the initial fluid, back-calculating the oil phase properties and compositions as depletion progresses; this approach is only useful for medium-rich to rich condensates because small errors in V_{ro} have a dramatic effect on the back-calculated oil properties.

Developing a "Common" EOS Model for Multiple Reservoir Fluids

An important requirement in the development of an EOS model is the need to have one set of components to describe all reservoir samples in a given field. This is particularly important if the reservoir fluids from different parts of the reservoir (layers or fault blocks) mix in the reservoir. It also may be important if mixing only occurs at the surface.

Our experience has shown that a single set of components and a single set of EOS component properties can be used to describe a wide range of reservoir fluids, ranging from leaner gas condensates to low-GOR oils – fluids which may or may not be in fluid communication initially. Whitson et al.[10] propose one method for developing a "common" EOS model for multiple reservoir fluids. Another approach is to develop the EOS model based on a single sample, and then "generate" the other reservoir fluids by flash calculations (saturation pressure, two-phase split, or isothermal gradient).

Generating Black-Oil PVT Tables

Once the EOS characterization has been developed, a primary application of the EOS is to generate black-oil PVT tables for reservoir simulation, material balance and flow calculations (also pipeflow calculations). The most common application of black-oil PVT is black-oil simulation.

The procedure proposed by Whitson and Torp[12] is recommended for generating black-oil PVT tables. They suggest using a reference fluid to conduct a depletion test (e.g. CVD), sending the equilibrium reservoir phases separately through a surface separation to obtain (R_s, B_o, μ_o) for the oil phase and (r_s, B_{gd}, and μ_g) for the gas phase. Surface densities are taken from the surface separation of the reference fluid.

The definition of black-oil PVT properties are:

$$B_o = \frac{V_o}{V_{oo}} = \text{oil formation volume factor}$$

$$R_s = \frac{V_{go}}{V_{oo}} = \text{solution gas-oil ratio}$$

$$B_{gd} = \frac{V_g}{V_{gg}} = \text{dry gas formation volume factor}$$

$$r_s = \frac{V_{og}}{V_{gg}} = \text{solution oil-gas ratio}$$

where subscripts are defined as:

o : reservoir oil phase at p and T
g : reservoir gas phase at p and T

oo : surface oil from reservoir oil ("solution" oil)
go : surface gas from reservoir oil ("solution" gas)
og : stock-tank oil (condensate) from reservoir gas
gg : surface gas from reservoir gas

The important black-oil PVT properties for IFIP calculations in gas condensate reservoirs are r_s/B_{gd} = the surface oil in place per reservoir gas volume[I], and $1/B_{gd}$ = the surface gas in place per reservoir gas volume. The term r_s/B_{gd} is the quantity required by "geologists" to convert reservoir gas pore volumes to surface oil – a kind of "oil FVF (B_o)" for the reservoir gas phase. In fact, for compositionally-grading reservoirs with a transition from gas to oil through an undersaturated (critical) state, the term r_s/B_{gd} *should equal* B_o – exactly – at the undersaturated gas-oil contact, thereby ensuring continuity and consistency.

Some special problems related to generating black-oil PVT tables with an EOS include:

1. How to extrapolate saturated PVT properties to pressures higher than the original saturation pressure of the reference fluid.
2. Non-monotonic saturated oil properties B_o and R_s for gas condensate systems.
3. Consistency requirements for comparison of black-oil and EOS simulations.
4. Handling saturated reservoirs with a gas overlying an oil, where black-oil PVT properties from the two fluid systems can be significantly different.
5. Modeling reservoirs with compositional gradients, and how to initialize these reservoirs in black-oil simulators.

Extrapolating Saturated Tables
Extrapolating saturated black-oil PVT tables can be done in a number of ways, depending on the reservoir process and why the extrapolation is needed. Extrapolation is usually required for (a) gas injection studies, (b) reservoirs with compositional gradients where the reference sample is undersaturated, or (c) ensuring numerical stability for near-critical fluid systems where pressures may exceed the original saturation pressure during iteration.

Methods for extrapolating black-oil PVT tables include: (a) mixing the incipient phase from a saturation pressure of the reference fluid to increase the saturation pressure, usually in a number of steps ("reverse DLE"), (b) using a compositional gradient algorithm, or (c) adding an injection gas in increments and determining the PVT properties of each incremental mixture, or (d) adding injection gas to a "maximum" saturation pressure and then conducting a depletion test – either stopping at the original saturation pressure or continuing all the way to a low (minimum) pressure.

The most appropriate method for extrapolating saturated properties may not be obvious. It will often depend on the reservoir process. Several extrapolation methods may be tested in a realistic reservoir simulation model, where results are compared with a fully-compositional EOS model. The extrapolation method which consistently gives results most similar to the EOS model can be said to "best represent" the reservoir process. Comparisons should include initial fluids in place, recoveries, and GOR profiles of individual wells.

Non-monotonic Saturated Oil Properties
For medium to lean gas condensates we have often found that the saturated oil black-oil PVT properties B_o and R_s are not monotonic – first increasing just below the

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[I] r_s/B_{gd} is equivalent to the compositional "equivalent" C_{7+} content in the reservoir gas, y_{7+}.

dewpoint pressure, reaching a maximum, and then decreasing with pressure in a "normal" fashion. The physical explanation for this behavior is that the first condensate which appears is (for lean and medium-lean condensates) quite heavy, with a high surface-oil density (e.g. low API gravity < 40). The "low-gravity" or heavy condensate has, as expected[m], a relatively low B_o and R_s.

As more condensate evolves from the reservoir gas, the total reservoir condensate becomes lighter with higher (API) gravity. The change in the gravity has a stronger influence than the decreasing pressure, so the net change in B_o and R_s is to increase with decreasing pressure.

As pressure continues to decrease, the condensate gravity stabilizes and "normal" pressure dependence of saturated oil properties results, with B_o and R_s both decreasing at decreasing pressures.

One solution we have found useful in this situation is to generate a separate set of black-oil PVT tables, starting with the incipient oil phase of the original reservoir gas at dewpoint, and using a depletion (DLE or CVD) test with this oil. The "oil phase" PVT table (B_o, R_s, and μ_o) from depletion of the incipient oil can then be used together with the "gas phase" PVT table (B_{gd}, r_s, μ_g) from depletion of the original reservoir gas.

Consistency Between Black-Oil and EOS Models

Coats[8] addresses the need for compositional EOS models for gas condensate reservoirs. He shows that gas cycling below the dewpoint is the only situation when black-oil modeling may be inadequate. He suggests that an EOS model with at least 3 C_{7+} fractions should be used to properly model vaporization recovery of retrograde condensate. His results indicate that depletion, single-well modeling, and gas cycling above the dewpoint are properly modeled with a black-oil model.

Fevang and Whitson[7] show that some modification of black-oil saturated oil viscosities may be needed to ensure accurate single-well modeling of condensate blockage. They show that the oil viscosity in the near-wellbore blockage region is the liquid which condenses from the flowing wellstream, and *not* a cumulative CVD-type liquid. The flowing blockage-area liquid can be significantly lighter than the CVD-type condensate, and with correspondingly lower viscosity (1.5 to 5 times lower).

Handling Saturated Gas/Oil Systems

Black-oil PVT properties for a saturated reservoir gas/oil system (gas cap overlying oil) may be difficult to generate using a consistent approach. Traditionally we generate a complete set of PVT tables separately for the reservoir oil and reservoir gas, using a depletion test for the reservoir oil (e.g. DLE) and a depletion test for the reservoir gas (e.g. CVD). From the depletion test of each reservoir phase, the complete set of black-oil PVT tables are consistent only at the initial saturation pressure. That is, the incipient oil from the dewpoint of the reservoir gas is identical to the reservoir oil; and the incipient gas from the bubblepoint of the reservoir oil is identical to the reservoir gas.

The saturated oil and gas phases which form from the two depletion tests are different below the original saturation pressure. This leads to differences in PVT properties

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[m] Expected, for example, based on a Standing-type saturated correlations for B_o and R_s.

which are not handled consistently in a black-oil simulator. One solution is to use two PVT regions, one for the cells originally in the gas cap, and another region for cells originally in the oil. This solution is incorrect for cells which originally are defined as one "phase" but become the other "phase" due to movement of the gas-oil contact. Still, this may be the best solution in some reservoirs.

<u>Initializing Reservoirs with Compositional Gradients</u>
Two problems arise when trying to use black-oil simulators for reservoirs with compositional gradients. The one problem is obtaining correct initial surface fluids in place (compared with initialization using an EOS model). The second problem is analogous to that discussed above for saturated gas/oil systems, where PVT properties of the different reservoir fluids are not the same.

The best way to ensure accurate initialization of surface gas and surface oil in place is to initialize using R_s and r_s versus depth, instead of using saturation pressure versus depth. The more-common practice of initializing with saturation pressure versus depth leads to problems of initial fluid in place because of the second problem mentioned above – i.e. though only one PVT table is used, the black-oil PVT properties of the different reservoir fluids are not the same.

Our recommended method of using R_s an r_s versus depth for initialization may lead to a small error in recoveries near the initial saturation pressures. However, this error is usually insignificant and always less than errors introduced by wrong initial fluids in place caused by initialization with saturation pressure versus depth.

Pseudoization (Grouping Components)
Some reservoir processes can not be adequately modeled with a black-oil PVT formulation. Gas injection, near critical oil and gas condensate systems, and laboratory simulations may require fully compositional EOS simulation. The mathematical complexity of integrating an EOS in a reservoir simulator is many times that of using a simple black-oil PVT formulation. The result is a simulator that runs much slower than a black-oil simulator. It may be necessary to economize the number of components used in compositional simulation by "pseudoization" (i.e. reducing the number of components in an EOS characterization).

The number of components used in an EOS characterization depends both on computational restraints, and on the desired level of accuracy from the EOS. Some balance between these two requirements is needed to determine the final number of components for solving a given problem.

An initial fluid characterization will typically contain from 13 to 20 components, and sometimes more. For best results, a stepwise pseudoization procedure is recommended, whereby several pseudoized characterizations are developed sequentially (e.g. 15, 12, 10, 7, and 5 pseudocomponents). The goal with each pseudoization is to maintain PVT predictions as close to the original full characterization as possible. With this stepwise approach, it is readily determined how few pseudocomponents are necessary to maintain a required similarity to the original

full characterization.[a] Reducing the number of components in a stepwise fashion has three main advantages:

1. It is possible to establish when a further reduction in number of components results in predicted properties that deviate unacceptably from the original N-component characterization.

2. The procedure usually results in several alternative characterizations with a common basis. One simulation might require more components than another (e.g. radial single-well study versus full-field simulation).   Because several characterizations are available, and they are "related" through the original N-component characterization, more consistency can be expected.

3. Experience has shown that better results are obtained in going from the N-component characterization to (for example) a 7-component characterization in several steps, than going from an N-component to a 7-component characterization in a single pseudoization.

The recommended stepwise pseudoization procedure is given below:

1. Use regression to develop an EOS characterization so that all relevant and accurate PVT data are adequately matched. (This is probably the most difficult part of any fluid characterization).

2. Using this tuned EOS, simulate several PVT experiments. Save the results of these calculations as "data". The experiments should cover as large as possible the pressure-, temperature-, and composition-space expected in the reservoir during its development.   If gas injection is being considered, multicontact gas injection experiments should be included, perhaps several with different injection gas compositions.

3. Reduce the number of components by 2 or 3 by grouping components, e.g., group iso- and normal-alkanes of butanes and pentanes.

4. Fine tune (by regression) the newly-created pseudo-component EOS parameters. Recommended parameters include multipliers to EOS constants A and B and volume shift parameter s for each newly-created pseudocomponent separately; and BIPs between methane and the C_{7+} fractions (collectively).

5. In a subsequent step, regress viscosities for the EOS model with the newly-created pseudocomponents.

6. Return to step 3, selecting 2 or 3 new components to group.

Fig. 5 summarizes an *example* pseudoization procedure.

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[a] The number of pseudocomponents will vary according to the application. Simulation of depletion processes and water flooding will generally require only 4 or 5 pseudocomponents; immiscible gas injection may require additional pseudocomponents, and developed miscible gas injection will probably require at least 6 to 8 pseudocomponents.

CONCLUDING REMARKS

We have tried to summarize and detail the importance of various PVT properties on the reservoir and well performance of gas condensate fields.

1. For calculation of initial gas and condensate in place the key PVT data are (a) initial Z-factor and (b) initial C_{7+} molar content. In terms of black-oil PVT properties, the two "equivalent" PVT quantities are (a) B_{gd} and (b) r_s/B_{gd}.

2. The constant composition and constant volume depletion tests provide the key data for quantifying recovery of produced gas and condensate during depletion. Above the dewpoint depletion recoveries of gas and condensate are equal and are given by the variation of Z-factor with pressure.

3. For calculation of condensate recovery and varying yield (producing oil-gas ratio) during depletion it is critical to obtain accurate measurement of C_{7+} (r_s) variation in the produced gas from a constant volume depletion test.

4. For near-saturated gas condensate reservoirs producing by pressure depletion, *cumulative condensate produced* is insensitive to whether the reservoir is initialized with or without a compositional gradient (even though initial condensate in place can be significantly different for the two initializations).

5. Oil viscosity should be measured and modeled accurately to properly model condensate blockage and the resulting reduction in gas deliverability.

6. For richer gas condensates, the oil relative volume (from a constant composition expansion test) has only a "secondary" effect on the modeling of condensate blockage; for lean condensates, V_{ro} has a small effect on blockage.

7. For gas cycling projects above the dewpoint, PVT properties have essentially no effect on condensate recovery because the displacement will always be miscible. Only the definition of initial condensate in place is important. Gas viscosity has only a minor effect on gas cycling.

8. For gas cycling below the dewpoint, the key PVT properties are Z-factor variation during depletion, C_{7+} content in the reservoir gas during depletion, and C_{7+} vaporized from the reservoir condensate into the injection (displacement) gas.

Nomenclature

B_o = formation volume factor (FVF) of reservoir oil phase
B_{gd} = dry gas FVF of reservoir gas phase
C_{og} = conversion factor for gas-equivalent of surface oil
C_{5+} = Pentanes-plus
C_{6+} = Hexanes-plus

C_{7+}	=	Heptanes-plus
C_{10+}	=	Decanes-plus
E_S	=	sweep (vertical and areal) efficiency
E_V	=	vaporization efficiency of condensate recovery below the dewpoint
k_{rg}	=	gas relative permeability
k_{ro}	=	oil relative permeability
K_i	=	equilibrium ratio (K-value) of component i
M_o	=	surface oil molecular weight
M_{7+}	=	C_{7+} molecular weight
N	=	total number
n_d	=	moles of gas at initial (dewpoint) pressure
Δn_{pk}	=	incremental CVD moles of gas produced in stage k
p	=	pressure
p_b	=	bubblepoint pressure
p_d	=	dewpoint pressure
p_i	=	initial pressure
p_s	=	saturation pressure
p_{sc}	=	standard pressure
q_o	=	surface oil production rate
q_{7+}	=	Heptanes-plus production rate
R	=	universal gas constant
r_s	=	solution oil-gas ratio of reservoir gas phase
r_{si}	=	solution oil-gas ratio at initial pressure
R_s	=	solution gas-oil ratio of reservoir oil phase
RF_{gD}	=	depletion recovery factor of gas
RF_{oD}	=	depletion recovery factor of condensate
RF_{oDx}	=	extra depletion recovery factor of condensate (after gas cycling)
RF_{oM}	=	gas-gas miscible recovery factor of condensate
RF_{oult}	=	ultimate recovery factor of condensate
T_{sc}	=	standard temperature
V_d	=	oil volume at dewpoint pressure
V_g	=	gas volume
V_o	=	oil volume
V_{ro}	=	oil volume divided by oil volume at saturation pressure
V_t	=	total (gas+oil) volume
x_i	=	oil composition
y_i	=	gas composition
y_{7+}	=	C_{7+} composition in the produced gas
z_{7+}	=	mole fraction of C_{7+} of produced wellstream
z_i	=	produced wellstream or total mole fraction
Z	=	Z-factor
Z_i	=	Initial Z factor
ρ_o	=	surface oil density at standard conditions
ρ_{7+}	=	surface density of C_{7+} at standard conditions
μ_g	=	gas viscosity
μ_o	=	oil viscosity

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Table 1 – Approximate Depletion Material Balance Calculations Based on CVD and CCE Test Results.

CVD Data Conversion to Surface Oil and Gas Recoveries

Based on Simplified Surface Flash (Surface Gas = C6- and Surface Oil = C7+)
© PERA a/s, programmed by Curtis H. Whitson (19981126)

C7+ Mole Weight   **161** kg/kmol
C7+ Density   **830** kg/m3
Cog   122 Sm3/Sm3 (assumed constant)
(p/z)i/(p/z)d   0.9120

Input (red)

	P	Z	n_p/n	dnp/nd	y_{7+}	Approx. Solution OGR r_s	RFg	RFo
	bara		%	%	mol-%	Sm3/Sm3	%	%
Pi	532	1.2172	0.000		3.996	3.407E-04	0.00	0.00
Pd	430	1.0788	0.000	0.000	3.996	3.407E-04	8.80	8.80
	408		2.710	2.710	3.339	2.827E-04	11.29	10.87
	372		7.070	4.360	3.366	2.851E-04	15.29	14.22
	320		14.720	7.650	2.875	2.423E-04	22.35	19.24
	272		24.420	9.700	2.245	1.880E-04	31.36	24.21
	221		36.060	11.640	1.742	1.451E-04	42.22	28.83
	170		49.130	13.070	1.302	1.080E-04	54.48	32.72
	121		62.630	13.500	1.055	8.727E-05	67.17	35.97
	62		79.160	16.530	0.675	5.562E-05	82.76	38.52

Table 2 – Approximate Depletion and Gas Cycling Calculations Based on CVD and CCE Tests.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1									Calculated Properties					No Vaporization	
2		Data from PVTx CVD Calculations							Below Dewpoint Only					Pi=Pd	Pi=900
3	Prssure	olution OGR*	Bgd	Visg	Gpw/Gi	Z-factor	Vro	Gp/G*	Gp/G*	Gw/Gi***	Np/N	Np/N	Gp/G*	Np/N	Np/N
4	Bar	Sm3/Sm3	m3/Sm3	cp	%	Z	%	frac.	Dew point	Dewpoint	%	%	%	%	%
5												RFoD	RFgD	RFoM	RFoV
6	900	8.07E-04	3.69E-03	0.06227	0.0	1.928	0.000	0.0000				0.0	0.00		100.0
7	800	8.07E-04	3.83E-03	0.05769	0.0	1.778	0.000	0.0364				3.6	3.64		100.0
8	700	8.07E-04	4.01E-03	0.05311	0.0	1.628	0.000	0.0789				7.9	7.89		100.0
9	600	8.07E-04	4.24E-03	0.04843	0.0	1.477	0.000	0.1297				13.0	12.97		100.0
10	500	8.07E-04	4.56E-03	0.04355	0.0	1.325	0.000	0.1917				19.2	19.17		100.0
11	450	8.07E-04	4.78E-03	0.04097	0.0	1.249	0.000	0.2284				22.8	22.84		100.0
12	398	8.07E-04	5.07E-03	0.03813	0.0	1.171	0.000	0.2721	0.0	1.000	0.0	27.2	27.21	100.0	100.0
13	375	7.62E-04	5.21E-03	0.03596	3.3	1.138	2.581	0.2943	3.0	**0.892**	3.2	29.5	29.43	**84.7**	**88.8**
14	350	7.09E-04	5.39E-03	0.03359	7.1	1.105	5.222	0.3214	6.8	0.786	6.7	32.1	32.14	70.9	78.8
15	325	6.45E-04	5.61E-03	0.03112	11.4	1.075	7.973	0.3522	11.0	0.690	10.3	34.7	35.22	59.2	70.3
16	300	5.75E-04	5.89E-03	0.02863	16.1	1.049	10.401	0.3873	15.8	0.605	13.8	37.3	38.73	50.0	63.6
17	275	5.06E-04	6.24E-03	0.02631	21.2	1.027	12.042	0.4264	21.2	0.533	17.2	39.8	42.64	43.6	59.0
18	250	4.46E-04	6.70E-03	0.02424	26.6	1.008	12.933	0.4689	27.0	0.471	20.5	42.1	46.89	39.6	56.0
19	225	3.95E-04	7.28E-03	0.02242	32.5	0.993	13.297	0.5145	33.3	0.415	23.5	44.3	51.45	37.3	54.3
20	200	3.52E-04	8.04E-03	0.02082	38.6	0.980	13.317	0.5627	39.9	0.364	26.4	46.4	56.27	36.1	53.5
21	175	3.16E-04	9.06E-03	0.01943	45.1	0.970	13.108	0.6135	46.9	0.316	29.0	48.4	61.35	35.8	53.3
22	150	2.86E-04	1.04E-02	0.01824	51.9	0.963	12.738	0.6662	54.1	0.270	31.6	50.2	66.62	36.2	53.6
23	125	2.64E-04	1.24E-02	0.01723	59.0	0.958	12.246	0.7206	61.6	0.226	34.0	52.0	72.06	37.0	54.2
24	100	2.52E-04	1.55E-02	0.01638	66.2	0.957	11.674	0.7762	69.3	0.181	36.3	53.6	77.62	38.2	55.0
25															
26	* using Gas Z-factor, not strictly correct since composition is changing with time								Cell J14: =A13/$A$12*F13/$F$12*(1-G13/100)						
27	** using 2-stage separator 50 bara and 50 deg C and then to Stc.								Cell N14: =(1-E13/100)*(B13/$B$12)*100*J13+K13						
28	*** Wet gas left in cell ngw=ntot-noil								Cell O14: =100-(100-N13)*(100-$M$12)/100						

**Fig. 1— Approximate Material Balance Calculations
Based on CVD Test Results.**

**Fig. 2 – Effect of error in Vro on gas relative permeability
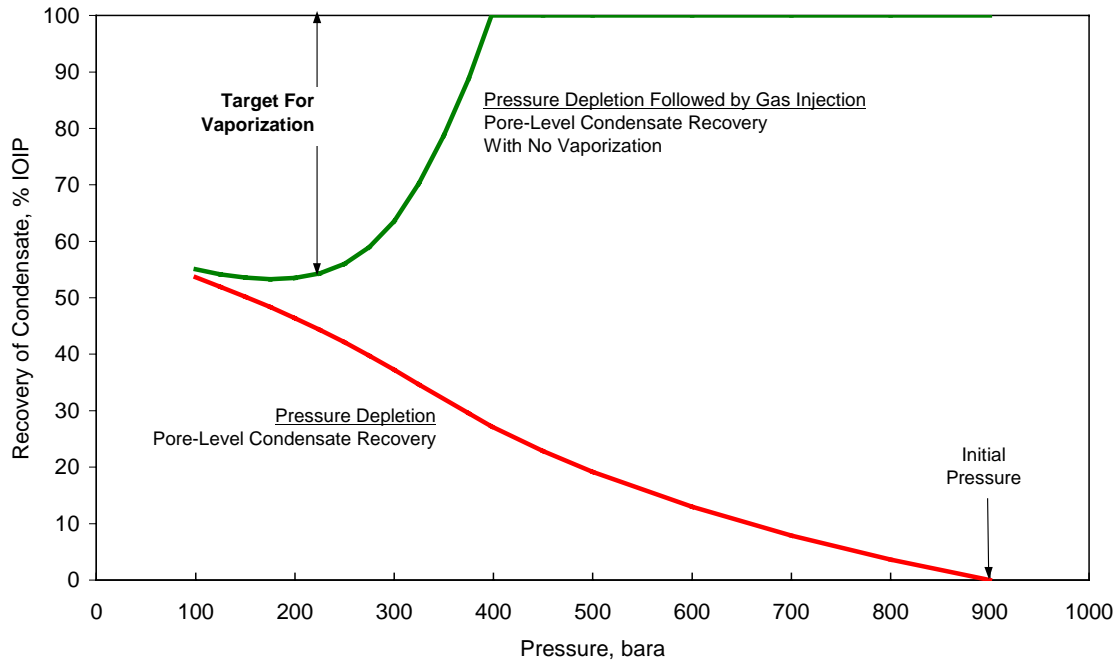in near-wellbore condensate blockage zone.**

**Fig. 3 – Condensate recoveries for pressure depletion and
gas cycling below the dewpoint in a high-pressure undersaturated reservoir.**
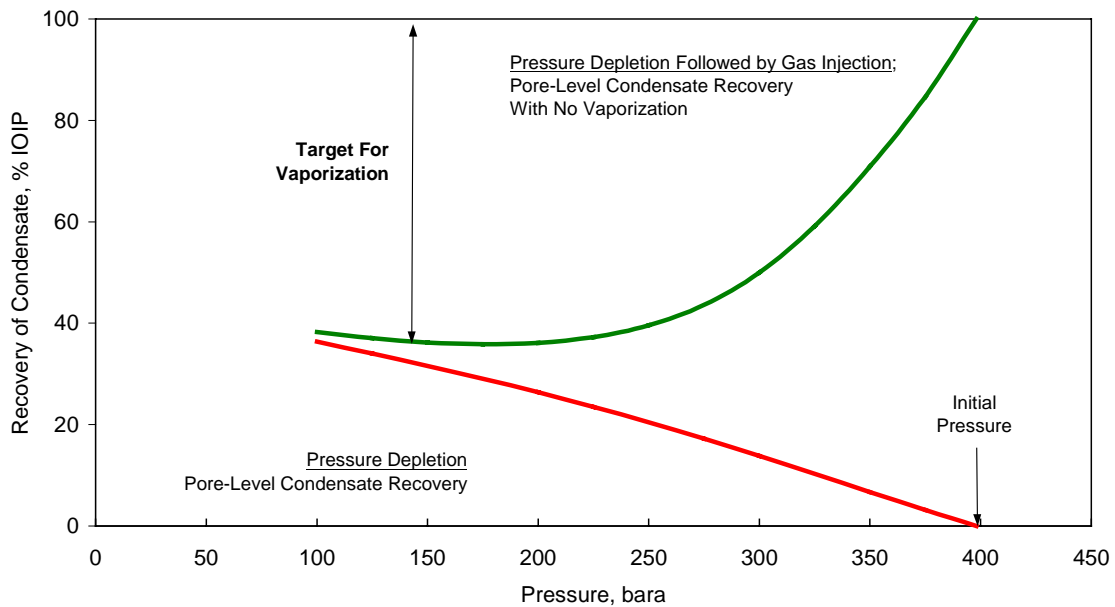

**Fig. 4 – Condensate recoveries for pressure depletion and
gas cycling below the dewpoint in a saturated reservoir.**

Component	EOS22	EOS19	EOS12	EOS10	EOS9	EOS6	EOS4	EOS3
N2	N2	C1N2	C1N2	C1N2	C1N2	C1N2		
CO2	CO2	CO2	CO2	CO2				
C1	C1				CO2C2	C02C2		
C2	C2	C2	C2	C2			C1N2CO2C2-C6	C1N2CO2C2-C6
C3	C3	C3	C3	C3	C3			
IC4	IC4	IC4NC4	IC4NC4	IC4NC4	IC4NC4			
NC4	NC4					C3-C6		
IC5	IC5	IC5NC5	IC5NC5	IC5NC5	IC5NC5			
NC5	NC5							
C6	C6	C6	C6	C6	C6			
C7	C7	C7	C7C8					
C8	C8	C8		C7C8C9F1F2	C7C8C9F1F2	C7C8C9F1F2	C7C8C9F1F2	
C9	C9	C9	C9F1F2					
C10+	F1	F1						C7C8C9F1-F8
	F2	F2						
	F3	F3	F3-F5					
	F4	F4						
	F5	F5	F3-F8	F3-F8	F3-F8	F3-F8	F3-F8	
	F6	F6	F6-F8					
	F7	F7						
	F8	F8						
	F9	F9	F9	F9	F9	F9	F9	F9

Fig. 5 – Example pseudoization procedure reducing an original EOS characterization with 22 components to multiple pseudoized characterizations.