



Input/Output, Inc.

Giving Seismic a Whole New Image

World Energy interviews Bob Peebler, President and Chief Executive Officer of Input/Output, Inc., a Houston-based provider of seismic imaging technologies.

Bob Peebler joined Input/Output (I/O) as CEO in April 2003 and has been on the board of directors since 1999. He was the CEO of Energy Virtual Partners from 2001-2003, a corporate vice president with Halliburton from 1998-2001, and the CEO of Landmark Graphics from 1993-1998. He began his career with Schlumberger as a wireline engineer and worked at Schlumberger for 17 years in positions ranging from head of U.S. wireline operations to executive in charge of strategic marketing for the global energy services group.

World Energy: You recently joined I/O as CEO. Can you tell us what made you sign on with the company full time?

Peebler: I had been on the Board of I/O since 1999 and knew the promise of the technologies, the people and the brand. I sensed that I/O had the potential to drive the adoption of the next wave of seismic imaging technology in the E&P business – what we are calling digital, full-wave imaging. I was part of the last seismic wave at Landmark Graphics when the industry went from 2D to 3D imaging, and I enjoy driving the adoption of new technologies that help our industry find more oil and gas at ever lower cost.

World Energy: What do you mean by digital, full-wave imaging?

Peebler: Seismic is a fairly old technology, having been around since the late 1930s. About every 20 years, the industry transforms to deploy a fundamentally new technology. In the early 1980s, it was the transition from 2D to 3D. While 3D is still an important tool for E&P, many of the technologies are fairly mature.

About 95 percent of the surveys acquired today use standard analog geophones. These are battle-tested devices, but they've been around for more than a half-century. The industry has recently begun the transition to digital sensor technologies. Digital sensors offer the promise of greater fidelity and improved resolution of the seismic signal. It's the same as the difference in sound quality when all of us began listening to CDs rather than audio tapes, or in video quality when we began watching DVDs rather than VHS tapes. Better signal fidelity results in better images.

The second progression is that associated with measuring the full-wavefield. Any vibration traveling through the earth – whether a sound wave or an earthquake wave – has two elements in the wavefield. The first is what we call the “p” (pressure) or compression wave. This is analogous to the playing of an accordion – particle motion is in the direction of wave propagation. The second wave is the “s” (shear) wave. The shear wave propagates in the same direction as the p-wave, but particle motion is perpendicular to the direction of propagation, revealing different properties about the reservoir.



More than 90 percent of the seismic surveys acquired today measure only the p-wave. This is because until recently, acquisition equipment and our industry's processing capabilities didn't enable oil companies to measure the full-wavefield – both the compression and shear components. So, we were using only a portion of the data that were actually available. Now the full-wavefield, including the shear component, can paint an even clearer picture of the subsurface. The full-wave image helps us better identify subtle structures and changes in rock properties, along with the movement of fluids in the reservoir. Whole data results in better images.

When you sense seismic motion digitally with the intent to sample the full-wavefield, you open up the next revolution in subsurface imaging. We think this revolution can bring the same sort of step change to seismic as was brought during the 2D to 3D transition.

World Energy: Hasn't the E&P industry been working on full-wavefield imaging for some time?

Peebler: Yes, it has. Most in our industry refer to full-wavefield imaging using the term multicomponent, referring to the pressure and shear components of both the source and reflected wavefields. The industry has been experimenting with multicomponent techniques for at least the last 25 years, but it's been mostly in the category of experimentation. We haven't seen widespread field adoption of the technique, but we think that is about to change.

World Energy: What changes will increase adoption of full-wavefield imaging?

Peebler: To date, our industry has neither developed all of the required seismic algorithms for multicomponent processing nor refined the algorithms that do exist to the unique challenges of individual depositional environments. Full-wave interpretation is an art that less than 2 percent of the world's geoscientists have mastered. What is needed are more robust interpretation tools, combined with faster and more effective processing, to extract value out of full-wave data. As new processing and interpretation tools

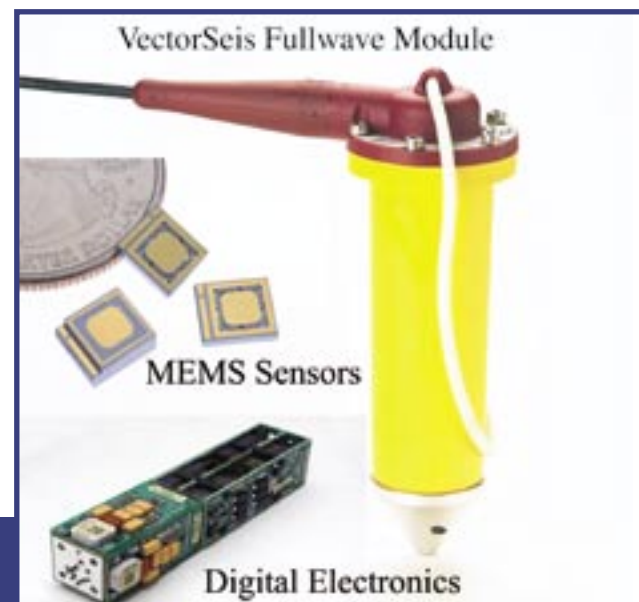
come into the market, the diffusion of the technology will significantly increase, similar to the early days of 3D.

World Energy: Doesn't that call for more computing power and new sensor technology?

Peebler: Seismic processing is already the most computationally intensive activity in any industry. Multicomponent processing increases computational intensity by at least an order of magnitude, which drives up both costs and cycle time. The movement towards grid or cluster computing will help the industry in these areas, as will the steady, general downward progression in computing costs.

On the equipment side, most of the early multicomponent experiments have been done with traditional geophones equipped with multiple sensors. In theory, they are intended to sample the full-wavefield. In practice, however, they are big and clumsy to work with and require near perfect horizontal placement in the ground to be effective. As we all know, perfection is hard to achieve in field operations, and the resulting data that were acquired using old geophone technology was not especially robust. Within the last several years, our industry has seen the introduction of new sensors that allow the full-wavefield to be acquired while actually enhancing the efficiency of field acquisition operations.

So, the technologies underpinning full-wavefield imaging are continuing to improve. As they improve, the costs to deploy them will fall and



MEMS are micro-electro-mechanical systems



the images that result will be better. We'll then see demand for these technologies increase. Over time, the installed base of seismic equipment will shift. But it will be a transition that occurs over the next two to five years, not the next two to five months.

World Energy: Where does full-wave imaging hold the most promise in the near term?

Peebler: We're already seeing increasing activity on the Gulf of Mexico shelf to collect full-wave data. The initial targets are deeper reservoirs that are obscured by gas clouds, which is gas that is percolating up from deeper horizons through shallower sands. Traditional towed streamer surveys can only acquire the "p" or compression wave (shear waves do not travel through water). The compression waves are distorted as they travel through these gas clouds, so the subsurface images are blurry. It's like looking through somebody else's glasses. The only way you can resolve the images is by acquiring the full-wavefield, and the only way you can acquire the full-wavefield is by placing the sensor directly on the seafloor.

World Energy: Sensors on the seafloor – is that something we'll be seeing more of?

Peebler: We think so. In a series of interviews we just conducted with our customers, nearly everyone said that, if cost were no object, they'd rather acquire seismic data from the seabed than use towed streamers. There is less noise underwater than at the surface where wave action, wind and the ambient distortions from pulling miles of streamer cable behind a boat interfere with the seismic signal. Our industry has developed techniques to remove some of this noise, but it still gets in the way of the signal. Further, you cannot sample the full-wavefield using towed streamer technology. It is only when you place the sensors on the seafloor that the shear wave can be acquired.

We're seeing lots of good ideas from our engineers and other companies on how to make seabed acquisition happen at lower cost. If our industry continues to associate seabed imaging with the dated, cumbersome, high-cost

ocean-bottom cable technology of ten to fifteen years ago, we'll never see widespread movement to the seabed. But, the improvements in cables, sensors, electronics and acquisition systems should result in costs falling significantly, perhaps by 60-70 percent, over the next three to five years.

In the same period, seabed acquisition should become quite cost competitive with towed streamer acquisition. If the images that result are better, we wouldn't be surprised to see seabed imaging begin to experience rapid growth, perhaps becoming a \$1 billion segment before 2010.

The rapid acceptance of time-lapse, or 4D, seismic will further drive the adoption of seabed imaging systems.

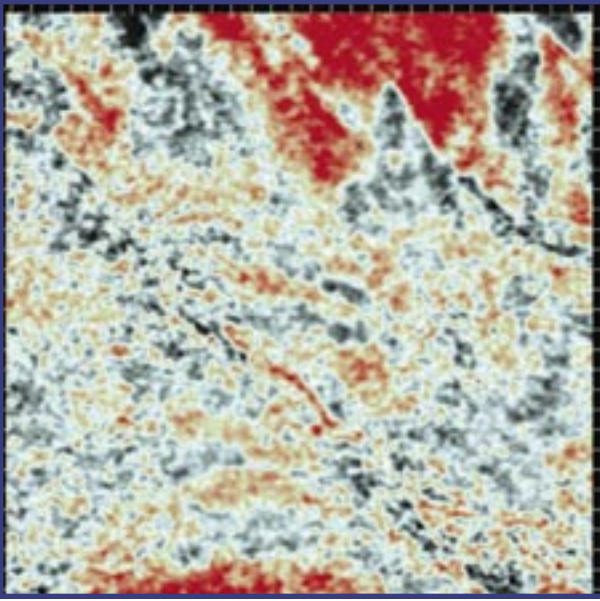
World Energy: What is driving the acceptance of 4D seismic?

Peebler: Fundamentally, it is the recognition by the oil companies that a lot of value can be captured by optimizing the development and production of assets that have already been found and that seismic can play a big part in that optimization.

Certain companies have been early adopters of 4D, applying the technology in a relatively narrow set of assets around the world. The North Sea is one big application area, with oil companies telling us that more than 75 percent of all marine surveys being acquired in the region are part of 4D programs. However, we're seeing the technology begin to go more mainstream and other companies are joining the 4D club. For example, the technologies are being applied more widely in other marine environments such as the Gulf of Mexico and in the shallow waters of the Middle East.

We're also receiving interest from companies asking about 4D applications on land. It turns out that the reservoir challenges 4D can help address – such as finding trapped oil and monitoring fluid front movements – are equally applicable in onshore or offshore environments.

Another interesting thing about 4D is that it takes the seismic imaging challenge to the next level of complexity and precision. You can't get just the first image right – each subsequent image also has to be of an extremely high quality, since geoscientists and engineers are



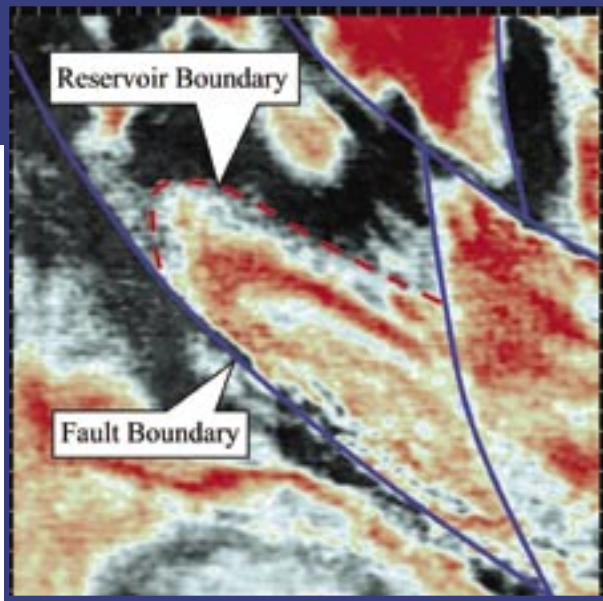
Traditional Processing (Time Slice)

looking for subtle differences from one survey to the next. If any one image, or the entire series, isn't acquired and processed using the best available technology, it will be extremely challenging for even the best geophysicist to make determinations about how fluids are moving within the pores of the reservoir. Back to my eyeglass analogy – this is like trying to describe the expressions on the faces of characters from one scene to the next in a movie while watching it through someone else's glasses.

World Energy: I/O has historically been viewed as an equipment manufacturing company, but you've also got a specialty processing group in Denver. Is the era of digital full-wave about equipment or processing?

Peebler: Actually, it's about both! In a digital world, it's extremely challenging to say where the sensor ends and the processing begins. At I/O, we are trying to fuse the technologies, bringing equipment together with processing in a manner that adds real value to oil companies and contractors. Our goal is a better image delivered at a lower cost over a reduced cycle time. And the best way we can do this is by approaching the seismic process as a total system that extends from equipment technology through survey design and field acquisition on to data processing and interpretation.

Our specialty processing group, called GMG/AXIS, is focused on a very specific element of seismic imaging, what we call anisotropic processing. Until now, all seismic algorithms



Anisotropic Processing (Time Slice)

have assumed that the earth is homogenous and that seismic waves travel at the same velocity in all directions. That is a faulty assumption, one the industry has tolerated because it was simply too difficult to develop the algorithms under anything other than a homogeneous view. Unfortunately, the assumption also results in a poor quality image. Because the seismic waves are bouncing off rock layers and traveling to the surface at different velocities in different directions (a condition called anisotropy), the resulting image will be distorted unless the anisotropic effects are properly considered.

GMG/AXIS has developed a solution consisting of both tools and services that allow for processing the seismic wavefield as it truly moves through the earth – in a non-uniform, anisotropic manner.

So, what we're trying to do at I/O is fuse all of these next-generation technologies together to acquire better seismic data that delivers a better image to our customers. It's about smart survey design and digital sensors. It's about sampling the full-wavefield. It's about taking into account anisotropic effects during processing.

It's about giving seismic a whole new image.

Further information is available by contacting:

Chris Friedemann
 VP Commercial Development
 Input/Output, Inc.
 12300 Parc Crest Dr.
 Stafford, TX 77477
 Phone: 281-879-3690
 email: chris.friedemann@i-o.com