Strategies in geophysics for estimation of unconventional resources

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The rise of unconventional resource plays to prominence in the oil and gas industry has presented geophysics with a set of unprecedented challenges, chief among which is the problem of resource and reserve estimation. Instead of the traditional concerns with trap mapping, spill points, and degree of fill, unconventional resource plays require information on reservoir quality, fracability, fracture networks, and the stimulated rock volume (SRV) resulting from frac-completion programs. Figure 1 shows the critical differences in risk assessment between traditional and unconventional systems. The quantification of the "deliverability system" is the principal area which geophysical methods must address. These requirements lead to a reliance on seismic inversion, attributes such as curvature and coherence, and microseismic data. Too, the low porosity of many unconventional reservoirs demands greater trace-to-trace fidelity and low noise in the geophysical data; premium acquisition programs and processing work flows are needed, together with strict quality assurance standards. The current perception of many geoscientists and petroleum engineers is that for unconventionals the geophysical tools struggle to meet the standards of reliability expected under the Petroleum Resources Management System (PRMS) (see Lorenzen et al. in this special section). However, the techniques are evolving rapidly. The purpose of this paper is to review the state-of-the-art and to describe some of the technical initiatives which are being pursued to advance the use of geophysics in unconventional resource estimation.

In addressing the problem of resource estimation and the deliverability system risks, several strategic principles are critical for the acceptance of geophysical methods in a more prominent role. These include:

1) The technology proposed must be reliable in the perception of the geoscience community and documented in professional technical papers.
2) Standards of acquisition must be documented and rigorous, such that a third-party auditor can readily quantify the uncertainties in resource estimates and have sufficient basis to confirm them to a regulatory body such as the SEC.
3) Standards of acquisition and processing must include data standards, instrument specifications and tests, and QC&A documentation, as well as documents showing relevant parameter testing or modeling.
4) Processing workflows and algorithms need a sufficiently detailed technical description to permit a reviewer to assess the adequacy and appropriateness of the application. In other words, black boxes are unacceptable.
5) A guiding principal in resource estimation and deliverability workflows is a thorough "fit-for-purpose" assessment of technologies and their QC&A standards.

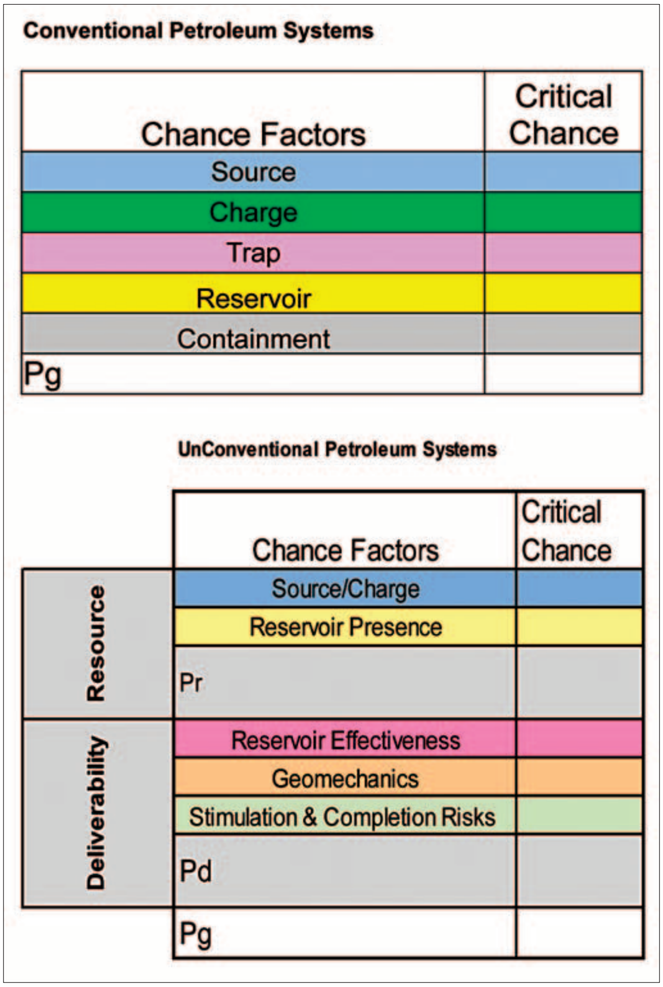

Figure 1. Critical differences between traditional and unconventional resource petroleum systems. In unconventional resource exploitation, the reservoir natural fracture network and the completion-induced fracture network connectivity become critical risk factors. The deliverability risk which must be described includes rock properties, principal stress fields, and effective porosity and natural fracture network interconnectivity. The risk also includes a technical assessment of the completion method chosen to enhance the resource deliverability (courtesy of Nexen).

Geophysical workflow

Given the nature of the resource estimation problem, the procedure for unconventional plays is necessarily much the same as that for other plays, but with different details and a different emphasis (see Kloosterman et al. in this special section). We outline here a general workflow, mentioning significant data requirements and concerns along the way.

Defining the container. With unconventional resource plays, the geophysicist knows from an early stage where the hydrocarbons are; there is no question of mapping degree of reservoir fill. Nevertheless, resource estimation still begins by defining the boundaries of the reservoir unit. This process is essentially the same as that followed in mapping a conventional play, and little need be said here in elaboration; established geophysical techniques constitute reliable technology in PRMS terms. Reservoir units, especially coal beds, are often interpretable markers; where this is not the case, reservoir boundaries can be phantomed by means of isopachs and isochrons from usable horizons. The greatest use for conventional horizon mapping is in the practicalities of field development: well prognosis, bit steering, and drilling hazard (e.g., fault) avoidance. In some shale gas plays, faults and diagenetically enhanced open fracture zones are to be avoided, as these act as conduits for water to break through the seals bounding the resource container and consequently drowning the wellbore.

Shale gas reservoirs can exhibit a subtle reflective character and may not be mappable by traditional horizon picking. In such cases, inversion volumes must be used to define reservoir boundaries. The effects of noise are serious in regard to elastic inversion. Acquisition and processing workflows, as well as additional geologic constraints input into elastic inversion, need to be carefully selected from the "fit-for-purpose" perspective.

Establish reservoir continuity. Unconventional reservoirs can be surprisingly heterogeneous, and a failure to recognize such heterogeneities has led more than one project to economic grief. For example, oil sands reservoirs often contain channel systems whose fill can be nonreservoir. Gas shales can contain nonreservoir facies that also act as frac barriers. These volumes cannot contribute to estimates of original gas in place (OGIP) or original oil in place (OOIP); as well, they can render reservoir zones inaccessible to drainage. In Figure 2, we show an example where OGIP was reduced because of a nonreservoir marl facies. All these nonreservoir zones must be identified and mapped and their volumes subtracted from the gross reservoir volume before a development plan with project economics can be prepared. None of this is essentially different from traditional reservoir evaluation; the problems arise in connection with the often low-contrast nature of these features in unconventional reservoirs and with the subtle character expression of lithology and mechanical stratigraphy. Statistical approaches can be of value.

The geophysical tool kit for dealing with reservoir continuity and compartmentalization includes many of the commonly used attributes. Inversion products such as Poisson's ratio and Young's modulus may be needed to characterize geobodies; coherence volumes, character-based facies classification, and such proprietary techniques as Ant Tracking are useful. These techniques are reliable technology under PRMS-AG (Guidelines for Application of the Petroleum Resources Management System), but they require local regional calibration. The subtle nature of the features being mapped can make calibration and consistent interpretation difficult.

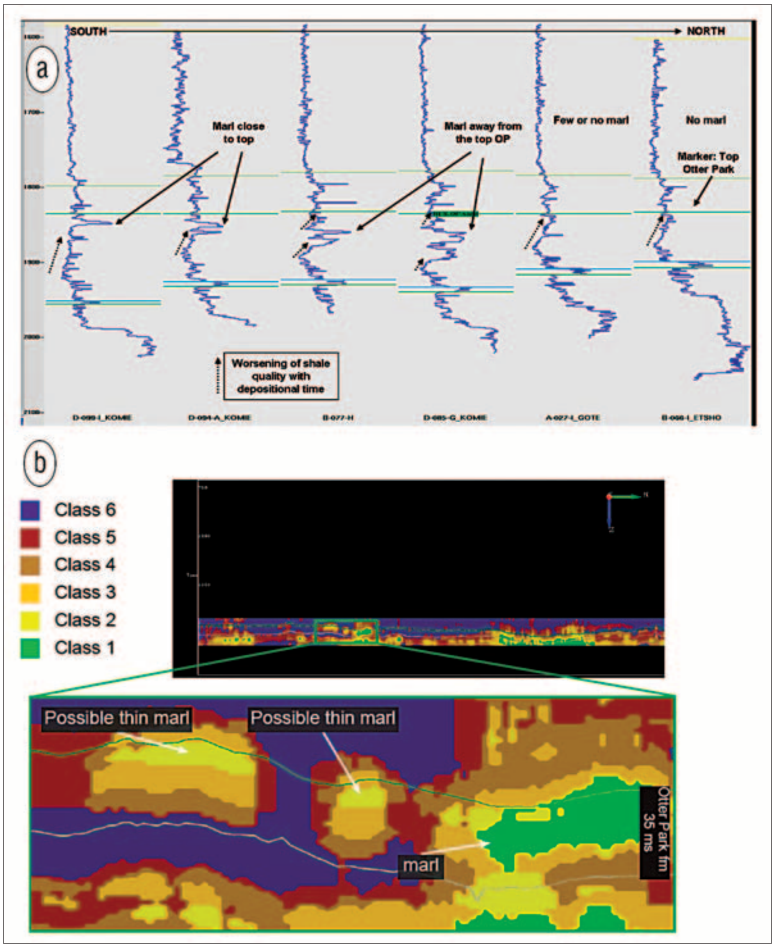

Figure 2. *(a)The resource hydrocarbon volume can be adjusted based on seismic waveform characterization. In this example, seismic waveform characterization is modeled from limited well control and then used to decompose the reservoir interval into seismic detected facies related to rock properties. (b) Six classifications representing different resource volume (in terms of OGIP by startigraphic interval) and detectable rock properties are used to form "consistent opinions" about the deliverability factor of the seismic facies. (Note is this particular case the limit to this technical application was ultimately controlled by "fit for purpose" acquisition and processing design decisions) (courtesy of Nexen).*

Predict reservoir properties. It is at this point that resource-play geophysics differs the most from conventional-play geophysics. We seek sweet spots in a known reservoir, and our work must contribute to an optimal development design. The tools of choice are multicomponent 3D surveys, elastic inversion, and, for shale gas, microseismic data, together with multi-azimuth VSP surveys.

In shale gas projects, geophysics is called upon to characterize reservoir properties before and after the frac program. Before the frac program, engineers want to know the in-place resource, the fracability, faults to avoid, variations in principal stress direction, the location and orientation of natural fracture systems (which can add complexity to a fracture pattern), and the locations of barriers. After the frac program, the engineers want to know the SRV, the overlap between fracture patterns, and the location or distribution of proppant emplacement, all of which are critical input for a geophysical

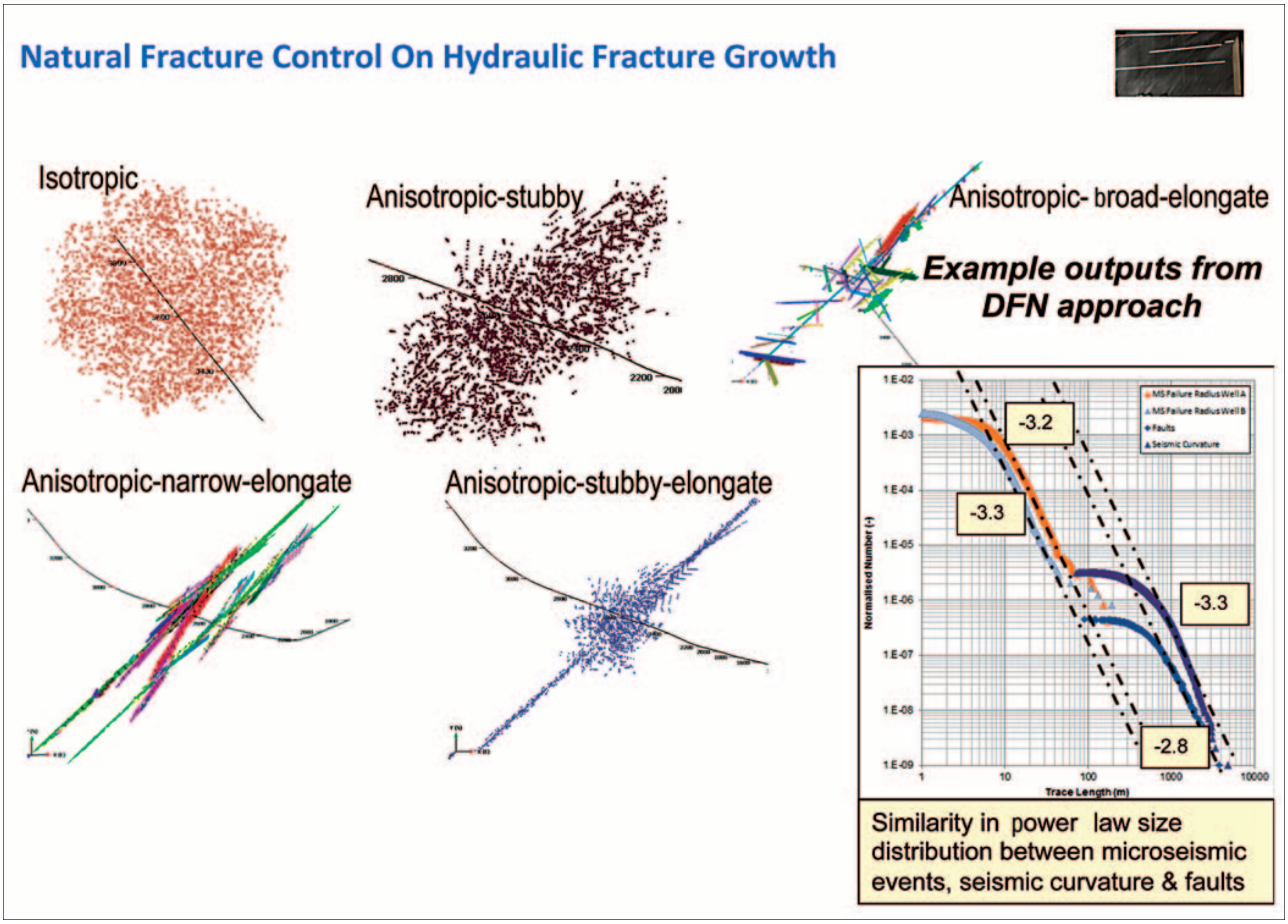

Figure 3. *The hybrid combination of stochastic models and visual classified textural effects can lead to a more robust description of the OGIP volumes ultimately accessed within an SRV, and its internal flow unit system which delivers hydrocarbon to the wellbore. In this example, the three principal stress components and pore pressure are the same for each of these possible frac geometry outcomes; yet, we note the fracture intensity, size, connectivity, aspect ratio, and flow efficiency could be significantly different. A critical element of constraint information for this stochastic model is comparison of the power law relationships between microseismic events, seismic curvatures, and faults observed.*

recovery factor calculation. In addition, engineers want to know how to improve the frac program to achieve a greater recovery factor and to reduce cost.

Resource-play unconventional resource geophysics, then, has two principal tasks. The first is to characterize the state of the reservoir before completion stimulation. In both shale gas and tight oil projects, hydrocarbon recovery is dependent on the existence and connectivity of natural fractures. Often the fairway of interest for the exploitation of such resources is found by mapping these natural fracture systems. In addition to the techniques discussed above, topics of current research interest for defining fracture-related producibility are velocity and amplitude anisotropy combined with shear-wave birefringence. In coal-bed methane, the characterization of the upper and lower bounding rock and its effectiveness as a seal barrier isolating the resource is an important initial objective. Geophysical tools which can relate rock types and natural fracture networks to in-situ stress and rock properties such as Poisson's ratio, Young's modulus, density, and rigidity become critical in planning the resource stimulation plan. This information comes from the 3D survey, its attributes, and its inversion products.

The second task is to evaluate the modification of the target reservoir into a state that permits economic production. This requires us to monitor the stimulated rock, identify bypassed resource pay, verify the resource confinement after stimulation, and predict or forecast the hydrocarbon delivery success from stimulation-induced changes in observed geophysical characteristics. In oil sands work, steam-assisted gravity drainage (SAGD) projects require geophysics to track the growth of steam chambers with 4D seismic surveys, look for bypassed bitumen, and examine the integrity of the seal barrier to prevent hazardous chamber failure and the loss of resource that occurs when the chamber bursts to surface.

In shale gas exploitation, we must determine the extent of both the natural fracture system and the frac-induced fractures, the likelihood of achieving the desired SRV based on rock mechanical properties, the initial state of stress both vertically and laterally, and the effectiveness of seals and barriers to isolate the producing rock media. These data are provided or might be provided in the future, with improved analysis, by microseismic data.

Integrate with other data analyses. This stage in the work flow is critical for unconventional resource geophysics; the more so in that tests and comparisons of new techniques are needed to evaluate their usefulness. Coherence techniques, curvature, horizontal anisotropy, and edge-detection algorithms can predict fracture zones, but they must be compared with core and image-log data from horizontal wells to calibrate them. Elastic inversion products can be used to predict in-situ shale gas resources and reservoir brittleness, but only after careful comparison with constraining well data. Estimates of SRV, proppant emplacement, and recovery factors can be generated only after comparison with production logging and decline curves. In unconventional plays, the geophysicist at present is perceived more as a supporting player than in traditional exploration and development, and geophysical interpretation products and predictions sometimes encounter skepticism. The standards for reliability, repeatability, and accuracy are high. This should clearly be the future direction of R&D efforts in order for geophysics to contribute seriously to resource and reserve estimation.

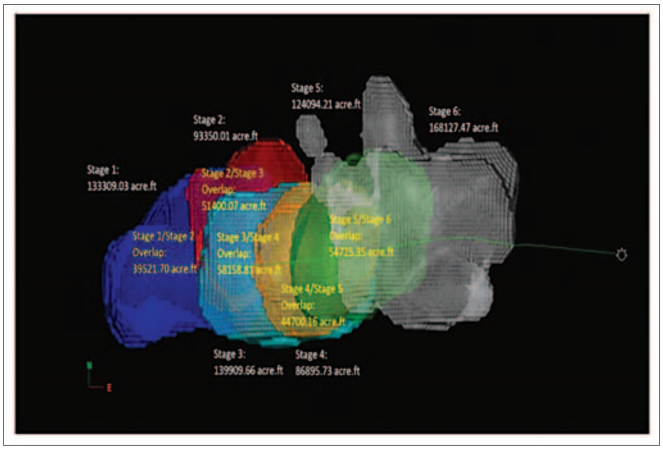

Figure 4. *This Bakken oil resource play example shows a complex pattern of microseismic events. The cloud is essentially an SRV encompassing six hydraulic frac completed stages. Each stage as it was pumping created a volumetric region correlated with the pumping program executed. The figure shows each stage highlighted with a different color, as well as the shared spatial subregions commonly shared or overlapping between stages. The overlapping regions would be our first guess to describe regions of fracture network interference. The question becomes which portion of this SRV is delivering significant hydrocarbon production to the horizontal wellbore (courtesy of Transform Inc.).*

Data requirements, processing and analysis standards, and emerging technologies

In this section, we discuss the requirements and associated problems with geophysical data acquisition, processing, and analysis for unconventional resource assessment. We also describe a number of emerging technologies and innovative procedures being tested in the Horn River Basin (HRB).

3D seismic acquisition, processing, and elastic inversion. For unconventional resources it is critical that seismic data be evaluated for:

- Acquisition footprint
- Vertical and horizontal resolution
- Spatial accuracy of seismic character
- Fidelity of the seismic trace and seismic gather
- Clarity

We emphasize trace and gather fidelity from several key perspectives:

- Seismic source bandwidth should be greater than three octaves and repeatable from shot-to-shot; the amplitude spectrum should be flat to better than 12 db.
- Seismic receiver signatures must have minimal distortion related to spread geometry, a critical element in subtle AVA and elastic inversion work.
- Careful attention to sensor-to-ground coupling, as well as to background noise, is needed.
- Provision of adequate trace fold as a function of both offset and azimuth must be ensured.

The specifics of acquisition and processing design is an extensive body of literature of which Berkhout (1984), and Vermeer (1990) are recommended.

As noted above, the variations in reservoir parameters that we attempt to map in unconventional resource plays can be subtle. This is particularly true for shale gas, with porosities often less than 5%, and with anisotropic organic material content of 2–10%. It is easy for acquisition artifacts or other noise to degrade the signal; it is essential that we do not trade quality of data for quantity of data. A bargain-basement survey will likely prove useless in the inversion stage. To begin, the survey must provide not only full fold over the area of interest, but also a full-offset range and a full set of azimuths. This means that tail spreads must be generous and the survey outline must be simple. The acquisition patch should be symmetric, to provide equal-offset ranges both inline and crossline. Source and sensor trace density in shooting should be chosen with horizontal anisotropy processing in mind; to sparse a spread will, for example, limit the choices for sector processing and require either overlap or interpolation. Seismic trace interpolation is not generally recommended, except to regularize the seismic trace spacing and grids as required for migration and inversion. Maximum offset should be generous, because the far offsets contribute disproportionately to the inversion, especially for density.

We recommend the use of three-component phones to provide a mode-converted shear-wave section. We also prefer vibroseis as a source to maintain a robust high-fidelity wavelet. A stable source wavelet is an essential element in an accurate elastic inversion.

Joint P- and S-wave 3D surveys can offer advantages. Although mode-converted S-wave spectra often have less than half the frequency content of the associated P-wave spectra, a direct measurement of the anisotropic S-wave field at the reservoir interval is useful for mapping fracture networks and maximum stress. Curvature features can be mapped with two different wavefields. Weak P-wave markers may be easier to image on shear sections. The measurement of class 2 AVA responses is more accurate when actual shear data are used in a joint P and S elastic inversion.

We acquire joint P-wave and S-wave multi-azimuth walkaway VSPs to provide anisotropy information for seismic processing and to enable a precise calibration of the P-wave and S-wave time-depth relationships. Given the problem of parallel P-wave and S-wave statics, we shoot a suite of shallow 2D refraction lines using both P-wave and S-wave sources to supplement the static solution from the 3D survey, which in general lacks the near offsets needed to resolve the near-surface statics. In the HRB, airborne EM has proven useful in mapping Pleistocene channel systems, a key input to the seismic statics solution.

It is necessary to rigorously remove noise, especially coherent noise, before attempting an inversion. The Horn River Basin is characterized by large-amplitude, high-velocity interbed multiples which often have velocities as fast as the primaries they overlay. These multiples are generated by massive carbonate units in the Mississippian and Upper Devonian. We have found that the usual Radon transform techniques must be supplemented by a deterministic demultiple approach to attack these multiples successfully. In this case, attempts at elastic inversion with inadequate multiple removal resulted in volumes riddled with obvious artifacts. (For details on deterministic demultiple techniques, see Verschuur, 1991; Kelamis and Vershuur, 2000; Yilmaz, 2001; and Dragoset and Jericevic, 1998).

It is not unusual to find that 3D inversions fail to adequately resolve short-wavelength variations in elastic parameters and to capture the range of variation inherent in the data. Stochastic inversions can address this to some degree and usually provide better vertical resolution. Software for this kind of inversion is undergoing rapid improvement, and the QC of the process presents new challenges. We find it valuable to involve those who are to perform the inversion in the QC of the basic processing, to ensure that the data are "fit-for-purpose."

VSP surveys for unconventional reservoirs. Vertical seismic profiles (VSP) provide useful information in both conventional and unconventional reservoirs. They are the main calibration point for all seismic data, 2D and 3D, as they provide a direct tie between the well-log-derived synthetic and the seismic trace, through the zero-phase corridor stack. As such, they provide a direct depth-conversion point from the seismic data to the well data which is crucial in converting seismic data from the time domain to the depth domain. In addition, this is useful when integrating seismic time data with microseismic depth data.

Time-to-depth conversion in thick, highly anisotropic rocks (> 15% over a 100-ms interval) often introduces a spatial error in linking seismic inversion volumes to well control and microseismic hypocenters. Surface seismic usually does not provide sufficiently accurate measures of this error. Hence, we emphasize borehole seismic methods in unconventional media. As well, pre- and postcompletion VSPs have demonstrated significant velocity and azimuthal anisotropy changes in the reservoir resulting from frac programs.

As mentioned previously, interbed or peg-leg multiples are a problem in certain basins and may create interference in the reservoir section of the seismic data. These multiples must be removed in order to obtain a reliable inversion product for reservoir parameters. VSP surveys are the best method to identify the multiples in the seismic section, as they are readily distinguished on the downgoing section as well as the corridor stack (Hampson and Mewhort, 1983). This information can then be input into deterministic demultiple seismic processing routines prior to inversion for optimal results.

Walkaway or multi-offset VSP surveys can provide an estimate of the VTI anisotropy due to layering of the overburden. These VTI anisotropy parameters are useful inputs for building velocity models for forward modeling, depth migration and also microseismic data analysis (Tsvankin et al., 2010). Walkaround or 3D offset VSP surveys are capable of providing azimuthal (HTI) anisotropy parameter estimates which are often related to vertical fractures. These natural fractures are important to completion programs in shale gas reservoirs.

Microseismic data for unconventional resource estimation. Gas shales have permeabilities on the order of 100 nanodarcies and tight oil reservoirs are some tens of microdarcies; these numbers severely limit the distance that gas or oil molecules can diffuse through rock during the lifetime of a project. Achieving an adequate recovery factor is therefore entirely dependent on having a complex network of fractures in the rock, whether natural or frac-generated. Traditionally the

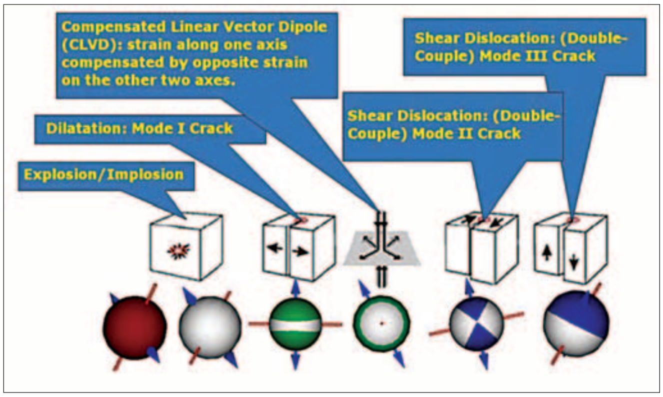

Figure 5. *Concepts of crack mode failure and simplified relationship to moment tensor presentations (courtesy of Urbanic, 2010).*

recovery factor has been estimated from production decline curves and reservoir modeling. Because the production life of shale gas wells can be on the order of years, the accuracy of recovery factors and production forecasts generated by model curve matching is low until much time has passed.

The microseismic technique offers an alternative approach for the assessment of reservoir deliverability and the recovery factor. The first attempts at this approach were presented nearly seven years ago by Mayhofer et al. The results were encouraging but still preliminary. Nevertheless, microseismic data are the geophysical tool of choice for estimating stimulated rock volume, future production, and recovery factor because it is the only technique that can directly observe the creation of a drainage network within the stimulated resource container. Microseismic data can provide the reservoir engineer with critical inputs to the reservoir simulation model, including SRV and an estimate of frac complexity, enabling a better and quicker decline curve match. Recent case histories indicate that the microseismic technique is making advances in establishing itself as fit-for-purpose as an information source for reservoir simulation and production history matching.

From displays of microseismic hypocenters, we attempt to determine frac-wing symmetry, azimuth relative to principal stress, and frac height, width and length (Figure 3). These observations are then compared with the time-synchronized frac-pumping curves. Two issues emerge quickly from analysis of these displays. First, the hypocenter locations produced from the same raw data vary substantially from processor to processor. Second, the hypocenters are often not located with sufficient precision to represent the simulated volume and drainage network. One has to admit that the current microseismic acquisition standards are poor, processing can be inconsistent, and interpretation lacks credibility. These are challenges that the geophysics industry is currently addressing.

The basic task of accurately locating event hypocenters is the first hurdle to overcome. There are three interwoven aspects of the problem that must be dealt with: first, designing an adequate acquisition geometry for the survey, whether a downhole or a surface array; second, selection of valid and robust processing algorithms; and third, detecting a credible number of events to produce a statistically valid interpretation.

The merits of surface versus downhole arrays are debated in the literature; we can employ both in the HRB. The HRB is presently being developed with large drilling pads (18 or more wells) and horizontal borehole laterals of up to 2200 m. We model proposed arrays configurations to provide sufficient solid angle to ensure accurate positioning. Downhole arrays connected by "whips" help to achieve the required array length.

In processing, we track the probable error of each location from start to finish and store it in the database. We find that inadequate velocity models are a great source of position error. 1D velocity models are grossly inadequate; 2D velocity models including anisotropic may be workable. But an anisotropic velocity model which incorporates thin layering and structure is much to be preferred. Another critical requirement is a time break for perf shots which is accurate at seismic time scales. This means, among other things, only one master clock on a well site. With these changes in standards, we have reduced our vertical positioning uncertainty to less than 10 m at a depth of 2500 m.

The third problem is to record and position sufficient microseismic events to statistically validate interpreted features. The SRV needs to be properly sampled. We currently process more than 750 events per frac stage and more than 30 events per 10-minute time window of the pumping process. Experience shows that if an SRV does not have a statistically significant population of events, cluster feature extraction will be misleading and inconsistent (Hendricks et al., 2012).

One can rarely predict a reasonable production history by combining the SRV with an arbitrarily assumed discrete fracture network (DFN). Maxwell (2010) describes three key elements within the SRV. The first is the rock volume ruptured by the hydraulic fluid during pumping operations. The second is that part of the ruptured rock in which the fractures are kept open by proppant or which remain open under the stress induced by the completion. The third is the rock volume which supports flow into the wellbore in a reasonable time frame. Details of these three elements are needed for reservoir simulation models and must be provided by the interpreted features of the SRV hypocenter cloud.

Geophysical approaches utilized by DFN shale gas models fall into four main types. These four approaches are dependent on the interpretation of the boundary edge of the SRV. Most work to date treats the boundary edge as a "shrink-wrap" skin encompassing the observed microseismic events (MSE). The SRV can be further refined based on additional MSE attributes.

The first approach describes a hydraulic fracture treatment as a biwing fracture zone characterized by height, length, width, azimuth and symmetry. These visual measurements are readily taken from microseismic "dot" or location patterns. In a multistage program in a horizontal wellbore, each stage is summarized in terms of its own SRV defined by its own hypocenter cloud. This style of SRV description is rapidly being replaced by more sophisticated methods.

A second common method of DFN characterization is to use the MSE observations statistically to derive fracture-network parameters. In this style of characterization, we describe a fracture network in terms of volume-based fracture parameters such as number of fractures per cubic meter, or the number of fractures for a given orientation, fracture size, and aperture. Rodriguez (2012) describes a method for the stochastic prediction of undetected MSEs which can be combined with a power-law approach to joint size and intensity distribution within the SRV.

A rapidly emerging method is to allow the DFN parameters to vary for different SRVs. We allow the wellbore global SRV, individual stage SRVs, and SRV overlap zones to be intrinsically different. These are interpreted from overlapping microseismic event clouds. Within each decomposed volumetric portion we must define an observed or probabilistic fracture network. This concept presents challenges to DFN modelers in scaling relationships for each subzone's permeability and interconnectivity. (Figure 4 displays five such stages.)

Finally, if we consider the limitations of each of the previous descriptions of MSE for DFN characterization, a fourth or hybrid methodology could be implemented. In some situations the internal fabric or texture image is highly suggestive of drainage pathways (Geiser et al., 2012). More often, the internal fabric yields a visual image of shades, which we interpret to represent a more likely style of hydraulic fracture network (Vermilye, 1998; Vasudevan, 2011).We can characterize the SRV associated with the multistage horizontal wellbore in terms of detected flow pathways which drain or deliver hydrocarbons from stochastically described subzones. The subzonation is based on mechanical stratigraphy and a probability estimation of small-to-medium fractures which are scaled to describe local connectivity of the fracture-induced network.

Current research on moment tensor inversion of event first motion appears likely to produce useful inputs to the DFN. Moment tensor analysis provides data on the following:

- Opening and closing fractures
- Orientation of the failure surface
- Classification of events relative to three mechanisms of failure: volumetric, double couple shear, and compensated linear dipole
- Stress /strain relationships as the frac process is completed
- Classification of events as mode I, II, or III failures (Figure 5)

Moment tensor inversion requires multiple arrays, whether surface or down hole, in order to obtain adequate solid angles.

4D seismic. The use of 4D seismic in SAGD projects has been mentioned; industry is also experimenting with its use in shale gas. There is some evidence that it can map the major fractures in a stimulated region. There may be some additional benefits in mapping changes in reservoir stress as production occurs. The use of 4D surveys for shale gas is in its early stages.

Conclusions

It can be seen from this review that the various geophysical techniques employed in the task of resource estimation for unconventional reservoirs are at a wide range of maturity and reliability. Surface 3D techniques for mapping the reservoir outline, discontinuities, and heterogeneous geobodies are well established and accepted. Other techniques such as microseismic are emerging technology. Unconventional resource plays are to a large extent the future of our industry. They are undergoing great expansion throughout the world. But the enormous engineering costs of these projects and their relatively narrow economic margins mean that it is more important than ever to have accurate and reliable estimates of recoverable resources early in the project life. Geophysics will play a large role in providing these data; it will be an interesting time for those of us in the field. TLE

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