<table>
<thead>
<tr>
<th>Name</th>
<th>Question</th>
<th>Answer</th>
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<tr>
<td>Tyler Conner</td>
<td>Is slip flow important in oil reservoirs?</td>
<td>No, slip flow conditions can only prevail in nanoporous gas reservoirs. However, there are some other unconventional flow regimes, which supplement Darcy flow or become dominant in tight oil reservoirs similar to the contribution of slip flow in shale-gas reservoirs.</td>
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<td>Sheraz Ahmed</td>
<td>Can you explain slide 20 again. It doesn't make sense as only pressure was plotted against time</td>
<td>What is shown in this plot is the change in pressure drop with respect to time to produce a fixed flow rate. To interpret the results shown in this figure, we need to consider the definition of productivity as the pressure drop required to produce a given fluid volume. Naturally, if we produce the same volume with less pressure drop, this is a more productive reservoir. In slide 20, the curve corresponding to no-slip flow case is above the curve for the slip-flow case; therefore, slip-flow leads to better productivity. Taking the effect of stress-dependent fracture permeability into account does not seem to create additional pressure drop and therefore does not affect productivity.</td>
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<td>Sheng Li</td>
<td>Is &quot;slip-flow&quot; theory also applicable to tight oil reservoir?</td>
<td>No, it is only important for gas flow in nano pores.</td>
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<td>Jia Shan</td>
<td>Do you use assumed data or real field data to get the results?</td>
<td>We have both. In general, we use syntactic data to develop and verify the concepts and the field data to demonstrate the applicability. Because of the interaction of a large number of parameters, use of the field data for the proof of the concept is difficult. When we work with the synthetic data, we can fix some of them and analyze the effect of the others. However, the final test of the concepts is with the field data.</td>
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<td>Franklin Useche</td>
<td>Would slip flow still be significant in liquid-rich formations?</td>
<td>No, it is only important for gas flow in nano pores.</td>
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<tr>
<td>Franklin Useche</td>
<td>What other considerations related to flow mechanisms in porous media must be considered for liquid-rich formation as the Eagle Ford shale?</td>
<td>Concentration driven diffusion, osmosis, molecular sieving, and constrictivity appear to play a role. Effect of confinement on PVT behavior should also be taken into account.</td>
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Many of the most successful shale developments are in "dirty shales", i.e., Bakken with lenticular carbonate features or where natural fractures are numerous. Given this fact, wouldn't investment in new "unconventional" formation evaluation tools that can detect and quantify these properties return the best bang for our investment buck? Detection and characterization of natural fractures is an important problem. However, unconventional reservoirs are not only about fractures. Fractures only provide the flow channels but they cannot store commercial volumes of hydrocarbons. We need to find (or create) fractures in regions where hydrocarbons have been generated, stored, and retained over the geologic ages. So, we should be looking for all favorable conditions; not just fractures.

You mentioned that HF $k$ has no impact, but if there is a considerable amount of NF $k$ or Density then the HF $k$ will also start to impact. wouldn't it?

That is correct. My comment was to emphasize that under certain conditions (poor natural fracture qualities), we may overdesign hydraulic fractures. This had never been a concern in tight-gas formations because the entire contact surface of the fracture with the sand was providing the flow. In shale, flow only enters into the hydraulic fracture through the small surface area of the hydraulic fracture/natural fracture intersections.

A wide variety of recovery factors (between 2 and 20%) are estimated based on different considerations. However, this is one of our weakest areas. To begin with, we do not have good estimate of original gas in place and technically recoverable gas (this issue is related to the question of where does the produced gas come from). Next, in most shale-gas plays, the end of recovery is dictated by economic rather than physical depletion. Therefore, the reported recovery factors should not be taken at the face value.

This is not my area of expertise but I can safely say that there are suitable applications for both. In general, when the producing formation has active (open) natural fractures, open hole or un-cemented completions with sliding sleeves may be expected to yield better results. If the natural fractures need to be rejuvenated (or created), then plug-n-perf design may be a better option.
Franklin Useche  
Is it possible to identify flow regimes using RTA plots on low-permeability formations with production history limited to a couple of years maximum?

The basic principle of RTA is the same as PTA with the exception that the rate data is less accurate and sensitive. Flow regimes change during production depending on the changes of the geometry of flow convergence. For a fractured horizontal well, the potential flow regimes, in chronological order, are the linear flow, intermediate-time SRV-depletion behavior, compound linear flow, compound radial flow, and reservoir depletion (not all flow regimes will be evident in every well). Time to see these flow regimes depends on the diffusivity of the medium. Therefore, in very tight formations, only linear flow may be observed in a couple of years of production.

Sandeep Gade  
For creating dense network of hydraulic fractures, do you think, Acoustic data & Mineralogy information is helpful? Additionally, is there any other information (which is currently unavailable) that would be critical in determining the ideal location of fractures?

Acoustic data and mineralogy are helpful to determine the fracability of the formation. However, the objective of hydraulic fracturing in shale is not to create a single or local fracture. Through hydraulic fracturing, we try to create a stimulated reservoir volume consisting of an invasive network of natural fractures. Therefore, instead of looking for ideal hydraulic fracture locations, we look for a large enough reservoir volume, which can be shattered into small pieces.

Carla Montiel  
What are the tools available to model flow regimes in shales, that are reliable for predicting future reservoir behavior?

The reliability of the tools to predict the future reservoir behavior depends on the physical basis of the flow models used in the tool. As we improve our understanding of the flow mechanisms in shale, we incorporate them into our flow models and then into the performance prediction tools. There is still much work to do but the commercial PTA and RTA analysis packages have been incorporating some of the new findings especially for single-phase flow. For tight oil and condensate, existing commercial (numerical) models are still mostly based on conventional flow considerations. Recently, some research groups have started making progress in this area and we can expect these developments to be incorporated into the commercial tools in the near future.

Juntai Shi  
Did you consider the effect of Knusen diffusion in the matrix flow?

Yes, the slip flow is a form of Knudsen diffusion.
How is the extend of the environmental impact of fracturing?
As everything else humans do, oil field practices may cause damage to the environment if precautions are not taken. Fracturing is not more damaging than most other practices; the key here is to carefully investigate the potential sources of damage and apply fracturing after taking appropriate preventive measures.

Can I get a copy of slide 6 as it appeared in the presentation today, please? It is covered up by some additional formatting in the Presentation Slides
I will be happy to provide a copy of the slide if you contact me directly.

Abit far from lecture, for undergraduated students, how can you advise them start the career of unconventional reservoirs?
Ironically enough, I do not think this is a matter of choice anymore. All of us, new or experienced, will have to deal with unconventional reservoirs. For working professionals, the skills required for unconventional reservoirs are acquired through on-job training, short-courses, continuing education activities, and self-study. For students, some aspects of unconventional reservoirs are being incorporated into the standard curriculum, but this will not be sufficient. Therefore, I would advise reading papers, attending lectures on the topic, and looking for internship opportunities.

What is the effect of nanopores in case they are not connected?
Here, the conventional wisdom applies. Unconnected pores do not count.

Is the adsorption mechanism available in Shale gas?
Yes, but its importance depends on many factors. In general, adsorption is effective on the pore surfaces of the organic material (kerogen). If organic pores are in good communication with the main flow paths (fractures, network of large pores, etc.), then the pressure drop in the system can reach these pore spaces in practical time period and desorption may contribute to flow. In other cases, where the organic material is encapsulated by tight inorganic matrix, then the time for the pressure drop to reach the organic pores and cause desorption is impractically long.
Karen Balch
How do the modeling techniques account for geologic unconformities such as pockets of higher permeability in a nano darcy type matrix? Incorporation of heterogeneity and compartmentalization in models follows the general lines as in conventional reservoirs as long as the unconformities can be characterized and quantified. However, the current models do not focus on these types of features because the predominant interest of the industry is to obtain quick and inexpensive predictions and fundamental interest of the researchers to understand the flow mechanisms in nano-porous media.

Aadish Gupta
You mentioned that geological characterization doesn't take into account the natural fractures / microfractures, and hence the reported permeability is lower than what your production data corresponds to. Is there a way to get a better estimate of the actual matric perm other that from your production data after a few months or years? Because it is difficult to obtain fractured reservoir samples (the cores we take are before fracturing and usually from the vertical section) lab measurements do not necessarily reflect the actual reservoir conditions. Furthermore, the contribution of the fractures (especially microfractures) becomes more significant under dynamic flow conditions in the reservoir. Therefore, the use of dynamic data may be one of our best options. However, we should find some new and more successful techniques to characterize fractured unconventional reservoirs.

Kh
What if we increased the pore pressure to increase natural fracture conductivity using heat energy. Will it work? In principle yes, but I do not know how it can be done.

Doreen Rempel
Is slip flow in shales similar to desorption in coals? Not completely. In coal, desorption is the mechanism by which gas stored in coal is released into the cleats and starts flowing to the wellbore. In shale, slip flow describes the movement of gas molecules in flow channels ( pores). These are two different concepts.

Joseph Doucette
I have drilled 20, 10,000' wells in the Bakken formation. Were you able to determine from your data, production by stage? This can be done by running a production log. If you just use the well production (this is usually the available data) to find out how it is distributed to n fractures, this is an under-defined problem (1 equation, n unknowns).

Dave Cook
Is slip flow knudsen diffusion? Slip flow is a subset of Knudsen diffusion.