



CSEG Chief Geophysicists Forum

Geophysical Applications – Using Geophysics for Hydrocarbon Reserves and Resources Classification and Assessment

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Scope

This document is based on Chapter 3 of the Guidelines Document for the Petroleum Resource Management System (PRMS), issued by its joint sponsors; the Society of Petroleum Engineers (SPE), the Society of Exploration Geophysicists (SEG), the American Association of Petroleum Geologists (AAPG), the Society of Petroleum Evaluation Engineers (SPEE) and the World Petroleum Council (WPC). The subsequent modifications were made by the Canadian Society of Exploration Geophysicists (CSEG) Chief Geophysical Forum (CGF) Reserves sub-committee for consideration by the SPEE Calgary chapter for an update to the Canadian Oil and Gas Evaluation Handbook (COGEH).

These modifications have not been reviewed by the joint sponsors of PRMS AD. Statements in this document are therefore not necessarily supported by those PRMS joint sponsors.

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Modified from the Society of Exploration Geophysicists Oil and Gas Reserves Committee (SEG OGRC) recommendation to the Society of Petroleum Engineers (SPE) for an update on Chapter 3 of the applications publication for the Petroleum Resource Management System (PRMS). Further modified by Canadian Society of Exploration Geophysicists (CSEG) Chief Geophysical Forum (CGF) Reserves sub-committee for consideration by the SPEE Calgary chapter for an update to the Canadian Oil and Gas Evaluation Handbook (COGEH).

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1. Introduction

Geophysical methods, principally seismic surveys, are some of the many tools used by the petroleum industry to assess the quantity of oil and gas available for production from a field or to assess the potential of an undeveloped resource. The interpretations and conclusions from seismic data are integrated with the analysis of well logs, pressure tests, cores, geologic depositional knowledge and other information from exploration and appraisal wells to determine if a known accumulation is commercial and to formulate an initial field development plan.

Figure 1 compares the resolution of the scientific tools used to measure rock and fluid properties for the determination of petroleum reserves. Historically, seismic data were used in reserves documentation to map the areal extent of the reservoir formation and the geometry and nature of the trap. However, in some cases, by matching seismic elastic properties to reservoir rock and fluid properties from well data, a meaningful interpolation and extrapolation of these properties allows us to determine reserve/resource volumes with greater confidence. This integration of geologic data, geophysical data, and engineering data is imperative to achieving a fully comprehensive reserve assessment with increased certainty.

The application of geophysics to reserve and resource estimation can be usefully divided into geophysics for conventional plays, where reservoir quality is fair to good; and geophysics for resource plays, where it is poor. In conventional plays, formation mapping plays a major role. In international work, where the existence and quality of source rock is often the limiting factor in hydrocarbon accumulation, the use of geophysical mapping for reserves extends beyond the bounds of individual pools to include source basins and migration pathways. In conjunction with geochemical modelling, geophysics can provide estimates of total hydrocarbons generated, timing of generation relative to key structural events, probable migration pathways, and possibility of refill of traps after fault-induced leakage. In the Western Canada Basin, the abundance of source often allows source and migration path to be assumed; the geophysical effort is concentrated on trap geometry, reservoir quality and heterogeneity, and fluid type. Elastic inversion and seismic attributes can be valuable here, along with 4-D seismic as reserves are produced. In resource plays, by contrast, there may be no geometric traps to map. Mapping is still useful to determine gross rock volume and stratigraphic subdivisions, to aid in bit steering, and to map faults which may be an unwelcome source of water. But the principal value of geophysics is in predicting resource content, natural fractures, fracability, and stimulated rock volume (or increasingly, stimulated surface area). 3D seismic and microseismic data are of critical importance to such work.

Many workflows are deterministic in nature and are still valid for resource and reserve determination so long as there is some assessment of uncertainty. Probabilistic methods such as stochastic simulation use random sampling of a repetitive process to calculate multiple deterministic realizations from which the uncertainty of the property being modeled is defined.

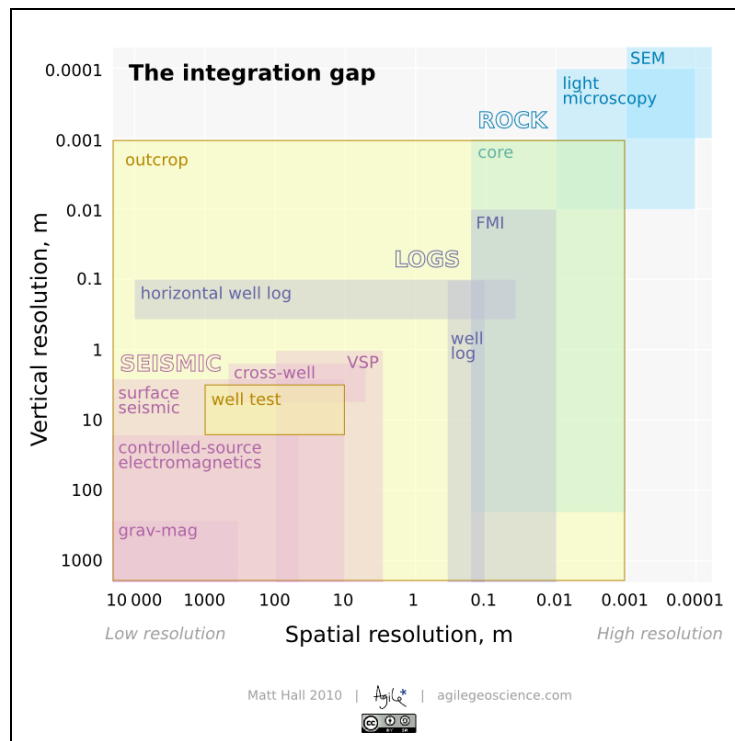


Figure 1. Vertical and spatial resolution of various geophysical and geological data. Geophysics, particularly seismic, allows interpolation between wells with greater confidence because it has good areal coverage; however, in its most commonly used form, its vertical resolution is restricted by the bandwidth of the seismic wave. All-in-all, geophysical data can provide a huge improvement over maps made with wells only, thereby decreasing the uncertainty. Newer methods, such as stochastic inversion and spectral decomposition attempt to redress the vertical resolution of seismic methods. Note how the poor areal coverage of well data is complemented by the larger areal sampling of the geophysical methods.

While 2D seismic lines are useful for mapping structures and for the early recognition and development of fields prior to significant well control, the uncertainty of seismic data decreases considerably when the seismic data are acquired and processed as a 3D data volume. Not only does 3D acquisition provide full spatial coverage, but the 3D processing procedures (seismic migration in particular) move reflections closer to their proper positions in the subsurface and significantly improve the clarity of the seismic image. In addition, 3D seismic data provide a greater confidence in reservoir continuity away from well control and also, in some cases, offer the geoscientist geologically reasonable seismic attributes.

The following discussion focuses on the application of 3D seismic data to the estimation of reserves and resources as classified and categorized by COGEH. However, in some areas, 2D seismic data play a crucial role when both reserves and prospective resources are being estimated, particularly in the early stages of a prospect. Once a discovery is made, and as an individual asset or project matures, it has become the norm to acquire 3D seismic data, which provide critical additional information in support of the estimation of contingent resources and/or reserves. Finally, once a field has been on production for some time, repeat seismic surveys can be acquired. The information from these time-lapse seismic surveys, also known as 4D seismic,

are integrated with well performance data and feed into the reserves and resources estimates and updates to the field development plan.

Seismic data are not the only geophysical product used in estimating resources and reserves. Potential field data primarily (gravity and magnetics) and magneto-telluric data have uses in setting the regional context and in establishing boundaries for reserves/resources in many mineral plays, including oil and gas. This should be kept in mind when integrating geoscience and engineering products for further definition of resources and reserves.

The Chief Geophysicist's Forum (CGF) in Calgary, Alberta, Canada suggests that the most significant contributions of geophysical data to the calculation of reserves and resources fall into the following categories:

Section 3 - Reservoir Mapping, Gross Rock Volume, and Fill

Section 3 focuses on reservoir mapping in terms of geophysically defined trap structure and stratigraphy, integrated with well data to calculate reservoir volume. This section includes tying well logs to geophysical data for reservoir identification and conversion to depth. Source kitchen and migration path mapping are treated in regard to degree of trap fill.

Section 4 - Reservoir and Fluid Characterization

Rock and fluid characterization based on seismic attributes such as amplitudes and seismic inversion, tied to elastic properties calculated from well logs, are discussed in Section 4. Rock properties determined from seismic inversion may demonstrate the continuity of reservoir, seals, and fluid contacts.

Section 5 - Uncertainty in Geophysical Predictions

Since the geological models interpreted from geophysical data are non-unique, uncertainty is described in Section 5. Many workflows are deterministic in nature and are valid for resource and reserve determination so long as there is some assessment of uncertainty. Probabilistic methods such as stochastic simulation use random sampling of a repetitive process to calculate multiple deterministic realizations from which the uncertainty of the property being modeled is defined.

Section 6 – Time Lapse: Geomodelling Inputs to Reservoir Simulations

Section 6 presents the application of 3D seismic analysis to monitoring changes in pore fluids, pressure, and temperature in the producing reservoir over time: the fourth dimension. This technique, called 4D or Time Lapse seismic, uses repeated 3D surveys to observe changes in elastic parameters from a baseline survey to map hydrocarbon production. Geomodelling inputs to reservoir simulations help identify the effectiveness of production-enhancing processes, reducing the uncertainty in the remaining reserves volume estimates. The application of 4D seismic represents the full integration of geophysical, geological, and engineering data for better reserve definition.

Section 7 – Resource plays: Microseismic, Fractures, and Fracability

3D seismic provides a number of tools (curvature, coherence, anisotropy, ant-tracking ®) to provide estimates of natural fractures. Rock property inversion provides estimates of fracability. Microseismic, especially with moment tensor inversion, permits the estimation of rock properties, frac complexity, proppant emplacement, and stimulated rock volume (SRV) or stimulated surface area. It provides powerful constraints on discrete fracture network models for reservoir simulation.

As development wells are drilled and put on production, the interpretation of the seismic data is revised and recalibrated to take advantage of the new borehole information and production histories. Aspects of the seismic interpretation that initially were considered ambiguous become more reliable and detailed as uncertainties in the relationships between seismic parameters and field properties are reduced. The seismic data evolve into a continuously utilized and updated subsurface tool that impacts both estimation of reserves and depletion planning.

We therefore suggest that geophysical technologies be classified in terms of the above categories in order to avoid rigidly regarding the actual techniques or processes utilized by companies and also to allow for technical advances in the future. To be considered as reliable technology, any geophysical technique or application must pass rigorous scientific testing and analysis of the uncertainties involved. The CGF cannot stress enough that the real impact of using geophysics in both classification and estimation of reserves and resources comes through the total integration of all geologic, geophysical, and engineering data in a comprehensive approach (Figure 2). Figure 3 shows the degree of uncertainty that may exist when a reserves/resource evaluator first assesses a new asset. Reserve/resource evaluators' primary role is to minimize this uncertainty using any and all practical disciplines. As time passes and more wells are drilled, additional 2D seismic or 3D seismic is acquired, more advanced geophysical analyses completed, further production history and reservoir performance characteristics are obtained, and additional geological and petrophysical studies are undertaken, the range of uncertainty is gradually narrowed until the last barrel is produced from the pool. Geophysical techniques have routinely proven helpful, and sometimes fundamental, in reducing the uncertainty in this integrated process involving the geological, geophysical, and reservoir engineering disciplines. The goal of a reserves evaluator is to use all of the interpretations from these disciplines to obtain low (P90), best (P50), and high (P10) estimates of the reserves and/or resources. It is clear that each of the disciplines has its strengths and weaknesses. Rather than focusing on these, the reserve/resource evaluator should utilize the combined contributions of each discipline to minimize the global uncertainty in these low, best, and high reserve and resource estimates (Figure 3).

2. Seismic Estimation of Reserves and Resources

The interpretations that a geophysicist derives from 3D seismic data can be grouped conveniently into workflows that (i) map the geometry of the hydrocarbon trap (including fault-related aspects and, if appropriate, source catchment area and migration path), (ii) characterize rock and fluid properties, and (iii) are directed at highlighting changes in the distribution of fluids and/or pressure variations, resulting from production.

Figures 2, 3, and 4 illustrate: uncertainty, the range of estimates on resources and reserves, and workflows utilizing integrated geophysical data versus stages in the life of a field or pool.

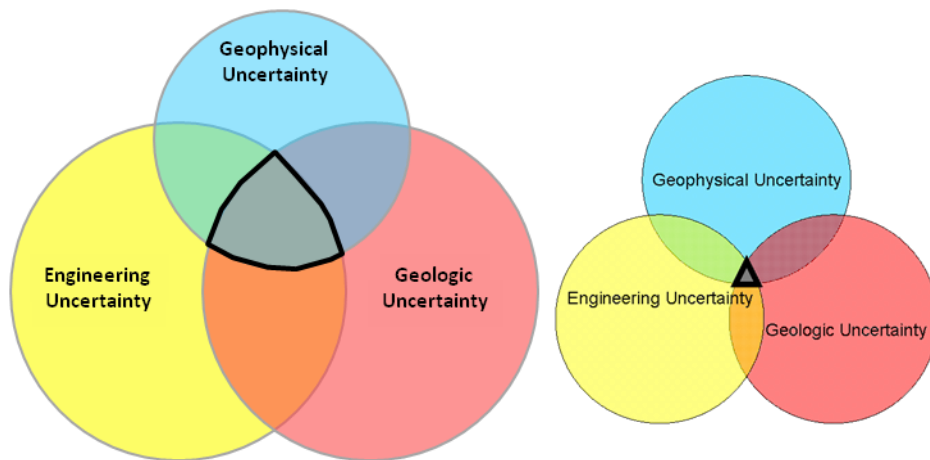


Figure 2. Combining different, independent information has the potential to significantly reduce the range of uncertainties. Adding geophysical information to geologic and engineering data has the potential to narrow the uncertainty in a resource or reserve assessment to a much smaller range, especially early in the assessment of a reservoir (left), while still adding significant value throughout the life of a reservoir (right).

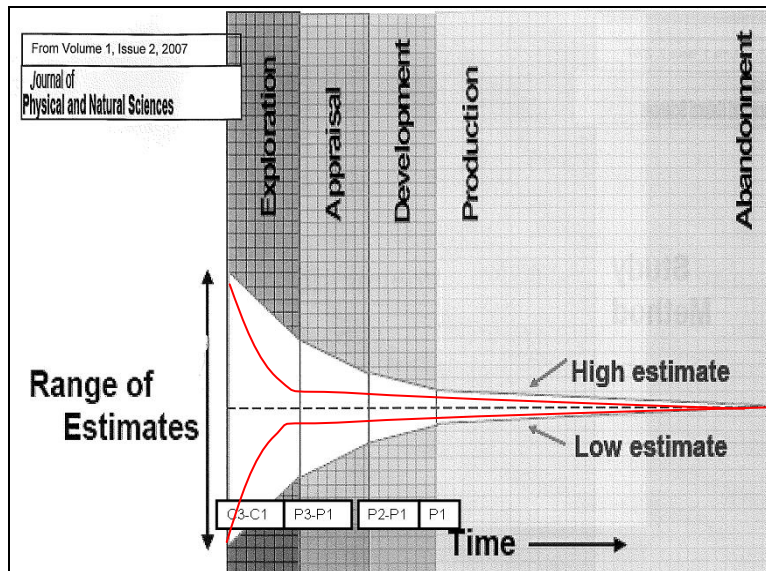


Figure 3. Temporal trends in reserves estimates. As more data (primarily production data) is collected over time, the range of uncertainty in reserves diminishes; an estimate incorporating geophysical data (red lines in figure) reduces the uncertainty of the estimate in the life of a hydrocarbon Pool/Field.

In the early stages of a field's appraisal, volumetric methods often dominate amongst the reserve evaluation techniques, as there is often insufficient well production and performance history to employ simulation studies, material balance, or decline analysis (Figure 4). Simply put, at this early stage in field development, the errors in reservoir engineering techniques are greater than those resulting from employing geophysical and geological data to calculate the volumetrics. At later stages of field development, engineering techniques provide greater accuracy, but it is still best to employ all available technologies from each discipline to minimize the uncertainty.

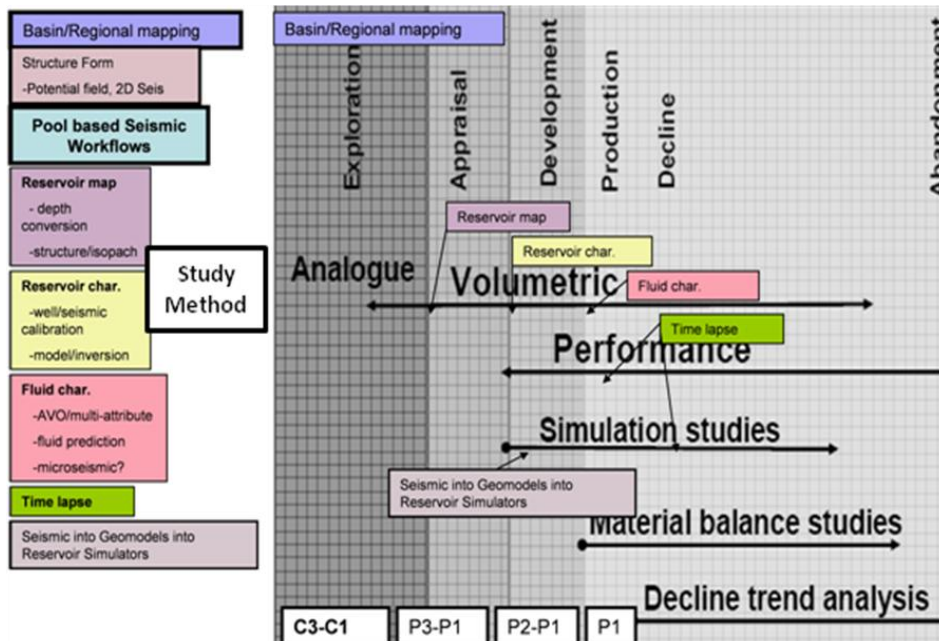


Figure 4. Various reserve determination methods are used at the different phases in a hydrocarbon pool/field. We utilize different seismic workflows during these various phases in the life of a hydrocarbon pool/field.

3. Reservoir Mapping, Gross Rock Volume, and Fill

Trap geometry is determined by the dips, strikes, and properties of reservoirs and seals; the locations of faults and fractures that facilitate or block fluid flow; the shape and distribution of the sedimentary bodies that make up a field's stratigraphy; and the orientations of any unconformity surfaces that cut through the reservoir. A 3D seismic volume allows the interpreter to map the trap as a 3D grid of seismic amplitudes reflected from acoustic/elastic impedance boundaries in the rocks in and around the trap. The resolution of 3D seismic typically ranges from 5 to 50 m in lateral dimension (depending on the seismic survey, the depth of the target, and seismic processing) and from 3 to 40 m in height (depending on the depth and properties of the objective reservoir as well as seismic acquisition and processing). A geophysicist uses various interpretive techniques available on a computer workstation to analyze the seismic volume(s). A geophysicist can synthesize a coherent and quite detailed 3D picture of a trap's geometry, depending on the data quality and resolution (Figure 5), by:

- Mapping seismic travel times or depths to selected acoustic/elastic impedance boundaries (geophysicists often call these boundaries or seismic horizons)
- Displaying seismic amplitude variations along these horizons
- Generating isochrons and isopachs between horizons
- Noting changes in amplitude and phase continuity through the volume
- Extracting pertinent attributes from the seismic amplitudes (e.g., AVO or amplitude vs. offset inversion, spectral decomposition and wavelet analysis)
- Displaying time and/or horizon slices and volumetric renderings of the seismic data and attributes in optimized colors and perspectives
- Generating and analyzing Allen diagrams of any bounding faults
- Velocity data from wells, optionally supplemented with seismic velocity data, is used to convert the horizons picked in time into depth and thickness

To fully analyze a trap, a geophysicist typically makes numerous cross sections, tying or incorporating well data, time and depth maps, 3D visualizations of both the upper and lower surfaces (bed boundaries, fault planes, and unconformities), bodies, and thicknesses of the important stratigraphic units comprising the trap. In particular, the geometric configurations of the reservoirs and their adjacent sealing units are carefully defined. The displays ultimately are distilled to geometric renderings of the single or multiple pools that form the field. The final work product of the trap analysis is a calculation of the reservoir bulk volume of these pools that will later be integrated with reservoir properties like porosity and hydrocarbon saturation, which might also be estimated from geophysical data, to compute original oil and gas in place.

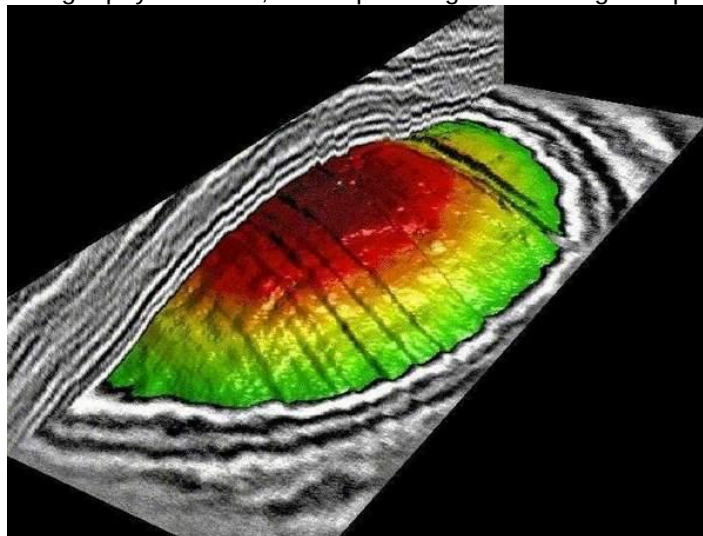


Figure 5. Showing trap (colour) interpreted from seismic data (grayscale) (Lyon et al, 1998).

Time-to-depth conversion is key to determining the gross rock volume of the trap. Accurate well ties using synthetic seismic traces calculated from logs are used to determine the necessary velocities for depth converted surfaces for the reservoir top and base, using time-depth pairs. Uncertainty in depths away from well control can be reduced by using interval velocities derived from seismic migration velocities. Other geophysical data, such as gravity data may be statistically combined with the interpolated velocities to further reduce the uncertainties.

Depth migration is not a replacement for depth conversion. Depth migration should be done in conjunction with depth conversion in order to use the wells to optimize the depths determined from the seismic data.

Seismic has often been used to delineate the extent of a reservoir(s) for land or licensed property continuation in addition to defining the lands/license available for, as an example, relinquishment. The definition of the area of the reservoir for retention or relinquishment involves the same integrated processes used to calculate reserves and resources for trap geometry and characterization along with geologic and engineering data available.

For fields interpreted to be faulted, it may be necessary to classify resource estimates differently for individual fault blocks. It is important to identify if the fault that separates the undrilled fault block from a drilled fault block can be considered a sealing fault. This will depend on the analysis of the extent of the fault, the fault throw as well as an assessment of fault transmissibility. Seismic amplitudes and flat-spots may be included in this assessment.

3.1 Gross Rock Volume (GRV) of a Trap

The reservoir geometry of a field is described by structural elements, such as depth maps and fault planes, resulting from an interpretation based on seismic and well data. Uncertainties affect parameters throughout the entire interpretation process. They have some bearing on the structural shape and subsequently on the Gross Rock Volume (GRV) of the field. This uncertainty on GRV also impacts volumes of hydrocarbons in place, reserves, and production profiles. Thus, the assessment of structural uncertainties is an essential first step in a field study for evaluation, development, or optimization purposes. Seismic attributes are best integrated with well and reservoir information 'in depth'. Conversion of seismic volumes from time to depth is a sensitive workflow dependent on good, detailed velocity analysis from both well and seismic data.

Other sources of uncertainty:

- The position of the seismic horizon pick on the seismic wavelet
- The bandwidth of the seismic data
- Lateral changes in the character of the seismic (e.g., when it changes from a peak to a doublet (double-peak), does the interpretation follow the upper peak, the lower peak, or something else?)
- Seismic attenuation
- Seismic anisotropy
- Migration velocities
- Migration algorithm
- Fresnel zone
- Local stress variations
- Local variations in the seismic velocity field (e.g., due to shallow gas)
- Thickness and lateral velocity changes in shallower layers or the water bottom
- Seismic data quality (includes poor acquisition procedure and processing error)
- Geologic factors such as scatterers (e.g., gravel or gas chimneys)
- With 2D data, migration error (sideswipe)

In severe cases, it may be impossible to determine the correct marker to map over part of a trap, or the relevant marker may simply vanish. In that case, optimistic and pessimistic maps must be made for input into a stochastic GRV estimator (see section 5).

It is important to appreciate the relative uncertainty in predicting depth to a trapping surface at a new location. Once the trap depth is precisely known at initial exploration or appraisal well locations, the error can be much less than the errors in predicting trap depth in an exploration setting prior to the drilling of the first well. Prior to drilling the first exploration well, uncertainty generally is tens to hundreds of meters off because there is no borehole control on the vertical velocity from the earth's surface down to the trap. In addition to the uncertainties in the velocities, alternative interpretations of the seismic data are the major source of uncertainties in (green-field) exploration settings, affecting the evaluation of in-place prospective hydrocarbon resources.

3.2 Degree of Fill, Catchment Area, and Migration Path

The majority of traps are not filled to spill point. If the trap under analysis has not yet been drilled, the estimate of filled rock volume is generally derived by the geophysicist. Frequently, especially in the Western Canada Basin, the data are good and the trap is well defined. In such cases, hydrocarbon fill can sometimes be directly detected by amplitudes or flat spots (see Section 4). Otherwise, the range of possible volumes can be estimated by using various interpreted spill points which depend on the effectiveness of seal as the critical factor. Assuming adequate sourcing, the P10 case might be a trap filled to ultimate spill, perhaps including a stratigraphic trapping component. The P50 case might be, e.g., a spill point interpreted from the Allen diagram of a sealing fault, and the P90 case could be the fault-independent 4-way-dip closure. Historical data for related traps, if available, can be used.

In much of the world, source, together with migration path is the critical limiting factor. Unless well control is available in the trap compartment being evaluated, or the data is good enough to permit direct detection of hydrocarbons, fill must be estimated using mapped catchment area together with geochemical analysis. Source beds are identifiable from well data and are usually visible on seismic as condensed sections. After depth conversion, catchment areas for the trap can be defined. This data can be combined with geochemical modelling to produce estimates of source maturity, expulsion efficiency, and migration losses. The result is a predicted volume of hydrocarbon available to charge the trap. The uncertainties in these calculations are high, but it is essential to make a best effort. Here too historical data is valuable and can be used to calibrate the calculation. Mapping of source kitchens is usually done with 2D seismic.

If bounding faults have reactivated, the trap will have leaked. The geochemist and geophysicist must then estimate the amount of trap refill.

3.3 Reservoir Characterization and Gross Rock Volume

Reserves/resource assessments generally determine the gross rock volume within the trap that has the potential to hold hydrocarbons. Within that volume, estimates are made of the net reservoir to non-reservoir (net to gross ratio - N/G) that can be used to modify the gross rock volume (GRV) into a net reservoir volume (NRV). The accuracy of the estimate of the thickness of each reservoir is a critical element in assessment of reserves.

Estimation of reservoir thickness from seismic is dependent on the bandwidth and frequency content of the seismic data and on the seismic velocity of the reservoir. Broadband, high-frequency seismic data in a shallow clastic section where velocity is relatively slow can resolve a much thinner bed than e.g., narrow band, low-frequency seismic data deep in the earth in a fast, carbonate section. Fortunately, geophysicists can analyze seismic and sonic log data to estimate what thicknesses can reasonably be measured for particular reservoirs under investigation (see Widess, 1973, and Puryear and Castagna, 2006). In addition, tuning of seismic reflections and

processing and analysis techniques that improve vertical resolution can be used to assist in improving the estimation of thickness.

Stacked reservoirs in a trap can be individually resolved and separate reservoir bulk volumes can be computed if the reservoirs and their intervening seals can be interpreted separately and if they individually meet the minimum thickness derived from the relevant tuning model. Under these conditions, a deterministic estimate of reserves in each reservoir is possible. When the individual reservoirs and seals are too thin to satisfy these conditions, seismic modelling can be used to get a general idea of how much hydrocarbons might be present in a gross trapped volume. These calculations generally are highly uncertain given the many parameters (bed thickness, spacing among beds, porosity, etc.). In this circumstance, a geostatistical estimate of the net hydrocarbon volume is usually more reliable than a direct estimate of net hydrocarbon volume from the seismic data. The approach presented above is indicative only and does not address the question of the spatial correlation of the uncertainties or, said in other words, the radius of influence of a well constraint (reservoir depth and thickness) on the uncertainty estimate.

Systematic approaches exist that can be used to estimate and combine time picking and velocity uncertainties to obtain the structural/geometrical uncertainties.

The following is an example of using seismic technology to determine pore volume and pool boundaries.

Broger, E.J.K., Syhlonyk, G. and Zaitlan, B., 1997, Glauconite Sandstone Exploration: A Case Study from the Lake Newell Project, Southern Alberta: **CSPG Memoir 18**

Fluvial-estuarine Glauconite channel sands of the Lower Cretaceous are arguably one of the most prolific oil and gas reservoirs in Southern Alberta. Existing well and seismic control indicated the Glauconite incised paleovalley likely extended beneath Lake Newell, Alberta, Canada. Based on the interpretation of several amplitude anomalies (diagnostic of reservoir porosity-meters), a drilling program was undertaken. Environmental concerns meant oil and gas development was restricted to five surface pad locations, requiring horizontal drill displacements more than 2600 meters. More than 15MM bbls of recoverable oil have been discovered beneath the lake in the Lake Newell portion of Countess Field.

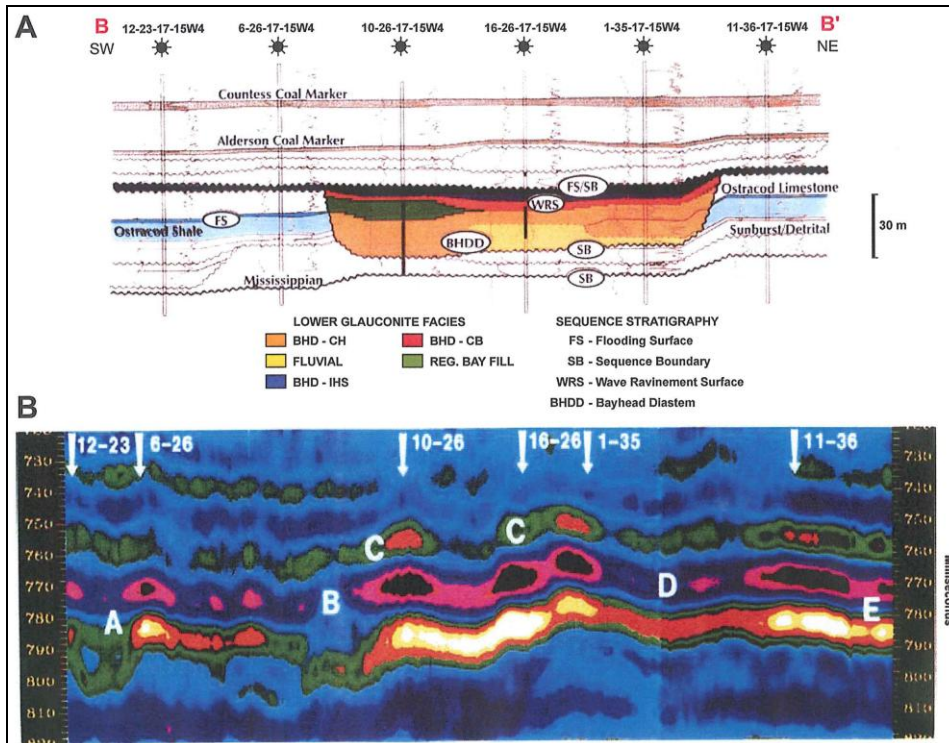


Figure 6. (A) SW-NE stratigraphic cross section through Countess YY pool, showing gamma ray/density logs, interpreted depositional facies, and sequence stratigraphic boundaries. (B) Companion 3D seismic line to cross section above. The letters B and D bracket the seismic anomaly associated with the Lower Glaucconite Sandstone reservoir, A and E denote the top-Mississippian unconformity surface and C denotes the Countess Coal Marker (Broger and Syhlonyk, 1995).

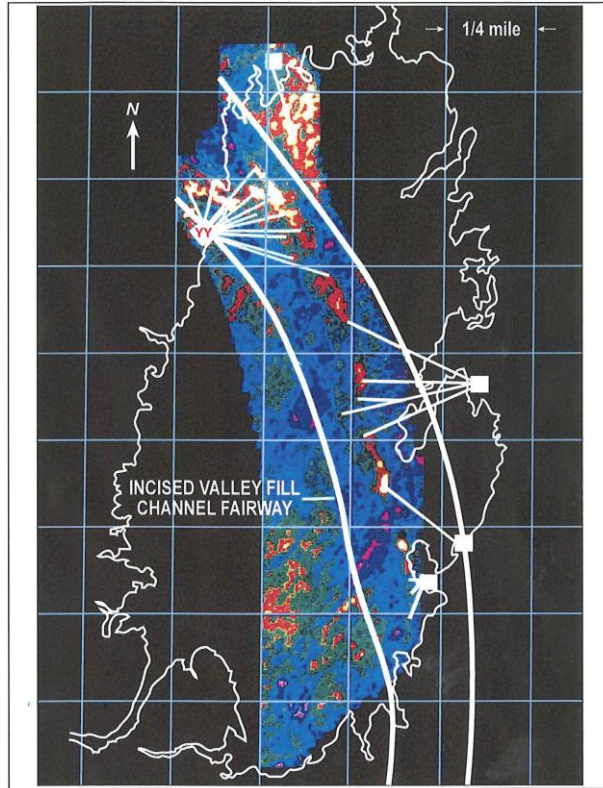


Figure 7. 3D seismic amplitude map of Lake Newell portion of Countess Field. Thin white lines outline Lake Newell. Thick white lines show boundaries of incised valley-fill fairway. Warm colors (red and yellow) indicate porous sands. Wells slant-drilled from land-based pads targeted five Lower Glauconite Sandstone pools beneath the lake. Location of pad and well trajectories for Countess YY pool can be seen in NW corner of the trend (Broger et al., 1997).

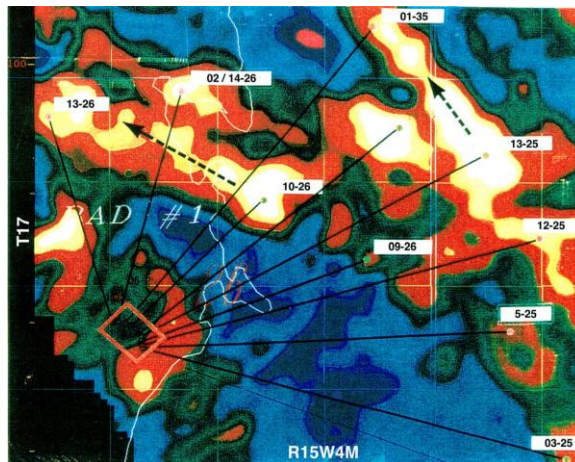


Figure 8. Enlarged area from Figure 7 showing location of YY drilling pad, well trajectories, amplitude anomalies and intercepts of wellbores with top of Lower Glauconite Sandstone reservoir in Countess YY pool (Broger et al., 1997).

In contrast to the 'conventional' Glauconite sandstone reservoir in the previous example, shale gas reservoirs can tend to be more laterally homogeneous than conventional reservoirs, and therefore may be less sensitive to vertical and lateral variations – yielding a much closer relationship between GRV. Another seismic technology (in addition to surface reflection seismic) used to determine 'effective' gross rock volume in shale or tight reservoirs is microseismic, which

is often used to constrain the volume of reservoir that is effectively fracture-stimulated during completion. Microseismic is treated in greater detail in Section 7. Characterization of such reservoirs using combined surface seismic and microseismic attributes shows the volume of the reservoir which contains the ultimate recoverable resource.

The next example is from the Nordegg tight gas reservoir in Alberta (Hunt, L, et al, 2010, Quantitative estimate of fracture density variations in the Nordegg with azimuthal AVO and curvature: A case study: The Leading Edge, **9**, 1122-1137). In such gas reservoirs, seismic elastic attributes may be used to predict 'brittleness', which is useful for predicting existing and induced natural fracture volumes.

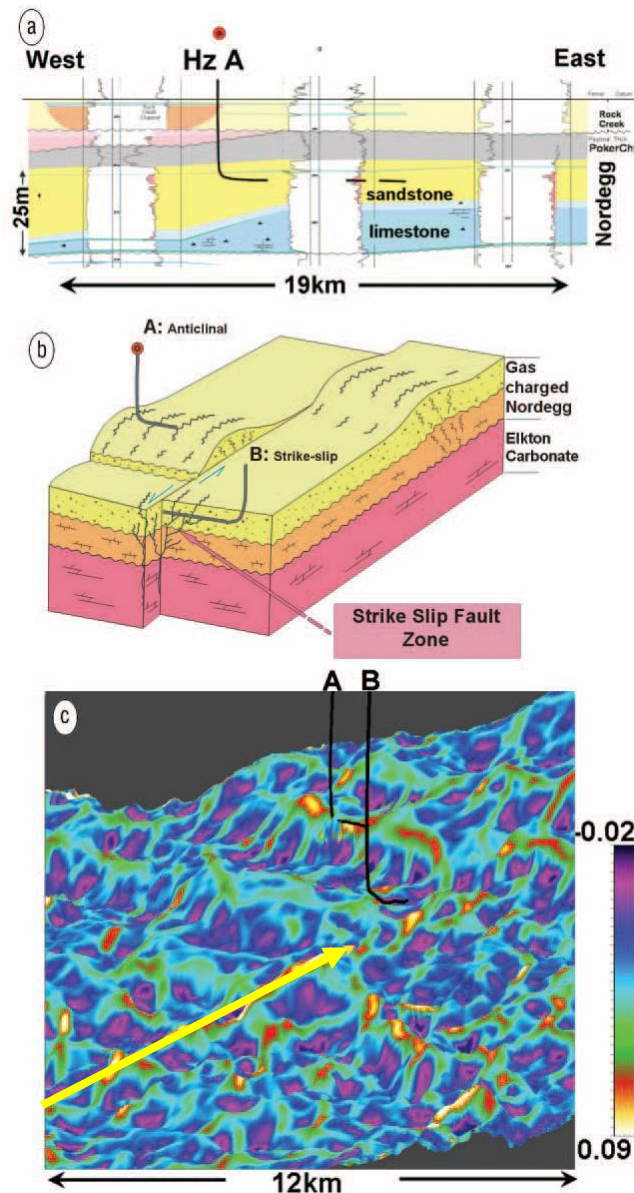


Figure 9. Depiction of wells A and B. (a) A stratigraphic cross-section of the Nordegg in local wells. Log displays include gamma ray and density porosity curves. The horizontal well A is depicted as if it intersects a nearby vertical well. (b) Schematic illustrating the relative position and setting of horizontal wells A and B. (c) A most positive curvature map of the Nordegg illustrated in a time relief map. The strike slip zone is indicated by the yellow arrow. (Hunt et al, 2010)

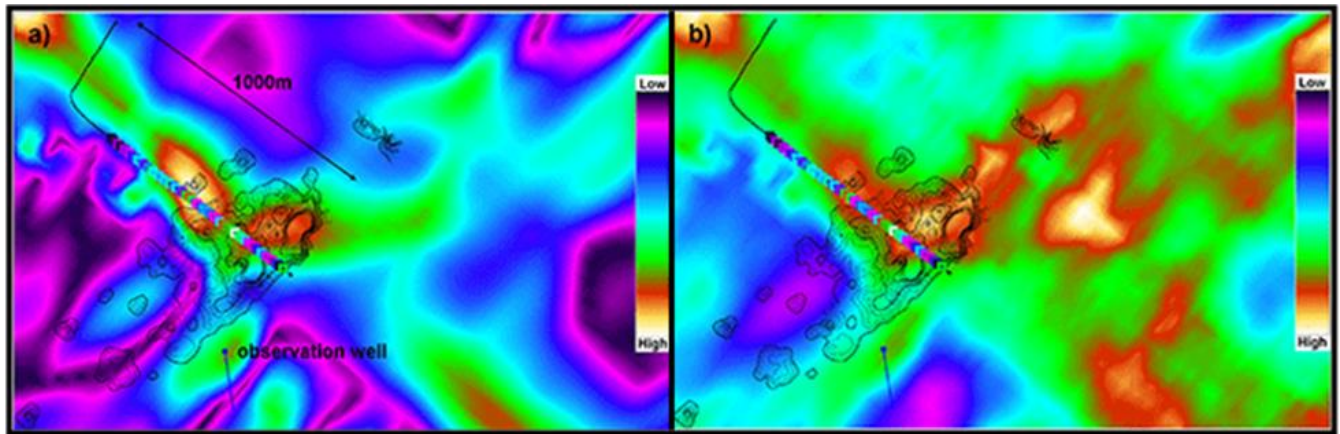


Figure 10. A comparison of curvature at well A with the image log fracture density shown by color and the cumulative microseismic moments shown by contours. a) Illustrates a different solution for low-resolution most positive curvature, while b) illustrates the λ/μ scaled version of this curvature. The λ/μ scaled curvature attribute appears to be a better match to the microseismic moments. (Hunt et al, 2010)

4. Reservoir and Fluid Characterization

The reservoir properties that 3D seismic can potentially predict are porosity, lithology, pressure and presence of gas/oil saturation, under good data conditions when supported by well control, a representative depositional model, and in appropriate geological settings. Other factors that affect the seismic response are density, hydrocarbon viscosity, temperature, stresses, and fractures. When validated supporting data are available, seismic can quantitatively predict these parameters, however when the supporting data are not available, the level of uncertainty increases and should be reflected in the volume classification.

There are hundreds of attributes that can be derived from seismic data. Careful, appropriate choices of these are compared to reservoir properties like porosity, fluid type, lithology, net-pay thickness, etc. The use of such seismic attributes requires that:

- A reasonable relationship exists or can be proven to exist at log scale between these attributes and specific reservoir characteristics
- This relationship still exists at seismic scale (which exhibits lower vertical resolution) and is consistent with all wells in and around the pool
- The seismic quality is satisfactory
- The quality of the well log being predicted is satisfactory
- A reliable tie between seismic horizons and well tops exists

In practice, a geophysicist develops the initial hypothesis by comparing the 3D seismic volume at the location of a well to the well's information, often through the intermediary of a synthetic seismogram (a modeled seismic trace derived from sonic and density logs), a vertical seismic profile or VSP (a seismic section recorded by placing the seismic source on the earth's surface and one or more receivers down in the well or vice-versa for a reverse VSP), or an inversion of the seismic data for well log properties. If synthetic seismograms, vertical seismic profiles, and 3D seismic volumes are correlative to the well control (i.e., reliable seismic to well ties exist), then rock and fluid properties can be interpolated (deterministically or geostatistically) away from the wells using the seismic attributes. This produces an inter-well seismic model that matches the actual inter-well 3D seismic data and the well logs as closely as possible. Subsequent drilling validates and refines the interpolation and provides new borehole data for another iteration of estimating rock and fluid properties between boreholes from the 3D seismic volume. Well-based

forward modelling is another powerful tool to determine the effect on seismic data of variations in the reservoir parameters.

Walkaway VSP's, are shot with several sources at increasing distances from the borehole. Walkaway VSP's are one of the most reliable measurements, which may help us to obtain the true pre-stack AVO and angle information, in order to further understand the differences between lithology, rock mechanics and stress anisotropy effects. They can be used to calibrate seismic gathers for AVO analysis (e.g. Chen et al, 1997) and they may be inverted for elastic properties and comparing the VSP inversions to these same properties measured at the borehole and inverted from seismic data is recommended for quality control (e.g. Goodway, 2001). 3D VSPs or multi-azimuth walkaway VSPs can be used in the same way for quality control of AVO and anisotropy (e.g. Leaney et al, 1999).

The following discussion mainly concerns the use of stacked seismic data. Stacked seismic data are generally studied in combination with pre-stack data for a more rigorous and robust analysis.

Hydrocarbon saturation in relatively unconsolidated sandstone reservoirs is a pore fluid property that has been very successfully mapped by 3D seismic surveys. The presence of hydrocarbon and/or porosity typically lowers the seismic velocity and density of unconsolidated to moderately consolidated sandstones and creates differential acoustic impedance (product of density and seismic velocity) contrast between the hydrocarbon charged sandstone and the surrounding water-bearing rock. The contrast produces an anomalous seismic amplitude that may be visible on seismic displays. Since the early 1970s, this amplitude anomaly effect has been widely exploited to explore for hydrocarbon accumulations. When the effect is validated by well control, the hydrocarbon extent can be accurately mapped across a field. Such is not the case for other conventional play types (carbonates, tight reservoirs) and unconventional plays although other specific useful properties can often be predicted from seismic in these plays. Integration of all geoscience and engineering data play an even more important role in these additional play types.

Stacked seismic data by itself is not capable of quantitatively predicting the characteristics and quality of the hydrocarbon accumulation, but it is always used in combination with other data sources, like well logs etc. For example, the percentage of free gas saturation in a reservoir often cannot be determined because most density information is difficult to obtain from seismic. A saturation of a few percent, which might be the residual left after the seal on an original gas accumulation is broken, produces virtually the same stacked seismic amplitude response as the saturation of a commercial gas reservoir. Hence, at least one well penetration into a seismic anomaly is needed to characterize the nature of the fluid and to promote prospective resources into contingent resources or reserves. Hydrocarbon-induced amplitude anomalies on stacked seismic data typically become less obvious with depth and age as sandstones become more cemented and less porous. When conventional amplitude anomaly interpretation is no longer applicable, or not considered robust enough, a geophysicist often employs pre-stack seismic data in addition to stacked data. For example, Amplitude-versus-Offset (AVO) analysis is used to differentiate free gas from water in the pore space. With sufficient understanding of rock properties from surrounding wells, AVO analysis can also be used for predicting reservoir and seal lithologies.

When a seismic amplitude anomaly is the result of hydrocarbon saturation, it may be possible to map the gas/oil and/or hydrocarbon/water contacts (GOC, GWC or OWC) themselves by noting where the amplitude anomalies terminate downdip across the 3D seismic volume. The terminations should occur at a common structural depth contour within the trap closure, which is the base of the trapped hydrocarbon. Seismic amplitudes normally vary at this contour because the strong acoustic impedance contrast between the reservoir and seal becomes much smaller (in relative value) when the reservoir pore fluid changes from gas to water. If the downdip termination of the anomaly does not follow a structural depth contour within the trap, there is considerable risk that the seismic amplitude anomaly is not caused by the presence of hydrocarbon, but instead has a lithologic origin. Of course, if several discrete contours are

followed by different segments of the downdip edge of the anomaly, this behaviour points to the presence of multiple pools with different fluid contacts (GWCs or OWCs) or vertical superposition of hydrocarbon and water.

The GWC/OWC itself in a reservoir can be an interface with a good seismic impedance contrast. Because the contact is normally horizontal in depth, owing to buoyancy, this contact sometimes can be directly detected as a flat amplitude seismic event (flat spot), particularly if the reservoir is thick and gently dipping. The flat spot directly outlines the base of the trapped hydrocarbons, and the depth of the flat spot is the depth of the GWC/OWC. It is important to note that the contact, while flat in depth, sometimes appears to be dipping on seismic time sections owing to lateral seismic velocity variations associated with the overburden (dipping sea bed for example), the hydrocarbon, and the constructive and destructive interference among different reflections in the reservoir interval.

A flat spot, which is the potential seismic expression of the GWC/OWC, should terminate at the same structural depth contour as the downdip edge of the corresponding anomaly, i.e., the seismic expression of the reservoir-seal boundary. When both of these seismic hydrocarbon indicators are present and terminate at the same spatial location, the probability that these seismic effects are caused by free hydrocarbon is very high, and risk is substantially reduced.

A fundamental requirement for the booking of reserves is that the accumulation must be "known" by virtue of having been penetrated by a wellbore and having demonstrated evidence of the existence of petroleum. Once this criterion is met, then the stipulated practices can be used, in conjunction with other geologic, geophysical and engineering data, to estimate reserves.

Figure 11 is an example of previously published recommended practices (modified from Ogilvie, J, and Keyser, W. (2004), Seismic considerations for classifying proved resources/reserves: West Africa example: SEG Expanded Abstracts 23, 478).

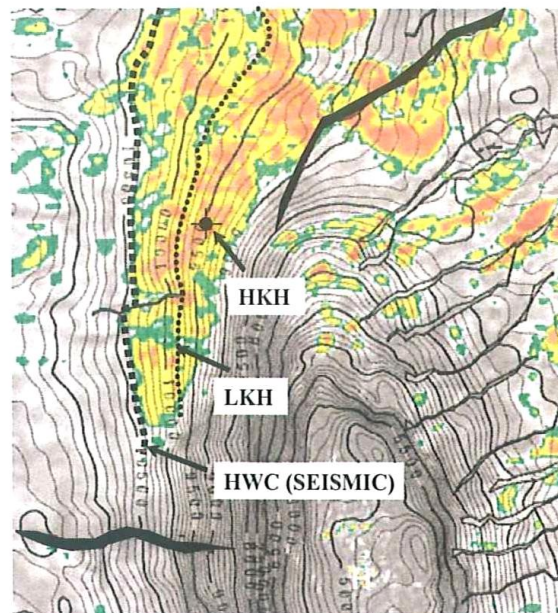


Figure 11. RMS amplitude extraction for reservoir unit with depth contours overlain. Indicated on map are the highest known hydrocarbon (HKH) and the lowest known hydrocarbon (LKH) as penetrated by the well and estimated hydrocarbon-water contact from seismic.

4.1 Conditions for Proved, Probable, and Possible Reserves

Reserves/resources may be classified as 'proved' in cases where 3D seismic is shown to be reliable indicators of fluid contacts. In these cases, the following criteria must be satisfied to reasonable certainty in order to be booked as proved (SEC 'reasonable certainty' or COGEH 'high degree of certainty'):

Simple lithology: Lithologic environment must not be complex. Sand/shale stratigraphy is preferred, yet carbonates could be considered. Stratigraphic zones that exhibit a high occurrence of exotic lithologies (coal beds, volcanics, salt welds, etc.) that might cause false seismic anomalies at the reservoir level are not acceptable, unless these seismic anomalies are well-separated and can all be accounted for by, e.g., correlation to well facies. For example, many carbonate reservoirs have shown good correlations between porosity and acoustic impedance.

Seismic data: Where modern high-quality 3D or 2D seismic coverage exists over the area to be booked and is shown to be of high S/N (signal/noise) at the reservoir zone, it should be used for reserves and resources. Inherently, appropriate well data is included and tied to the seismic. The use of partial angle/offset stacks is highly encouraged to demonstrate Amplitude Versus Angle (AVA)/AVO uniqueness between hydrocarbon and brine-bearing reservoir. Seismic gathers at the wellbore(s) should be displayed and compared to offset synthetic seismograms to demonstrate an acceptable signal/noise ratio in the data, if AVO analysis is being used.

Often reserves are being booked on the basis of one or many wells in an area. If 2D seismic is available, it is used to aid in this process, especially where there may only be a test showing capability of production and tie-in (i.e. reserves) but little production data for decline or material balance, etc. 2D seismic is still used to map the pool volumetrically. 3D seismic is not a necessity for reserves booking. A lot of reserves are booked globally on the basis of sparsely tested wells and 2D seismic.

Good seismic-to-well tie and geobody interpretation: Good seismic-to-well tie and extrapolation from well(s) defining anomalous amplitude events/packages with accurate top and base horizon interpretation or sub-volume/sub-element detection and a proper attention to wavelet phasing is necessary.

Evidence for continuous, fault-free reservoir: Seismic amplitude response must be continuous from well control with productive hydrocarbons to area of conformance or 'flat spot'. No discontinuities can exist in the area of amplitude to be booked. Seismic amplitude must reside in the same fault block as well control. No sealing faults may exist from well control to area of conformance or within area to be booked. Updip and/or adjacent fault blocks without well control are not acceptable for booking proved reserves regardless of seismic attributes, and require categorizing those resources appropriately.

Well-based forward modelling meets expectations, fits observations and rock physics: Reliable velocity and density data, and shear wave velocity data if AVO is done, have been acquired in well(s) over the reservoir (or in the same reservoir in adjacent/nearby areas) for both the hydrocarbon and brine zone. Both compressional and shear velocity information is preferred for full offset acoustic/elastic modelling, yet in the absence of shear data, shear wave prediction is acceptable, provided that the predictions are validated in nearby and/or analog fields. Fluid substitution for the brine case may be used if shown to be reliable in the area. Both acoustic/elastic seismic synthetic models and cross-plots based on well control have been generated and confirm the seismic amplitude anomaly, flat spot, and/or AVA/AVO behaviour observed. Reservoirs should exhibit clear uniqueness in both modeled and observed AVA/AVO behaviour between brine and hydrocarbon bearing cases. A reservoir wedge model should be generated demonstrating the vertical resolution achievable with the bandwidth contained in the seismic volume. All reasonable causes for a seismic anomaly should be investigated through

modelling. These causes include: hydrocarbon saturation, low gas saturation (fizz-gas), porosity, lithology, anisotropy, etc.

Conformance of hydrocarbon contacts: Downdip limit of the amplitude anomaly or recognized 'flat spot' reflection conform to depth structural contours. Time contours are not acceptable on their own and should be accompanied by a depth converted contour set at a minimum. Lateral velocity variations should be taken into account or shown to be minimal. Where pressure data (MDT, other) is available in the reservoir zone to be booked, it must be integrated. Acquisition of such data to support seismic is highly encouraged. Reliable high quality pressure gradients acquired in the reservoir zone over the hydrocarbon and brine that support a hydrocarbon-water contact must be consistent with the seismic fluid contact.

Sensitivities and alternate interpretations have been considered: Significant seismic sensitivities (thickness, porosity, anisotropy, lithology, saturations, pressure, temperature, etc.) that might strongly influence the amplitude response should be investigated by modelling possible scenarios. This may be particularly important for the updip definition of the reservoir in the case of a stratigraphic trap.

Endorsement through peer review: The recommendation to book Proved Reserves using seismic has been reviewed and endorsed by a peer review, reserve advisory committee, and/or independent consultants.

Documentation: Geophysical techniques and applications must be well documented showing that all the above criteria have been met. Each map is appropriately labeled, identifying the attribute being displayed along with the location of wells being clearly marked. Scales are displayed on all maps and sections. Seismic sections identify the polarity and vintage of the seismic data being displayed. If analogs are referenced and used as evidence, corresponding analog displays should be included as well.

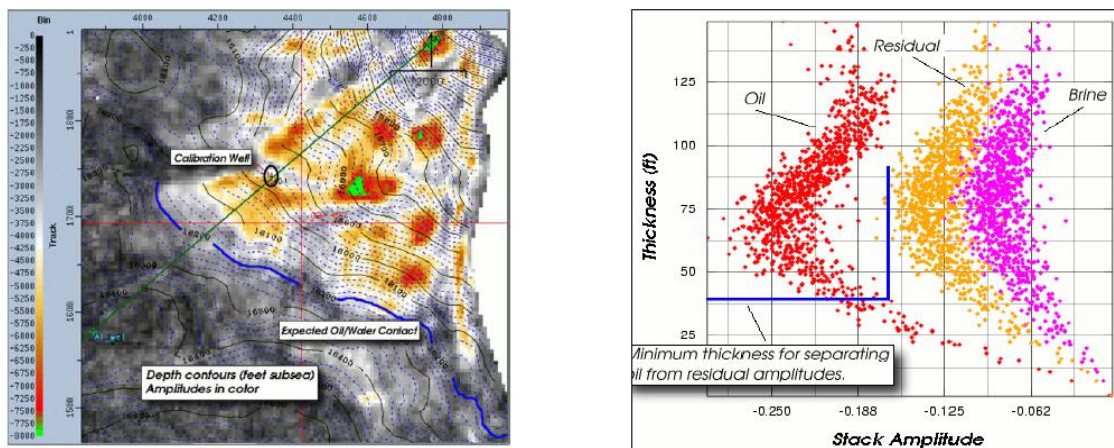


Figure 12. Example of using Seismic Technology to assess fluid contacts.

The field in Figure 12 shows a seismic expression of an apparent oil-water contact in a high quality oil sand. The normalized seismic amplitude map in the figure shows a good fit-to-structure of the amplitude change at the apparent oil-water contact. However, some amplitude variations (blotchy character) are present as well at shallower levels, suggesting variability in the lithology. Key results are shown in the plot on the right in Figure 12. The impact of both reservoir thickness as well as pore-fill on the seismic response can be clearly observed.

It is noted that in many other examples, in which the seismic evidence itself is not as convincing, other data sources (e.g. pressure data, performance data, geologic deposition model) will also

contribute as part of an integrated analysis to achieve comparable confidence of the recoverable volumes below the Lowest Known Hydrocarbons (LKH), as observed in the wells.

When a known hydrocarbon accumulation is being appraised, seismic flat-spots and/or seismic amplitude anomalies can be used to increase confidence in fluid contacts when the following conditions are met:

- The flat-spot and/or seismic amplitude anomaly is clearly visible in the 3D seismic, and not related to imaging issues
- Within a single fault block, well logs, pressure, and well test and/or performance data demonstrate a strong tie between the calculated hydrocarbon/water contact (not necessarily drilled) and the seismic flat-spot and/or downdip edge of the seismic anomaly
- The spatial mapping of the flat-spot and/or downdip edge of the amplitude anomaly within the reservoir fairway fits a structural contour, which usually will be the downdip limit of the accumulation

Seismic amplitude anomalies may also be used to support reservoir and fluid continuity across faulted reservoir provided that the following conditions are met:

- Within the drilled fault block, well logs, pressure, fluid data and test data demonstrate a strong tie between the hydrocarbon-bearing reservoir and the seismic anomaly
- Fault throw is less than reservoir thickness over (part of) the hydrocarbon bearing section across the fault and the fault is not considered to be a major, potentially sealing, fault
- The seismic flat-spot or the seismic anomaly is spatially continuous and at the same depth across the fault

If these conditions are met, the presence of hydrocarbon in the adjacent fault block above the seismic flat-spot or seismic amplitude anomaly may be judged sufficiently robust to qualify the hydrocarbon volumes as within the same known accumulation and thus qualify as reserves. If these conditions are only partially met, the interpreter must consider the increased level of uncertainty inherent in the data and appropriately classify the volumes based on the uncertainty components. Caution should be exercised in assigning reserves and resource classification categories. The levels of risk and uncertainty should be commensurate the quality of the data, velocity uncertainty, repeatability, and quality of supporting data.

When rock/pore-fluid conditions are favourable for detecting hydrocarbon-related seismic anomalies, reservoir properties like porosity or lithology can sometimes be directly estimated through comparisons between a 3D seismic volume and borehole information.

Unpenetrated fault blocks adjacent to drilled/proven fault blocks can be classified as probable reserves if immediately adjacent and structurally higher. Possible reserves may be assigned if the adjacent fault block is structurally lower, but above the lowest known hydrocarbons in the penetrated fault block as long as there is a high confidence level of reservoir continuity across the fault blocks (e.g., regional sheet sand) accordingly in both COGEH and PRMS. If the conditions of the above bullet points are met, the presence of hydrocarbon in the adjacent fault block above the seismic flat spot or seismic amplitude anomaly may be judged sufficiently robust to qualify the hydrocarbon volumes in the undrilled compartment as probable or possible reserves. The SEC has acknowledged that there should be the potential for Probable and Possible reserves both updip and downdip of Proved reserves. Previous SEC guidance indicated updip of Proved is Probable and downdip of Proved is Possible.

4.2 Seismic Inversion

Standard seismic volumes spatially display seismic amplitude in either travel time or depth. Conversion of seismic amplitude data to elastic property volumes of compressional velocity,

shear velocity and density is called seismic inversion. From these inverted volumes, estimates of other rock properties such as acoustic impedance, Poisson's ratio (Figure 13) and Young's modulus (Figures 14 and 15) can be calculated to predict lithology, rock heterogeneities, reservoir continuity, porosity, pore fluids, possibly water saturation and permeability. Seismic anisotropy properties related to lithology, layering, fractures, and stresses are illustrated in Figures 16, 17, and 18. Good quality inverted acoustic impedance volumes convey the same basic information as a conventional seismic stack plus information from a low frequency model that is frequently inferred from well data, and in many cases from the seismic velocities and seismic attributes. This low frequency model is necessary to 'scale' the inverted relative impedances to an absolute impedance-unit. These models provide information below the seismic bandwidth that can allow the inverted attributes to be tied to well data. AVO and joint AVO and azimuthal seismic inversions allow for estimates of many other relevant seismic and reservoir properties in addition to acoustic impedance. Inversion data are displayed in a format that looks like well logs and hence is more familiar to geologists and engineers than seismic traces. Some features in the data may be more obvious or easier to interpret in the inverted format than the conventional format, so there can be value to analyzing the basic seismic information in both formats.

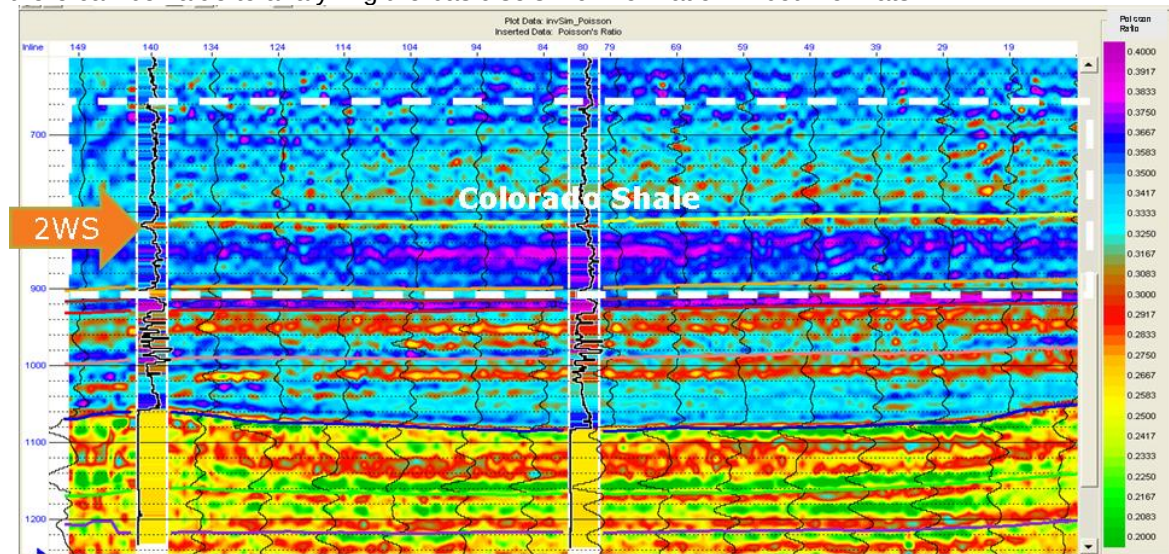


Figure 13. Poisson's ratio estimated from pre-stack AVO inversion of seismic data. The scale is on the right, and inserted traces are the same attribute calculated from well logs. After Gray 2010.

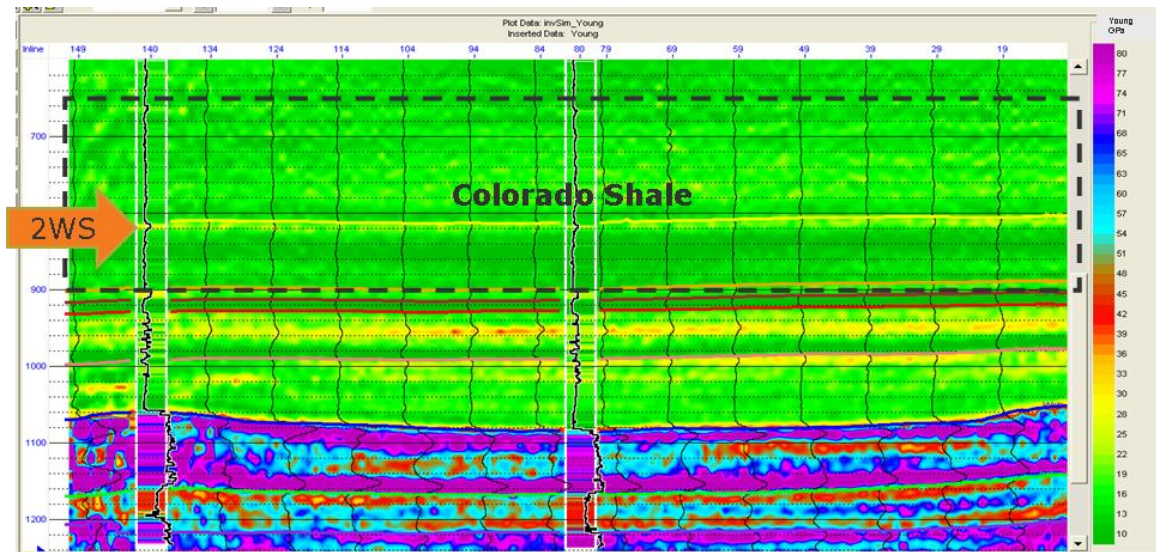


Figure 14. Young's modulus, in GPa, estimated from pre-stack AVO inversion of seismic data. The scale is on the right, and inserted traces are the same attribute calculated from well logs. After Gray 2010.

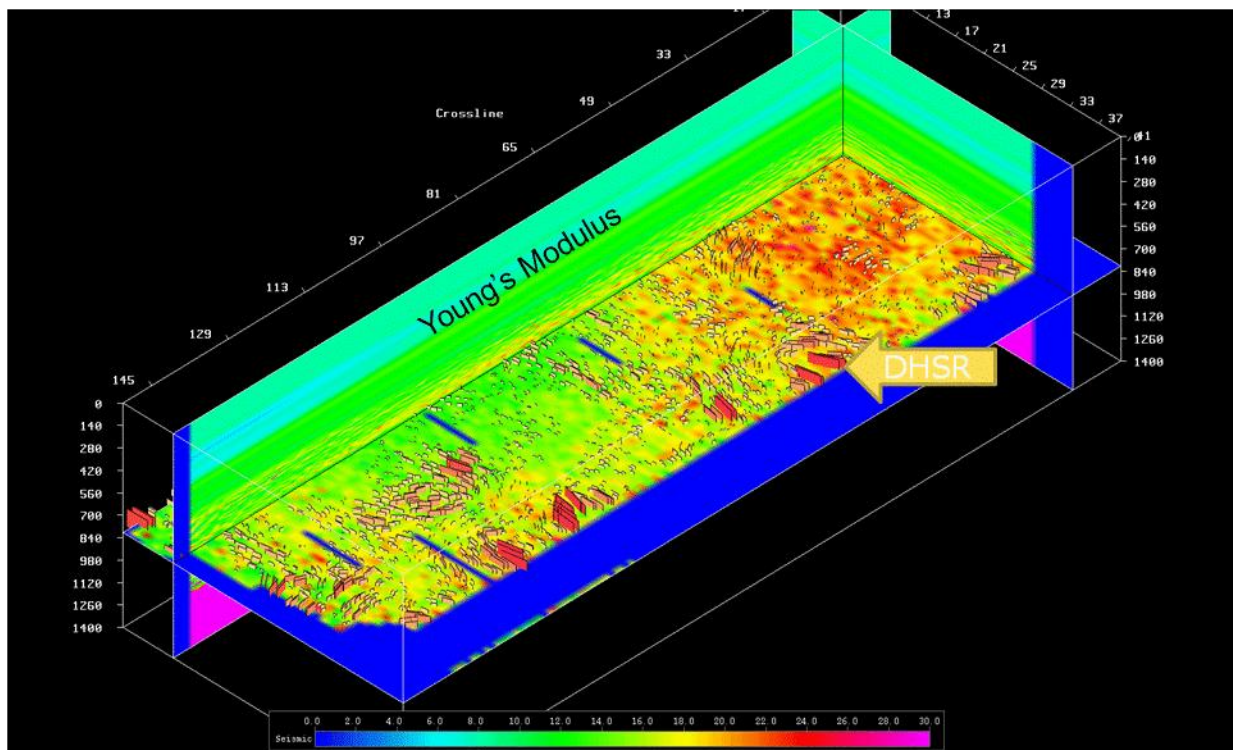


Figure 15. Colour background shows Young's modulus estimated from seismic data, with its scale in GPa at the bottom of the figure, on this 3D seismic volume. 'Plates' (indicated by the arrow) show the difference in horizontal stresses estimated from seismic anisotropy. The size of the plate is proportional to the magnitude of the stress difference, and the direction of the plate indicates the direction of the local maximum horizontal stress. The long axis of the survey is E-W and survey area is 9 km². After Gray 2010.

Acoustic (and shear) impedance is a rock property and is closely related to lithology, porosity, pore fill, and other factors. One often is able to obtain strong relationships between acoustic/shear impedance and these reservoir model properties. However, it is important to appreciate that the computational process of inversion is not completely uniquely determined, but inversion results are within a range of acceptable outcomes, which will assist in constraining the reservoir model properties. For example, in shale gas reservoirs, seismic elastic attributes may be used to predict 'brittleness' (see Figure 18), which is useful for predicting existing and induced natural fracture volumes. Stochastic AVO inversion can provide reasonable ranges for these properties away from well control. It also captures the statistical variability of the inverted parameters better than deterministic inversion. It may, however, be somewhat early to consider it as fully validated reliable technology.

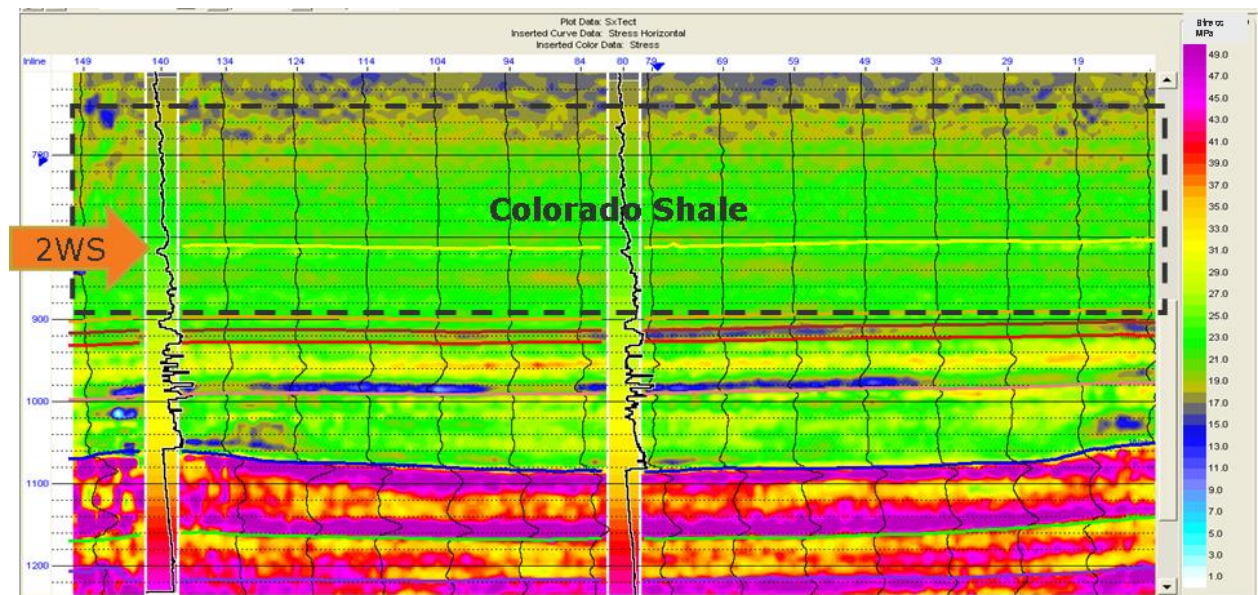


Figure 16. Closure stress estimated from pre-stack azimuthal AVO inversion for density, Poisson's ratio, and normal compliance. The scale is on the right, and inserted traces are the same attribute calculated from well logs. After Gray 2010.

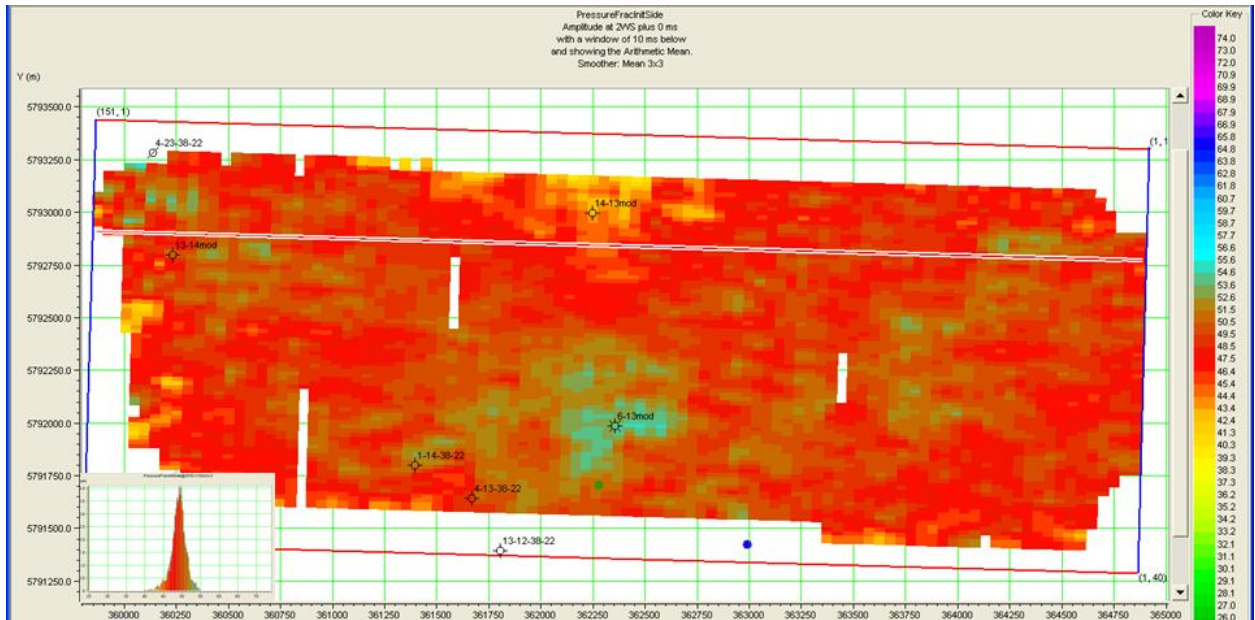


Figure 17. Map of average fracture breakdown pressure that would be encountered at the side of a horizontal borehole in the 2nd White Speckled Shale from central Alberta, Canada. It has been estimated from pre-stack azimuthal AVO inversion of seismic data. Note the significant heterogeneity in its values. The histogram in the lower left shows that over this 9 km² area. The fracture breakdown pressure is from 40-55 MPa. Image courtesy of CGGVeritas.

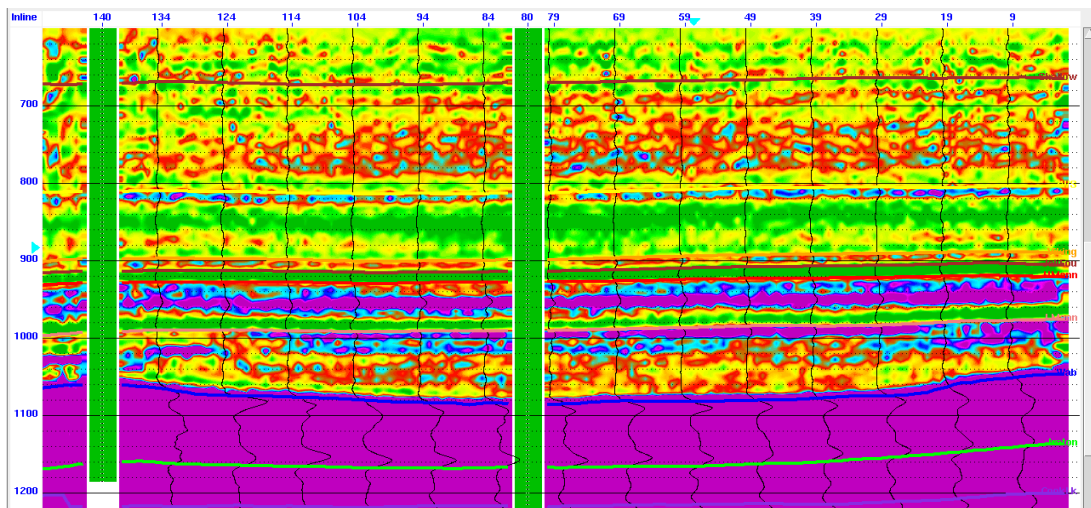


Figure 18. Brittleness (%) estimated from Young's modulus and Poisson's ratio (Gray et al. 2011).

Inversion data can also be of great assistance in resolving unconventional, shale gas or tight gas sand reservoirs. The following example demonstrates one such workflow for unconventional reservoirs.

Unconventional Reservoir Workflows (modified from Close, David I., Simon Stirling, David Cho, Frederik Horn, 2010, An Integrated Workflow for Shale Gas in the Western Canadian Sedimentary Basin: Surface Seismic to Stimulation: Search and Discovery #40569).

Exploration and drilling for natural gas in North America has moved radically away from conventional reservoirs to focus on unconventional reservoirs such as tight gas sands and

shales. These reservoirs have low porosity and near zero permeability with gas stored in natural fractures and within the matrix porosity. Economic gas production requires hydraulic fracture stimulation to open connections to existing natural fractures or matrix porosity and successful stimulation is dependent on the formation's geo-mechanical brittleness capable of supporting extensive induced fractures. However, despite adequate stimulation, significant variations exist between wells in expected ultimate recovery (EUR), due to the heterogeneity of these Resource Plays. Consequently, predicting natural fractures or fracture prone "sweet spots" is essential to optimize development of such plays.

Integrated workflows for shale reservoirs have received increased attention following the step changes achieved in operational efficiency over the last decade. A crucial link in the workflow is analysis and inversion of pre-stack seismic data. An increasing number of major leaseholders are exploiting the Barnett, Haynesville, Eagle Ford, Bakken, Horn River and Montney in addition to other plays in North America and worldwide utilizing pre-stack amplitude variation with offset (AVO) inversion and converted-wave seismic data to assist in well placement and field development planning.

It is known from well log analysis that the ratio of compressional to shear sonic velocities (V_p/V_s), or equivalently Poisson's ratio, is a good indicator of sand-shale or quartz-clay ratios in shales and/or tight siltstones.

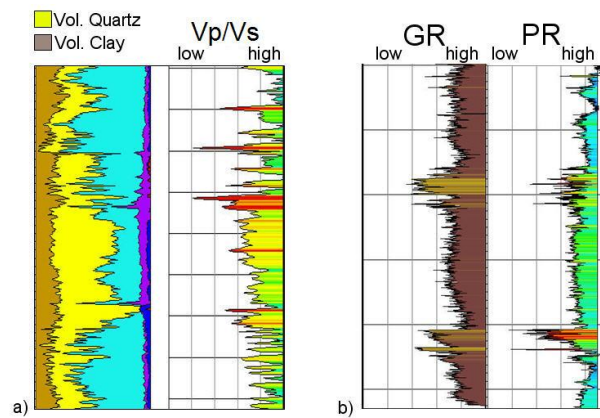


Figure 19. Qualitatively and empirically, an increased sand-shale ratio correlates to increased porosity, lower breakdown pressures for stimulation, and enhanced relative production (Miller et al., 2007).

AVO inversion of 3D seismic data allows for the creation of V_p/V_s and Poisson's ratio volumes and maps of the reservoir interval that can be utilized for exploration and field development, which reflect the reservoir quality based broadly on the sand-shale ratio. Inversion data and other attributes derived from pre- or post-stack seismic data require corroboration from independent sources to confirm its utility. Data that can provide such calibration for these seismic based properties includes log data, micro-imaging data, production log data, production data, and micro-seismic monitoring data.

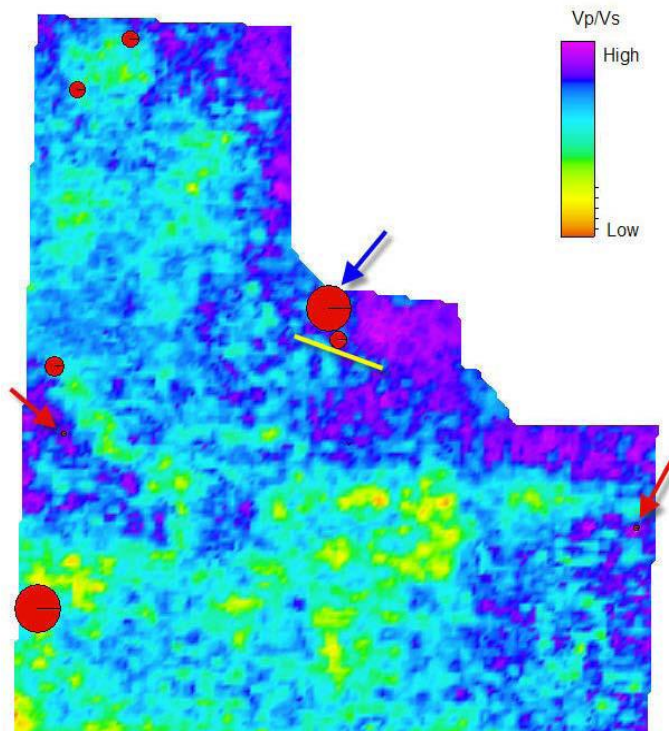


Figure 20. Map of median Vp/Vs ratio and porosity-height from 8 wells through the Lower Doig and Upper Montney. The red arrows highlight wells with very small porosity-height values and correspond in general to areas of higher Vp/Vs ratio. The blue arrow highlights a well with a large porosity-height at the edge of the seismic data where the inversion is adversely affected by decreased fold. The yellow line is the approximate location of a horizontal well where microseismic data were recorded.

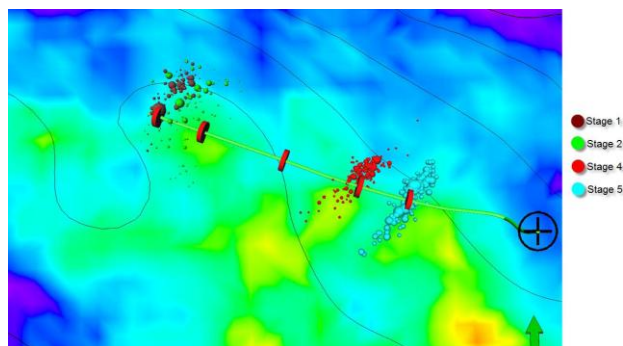


Figure 21. Microseismic monitoring data overlain with a Vp/Vs ratio map from AVO inversion. Fracture stimulation ports (frac ports) are located as red disks along the lateral. The microseismic events seem to favour areas of lower Vp/Vs ratio.

Figure 22 show the relationship of anisotropy as seen in core to seismic scale. Prediction of natural fractures from seismic is essential to optimize development of fractured or stressed reservoir plays and to aid in estimation of EUR (estimated ultimate recovery).

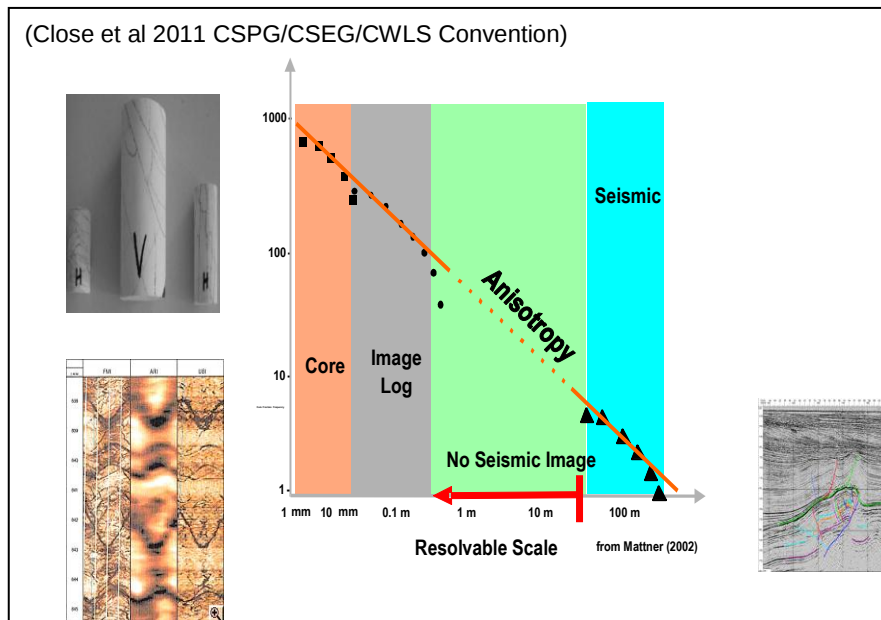


Figure 22. For fractured reservoirs and reservoirs under stress, seismic anisotropy attains some of the scales between the seismic and log resolutions for these properties. (After Close et al, 2011).

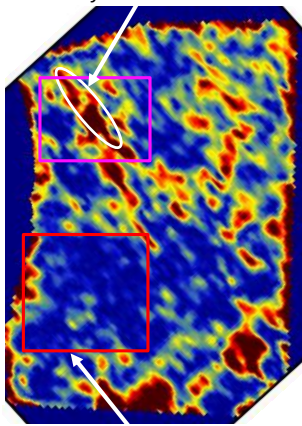


Figure 23. Low stress anisotropy estimated from 3D azimuthal AVO (Gray et al, 2010) indicates the significantly better production in the South (red) shale gas pad compared to the high stress anisotropy indicating poorer performance in the North (pink) pad. (After Close et al, 2011).

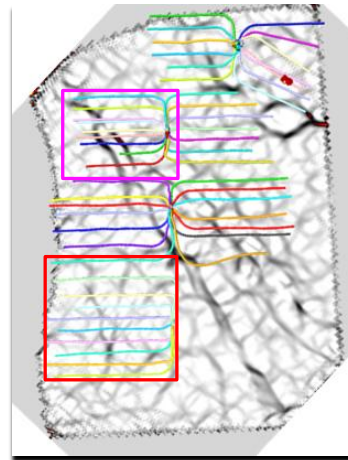


Figure 24. Edge detection is ambiguous in predicting the very different production performance between shale gas pads in the North (pink) and South (red) (After Close et al, 2011).

In shale plays, better production performance is expected where hydraulic fracturing creates a fracture network. This is far more likely in areas of low differential horizontal stress than in areas of high differential horizontal stress. When the maximum horizontal stress is much greater than the minimum horizontal stress, open fractures will tend to form parallel to the maximum stress, restricting the ability to create cross-cutting fractures. Therefore, areas of low differential horizontal stress should produce better than areas where it is high. Figures 23 and 24 shows an example from the Western Canadian Sedimentary Basin where this has occurred. In Figure 24,

the southern pad, highlighted by the red square, shows low differential horizontal stress and produces strongly. The northern pad, highlighted by the pink square, shows significant differential horizontal stress and produces less. Furthermore, these two areas do not show significant differences in the amount of faulting indicated by the edge detection shown in Figure 24 as compared to Figure 23, so identification of seismic-scale faults alone is insufficient to indicate the production.

Below is another example of using stochastic inversion.

(adapted from Contreras, A., C. Torres-Verdin, K. Kvien, T. Fasnacht, and W. Chesters, 2005, AVA Simultaneous Stochastic Inversion: EAGE 67th Conference & Exhibition, Paper T-15. accessed at http://www.fugro-jason.com/readingroom/techpapers/Paper_EAGE-2005-Final.pdf)

The following application of stochastic inversion to support a field development plan is discussed and compared to a deterministic inversion result.

Four 3D partial angle stacks were simultaneously inverted with well logs using a stochastic inversion technique based on the Markov Chain Monte Carlo (MCMC) method [reference 1]. This inversion combines the Gauss random field conceptual model underlying traditional geostatistics with iterative local updates inherent to nonlinear optimization. In stochastic inversion a stratigraphic/structural framework is defined to build a 1-ms micro-layering to be enforced by the inversion results. Input data consisted of: (1) four partial angle stacks and angle-dependent wavelets for the following angle ranges: (6-16), (16-26), (26-36), and (36-46) degrees; (2) lithotype, P-Velocity, S-Velocity, and density logs, and (3) well-log generated geostatistical information in the form of variograms and lithotype-dependent 3D joint PDFs of the acoustic properties to be inverted (P-Velocity, S-Velocity, and density).

Figure 25 shows the results of the AVA stochastic inversion, consisting of high-resolution (1 ms) 3D distributions of lithotype (sand/shale), P-Velocity, S-Velocity, and density. Figure 26 is a comparison between the high-resolution stochastically derived acoustic impedance (sampled at 1ms) and deterministic inversion results generated using a constrained sparse spike inversion (CSSI) algorithm (sampled at 4 ms).

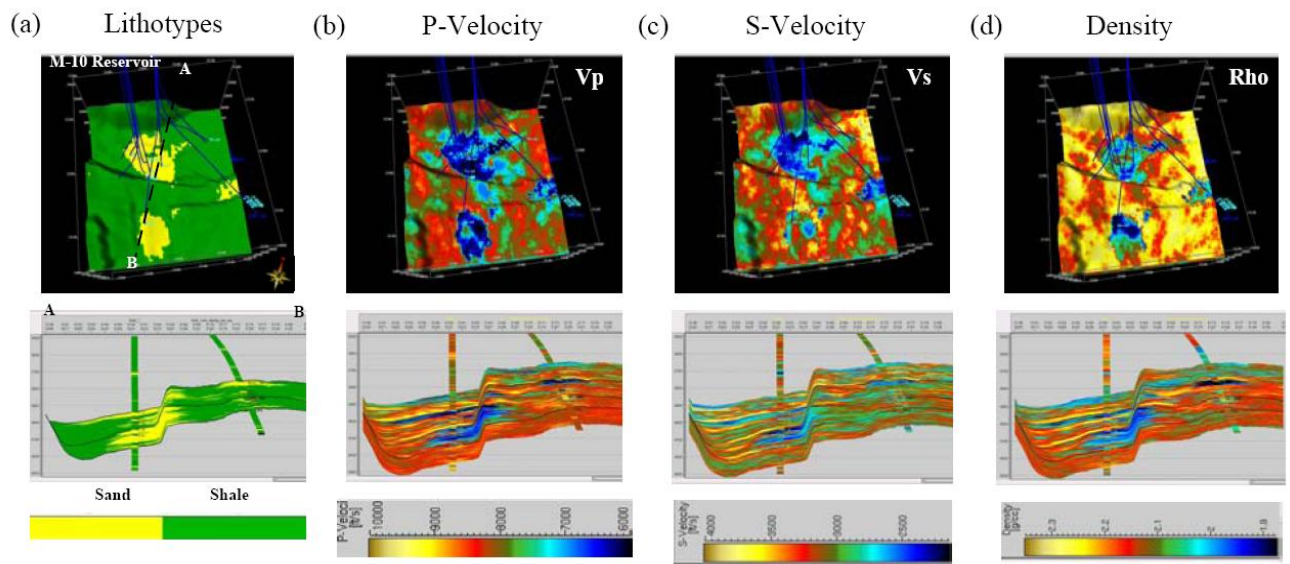


Figure 25. AVA stochastic inversion results: (a) Lithotypes (sand/shale); (b) P-Velocity; (c) S-Velocity; (d) Density. The spatial coverage is approximately 4 km², and the vertical interval: 3500-4300 ms.

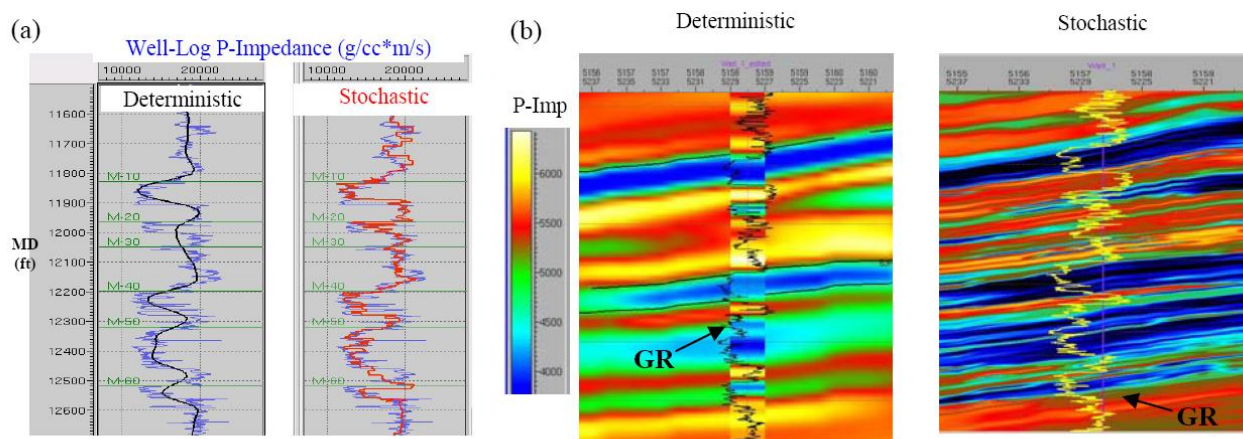


Figure 26. Deterministic versus stochastic inversion results: (a) inverted P-impedance pseudo logs extracted at a well location; (b) inverted P-impedance cross-sections. Deterministic results are sampled at 4 ms whereas stochastic inversion results are sampled at 1 ms. Vertical interval: 3800-4300 ms.

Co-Simulation of Petrophysical Properties

Finally, 3D spatial distributions of petrophysical properties (porosity, permeability, and water saturation) were constructed via co-simulation of the AVA stochastic inversion results using multivariate statistics. Figure 27 (a) is an example of the layer- and lithotype-dependent multidimensional joint probability distributions of acoustic and petrophysical properties used for co-simulation. The use of multivariate statistics to relate acoustic and petrophysical properties such as P-Velocity, S-Velocity, density, porosity, permeability, and water saturation, allows the construction of accurate 3D distributions of petrophysical properties, especially when compared to similar distributions constructed with empirical linear relationships and/or cloud transforms.

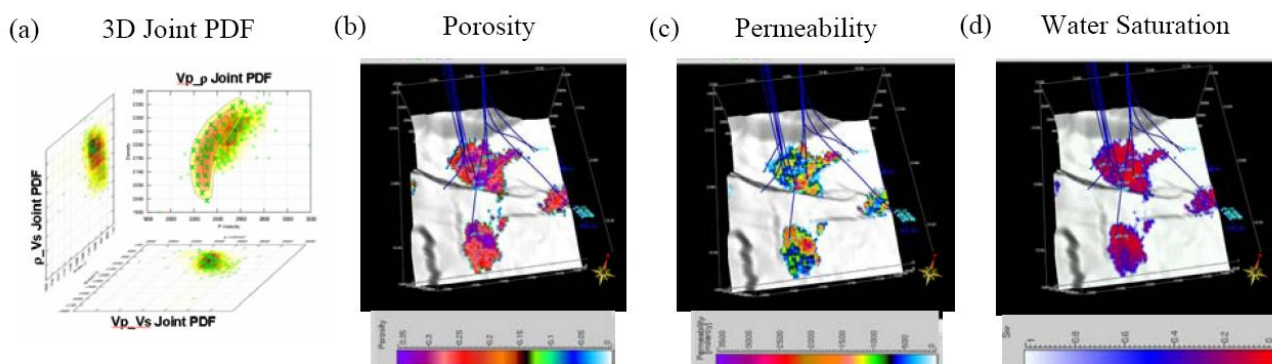


Figure 27. (a) 3D joint PDF of acoustic properties (six properties were used for co-simulation: P-Velocity, S-Velocity, density, porosity, permeability, and water saturation); (b), (c), and (d) Co-simulated porosity, permeability, and water saturation, respectively, for M-10 reservoir.

Conclusions

Standard AVA analysis indicates that the shale/sand interface at the top of the M-series reservoirs generates significant AVA anomalies. On the other hand, Biot-Gassmann fluid substitution indicates that presence of low density pore fluids clearly affects the elastic response of sands. Accordingly, joint stochastic inversion of pre-stack seismic and well-log data provides quantitative information about the spatial continuity of reservoir units and of their pore fluids. Pre-stack stochastic inversion provides more realistic and higher vertical resolution results than those obtained with analogous deterministic techniques. Furthermore, 3D petrophysical models

can be more accurately co-simulated from AVA stochastic inversion results. By combining geologic information with AVA sensitivity analysis techniques and pre-stack stochastic inversion, it is possible to substantially reduce development risk associated with non-conventional reservoirs.

5. Uncertainty in Geophysical Predictions

Like most predictions in the physical sciences, predictions from 3D seismic data and other geophysical data – whether about trap geometry, rock/fluid properties, or fluid flow – have an inherent uncertainty. The accuracy of a given seismic prediction is fundamentally dependent on the quality of the seismic data (bandwidth, frequency content, signal-to-noise ratio, noise type, and processing), the uncertainty and variability in the rock and fluid properties measured and implied, in addition to the quality of the seismic model used to tie subsurface control to the 3D seismic volume. A seismic model that accurately predicts a subsurface parameter or process as judged by drilling results from new wells has demonstrated an ability to reduce uncertainty that can be quantified after several successful predictions. Such an integrated reservoir model is far more valuable than an untested reservoir model or method, even though the latter may be more sophisticated. See Figure 28.

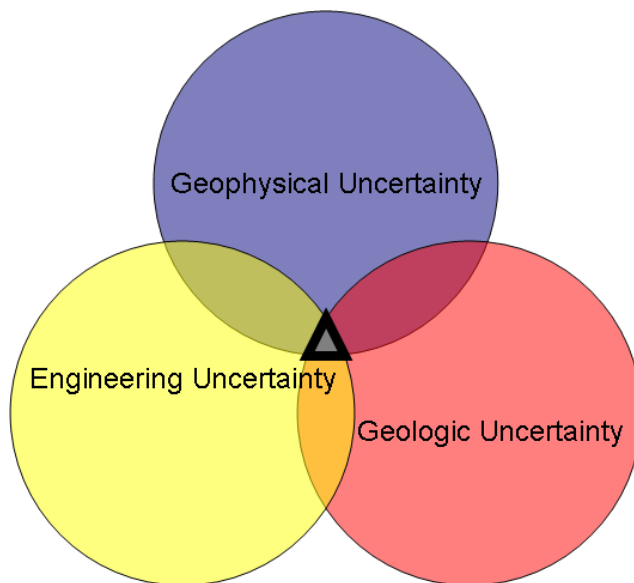


Figure 28. Combining different, independent information has the potential to significantly reduce the range of uncertainties. Adding geophysical information to geologic and engineering data has the potential to narrow down the possibilities to a much smaller range.

Since seismic inversion results are non-unique, a stochastic approach can be followed to capture the full range of possible and acceptable inversion outcomes. The probabilities of the various outcomes can then subsequently be used as input to reserves and resource volume assessments. An example of the estimation of low, mid, and high net sand thicknesses from stochastic inversion results is given below.

The net sand maps in Figure 29 illustrate the probabilistic output from the inversion package for low, mid, and high cases. Each map fits the well data used to constrain the model. The three net sand maps reflect the uncertainty in the net sand distribution and can be used to constrain three different “oil-in-place” scenarios in low, mid and high case static models that can be carried through to reservoir simulation and are thus key input to the resource volume assessment and classification.

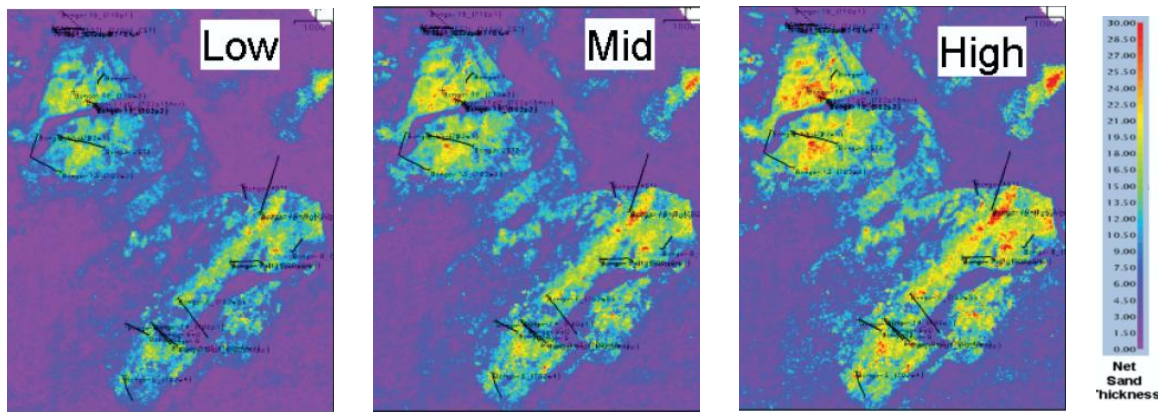


Figure 29. Model-based, stochastic seismic inversion provides low, mid, and high scenarios for net sand distribution, which is the main driver for variation in oil-in-place estimates.

Quantifying Seismic Attributes/Maps

One method to help make a seismic attribute or analysis more quantitative is to cross plot the key seismic attribute against the related reservoir parameter determined from open hole logs, core analysis, and/or testing (Figures 30, 31, and 32). The distribution of real data points relative to the trend line in the cross plot trend line yields a range of uncertainty.

Another method to quantify seismic data is through the application of stochastic inversion. Stochastic inversion generates many realizations of the reservoir and surrounding rock properties that affect the seismic response, such that there is a high probability that the distribution of these realizations will cover the possible reservoir properties. Statistical analyses of these distributions provide a means of assessing the range of reservoir uncertainty.

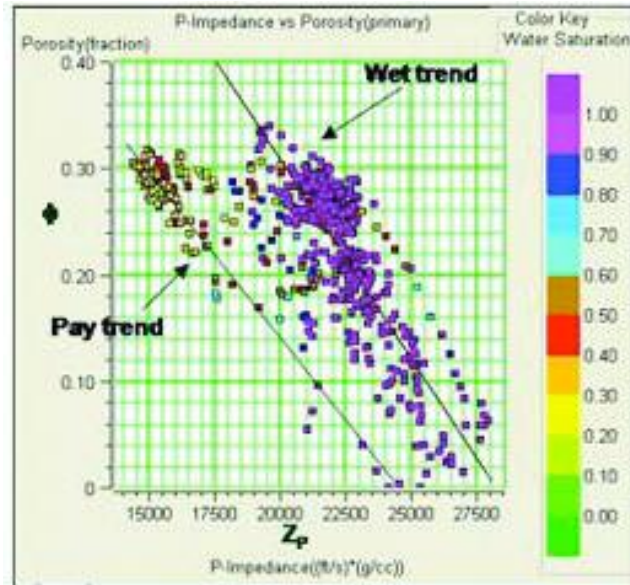


Figure 30. A cross-plot of porosity (from wells) versus P-impedance used to predict porosity from the P-impedance volume. The distance of actual values away from the trend lines gives an estimate of the uncertainty of this prediction (from “An Inversion Primer” by Brian Russell, Dan Hampson and Bradley Bankhead in CSEG Recorder 2006 Special Edition).

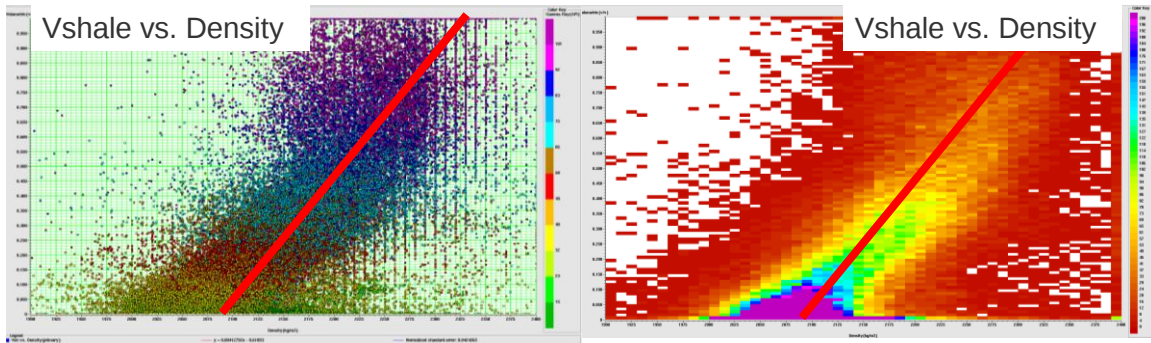


Figure 31. Crossplot of volume of shale (VSH) versus bulk density (RHOB) for McMurray oilsands in the Athabasca area of Alberta, Canada (left) and a density plot showing the count of data falling in each bin (right). A trend line follows the most densely populated areas of the crossplot. The distribution of points around the trend line, as determined from the density plot, can be used as an indication of the uncertainty of this prediction. Here a normal distribution with a standard deviation of 0.05 would appear to adequately describe the uncertainty in the prediction of Vsh from bulk density.

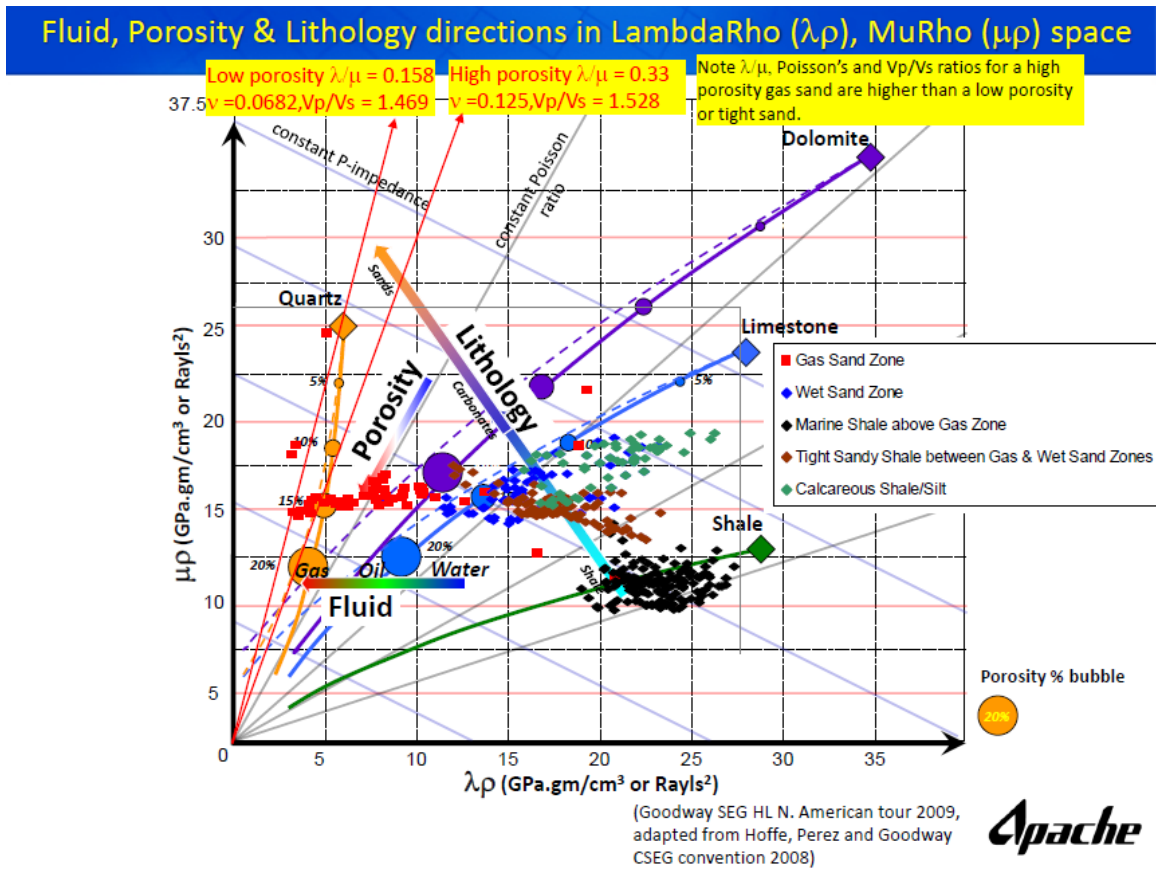
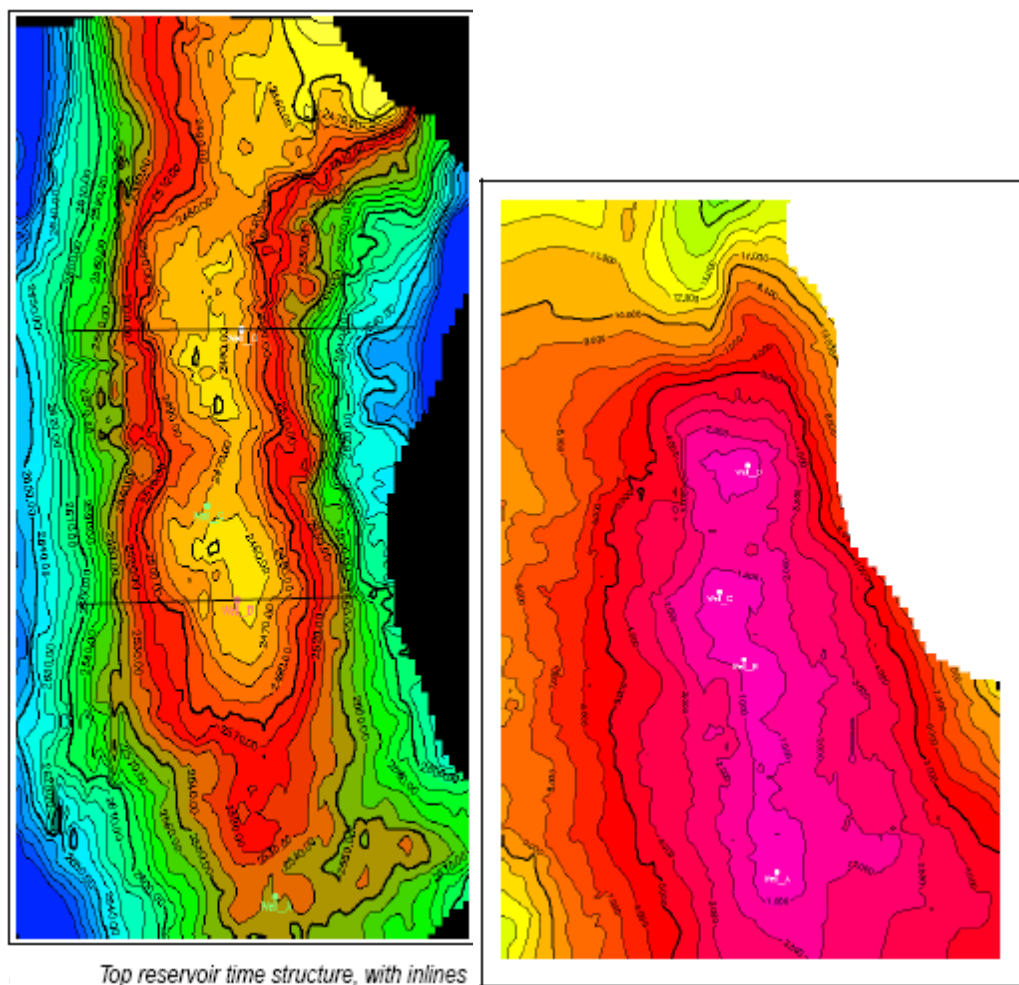


Figure 32. Cross plot calculated from well data and/or pre-stack seismic inversion of LambdaRho (low LambdaRho is gas indicator; high LambdaRho is water indicator) and MuRho (rock fabric or lithology) – an example from the Western Canadian Sedimentary Basin used to discriminate lithology and porosity variations.

Another method to make a seismic analysis or workflow more quantitative is to perform a so-called *drop out* or *cross-validation analysis* if the hydrocarbon pool contains multiple wells (Figure 33). The process involves systematically dropping out successive wells from the seismic workflow, re-calculating the seismic attribute with the remaining wells, then comparing the seismic prediction against the dropped well. This process yields an uncertainty value for the seismic reservoir attribute (usually in map form) against the well control.



standard deviation (right) of the Top Reservoir depth structure.

Figure 33. An example from “Using cross-validation to improve depth conversion – a West Africa example” by Nick Crabtree 2004 CSEG National convention extended abstracts. The first figure is a top reservoir time structure map produced from seismic while the second figure represents the standard deviation of error at the top reservoir after depth conversion and cross validation of the depth conversion transform.

It is useful to assess the track record of a given 3D seismic volume in predicting subsurface parameters at new well locations before drilling. The predictive record is the best indicator of the degree of confidence with which one can employ the seismic to estimate reserves and resources as exploration and development proceeds in an area.

This is a general quantification of the uncertainty in using 3D seismic to estimate reserves and resources. Specific cases should be analyzed individually with the geophysical team member to determine if a project’s seismic accuracy is better or worse than this general quantification.

6. Time Lapse: Geomodelling Inputs to Reservoir Simulations

Another general application of 3D seismic analysis is monitoring changes in pore-space composition, pressure, and temperature with fluid movement in the reservoir. This application is often called time-lapse seismic or, more commonly as 4D seismic, where the 4th dimension is time between the surveys. Flow surveillance is possible if one:

- Acquires a baseline seismic data set at a point in calendar time
- Allows fluid flow to occur through production and/or injection with attendant pressure/temperature/saturation changes
- Acquires at least one more 3D seismic data set some time after the baseline
- Observes differences between the seismic character of the two data sets in the reservoir interval
- Demonstrates through seismic modelling and/or rock and fluid physics based on a relevant set of well log data that the differences are the result of physical changes related to the hydrocarbon recovery process

One must be careful not to vary seismic acquisition and processing parameters drastically between surveys and thereby introduce differences between the seismic data sets that can be mistaken for reservoir effects. Pre-stack interpolation has been used to mitigate these effects. One expects that the seismic character of horizons laterally distant from the affected reservoir would be virtually identical between the seismic data sets because background geology would be much less affected by production/injection than the reservoir interval. Hence, observing the difference between the data sets highlights changes caused by depletion/injection in the reservoir interval. Frequently, there is stress arching above and below the reservoir as a result of production effects. Care must be taken to maintain these effects in the 4D analysis. One can acquire additional seismic surveys in the same locations and continue the surveillance by comparing successive data sets to one another.

Seismic responses to production usually take a limited number of forms, for example: amplitude changes between surveys, travel-time differences between surveys, and anisotropy differences between surveys. These differences can be caused by a variety of possible causes depending on the particular reservoir and the way that it is produced. Possible causes of the seismic differences are changes in: saturations, pressure, the local stress regime due to production, fracturing of the reservoir and/or surrounding rock, reservoir temperature, hydrocarbon viscosity, etc. Often, more than one of these affects the 4D seismic response. Care must be taken to attribute different portions of the seismic response to the appropriate reservoir changes. For example, in some reservoirs, certain AVO attributes have been shown to distinguish between saturation changes and pressure changes.

Time-lapse seismology impacts estimation of reserves when an extraction procedure changes a reservoir's properties sufficiently so that a robust response occurs in the seismic data. For example, gas injection to pressurize or flood a reservoir produces an expanding seismic amplitude anomaly around the injection well, owing to the same rock physics that causes naturally occurring gas zones to appear as bright seismic amplitude anomalies. In this case, the expansion of the seismic bright spot is directly measurable on successive 3D volumes and clearly shows the movement of the front of the injected gas. Observing where the gas does not flow (i.e., where no seismic amplitude changes) highlights areas of the reservoir that are not being swept by the gas injection.

As a second example, bypassed oil reserves can be spotted on time-lapse seismic when a compartment (fault block or other discrete component of the trap) is unaffected by a drop in reservoir pressure below bubble point (i.e., there is no indication on the seismic of gas coming out of solution in that particular compartment at the time in the field's production life when overall field pressure is dropping below bubble point). When employed in this manner, time-lapse seismic identifies isolated pools that previously were believed to be part of the field's connected pool or pools.

As a third example, direct detection of the original versus current depth of the oil/water contact (OWC) in a producing field is easier on time-lapse seismic data set than on a single data set because changes of saturation in the interval swept by the water can noticeably alter the acoustic

impedance of this part of the reservoir. This impedance change can be detected by time-lapse seismic comparisons. An example of this is given in Figure 34.

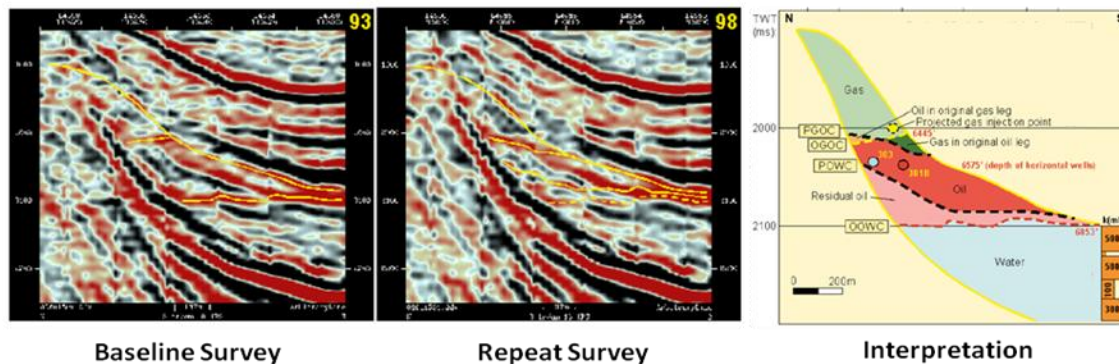


Figure 34. Example of using time-lapse seismic to assess OWC movement.

These OWC-changes as derived from the time-lapse seismic results can then subsequently be mapped out laterally and used to update the static and dynamic reservoir models that underpin the resources and reserves volume estimate.

In general, the seismic tool is useful in a time-lapse mode as a check on the validity of the assumptions in a reservoir simulation of fluid flow. Because seismic monitoring is more spatially specific than pressure monitoring, estimation and extraction of reserves can be optimized over time by using the seismic to guide detailed simulations of depletion and to resolve contradictions between the seismic and the reservoir model. In general, the incorporation of time-lapse seismic results prompt model updates that usually improve production history matches.

An example to illustrate this is presented in Figure 35. In this case, time lapse seismic results revealed an area in the west of the F block without 4D sweep (Figure 35, left panel), different to what was expected. New spectrally boosted 3D seismic (Figure 35, centre panel) shows evidence for a normal fault cutting the F block into separate blocks. The 3D horizon (Figure 35, right panel) shows that the downthrown block corresponds to the same area seen to be unswept on the time lapse seismic (left panel).

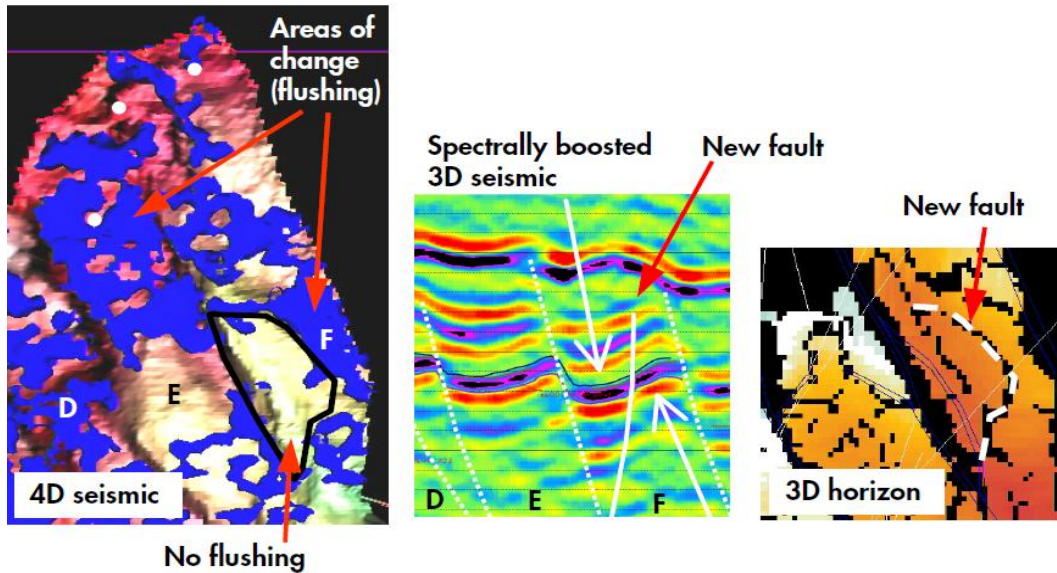


Figure 35. Time-lapse seismic results indicate the presence of a sealing fault.

The new fault was incorporated in the model update, from which a good quality history match was obtained by adjusting fault seal properties (see Figure 36).

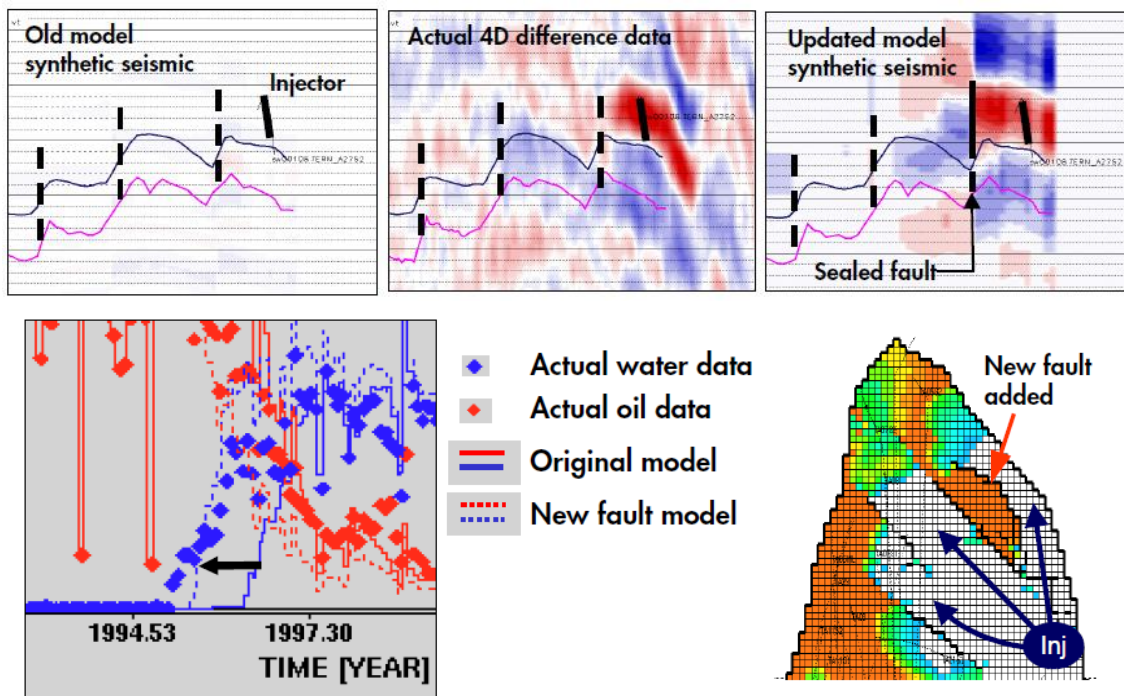


Figure 36. (top panel) Modeled 4D seismic difference based on original model (left). Actual 4D seismic difference (center). Modeled 4D seismic after incorporating new fault (right). Note the improvement in the match to the actual 4D seismic difference.

(bottom panel) Integration of time-lapse seismic results into Reservoir Simulation.

Simulated production data from the northern EF blocks prior to the time-lapse seismic results (Figure 36, left panel – solid lines) show a much later water breakthrough, as compared to actual production data (Figure 36, lower left panel – diamonds). After adding the new fault to the model, resulting in the bypassing of the block (Figure 36, right panel), the water breakthrough timing is greatly improved (Figure 36, upper left panel – dotted lines). As a result of incorporating the time-lapse seismic results, the bypassed volumes in the SW part of block F will have to be reclassified from developed reserves into contingent resources until further development activities are in place.

Below are two examples from a heavy oil reservoir and a carbonate reservoir on 4D monitoring.

Byerley, G., G. Barham, T. Tomberlin and B. Vandal, 2009, 4D seismic monitoring applied to SAGD operations at Surmont, Alberta, Canada: SEG Expanded abstracts 28

Surmont is a heavy oil field located in northeast Alberta which is currently being developed by a joint venture between ConocoPhillips and Total. The estimated oil in place over the Surmont lease is approximately 20 billion barrels of bitumen located approximately 400 meters below the surface. Steam Assisted Gravity Drainage (SAGD) is the in-situ thermal recovery method being used to develop the field. This method utilizes a pattern of horizontal well pairs that continually inject steam into the reservoir to mobilize the heavy oil so it can be produced to surface.

The acoustic properties of heavy oil sands exhibit a strong response to temperature changes resulting in a significant velocity decrease through zones in the reservoir which have been thermally altered by the SAGD process. This unique response makes it possible to utilize time lapse seismic methods to monitor the thermal evolution of the steam over time. Highly repeatable 4D seismic surveys have been acquired at Surmont over six month intervals since commercial production began in 2007.

Figures 37-40 are examples from this presentation illustrating the value of integrating seismic, geology and production data.

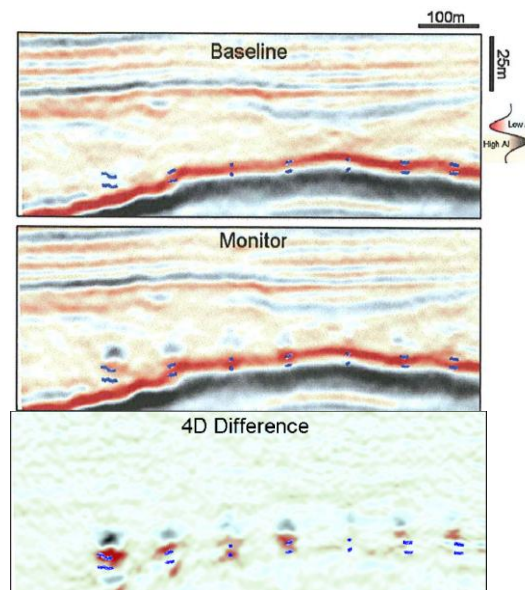


Figure 37. Cross-section through SAGD well pairs showing baseline volume (top), 1st monitor survey after warping (middle) and 4D difference volume following 6-12 months of SAGD production (bottom). The location of the SAGD well pairs are shown in blue.

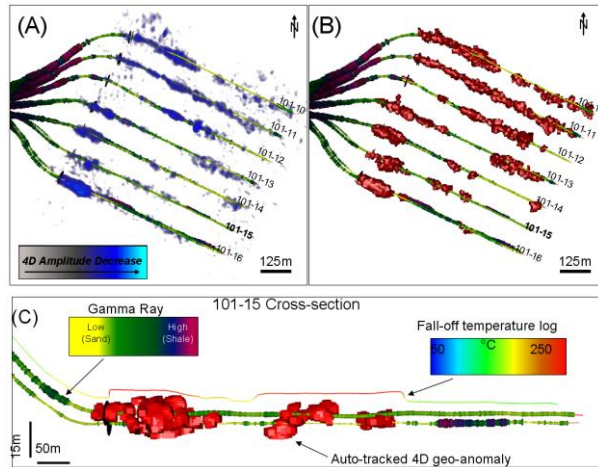


Figure 38. (A) Map view of 4D amplitude differences using an opacity cut-off. (B) Map view of auto-tracked 4D geo-anomalies. (C) Vertical cross-section along 101-15 showing 3D view of the 4D geo-anomaly compared to the temperature log acquired in the injector.

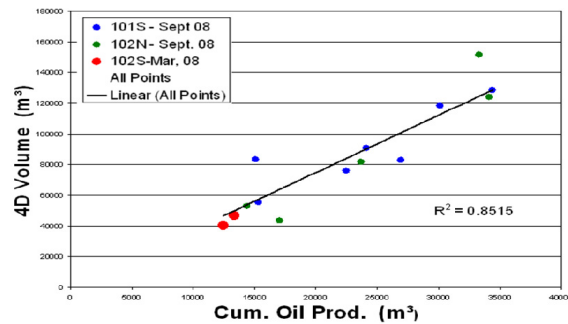


Figure 39. Crossplot of 4D geo-anomaly volume and cum. oil production (each point represents a single well pair).

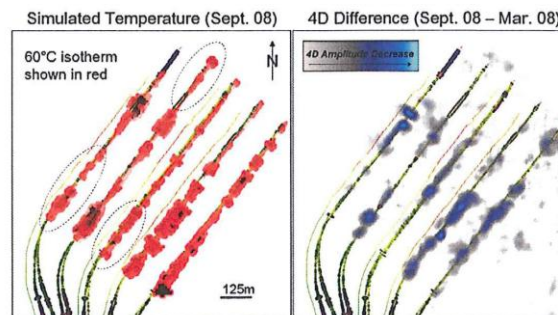


Figure 40. Comparison between 3D STARS simulation (left) and 4D amplitude differences (right). The black circles identify mismatches between the 4D field measurements and the simulated results which are the focus of ongoing history matching efforts.

Pendrigh, N.M., 2004, Core analysis and correlation to seismic attributes, Weyburn Midale Pool, southeastern Saskatchewan, Summary of Investigations, Volume 1: Saskatchewan Geological Survey, Sask. Industry Resources, Misc. Rep. 2004-4.1.

The Weyburn Unit is an oil pool in Saskatchewan reservoirized in carbonates of Mississippian age. The total unit Field Size is 70 sq. miles with OOIP of 1.4 billion bbls and 350MMbbl of oil recovered. The Reservoir Characterization Project at the Colorado School of Mines has acquired multi-component time-lapse data over a small portion the Weyburn Midale Pool to monitor the CO2 flood for enhanced recovery. Using the time-lapse data, geophysically rendered maps of the pool have been created. Although specific attributes aid in the interpretation of certain shapes or anomalies that may be associated with the CO2 injection, particular questions about the geology remain unanswered.

The contact between the Midale Marly and the Midale Vuggy (lower reservoir unit) may have been an exposure surface, which now has drastically different porosity and permeability values that prevent fluid from flowing from one zone to another.

Preliminary analysis of selected seismic attributes allows for several possible geological interpretations. For example, analysis of seismically rendered p-wave amplitudes may show a correlation to differences in reservoir quality rocks within the Marly zone; an interval of thinly interbedded limestone and dolostone at one well and a 6.1 m (20 ft) thick layer of massive, bioturbated skeletal dolostone at another well are situated in areas with different p-wave amplitude anomalies. Also, change in p-wave acoustic impedance maps indicates that the injected CO2 is not entering the Marly, but is finding a pathway, possibly through vertical fractures, that allows fluids to migrate downwards in to the underlying Frobisher Beds, a process which may account for oil staining seen below the Frobisher contact. This oil staining is evidence that no basal seal is present at that well.

To integrate geology and geophysics, rock properties known at each well location can be cross-plotted with seismic attributes. If linear trends are produced, a direct relationship between the geology and the specific attribute is inferred.

Some examples are shown in Figures 41-44 from this Weyburn Midale Pool example.

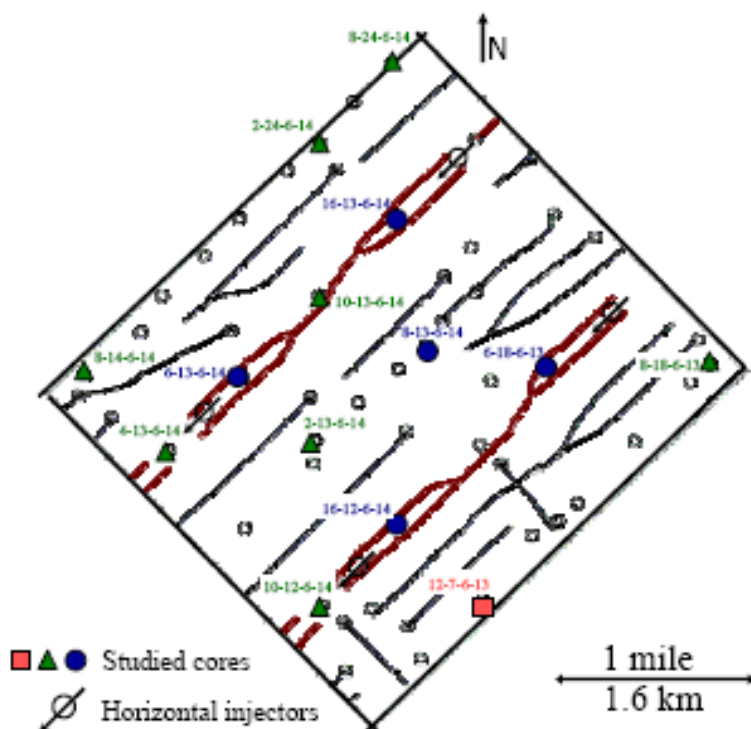


Figure 41. Plan view of the wells in the RCP Study Area, Weyburn Midale Pool. Note the location of the horizontal CO₂ injectors.

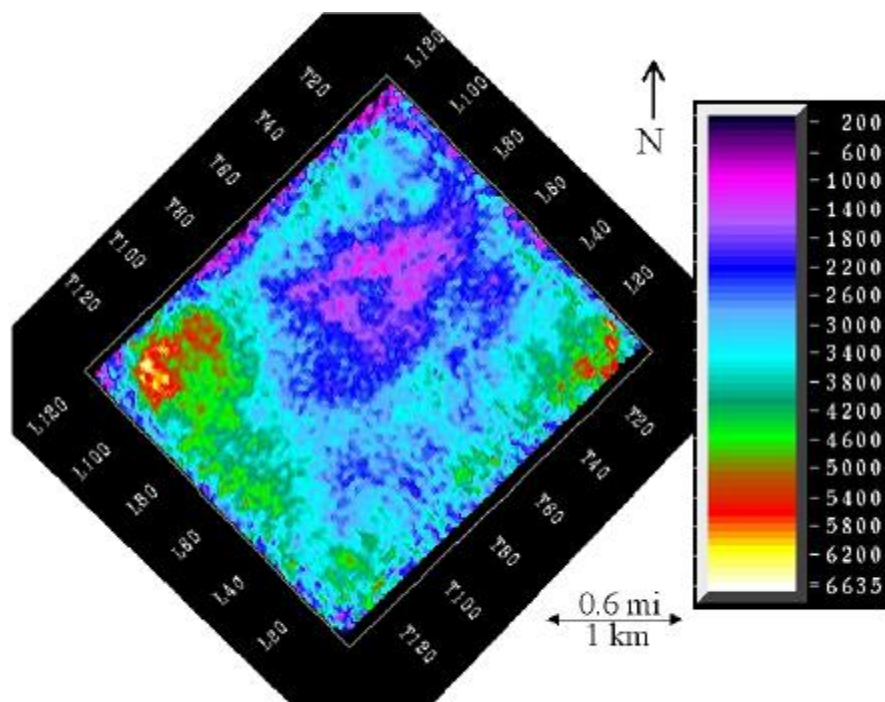


Figure 42. P-wave amplitude map over the study area, at the Midale level. Note the low amplitude in the center and the higher amplitudes to the west south and east.

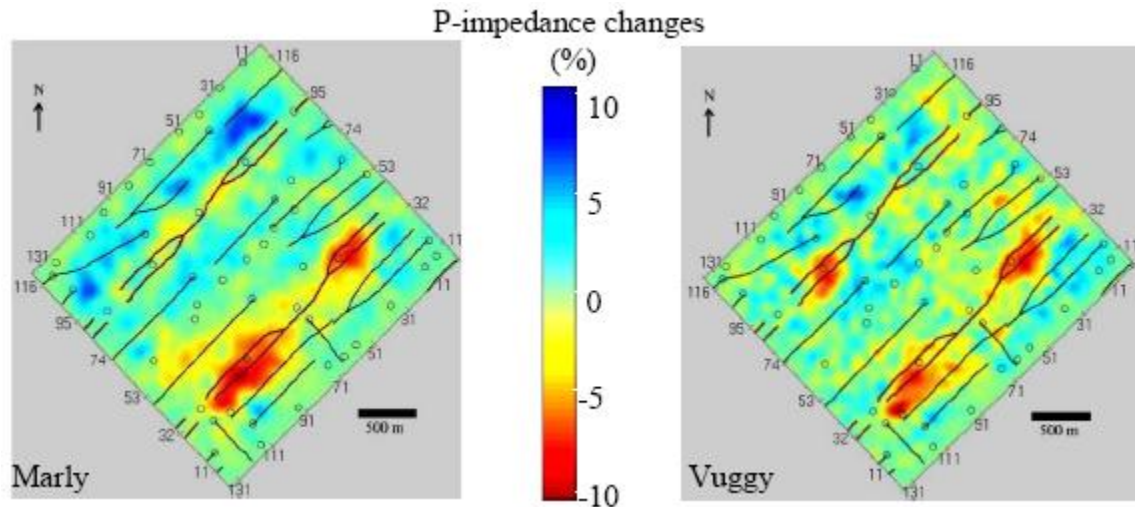


Figure 43. Acoustic impedance difference maps (monitor survey 2001 minus baseline survey 2000). The anomalies indicate change in impedance in response to the CO₂ flood; note the change in the western injector of the vuggy unit that is not apparent in the marly unit.

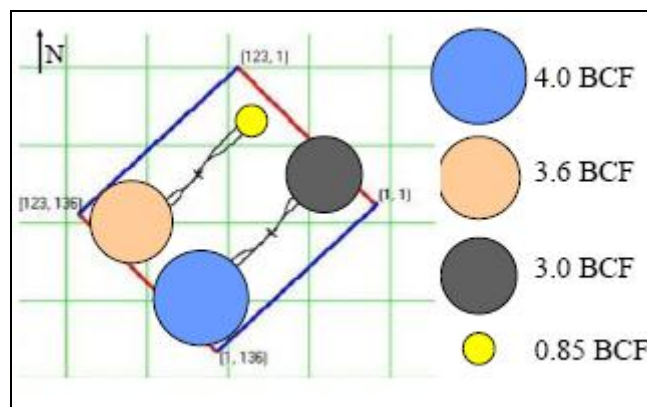


Figure 44. Cumulative injection of CO₂ up to August 2002.

7. Resource Plays: Microseismic, Fractures, and Fracability

Microseismic theory is rooted in earthquake seismology. Like earthquakes, microseisms emit elastic waves – compressional ('P-waves') and shear ('S-waves'), but they produce waves of much higher frequencies than earthquakes and generally fall within the acoustic frequency range of 200 Hz to more than 2000 Hz. Hydraulic fracture treatments and other injection processes such as SAGD alter the subsurface stress profile; this in turn reactivates natural fractures (including weak bedding planes) and often induces new fractures into the surrounding rock. The in situ rock stress profile is described in terms of two mechanisms: pore pressure increase and formation stress increase. Both mechanisms affect the stability of planes of weakness (such as natural fractures and bedding planes) surrounding the hydraulic fracture and therefore cause them to undergo shear and tensile slippage. These microseismic emissions of slippages are analogous to small earthquakes along faults, hence the name 'microseism' or 'micro-earthquake'.

The microseismic method has been used successfully in civil engineering hazard assessments, the mining industry, geothermal power generation, and the petroleum industry. It is considered to be a proven and reliable technology in a number of these fields. Within the petroleum industry, microseismic concepts have been used to evaluate the stability of reservoir and seal rocks in

subsurface gas storage and in gas reservoirs and to map the progress of heavy oil and *in situ* tar sand production. Current applications within the petroleum industry of passive seismology or microseismic monitoring include:

- Monitoring of: gas storage reservoir pressure responses; steam and fluid injection in reservoir rock in such processes as SAGD; casing failure in thermal wells and acoustic signals from crack formation in seal rock in hydrocarbon fluid traps
- Monitoring of wellbore stimulation processes such as hydraulic frac treatments

Each microseismic emission observed during the hydraulic frac treatment corresponds to a fracture surface slippage in a tensile or shear displacement. Once the microseismic events are located, the stimulated fracture network is interpreted to be a portion of the Stimulated Reservoir Volume (SRV) outlined in some manner by the cloudlike pattern formed by the event locations. In reservoir characterization, the SRV is used to describe the probable conductivity or connectivity of the induced fracture network within the low perm host reservoir rock. Producing reliable SRV estimates for reservoir modelling is one of the goals of microseismic monitoring research, as will be described below.

Knowing the stimulated fracture geometry can improve production economics by increasing reservoir productivity and/or reducing completion costs. This includes optimizing individual fracture treatments, optimizing fracture length, verifying effective pay zone coverage, or optimizing the entire field development in terms of well spacing and well layout.

Current Status of the Technique

Hydraulic fracturing in well completions is not a new technology and has been used to improve the performance of low permeability reservoirs since the 1950's. The usage of hydraulic fracture techniques has become increasingly important within recent years with the need to recover hydrocarbons from very tight (i.e. low perm) sandstone, shale and carbonate reservoirs. Industry usage of hydraulic fracs has increased enormously, both in volume and in scale, a direct result of the industry need to produce commercial hydrocarbons from ever poorer quality reservoir rock.

In the past, the information provided by microseismic data was largely limited to the location of the hypocentres and relative event strength. Technical presentations were based on located events, and frequency-of-event counts were stated to be a relative indicator of a "successful frac treatment".

The error associated with these microseismic events was often large, especially when the separation of the event location and monitoring array exceeded a few hundred metres. Prime sources of location error were (and are) overly simplified and poorly constrained velocity models; failure to deal with anisotropy; challenging 'picks' of the microseismic events; and too few (often only one) monitoring arrays, resulting in poor geometry for triangulation. These issues have been gradually addressed in recent years for both downhole and surface monitoring passive arrays. Some microseismic companies now offer 3D velocity models with input from 3D mapping and multiple well control; models which can deal with anisotropy have been slower to make their appearance. Multiple monitoring arrays are now routinely accepted as the most reliable source of microseismic event location, including vertical and horizontal downhole arrays plus surface arrays. Processing algorithms, such as double-difference processing, event clustering, and swarm optimization, have also improved the accuracy of hypocentre interpretation.

Hypocentre maps provide information on the style of the generated frac: long, narrow bi-wing fracs contrast with shorter, broader hypocentre clouds indicative of greater fracture network complexity. Sometimes, but not always, the clouds suggest details of the fracture geometry, particularly in areas where horizontal anisotropy is not large. Overlap between adjacent frac stages can be inferred, which is strongly suggestive of likely production interference between

producing wellbores. Hypocentre clouds can also suggest if a frac is staying in the targeted reservoir zone; and if not, where it is going. Faults and natural fractures are sometimes revealed from the cloud geometries. But attempts to use these microseismic hypocentre clouds to directly determine “effective” stimulated rock volume (SRV) have been challenging. Proposed approaches to date are generally heuristic rules of thumb, lacking theoretical or experimental validation. A case in point is the Rule of 80%, in which 80% of the dimensional extremes of the cloud are taken as defining the boundary of the SRV. The volumetric estimates provided by these approaches are generally far too large when compared with estimates from production. Nor can hypocentre mapping alone determine the zones of proppant emplacement within the fracture network.

In an effort to deal with these difficulties, current research and development efforts concentrate on moment tensor inversions of the first motion of the fractures. Such measurements require multiple arrays subtending obtuse solid angles together with good quality data; the algorithms employed for first motion analysis are familiar from earthquake seismology and from mining industry practices. First motion data provide far greater detail on the fracturing process than do hypocentres alone. For example, isotropic solutions indicate fracture dilation (and also collapse). Contiguous zones of such solutions, especially when adjacent to the perf point, are believed to outline the zone of probable proppant emplacement. By contrast, double couple (DC) solutions, indicative of shear failure, may be less likely to receive proppant, especially when far from the perforation. Event multiplets, which are microseismic events near each other in time and space and which exhibit the same type of first motion, may be diagnostic of a discrete fracture plane in the process of formation. Solutions indicating fractures not aligned with the principal stress axis are likely diagnostic of reactivated natural fractures. The combined data set derived from moment tensor analysis and from hypocentre mapping provides a more credible and conservative estimate of the “effective SRV.”

Microseismic wave trains are often complex, but the complexities are related to the rock characteristics, including fractures. For example, microseismic waves usually present direct observations of both compressional (acoustic) and shear (elastic) wave propagation as wave energy passes through the reservoir rock. Consequently, travel time inversion of P&S waves between source location and monitoring array provides a first order estimate of rock properties such as Poisson's ratio and Young's modulus. In general, anisotropic rock characteristics are related to fractures (whether natural or hydraulically induced), stress field variations (both pre- and post-frac) and/or bedded or laminated rock. Microseismic observations during a hydraulic fracture treatment provide a realistic inference of fracture density and of its spatial distribution within the reservoir, which are then usable for estimating the major flow pathways within the very low permeability reservoir rock. Microseismic data can also exhibit two distinct shear wave arrivals, which result from bi-refrigrant shear wave propagation within the reservoir rock. Microseismic wave form analysis can therefore provide detailed physical information on the *in situ* characteristics of the reservoir and its sealing barriers. These observations, when measured accurately and calibrated with rock physics models, are very sensitive at the scale required to link core and petrophysical data to surface seismic data, which provides macroscale measurements.

First motion data and other microseismic measurements, in conjunction with core analysis, formation imaging logs, and fault interpretations from surface seismic, can be used to calibrate statistical discrete fracture network models. Where this works, SRV estimates can be supplemented or replaced by stimulated rock surface (SRS) numbers. Such measurements, in conjunction with diffusion theory, provide a far more detailed input into reservoir models than SRV.

As confidence in the microseismic technique increases and as SRV and SRS estimation procedures are tied to production profiles, microseismic interpretation will become accepted as a reliable tool for production prediction. It must be stated that the first motion studies outlined above represent promising work in progress and are not yet established and validated techniques for reserve calculation. It is anticipated that this state of affairs will rapidly change. But even at

present, microseismic results, when integrated with the traditional geological and engineering procedures used in reserve estimation, reduce the uncertainty and increase the reliability of those estimates. As well, microseismic data can be used to confirm rock property inversions of 3D seismic. If these efforts continue show success, geophysics can then be used to predict fracability with reliability, permitting more cost-effective frac programs. Microseismic is, in its current state, a rapidly advancing new technology for the purposes of resource and reserve evaluation.

8. Summary

In summary, geophysical data being integrated into resource/reserve evaluations enable a better characterization of the hydrocarbon volumes. The existing geophysical techniques applied to this task constantly improve as their acquisition, processing, and analysis tools improve – generally yielding better vertical and spatial resolution (e.g., 3D-3C reflection seismic or gravity gradiometry), which make the data ‘more reliable’ for resource/reserve assessment purposes.

There are also many new geophysical technologies constantly being developed (e.g., microseismic monitoring of fracture stimulations or CSEM). A new technology can be used in reserves evaluation when

- It has a reasonable physical cause for indicating the presence of reservoir (e.g., P-impedance or density derived from seismic might be an indicator of porosity).
- It indicates the presence of hydrocarbon reservoir in other wells in the field or wells in analog fields with a high degree of certainty.
- The type and quality of data is suitable for the use of the technology.
- The uncertainty of the application of the technology on these data is made plain.
- The technology is generally accepted as valid by the geophysical community.
- There is a low probability of a spurious correlation between technology results and existing well results.

Numerous examples were included in this document in order to give the reader a sense of the types of geophysical data used in Canada (and elsewhere) to help characterize reservoirs, often for resource/reserve estimations. These examples are not meant to be prescriptive; however they illustrate good workflows that significantly improved the characterization of the reservoir in question.

Integration of the geophysical data with all of the other available data has been stressed in this document. When geophysical data is combined with geological, petrophysical, production, analog, and simulation data, the analysis becomes ‘more reliable’. This integration often takes place through the creation of a geo-model, which frequently provides the input for reservoir simulation models; however, geophysical data, in itself, can directly influence changes in the reservoir shape, size, and properties without invoking the creation of a geo-model.

When engaged in their own resource/reserve evaluations, the reader is urged to constantly consider (and quantify where possible) the reliability of their geophysical data, and to take the opportunity to integrate their geophysical data with all other available data.

Contributors of all of the examples used in this document are given heartfelt thanks.

9. Additional Reading

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