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Is "Practical" Reservoir Simulation an Oxymoron?

What do you know about numerical dispersion, implicit vs. explicit solutions, corner point geometry, drainage vs. imbibition curves, "real" relative permeability curves vs. "pseudo" relative permeability curves? What time steps should you use and what error tolerance in the solutions is applicable?

Reservoir simulation specialists are doing to the industry today what geophysicists have been doing for years, "GOK"ing us. GOK is an acronym I coined for "Guardian Of the Knowledge". Both groups throw out lots of big words, which although important from a theoretical standpoint, are often of limited value in the real world. We feel that if we can intimidate/confuse those who would question our knowledge then we can often instill a false sense of importance and accuracy to our work.

I can already hear the Reservoir Engineers Union screaming. Don't get me wrong I appreciate the fact that many dissertations have been published on the correct method of guesstimating relative permeability in a water wet "conglomstonesands", but the fact of the matter is that until you start putting water in the ground it is simply an educated guess.

The SPE technical interest group on reservoir simulation is full of brilliant people who have come up with elegant solutions to many of the problems seen during a simulation. The software vendors do a fine job of implementing so many new features and options that they cannot even properly document them all. The problem is that no matter who does the simulation – **IT IS WRONG**. That is the only given.

So why do a simulation if it is wrong? Because it is often the best tool for the job. An evaluation needs to be made on a project and often a simulator will provide the best possible (but wrong) answer. The simulation may be high or it may be low, but it is not right on the money. It will need to be tweaked as the field is produced. It will be much closer than some of the old standby techniques such as Buckley-Leverett and other such correlations.

What are simulations good for?

Material Balance (Does your map match reality)

I have attended many industry schools dealing with the use of reservoir simulators. Without exception there has been little to no **direct** instruction in the use of the simulator as a simple tool for Material Balance. I believe that this is one of the best uses for the simulators and one of the most accurate uses as well.

What do I mean by using the sim for material balance calculations? In most of the simulation work I do I have very little data. I never have relative perm data, typically I don't even have good GOR data because the oil wells do not make enough gas to run a pumping unit, much less measure. What I do have is pressure data. Most of the fields I deal with have DST (Drill Stem Tests) conducted on every zone in every well. This typically provides excellent pressure history.

The material balance is crucial for confirming the geologist's interpretation of the field. If after I construct the model I see that the average BHP is 150 psi and that the field has recovered 50% of the original oil in place, I know I have a problem. There are not many solution-drive reservoirs where you can recover more than 15% OOIP through primary recovery.

With this new found knowledge I have to go back and add some volume to the reservoir in order to get the recovery down to a reasonable level. Do I add this volume through the porosity, areal extent or water saturation? This is why you make the big bucks, figure out the most reasonable alternative and work from there.

Because people get paid on the amount of oil and gas produced from a field, they tend to keep pretty close tabs on those volumes. These are probably the most (only?) accurate numbers in the oil patch. Pressures although they don't have the certainty of the produced volumes of oil and gas are typically more accurate than log derived values. Because the material balance is based on things that are measured in a macro scale, it tends to be more accurate that those measured on a micro scale such as relative permeability.

Because the material balance solution is that it is totally independent of permeability and therefore relative permeability, it is wonderful for determining reservoir size. When we are trying to determine reservoir size, it is immaterial how fast the oil/gas/water comes out (permeability) or what percentage of each comes out (relative permeability). We just care how much comes out and what it did to the pressure.

As you have probably deduced I tend to make grand sweeping statements that, from a practical aspect, are reasonable but from the academic pulpit may be questioned. **With this in mind I can state emphatically that if the material balance is wrong the rest of the simulation will be wrong.** If you are paying for a simulation, make sure that the recorded pressures match with those calculated by the sim.

Every simulation I have done has required a change to the preconceived geologic interpretation. And I only do fairly simple simulations. I am not talking about a 2 degree change in the alignment of the fractures in a dual porosity system. I am talking about the reservoir being one-half the size that the geologist who generated the prospect thinks it is.

The material balance can be handy for finding bypassed oil. I have done a couple of simulations where the material balance showed that the reservoir had to be significantly larger than what the geologist had drawn. Both had in excess of 50% recovery of OOIP with solution gas drive. The question was which direction to go with the additional volume.

In the first case, injection had already started and we had seen some water breakthrough. No subsurface or seismic data was available to indicate if the additional volume was to the south or to the north. What I found out was that by moving the reservoir boundary closer or further from the wells I could have a profound effect on when the water breaks through. The further I moved the barrier away from the wells, the longer it took the water to break through. I surmised that the southern boundary must be fairly close to the wells because of how quickly the water broke through.

Is this a unique solution, of course not. I can hear everyone yelling "what about rel perm" and "how do you know its not a fracture" etc. In this case the formation was an unconsolidated sand so no fractures. Thanks to the powers of computing I was able to test the sensitivity to various relative perm curves, they did not make much difference. Try doing all that with Buckley-Leverett et.al. The fact is that I needed so much additional volume there is no way the extra volume could all be close to the producers. This sim pointed out the obvious need for an additional injector in the north end of the field.

So here we have an application for the simulator where very little data was available. We had no cores and no core analysis, minimal logs, no transient data for calculating perms and no million cell geologic model. But guess what, the project made money and could not have been done without the simulator to calculate the material balance.

While still on the subject of material balance, it proved useful in another simulation. The field is in Colorado and is a 30 Mmbo Morrow Field. It is unconsolidated sandstone with several darcies of perm. They have wells that make 100 bopd with less than 100 psi of reservoir pressure.

The problem appeared when I could not get the pressures to match up. Without getting into all the gory and time consuming details of how I arrived at my conclusions, too much water was being produced. In fact, the channel would have to be tied directly into the spring snowmelt in the Rockies to fit the data. After reviewing the well histories I found that the same company had cemented all of the wells and that there was a large water zone below this zone. Turns out that there was not one good cement job in the field. All these years the operator had been handling water from another zone. They have since embarked on a project to squeeze this water zone off.

Here again it was the material balance that showed what was really going on. My simulator and I am sure others, has the ability to convert all of the oil/gas/water production to reservoir barrels. This further simplifies the material balance because it takes the relative perm out of the calculation completely.

For those who have never done a simulation, the material balance goes like this.

1. Create the structure and isopach maps

2. Input porosity, Sw, formation compressibility

3. Input fluid properties (correlations are typically built into the sim)

4. Input oil/gas/water production data and convert to reservoir barrels (automatic)

5. Input a perm that will allow all of the barrels to be produced.

6. Run the sim

7. Compare on a graph the simulator pressures and the measured pressures.

8. If they match you are probably still in college, found the professors notes and cheated

9. If they don match go back and change 1 or 2.

10. Etc.

<u>Infill Drilling</u>

The sim can be useful in determining both where to drill and how much to expect from the new well. Before a flood is started, and before the oil/water rel perm becomes an issue, the sim can provide some pretty accurate estimates as to producing rates and reserves.

As a practicing (and practical) reservoir engineer I prefer to recommend injection wells over producers. Typically I get much closer on my recoverable reserve numbers with an injector. If a field is already being flooded the whole rel perm things comes to life and becomes more important. This is where running a range of curves is critical to the drilling evaluation.

<u>Sensitivity to Rel Perm</u>

I never have relative permeability data and I doubt that if you have any that it is any good. How was it derived, from a core? Is it a drainage or imbibition curve? How are the end points determined. Did they use reservoir fluids or mercury. Were the cores oriented properly? Even if you know all of this stuff exactly, there is still one problem.

The core is a 4" diameter section of a reservoir that may be several hundred acres in area. Is there anyone who believes for one minute that that core is representative of the entire reservoir? It is better than nothing, but you would have to argue long and hard to convince me that it was much more than that.

That is not to say that I would not love to have this data. With this data in hand I could tell my client, when the waterflood falls on its face, that the fault is not mine but lies squarely on the doorstep of the core analysis company. It is nice to have someone else to blame.

Unfortunately as I mentioned before I rarely have GOR data, much less relative perm data. So what do I do? I guess at the endpoints and use a Honapour correlation. I will create several different rel perm tables that hopefully will define the extremes of what is reasonable. Then I start trying to match the production, assuming I have multi phase flow.

My simulator has a simple economics package built in. With this I can see immediately what the financial impact is with respect to relative perm. Typically I find that the viability of the project is not dependent on the relative perm.

This is one of several areas that Exxon and I differ. My clients want to know if they can make money by waterflooding a field and what patterns work best. Exxon is trying to unitize a field with 200 gazillion barrels and every point of ultimate recovery is worth 6 gazillion dollars to their interest.

Remember the title of this article is "Practical". I have found that as a rule of thumb the relative permeability curves do not make or break a project in the areas where I work. **If I can kill a project with a <u>reasonable</u> estimation of rel perm, then the project does not need to be implemented**. There are too many other variables working against you.

<u>Economic Range of Returns</u>

It seems that once you leave college everything is about making money for your employer. No one is interested in science for the sake of science. No one is interested in squeezing the last barrel out of a reservoir, unless it makes money. If you find this troubling then you are probably out of work and thinking of going back to school and getting a PhD. There you will be appreciated.

To determine the viability of a project, it must me fairly easy to turn your simulation results into dollars, at least on paper. None of my clients are interested in how many incremental barrels can be produced. They all seem fixated on the **net** value of those barrels.

The nice thing about a simulation is that you can run sensitivity cases to you heart's content. As a matter of course I try to determine which parameter has the most influence on the value. I try to provide my clients with a range of values as the critical parameters change. If I have to take the model results and hand input them into an economics program, it is a pain and I will not make as many runs.

From the practical aspect it needs to be easy to generate cashflows from the sim output. If it is difficult, human nature will limit your sensitivity runs.

Summary

The simulator is a tool just like all the spreadsheets you have created over the years. Although the inner workings are very complex, the output should not be. Every model ever created is wrong in varying degrees. **The trick is knowing whether or not the deficiencies are important to the overall return on the project.**

I performed a simulation where I wound up using Standing's correlation for the PVT data. Measured data was available. I had originally used the measured data but switched to the Standing's in the process of the history match.

The result of the model showed that the field has such a large vertical perm that a flood would be ineffective. I was reviewing my findings with my client and the simulation **team** of a **very** large independent. They fixated on the problem with the PVT data. Any values of PVT data could have been used with no effect on the project economics. The flood was not going to work, practically speaking.

Instead of **thinking** through the results of changing the PVT data and calling it quits, they had me go back and re-history match the data with the measured PVT. After a few minor changes all the puzzle pieces fit, but the flood still would not work. A little common sense goes a long way.

Do not accept GOKing on a simulation. If you don't understand, ask questions. If the project is dependent on a very small range of relative perm data, look real hard at the source of the data. If the initial material balance does not match, keep trying. Everything else will be based on it.

Thanks for taking the time to read this. If you found it useful please drop me an email bill@wellevaluations.com and let me know. If you think I need to be kicked out of the union, that is OK as I am probably behind on my dues anyway. If you have any other questions or comments please let me know.

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