Understanding Gas-Condensate Reservoirs

How does a company optimize development of a gas-condensate field, when depletion leaves valuable condensate fluids in a reservoir and condensate blockage can cause a loss of well productivity? Gas-condensate fields present this puzzle. The first step must be to understand the fluids and how they flow in the reservoir.

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A gas-condensate reservoir can choke on its most valuable components. Condensate liquid saturation can build up near a well because of drawdown below the dewpoint pressure, ultimately restricting the flow of gas. The near-well choking can reduce the productivity of a well by a factor of two or more.

This phenomenon, called condensate blockage or condensate banking, results from a combination of factors, including fluid phase properties, formation flow characteristics and pressures in the formation and in the wellbore. If these factors are not understood at the beginning of field development, sooner or later production performance can suffer.

For example, well productivity in the Arun field, in North Sumatra, Indonesia, declined significantly about 10 years after production began. This was a serious problem, since well deliverability was critical to meet contractual obligations for gas delivery. Well studies, including pressure transient testing, indicated the loss was caused by accumulation of condensate near the wellbore.[1]

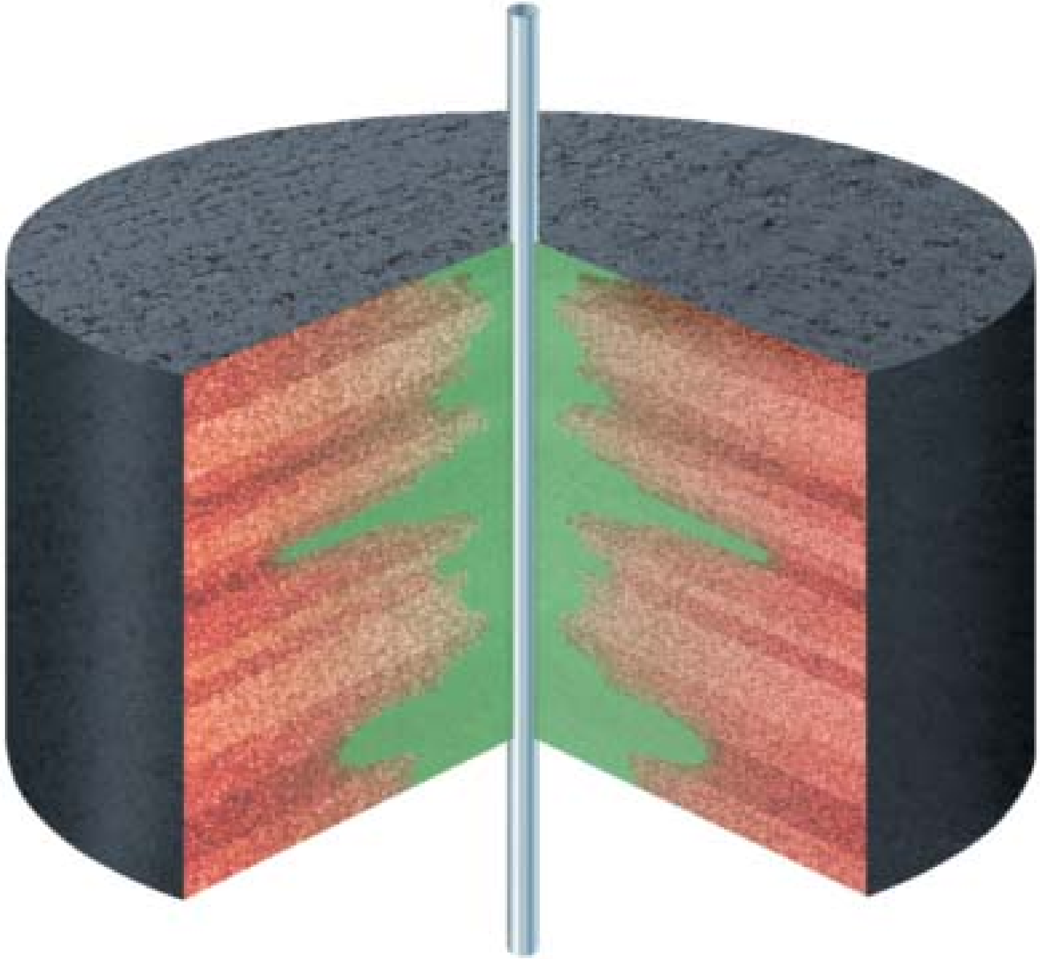
Arun is one of several huge gas-condensate reservoirs that together contain a significant global resource. Other large gas-condensate resources include Shtokmanovskoye field in the Russian Barents Sea, Karachaganak field in Kazakhstan, the North field in Qatar that becomes the South Pars field in Iran, and the Cupiagua field in Colombia.[2]

This article reviews the combination of fluid thermodynamics and rock physics that results in condensate dropout and condensate blockage. We examine implications for production and methods for managing the effects of condensate dropout, including reservoir modeling to predict field performance. Case studies from Russia, the USA and the North Sea describe field practices and results.

Forming Dewdrops

A gas condensate is a single-phase fluid at original reservoir conditions. It consists predominantly of methane [C_1] and other short-chain hydrocarbons, but it also contains long-chain hydrocarbons, termed heavy ends. Under

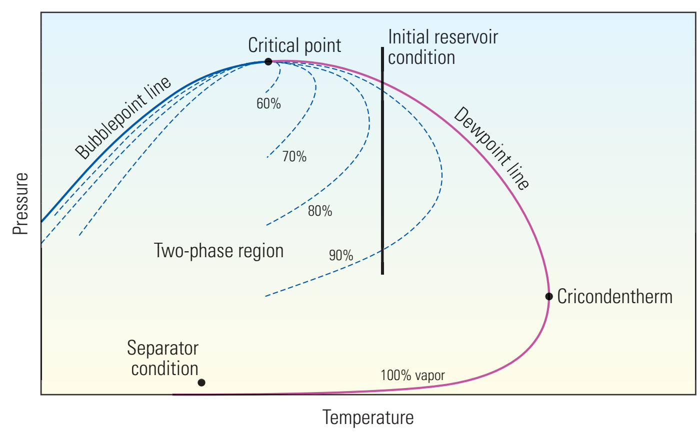
1. Afidick D, Kaczorowski NJ and Bette S: "Production Performance of a Retrograde Gas Reservoir: A Case Study of the Arun Field," paper SPE 28749, presented at the SPE Asia Pacific Oil & Gas Conference, Melbourne, Australia, November 7–10, 1984.
2. For a case study of the Karachaganak field: Elliott S, Hsu HH, O'Hearn T, Sylvester IF and Vercesi R: "The Giant Karachaganak Field, Unlocking Its Potential," *Oilfield Review* 10, no. 3 (Autumn 1998): 16–25.
3. Gas-condensate fluids are termed retrograde because their behavior can be the reverse of fluids comprising pure components. As reservoir pressure declines and passes through the dewpoint, liquid forms and the amount of the liquid phase increases with pressure drop. The system reaches a point in a retrograde condensate where, as pressure continues to decline, the liquid revaporizes.
4. Injection of cold or hot fluids can change reservoir temperature, but this rarely occurs near production wells. The dominant factor for fluid behavior in the reservoir is the pressure change. As will be discussed later, this is no longer the case once the fluid is produced into the wellbore.



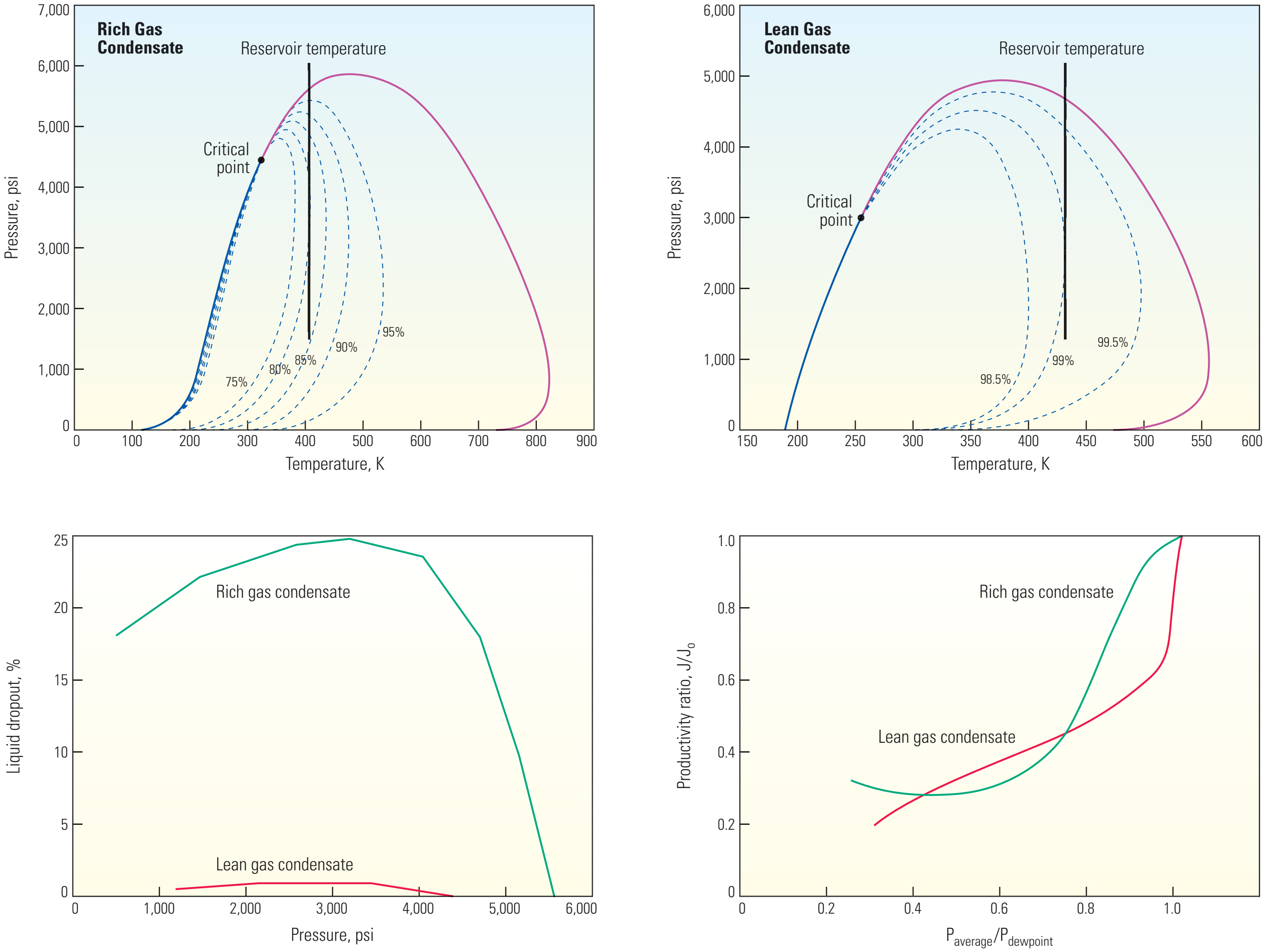
certain conditions of temperature and pressure, this fluid will separate into two phases, a gas and a liquid that is called a retrograde condensate.[3]

As a reservoir produces, formation temperature usually doesn't change, but pressure decreases.[4] The largest pressure drops occur near producing wells. When the pressure in a gas-condensate reservoir decreases to a certain point, called the saturation pressure or dewpoint, a liquid phase rich in heavy ends drops out of solution; the gas phase is slightly depleted of heavy ends (right). A continued decrease in pressure increases the volume of the liquid phase up to a maximum amount; liquid volume then decreases. This behavior can be displayed in a pressure-volume-temperature (PVT) diagram.

The amount of liquid phase present depends not only on the pressure and temperature, but also on the composition of the fluid. A dry gas, by definition, has insufficient heavy components to generate liquids in the reservoir, even with near-well drawdown. A lean gas condensate generates



^ Phase diagram of a gas-condensate system. This pressure-volume-temperature (PVT) plot indicates single-phase behavior outside the two-phase region, which is bounded by bubblepoint and dewpoint lines. Lines of constant phase saturation (dashed) all meet at the critical point. The numbers indicate the vapor phase saturation. In a gas-condensate reservoir, the initial reservoir condition is in the single-phase area to the right of the critical point. As reservoir pressure declines, the fluid passes through the dewpoint and a liquid phase drops out of the gas. The percentage of vapor decreases, but can increase again with continued pressure decline. The cricondentherm is the highest temperature at which two phases can coexist. Surface separators typically operate at conditions of low pressure and low temperature.



^ Examples of rich and lean gas-condensate behavior. When pressure decreases at reservoir temperature, a rich gas (*top left*) forms a higher percentage of liquid than a lean gas (*top right*). The rich gas drops out more condensate than the lean gas (*bottom left*). The liquid dropout curve assumes the two phases remain in contact with one another. However, in a reservoir, the mobile gas phase is produced; the liquid saturation in the near-well region builds until it is also mobile. As a result, eventually condensate blockage can affect formations with both lean and rich gases, and the normalized well productivity index (J/J_0) of both can be severely impacted (*bottom right*).

a small volume of the liquid phase, less than 100 bbl per million ft^3 [561 m^3 per million m^3], and a rich gas condensate generates a larger volume of liquid, generally more than 150 bbl per million ft^3 [842 m^3 per million m^3] (above).[5] There are no established boundaries in the definitions of lean and rich, and further descriptors—such as very lean—are also applied, so these figures should be taken merely as indicators of a range.

5. Gas volumes in this article are given at the conditions that are considered standard at the measurement location, which is not the same around the world. Conversions between metric and oilfield units are volumetric.

6. For more on artificial lift: Fleshman R, Harryson and Lekic O: "Artificial Lift for High-Volume Production," *Oilfield Review* 11, no. 1 (Spring 1999): 48–63.

Determining the fluid properties can be important in any reservoir, but it plays a particularly vital role in gas-condensate reservoirs. For example, condensate/gas ratio plays a major role in estimates for the sales potential of both gas and liquid, which are needed to size surface processing facilities. The amount of liquid that may be stranded in a field is also an essential economic consideration. These considerations and others, such as the need for artificial lift and stimulation technologies, rely on accurate fluid sampling. Small errors in capturing samples, such as an incorrect amount of captured liquid, can have significant errors in measured behavior, so great care must be taken in the sampling process (see "Sampling for Fluid Properties," *next page*).

Once reservoir fluids enter a wellbore, both temperature and pressure conditions may change. Condensate liquid can be produced into the wellbore, but liquid also can drop out within the wellbore because of changes in conditions. If the gas does not have sufficient energy to carry the liquid to surface, liquid loading or fallback in the wellbore occurs because the liquid is denser than the gas phase traveling along with it. If the liquid falls back down the wellbore, the liquid percentage will increase and may eventually restrict production. Gas lift and pumping technologies that are used to counter this behavior will not be discussed in this article.[6]

Sampling for Fluid Properties

Fluid composition is determined by capturing a representative sample of reservoir fluid. Surface samples can be obtained relatively easily by collecting liquid and gas samples from test or production separators. The samples are then recombined in a laboratory. However, the result can be unrepresentative of reservoir conditions, particularly when sampling from a gas-condensate reservoir. A few examples of potential problems include recombining the gas and liquid samples at an incorrect ratio, changing production conditions prior to or during sampling and commingling zones with different properties. If the liquid content is low when capturing surface samples, a small loss of the liquid in production tubulars or separators could render the condensate sample unrepresentative of the formation fluid.

Samples can also be collected downhole from wellbore fluids in gas-condensate reservoirs. This is practical and desirable if the wellbore flowing pressure is above the dewpoint pressure, but it is generally not recommended if the pressure anywhere in the tubing is lower than the dewpoint pressure. In that condition, there is two-phase flow in the wellbore. Any liquid forming in the tubing during or prior to the sampling may segregate to the bottom of the tubing string—where a bottomhole sampler collects fluids—potentially resulting in an unrepresentative sample with too much of the heavier components.

Formation testers have improved significantly over the past decade. The MDT Modular Formation Dynamics Tester collects fluids by pressing a probe against an uncased borehole wall and withdrawing fluids from a formation.[1] The LFA Live Fluid Analyzer module on the tool measures the cleanup of contamination from oil-base drilling or completion fluids, minimizing the wait time and assuring quality samples.[2] The LFA detector also provides an indication of the amount of methane, other light components and liquids. From these data, the ratio of methane to liquid provides a measure of the condensate/gas ratio, an important consideration for early economic evaluation of a prospect. The analysis can also show zones with different compositions or compositional gradients.

Measured data from the MDT tool are transmitted to surface immediately, so sampling decisions can be made based on knowledge of approximate composition and reservoir pressure, another measured parameter. If desired, fluid samples can be collected before moving to another downhole location.

For gas condensates that are at pressures above the dewpoint in the reservoir, it is important to capture and maintain single-phase fluid. If the fluid pressure drops below dewpoint, it may take a long time to recombine the sample. Even worse, some changes that occur in a sample on its trip to surface may be irreversible. By providing evidence when a fluid goes through its dewpoint, the LFA measurement can indicate when the pressure drawdown is too large and should be decreased before sampling to keep pressure above the dewpoint.

A sample that is single-phase when collected should be kept in a single phase when brought to surface. Special MDT sample bottles are available for this purpose. A single-phase bottle uses a nitrogen cushion to increase the pressure in the sampled fluid.[3] The sample cools as it is brought to surface, but the nitrogen cushion on the sample keeps its pressure above the dewpoint.

In most cases, the PVT Express onsite well fluid analysis service can provide fluid property measurements at the wellsite in about 24 hours, saving the weeks or months that may be needed to get results from a laboratory.[4] The PVT Express systems can measure gas/liquid ratio, saturation pressure—bubblepoint or dewpoint—composition to C_{30+}, reservoir fluid density, viscosity and oil-base mud contamination.[5] These measurements are critical because an operating company can use them immediately to make a decision to complete or to test a well. Rapid turnaround may be crucial when drilling exploration or development wells from an expensive offshore rig. More complete analyses can be obtained later from samples sent to a laboratory.

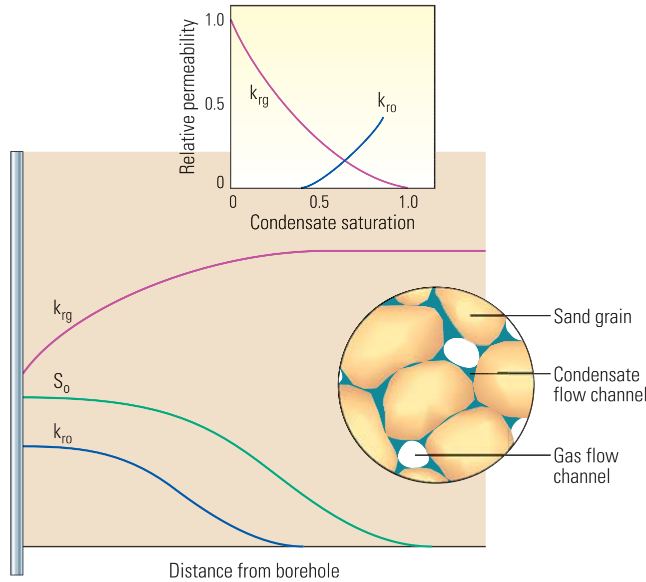
With the basic understanding of where and how condensate drops out of the gas phase, engineers can devise ways to optimize production of gas and condensate.

1. Andrews RJ, Beck G, Castelijns K, Chen A, Cribbs ME, Fadnes FH, Irvine-Fortescue J, Williams S, Hashem M, Jamaluddin A, Kurkjian A, Sass B, Mullins OC, Rylander E and Van Dusen A: "Quantifying Contamination Using Color of Crude and Condensate," *Oilfield Review* 13, no. 3 (Autumn 2001): 24–43.
2. Betancourt S, Fujisawa G, Mullins OC, Carnegie A, Dong C, Kurkjian A, Eriksen KO, Haggag M, Jaramillo AR and Terabayashi H: "Analyzing Hydrocarbons in the Borehole," *Oilfield Review* 15, no. 3 (Autumn 2003): 54–61.
3. Jamaluddin AKM, Ross B, Calder D, Brown J and Hashem M: "Single-Phase Bottomhole Sampling Technology," *Journal of Canadian Petroleum Technology* 41, no. 7 (July 2002): 25–30.
4. Jamaluddin AKM, Dong C, Hermans P, Khan IA, Carnegie A, Mullins OC, Kurkjian A, Fujisawa G, Nighswander J and Babajan S: "Real-Time and On-Site Reservoir Fluid Characterisation Using Spectral Analysis and PVT Express," *Australian Petroleum Production & Exploration Association Journal* (2004): 605–616.
5. The nomenclature "composition to C_{30+}" indicates compounds up to 29 carbon atoms are separately discriminated, with the remainder combined into a fraction indicated as C_{30+}.

Dewdrops in a Reservoir

When condensate liquid first forms in a gas reservoir, it is immobile because of capillary forces acting on the fluids. That is, a microscopic liquid droplet, once formed, will tend to be trapped in small pores or pore throats. Even for rich gas condensates with substantial liquid dropout, condensate mobility, which is the ratio of relative permeability to viscosity, remains insignificant away from wellbores. As a consequence, the condensate that forms in most of the reservoir is lost to production unless the depletion plan includes gas cycling. The effect of this dropout on gas mobility is typically negligible.

Near a producing well, the situation is different. Once bottomhole pressure drops below the dewpoint, a near-well pressure sink forms around the well. As gas is drawn into the pressure sink, liquid drops out. After a brief transient period, enough liquid accumulates that its mobility becomes significant. The gas and liquid compete for flow paths, as described by the formation's relative-permeability relationship. Condensate blockage is a result of the decreased gas mobility around a producing well below the dewpoint (right).



^ Condensate blockage. Once bottomhole pressure in a well falls below the dewpoint, condensate will drop out from the gas phase. Capillary forces favor having condensate in contact with the grains (*inset, right*). After a brief transient period, the region achieves a steady-state flow condition with both gas and condensate flowing (*inset, top*). The condensate saturation, S_o, is highest near the wellbore because the pressure is lower, which means more liquid dropout. The oil relative permeability, k_{ro}, increases with saturation. The decrease in gas relative permeability, k_{rg}, near the wellbore illustrates the blockage effect. The vertical axis, represented by a wellbore, is schematic only.

Reservoir pressure dropping below the dewpoint has two main results, both negative: gas and condensate production decrease because of near-well blockage, and the produced gas contains fewer valuable heavy ends because of dropout throughout the reservoir, where the condensate has insufficient mobility to flow toward the well.

Large productivity losses have been reported for wells in gas-condensate fields. In the Arun field, which was operated by Mobil, now ExxonMobil, the loss in some wells was greater than 50%.[7] In another case, Exxon, now ExxonMobil, reported two wells that died due to condensate blockage.[8] Shell and Petroleum Development Oman reported a 67% productivity loss for wells in two fields.[9]

In another field, the initial productivity decline has reportedly reversed. The productivity of wells in the moderately rich gas-condensate reservoir declined rapidly when bottomhole pressures dropped below dewpoint. This decline continued until pressure throughout the reservoir dropped below dewpoint, then gas productivity began to increase. Compositional modeling showed that condensate saturation increased near the wells to approximately 68%, decreasing gas permeability and therefore gas productivity. However, when pressure throughout the reservoir dropped below dewpoint, some liquid dropped out everywhere. The gas moving toward the wellbore was leaner and had less condensate to drop out in the near-well region, resulting in decreased condensate saturation to about 55% and increased gas productivity.[10] The condensate blockage decreased as the near-well gas mobility increased.

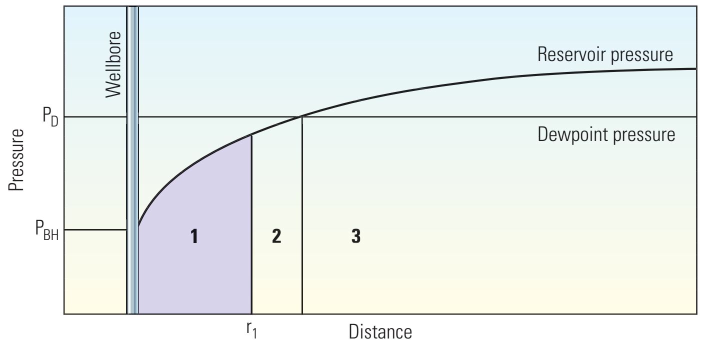
Condensate Blockage

Not all gas-condensate reservoirs are pressure-limited because of near-well condensate blockage, even though all of these fields will experience condensate blockage. The degree to which condensate dropout is a production problem depends on the ratio of the pressure drop that is experienced within the reservoir to the total pressure drop from distant areas of the reservoir to a control point at surface.

If reservoir pressure drop is significant, then additional pressure drop due to condensate blockage can be very important for well deliverability. This condition typically applies in a formation with a low *kh*, the product of permeability and net formation thickness. Conversely, if little of the total pressure drop occurs in the reservoir, typical of high *kh* formations, then adding more pressure drop in the reservoir due to condensate blockage will probably have little impact on well deliverability. As a general guideline, condensate blockage can be assumed to double the pressure drop in the reservoir for the same flow rate.

Conceptually, flow in gas-condensate fields can be divided into three reservoir regions, although in some situations not all three are present (next page).[11] The two regions closest to a well can exist when bottomhole pressure is below the dewpoint of the fluid. The third region, away from producing wells, exists only when the reservoir pressure is above the dewpoint.

This third region includes most of the reservoir away from producing wells. Since it is above the dewpoint pressure, there is only one hydrocarbon phase, gas, present and flowing. The interior boundary of this region occurs where the pressure equals the dewpoint pressure of the original reservoir gas. This boundary is not stationary, but moves outward as hydrocarbons are produced from the well and the formation pressure drops, eventually disappearing as the outer-boundary pressure drops below the dewpoint.



^ Three reservoir regions. Gas-condensate field behavior can be divided into three regions once bottomhole pressure, P_{BH}, drops below the dewpoint pressure, P_D. Far from a producing well (3), where the reservoir pressure is greater than P_D, there is only one hydrocarbon phase present, gas. Closer to the well (2), there is a region between the dewpoint pressure and the point, r_1, at which the condensate reaches the critical saturation for flow. In this condensate-buildup region, both phases are present, but only gas flows. Once condensate saturation exceeds the critical saturation, both phases flow toward the well (1).

In the second region, the condensate-buildup region, liquid drops out of the gas phase, but its saturation remains low enough that it is immobile; there is still single-phase gas flow. The amount of liquid that drops out is determined by the fluid's phase characteristics, as indicated by its PVT diagram. The liquid saturation increases and the gas phase becomes leaner as gas flows toward the wellbore. This region's inner-boundary saturation usually is near the critical liquid saturation for flow, which is the residual oil saturation.

In the first region, closest to a producing well, both gas and condensate phases flow. The condensate saturation here is greater than the critical condensate saturation. This region ranges in size from tens of feet for lean condensates to hundreds of feet for rich condensates. Its size is proportional to the volume of gas drained and the percentage of liquid dropout. It extends farther from the well for layers with higher permeability than average since a larger volume of gas has flowed through these layers. Even in a reservoir containing lean gas with low liquid dropout, condensate blockage can be significant, because capillary forces can retain a condensate that builds to a high saturation over time.

This near-well condensate blockage region controls well deliverability. The flowing condensate/gas ratio is essentially constant and the PVT condition is considered a constant-composition expansion region.[12] This condition simplifies the relationship between gas and oil relative permeabilities, making the ratio between the two a function of PVT properties.

However, additional relative-permeability effects occur in the near-well region because the gas velocity, and therefore the viscous force, is extreme. The ratio of viscous to capillary forces is called the capillary number.[13] Conditions of pressure gradient caused by high velocity or low interfacial tension have high capillary numbers, indicating that viscous forces dominate, and the relative permeability to gas is higher than the value at lower flow rates.

At even higher flow velocities nearer the wellbore, the inertial or Forchheimer effect decreases the gas relative permeability somewhat.[14] The basis of this effect is the inertial drag as fluid speeds up to go through pore throats and slows down after entering a pore body.[15] The result is a lower apparent permeability than would be expected from Darcy's law. The effect is usually referred to as non-Darcy flow.

The overall impact of the two high-velocity effects is usually positive, reducing the impact of condensate blockage. Laboratory coreflood experiments are needed to measure the inertial and capillary number effects on relative permeability.

Although the first indication of condensate blockage is typically a productivity decline, its presence is often determined by pressure transient testing. A pressure-buildup test can be interpreted to show the distribution of liquid before the well is shut in. The short-time behavior in the transient test reflects near-well conditions. Condensate blockage is indicated by a steeper pressure gradient near the wellbore. With longer test times, the gas permeability far from the wellbore dominates the response; permeability can be determined from the derivative curve on a log-log plot of pseudo-pressure and shut-in time. If the test continues long enough—and that shut-in test time depends on the formation permeability—flow properties far from the well will be evident.

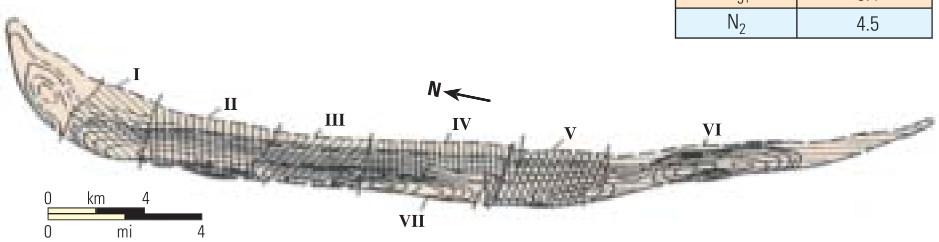
Gas-Condensate Reservoir Management

Historically, condensate liquids have been significantly more valuable than the gas, and this is still true in a few places far from a gas market or transport system. The price differential made gas cycling a common practice. Injecting dry gas into a formation to keep reservoir pressure above the dewpoint slowly displaces valuable heavy ends that are still in solution in the reservoir gas. Eventually, the reservoir is blown down; that is, the dry or lean gas is produced at a low bottomhole pressure.

7. Afidick et al, reference 1.
8. Barnum RS, Brinkman FP, Richardson TW and Spillette AG: "Gas Condensate Reservoir Behaviour: Productivity and Recovery Reduction Due to Condensation," paper SPE 30767, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 22–25, 1995.
9. Smits RMM, van der Post N and al Shaidi SM: "Accurate Prediction of Well Requirements in Gas Condensate Fields," paper SPE 68173, presented at the SPE Middle East Oil Show, Bahrain, March 17–20, 2001.
10. El-Banbi AH, McCain WD Jr and Semmelbeck ME: "Investigation of Well Productivity in Gas-Condensate Reservoirs," paper SPE 59773, presented at the SPE/CERI Gas Technology Symposium, Calgary, April 3–5, 2000.
11. Fevang Ø and Whitson CH: "Modeling Gas-Condensate Well Deliverability," *SPE Reservoir Engineering* 11, no. 4 (November 1996): 221–230.
12. In a constant-composition expansion condition, the fluid expands with pressure decline and two phases may form, but no components are removed. This contrasts with the second region, which is considered a constant-volume depletion region, because the liquid phase that forms drops out from the gas phase and becomes trapped.
13. Henderson GD, Danesh A, Tehrani DH and Al-Kharusi B: "The Relative Significance of Positive Coupling and Inertial Effects on Gas Condensate Relative Permeabilities at High Velocity," paper SPE 62933, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 1–4, 2000.
    Whitson CH, Fevang Ø and Sævareid A: "Gas Condensate Relative Permeability for Well Calculations," paper SPE 56476, presented at the SPE Annual Technical Conference and Exhibition, Houston, October 3–6, 1999.
14. Forchheimer PH: "Wasserbewegung durch Boden," *Zeitschrift ver Deutsch Ingenieur* 45 (1901): 1782–1788.
15. Barree RD and Conway MW: "Beyond Beta Factors: A Complete Model for Darcy, Forchheimer, and Trans-Forchheimer Flow in Porous Media," paper SPE 89325, presented at the SPE Annual Technical Conference and Exhibition, Houston, September 26–29, 2004.

Type	Permeability, mD	Porosity, %
Fine porosity, microvugs, microfractured	<0.1	0.1 to 3
Porous, microvugs, microfractured	0.01 to 0.1	3 to 6
Fractured, microvugs, porous	0.1 to 4513	>6

Component	Composition, % by mole volume
C_1	74.6
C_2	8.9
C_3	3.8
C_4	1.8
C_{5+}	6.4
N_2	4.5



^ Vuktyl field, Russia. The Vuktyl field in the Komi Republic in western Russia (*top*) is an anticline, 80 km [50 mi] long and up to 6 km [3.7 mi] wide (*bottom*). The Roman numerals denote gas-processing facility collection areas. The fluid is predominantly methane [C_1], but with a significant amount of intermediate hydrocarbon components and nitrogen (table, *right*). The field has three lithotypes (table, *left*).

The price of gas has risen to a value that makes reinjection a less attractive strategy, unless the fluid is very rich in heavy ends. Gas injection is now more commonly used as a temporary activity, until a pipeline or other transport facility is built, or as a seasonal activity during periods of low gas demand.

Operators also work to overcome condensate blockage. Some techniques are the same in a gas-condensate field as they are in a dry-gas field. Hydraulic fracturing is the most common mitigating technology in siliciclastic reservoirs, and acidizing is used in carbonate reservoirs. Both techniques increase the effective contact area with a formation. Production can be improved with less drawdown in the formation. For some gas-condensate fields, a lower drawdown means single-phase production above the dewpoint pressure can be extended for a longer time.

However, hydraulic fracturing does not generate a conduit past a condensate saturation buildup area, at least not for long. Once the pressure at the sandface drops below the dewpoint, saturation will increase around the fracture, just as it did around the wellbore.

Horizontal or inclined wells are also being used to increase contact area within formations. The condensate still builds up around these longer wells, but it takes a longer time. The productivity of the wells remains high longer, but the benefit must be weighed against the increased well cost.

Some operators have tried shutting in wells to allow time for the gas and condensate to recombine, but fluid phase behavior generally does not favor this approach. Separation of a fluid into a gas and liquid phase in the two-phase region of the phase diagram happens quickly, and after this the phases tend to segregate, either within a pore or on a larger scale. This phase separation dramatically slows the reverse process of recombining gas and liquid. This reversal requires immediate contact between the gas and liquid phases.

Another method, cyclic injection and production from one well, sometimes called huff and puff injection, uses dry gas to vaporize condensate around a well and then produce it. This can have short-term benefit for increased productivity, but the blockage returns when production begins again and the formation drops below the dewpoint pressure of the current gas mixture.

In a field test, methanol solvent was injected into Hatter's Pond field, Alabama, USA. In this field, production of a gas condensate comes mainly from the lower Norphlet sandstone, but the field also produces from the Smackover dolomite. Wells in Hatter's Pond field are about 18,000 ft [5,490 m] deep with 200 to 300 ft [60 to 90 m] of net pay. Gas productivity had declined by a factor of three to five because of condensate and water blockage. The operator, Texaco (now Chevron), pumped 1,000 bbl [160 m^3] of methanol down tubing at a rate of 5 to 8 bbl/min [0.8 to 1.3 m^3/min] into low-permeability formations.[16] The methanol treatment removes both oil and water through a multiple-contact miscible displacement.[17] As a result of the treatment, gas production increased by a factor of three initially, then stabilized at 500,000 ft^3/d [14,160 m^3/d], a factor of two over the pretreatment rate. Condensate production doubled to 157 bbl/d [25 m^3/d]. Both gas and condensate rates persisted for more than 10 months after treatment.[18]

Treatment methods have been suggested for removing condensate blockage through injection of surfactants mixed with solvents to alter wetting preference in the reservoir. This topic will be discussed later in this article.

Remobilizing Stranded Condensate

The Vuktyl gas-condensate field in the Komi Republic, Russia, has been in production since 1968. Although productivity was not severely impacted by condensate blockage in the field, a significant amount of condensate dropped out in the carbonate reservoir. Several condensate recovery pilots were run in this field.

The field is a long anticline with production from the Middle Carboniferous Moscow and Bashkir sequences (above left). The 1,440 m [4,724 ft] thick structure comprises alternating limestone and dolomite layers, with an average interbed thickness of 1.5 m [5 ft]. The reservoir properties vary widely throughout the field, but the field has been divided into seven pay sequences of three basic types. All three types have microfractures and microvugular porosity. Fine pores, low permeability and low porosity distinguish the first type. The third type has fractures large enough to contribute to permeability. The other type is intermediate.

At discovery, reservoir conditions were 36 MPa [5,200 psi] and 61°C [142°F], with 77.5% initial gas saturation. There is a small rim containing light oil. Initial gas in place was about 430 x 10^9 m^3 [15 x 10^{12} ft^3] and initial condensate was about 142 million metric tons [1,214 million bbl].[19] The initial, stable, producing condensate/gas ratio was 360 g/m^3 [87.1 bbl per million ft^3].[20] The field has an underlying aquifer, but the water drive was insignificant and laterally uneven.

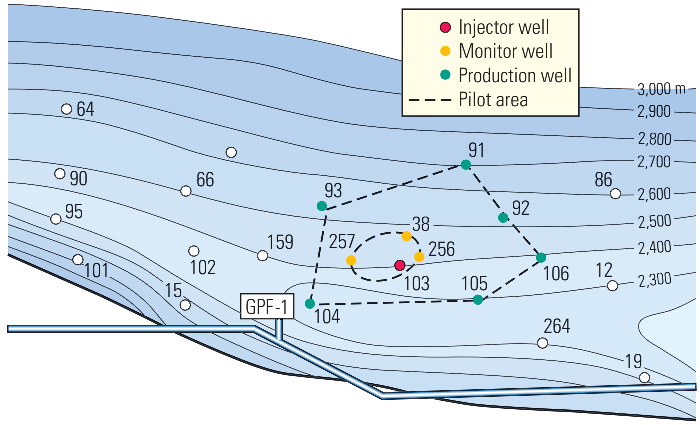
The complex geology of the field, including high-permeability zones that could have acted as thief zones, led the operator, Gazprom, to develop the field with no gas cycling, using depletion gas drive as the primary production mechanism.

Approximately 170 vertical wells at a typical spacing of 1,000 to 1,500 m [3,280 to 4,920 ft] were placed in an irregular triangular grid. Most of the production wells had 10-in. intermediate casing and 6⅝-in. production casing. Several prolific wells had larger, 7⅝-in. production casing, allowing 4⅝-in. tubing. Typical completions in the 500- to 800-m [1,640- to 2,625-ft] producing zone were perforated casing, but some wells used screen or openhole completions. The deepest producers were drilled about 100 to 150 m [328 to 492 ft] above the gas/water contact. A two-stage hydrochloric acid treatment was the main method of well stimulation.

After nine years, the production plateau was 19 x 10^9 m^3/yr [671 x 10^9 ft^3/yr]. A peak stable condensate production of 4.2 million tons/yr [36 million bbl/yr] occurred during the sixth year of development.

Currently, the Vuktyl field is in its final development phase. Reservoir pressure is 3.5 to 5 MPa [508 to 725 psi]. Approximate field recoveries are 83% of the gas and 32% of the condensate, so about 100 million tons [855 million bbl] of condensate remain in the field.

Experts from Severgazprom, a part of the Gazprom Russian Joint Stock Company, and the VNIIGAZ and SeverNIPIgaz institutes conducted a variety of pilot projects in Vuktyl field to recover additional condensate. In 1988, the company began the first pilot experiment, using a solvent to recover stranded condensate.[21] The pilot included six producers, one injection well and three monitor wells (above). The solvent, 25,800 tons [293,000 bbl at formation conditions] of a mixture of propane [C_3] and butane [C_4], was injected into the formation followed by 35 million m^3 [1.24 x 10^9 ft^3] of separator gas.[22] The intent was to recover condensate through miscible displacement of the solvent bank.



^ Plan view with depth to the formation top at a solvent-injection pilot project near gas-processing facility number 1 (GPF-1). Propane and butane were injected into Well 103, followed by separator gas. Six production wells—designated 91, 92, 93, 104, 105 and 106—and three monitor wells—designated 38, 256 and 257—made up the pilot study area. Solvent was observed and produced only from the two closest monitor wells: Wells 38 and 256.

Geophysical observations conducted during the experiment indicated that solvent and injected gas entered the producing intervals of the injection well unevenly. Component analyses of samples from the production and monitor wells indicated solvent and injected gas broke through only in the two closest monitor wells and in none of the production wells. Two events were seen in these two monitor wells, a change in condensate/gas ratio from 43 to 65 g/m^3 [10.4 to 15.7 bbl per million ft^3] with a decline to the initial ratio, followed by a second increase from 43 to 54 g/m^3 [to 13 bbl per million ft^3].

Production logging in the monitor wells revealed two-phase flow—gas and solvent—only in the bottom part of the productive section. Overall, 95% of the solvent was produced from the two monitor wells, but condensate recovery was only about 0.4%. The pilot study concluded that the propane and butane solvent bank was not sufficiently effective in recovering condensate.

A different recovery method, injecting dry gas, began in the Vuktyl field in 1993. The gas, from a trunk pipeline that originated in the Tyumen district, is injected under pipeline pressure at 5.4 to 7.4 MPa [780 to 1,070 psi]

16. Al-Anazi HA, Walker JG, Pope GA, Sharma MM and Hackney DF: "A Successful Methanol Treatment in a Gas-Condensate Reservoir: Field Application," paper SPE 80901, presented at the SPE Production and Operations Symposium, Oklahoma City, Oklahoma, USA, March 22–25, 2003.
17. In a miscible displacement, a solvent allows fluids to mix freely in a homogeneous mixture. Multiple-contact miscibility requires sufficient mass transfer between the solvent and hydrocarbons to achieve miscibility.
18. Al-Anazi et al, reference 16.
19. Zhabrev IP (ed): *Gas and Gas-Condensate Fields—Reference Book.* Moscow: Nedra, 1983 (in Russian).
   Ter-Sarkisov RM: *The Development of Natural Gas Fields.* Moscow: Nedra, 1999 (in Russian).
   Conversion from mass to volume is based on condensate density of 8.55 bbl/ton.
20. Vyakhirev RI, Gritsenko AI and Ter-Sarkisov RM: *The Development and Operation of Gas Fields.* Moscow: Nedra, 2002 (in Russian).
21. Ter-Sarkisov RM, Gritsenko AI and Shandrygin AN: *Development of Gas Condensate Fields Using Stimulation of Formation.* Moscow: Nedra, 1996 (in Russian).
   Vyakhirev et al, reference 20.
22. For more on the role of propane in lowering the dewpoint of a gas-condensate field: Jamaluddin AKM, Ye S, Thomas J, D'Cruz D and Nighswander J: "Experimental and Theoretical Assessment of Using Propane to Remediate Liquid Buildup in Condensate Reservoirs," paper SPE 71526, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 30–October 3, 2001.

without local compression.[23] Formation gas, which is in equilibrium with the retrograde condensate, is replaced by injected dry gas. The light C_2 to C_4 components and intermediate C_{5+} fractions evaporate into the dry gas.[24] Thus, recovery is improved both by producing more formation gas, which still contains components other than methane, and by vaporizing stranded liquids and producing them along with the injected gas. In addition, the injected gas causes no problems for the production facilities when it breaks through. However, a significant volume of dry gas has to be injected to produce tangible amounts of condensate.

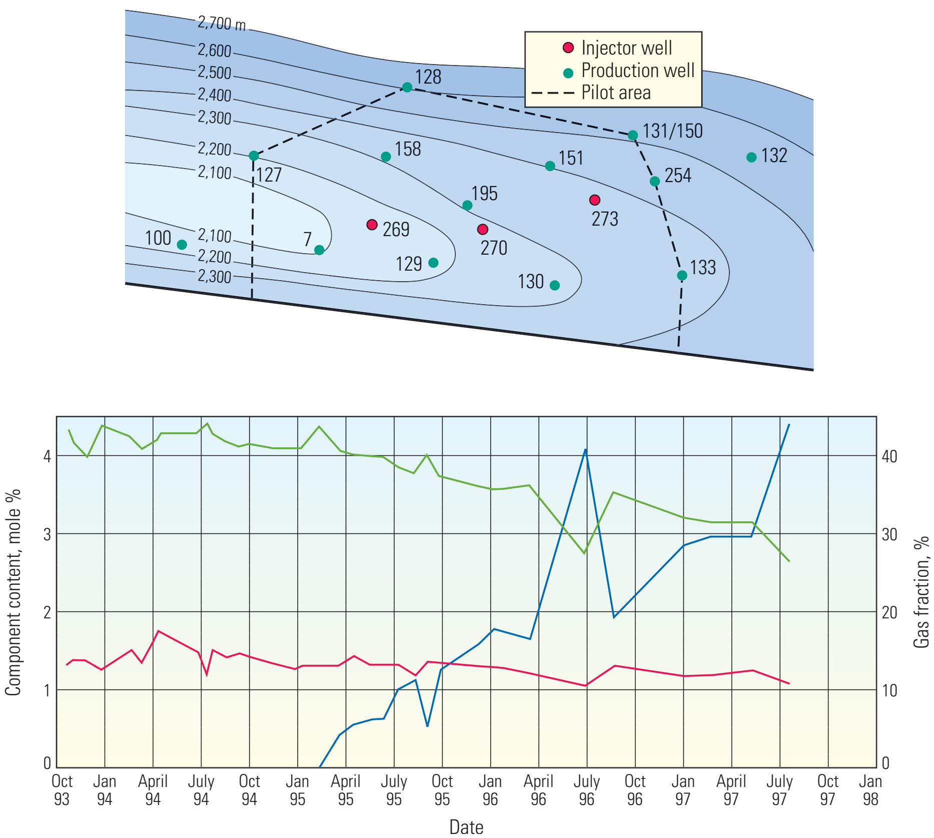
Engineers monitored the process in both injection and production wells using gas-liquid and gas-adsorption chromatography (below).[25] Since the injection gas did not contain nitrogen, the nitrogen content was used as the indicator of formation gas.[26]

The 1993 pilot test program was expanded to additional pilot locations in 1997, 2003 and 2004. By the middle of 2005, the operator had injected 10 x 10^9 m^3 [354 x 10^9 ft^3] of dry gas into the pilot wells, and recovered a significant amount of liquid. Comparing the recovery with estimates of production through depletion alone showed that the pilot area produced an additional 785 thousand tons [9.45 million bbl] of C_2 to C_4 and 138 thousand tons [1.22 million bbl] of C_{5+}.[27]

The operators also ran single-well pilot projects in Vuktyl field. Although blockage was not severe enough to cause a dramatic drop in productivity in this field, the operator sought ways to counteract the increased saturation that had formed around wells. The treatment included injecting solvent—a mix of ethane and propane—into a well, followed by dry gas. After a sufficient volume of injection, the well was returned to production.

When the solvent contacts the trapped condensate, the solvent, formation gas and condensate mix freely into a single phase. The dry gas that follows is able to mix freely with the solvent mixture. Thus, when the well produces again, the injected gas, solvent and condensate are produced as a single fluid. As a result, the condensate saturation is at or near zero in the treated zone. As formation gas follows the mixture back through the treated zone, a zone of increased condensate saturation will reform, but well productivity can be improved by periodic treatments.

Treatment volumes ranged from 900 to 2,900 tons [10,240 to 33,000 bbl] of solvent and 1.2 to 4.2 million m^3 [42 to 148 million ft^3] of dry gas.[28] Although the effectiveness varied from well to well, the treatments generally had good results. The productivity of four of the wells increased by 20% to 40% over a period ranging from 6 months to 1.5 years, followed by a decline to the original production levels (next page).



	Dry gas, million m^3	Formation gas, million m^3	Component from: Formation gas, thousand tons	Component from: Stranded condensate, thousand tons
Injected gas	10,035			
Produced gas	7,366	5,973		
Produced C_2 to C_4			1,996	238
Produced C_{5+}			380	208

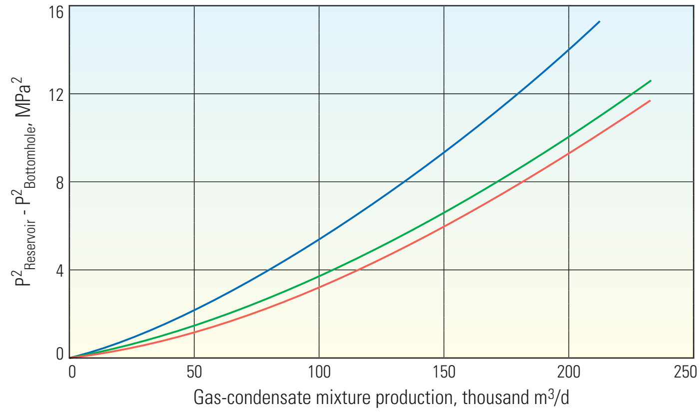
^ Dry-gas injection pilot. Separator gas injected into three wells— designated 269, 270 and 273—vaporized stranded condensate for production from surrounding wells (*top*). Dry gas (blue) broke through a few months after the pilot began (*middle*). Nitrogen in the produced gas (green) gradually decreased, indicating that less formation gas was being produced. The liquid C_{5+} fraction (red) indicates a slow decline after gas breakthrough. The results show significant production of formation gas, light (C_2 to C_4) and intermediate components (C_{5+}) from both produced formation gas and remobilized stranded condensate (table, *bottom*).

Modeling Condensate Blockage

Reservoir-simulation models are commonly used to predict the performance of gas-condensate fields. The models incorporate rock and fluid properties to predict the dynamic influence of condensate blockage on gas and condensate production. However, a typical gridblock of a full-field model (FFM) can be much larger than the blockage zone, so a coarse grid model may significantly overestimate well deliverability.

The most accurate way to determine near-well behavior of a gas-condensate field is by using a simulator with a fine grid. There are two ways to do this: use a FFM with local grid refinement (LGR), or use a single-well model with a fine grid near the well.

Modern simulators, such as the ECLIPSE 300 reservoir simulation software, include capability for LGR. Small gridblocks can be used near wellbores or other features—such as faults—that can significantly impact local flow. Farther



^ Changes in well productivity as a result of injection of ethane and propane followed by dry gas. The difference of the squares of the reservoir pressure, P_R, and the bottomhole pressure, P_{BH}, as the flow rate increases provides a measure of productivity. Before treatment (blue), the well required a larger pressure difference to produce than it needed after treatment (red). Four months after treatment, productivity had degraded slightly (green), but it was still significantly better than productivity before the treatment.

away from such features, the gridblocks grow to a size typical of a FFM. The cost of using LGR may be a significant increase in computation time in some cases.

Another way to examine gas-condensate blockage effects is by using a single-well model. In many cases, radial symmetry allows a well to be treated in a two-dimensional model, using the dimensions of height and radial distance. The gridblocks nearest the well are small, nominally half a foot [about 15 cm] in the radial direction. The radial dimension increases with each gridblock away from the wellbore, until it reaches a maximum size used for the rest of the model. The fine grid provides good resolution where the flow is highest and the formation saturation behavior is at its most complex. Capillary, viscous and inertial forces can be appropriately modeled. Far from the wellbore, conditions of pressure and flow can be taken from a FFM and applied as boundary conditions.

Sometimes, gas-condensate reservoir simulations can be performed using a black-oil model. This type of model assumes that there are only two hydrocarbon components in the fluid, oil and gas, and it allows for some pressure-dependent mixing of gas in oil. This model is inappropriate when the compositions change significantly with time, such as through gas injection, or when there is a significant compositional gradient. In those cases, a compositional model with many hydrocarbon components is necessary. In addition, some black-oil models do not include capillary number effects, which are important for determining well deliverability.

Another way to account for condensate blockage in a full-field model is through the use of pseudopressures. The equation for flow of gas from a reservoir to a wellbore can be expressed in terms of a pseudopressure, which is an integral over pressure. By separately treating the three regions described before—two-phase flow near the well, gas flow with condensate buildup next, and single-phase gas flow far from the well—it is possible to calculate the pseudopressure from the producing gas/oil ratio, PVT properties of the fluid, and gas and oil relative permeabilities.[29] As discussed previously, the constant-composition expansion condition in the first region simplifies the relative-permeability ratios. This pseudopressure method adds little time to running a FFM.

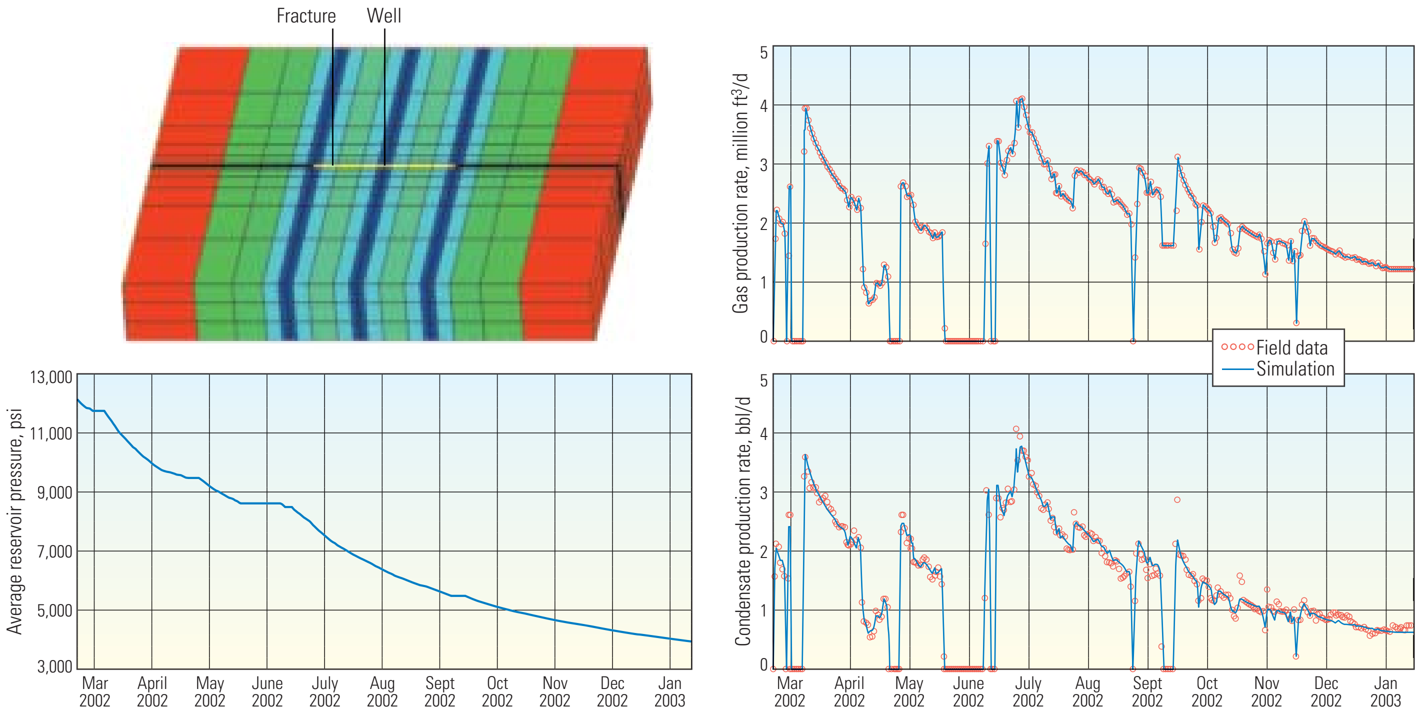
Pseudopressure methods have also been implemented in spreadsheet format.[30] These spreadsheets assume a homogeneous reservoir and a simple black-oil model. They provide fast predictions that can be used when many sensitivity runs are necessary. A similar semianalytical method was combined with the effects of non-Darcy flow and permeability layering. Comparisons using a compositional simulator with a fine grid showed that the semianalytical method captured all the near-well effects accurately and was easy to embed in a FFM at essentially no increase in computational time.[31]

Modeling Behavior Around a Fracture

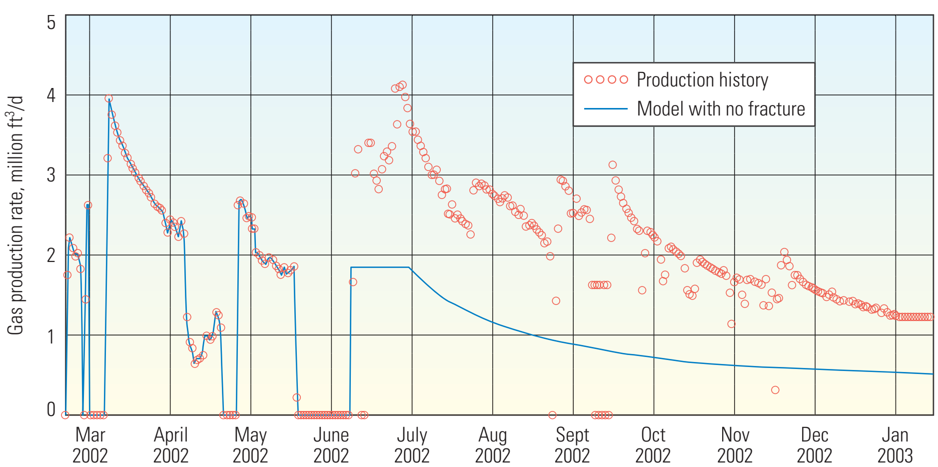
Reservoir simulation modeling was used to determine the effectiveness of fracturing in the SW Rugeley field in south Texas, USA. This field produces gas condensate from low-permeability—about 1-mD—Frio sand. A well in this field, which was drilled and completed by Wagner & Brown, was hydraulically fractured initially, but a rapid decline in productivity led the company to refracture the formation about three months later, in June 2002. Productivity improved, but then continued to decline over the next few months. The drawdown in the vicinity of the well was below the dewpoint pressure, so the company investigated the accumulation of condensate saturation around a fracture.

Engineers at Schlumberger developed a homogeneous, radially symmetric, single-well model. This simple model demonstrated that condensate blockage could result in a rapid falloff in productivity. It also provided a means to quickly check the impact of permeability reduction due to compaction caused by pressure decline.

23. Ter-Sarkisov RM, Zakharov FF, Gurlenov YM, Levitskii KO and Shirokov AN: *Monitoring the Development of Gas-Condensate Fields Subjected to Dry Gas Injection. Geophysical and Flow-Test Methods*. Moscow: Nedra, 2001 (in Russian).
    Dolgushin NV (ed): *Scientific Problems and Prospects of the Petroleum Industry in Northwest Russia, Part 2: The Development and Operation of Fields, Comprehensive Formation and Well Tests and Logs, A Scientific and Technical Collection*. Ukhta: SeverNIPIgaz, 2005 (in Russian).
    Vyakhirev et al, reference 20.
    Ter-Sarkisov et al, reference 21.
    Ter-Sarkisov, reference 19.
24. For a laboratory study of methane injection into cores with condensate saturation: Al-Anazi HA, Sharma MM and Pope G: "Revaporization of Condensate with Methane Flood," paper SPE 90860, presented at the SPE International Petroleum Conference, Puebla, Mexico, November 8–9, 2004.
25. Dolgushin, reference 23.
26. Vyakhirev et al, reference 20.
27. Dolgushin, reference 23.
28. Gritsenko AI, Ter-Sarkisov RM, Shandrygin AN and Poduyk VG: *Methods of Increase of Gas Condensate Well Productivity*. Moscow: Nedra, 1997 (in Russian).
    Vyakhirev et al, reference 20.
    The density of the solvent mixture is 553 kg/m^3.
29. Fevang and Whitson, reference 11.
30. Mott R: "Engineering Calculations of Gas-Condensate-Well Productivity," *SPE Reservoir Evaluation & Engineering* 6, no. 5 (October 2003): 298–306.
31. Chowdhury N, Sharma R, Pope GA and Sepehrnoori K: "A Semi-Analytical Method to Predict Well Deliverability in Gas-Condensate Reservoirs," paper SPE 90320, presented at the SPE Annual Technical Conference and Exhibition, Houston, September 26–29, 2004.



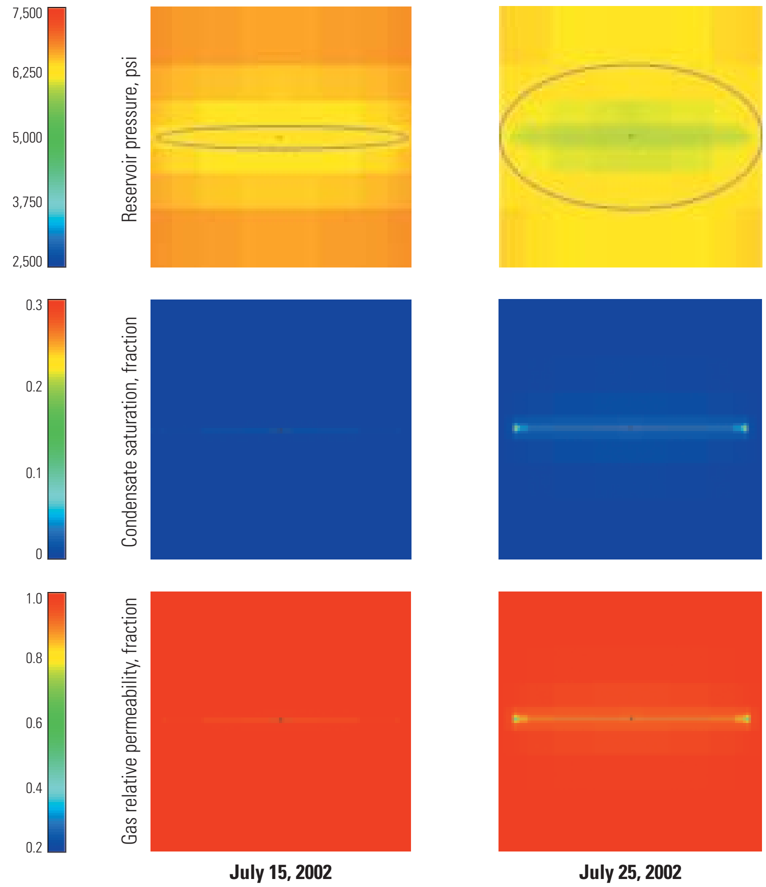
^ History-match of model of SW Rugeley field with a hydraulic fracture. The ECLIPSE 300 model of one well in the Frio sand has small grids around the well and along the fracture (*top left*). Smaller grids were also placed at the fracture tips. The field gas-rate history was matched by the simulation (*top right*), yielding good results for condensate rate (*bottom right*). The changes in production after the fracture job were due to fracture cleanup and changes in pressure in flowlines. The model indicated the average reservoir pressure dropped below the 6,269-psi dewpoint pressure during this production period (*bottom left*).



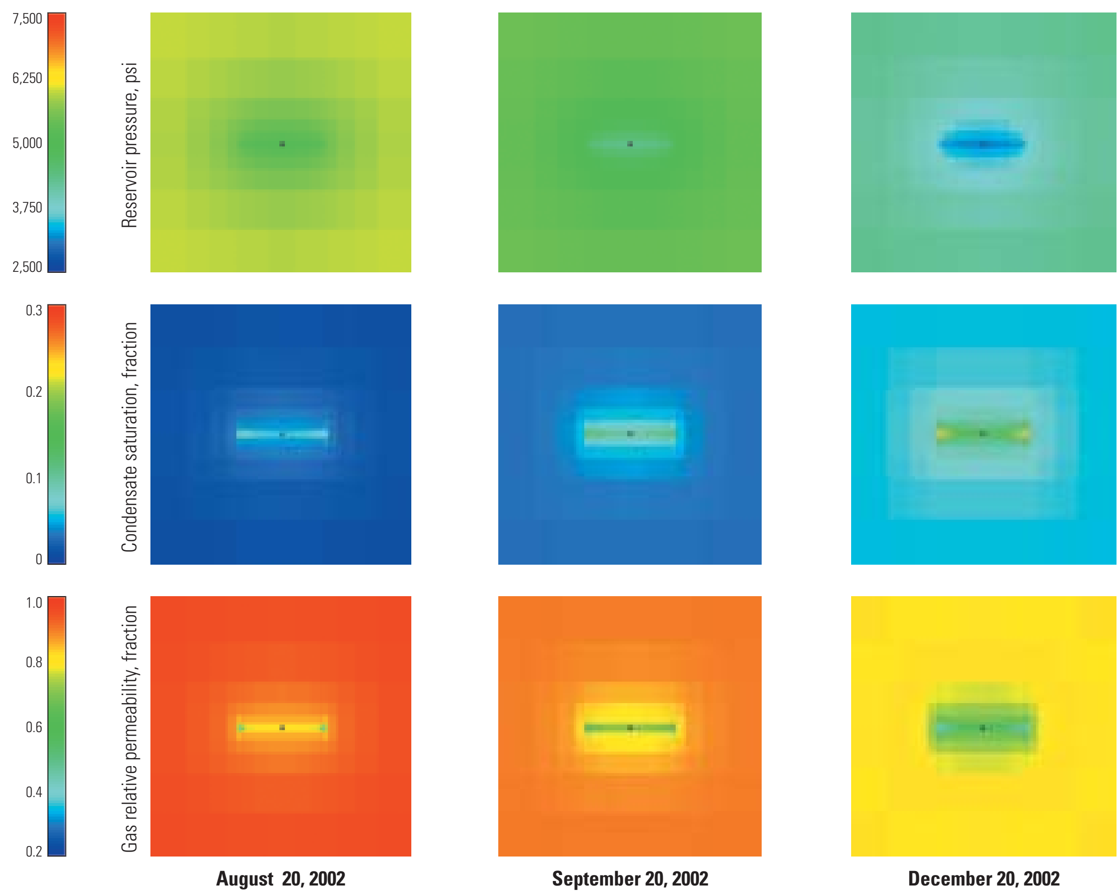
^ The hydraulic fracture effect. Rerunning the Frio well model with no fracture generated a simple decline curve indicating a significant productivity increase could be attributed to an induced fracture.

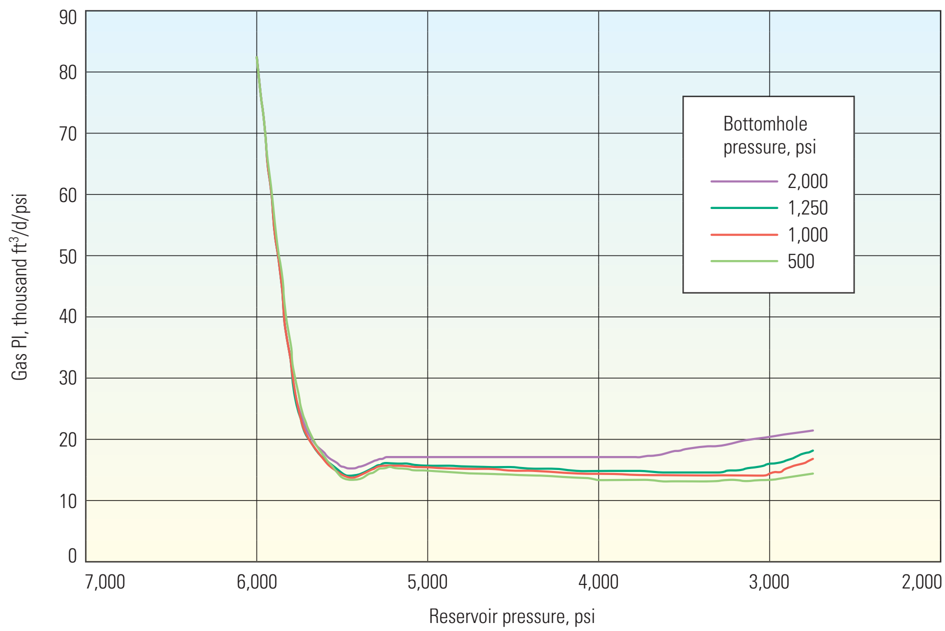
With these results in hand, Wagner & Brown had Schlumberger develop a more detailed reservoir model, using ECLIPSE 300 reservoir simulation software (above). The model was refined by history-matching to the gas production rate, which also provided a good correlation to the condensate production. Drawdown in the fracture induced the buildup of condensate saturation along the fracture (next page). The average reservoir pressure dropped below the 6,269-psi [43.22-MPa] dewpoint pressure during the modeled period.

With a good history-match, Wagner & Brown could determine whether the fracture provided significant gains in productivity. The model was rerun without the fracture, which resulted in a production curve that continued the previous decline rate (left). The difference between the nonfractured case and the measured production indicates the success of the fracture job. Over a seven-month period, the cumulative production attributed to the fracture job was 256 million ft^3 [7.25 million m^3] of gas and 15,300 bbl [2,430 m^3] of condensate. This modeling study verified the success of a field application.



< Condensate blockage around a fracture, Frio model. For each time step, model results indicate pressure decline (*top*), condensate saturation (*middle*) and gas relative permeability (*bottom*). The first two time steps in July 2002 (*left*) focus on the immediate vicinity of the fracture and the later three time steps (*below*) show a wider view of the whole model area. Pressure declines rapidly along the fracture (*left, top*). The approximate dewpoint profile (oval curves) expands outward from the fracture. The low gas permeability around the fracture at later time steps indicates the condensate blockage.





^ Spreadsheet model results for a North Sea well. A homogeneous single-well model in a spreadsheet provided a way to quickly examine different effects. For example, the bottomhole pressure had little effect on gas productivity index, PI.

Application of Best Practices

Chevron recently completed a study of five gas-condensate reservoirs that are at different stages of development. The objective was to transfer best practices among various development teams.

One of the fields in the study, a North Sea reservoir, is a marine turbidite with gross-pay interval of more than 120-m [400-ft] thickness. The average reservoir permeability is 10 to 15 mD, with average porosity of 15%. The original reservoir pressure of 6,000 psi [41.4 MPa] is a few hundred psi [a few Mpa] above the dewpoint pressure, although the dewpoint varies from east to west.[32]

The bottomhole pressure was below the dewpoint from first production. The condensate/gas ratio ranged from 70 bbl per million ft^3 [393 m^3 per million m^3] in the east to 110 bbl per million ft^3 [618 m^3 per million m^3] in the west. Some wells experienced a productivity reduction of about 80%, most of which occurred in early production.

Chevron followed a step-by-step procedure to understand and history-match the field's gas-condensate behavior. The operator selected core samples that spanned the range of permeability and porosity of the field and fluids that mimic reservoir-fluid behavior—liquid dropout as a function of pressure, viscosity and interfacial tension—at lower temperature. The company measured relative permeability over a range of flow conditions and fitted those data to several relative-permeability models for use in simulators.

A spreadsheet using an analytical pseudopressure method was used to calculate deliverability. The calculation showed that productivity index (PI) decreased from about 80 to about 15 thousand ft^3/d/psi [33 to 6 thousand m^3/d/kPa], with little difference based on bottomhole pressure until late in field life (above).

A detailed single-well, compositional flow simulation using the Chevron CHEARS reservoir simulator was performed with realistic geology. Far-field boundary conditions came from a full-field model. The simulation honored well production practices and differential depletion in the field. The predictions provided a good match to results from three vertical wells and one inclined well (next page).

This study led to several initiatives in the field. Hydraulic fracturing to improve productivity is an active effort in this field, so these models are being used to better understand fracture effectiveness. In addition, lessons learned from this field regarding the impact of condensate blocking have been used extensively in planning for wells in new projects in other gas-condensate fields.

A Fundamental Alteration

The high price of natural gas on world markets in recent years has stimulated interest in developing gas reservoirs. Companies seek new ways to optimize their gas-condensate resources.

Hydraulic fracturing can mitigate the effect of condensate blockage, but it does not eliminate the accumulation of condensate in

32. Ayyalasomayajula P, Silpngarmlers N and Kamath J: "Well Deliverability Predictions for a Low Permeability Gas Condensate Reservoir," paper SPE 95529, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 9–12, 2005.
33. Fahes M and Firoozabadi A: "Wettability Alteration to Intermediate Gas-Wetting in Gas/Condensate Reservoirs at High Temperatures," paper SPE 96184, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 9–12, 2005.
34. Kumar V, Pope G and Sharma M: "Improving Gas and Condensate Relative Permeability Using Chemical Treatments," paper SPE 100529, to be presented at the SPE Gas Technology Symposium, Calgary, May 15–18, 2006.

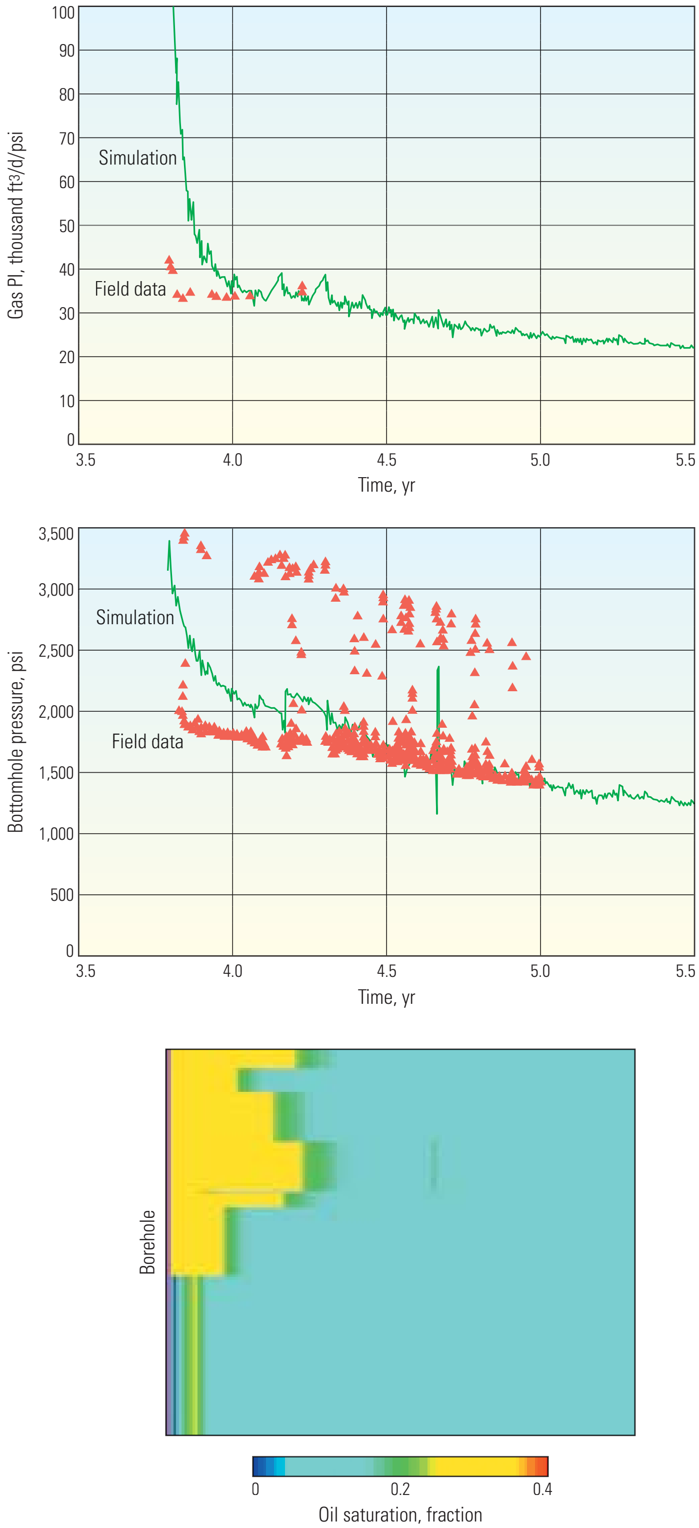
areas where the pressure in the formation is below dewpoint. Dry gas and solvent injections are able to mobilize some condensate, but the liquid saturation profile near a producing well reforms and the blockage effect returns.

New alternatives are being examined in laboratories. For example, some studies have focused on ways to prevent fluid buildup by altering reservoir-rock wettability.

Although mineral surfaces such as quartz, calcite and dolomite prefer to be wetted by liquids rather than gas, there are solids that have a gas-wetting preference. In particular, fluorinated compounds such as Teflon surfaces are gas-wetting. So, fluorinated solvents have been used to alter the wettability of cores. Recently reported results at high temperature—140°C [284°F]—typical of gas-condensate reservoirs showed a strong reversal of wetting in a gas-water-reservoir rock system, but was less successful in a gas-oil-reservoir rock system.[33]

Researchers at the University of Texas at Austin conducted laboratory tests using 3M fluorocarbon surfactants.[34] The results on reservoir core samples blocked by condensate indicate about a doubling of the gas and condensate relative-permeability values after treatment. Based upon these promising laboratory data, Chevron may test this treatment in a blocked gas-condensate well sometime in 2006. Treatments such as these must be field tested under a variety of conditions to fully develop and prove the technology. If the technique is ultimately successful, then the cost of the surfactants used in the treatment will be very small compared to the benefits of increased gas and condensate production rates.

The alteration these solvents make in the rock addresses a fundamental cause of condensate blockage: capillary accumulation of liquid because of the wetting preference of the rock. Avoiding liquid buildup alleviates the problem of choking production, so that a high production rate can be achieved. —MAA



^ Single-well simulation results. The simulator gave a good match to both gas PI (*top*) and bottomhole pressure (*middle*) for behavior in a North Sea well. Different layer properties resulted in different extents of condensate saturation buildup (*bottom*).