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THE PRECISION OF HISTORY MATCHING A RESERVOIR SIMULATION TO FIELD PRODUCTION DATA

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(The following discussion is an informal evaluation of errors commonly encountered in reservoir simulation projects taken from the personal experience of the author. Although no references are given, the author does not claim that the work is original and is indebted to the work and advise of many people over the years. In addition, generalizations are mentioned which must be evaluated for each simulation model, especially in regard to the mathematical model formulation, which is continually improving.)

The process of history matching a reservoir simulation model to field data involves the adjustment of reservoir and well parameters to accurately represent the measured field data. When the data are adequately matched, then it is assumed that the inferred reservoir and well parameters will adequately represent the actual field conditions. Thus, in performing the history match, it is important to understand the quality of match which is attainable and which should be expected. This involves understanding the performance and limitations of the simulation model due to both mathematical and reservoir description imprecision and the accuracy of the data with which the model is calibrated. In general, the data used to match the simulation model consist of pressures and production rates. For this reason, the following summary evaluates the accuracy of the model and the data from an objective and mathematical viewpoint.

Reservoir Simulator Issues

An isothermal reservoir simulation consists of the solution of the partial differential equations for fluid flow in a porous media. These equations are the diffusivity equation (for each flowing phase), along with equations describing the fluid and rock properties as a function of pressure and saturation. Boundary conditions are imposed on the solution by specifying the performance at the edges of the model, which are usually either closed or connected to an independent aquifer equation. Production and injection from wells is represented using source/sink terms in the diffusivity equation.

To perform the simulation, the partial differential equations and boundary conditions are approximated by finite difference equations, resulting in a large set of simultaneous, approximately linear equations which must be solved for each time step. The number of equations solved is essentially equal to the number of grid blocks in the simulation plus the number of wells, all multiplied by the number of phases. Since the diffusivity equation describes both pressure and saturation everywhere in the reservoir and some reservoir and fluid properties depend upon pressure while others depend upon saturation, the general solution is extremely complicated. Normally the solution is done in two stages. In the first stage, the saturation dependent properties (saturation, relative permeability and capillary pressure) are assumed to change by a predetermined amount (usually dependent on the rate of change during the previous time step) and the pressures are calculated everywhere in the reservoir. Next, once the pressures have been calculated, the saturations are updated using the flowing velocities determined from the pressure solution. Essentially, the pressures are determined implicitly (ie. all the pressures in the reservoir are determined by simultaneous solution of the equations) and the saturations are determined explicitly (ie. by direct computation for each grid cell). This is called the IMPES (IMplicit Pressure Explicit Saturation) method of solution.

Finite Difference Approximations

The limitations of this method can be determined by examining the underlying mathematics. If we assume constant reservoir and fluid properties, the partial differential equations for fluid flow, the diffusivity equation, in simplified form is

$$\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2} + \frac{\partial^2 p}{\partial z^2} + \frac{\tilde{q}\mu}{kk_r} = \frac{\phi\mu}{kk_r}\frac{\partial S}{\partial t}$$

To convert this equation into finite difference form, it is necessary to approximate the spatial derivatives of pressure and the time derivative of saturation. Note that by using Taylor series expansions, it is possible to write the following relations for a general non-uniform grid, where e_p and e_S represent truncation errors in the approximation. Analogous equations can be written for the y and z direction derivatives, also.

$$\frac{\partial^2 p}{\partial x^2} = \frac{2}{\Delta x_1(\Delta x_1 + \Delta x_2)} p_{x-\Delta x_1} - \frac{2}{\Delta x_1 \Delta x_2} p_{x_1} + \frac{2}{\Delta x_2(\Delta x_1 + \Delta x_2)} p_{x+\Delta x_2} + e_p$$

$$\frac{\partial S}{\partial t} = \frac{1}{\Delta t} S^{t+\Delta t} - \frac{1}{\Delta t} S^t + e_S$$

$$e_p \propto \frac{1}{3}(\Delta x_2 - \Delta x_1)\frac{\partial^3 p}{\partial x^3} + \frac{1}{12}\left(\Delta x_1^2 - \Delta x_1 \Delta x_2 + \Delta x_2^2\right)\frac{\partial^4 p}{\partial x^4} + \ldots$$

$$e_S \propto \frac{\Delta t}{2}\frac{\partial^2 S}{\partial t^2} + \frac{\Delta t^2}{6}\frac{\partial^3 S}{\partial t^3} + \ldots$$

From these relations it can be seen that for a given grid size, the error in pressure is proportional to the 3rd derivative of pressure, which is generally small, but the error in saturation is proportional to the 2nd derivative of saturation, which may be significant, especially when fluid fronts exist in the reservoir. However, if we specify a uniform grid, then $\Delta x_1 = \Delta x_2 = \Delta x$ and the 3rd derivative term in the pressure equation becomes zero, so the error in the pressure approximation is proportional to the 4th derivative of pressure, which is almost always negligible.

For this reason it is almost always advisable to use a uniform grid if possible, since the pressures calculated by the simulator will be nearly exact, for practical purposes. Unfortunately, the only way to reduce the error in the saturation calculation is to use a small time step, reducing Δt , since we cannot control the saturation derivative. Note that the more rapidly the saturations change, the smaller the time step that is needed to maintain a small error in the solution of the flow equations. (It should be noted that the above discussion is only exactly true when the reservoir properties do not change rapidly with distance. In addition, there are methods for reducing the truncation error in the time derivative, but these are beyond the scope of this document.)

There is also another consideration in the mathematical model related to the finite difference equations. Basically, the reservoir quantities, pressure and saturation, can be specified at either the nodes of the grid or at the center of the grid cells. If the pressures, etc. are specified at the nodes, then the exact amount of mass inside the grid block is not precisely known, since the pressure, saturation, etc. will vary across the grid block, but the quantities at the grid nodes are accurately represented. On the other hand, if the pressures, etc. are specified at the grid center, then the mass of fluid is more precisely represented, but the pressure and saturations at the grid nodes are not precise. Generally, it has been found that the exact mass in the reservoir controls reservoir performance more than any other parameter, so a grid block centered formulation is nearly always used. That means that material balance is ensured and that the average pressure of each grid block should be extremely accurate. Unfortunately, it also means that the saturation changes in between grid blocks is not perfectly represented and the pressure at the grid nodes is more uncertain. In most simulation models this is not a major factor, however, the consequence is that pressure transient tests and reservoir performance near a boundary will not be as accurately modeled, since the well and the boundary should precisely be at grid nodes rather than grid centers.

In summary, we can conclude, based on the mathematical formulation of the reservoir simulation model, that the pressures and overall material balance calculated by the simulator should be extremely accurate, but the saturation changes will be less accurate and the only means for controlling the saturation truncation error will be to take small time steps or use different numerical methods, especially when the saturations are changing rapidly in the reservoir.

Well Performance

In the diffusivity equation shown above, note the wells are represented as source/sink terms in the diffusivity equation. This means that we must some how specify the rate of fluid mass that is injected or produced by the wells, independently of the reservoir properties. During the history match phase of a simulation study, the well rates can be specified, but during the prediction phase the well producing conditions are usually used to calculate the rates.

To model the well performance, it is necessary to understand the well source/sink term in the diffusivity equation , $\frac{\tilde{q}\mu}{kk_r}$. First, note that the values for the fluid viscosity, permeability and relative permeability are reservoir properties, since the diffusivity equation only describes flow in the reservoir. Second, note that the assumption is that the flow rate, $\tilde{q}$, is the rate per unit volume of reservoir, not the actual well rate. To approximate the well contribution to reservoir flow in the finite difference equations, it is necessary to multiply this flow rate by the grid block volume, which is equivalent to assuming that the well production comes uniformly from every part of the grid block. Therefore the well performance can be made to depend indirectly on the average properties of the grid cell. Third, note that this term has no description of the well producing (or injecting) conditions and that there must be a corresponding term in the equations for the flow of each of the phases present in the simulator.

To overcome the inherent problem of representing wells within the simulator, a simplified well performance equation is normally used. For the case of a steady state well producing at the center of the grid block, the well performance can be modeled using a steady state flow relation of the form $q_w = J\left(p - p_w\right)$, where p is the grid cell pressure, p_w is the well producing pressure and J is the productivity index for the phase. There will be one equation for each well, for each phase, for each grid cell where a well is completed. In addition, it is important that the well production be related to the fluid saturations in the grid block so that a material balance is maintained in the simulator. If that were not ensured, it would be possible to produce more fluid from the grid block than exists. For that reason, during history matching, the rate of only 1 phase (usually oil) is specified in the well model. Alternatively, the total volumetric rate may be specified and the phases will flow in proportion to their relative mobilities. The steady state well equation is used to calculate the producing pressure and then the flow of the other phases are calculated from their phase properties and the well drawdown. This type of well model contains an inherent limitation, since the well model is steady state and the reservoir model is inherently transient. The implication is that transient well behavior cannot be accurately modeled.

Based on a steady state well model, it can be shown that the flow rate of each phase is related to the pressure drop, relative permeability and fluid viscosity. If we assume that the oil producing rate has been specified, then the ratio of the production of the other phases can be calculated directly from the viscosity and relative permeability relations. Neglecting capillary pressure effects, which are usually very small in relation to the well drawdown, this gives

$$q_w = \left(\frac{B_o k_{rw} \mu_o}{B_w k_{ro} \mu_w}\right) q_o$$

$$q_g = \left(\frac{B_o k_{rg} \mu_o}{B_g k_{ro} \mu_g} + R_s\right) q_o$$

If we assume that the PVT properties (volume factors, viscosities, and solution GOR) are accurate, but the oil production rate and saturations may be uncertain, then the uncertainty in the well production will depend on the relative permeability ratios, which are functions of saturations. Since we previously noted that the calculated saturations are the least accurate reservoir parameter calculated in the simulator, the uncertainty in well production rate can be related to the uncertainty in saturation through the phase relative permeabilites.

$$\frac{\Delta q_w}{q_w} \approx \left(\frac{1}{k_{rw}} \frac{dk_{rw}}{dS_w} - \frac{1}{k_{ro}} \frac{dk_{ro}}{dS_w} \right) \Delta S_w + \frac{\Delta q_o}{q_o}$$

$$\frac{\Delta q_g}{q_g} \approx \frac{q_g - R_s q_o}{q_g} \left(\frac{1}{k_{rg}} \frac{dk_{gw}}{dS_g} - \frac{1}{k_{ro}} \frac{dk_{ro}}{dS_g} \right) \Delta S_g + \frac{\Delta q_o}{q_o}$$

To estimate the imprecision due to saturation uncertainty for a simulation, assume linear relative permeabilites (essentially segregated flow within the reservoir) with a residual oil saturation of 0.15, a connate water saturation of 0.15 and a critical gas saturation of 0.05 and relative permeability end points of 1.0 for oil and gas and 0.25 for water. Then approximately, the derivatives for oil, water and gas can be estimated independent of saturation as 0.42 for water, 1.25 for gas, and 1.17 for oil. In the middle saturation range, the relative permeabilites can be estimated as half of the end point values or 0.5 for oil and gas and 0.125 for water. Substituting these values into the equations gives

$$\frac{\Delta q_w}{q_w} \approx 5.7 \Delta S_w$$

$$\frac{\Delta q_g}{q_g - R_s q_o} \approx 4.84 \Delta S_g$$

That indicates that if we calculate the saturations to within 1% (0.01), then we can estimate the flow rates to within about 5% (0.05).

The result of this analysis indicates that in a reservoir simulation history match, where oil flow rate is specified and static pressure, water and gas flow rates are used as matching criteria, the static pressure should be accurately calculated due to the model formulation, but the gas and water flow rates will be imprecise due only to the mathematical approximations. In the best case, as shown in the example above, a saturation imprecision of 1% results in fluid rate uncertainties of about 5%. We should therefore give far more weight to the pressure data in evaluating a history match than to the production data, since they are inherently more imprecise.

Grid Orientation Effects

Thus far it has been assumed that the reservoir model is accurate. This means that the gridded reservoir model corresponds exactly to the actual reservoir model in that the reservoir and fluid properties, as well as the well data, are adequately represented at the center of each grid block. Of course, in any complex model, it is virtually impossible to place every well in the center of a grid block, so there will be some imprecision in the simulation due to the inaccuracy of the well location. In addition, it has been implicitly assumed that the flow in the reservoir essentially occurs in the direction of the major coordinate axes (x, y, and z), since the finite difference equations are developed along these axis. Again, in general, it is impossible to assure that this occurs throughout a simulation, so an additional imprecision is introduced due to the grid orientation. Note that these are not errors due to bad well locations, structure or thickness estimates, but are a result only of approximating the reservoir geometry with a finite difference grid. The partial differential equations of fluid flow and the geometrical information are assumed to be accurate and the imprecision is a result of gridding the model and solving the equations using a numerical rather than analytical method.

To estimate the effect of grid orientation, assume there is horizontal flow at an angle θ with respect to the grid orientation and that the pressures, saturations, reservoir and fluid properties in all of the grid blocks are accurate. First we note that there is no diagonal term in the finite difference equation, so that flow between diagonal grid cells will take at least 2 time steps to develop, resulting in a time lag of at least 1 time step when the flow should go directly between diagonal grid cells. Thus, the calculated distance that the fluid flows will be $u_a = u_x\Delta t + u_y\Delta t$ in a given time step while the actual distance traveled should be $u_t\Delta t$, where the x and y direction velocities are related to the total velocity by the flow direction. Expressing this in terms of the flow direction with respect to the coordinate system gives

$$u_a = u_t / (\cos\theta + \sin\theta)$$

If the flow is parallel to the coordinate grid axes, then the angle would be 0 or 90 degrees and the apparent velocity would be the same as the true velocity. If the flow is along a diagonal, then the angle is 45º, and the velocity would be 0.707 times the true velocity. This would result in a lag of fluid breakthrough times of about 30% and cause imprecision in the calculated saturation changes.

In a reservoir simulation history match, the actual flow may come from any arbitrary direction, so the expected time lag would be the expected value of the time lag averaged over all of the possible angles, so the expected breakthrough time lag would be about 10%, since most of the possible flow directions would be less than 45º. Since there is a natural tendency to adjust reservoir properties to match the average production in the simulation, we should expect a time lag of between +15% and –15% when the history match adjustments have been made. That means that some wells will show fluid breakthrough early and others late and that this is a normal deviation from actual reservoir flow due only to the process of representing the reservoir on a grid.

Besides the grid orientation effect, there is an additional effect if the wells are not exactly in the center of a grid cell. In this case, even if the flow is along the grid axes and the grid cell pressures are accurately calculated by the finite difference model, the breakthrough times will exhibit a time lag due to the imprecision of the approximate well location. This effect is difficult to estimate, due to variations in frontal velocities, but an order of magnitude estimate can be made by estimating the frontal velocity as it approaches a well. If the well is at the edge of the grid cell, breakthrough would occur immediately, while if the well is at the far edge, the breakthrough would lag by the frontal velocity times the grid cell width, while in either case the simulation would calculate breakthrough at the same time. Thus the potential imprecision in the breakthrough could be as large as $0.5\Delta x/u_f$. If we assume a 500 ft grid width and a frontal velocity of 10 ft/day, the range of expected breakthrough times would be +/-25 days. However, the actual expected range of breakthrough times would depend on the distribution of locations within the grid cells and frontal velocities in the model and would be substantially less on the average.

A further source of inaccuracy results from the well location, even if there is no frontal passage. Since the pressure used to calculate well performance is based on the pressure at the center of the grid block, if the well is not physically at the center, then the calculated drawdown will be incorrectly estimated in the simulation model. The exact magnitude of the difference will depend upon the pressure distribution in the reservoir, but in general, the static pressure used in the well calculation will be too low by an amount depending on the well location in the grid and the pressure distribution in adjoining grid cells. The effect will be to overestimate the flow from the well, but normally this is compensated by adjusting the well productivity to reflect the difference. The amount of discrepancy caused by this approximation is extremely difficult to quantify and no attempt to do so will be made here. It should also be noted that there are more complex finite difference schemes which minimize grid orientation errors.

Data Accuracy Issues

In addition to the accuracy of the simulation results, the precision of the data being matched must be considered, since the quality of the match will be affected by both the deviation of the model from the actual values and the deviation of the data from the actual values. For this reason it is imperative to evaluate the quality of the available data, which is often a much more subjective evaluation than the mathematical treatment of the reservoir simulation model.

Static Pressure Data

Data concerning static pressures in a reservoir would seem to be easily measured, however, to compare the data with simulator results requires an understanding of both the pressure measurements and the nature of the simulator calculations being compared. Normally the static pressure data are measured using a downhole pressure gage which has an accuracy stated by the manufacturer. Most pressure data measured with mechanical gages has a stated accuracy of 0.1% of full scale, if the gage has been properly calibrated. For a 3000 psi gage, this amounts to a manufacturer rated precision of +/-3 psi. Electronic digital gages are generally more accurate, if they are properly calibrated and temperature compensated.

Ideally the pressure measurements could be compared directly to the reservoir pressures calculated in the simulator and a direct comparison could be made. Unfortunately this is not the case for at least 3 separate reasons. First, the well must theoretically be shut in for an infinite time before the true static pressure is reached, which is impossible. Second, the actual static pressure is never actually directly measured, but determined by extrapolation of pressures measured inside the wellbore. And third, the well in the simulator is usually not shut in at all, but the static pressure is estimated by averaging the pressures in grid cells near the well.

To estimate the effect of shut in time on the expected pressure response of a well it is necessary to consider the pressure performance during a pressure buildup test. In general, once wellbore storage and skin effects have diminished after a few hours of shut in, the well pressure response can be modeled using the Horner equation, where p* is the pressure which would be reached at infinite time. If the well is located in the center of a regularly shaped closed drainage area, p* will generally be very close to the static pressure, but if the drainage area has a constant pressure outer boundary, the actual static pressure may be lower than the extrapolated value. For purposes of this analysis, the Horner equation can be written as

$$p = p^* - m\log\left(\frac{t_p + \Delta t}{\Delta t}\right) \approx p^* - m\log\left(\frac{t_p}{\Delta t}\right)$$

$$m = \frac{162.6 qB\mu}{kh}$$

where t_p is the producing time prior to shut in and Δt is the shut in time. If a well is shut in for 1 day for every year of prior production, the time ratio will be about 365. If it is shut in for 2 days for every year it had produced, the ratio is 182, etc. From this it can be seen that the logarithmic term will generally be in the range of 2 to 3, so 2 (time ratio of about 100) can be conservatively used as an estimate of the static pressure accuracy.

If we use an average production rate of 1000 BOPD, volume factor of 1.25, viscosity of 1 cp, permeability of 300 md, and thickness of 200 ft, then m = 3.4 psi/cycle, so the error in static pressure estimation would be about 7 psi. Combining the effect of gage accuracy and well shut in time yields a pressure accuracy of about 10 psi.

The greater concern in static pressure measurement arises from the fact that pressures are desired in the oil phase in the reservoir at the datum depth. Pressures are measured, however, in the wellbore at various depths in whatever fluid happens to be in the well. This requires that the measured pressures be extrapolated to the datum depth to provide an estimate of the static pressure. The technique for doing this is to determine the fluid pressure gradient in the wellbore from the measured pressure data, extrapolate the pressure to the center of the perforated interval using the wellbore fluid pressure gradient, then extrapolate the pressure from the center of the perforations to the datum depth using the in-situ oil density in the reservoir. In many cases, however, the assumption is implicitly made that the wellbore fluid pressure gradient is the same as the oil pressure gradient in the reservoir, so that the extrapolation can be directly made from the last measured pressure to the reservoir pressure datum depth. The error introduced by this method can be estimated by $\Delta p = \Delta D\, \Delta\rho$, where ΔD is the distance between the perforated interval and the datum depth and $\Delta\rho$ is the difference between the reservoir and well fluid gradients. In general it has been observed that the estimated fluid density is too low in up-dip areas of reservoirs and too high in down-dip areas due to the presence of gas or water in the wellbore. Assuming that the density difference is on the order of 0.01 psi/ft due to the separation of gas from the fluid, and an extrapolation of 1000 ft is made from the center of the perforations to the datum, then the estimated error in the static pressure would be about 10 psi. If the wellbore contains mainly gas, then the density difference might be as large as about 0.30 psi/ft, yielding an error of -300 psi. Conversely, if the well contains water, the density difference might be on the order of 0.05 psi/ft, yielding an error of +50 psi.

As can be seen, the error due to pressure extrapolation can easily exceed the errors due to well shut in time and gage accuracy combined. For this reason it is extremely important that all static pressure data be reviewed and, if possible, the static pressures should be re-estimated from the original pressure survey data. If this is not possible, then the acceptable accuracy of the history match should account for the possible errors due to extrapolation, which might be as high as several hundred psi.

Oil Production

Generally the total oil production from a field is measured with a high degree of accuracy, since the oil is being sold and it is in the interest of both the seller and purchaser to maintain accurate records. The production rate of individual wells, however, is usually allocated based on periodic production tests on the individual wells, which are assumed to be representative of the well performance until the next test is conducted. This procedure can lead to errors in the reported production rate due to fluctuations in well performance as well as due to measurement errors in the test data.

The error due to test data measurement usually depends upon the size and operation of the test separator used in the field. Nearly all separators have a dump valve which activates when a certain volume of oil has accumulated in the separator. If the separator dump volume is V and the time of the test is h hours, then the possible error in the daily production rate of the well could be as large as 2(24)V/h, since it is not known whether the separator dumped immediately before beginning the test nor whether it dumped immediately before concluding the test. If the dump volume is 1 bbl and the test was conducted for 6 hr, then the possible daily rate uncertainty might be on the order of 8 BOPD. On the other hand if the test were conducted for an entire day, the rate uncertainty would be only 2 BOPD. In high rate wells these errors are relatively insignificant, however, when the oil producing rate is low and the test times are short, the precision of the daily rate measurements can be a large percentage of the total flow rate, yielding exceedingly inaccurate results. In high rate wells, these errors are usually assumed to be negligible, with accuracy on the order of 1%. Thus, for a well producing 1000 BOPD, the oil rate uncertainty might be on the order of 10 BOPD, assuming the separator dump is properly operated, etc.

When the rate is fluctuating, as is usually the case in most wells, the errors due to neglecting the changing rate can lead to additional measurement errors. If the rate varies randomly about a mean, then the probability of sampling a given rate will depend upon the distribution of the rate fluctuations. For a 1% standard deviation rate fluctuation, the inaccuracy of the measurement would be about 2% of the mean flow rate for a normal distribution. For a 1000 BOPD well, this would amount to about 20 BOPD. If the well is heading, the distribution of rates would vary much more wildly and the potential measurement error could vary as much as 100% or more of the average flow rate.

A more insidious problem occurs when a well rate is changing in a consistent manner. If, for example, a well is declining at a rate of 1% per month, the error in average daily rate for the month would be about 0.5% of the well rate. Again, for a 1000 BOPD well, this might amount to about 5 BOPD error, averaged over a month. Of course, the more infrequent the well tests are taken and the more dramatic the rate fluctuations, the more error will accumulate.

An additional error may accumulate due to the allocation procedure. If we assume that 2 wells yielded the same production rate during a test, but 1 well produced at 1% higher rate in reality, then the process of allocating the production would allocate half of the error to each of the wells. Thus, even the well with the accurate test would receive half of the measurement error. For this reason it should be ensured that representative well tests are taken and that the tests are conducted long enough to minimize the error in the well test volumes. For practical purposes, it seems reasonable to assume that oil production rates might be accurate to about 1% in the best case. This accuracy should be evaluated for each field studied.

Water Production

In most field installations the water production is not directly measured on a well by well basis, but is measured indirectly during the well tests and then allocated to the individual wells based on a measured water cut (percent water). This means that the reported water production can be no more accurate than the reported oil production, since the allocated oil production rate is used to determine the water rate. In most cases the water cut is determined by “shake out”, where a sample of well fluid is placed into a centrifuge, the oil and water are separated, and the fraction of water is reported. The accuracy of the reported water fraction will depend upon the accuracy of reading the centrifuged volumes and the amount of fluctuation which occurs in the well. For the effect of fluctuations, the same considerations discussed above in connection with oil production rate apply. In practice, it is rarely possible to consistently measure the water cut with a precision greater than about 1% of the total volume. Thus for a 1000 BOPD well producing mostly oil, the water rate uncertainty could be 10 BWPD due to water cut uncertainty and 10 BWPD due to water cut fluctuations. Of course at higher water cuts and more wildly fluctuating well conditions, the uncertainty in the water production rate can be much higher.

The more important effect of comparing the water production rate with simulator results arises from the specification of an oil producing rate in the simulator which might be inaccurate. Using the relations established previously, it is apparent that the simulator water production rate will also be inaccurate by the amount of uncertainty in the oil production rate, in addition to any imprecision due to saturation changes.

To put this in perspective, if a well produces at 1000 BOPD and 50 BWPD (5% water cut) with 1% uncertainty in oil rate measurement, the uncertainty in the water rate measurement might be about 40% of the reported water rate (10 BWPD due to water cut uncertainty and 10 BWPD due to rate uncertainty, or 30 – 70 BWPD), while the simulator could predict a rate in error by as much as 6% (2.5 BWPD due to 1% saturation uncertainty and 0.5 BWPD due to oil rate uncertainty, or about 47 – 53 BWPD). Thus the total imprecision in comparing production data to simulator calculations could be no better than (20 + 3) = 23 BWPD, or 46% of the water production.

Gas Production

It is commonly acknowledged that the gas production rates in typical oil field operations are perhaps the least accurately measured of all the fluid volumes. Usually this is due to the fact that the gas has little relative economic value and is perceived as a nuisance in field operations. Unless the gas has an immediate economic value, gas measurements are rarely made with precision.

In normal operations, gas flow rates are measured using an orifice meter, where a pressure drop due to flow of the gas through a reduced diameter orifice is related to the flowing velocity of the gas through its density changes. During a well test, the pressure drop across the orifice and the pressure upstream of the orifice are recorded on a chart, which is later integrated to determine the volume of gas flowing. Depending on the rate fluctuations and operating pressure of the orifice meter, it appears that an accuracy of about 2-5% of the gas volume can be achieved with this type of system, depending mainly on the extent and magnitude of the rate fluctuations and the accuracy of chart integration.

As noted above for the water production, the gas production is normally estimated by applying the calculated gas-oil ratio to the allocated oil production rate, so that any uncertainties in oil production rate are reflected in the reported gas production rate as well. Thus, if it is assumed that the gas rate during a well test is measured with 2% precision, then the uncertainty in the actual gas rate could be 1% due to the uncertainty in the oil rate and 2% due to the uncertainty in the gas rate measurement for a total of 3%. Thus a well producing 1000 BOPD and 1000 MCF/D (1000 SCF/BO) could have a gas rate inaccuracy of 10 MCF/D due to oil rate uncertainty and 20 MCF/D due to measurement uncertainty, for a combined uncertainty of 30 MCF/D.

However, as noted above for water, the problem is compounded when an inaccurate oil rate is used in a simulation, since the calculated gas rate will reflect the imprecision in the oil rate, as well as the uncertainty in the saturation. Using the previous equations for gas production rate, it is possible to estimate the total effect of these uncertainties. If ½ of the produced gas is free gas in the reservoir, then for a well producing 1000 BOPD with a flow rate uncertainty of 10 BOPD, the gas rate calculation would be uncertain by 25 MCF/D due to a 1% saturation uncertainty and an additional 10 MCF/D due to the oil rate uncertainty, or a total of 35 MCF/D uncertainty in the simulator.

As above to put this into perspective, if a well produces 1000 BOPD with 1000 MCF/D (1000 SCF/BO) with ½ of the gas flowing as free gas in the reservoir and the oil rate is uncertain by 1% (10 BOPD), then the inaccuracy expected in the measured gas rate is about 3% (970 – 1030 MCF/D), but the simulator could calculate gas production rates inaccurate by as much as 3.5% (25 MCF/D due to 1% saturation uncertainty and 10 MCF/D due to oil rate uncertainty, or 965 – 1035 MCF/D). Thus the total imprecision in comparing production data to simulator calculations could be no better than (30 + 35) = 65, or 6.5% of the gas production.