The curmudgeon's column, Part 2: Diffraction imaging

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In the last Research Committee Update (*TLE*, September 2020, 681–682), I explained that the title of this column comes from a book by Charles Murray, *The Curmudgeon's Guide to Getting Ahead*. With the curmudgeon still in mind, I have a few more comments to make about our lives as researchers, pushing the leading edge of technology in our industries. In small companies, it helps to be a contrarian, to develop novel algorithms in areas overlooked by large research groups or the academic groups funded by them. One such technology that our group started working on a few years ago, nudged by the research group at Saudi Aramco, is diffraction imaging (DI). Aramco was looking for a company with a good quality commercial Kichhoff migration, since this particular DI implementation involved modifying a Kirchhoff kernel.

DI is a high-resolution imaging technology designed to image and identify in very fine detail the small-scale fractures in shale and carbonate reservoirs that form areas of increased natural fracture density. DI provides a separate 3D (stack), 4D (angle gathers), or 5D (angle and azimuth gathers) image of discontinuities, or objects which are small compared to the wavelength of seismic waves such as fault edges, small-scale faults, fractured zones, pinch-outs, reef edges, channel edges, salt flanks, reflector unconformities, injectites, fluid fronts, caves, and karst — in general, any small scattering object. Our DI implementation works by eliminating the large-amplitude specular reflections from the migrated image and preserving the diffraction amplitudes that can be hundreds of times smaller in amplitude than specular reflections.

I was initially reluctant to work on DI. To me, it sounded like yet another coherency attribute, similar to negative or positive curvature, and I didn't think the industry needed another similarity attribute. I found out I was wrong and the Aramco researchers were right after we started to use DI on unconventional shales. First, I was wrong because the DI volume is not just an attribute; it is a migration volume with phase and amplitude as well as offset (4D) and azimuth (5D) distribution. The azimuthal distribution of the DI amplitudes gives information about the direction of the stress field. Second, a big surprise to me was the resolution of the faults and fractures that we could see in the DI prestack migrated data. We spent almost a year modeling and DI migrating increasingly smaller discontinuities to understand the method's resolution limits. We created a simple model — a few layers with variable velocity and discontinuities of various lengths in the density model. Initially, we used finite-difference modeling employing a fixed acquisition geometry and fixed output image grid. Later we switched to ray-Born modeling as the length of the discontinuities became meters and then centimeters, and finite difference modeling on a centimeter grid was too computationally expensive. The conclusion is obvious once I state it, but it took me lots of CPU time to reach it. We could see in the DI migrated image even the centimeter-length discontinuities, since there was no noise in the synthetic, the very small diffracted energy from small fractures and discontinuities gets focused in the output grid, independent of the size of the discontinuity. Of course, in real life, the noise level in the data impacts the visibility of the small-amplitude diffractions, but these were synthetics.

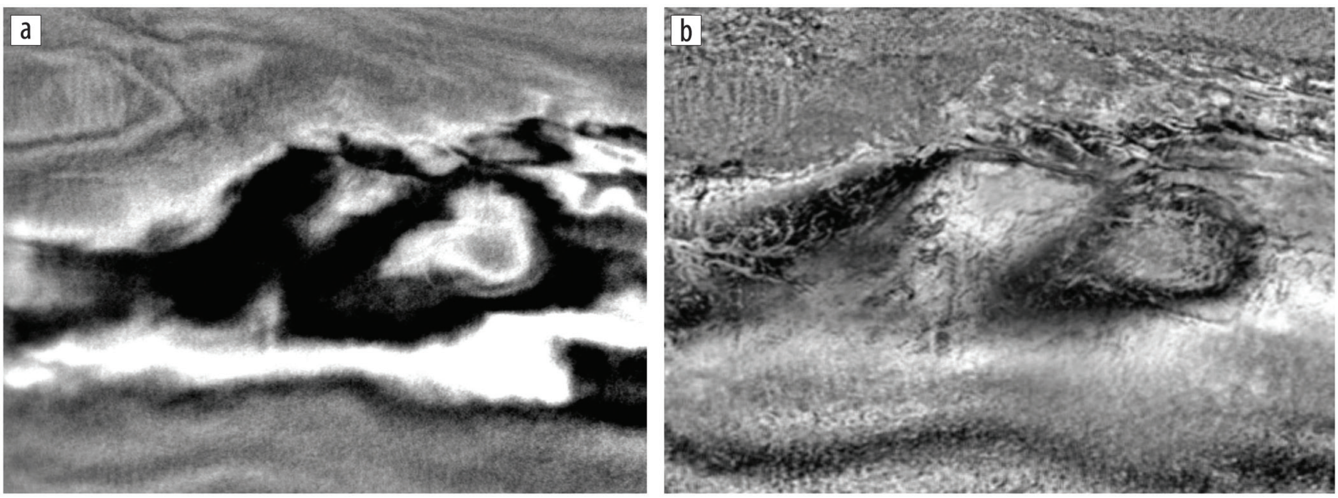

Figure 1. Diffraction imaging depth slice in Eagle Ford. (a) Prestack depth migration. (b) DI. Notice the increased resolution of discontinuities.

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In the early 2000s, unconventional shales drilling technology was spearheaded by small companies with expert drilling engineers, without much focus on seismic imaging, reservoir engineering, or field optimization. The emphasis was on drilling cost and on recovering the drilling cost for each well through individual well production. As larger companies with reservoir characterization and reservoir optimization teams became involved, the emphasis changed from the cost of individual wells to field optimization. It was noticed that wells placed close together using a grid pattern could have very different oil and gas production. The hypothesis was that the structure is very simple, and therefore the production should be uniform. In reality, the production is not uniform, and two wells placed in close proximity can have very different production.

New high-resolution technologies are needed to define and visualize the structure and the natural fracture distribution and orientation in shale layers. Optimal well placement requires the operator to factor the predominant trend of natural fractures in the selection of the wellbore orientation. DI is a new approach to image with super-resolution small-scale faults, fractures, reflector unconformities, or, generally, any small scattering objects. Typically, DI is used as a complement to the structural images produced by reflection imaging. By identifying the areas with increased natural fracture density, reservoir engineers can design an optimal well placement program that targets the sweet spots, areas with increased production, and minimizes the total number of wells used for a prospective area. Using an optimal number of wells decreases the drilling cost while maximizing production. It also decreases the environmental impact of developing the field by using less water, pumping less sand and fewer chemicals in the well, and not disturbing local communities. TLE