Complexity and Simplicity in Modeling Oil Reservoirs

Intreerede

Delft University of Technology
W. R. Rossen

21 Nov. 2007

[slide 1] It is an honor to address you all today. I have long had the highest regard for the research and education here at TU Delft, and I am delighted to have joined you on the faculty. My wife Janice and I have a great affection for TU Delft extending back more than 15 years, when we first met Hans Bruining of the Petroleum Engineering program, during his sabbatical at The University of Texas at Austin, where I taught for many years. I especially thank my colleagues in the Department of Geotechnology, at TU Delft, who have done so much to help me fit in.

My topic today is the tension between simplicity and complexity in modeling oil and gas reservoirs for the purpose of predicting and optimizing their performance. Oil and gas reservoirs are incomprehensibly complex, from the microscopic scale up to that of kilometers. In our lifetimes, we will never be able to represent all the spatial variation of properties in these geological formations, even if computers grow larger and more powerful for many years to come. In addition, we lack sufficient information about those properties (except in a relatively few locations), even if we had the power to represent them in computer models. Finally, the recovery processes themselves introduce another layer of complexity to that provided by the geological formation.

Therefore, radical simplification is needed, to begin to represent and predict what happens underground as an oil or gas field is produced. And yet the very process of reducing a model to its essentials calls for careful judgment, lest we over-simplify. How does one decide how much complexity is enough in a model? Which mechanisms are necessary in creating a meaningful model, and which can be safely left out?

The tension between complexity in the real world and simplifications we must make in our models is a continuing and unavoidable challenge—amounting at times to exasperation. However, there is also an esthetic pleasure in finding a particularly elegant and simple solution to a complex problem. There is a joy both in discovering beautiful complexity in a seemingly simple physical phenomenon and in finding an elegant mathematical model to represent it. I hope in this talk to highlight both the tension and the joy in this process of simplification.

I don't need to convince my colleagues in the geosciences of the complexity of geological formations. [SLIDE 2] Traditionally, it is engineers that are most guilty of oversimplifying this. My first slide [SLIDE 3] starts on the scale of micrometers: an electron microscope image that illustrates the complexity of pore shapes and the roughness along pore walls introduced by clay deposition. The oil and gas we want to produce fills the gap between these grains and clay particles.

My next slide [SLIDE 4] moves up a little, to the scale of a mm or two. This is a slice through the rock and illustrates the complex pore geometry and heterogeneity of grains and minerals. We can represent the pore network mathematically on a scale of a few mm [SLIDE 5], but it requires the largest computers now available, and we've already thrown away the information on the pore surfaces shown earlier.

Next [SLIDE 6] we're at a scale of a cm or two, and one can see heterogeneity of a larger scale, with grains further apart at the bottom of the image. Fluids would flow more easily through this pore space than through the pores above this. Moving up to the scale of 5-10 cm [SLIDE 7] it becomes clear that there is large heterogeneity on a scale of mm. In this case the black layers would block the flow of oil and gas and the gray areas conduct flow.

Reservoirs are modeled on the computer on a scale of hundreds of meters or kilometers [SLIDE 8], where one tries to include heterogeneity on a scale of 10s m, but one throws away (or

tries to average) the effects of heterogeneity on smaller scales. Here are shown two large reservoir computer models, illustrating that one tries to represent large-scale heterogeneities, but the small scale is lost. We can never create a complete, or true, model of the reservoir if completeness or truth means representing all of the complexity in the reservoir.

A motto I find very helpful in such situations was suggested by a colleague, Larry Lake [SLIDE 9]:

"*All* models are false, but *some* models are useful."
-George E. P. Box

By "false," I believe this means incomplete. All models are false because none of them includes everything in nature. Beginning with this realization saves us from fruitless arguments about why the *other* guy's model is wrong because it doesn't include some aspect which *my* model *does* include. Scientists do argue about which model is better because it is more complete.

The real test, however, is whether a model is *useful*. By useful, I mean a model that provides insights we would not otherwise have, or that is accurate enough for prediction and use in design. Sometimes the useful models are ones that are not as complete, because complexity in modeling can blind us to relatively simple explanations for the most important features of a situation. For instance, Newtonian mechanics is a false model; it doesn't include relativistic effects. But it is almost always useful.

I would like to describe three examples of this tension. The first example is the question of how to represent naturally fractured oil and gas reservoirs. I have no answers at this point, but the case illustrates the difficulties in determining what is essential; that is, what makes a model useful even if it is false. The second example is modeling gravity effects that occurs in processes that use injected gas to recover oil. In this case remarkably simple models are clearly useful, though not complete. The third case is the use of foam for improved oil recovery and well stimulation. In this

case I have played both sides; sometimes illustrating the remarkable complexity that would be required in a model that claims to be complete; and in other cases finding simplifications that lead to useful, incomplete models.

My first test case is the modeling of Naturally Fractured Reservoirs [SLIDE 10]

An open fracture in a geological formation is like a superhighway for flow. [SLIDE 11] A rough rule of thumb is that all of the flow through the reservoir is through the fractures, while all of the fluids reside in the "matrix," or solid rock between the fractures. A successful recovery process then works something like an urban highway system. The workers reside in the suburbs, on small streets. To get to the city, they first travel through the slow, inefficient side streets until they reach the highway, after which they rapidly reach the city. Similarly, in fractured reservoirs there is a slow process of oil or gas reaching the fractures, but rapid flow to the well through the fractures. (At this point, admittedly, my analogy breaks down, because it most cities the highways are jammed at rush hour.)

Moreover, the longer the fracture is, the more important it is; not only because it carries flow a longer distance, but because length tends to correlate with ability to conduct flow. But large fractures are relatively rare. Because fractures are often nearly vertical, one is unlikely to observe one directly with a vertical well. Because the large fractures are so important to the flow in the reservoir, the position or existence of a single fracture could have a large impact on the flow in the entire reservoir.

One can map fractures in outcrops, where the fracture rock comes to the surface as shown in the next slide [SLIDE 12], and try to relate this to what occurs underground. (This slide shows a map of fractures at an outcrop created by Michiel van der Most, a current MSc student here at TU Delft. There are three sets of fractures, shown in three colors, that were created at three different periods of stress within the reservoir.) One could take the

properties from maps like this and create possible arrangements of fractures in the reservoir consistent with these fractures on the computer.

Moreover, some studies suggest that fractures are more frequent the smaller they are, and that there are an infinite number of fractures at the smallest scales. Thus we clearly can't represent all the fractures. Moreover, there is no completely dependable way to average the properties of fractures to allow one to move to larger scales with the averaged properties.

The next slide [SLIDE 13] shows two computer-generated sets of fractures. In the set on the right, there is a continuous path for flow from top to bottom in the big square, but not through every one of the smaller squares. In the set on the left, there is a path for flow from top to bottom across every one of the smaller squares, but not across the big square. Scaling the properties from small to large scales is difficult with fractured reservoirs.

What are the most important features of naturally fractured reservoirs? One might list the aspects as follows [slide 14], in increasing level of sophistication; [READ POINTS OUT LOUD]:

Of these features, the most common computer modeling method includes the first two points, but leaves out the rest. A colleague at TU Delft believes the third point is crucial. I worked for a time on point 4, but I am currently wondering whether points 5 and 6 are first-order effects or can be left out.

Issues involved in modeling fractured reservoirs then are listed on the next slide [slide 15]; [READ POINTS ALOUD] . The first point is the heart of most current models of fractured reservoirs. A group of researchers at TU Delft and the Free University of Amsterdam are at work on point 2, which would feed information into that approach. My colleague at TU Delft is at work on the fourth point, and points 3 and 5 are the focus of my curiosity at the moment.

For fractured reservoirs, as for other oil and gas reservoirs, the key is determining which kinds of complexity are of second-

order importance and can be left out, and which are essential for accurate understanding and prediction of behavior.

[Slide 16] My second case study is Gravity Segregation in Gas Improved Oil Recovery.

On average, about 2/3 of the oil initially in place in an oil reservoir is left behind when the field is abandoned. One way to increase this total a bit is by injecting gases that are miscible with the oil. A schematic of the process is shown in the next slide [SLIDE 17]. As this slide shows, the gas (in this case carbon dioxide, or CO_2) is usually injected in alternating slugs along with water. In principle, miscible gas flooding could recover 100% of the remaining oil, but in practice recovery is much less, for a reason not shown in this picture.

One reason is that the injected gas only sweeps a portion of the reservoir, and part of the reason for this is gravity segregation. The gas is much less dense than water and oil; it quickly moves to the top of the reservoir and leaves most of the reservoir untouched, as illustrated in the next slide [SLIDE 18]. Here the injection well is along the left-hand side, and the production well on the right. Gas recovers oil only in the mixed zone and the thin override zone at the top of the reservoir.

A remarkably simple model for this process was proposed by two engineers, Stone and Jenkins, 25 years ago; it describes the process of gravity segregation when gas and water are injected continuously in a homogeneous reservoir. Stone and Jenkins give an equation for the distance gas and water flow before they segregate. The model is clearly false, i.e. incomplete. For instance [SLIDE 19], it leaves out geological complexity, details of how the gas and water flow together, and even the oil, which is the target of the whole process. Moreover, the model says that many factors it does account for are unimportant: the reservoir's permeability (or ability to conduct flow), for instance.

Nonetheless, the model gives one clear insight: the key to avoiding gravity segregation of water and gas, as shown in the previous slide, is to maximize the horizontal pressure drop in its

fight against the vertical effects of gravity, and to do so at the leading edge of the gas front, where gas is deciding whether to override or not. The model also suggests the challenge in doing this [SLIDE 20]. In this figure radial distance from a well is shown on the horizontal axis; note the nonlinear scale, with most of the scale taken up with the first few m from the well.

Plotted here are two features: The diagonal lines represent dissipation of injection pressure, computed in two ways, which mostly occurs near the well. The bottom curve is the extent of segregation that has happened at the same position. It is clear from this plot that most of the injection pressure is dissipated near the well, where it does no good, and where practically none of the segregation occurs. From this insight a number of improved designs have emerged that minimize the dissipation of pressure near the well and focus the pressure drop on the outer edge, where gravity override is determined.

This model is useful, but incomplete. I and my students are extending it now to heterogeneous formations, starting with simple layered formations. I'll show one success and one failure of the model tested in this way. First [SLIDE 21] is a comparison of two processes with different injection pressures (what is shown is actually injection pressure minus reservoir pressure). The layers are shown in the upper right: light blue represents layers with higher permeability; i.e. that take flow more easily. There is a high-permeability layer at the top in this case.

The bottom two figures show gas saturation in the reservoir during gas injection. It may look like the left-hand process is winning, because gas is advancing faster along the top there. Actually, this process is losing, because once this gas reaches the production well the remaining parts of the reservoir may have to be abandoned. The right-hand plot, with the higher injection pressure, is the winner, because the sweep is more even. As the model predicts, maximizing injection pressure is the key to maximizing the sweep of gas and therefore oil recovery.

Next [SLIDE 22] is an example of a reservoir with lower permeability on the top, as shown on the left. I should mention that what is shown in these two slides are not just gas processes but processes involving foam; I'll say more about foam in a minute. The sort of reservoir shown on this slide is supposed to perform better than the first one, but in this case gas breaks rapidly through the lower-permeability layer at the top and rapidly reaches the production well; you can just see it at the top of the figure. The model missed this feature. In this case the simple model was false in a way that also made it less useful. Therefore I am some students are modifying it to add needed complications.

My final example is modeling foam in porous media [SLIDE 23]. Foam is used to divert gas flow in improved oil recovery, as illustrated in the previous slides; to divert the flow of acid in well-stimulation treatments; and to direct the flow of remediation fluids in aquifer cleanup. I confess to a passion for this research topic that has extended over 20 years. [SLIDE 24] In part this passion arises from the esthetic pleasures of contemplation of bubble shapes and curved interfaces, something like the boy shown at left here. Shown at right is a huge bubble, one or 2 m in length, created by one of those bubble toys you can buy in a toy store. I own several of these toys, but I've never made a bubble quite like this.

[SLIDE 25] In geological formations, foams greatly reduce the ability of gas to flow, in effect making it more viscous, or even trapping it in place like a solid. The basic idea of this foam is much like you would think: bubbles separated by soap films, stabilized by detergents. But the foam is inside of pores that are as small as the bubbles are. So the picture inside the rock is like that shown on the right. In this picture the soap films between bubbles are shown in blue, and the grains of sediment are hashed. Bubbles fill the space between the liquid films. The bubbles flow between the grains of sediment, while water (shown here schematically at the bottom) fills the smallest pores and flows along separately on its

own. In only the largest pores the gas bubbles flow; in the middle-sized pores the bubbles are trapped.

In addition to the properties of the pores, the water and the gas, the behavior of foam depends on the fraction of the bubbles that flow; the drag on the bubbles that do flow; both of these properties depend on the size of the bubbles. The size of the bubbles in turn depends on a variety of processes that create and destroy soap films. A former student created a chart once to try to express the interdependency of all these mechanisms. [SLIDE 26] The point of this slide is just to illustrate that the interactions that govern foam properties are complex.

To illustrate the complexity of all this, I would like to describe just one aspect: the yield stress and drag on moving bubbles, which determines the fraction of the bubbles that can flow, the box circled in the next slide [SLIDE 27]. The resistance to flow is reflected in and caused by the curvature of the soap films [SLIDE 28], illustrated here; films that bulge forward resist the forward movement and increase the drag on the foam. The soap films are perpendicular to the pore wall. So in this example the first soap film is resisting forward movement; the next is pulling the foam forward; the next two resisting, and so on. To simplify the problem, one might imagine that the pores are identical and conical in shape, as shown here, and, initially, that the foam is moving extremely slowly. This pore shape has symmetry both front-to-back and radially.

This work was done some time ago, so I'm going to have to change color scheme in my slides [SLIDE 29]. The first surprise is that although the pore is symmetric front to back, the soap film does not spend half its time bending forwards and half backwards. The front-back symmetry is broken because when the soap film reaches the midpoint of the pore it already occupies more than half the volume of the pore. Therefore, when it reaches the midpoint of the pore it has to jump part-way up the pore wall in order to conserve volume. Again, the sequence of film shapes determines the resistance to flow, and how much of the foam remains trapped.

I went to the lab with a conical pore about 10 cm long to document this jump. [SLIDE 30] The pore is held vertically in this photo and the soap film is near the entrance. At first things went according to plan ([CLICK 3 TIMES]. The next step was something of a shock. [CLICK] Although the pore was radially symmetric (or as close as we could make it), the soap film jumped to an asymmetric shape. This change in shape changes the curvature of the film and the resistance of the gas to flow. It keeps this shape a while longer [CLICK] and then eventually reverts to the symmetric shape for its remaining passage through the pore. [CLICK TWICE]

When I saw this, I thought what you're thinking now - the glass must be dirty. But it turns out [CLICK] the jump is predicted by theory, if one doesn't start off by assuming that the soap film is symmetrical. Solving for the sequence of steps in two dimensions is pretty easy, but doing so in three dimensions [SLIDE 39] required help from colleagues at Trinity College, Dublin.

Moreover [SLIDE 40], theory predicts that the asymmetric jump disappears at high velocity. In some cases it disappears abruptly, suddenly going from the sequence on the left to that in the middle; in other cases it becomes more symmetrical gradually, as shown on the right. Which way the process falls out depends on the pore shape. All this was worked out in two dimensions , however; the process still hasn't been worked out in three dimensions .

Back to the movement at very slow velocity: it turns out [CLICK] that the compressibility of the gas plays a role in how the soap films jump. But not just the compressibility of the gas in the moving bubble [CLICK]: the expansion and contraction of gas in bubbles surrounding the moving bubble makes the moving bubble behave as if it were more compressible. This feature turned out to be essential in fitting laboratory data on bubble movement through beadpacks. In addition [CLICK], liquid in the corners of pores is expelled and drawn back in as pressure in the bubbles fluctuates, making the bubbles behave as if more compressible still.

Finally [CLICK], when a chain of compressible bubbles moves through a sequence of pores as shown here, they all tend to jump together. Physicists, I believe, call this "self-organized criticality." As a result, the soap films tend to spend more time in pore constrictions, where the resistance to flow is highest, and this raises the resistance to flow yet further.

This solution is far from finished, and much of what's been done has only been in two dimensions. [SLIDE 45] All of this is then only a partial solution of the mechanism in one box in the schematic of foam mechanisms. Clearly we are not close to a complete (i.e., not a "false,") model for foam.

But sometimes nature is kind. I will conclude [SLIDE 46] with an example where a stunning simplification appears to work well for describing foam.

The next slide [SLIDE 47] shows a large amount of laboratory data taken in flow of foam through a sandpack. The vertical axis is gas flow rate through the pack; the horizontal axis is liquid flow rate. Each little dot, which you can barely see, is a separate experiment, in which the pressure drop was measured across a foam-filled sandpack. There are about 40 dots in this figure. From each of the individual pressure-drop measurements a contour plot has been constructed. Pressure drop is lowest along the left and bottom sides of the figure, and climbs as one moves upwards and toward the right.

What is striking about this figure is the existence of two very different kinds of behavior. In the upper left, circled in red, at high gas flow rates and low water flow rates, pressure gradient does not change as one increases the flow of gas. In the bottom right, the opposite is true; one can vary the flow rate of liquid without changing the pressure response. This is especially striking that one can increase the flow rate of liquid, the more-viscous fluid, and not increase the pressure drop across the core.

Actually, it turns out that the explanation is relatively simple. Returning to the schematic of foam mechanisms [SLIDE 48], in

each case a single mechanism controls all the others. Like an extremely strong feedback loop in a controller in a chemical plant, all other factors respond as needed to maintain the fixed set point. The two boxes are highlighted on this figure, with the same colors as the regime they control in the previous slide. In fact, one can represent this behavior relatively simply, using just two parameters. The results are shown in the next slide [SLIDE 49]. The fit isn't perfect, but it comes close enough for design work for field applications of foam.

In modeling oil reservoirs, for the purpose of predicting and optimizing their behavior, it is essential to simplify a complex reality. No model can be true in the sense of being complete. So we return to the motto with which I began [SLIDE 50]; the goal is not a model that is complete, or even necessarily *more* complete, but one that is useful, in that it provides insights that one did not have before, or makes predictions that are close enough to guide design and optimization.

These challenges continually provide the fascination of pursuing research, which all of my colleagues share, and which make it exciting to come to work each day. As Hamlet tells Horatio, 'there are more things in heaven and earth than are dreamt of in your philosophy'—perhaps, as he might have added, in an academic's chosen 'model.' But the search itself is what continues to beckon us all.

[SLIDE 51 -TUD SEAL]