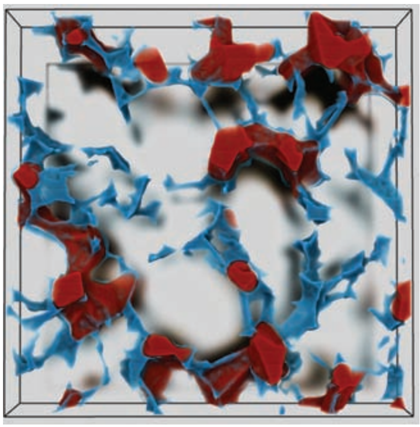
Digital Rocks Out to Become a Core Technology

Stephen Rassenfoss, *JPT/JPT Online* Staff Writer

The future of oil and gas exploration depends on rocks such as carbonates and shale that can be described as tight, complex, nearly impermeable, and even stubborn. On the production side, the goal has long been to get more of the oil out of the ground, but recovery percentages have hardly budged.

The search to better understand the inner workings of these rocks that challenge traditional laboratory testing has led to a new approach known as digital rock physics. It is a technological hybrid drawing on fields ranging from medical testing to microchip production. By marrying computerized tomography (CT) and other X-ray scanning technologies, pioneers in this emerging field are creating 3D images showing the internal structure—including pore spaces and how they connect—as well as the minerals and organic matter within.



This image shows residual hydrocarbons left after waterflooding in a conventional sandstone. The residual hydrocarbon is shown in red and the water (wetting phase) in blue. This sort of information offers insights in planning an enhanced oil recovery program.

Digital rock physics providers promise faster, better, lower-cost analysis. The potential payoffs could include wells targeting the most productive rock, more effective well completions, and simulations speeding the development of enhanced oil recovery (EOR) techniques.

The graphics are stunning. The attention to detail is exacting. But using imaging to directly measure reservoir properties is still a work in progress. Getting a clear look at the smallest details in some rocks requires scanning samples that are measured in microns. Finding ways to accurately scale up this data to provide telling details about a formation will define the future of this young business.

The oldest of the three fast-growing companies selling digital rock physics services for exploration and production (E&P) goes back four years. Even the name "digital rock physics" is not set in stone. The growth in demand is in difficult formations such as shale and carbonates, and for simulating EOR projects that are hard to analyze using traditional means. Chevron, Shell, Statoil and Schlumberger are among the users.

At Chevron Energy Technology Company, the digital rock work is led by Jairam Kamath, who organized a SPE forum to consider the future use of this technology. "The more you work with it, the more you are convinced," he said. "It took me a couple years, but I am convinced this is how we will be doing business five or 10 years from now."

Shell is working with Schlumberger on a digital rocks project. It is one of many research projects at Shell seeking new ways to increase the output from aging fields. "I do believe there are large opportunities" there, said Gerald Schotman, chief technology officer of Shell. He described it as a way to deal with anomalies, when indicators such as the production history are out of line with predictions by the reservoir model.

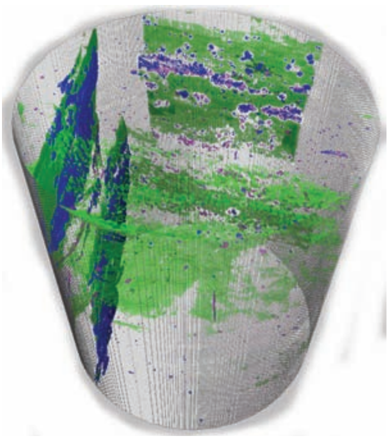
An anomaly accelerated the growth of Ingrain by pulling the Houston-based digital rocks startup into the shale business. A client saw the potential for oil in the Eagle Ford Shale. However, data from traditional core analysis using crushed rock samples suggested the permeability of the rock was far less than the company expected using other data. The analysis by Ingrain supported the more optimistic reading, giving the company confidence to pursue what has been a successful play.

In the year since, Ingrain's shale business has gone from one to 15 clients. Its revenues were up 400% in 2010 over 2009 and its staff has grown from five in 2007 to 64 in March. In addition to its largest laboratory in Houston, it has one in Abu Dhabi and is building another in Brazil.

Shale, carbonates, tight gas, and coal seam gas are among the prime drivers behind the growth of digital rock physics.

"More than half of our work is on samples, where it is difficult to do (analysis) with conventional measurements," said Mark Knackstedt, chief technology officer at Digitalcore, an Australian company founded in 2009 that grew out of research supported by 14 oil and gas companies at the Australian National University and the University of New South Wales.

Digitalcore is growing rapidly as is Numerical Rocks, a Norwegian company spawned by Statoil research. A key researcher there was Pal-Eric Oren, who is technical director of Numerical Rocks. Both companies have nearly 30 workers doing projects, such as multi-



This image illustrates fractures in a coal sample known as cleats. The green regions are the open fractures while blue regions signify carbonate cement material in the cleats. The pink/purple regions show other cement material within the fractures.

ple image studies to predict the impact of a low-salinity waterflood or in analyzing production from coal seam gas fields. Neither company does the sort of shale analysis done at Ingrain.

Schlumberger has been working on aspects of the "digital rocks workflow" for five years, wrote Dimitri Pissarenko, director of Schlumberger Moscow Research. The work includes research into fluid dynamics at the micro scale, X-ray microtomography, advance algorithms and 3D image processing. At this stage Schlumberger is "validating and calibrating" the components and how they fit into this process, which it sees as a useful long-term tool..

"Opinions on this subject in the industry and in the R&D community range from extremely skeptical to overwhelmingly optimistic," Pissarenko said. "Some believe that no computer model can encompass all the richness of the multiphase fluid physics and chemistry inside the pore space while others believe that digital rock will eventually replace laboratory core tests. The reality is likely to be somewhere in between these two extremes."

"Today, we can clearly see the future benefits of digital rock as a complementary tool to laboratory core tests," he added. "We see this adding great value when one needs to screen multiple scenarios, repeat tests with varying injection parameters, and extrapolate measured characteristics to temperature and pressure conditions that are not attainable in the lab."

The Image of What is Next

The evolution of this young field has parallels to the evolution of 3D seismic. Both rely on state-of-the-art graphics software, evolving algorithms and rapid increases in supercomputing power to create images and data that provoke debates about how to interpret the results.

"This type of stuff has been a toy for academics. They have been fiddling with it and fiddling with it," Kamath said. "It has reached the point where I feel it has the real potential to change the industry. Our vision is petrophysicists will pull up these images in 20 years, or even five years. Any time he looks at the data that image will be out. A geologist will look at this and can bring tremendous insight to it."

Two key words are potential and vision. While testing at Chevron and elsewhere has show that digital rock analysis can reliably predict characteristics such as porosity and permeability in conventional rocks, the upside in digital rocks lies in answering challenging questions. For example, why does a shale formation produce far more in some spots than others? Will a shale formation in Poland produce like one in Texas?

When asked what he thought of the technology, one oil company technical adviser with long experience in shale E&P responded: "Interested? Yes. Convinced? No."

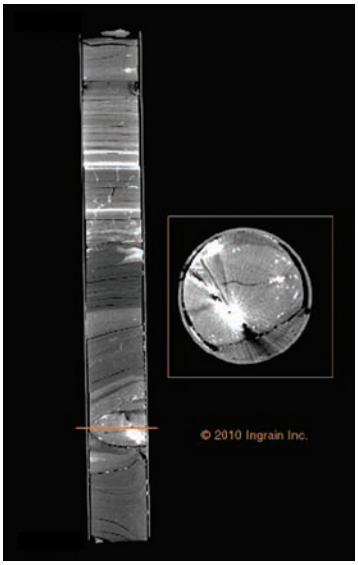
The shortcomings of digital rock physics also reflect the limited understanding of unconventional rocks such as shale, which were not much studied until recent years with the shale gas exploration boom. Recent research has shown many of the textbook explanations about how oil and gas is deposited and moves through conventional formations are not good models for what is observed in unconventional rocks.

Digital models allow direct observations of the pores inside rocks and how they are connected. But there is still much to learn about how various fluids are transported inside the many types of formations called shale.

"We are trying to define the physics that are applicable to the problem," said Carl Sondergeld, a professor at the University of Oklahoma, who heads a shale laboratory that has developed several approaches to shale imaging as part of a broad research effort to better understand the rock.

Kamath's co-chairman on the digital rocks forum was Anthony R. Kovscek, an associate professor of energy resources engineering at Stanford University, who has followed the development of the technology for three decades. In the early 1990s, Kovscek turned to this approach because he wanted to find a nondestructive test to study wettability—how various fluids move over different surfaces and films. While he has long used digital technology, he also sees the challenges presented by unconventional rocks as an argument for better laboratory testing methods.

"I think a lot of people in the industry see this as a way to replace lab experiments and I am skeptical in the end



A scan of the whole core is shown, left. This series of relatively low-resolution slices is assembled to highlight the makeup of the shale, and to calculate the bulk density and average atomic number at each point. An animation is created based on the cross sections, right. The data is then used to select 1-in. plugs for a closer examination.

about that," Kovscek said. "The fact you can do computations and match the measurement made digitally gives you some assurance you understand the underlying physical nature of it."

Knackstedt, a pioneer in digital rock imaging, said there needs to be work on better integrating images taken at differing resolutions, and multiple testing techniques. It is also important to understand why each type of data is gathered and the uncertainty in it, in order to better interpret it.

Schotman, who is also in charge of innovation and R&D at Shell, sees it as a useful additional tool, but he added that this virtual version of rocks, like reservoir models, should not be confused with reality.

From Minerals to Pixels

Digital rocks are built from X-ray scans that show differences in the density (attenuation) in the rock, like bone versus soft tissue in traditional X-rays. The hard part is taking a digital version of that image and creating a map of the rock defining the pore spaces, minerals, fluids, pore spaces and how they connect. Other programs can then analyze critical details, particularly the location of hydrocarbons, pore spaces, and how they are connected.

For example, at Digitalcore the starting point is a small plug of rock from a cutting or a core, often no larger than an inch. An initial scan of the plug is used to pick sections within with details worthy of a closer inspection.

The size of these samples for special analysis depends on the rock type. For large grained sandstone, a sample as big as a cubic centimeter can be used to examine details as small as 5 microns. For rocks with extremely small details, such as tight gas, carbonates, and clay-rich sands, far smaller volumes are required to reach the level of magnification needed to spot telling details.

Each of these rocks is X-rayed, sometimes multiple times at various magnifications. At Digitalcore, the starting point is commonly a 3D CT scan. Others begin with scanning electron microscopes (SEM). Addition information can be collected using techniques such as petrography, backscattered SEM and focused ion beam SEM (FIBSEM).

Each image is converted to digital form with each piece of information coded by location. Digitalcore uses a variety of techniques to create an image overlaying data points from multiple sources and clearing up distortions. An algorithm takes these grayscale images and creates a colored 3D image defining the structure and the mineralogy.

The growth of this industry has depended on the rapid rise in the supercomputer power needed to process images that are far larger than a typical reservoir model. A common size for the images can be 256 gigabytes or one quarter of a terabyte (1 trillion bytes of data). Knackstedt of Digitalcore said significant advances in computer power over the past five years have significantly reduced the cost of this service, and this expense is expected to continue falling. The company has developed algorithms used to define the internal structure of the minerals and pore space and analyze multiphase fluid displacement to simulate how oil, gas, and water will flow through the rock.

It is possible to isolate just the pore spaces and how they connect. Using this 3D image, Oren of Numerical Rocks said it is possible using the fundamental transport equation to calculate permeability, resistivity, and capillary pressure in conventional rocks. Numerical Rocks has seen strong growth in demand for analysis of carbonates, which are complex, with significant structural details in different size ranges. Digital methods can do some measures on difficult samples in weeks that could require more than a year using traditional methods.

A big question facing those doing digital rock analysis is: Can it reliably estimate transport properties based on an analysis of small samples of a fine-grained rock such as shale? Knackstedt said he understands those who are skeptical that digital rock analysis can reliably measure these multiphase flow properties in shale, noting: "We have to be careful. We don't know all the physics."

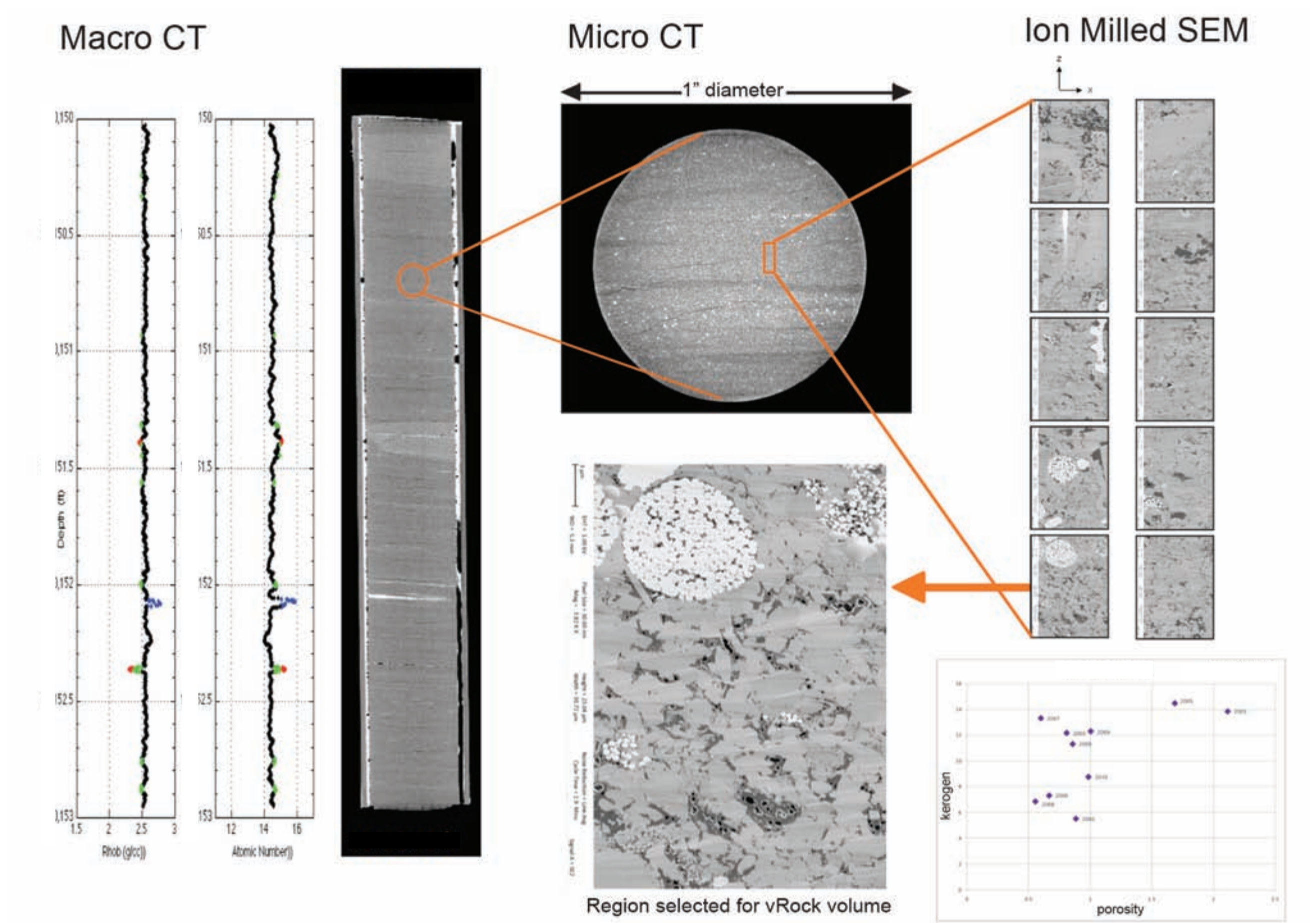
Ingrain is confident of its mathematical modeling of pore spaces and how they connect. Generating numerical estimates of how fluids move through the rocks requires collaboration between clients and geologists, the company said. For example, its staff suggests what rock should be sampled, but the client makes the final decision. While it will calculate two-phase relative permeability, critical data, namely fluid properties, wettablity and interfacial tension, come from the client.

Those three variables are among the significant questions facing those studying unconventional formations. "The complexity of unconventional reserves come to a great extent from the interplay between extremely heterogeneous multiscale pore space, and the complexity of the fluid itself," said Pissarenko of Schlumberger.

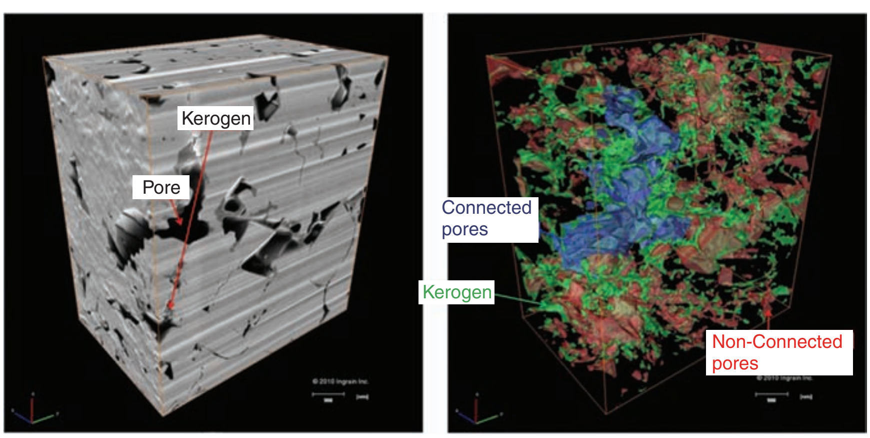
From Small, Small Scale to Reality

One of the biggest questions facing digital rock physics is: What is a telling detail? One of the positives, and negatives, in digital rocks is the sample of rock examined is small. On the plus side there is no need for a full core, which can be hard to come by in some wells. On the minus side, getting down to the scale of the telling details in shales or carbonates requires focusing in on a sample that is infinitesimal.

In shale, the level of resolution needed to see the passages connect-



Based on the telling details spotted by geologists at Ingrain and the client's final decision by the client, plugs about 1 in. in diameter are removed, imaged with a micro CT scan, and used to target smaller samples.



Small samples from the plugs are selected for close study. Images from a focused ion beam scanning electron microscope is assembled into a 3D representation, left. Key features are shown in isolation, right. The minerals are dropped out to highlight the pore structure and the kerogen, which yields hydrocarbons. Connected pores are shown in blue, nonconnected pores in red, and kerogen in green.

ing pores can be around 100 nm. To put that in perspective 1 cm equals 10,000,000 nm. Users are trying to balance quantity with image quality.

"An image has to be big enough to have some meaning. Otherwise you might be looking at one crack. At some point you get lost in the minutiae," said Kamath. It is a serious stumbling block to widespread use of the technology.

"A key constraint in this approach is that today's images can only practically obtain high resolution images on rock volumes as small as 20 to 50 microns (0.000787 to 0.001968 of an inch)," said Alan Byrnes, chief petrophysicist at Chesapeake Energy. "This presents a problem in that the volume imaged at the resolution appropriate does not always image a true representative elementary volume (REV)—the volume that is capable of characterizing the properties of the whole rock."

Those in the digital rocks business have created systems designed to ensure their results statistically represent a larger area. All of them rely on multiple images, beginning with images covering larger areas to select representative smaller targets. Results are checked against other indicators.

A Torrent of R&D Aimed at Getting More Oil Out of Fields

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Shell R&D head Gerald Schotman uses a lot of analogies when explaining things. Developing new technologies, for example, can be unpredictable, like the turbulent flow of liquids inside a pipe.

As chief technology officer and executive vice president of innovation and research and development (R&D), Schotman is charged with bringing some order to this process by serving as an advocate for the needs of the company's businesses units, and to spread new ideas through an enterprise.

Near the top of Shell's priority list is increased recovery rates from aging oil fields. The industry average is 35% of the oil will be recovered. And that estimate is at the high end. For difficult formations, the rate is significantly lower. The payoff for an improved enhanced oil recovery (EOR) technique capable of getting out the next 10% is huge.

When describing Shell's approach to getting more out of an aging field, Schotman likened it to treating a patient with a hard to diagnose condition. The process begins with a check of the vital signs, tests, monitoring, and analysis—with some techniques rooted in medicine. This will lead, he hopes, to a diagnosis suggesting minimally invasive treatments that will significantly improve the performance.

An example of how that approach is applied at Shell is what Schotman calls "designer water," a customized mix of water and chemicals. The formulation is based on a detailed evaluation of the reservoir. Shell systemically tests emerging technologies to validate the claims of innovators.

Schotman

A project with Schlumberger is developing a deeper understanding of reservoirs on the pore scale using what is known as digital rock technology, which combines X-ray scanning and digital imaging. This allows multiple simulations of how changes, such as varying the salinity in the waterflood, may affect production. It could also offer useful clues when a production history does not agree with the reservoir model's prediction.

Data mining is another focus of Shell research. The focus is sifting through the information to see what it is telling and what is not. The company is working with computer graphics providers, including ones with Hollywood experience, to create displays highlighting trends in the flood of data gathered in digital oil fields. Underneath the colorful displays are algorithms seeking patterns like a doctor checking out an irregular heartbeat.

The research work is also looking for ways to more effectively use seismic to understand the needs of mature fields. Schotman sees each new technology as providing useful additional detail but not as the final word. As he put it: "I don't believe in single point solutions."

Another line of work is aimed at cost reductions. Advanced seismic studies offer valuable information on the impact of production, which can be used to extend the life of fields. These studies include the time-consuming task of placing the receivers on the ocean floor with remotely operated vehicles (ROVs). Rather than using ROVs to deliver the devices, Shell is working on creating remotely controlled, self-propelled receivers able to go out on their own to their station on the ocean floor, and then return to the ship when the work is done.

Shell R&D has three research hubs: Houston, the Netherlands, and Bangalore, India, where a research facility is being expanded. Other research centers reflect the many faces of the operation—deep water in Norway, oil sands in Calgary, and EOR in Oman.

Schotman said he often uses the word "frustrated" when talking about the long lead time in this work. But there is a reward for this demanding effort. With increasingly difficult formations, there is a premium on gaining additional insights using new technology. "With the nasty ones, you better know what is in the subsurface," he said. If not, it can be an expensive lesson learned.

Ingrain's multistep testing method starts out with the largest sample—a scan of the whole core sample while it is still in the case used for shipping. This allows it to create an overview of core samples that can be hundreds of feet long. The result is an animation built from about 1,500 cross-section CT images shot of the core. Each image represents a slice of less than 1 mm. The care scanning data is used to estimate the bulk density (RhoB) and the effective atomic number (Zeff), which offer an indication of the mineral content and reservoir quality.

Based on those numbers and a visual inspection of the core, cylindrical plugs about 1 in. in diameter, are removed and imaged in the search for small sections with features representative of what is seen in the core. The result is a series of small cubes—with each side about 20 to 30 microns—that is imaged and analyzed. The company recommends doing a minimum of 10 to 12 per well to get a statistical distribution when measuring properties. Ideally similar studies would be done in multiple wells.

The future of digital rock physics depends on improving how it scales up. "Digital rock physics is all about a descending scale of interrogations and an ascending scale of integration," said Avrami Grader, chief scientist at Ingrain. Scaling up is a challenge, but he sees enormous potential in a technology that creates 3D images of pore systems, adding: "That is something you cannot do in a lab." **JPT**