Seismic Applications in the Exploration for and Development and Production of Unconventional Hydrocarbon Resources (An overview)

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Abstract

Relationships between the sensitivity of surface recorded seismic data to various geological and engineering parameters characterizing five types of unconventional hydrocarbon resources are addressed. Specifically, seismic properties that may be extracted by the analysis of conventional 3D seismic data, as well as 3C multicomponent seismic data, are identified and correlated with several geologic and engineering parameters that may characterize the productive capability of the unconventional resources. Examples for the seismic response to the five (coal bed methane, heavy oil, tight gas sands, and gas and oil producing resource shales) resource types are discussed. From these observations, I conclude that seismic characterization will likely require high quality 3D seismic data to provide a structural and stratigraphic context of the subsurface along with 3C multicomponent seismic data for detailed characterization of the internal properties of the unconventional reservoirs.

Introduction

Unconventional Hydrocarbon resources are just that—unconventional. Thus, application of seismic methods in their exploration and exploitation may be expected to be—perhaps—unconventional. Many conventional methods, and variations on conventional methods, however, may prove quite effective in pursuing these objectives. The approach of this discussion is to examine just what geologic and engineering characteristics of unconventional resources may be sensitive to a seismic response, and then address just what seismic methods—conventional or otherwise—may be used to examine that particularly geologic or engineering characteristic. Thus, the objective is to isolate those rock, reservoir and fluid properties associated with unconventional resources that may be expected to have a sensitivity, or response, to some specific seismic property.

Of the many so-called unconventional resources, some have just recently emerged as active exploration and production targets. This is particularly true for 'shale' resources where the very term shale is evolving in its meaning. Thus, in identifying characteristics of unconventional resources that may have a seismic response we will also need to simultaneously and interactively evolve the relevant rock, reservoir and fluid characteristics for the Exploration and Production targets.

This paper addresses five types of unconventional resources: Coal bed methane (CBM), Heavy oil (produced through boreholes), Tight gas sands and two types of resource shales, gas saturated shales and oil saturated shales. Other seismic applications in the area of unconventional resources, especially shale applications, include passive microseismic monitoring during hydrofracturing (hydrofracing) operations and geomechanical considerations. These last two topics are discussed elsewhere in this issue of Geohorizons, and thus the present discussion will be limited to active-source seismic operations on the surface and in borehole situations.

Of the five types of unconventional resource areas considered, the gas and oil resources shales are, by far, the least well understood. This limitation of knowledge starts from the most basic definition of a shales. Many of the shales being produced are dominated by siliceous and carboniferous minerals with only small fractions of clay minerals. Thus the most basic concepts of what is a shale are evolving as we continue to develop these shale plays. As a result, we will ultimately study seismic response and geological characterization of shales in a parallel, interactive fashion. (For a discussion of merging some conventional stratigraphic concepts with unconventional shales see Slatt and Abousleiman, 2011.)

Table I provides a summary of basic Geologic and Engineering properties that may have some sensitivity to seismic wave propagation. These include the geologic and engineering properties associated with specific seismically derived parameters. Note that the geologic and reservoir parameters are limited to those properties that show sensitivity to surface seismic data. That is, we only discuss those properties that might be able to be extracted from seismic data.

Full 3D volumetric seismic coverage with a wide range in source-receiver offsets and azimuths is considered. Further, some geologic properties will most likely require the shear wave response from mode-converted 3C seismic data. The 3C data will likely be particularly important in revealing the seismic anisotropy response required to fully characterize some of the characteristics of both gas and oil shales. Many of the shale properties that are reflected by seismic VTI and HTI anisotropy are just beginning to be fully understood,

Table I. Relation between Geologic / Engineering and Seismic Properties

Geologic Property	Seismic Property
Structural characterization of Reservoir Defining faulting as a hazard Defining fault patterns and pressure cells	Detailed 3D volumetric image
Reservoir Characterization, potential fracturing	Detailed attributes extracted from reflecting horizons in 3D data of the target
Geological Characterization: Lithology (Siliceous content) Gas Saturation 'Fracability'	Poisson's ratio from Vp/Vs
Fracturing (Cleating) in Coal Bed Methane	HTI anisotropy for P-P & P-SV data, or controlled source 9C seismic data
Vertical fracturing in tight gas sands and shales	HTI Anisotropy from P-P and P-SV wide azimuth data
Shale (Resource) Characterization Shaliness (clay content, source/seal properties) Total Organic Content (TOC) in resource shales	VTI Anisotropy from P-P and P-SV data
Gas/Liquid properties Crack stress conditions	Crack Parameters from modeling/inversion for Aspect Ratio Crack Concentration from 3C wide azimimuth data
Density	AVO of P-P and P-SV data
Monitor hydrofacing operations	Microseismic
Steam flood monitoring	Time-lapse surface and borehole seismic

but there is growing evidence that the layering-like VTI anisotropy is quite sensitive to clay content and total organic content (TOC). Thus, this may become a very important, if not the most important, parameter to extract from the seismic observations in characterizing resource shales.

Types of Unconventional Resources and Examples of Seismic Applications

This discussion reviews the five basic types of unconventional resources under consideration and provides illustrative examples of seismic response from the literature for each type. For shales, some of the examples address forward modeling of the seismic response to variation in seismic anisotropy that is hypothesized to be related to an important shale property associated with production. Following this example-oriented introduction, I will address specific anticipated requirements for seismic data acquisition.

Coal Bed Methane (CBM)

One source of ‘unconventional’ hydrocarbons is gas (methane) produced from fractured, or cleated, coal bed reservoirs, generally referred to as Coal Bed Methane (CBM). Coal is an unusual reservoir rock that, in this context, consists of a fractured (cleated), impermeable and isotropic matrix with the fractures defining an anisotropic fabric providing the basic permeability of the reservoir. Further, the fractures (consisting of sets of ‘face’ cleats and orthogonal ‘butt’ cleats) provide an interface for the accumulation of gas in the porous cleats of the reservoir. Gas (methane) is typically adsorbed onto the fracture surfaces and moves into the pore space. Unlike many other sources of gas, CBM is commonly limited to ‘sweet’ methane, without higher fractions of hydrocarbons or other gases.

Implementation of seismic applications in characterizing coal bed methane resources include ‘conventional’ 3D seismic for defining the structure of the coal beds and larger ‘through-going’ faults that may compartmentalize the reservoir into separate production units and form the boundaries for pressure cells. Such a structural interpretation provides the background for further, more detailed characterization of zones within the reservoir itself.

Detailed analysis of the actual fractured fabric (the distribution of cleats) may be realized by a complete analysis of multicomponent seismic data, especially the anisotropy observed in the shear-wave data. This type of analysis may lead to defining heterogeneities, such as isolated pressure cells, spatial variations in fracture density (and production potential) and variable fracture directions within the reservoir.

Example of Coal Bed Methane (CBM):

Cedar Hill Field: An example from a 9C survey conducted in the Cedar Hill Field in the San Juan Basin (northwest New Mexico in the USA) is used for illustrating such an analysis. The survey was conducted by the Reservoir Characterization Project of the Colorado School of Mines, and consisted of full controlled polarization 9C multicomponent data, including both 3-component sources and 3-component receivers. (Shuck et al., 1996) Use of three-component sources, as well as receivers, provides fully controlled source polarizations for the analysis of shear-wave anisotropy effects.

A summary of the Cedar Hill survey (Shuck et al., 1996) is given in Figure 1.These data were collected over an approximately one square mile portion of the field and show a relation between the actual crack densities, derived from analysis of the observed anisotropy of the S1 and S2 polarized shear wave data in the lower producing unit of the Cretaceous Fruitland Coal. The field-scale strike-slip faulting derived from the 3D structural data provides a background for analysis of the fracture fabric. Note the variations of the crack (fabric scale fracture) density shown by the gray-scale plot. This detailed reservoir characterization, superimposed on the 3D seismically defined fault blocks, would not be possible without the inclusion of the 9C multi-component seismic data.

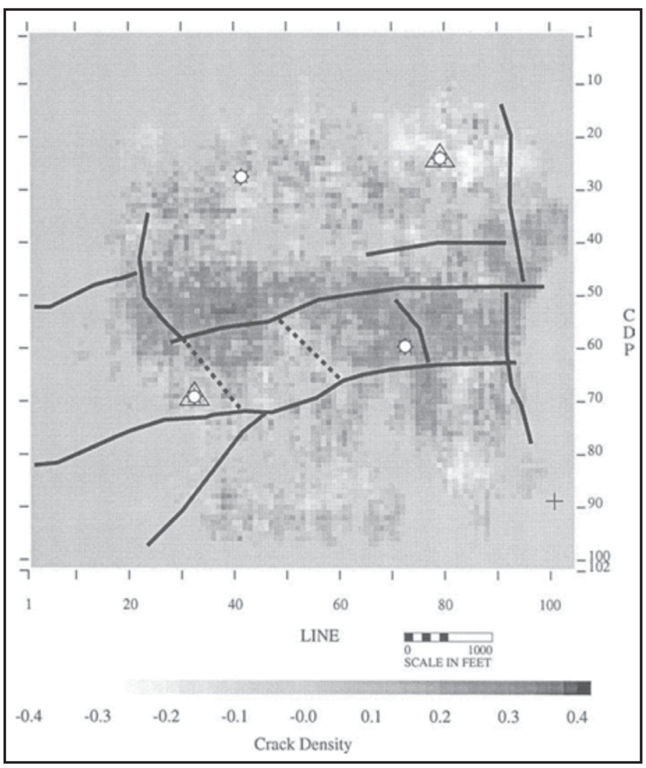

Fig. 1: Several maps of seismic characteristics were included in this study. This map of estimated crack density is at the reservoir depth of about 800-850 meters. Shading shows crack density derived from lower producing coal using amplitude anisotropy of the seismic shear waves. Negative crack densities indicate that the fast polarization direction (S1) is to the northeast rather than northwest. Faults derived from the 3D P-wave structural interpretation have been superimposed for reference. This faulting pattern my assist in isolating pressure cells in the reservoir. From Shuck et al. (1996).

Heavy Oil

Heavy oil resources have been exploited for many years, and although considered unconventional resources, they have a relatively mature history of development. Heavy oil consists of heavier fractions of hydrocarbons, and commercial gas is rarely, if ever, present. In our context, we will address heavy oil as very low API gravity oil (less than 20° API) produced through a borehole. Most heavy oil resources are highly viscous and require some enhanced recovery technique (EOR)—typically thermal—to be economically produced. The examples shown below involved steam flooding to reduce the viscosity to a producible level. Heavy oil generally requires greater refining than lighter grades, and hence is traded at a lower price. Further, production EOR techniques add to the production costs. On the positive side, heavy oil deposits tend to be very large (billions to tens of billions of barrels of reserves) at fairly shallow depths, from a few hundred to—perhaps—a few thousand feet deep. The shallow depths allow for exploitation by extensive drilling, and this drilling may limit the need for regional seismic surveys. Most seismic applications in heavy oil have been focused on improving production efficiency by actively monitoring the efficacy of thermal EOR operations, such as steam flooding.

Example of Surface Seismic for Heavy Oil:

Duri Field: A time-lapse, or 4D (3D surveys repeated over time), seismic survey over a portion of the Duri field, operated by CalTex in Sumatra, Indonesia, was conducted to demonstrate the application of seismic methods to monitor the EOR (thermal) steamflood operation and improve productivity. In 1997, the Duri steam flood consisted of some 900 steam injection wells and nearly 2700 producing wells. The shallow reservoir depth (100 to 300 m) allow for drilling many wells and quite high-quality seismic data.

A pilot seismic study (Jenkins et al, 1997) conducted over a 31 month period from 1992 to 1995 established the efficacy of reservoir monitoring during actual EOR production activity. The effects of the steam injection are shown on a series of time-slices from a portion of the survey area (Figure 2). This figure shows differences in reflection times from a seismic reflector below the reservoir interval. Increases in the reflection time (push-down of the reflector in time) are consistent with a decrease in seismic P-wave propagation velocity associated with the increase in temperature caused by the steam injection after about 18 months of steam injection at the center of the injection pattern. Note that at the 31

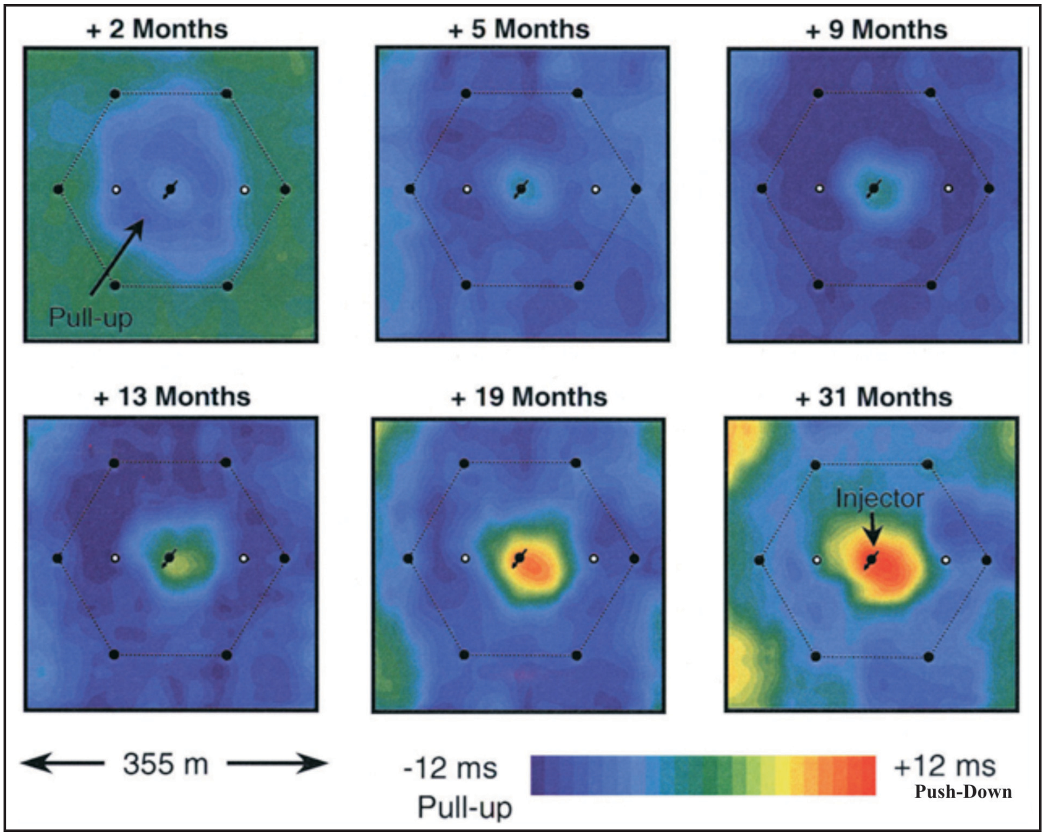

Fig.2 Traveltime differences between the baseline and monitor surveys for a reflection below the steam injection zone. Green areas have the same interval traveltime in both baseline andmonitor surveys. Blue areas represent pull-ups (Velocity increases) in the monitor data withrespect to the baseline. Yellow/red areas represent push-downs (Velocity decreases) in the monitor data. A pull-up develops around the injector after 2 months andextends over the whole pattern after 5 months. Push-downs grow around the injector well to a maximum radius of 50 m after 31 months of injection. These observations allow monitoring of the efficacy of the steam injection process. The push-downs results from lower P-wave velocities caused by the heating of the heavy oil zone associated with the steam injection. The reflector depth is about 250 ms (about 750 ft. depth.) From Jenkins et al. (1997)

month time point, the steam has extended to a radius of steam injection to about 50 meters beyond the injection well, but in a pattern that is not fully circular. This observed deviation from an ideally circular pattern is useful in modifying the injection program to efficiently sweep the entire reservoir.

The success of the pilot time-lapse survey led to an active reservoir monitoring survey in 1997 (Waite and Sagit, 1997).The integration of temperatures observed in observation wells and the seismic response led to alteration of the steam injection protocol and improved production.

One example of the seismic response to the steam injection is shown on a seismic reflection profile in Figure 3. This reflection profile was extracted from one of the 3D post-injection monitoring surveys, and follows a production and observation well profile. The total profile length is about 300 meters, and the reservoir depth is between 100 and 300 m. Waite and Sigit (1997) describe this profile in some detail:

Interpreted boundaries for the Upper Pertama, Lower Pertama, and Kedua are delineated in yellow. Flow-unit boundaries were established using vertical seismic profile information, sonic log data, and seismic stratigraphic interpretation.

Three distinct steam indicators are evident on A-A'. Similar to classic gas "bright spots", the top and base of a low velocity steam zone is identified seismically by a high amplitude trough (red), followed by a high amplitude peak (blue). One steam indicator can be seen in the Upper Pertama extending from the injector to the observation well. Note that this Upper Pertama steam indicator is the only one present at the observation well, which is consistent with the temperature survey. However, despite this agreement, neither breakthrough producer appears sourced in the Upper Pertama, as was previously inferred from the conventional well-based data alone! A second steam indicator in the Lower Pertama extends from [injection well] *I3 to* [producing well] *P3. Steam in producer P2 appears to be delivered by the Lower Pertama also, but sourced from the adjacent pattern to the north. Note that Kedua steam indicators are absent in the seismic data.*

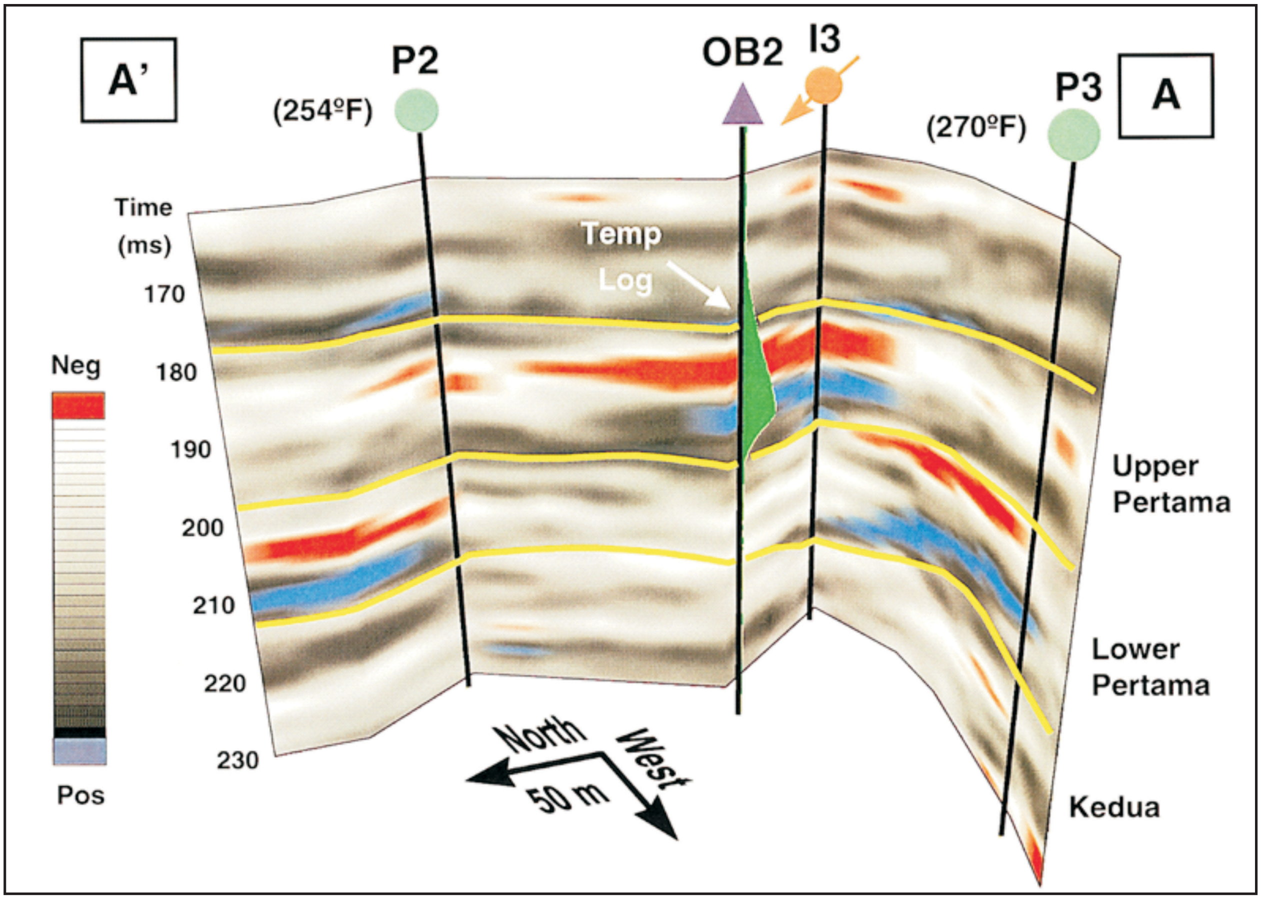

Fig.3 A seismic reflection traverse along the path (A-A').This profile is in a different part of the field than the example in Figure 2. Three distinct high amplitude steam indicators (red over blue signature) reveal steam pathways between wells. Despite being consistent with the well-based data, the seismic data indicate thatthe Lower Pertama-not the Upper Pertama-is the steam source for break-through producers P2 and P3. No steam indicators are present in Kedua. From Waite and Sagit (1997)

Waite and Sigit (1997) further summarize the results of this survey in noting that the steam injection program was modified to interrupt steam channeling to the break-through producing wells and promote steam expansion into the unswept regions of the reservoir.

Example of cross-well seismic for Heavy Oil:

Steepbank, Alberta: This example focuses on cross-well seismology, a technique that provides quite detailed observations of production processes, especially in steam flooding operations. Cross-well methods require access to relatively closely-spaced boreholes, thus is limited to developed EOR production applications. In this setting, it provides remarkably detailed observations of the steam injection and resultant thermal effects during the actual steam flood operation. Cross-well methods typically deploy sources and receivers in nearby well bores (sources and receivers in separate wells) and result in detailed 2D profiles of seismic P- and, sometimes, S- wave propagation velocities between the wells. The images are typically constructed by tomographic analysis of multiple propagation paths between the well bores. More details, and examples, are included in in recent book edited by Chopra et al. (2010) and published by the Soc. of Exploration Geophysicists.

The Steepbank seismic surveys (Paulsson et al, 1994) were conducted in an oil sand located about 60 km northeast of Fort McMurray, Alberta, Canada—near the Alberta Tar Sands region. The production is through horizontal boreholes, and is a pilot project for HASD (Heated Annulus Steam Drive) where steam is circulated through horizontal wells in order to preheat the tar sands prior to more conventional steam injection. Time-lapse surveys were conducted over a 72 day interval (late 1991 and early 1992) to evaluate the efficacy of seismic monitoring of changes associated with the EOR activities. Four cross-well profiles between four producing wells and a steam injection well were gathered. A horizontal well passed through the center of the injection pattern.

The four tomographic cross-section profiles of the P-wave velocity taken both before HASD injection began and ten weeks after continuous injection are shown in Figure 4. The profiles are shown as a continuous plot, but they do zig-zag through the subject steam injection pattern. (The

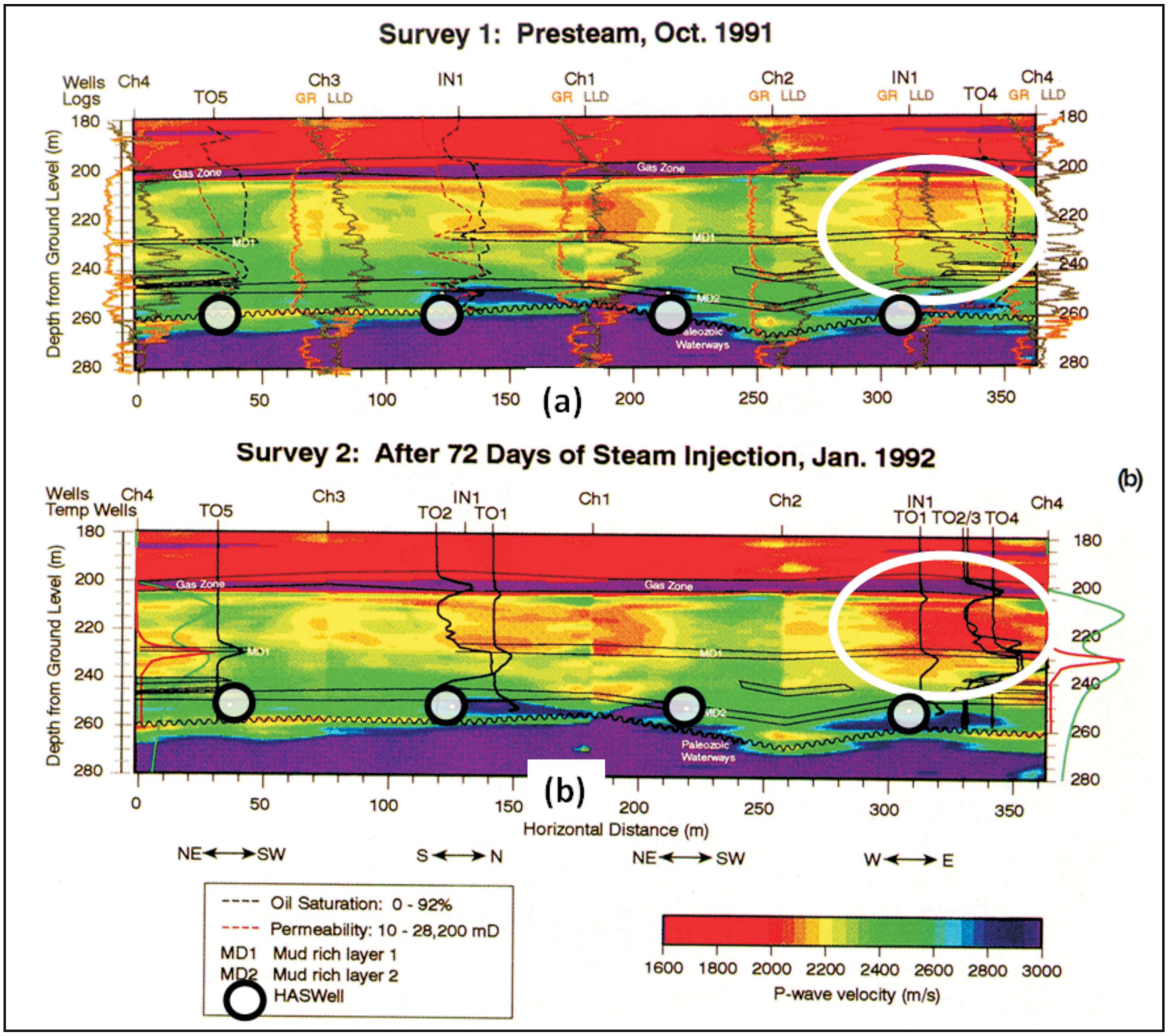

Fig.4 Four P-wave velocity tomograms. Overlain on profile (a) are gamma and resistivity logs from indicated wells; bitumen saturation and permeability from core measurements in T05, IN1, and T04; and the geologic model. In profile (b) the decrease in P-wave velocity, indicated by an increase in the red colors in section CH4-CH2 (Circled), shows the direction taken by the steam. The steam, injected near the center of the figure at a depth of about 250 m, appears to have risen about 20 m around the wellbore and then escaped to the east. Also shown are temperature logs from several wells. Two are shown for CH4.The one with the single spike was taken at the time of the second crosswell survey; the other, taken six weeks later, show the heat has expanded upward, which is also apparent on the tomogram. These four profiles are continuous, but not along a single straight line. The location of the intersection of the horizontal borehole with the profiles is highlighted by the black circles. Note the detail of the velocity variations: The total length of the four profiles is about 360 m., and the depths vary from 180 to 280 m. The resolution of these crosswell profiles is on the order of 10 m. From Paulsson et al. (1994)

horizontal borehole intersects the zig-zagging profile at four locations.) The intersections of the profile with the single horizontal well are highlighted with large dots with a heavy black outline. Considerable complexity in the geology is observable at quite a remarkable scale. Note that the total profile length is about 250 m, and the vertical depth range is from 180 to 280 m. Depth of steam injection is at about 250 meters. The authors (Paulsson et al., 1994) point out that the effect of steam injection is clearly seen by the increase in red colors (lower P-wave velocities, or higher temperatures) on the second (monitor) survey. This area is highlighted by a white circle in both the pre-steam and monitor profile. This large velocity change is only seen in this one section, and comparison with the location of the horizontal bell bore and the steam injector (IN1) indicates that the heat has not followed the expected path along the horizon well, but has migrated upward around the injector.

Overall, these two profiles show considerably more geologic detail, even before steam injection, than is available from the rather complete set of logs in separate well bores. Detail at a scale of 10 meters in the pre-steam profiles should improve planning of steam injection programs, and active monitoring should provide guidance in the steam injection program, guiding the locations and timing of the injected steam.

Tight Gas Sands

The term Tight Gas sand generally refers to gas trapped in low porosity and very low permeability reservoirs, making them difficult to produce. Seismic methods may be applied to identity areas of greater porosity (and hence improved permeability) to allow commercial production. In many aspects, seismic interpretation is an extension of 'conventional' interpretation to low permeability reservoirs.

Example of gas-sand thickness estimation:

Bossier Sands and Shales: The Bossier is close to a stratagraphic equivalent of the Haynesville Shale in East Texas, but is located along the deltaic boundaries of the depositional basin. The York sandstone member and other sandstone bodies within the Bossier Formation are characterized by low porosity and permeabilities (6% and 0.2-0.001 md respectively); they are Upper Jurassic in age in the EastTexas basin and have been a target for dry gas since the late 90's. Valentin and Tatham (2010) present the results of petrophysical analyses of five wells with dipole sonic logs, together with a detailed joint interpretation of conventional PP and converted PS Seismic data to infer the distribution of these Jurassic sandbodies. The objective of the study was to locate possible new locations for development wells in the Bossier Fm., in the East Texas Basin.

The results of the petrophysical analysis suggests that despite the low impedance contrast and some overlap of Vp/Vs values, this ratio could be used as a lithology indicator where low values of Vp/Vs ratio (1.55 or less) are expected for clean dry gas sandstones and values larger than 1.6 are related to silt and shale lithologies.

A joint interpretation of the P-P and P-SV data (Figure 5) led to the seismically extracted interval Vp/Vs ratios between the correlated Cotton ValleyLimestone and Bonner member tops (an interval including the York sandstone). From this interpretation, it may be concluded that there are zones where anomalously low Vp/Vs ratio (<1.6), may indicate sand-rich depositional catchment areas associated to topographic lows where major sandstone bodies could have been deposited. Despite the fact that some of the most productive wells donot show anomalously low Vp/Vs values, the map does show pathways of relative low Vp/Vs ratios <1.8), that canbe associated with sandstones bodies encased in shale lithologies (>1.9).

In order to test the capabilities of the Vp/Vs attribute (Shown in Figure 5) as a lithology discriminator the authors developed a detailed registration between the PP and PS seismic data available incorporating log and VSP data. To develop this task they used a multicomponent VSP (Well-3), together with a detailed structural interpretation of faults and seven key horizons that could be recognized through the whole Jurassic and Cretaceous section in both seismic P-P and P-SV data sets. Once a confident registration between the two seismic volumes was obtained, the interval Vp/Vs ratios were computed at the level of interest. This attribute was calculated between two horizons, one above and one below the interest unit (Bonner and Cotton Valley limestone

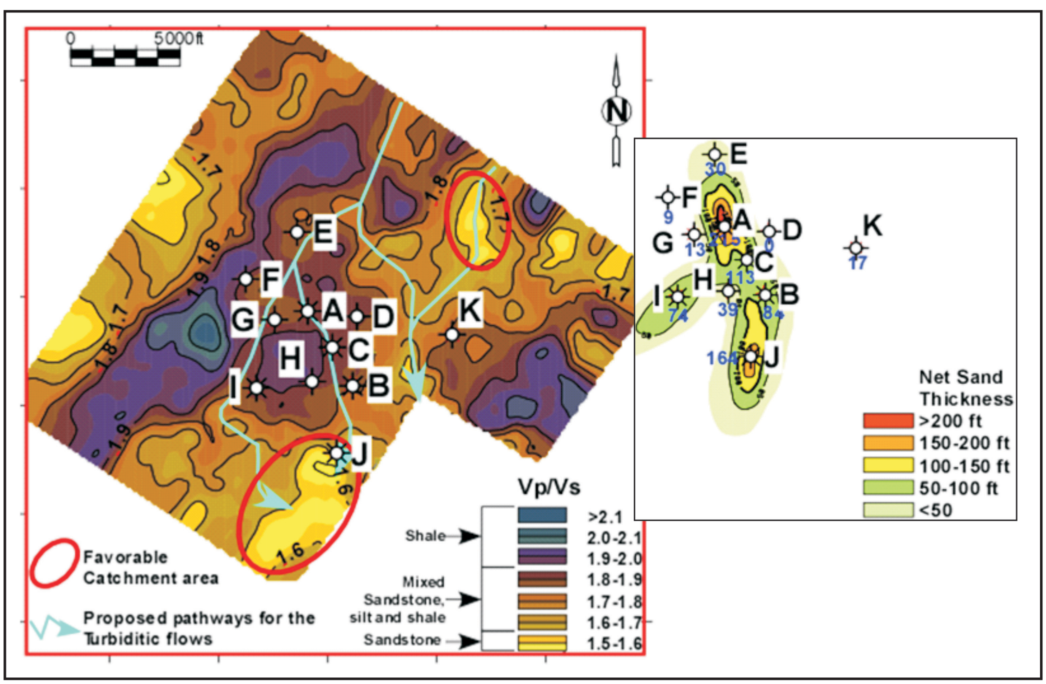

Fig.5 Interval Vp/Vs map extracted from the joint interpretation of the Bonner and Cotton Valley Limestone horizons. A decrease in values of Vp/Vsis associated with increased thickness of gas saturated sands in the mapped (Bonner-Cotton Valley). Note comparison with net gas sand thickness estimated from well control (insert). After Valentin and Tatham (2010)

horizons respectively). These horizons were identified with a high confidence based on the tie between the VSP data and the seismic data. After the joint interpretation was completed, isochron maps for the same interval were generated in both 3D volumes and the equation below was used to compute the interval Vp/Vs ratio attribute map.

Vp/Vs = ((2Δtps)/Δtpp)-1

Where:

Δtps: Isochron between two horizons interpreted at the converted PSV wave section.

Δtpp: Isochron between two horizons interpreted at the conventional PP wave section.

Figure 5 shows the results of the Vp/Vs interval velocity. Valentin and Tatham (2010) observe that there are areas toward the south and the north in which the Vp/Vs ratio is lower than 1.6. The area to the south coincides with the location of one of the best well (Well-5). Despite the fact that some productive wells like Well-1, Well-2, Well-3 and Well-11 do not show low values of Vp/Vs ratio, we can see a clear decrease in the Vp/Vs ratio (red and green arrow trends, values varying between 1.6 and 1.8), with respect to a dominant Vp/Vs ratio larger than 1.9 in this zone. Taking into account that the sandstone reservoir here is associated with turbidite deposits, they speculate that those areas with low Vp/Vs ratios (<1.6), could be related to paleo-lows (good catchment places for sandstone), probably created by the early salt movement at the Louann Formation during the late Jurassic prior to the deposition of the Bossier Formation. The area where wells such as Well-1, Well-2, Well-3 and Well-11 (red and green arrows), represent zones where the turbiditic flow was channelized.

From the petrophysical analysis Valentin and Tatham (2010) conclude that anomalous low values of Vp/Vs (< 1.6), a result of the joint interpretation of conventional PP and converted PS seismic data, may be related to the presence of large gas saturated sand bodies in the Bossier Formation. High Vp/Vs values (>1.9), are related to shale values. Interval Vp/Vs analysis using multicomponent data is very encouraging for the possibilities of new development wells in the field in those areas where the Vp/Vs ratio isanomalously low.

Shales (Resource Plays)

As resource plays, these shales typically act as source, seal and reservoir in a single unit—and require a quite different characterization than conventional petroleum systems. Earlier discussion above outlined some of the problems in characterizing (in fact, even defining) shales that may have a wide variation in mineralogic composition. Some of these differences are reflected in the example below. Two shales (one gas and one oil) have been selected to demonstrate the potential of VTI and HTI seismic anisotropy as a potential characteristic property within shale units amenable to observation by surface seismic methods. We note that our understanding of resource shales is evolving with our understanding of their seismic character.

Shale Gas

Many gas shales are currently being actively developed in North America, including the Barnnet, Marcellus, Haynesville, Marcellus and Woodford Shales. As expected, there are pronounced similarities, and differences, between each of them—so a range of seismic methods may evolve to fully describe them. Here we focus on seismic characteristics of two examples of possible characteristics in two actual shales.

Example of gas shale:

*Woodford Shale:*The Devonian Woodford shale occurs in several North American basins, including the Anadarko Basin of Oklahoma and the Delaware and Pecos basins of West Texas. A borehole selected for seismic modeling is located in Pecos County, Delaware Basin, West Texas. The Woodford Shaleinterval is gas saturated and the porosity is less than 10%.Using the gamma ray, resistivity and density logs, theWoodford Shale was divided into three units, upper, middle and lower. The middle Woodford has relatively higher resistivity, higher gamma ray response and lower density than those of the other two units. The rock properties of each of these Woodford units were extracted from the rather complete borehole log suite, which included crossed diploe sonic logs (Sonic Scanner) and detailed lithology descriptions.

Seismic models were constructed (Shan et al. 2010) to generate synthetic seismic shot records with an impulsive vertical source, which directly generates PP, PS and SS waves. Since we used only a vertical source and a single line orientation, there are only Z and X components (vertical and radial respectively), but no Y(transverse) component. A careful observation of the log shows possible VTI in the middle Woodford, which is characterized as interbedded chert and shale by the gamma ray response, and possible HTI in the middle Woodford,whose dipole shear log shows a clear separation of fast and slow shear waves.The VTI anisotropy parameter may be related to clay content and Total Organic Content (TOC).

The constructed models are based on a layered half-space, with the Woodford unit situated between two thick layers. The top Woodford interval is at a depth of just under 4,000 m, and the total thickness of the Woodford is about 200 ft. (60 m), consisting of upper, middle and lower units. To examine the sensitivity of VTI anisotropy to the seismic AVO response to P-P and P-SV reflectivity, a range of values for Thomsen's epsilon parameter are included in the models. The amplitudes at various offsets are then computed for each epsilon and wave-type for both the vertical and horizontal geophone components.

Figure 6 is the sensitivity test for VTI anisotropywhere Shan et al. (2110) show changes in amplitudes with source-receiver offset fordifferent values of the Thomsen parameters. We note that the amplitudes in Z or X component are not sensitive to changes in γ, in particular. In this test, ε changes from 0 to 0.1 setting γ and δ each equal 0.1; δ varies from -0.1 to 0.1setting ε and γ each equal 0.1. The probable sensitive part for ε is the Z component of PS wave at far (4-6 km) offset, where a relatively larger separation of AVO curves is observed on the X component of the P-SV reflection at an offset range of 2-4 km. Some sensitivity in the X component of the P-P reflection at larger (3-6 km) is also observed. Note the relatively modest offset (less than the reflector depth) required to observe VTI anisotropy effects in the horizontal component of the P-SV reflections. There is also sensitivity to the P-SV reflectivity in the vertical component, but at offsets greater than 4 km, or the approximate depth to the reflector. Thus, if 3C data are not available, considerable offsets of the conventional 3D data would be requited. Further, isolating P-SV reflections in the vertical component dominated by the P-P reflections might be problematic.

Shale Oil

Although less common than gas shales, some shales, such as the Bakken and parts of the Eagle Ford in North America, produce predominately liquids. Depending on commodity markets in various areas, oil production can be more attractive than gas. Further, in the shale-production

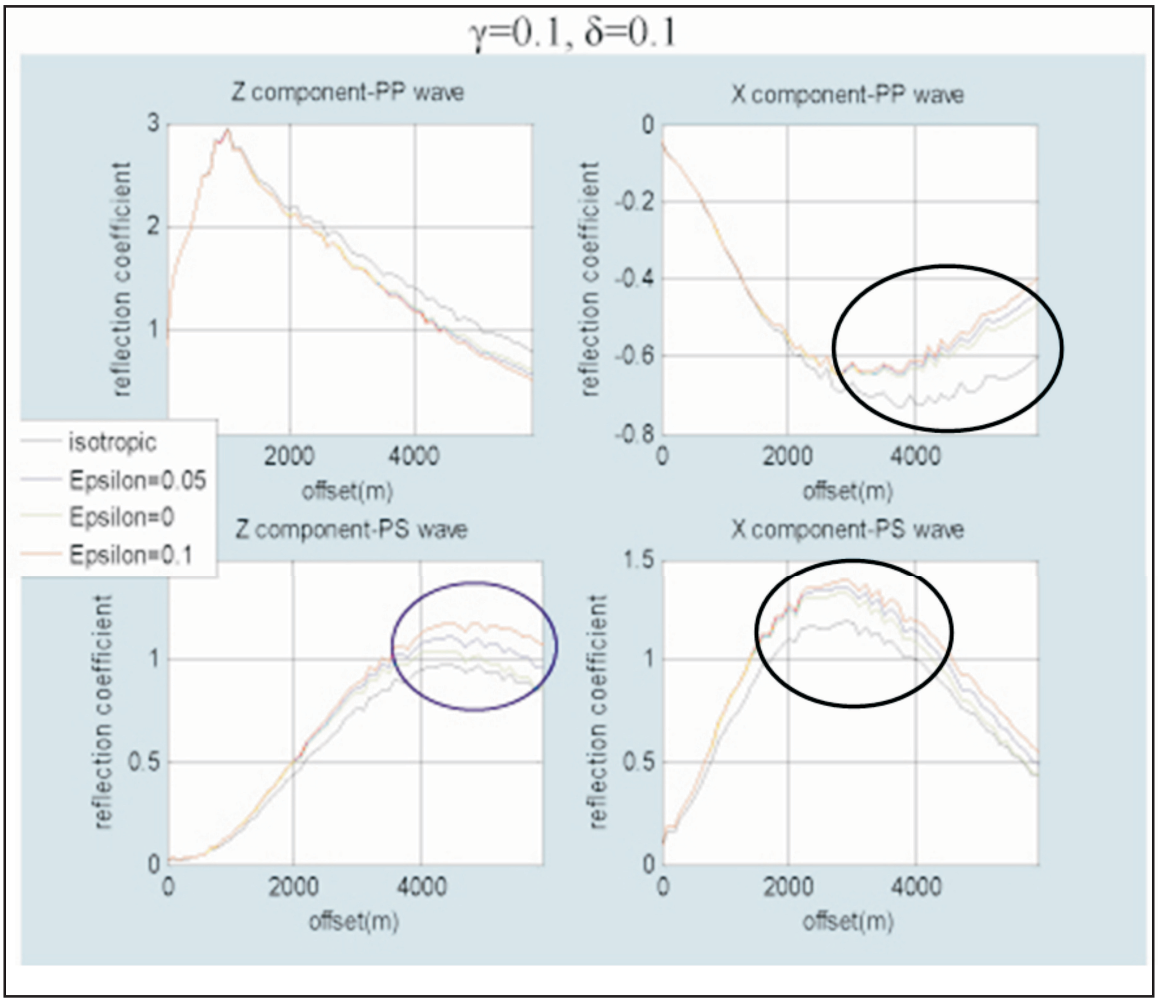

Fig.6 Sensitivity tests for VTI anisotropy, as expressed by the Thomsen ε parameter,for AVO response of both P-P and P-SV reflectivity observed on both vertical (Z) and horizontal (X) geophones. All these results are in the model data derived from the Pecos Co., Texas, borehole. The depth to the reflector is just under 4000 m. In particular, note the variation in reflectivity of the mode-converted P-SV wave on both the vertical and horizontal recording. The X component has sensitivity in the 2-4 km offset range, while the vertical component requires offsets greater than 4 km to realize the same sensitivity to VTI anisotropy. The P-P reflection also shows sensitivity on the horizontal component at offsets beyond 3 km. If the horizontal component from 3C seismic data were not available, the only sensitivity to epsilon parameter is, possibly, in the vertical component of the P-SV data at offsets greater than 4 km. After Shan et al. (2010).

area, the Bakken is a relatively mature area with data log, borehole and production data available for development of seismic analysis techniques.

Example of Shale Oil:

Bakkan Shale: Ye et al., (2010), analyze borehole data of Bakken wells from both the Cottonwood and the Sanish Field, including density information and seismic P and S wave velocities from dipole sonics (Sonic Scanner) logs. The Sonic Scanner log data suggest that the Upper and Lower Bakkenshales can be treated as VTI media while the Middle Bakken may be considered as seismically isotropic. Some investigators have addressed the middle Bakken as seismically anisotropic with HTI symmetry—and relate this to fractures and potential productivity of the middle Bakkan unit. Ye et al. (2010) simulate different types of models for both fields, including isotropic models. They generated full offset elastic synthetic seismograms to simulate the seismic responses of the various models of Bakken Formation. They then compared the anisotropic responses with isotropic responses to investigate the effect of anisotropy. Results show that anisotropies of the Upper and Lower Bakken shales, fractures/cracks and fluid fill in the fracture/cracks all have influences on the seismic responses of the Bakken Formation.

From log observations, Ye et al. (2010) observed distinct differences between vertical and horizontal dynamic Young's modulus and Poisson's ratio for both the Upper and Lower Bakken shales. The vertical Young's modulus is much smaller than the horizontal Young's modulus while the vertical Poisson's ratio is much larger than the horizontal Poisson's ratio. However, the vertical and horizontal Young's moduli and Poisson's ratio are quite similar for the Middle Bakken. Based on this log data analysis, they concluded that the Upper and Lower Bakkenshales can be treated as VTI media and the Middle Bakken may be considered as isotropic.

From this log information Ye et al. (2010) constructed several types of models for both the Cottonwood and Sanish Fields in the Bakken, including isotropic VTI and HTI models. Each model consists of five homogenous, continuous layers. Everything above the Bakken Formation is considered as one single layer. The second layer is the Upper Bakken Shale. The third layer isthe Middle Bakken. The fourth layer is the Lower Bakken Shale, and the fifth layer is everything below the Bakken Formation. P and S wave velocities and density for each layer are from the well log analysis.

The first (base) model assumes all five layers are isotropic. Full offset elastic synthetic seismograms assuming a vertical point source are then generated (e.g., Sil and Sen 2008). Output included direct P-P, mode-converted P-SV and direct SV-SV reflections. Considering the approximately 30m thickness of the total Bakken interval, each reflection packet includes the resone of the entire interval. They next assume that the Upper and Lower Bakken Shales have VTI symmetries; all other layers are isotropic. Anisotropy parameters of the Bakken Shales are based on the data reported by Vernik and Liu (1997). Figure 7a showsthe difference between the VTI anisotropic seismic response and the isotropic seismic response. The vertical impulsive source is used to simulate P-P, P-SV and SV-SV reflections, which respond differently to VTI anisotropy. The vertical component and the radial component also have different characters. P-

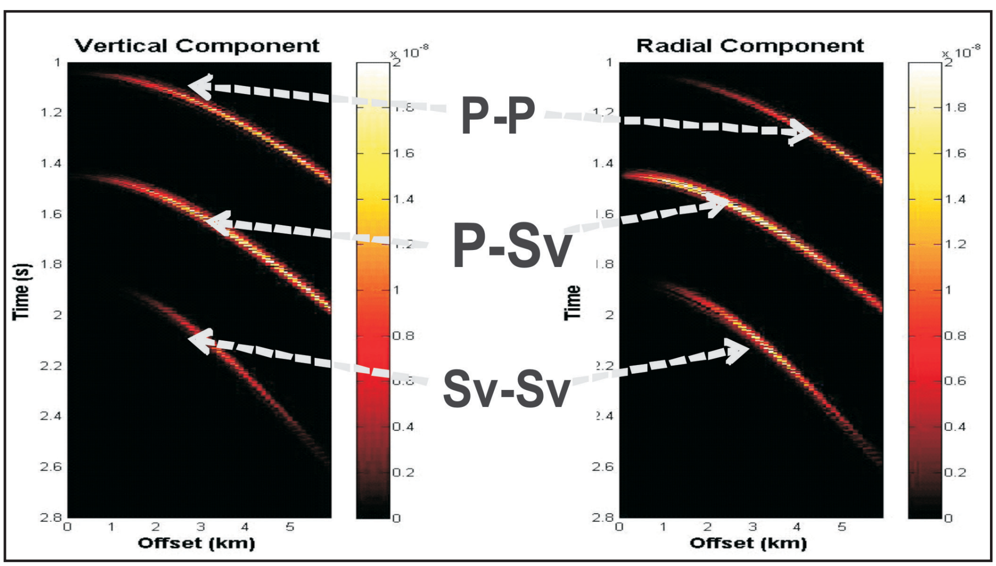

Fig.7a Difference between VTI (Upper and Lower Bakken) and isotropic seismic responses. Each reflection packet represents the total response to the 30 m thick Bakken unit. Depth to the Bakken is about 3,000 m and the maximum source-receiver offset in these models is 6,000 m. Note that the strongest differences in the VTI response is greatest in the P-Sv mode-converted reflection, with the vertical component showing the strongest difference in the 2-5 km offset range, while the horizontal (radial) component shows the strongest response in P-Sv reflectivity in the more modest offset range of 2-4 km. After Ye et al., (2010)

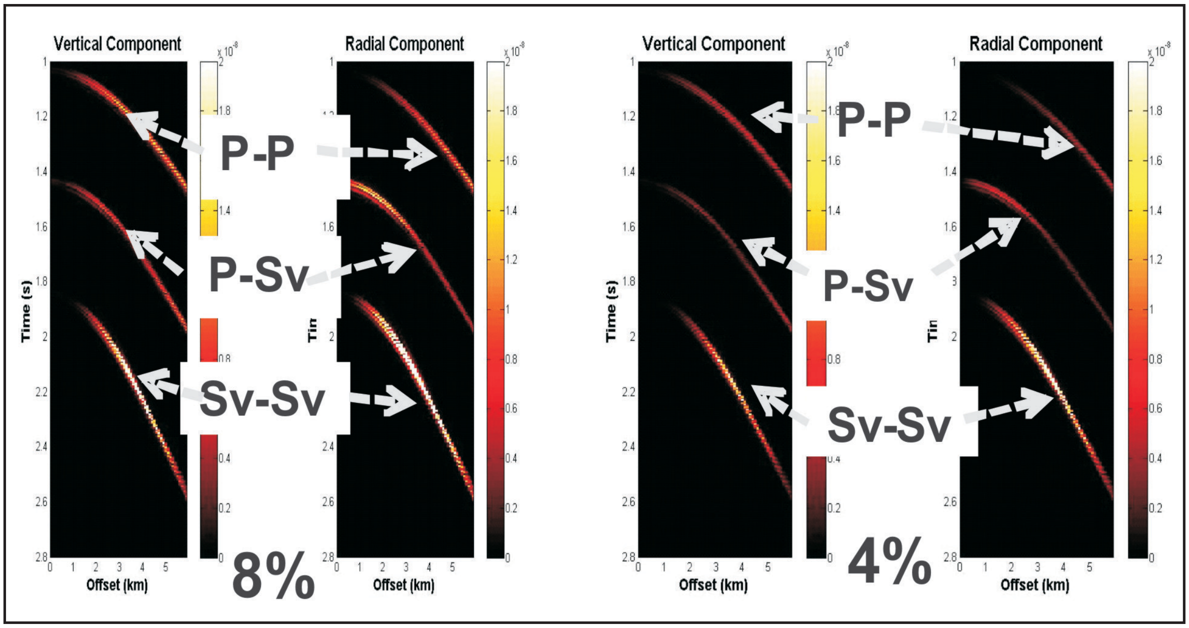

Fig.7b Differences in seismic reflections of P-P, mode-converted P-Sv and direct Sv-Sv reflections between HTI (Middle Bakken) and isotropic seismic responses crack with crack density e of 4% and 8%. Note the greater differences (sensitivities) between Isotropic and HTI conditions for the greater crack density. Also note the effects on the shear-wave date, both the P-Sv and the Sv-Sv reflections. The maximum source-receiver offset is 6 km, with the greatest sensitivities to HTI observed in the 2-5 km. offset range. Depth to the Bakken is about 3 km, and the total Bakken interval is about 30 m. After Ye et al., (2010)

SV carries more VTI information than P-P or SV-SV. Note that the greatest difference (most sensitivity) for VTI anisotropy is seen in the radial (horizontal) component of the P-SV data at offsets of about 1-3 km. (Reflection depth is about 3 km) If horizontal data were not available, the P-SV response on the conventional vertical component does show differences as well—but at offsets greater than 3 km. Further, as mentioned above, isolating P-SV reflections on a vertical comment dominated by P-P reflections may limit this approach.

In HTI, we assume that the Middle Bakken has one set of vertical fractures/cracks oriented normal to the X-direction (line orientation) whereas the remaining four layers areisotropic. HTI parameters are calculated based on a methodproposed by Bakulin et al. (2000). They chose five azimuths of 0°, 30°, 45°, 60° and 90°, and observed azimuthal anisotropy. Crack densities were varied and fluids filled in the crack to investigate the difference between HTI and isotropic seismic responses (Figure 7b). It can be seen that SV-SV carries more HTI information than P-SVor P-P. Models with higher crack densities show more influence of the fluid on anisotropy than models with lower crack densities. Anisotropies caused by dry cracks are slightly more sensitive to crack densities than anisotropies caused by wet cracks. Overall, larger crack densities seem to enhance the sensitivity to HTI anisotropy. Also, including the horizontal component from 3C data brings the sensitivity to smaller source-receiver offsets.

Summary of Seismic Applications to Unconventional Resources

From this brief review of examples, we can see that a wide range of seismic techniques may be applied to unconventional resources. A summary of some of these seismic data types, along with the application and the type of unconventional resource being addressed is included in Table II. Also included in this table are comments on the actual seismic requirements for interpreting each data type.

Overall, for most unconventional resources, the following hierarchy of seismic data may be considered:

- High quality 3D seismic data volumes with a wide range of source-receiver offsets and azimuths.

- For detailed structural analysis, fault identification and horizon attribute extraction.

- Include 3C recording in the 3D data sets—with appropriate source-receiver offsets

  For extraction of VTI, HTI and Vp/Vs parameters to allow detailed characterization of shale properties.
  Note that, for large offsets, it appears that the vertical component of the P-SV reflection does show sensitivity to VTI and HTI anisotropy. We did note, however, that these types of data may not be readily extracted from the

Table II. Summary of geologic / engineering objectives and required seismic method

Seismic Data Type	Application	Type of Unconventional Resource	Seismic Requirement
3D structural image	Structural Interpretation	All	High quality 3D P-wave seismic
Horizon attributes	Fracturing	CBM Tight Gas Shale Resources	High quality 3D P-wave seismic
Multicomponent seismic data	Shale Characterization Fracturing, Cleates Lithology estimation Gas saturation'fractability'	CBM Tight Gas Shale Resources	3D (wide azimuth) 3C seismic *Analyze for Vp/Vs, HTI and VTI.* 9Cdata to characterize cleats
Microseismic	Fracture monitoring	Shale Resources	Passive monitoring with receivers locations around the borehole.
Time-Lapse 3D (4D)	Production Monitoring	Heavy Oil	High Quality 3D P-wave time lapse data
Vertical Seismic	Tie P and S wave	Shale Resources	High quality multi-
Profiles (VSP)	reflections Detailed imaging near wellbore	CBM Tight Gas Sands	component data
Cross-well tomography	Production Monitoring	Heavy Oil	Well bores and down-hole sources and receivers

stronger P-P reflections also recorded on the vertical component of the conventional 3D data.

- Specialized techniques, such as dense time-lapse 3D surface seismic and cross-well tomography.

For thermal EOR monitoring in Heavy Oil.

From the currently evolving experience in unconventional resources, it appears that seismic shear wave data, from either 9C or 3C data, will be required to fully characterize shale bodies. The question often arises as to what part of this information will be available in the conventional P-P data alone. From the sensitivity studies to date, it appears that to extract the VTI anisotropy parameters will require horizontal components of the P-SV data.

Conclusions

In conclusion, we can suggest that seismic techniques to fully support exploration and exploitation of unconventional resources will require very good 3D seismic data that includes a broad range of source-receiver offsets and azimuths. Further, for characterization of shale units themselves, full 3C recording of the data will be required. These requirements apply particularly to Coal Bed Methane, Tight gas sands and both gas and oil shales. Heavy oil applications tend to have their own, more specific requirements for the shallow reservoir depths, time-lapse nature of reservoir monitoring and EOR monitoring objectives.

Analysis and interpretation techniques for gas and oil shales are still evolving, as is a complete understanding of the actual geological and reservoir shale characteristics relevant to production. Evolution of the seismic needs is expected to mature along with improved understanding of the shale characteristics themselves.

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