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Abstract:

During this last quarter of the "Seismic Evaluation of Hydrocarbon Saturation in Deep-Water Reservoirs" project (Grant/Cooperative Agreement DE-FC26-02NT15342), we have moved forward on several fronts, including data acquisition as well as analysis and application.

During this quarter we have:

- Completed our site selection (finally).
- Measured fluid effects in Troika deep water sand sample
- Applied the result to Ursa 'fizz gas' zone
- Compared thin layer property averaging on AVO response
- Developed target oriented NMO stretch correction
- Examined thin bed effects on A-B crossplots
- Begun incorporating outcrop descriptive models in seismic forward models

Several factors can contribute to limit our ability to extract accurate hydrocarbon saturations in deep water environments. Rock and fluid properties are one factor, since, for example, hydrocarbon properties will be considerably different with great depths (high pressure) when compared to shallow properties. Significant over pressure, on the other hand will make the rocks behave as if they were shallower. In addition to the physical properties, the scale and tuning will alter our hydrocarbon indicators. Reservoirs composed of thin bed effects will broaden the reflection amplitude distribution with incident angle. Normal move out (NMO) stretch corrections based on frequency shifts can be applied to offset this effect. Tuning will also disturb the location of extracted amplitudes on AVO intercept and gradient (A-B) plots. Many deep water reservoirs fall this tuning thickness range. Our goal for the remaining project period is to systematically combine and document these various effects for use in deep water exploration.

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Executive Summary:

In this joint project involving research at The University of Houston, Texas A&M University, the Colorado School of Mines, and Paradigm Geophysical Corporation we are combining rock measurements, observed property trends, forward modeling, and interpretation of 2-D seismic data to further develop our ability to predict hydrocarbon saturation. Our second industry DHI minisymposium was held last summer, and several aspects of Direct Hydrocarbon Indicators need to be better calibrated and tested. We are still in the process of digesting and addressing all of the issues raised during that meeting (see the year 2 annual report for a meeting summary).

The data acquisition is near complete with the agreement of Veritas to provide 2-D seismic data from the Neptune area. Log data was already donated for this and other sites. Although other sites were also candidates, the seismic lines for those was deemed too poor to make the data useful for our purposes.

Our ability to ascertain the type and level of saturation of hydrocarbons in situ from seismic data is limited by several factors. In this quarter, we continued to address several of the specific factors in order to build up our knowledge base for applying improved DHI's. The fluid and rock properties themselves are complicating factors. Particular combinations of fluids and pressures can result in seismic amplitudes that may be misleading. Although many deep water sands in the Gulf of Mexico are quite clean and high porosity, the fluid saturations may not be easily assessed. In deep, over-pressured conditions, even a hydrocarbon gas phase may have a high modulus and density and make it difficult to distinguish. In addition, partial saturations can further blur the observed difference between various fluid types. However, from the measurements and modeling, it appears that the upper zone in the Ursa field, originally identified as a "fizz gas" zone, was incorrectly classified, and another cause is responsible.

AVO analysis is affected by several complications and pitfalls. Thin bed, tuning, and NMO stretch are among other sources of error. Examining the logs we see that reservoir sands themselves are complexly interlayered. In this case the Backus average models capture most of the scatter in the reflection coefficient, though they slightly underestimate the standard deviation of the coefficient at near normal incidence. This shows that most of the change in coefficient is caused by variations in the tuning of reflections from the top and bottom of the reservoir, not by scattering from internal boundaries. For gas sands type Class III, the tuning effect causes estimation of AVO intercept and gradient to be more negative than the rock properties of the reflecting interfaces predicts. However, an erroneous classification of gas sands as brine sands could be possible for very minute layer thicknesses. On the other hand, we suggest the tuning effect as one explanation for the discrepancy that is sometimes encountered between estimation of intercept (A) and Gradient (B) from seismic data and fluid substitution via Gassmann's equations.

Results and Discussion

Test Site Status

The final site selection is complete with the inclusion of the Neptune field. Our various test sites were chosen based on the availability of samples, well logs, and seismic data. Obtaining the actual seismic data (the digits) has proved the greatest obstacle. Even when lines from one preferred location were available, the quality of the data may have been so poor as to prevent any useful application of our techniques. This was the case for both Mensa and Troika fields: Veritas was willing to provide the data, but strongly suggested we switch to Neptune due to the superior quality. The locations of our Gulf of Mexico sites are shown in Figure 1. The general condition of each area and types of data available are listed in Table 1.

Although the Veritas data through Troika was deemed of very poor quality, this is the only other field for which we have core samples. We will thus continue to measure Troika samples, and use them as analogs to our other areas.

Figure 1. Test site locations, Gulf of Mexico. Neptune is the final site and data transfer is now being arranged.

TABLE 1.

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Field	Attribute	Status
Neptune	High quality seismic data	Veritas 2-D line, Logs obtained
Nansen	Core samples & logs available	Samples measured, Logs obtained
Ursa	Multiple real and false HCI	TGS 2-D lines, Logs obtained
Mars	Complex stacked turbidites	Logs obtained
Troika	Some data already published	Some samples measured
Mars	Published data, salt confined	Veritas 2-D lines*, Logs obtained
Boomvang	Near Nansen (Kerr-McGee)	Samples & logs obtained
Viking Gr.	Prestack seismic and logs available	Data at CSM and TAMU
Teal South	Shelf, only one well, data available	Post-stack data at TAMU

Troika Sample measurements

Ultrasonic measurements were taken on a highly unconsolidated clean sand core sample from the deep-water field in the Gulf of Mexico (Troika field sample #1815). The reservoir conditions such as pressure and porosity are discussed in detail in the paper by Merkel et al. (2001) These reservoir properties were used to design the measurement procedure and to simulate the in-situ conditions of the Troika field. The P-wave velocity, S-wave velocity and deformation of this core were measured at various pressures for the case of the dry, brine and oil saturated rock. The results from these measurements were then analyzed, reduced and compared to theoretical calculations using Gassmann's equation. The results were then interpreted and compared to other results of fluid substitution for the near-by deep-water Ursa field well.

In the Troika sample measurements, there were several conclusions that were made about the impact of fluid and pressure changes on velocities. Particular combinations of fluids and pressures can result in seismic amplitudes that may be misleading. But if the right assumptions are made about fluid and mineral bulk modulus, porosity and fluid and mineral density we can come closer to a true interpretation of the presence of fluids in the subsurface. Liquid saturation causes increase in velocity in compressional waves. Shear wave velocities do not change with the presence of fluids. The impedance plots show that brine and butane may be difficult to distinguish between at high pressure while dry and butane saturations may be difficult to distinguish between in low pressure. Also, in over-pressured conditions it may be difficult to distinguish between various fluid saturations when the fluid is not a pure brine or butane i.e. partial saturations. Also low-pressure conditions result in decreased impedance.

Initial measurements were made with the sample partially saturated with light hydraulic oil. The presence of the hydraulic fluid in the sample changes the effect of fluid causing lower brine saturated velocities and higher butane saturated velocities. This demonstrates that partial saturation will blur the differences among saturations.

For the cleaned sample, the impedance decreases when the reservoir is over-pressured. When over-pressured conditions exist, is relatively easy to distinguish between the impedance values of dry, butane and brine saturated rock. When we compare Troika measured results to the Ursa well log fluid substitution on logs, similar results can be seen. In the Ursa well upper interval, the 50% gas saturation seismic response and the oil saturated response are nearly indistinguishable and if random noise is added they will appear to be identical on a typical seismic line. The same applies for the lower interval when the 50% and 10% gas saturation and oil saturation response are compared. Therefore, the amplitude response from these fluid saturations could be misleading if interpreted from a seismic line.

When comparing these results to what we see in the seismic traces, we have to consider that the scale is much different. The Troika core a small fraction of the seismic wavelength. Nevertheless the Troika measurements offer insight into the effects of the presence of fluids and pressure changes on seismic velocity. In addition, careful

calibrated use of assumed bulk moduli, fluid and rock densities can help to increase the ability to distinguish between different fluids in the subsurface to produce more accurate results.

Sample Characteristics

According to Merkel et al., (2001) Troika field is composed of clean, well sorted, unconsolidated, deepwater sandstones. The porosity of the sand ranges from 27 to 29 % and the permeability is 1-3 Darcys. Based on this information the mineral density and matrix bulk modulus were assumed to be that of quartz which is 2.65 g/cc and 36.6 GPa respectively.

The pressure changes for the measurements were designed based on the in-situ reservoir conditions described in Merkel et al., (2001). The Troika reservoir is over pressured at 12000 psi at a depth of 15050 ft with a reservoir thickness of 2260 ft. Conversions were made to accommodate the pressure vessel in the lab and simulate normal reservoir pressure conditions. The measurements were designed to compact the unconsolidated, clean, well-sorted sands of the sample by pressuring in several cycles. The information that was recorded from sample measurements is initial length, initial diameter, initial voltage, pressure, fluid volume and arrival time of P- and S-waves.

Gassmann's equation is used to calculate the effect of different fluid saturations on seismic velocities. It is useful because it allows the comparison of theoretical effects of fluids to be compared to the actual measured effects of fluid saturations on the seismic velocity. Gassmann's equation requires assumptions about rock/reservoir properties such as porosity, fluid and rock density, and fluid and rock bulk modulus. Error can be present in the measurements if the assumptions about these constant values are incorrect. Equations 1-4 require the use of constant values for performing fluid substitutions. First we use equation 1, which requires an assumption for fluid density and porosity. We then use the calculated density and velocity to calculate bulk and shear modulus. Then Gassmann's equation is used to calculate the fluid saturated bulk modulus (3) and from there we can calculate the new theoretical fluid saturated shear and compressional velocities. In these equations we must assume porosity (ϕ), fluid density (ρ_f), mineral density (ρ_m), bulk modulus of the dry rock, mineral and fluids (K_{dry} , K_m , K_f). For example density and porosity are assumed but could be inaccurate and therefore impact the result of the velocity. It is important to note that Gassmann's equation assumes low seismic frequencies and therefore do not accurately describe ultrasonic measurements, while sonic logging frequencies may or may be valid depending on fluid type and rock type. Gassmann's equation also assumes the rock is isotropic, all minerals making up the rock have the same bulk and shear modulus and the fluid bearing rock is completely saturated. (Mavko, et al., 1998) In these calculations the matrix density was assumed to be 2.65 g/cc and porosity was assumed to be 28% based on Merkel et al. (2001). The fluid bulk moduli and density for various fluids was adopted from the plots in Figure 2 (Hofmann, 2001). It can be seen if an inaccurate density is assumed then the shear modulus will be affected as well as the bulk modulus and this will result in errors in the velocities for fluid saturation.

$$\rho_{rx} = \phi * \rho_{fl} + \rho_m * (1 - \phi) \quad (1)$$

$$K_{sat} = K_{dry} + (1 - K_{dry}/K_m)^2 / (\phi / K_{fl} + 1 - \phi / K_m - K_{dry}/K_m^2) \quad (2)$$

$$V_p^2 = (K + 4/3 \mu) / \rho \quad (3)$$

$$V_s^2 = \mu / \rho \quad (4)$$

A main source of error in this experiment is related with the fluid saturation of the sample. During one pressure saturations cycle, there was leakage of hydraulic fluid into the sample. There were also inaccuracies due to inconsistencies in measurement of fluid volume in the tubing. The range of fluid volume that the sample could hold for the clean sample ranged from 20-24.8 cc of fluid for low (2000psi) to high (6500psi) pore pressure respectively. For the clean sample, 50-66 % fluid saturation was estimated. However, in the first set of measurements (partially saturated) there was a large error induced in the measurements due to the leaking of hydraulic oil into the sample. Therefore it is not certain how saturated the sample was. Also the amount of fluid in the tubing could induce error in the sample. A volume of approximately 2.35 cc volume of tubing was present for fluid occupation. If an air bubble was present fluid displacements could occur causing error in the fluid volume. This error was assumed to be negligible for this experiment because the sample was vacuumed before measurements were made and pore fluids were raised to high pressure.

Data Analysis and reduction

Subsequent to ultrasonic measurements, data reduction was performed to obtain velocities for measured dry, butane and brine saturated, partially saturated and clean samples. From these data theoretical fluid substitutions were made using Gassmann's equation. (Mavko, et al., 1998) Figures 4 and 5 display P- and S-wave velocities for the two sets of measurements, the partially saturated sample and clean sample.

Figure 2. Calculated fluid modulus (a) and density (b) used for fluids substitution (Hofmann, 2004)

Figure 3. Compressional and shear velocity pressure with respect to differential pressure for a partially saturated sample. The plot shows an increase in velocity with pressure. Brine saturated rock has higher velocity than butane saturated and “dry” rock. This sample had hydraulic fluid saturation.

Figure 4. Compressional and shear velocity pressure with respect to differential pressure for clean sample. The plot shows an increase in velocity with pressure. Brine saturated rock has higher velocity than butane saturated and dry rock.

For both clean and partially saturated sample the s wave velocity remains largely independent of fluid saturation while p wave velocity varies for fluid saturation. The bulk fluid modulus has a strong influence on compressional velocity. If the fluid density of brine and butane (brine=1.0 g/cc butane= 0.6g/cc) are compared to that of hydraulic oil (0.89 g/cc) it can be seen that if we average the densities, the brine saturation will decrease while the butane saturation will increase causing the velocities to be closer together. The larger difference between the dry and butane velocities can be explained by the possibility that during the first “dry” measurements the sample was not fully saturated with hydraulic oil yet. In addition it can be seen that the velocities are increasing with differential pressure and for the clean sample the difference in velocities between brine and butane are much greater.

Figures 5 and 6 show the shear modulus for the two measured cases. Gassmann’s equation assumes that shear modulus for dry rock and shear modulus for fluid saturated rock should be the same and therefore the shear wave velocities for all three saturations should be similar with each other as should the shear moduli. In Figures 5 and 6, the shear wave velocities did coincide for the clean rock and partially saturated rock. The shear modulus (Figure 6) is unchanged with respect to fluid saturation. Figure 5 shows that the shear moduli do not coincide for different fluid saturation. The reason for this difference in shear modulus is due to the presence of hydraulic oil, which causes changes in density of the fluid and rock density and also the pressure affect of the pore fluid. Adjustments in original assumptions of fluid density and fluid moduli should be made to include the presence of hydraulic oil in the sample.

For the Gassmann’s fluid substitution, Equations 1-4 were used to calculate the densities, bulk and shear moduli and velocities for saturated rock. Table 2 below shows the steps of fluid substitution using Gassman’s equation. (Mavko, et al.,1998) First from the density the shear modulus for dry rock was calculated and from those values the bulk modulus for the saturated rock was then calculated using Gassmann’s equation and this was used to calculate velocities with fluid substitutions.

-
- 1. Calculate velocities from length and transit times**
 - 2. Calculate density from porosity and fluid content**
 - 3. Extract shear modulus for all measure V_s ($\mu = V_s^2 * \rho$)**
 - 4. Derive bulk modulus for all measurements V_p ($K = V_p^2 * \rho - 4/3 \mu$)**
 - 5. From K_{dry} estimate K_{sat} using Gassman’s equation (equation 5)**
 - 6. Recalculate new velocity from K_{sat}**
-

Table 2. Procedure for fluid substitution using Gassmann’s equation

Figure 5. shear modulus for dry/partially saturated sample

Figure 6. Shear Modulus for clean sample

Figure 7. Bulk modulus for dry/partially saturated sample

Figure 8. Bulk modulus for clean sample

Figures 7 and 8 show the bulk moduli calculated at different fluid saturations for the two types of measurements. For the partially saturated sample in Figure 7 it can be seen that

the bulk modulus or hardness of the sample is similar for both brine and butane saturated rock. Since the shear modulus is dependent on density of the fluid and rock combined it should be noted that the density of the hydraulic fluid has an effect on the result. When the dry rock density (1.86 g/cc) was substituted with brine density (1.001 g/cc) and used to calculate the shear and bulk moduli there was a larger difference was in the dry sample measurements. In cleaned sample (Figure 8) the change in bulk modulus between dry, butane and brine saturated samples was much larger than for the sample with hydraulic oil.

From the bulk moduli the velocities resulting from fluid saturations for both brine and butane were calculated using the bulk modulus for the liquid as a function of pressure. The new Gassmann's theoretical compressional and shear wave velocities were calculated using the new bulk moduli and fluid density. The theoretical and actual velocities are plotted on Figures 8 and 9 for both measurements. The main point to consider is that Gassmann's calculated value may be inaccurate because it did not take the hydraulic oil saturation into account for the partially saturated sample. For the clean sample the measured brine fits the theoretical curves well. Gassmann's calculation put the butane at similar velocities to the measured velocities for the partially saturated sample.

Figure 9. Gassmann's fluid substitution for compressional velocity for brine and butane. Theoretical calculations indicate Gassmann's Brine velocity is faster than measured butane velocity.

Figure 10. Gassmann's fluid substitution for compressional velocity for brine and butane for clean sample. Theoretical calculations indicate Gassmann's Brine velocity is faster than measured butane velocity

Interpretation

From the measurements of the Troika sample and Gassmann's fluid substitutions we can conclude that increase in pressure results in increasing velocity. Liquid saturation causes increase in velocity in compressional waves. Shear wave velocities do not change with the presence of fluids. The presence of the hydraulic fluid in the sample changes the effect of fluid causing lower brine saturated velocities and higher butane saturated velocities. The assumed bulk moduli, fluid and rock densities may be inaccurate especially for the partially saturated measurements. Changing initial assumed parameters such as porosity, density and bulk modulus may produce more accurate results.

Figures 11 through 14 show the impedance response for different fluids for both partially saturated and clean samples for low and high-pressure conditions. It can be observed that for high differential pressure (~6500 psi) the impedance is high for butane and brine while the dry is relatively low for the partially saturated sample, which could create problems when trying to characterize fluid type. (Figure 11). The Impedance values for

over pressured partially saturated sample are very similar (Figure 12). This indicates that in over-pressured conditions it may be difficult to distinguish between various fluid saturations when the fluid is not a pure brine or butane. Also low -pressure conditions decrease the impedance.

Figure 11. Impedance for high differential pressure for partially saturated Troika sample

Figure 12. Impedance for low differential pressure for partially saturated Troika sample

Figure 13. Impedance for high differential pressure for clean Troika sample

Figure 14. Impedance for low differential pressure for clean Troika sample

When the high and over-pressured conditions are compared for the clean sample measurements the main difference is the impedance decreases when the reservoir is over-pressured. But in this case it is relatively easy to distinguish between the impedance values of dry, butane and brine saturated rock.

When comparing these results to what we see in the seismic traces, we have to consider that the scale is different. Overall the changes in this core could be a little as 0.03% of the wavelength if it is assumed to be 100m. Also, the primary drawback to ultra-sonics is their very high frequencies (100 kHz to 1 MHz). The velocities derived at these frequencies may differ substantially from seismic frequency velocities due to velocity dispersion. (Hofmann, 2004)

Comparison of results to Fluid Substitutions and Synthetic Seismic Response

When we compare the results of fluid substitution from the Troika field sample to the results of fluid substitutions in the nearby deep water Ursa well we observe similar trends in velocity changes and seismic amplitudes. It is important to remember that the results of the well log fluid substitutions are at a much larger scale.

Fluid substitution calculations were made on the upper and lower hydrocarbon intervals on the Ursa well from Mississippi canyon in Figures 15 and 16. These intervals were identified by Hiltermann (2001) in the Seismic amplitude Interpretation workshop book. For the upper interval, which was originally assumed to be at 10% gas saturation, fluid substitution was made for brine and from the brine saturated case fluid substitution was made for 50% gas saturation and oil. For the lower interval which was assumed to be oil, fluid substitution was performed to get the brine saturated case and from the brine saturation 10% and 50% gas substitutions were made. All of the fluid substitutions were performed using the Gassmann equation at normal pore pressure which was calculated to be ~6000 psi. For the upper interval the P-wave response has a slightly higher velocity at 10% gas saturation than at oil saturation. For the lower interval the P-wave velocities for the oil and gas saturated intervals have increased and there is a distinguishable gap between the oil and 10% gas saturation. For the logs brine saturation is represented by blue, oil saturation is represented by red, 10% gas saturation is represented by green and 50% gas saturation is represented by orange. When the seismic response correlating with its corresponding fluid saturation is examined it can be seen that the 50% gas saturation gives high amplitudes whereas the brine saturation results in lowest amplitudes. In this upper zone, 50% gas saturation is required to match the observed seismic amplitude, thus it is unlikely that this zone is “fizz”. What is interesting to note is that for the upper interval, the 50% gas saturation seismic response and the oil-saturated response are nearly indistinguishable and if random noise is added they will appear to be identical on a typical seismic line. The same applies for the lower interval when the 50% 10% gas saturation and oil saturation response are compared. Therefore, the amplitude response from these fluid saturations could be misleading if interpreted from a seismic line. This could be the same problem we are seeing in the Troika core measurements of the partially saturated sample. The properties used for the fluid substitution are shown in Table 3 below.

Properties used for the fluid substitution (from flag)

	API/Salinity	Density	Modulus
Gas	.6 API	.3092	.1524
Brine	100000 ppm	1.0266	2.8807
Oil	45.375 API	.7135	
Rock		1.85 ($\phi=30\%$)	20

Table 3. Properties used for the fluid substitution (from flag)

Figure 15. Fluid substitution for upper interval of Ursa Well

Figure 16. Fluid substitution for upper interval of Ursa Well

Conclusions

Changes in velocity with respect to presence of fluids and pressure changes in rock that are measured in the lab can be used predict how these parameters influence the seismic velocities that we see in field data. Gassmann's fluid substitution helps us to theoretically predict the influence of the fluids on the velocities. In the Troika sample measurements, there were several conclusions that were made about the impact of fluid and pressure changes on velocities. Particular combinations of fluids and pressures can result in seismic amplitudes that may be misleading. But if the right assumptions are made about fluid and mineral bulk modulus, porosity and fluid and mineral density we can come closer to the truth about the presence of fluids in the subsurface.

From the measurements of the Troika sample and Gassmann's fluid substitutions we can conclude that increase in pressure results in increasing velocity. Fluid saturation causes increase in velocity in compressional waves. Shear wave velocities do not change with the presence of fluids in these samples. The presence of the hydraulic oil in the sample changes the effect of fluid causing lower brine saturated velocities and higher butane saturated velocities when partially saturated. The impedance plots show that brine and butane may be difficult to distinguish in high pressure while dry and butane saturations may be difficult to distinguish between in low pressure. Also, in over-pressured conditions it may be difficult to distinguish between various fluid saturations when the fluid is not a pure brine or butane. Also low -pressure conditions have decreased impedance. When the high and over-pressured conditions are compared for the clean sample measurements the main difference is the impedance decreases when the reservoir is over-pressured. But in this case it is relatively easy to distinguish between the impedance values of dry, butane and brine saturated rock. When we compare Troika measured results to the Ursa fluid substitution we saw similar results. In the Ursa well upper interval, the 50% gas saturation seismic response and the oil saturated response are nearly indistinguishable and if random noise is added they will appear to be identical on a typical seismic line. The same applies for the lower interval when the 50%, 10% gas saturation and oil saturation response are compared. Therefore, the amplitude response from these fluid saturations could be misleading if interpreted from a seismic line.

Modeling AVO Response of Stratified Reservoir Models

Previous reports have summarized the propagator matrix methods used to compute *composite reflection coefficients* from stratified reservoir models. Briefly, this method allows the computation of exact P-wave reflection coefficients for a stack of horizontal, planar layers. This reflection coefficient is the magnitude of the total P-wave energy reflected by the stack of layers, including all internal reverberations and mode conversions between compressional and shear waves. Propagator matrix methods are a well known, standard approach for solving problems like this in a fast and efficient way that avoids explicitly solving boundary condition equations at all of the interfaces in the model (e.g., Aki & Richards, 2002). An example of the type of models we consider is shown in Figure 17, which includes a 30 m thick reservoir that is comprised of a stack of layers that are each 1 m thick. The elastic moduli of each internal layer were chosen by randomly perturbing the bulk and shear moduli of the reference value of 2.9 km/s. The bulk modulus perturbation was selected from a Gaussian probability distribution function with a mean of zero and a standard deviation of 0.5 GPa, and the shear modulus was varied so that the V_p/V_s ratio remained about 1.8.

A total of 50 such models were generated to study the fluctuations in AVO response that might be encountered where reservoir properties vary laterally because of changes in lithology. An important and relevant example of such geologic variation would be in areas where turbidite deposits are found, such as many deep water hydrocarbon exploration and production sites. While the propagator matrix solution does allow the computation of the exact response, an important practical question is whether or not it is in fact necessary to model all of the complex, fine-scale velocities to accurately model the reflection coefficient. One option would be to estimate the *average* properties of the layer, using, for example, the Backus averaging method (Backus, 1962). In the past quarter, we directly examined the difference between the exact response and the values obtained from homogeneous, reservoir models with properties obtained by computing the Backus average of the velocities of the 30 layers inside each reservoir model. For simplicity, we utilized the vertical velocity values for both P- and S-waves, neglecting effective anisotropy in computing averages, which is reasonable since we consider near-vertical wave propagation in most results.

Figure 18 compares the reflection coefficients for the exact (green) and the average models (red) for an incident wave with a frequency of 30 Hz. The mean and standard deviation of the coefficients are shown in Figure 19. In this case the Backus average models capture most of the scatter in the reflection coefficient, though they slightly underestimate the standard deviation of the coefficient at near normal incidence. This shows that most of the change in coefficient is caused by variations in the tuning of reflections from the top and bottom of the reservoir, not by scattering from internal boundaries. It is not too surprising that the Backus averages produce good results for this model, since the velocities themselves are essentially fluctuations about a mean value. In this case, computing the average formation properties is therefore reasonable. Similar calculations for models with larger variations in velocity inside the reservoir, however,

show that the average models become less accurate and internal velocity structure is more important.

Figure 17. An example of the stochastic models used to compute composite reflection coefficients. The black line indicates the reference model with a 30 m thick homogeneous reservoir, and the red line shows one of the heterogeneous reservoir models

Figure 18. Comparison of reflection coefficients computed for the stochastic, heterogeneous reservoir models with 30 internal layers (green) and the homogeneous reservoir models with velocities determined by taking the Backus averages of the heterogeneous models

Figure 19. The curves show the mean value of the reflection coefficients for the 50 models shown in Fig. B. The error bars show values one standard deviation above and below the mean value of the reflection coefficient.

Introduction

Attenuation is becoming an important seismic property for reservoir characterization because of its sensitivity to fluid saturation. The study of attenuation is not an easy problem because it makes seismic amplitude frequency dependent along with wave propagation effects, such as tuning. Also, processing artifacts, such as NMO (Normal MoveOut) stretch, could distort the frequency and amplitude content severely according to reservoir depths and offset locations, which makes problems more complicated. Thus, our objective here is (1) to study the effects of wave propagation and processing artifacts and (2) to consider or remove those effects for a better characterization and quantification.

The AVO (Amplitude Variation with Offset) technique has been used quite successfully for the detection of hydrocarbons while the estimation of hydrocarbon saturation is still a challenging task. The recent detection of hydrocarbons based on low frequency related phenomena can be highlighted by Castagna et al. (2003) and Goloshubin et al. (2002), which motivated us to investigate an additional problem of low frequency effects by hydrocarbon saturated thin layers. Meanwhile, the following publications deal with issues related to tuning and NMO stretch. Dunkin and Levin (1973) derived equations for stretch ratio and used it as a linear correction factor. Swan (1999) removed offset-dependent tuning and analyzed AVO crossplots based on a three-term equation over reservoir models with different fluid content. Castoro et al. (2001) studied effects of tuning and NMO stretch and corrected the NMO stretch based on wavelet deconvolution, which could overwrite important low frequency effects. Lazaratos and Finn (2004) used near offset traces to avoid this problem while redundantly applying their algorithm to the whole data for automation with a localized Q compensation filter. Several other

approaches to avoid the stretch correction at the stage of moveout can be found in Rupert and Chun (1975) and Trickett (2003).

These studies on AVO analysis are based on broadband data with a single central frequency. To better understand the frequency related effects by attenuation, we need to develop a scheme that considers individual frequency components because different constructive or destructive interferences will occur in different frequency bands. In our previous study, we tried to seek examples of frequency dependency and to identify possible roadblocks from the field data observations and demonstrated that the NMO stretch and tuning could distort frequency and amplitude information (Yoo and Gibson, 2004). Here, we verified a simple frequency shift scheme to correct frequency content using full waveform synthetics and field data. Finally, we analyzed the crossplots of AVO attributes of Teal South field data after the stretch correction over three different frequency regions.

Target oriented stretch correction

A full waveform synthetic over a two half spaces model has been computed to test the idea. Figure 20a shows the NMO corrected synthetic data in this model. To test the effectiveness and to identify possible problems of this algorithm, an extreme case (shallow and far offset trace) is considered. As traces go to far offset, the width of the wavelet increased due to the NMO stretch. Two 3000 m offset traces (before and after NMO) are shown in Figure 21a. In this ideal case, exact values for stretch ratio and amplitude before NMO are known. The numerical estimation of stretch ratio and the exact stretch ratio that is computed from synthetics are shown at Figure 21b. Stretch ratio can be estimated quite accurately using the equations from Dunkin (1975). By shifting the Fourier components by this stretch ratio amount, we can reverse the NMO stretch effect. As noted earlier, low frequency data is less affected compared with high frequency data. Amplitude values before NMO, after NMO, and after stretch correction are shown in Figure 21c-d. After NMO, the maximum amplitude of the wavelet has been changed. After the target oriented NMO stretch correction, the correct amplitudes have been recovered. The percent errors on amplitudes after the stretch correction (Figure 22a) shows less than 5% over all offset ranges compared with ~40% error at 3000 m offset. For a better quantification of amplitude and frequency, time-frequency representation based on wavelet matching (Liu et. al., 2004) is used (Figure 22b-d). The amplitude and frequency information matches very well while the after NMO trace shows severe distortions in amplitude and frequency.

Analysis of AVO crossplots after stretch correction

In our previous study of Teal South data (Yoo and Gibson, 2004), low frequency data showed the stronger amplitude increase with offset while high frequency data exhibited almost no increase (actually decrease) in amplitude with offset. We concluded that this observation was coming from the NMO stretch artifacts not from any other frequency dependent phenomena.

Two productive zones from the time lapse data, 20 CMP gathers near 4500 ft sand and 10 CMP gathers near “little neighbor”, have been picked for an AVO attribute analysis. First, we applied the target oriented stretch correction only to the events of our interest (Figure 23). This is because class I and II anomalies will be affected by very small amount compared with class III and IV AVO anomalies (Downton, 2004). Some of the difficulties include (1) severe mute of input data, (2) high S/N ratio, (3) non-regular offsets. After careful choices of the stretch ratio threshold, the application window length, and the taper size, the result of stretch correction is shown in (Figure 23b). Narrower wavelets are clearly visible at far offsets and the alignment of events was significantly improved. Time-frequency representations of a CMP gather before and after the stretch correction are shown in Figure 24. By comparing relative amplitude with offset at ~1.42 sec, we can see a clear difference at the 50 Hz plot. Before the stretch correction, the amplitude changes from strong to weak (Figure 24c). On the other hand, the amplitude changes from strong to strong can be observed after the stretch correction (Figure 24f).

We performed a further test using crossplots of AVO attributes of normal incidences and gradients to see how significant amount of changes were done after our stretch correction. First, the crossplots from two events (4500 ft sand and little neighbor) was compared (Figure 25). It is clearly visible that many points in the 2nd and 4th quadrants systematically moved to 1st and 3rd quadrants in the 4500 ft sand case. These random points occur due to the NMO stretch or the misalignment of events. On the other hand, we do not see a very large amount of change in the little neighbor case. Over three different frequency ranges, we performed the same analysis. Considering the previous study and our synthetic tests, we expect a very small amount of change in low the frequency region due to the smaller shift of energy to high frequency region. As expected, it showed almost no change only with a very small amount of decrease in gradient values (Figure 26). They tend to have a trend over the 1st and 3rd quadrant before the stretch correction and it is still maintained with very subtle changes in gradient after the stretch correction. In case of mid and high frequency data, a significant amount of change could be observed. Specifically in high frequency data, they tend to have a trend over the 2nd and 4th quadrants before the stretch correction. After the correction, it clearly showed a different trend, which is similar to the low and mid frequency data. In this 4500 ft reservoir, the class III AVO anomaly over three different frequency ranges after the target oriented stretch correction becomes more obvious.

Further analysis using time-frequency representation is shown in Figure 27. As expected, slight decrease of amplitude was observed at the 20 Hz slice and significant amounts of amplitude increases were clear at 35 Hz and 50 Hz slices. Also, misalignments before stretch correction have been improved for a better AVO inversion. After constructing frequency cubes by spectral decomposition, we inverted the amplitude for normal incident and gradient attributes (Figure 28). The crossplots of spectral decomposition is different due to the all positive nature of its outputs. Background trends are located over the 2nd and 3rd quadrants and we observe systematic increases of gradient values like Figure 26. The major difference comes from negative normal incidence values due to

some strong gradient values. These points were plotted in the 2nd quadrant rather than the 1st quadrant, which makes a clear separation. In the three band-pass filtered data experiment, these points were plotted in the 1st and 3rd quadrants mixed together with less separation. In other words, stronger changes in gradient attributes mean different rock or fluid properties and this analysis found to be more sensitive in distinguishing details in AVO with extended frequency information.

Figure 20. . A synthetic data from two half spaces model. (a) NMO corrected shot gather, (b) Stretch corrected shot gather. Notice wider wavelets with increasing offset after NMO.

Figure 21. Comparisons among before NMO, after NMO, and after stretch correction. (a) 3000 m offset traces (before NMO and after NMO), (b) Stretch ratio (blue: computed from input data, red: estimation using Dunkin (1975) equation), (c) and (d), Absolute maximum amplitude of wavelets of before NMO (blue), after NMO (red), and after stretch correction (black).

Figure 22. Amplitude changes of after-NMO and after-stretch-correction over before-NMO (Upper left). After the stretch correction, percent errors in amplitudes show less than 5%. Time-frequency representations based on wavelet matching (3000 m offset traces for before and after NMO, after stretch correction). Notice the match of frequency contents after the stretch correction.

Figure 23. Teal South CMP gathers (10981144) before and after stretch correction. The resolution of far offset reflections and the alignment of reflections have been improved: clearly visible at far offsets. Using stretch ratio threshold of 1.01, traces after the 4th are corrected for NMO stretch.

Figure 24. Comparisons of TF analysis for three different frequencies (20 Hz, 35 Hz, 50 Hz). Left column: before stretch correction. Right column: after stretch correction. Notice the relative amplitude increase at 50Hz data after the stretch correction. Anomaly at far offset of 20Hz data are still observable in both cases. Phase II of CMP 11041150. Each plot has been normalized to the maximum value between 1.35-1.55 sec.

Figure 25. AVO crossplots of normal incident and gradient attributes. Left column: before the stretch correction. Right column: after the stretch correction. (a) and (b): data including 4500 ft sand from Phase II. (c) and (d): target reservoir only of (a) and (b): data including 4500 ft sand from Phase II. (e) and (f): data including little neighbor from Phase II.

Figure 26. AVO crossplots of normal incident and gradient attributes from the three different bandpass filtered data ($f_c=20, 35, 50$ Hz). Only the target event is used. Left column: before the stretch correction. Right column: after the stretch correction. (a) and (b): low frequency data. (c) and (d): mid frequency data. (e) and (f): high frequency data. Notice significant changes in mid and high frequency data after the stretch correction while low frequency data shows a subtle decrease in gradient.

Figure 27. Zoomed time-frequency representations of CMP 1139 before (left column) and after stretch correction (right column). Horizontal axis for trace numbers and vertical axis for time. (a) and (b): 20 Hz, (c) and (d): 35 Hz, (e) and (f): 50 Hz. Notice the very slight reduction of amplitude at 25 Hz while amplitudes increase with offset at 35 and 50 Hz with better alignment. Colorbar denotes normalized amplitude to the maximum of each gather.

Figure 28. AVO crossplots of normal incidences and gradients from spectral decomposition before (left column) and after (right column) stretch correction. (a) and (b): 20 Hz, (c) and (d): 35 Hz, (e) and (f): 50 Hz. Results are similar to three bandpass experi

Conclusion

For a better amplitude and frequency analysis, a NMO stretch correction scheme based on simple frequency shift is successfully applied to simple synthetics and several reflections of our interest in Teal South data. Our current algorithm can be considered as a quick fix for the amplitude based analysis among targets, but it seems to be more proper than wavelet deconvolution based methods that could change the frequency content. Amplitude and frequency corrections have been verified through full waveform synthetics over wide offsets with the additional improvements in the event alignment. Combined with a time-frequency representation and an AVO attribute analysis tool, this work flow found to be a very fast and effective. The field data application clearly showed changes in amplitudes with offset, which result in the increase of gradient attributes significantly in the high frequency region on the class III AVO anomalies. In the frequency dependent analysis, the low frequency data is less affected by NMO stretch while significant changes and improvements were observed in mid and high frequency data. In a further analysis using spectral decomposition, we observed similar gradient increases but different AVO crossplot behaviors due to the all positive amplitudes. Using the combination of spectral decomposition and AVO attribute inversions, more details within reservoirs could be studied from increased sensitivity and extended frequency information.

Tuning Effect on A-B Crossplot of Class III Type Gas Sands

Fluid Substitution via Gassmann's equations, Statistical Rock Physics' tools (Montecarlo simulations), Forward modeling and amplitude estimation using Zoeppritz's equations were used to analyze the tuning effect (thin layer tuning and offset differential moveout) on AVO intercept/gradient classification of Class III type gas sands.

For gas sands exhibiting P-wave impedance lower than brine sands and shale, the tuning effect can be observed on A-B crossplot when AVO intercept and gradient become more negative as layer thickness decreases; however for very thin layer thickness (less than $\lambda/4$), AVO intercept and gradient decrease in magnitude creating a possible source of mis-classification of a Class III type gas sands as a Class III type brine sands.

In seismic exploration, geophysicists must consider the different problems and pitfalls affecting amplitudes in order to determine the applicability of amplitude variation with offset (AVO) in a reservoir area. AVO response can be interpreted based on the combination of intercept and gradient estimates, to form indicators that remove background reflections and enhance anomalous events. Swan (1991) and Lin (1993) discuss several sources of error for AVO intercept and gradient estimates, including offset differential moveout and thin layer tuning. The first source of error is especially true for reflectors having a large zero-offset response, such as, class I and class III sands.

Thin layer tuning, another source of error in AVO analysis to be studied here. Resolvability depends upon both seismic frequency and layer thickness (Lin, 1993). Widess (1973) explained that the relationship between amplitude of the reflection is proportional to bed thickness and inversely proportional to the wavelength. However, if two media bounding the thin bed have the same acoustic impedance, reflections from thin beds are not necessarily restricted to small amplitudes. The purpose of this section is making use of statistical Rock Physics' tools as Montecarlo simulations expose the tuning effect on the classification of typical gas sands type class III based on AVO intercept/gradient estimation.

After establishing some preliminary definitions, we present and analyze the results obtained applying a simple methodology, which includes, fluid substitution using Gassmann's equations, employment of Montecarlo (MC) simulations to obtain synthetic gathers and finally AVO intercept and gradient estimation using Zoeppritz's equations to examine the effect of layer thickness in AVO response.

Theoretical background

The effect of offset differential moveout can be illustrated modeling the response of a simple earth model with three flat beds; a gas sand encased in two layers with the same acoustic impedance (Figure 29a). Offset differential moveout or offset dependent tuning can be explained as the direct result of the non-parallel nature of normal moveout (NMO) hyperbolae, this means that when NMO decreases with time, the time difference between the top and base sand reflections narrow as offset increase (Figure 29b), i.e., $\Delta T_x < \Delta T_0$

(Ostrander, 1984). For extreme cases, the time difference of two events involved in tuning phenomenon can decrease from near to far offset nearly 30%. In the same manner, differential tuning affects the amplitude in 30% (Ostrander, 1984).

Lin (1993) derived the following equations for intercept amplitude and gradient amplitude under tuning conditions. It shows that differential moveout (tuning) can cause AVO behavior. Following calculations for offset differential moveout can be defined using the same earth model displayed in Figure 29a. The intercept amplitude derived from Zoeppritz's equation (6) is exactly equal to offset tuning amplitude at each offset (2), which is a modified version of Widess formula at incidence angle, it can be expressed as:

$$A = \frac{1}{2} \left(\frac{\Delta Vp}{Vp} + \frac{\Delta \rho}{\rho} \right) \quad (6)$$

$$A_i(\theta) = \frac{4\pi b}{VgT} A \quad (7)$$

Where A is the true normal incident amplitude, b is the thickness, Vg is the interval velocity and θ is the incidence angle. On the other hand, the gradient derived from Zoeppritz's equations and the tuning amplitude gradient B_t can be defined as follows:

$$B \approx \frac{V^2 s}{V^2 p} \frac{\Delta \rho}{\rho} + \frac{1}{2} \frac{\Delta Vp}{Vp} - 4 \frac{V^2 s}{V^2 p} \frac{\Delta Vs}{Vs} \quad (8)$$

$$B_t = \frac{4\pi b}{VgT} (B - \frac{1}{2} A) \quad (9)$$

The above calculations indicate that AVO analysis is not only affected by layer thickness but also by differential moveout (Lin, 1993).

In order to understand the effect of layer thickness on AVO intercept and gradient classification, several tasks were included in our technical approach:

1. Using well-log information, sand and shale bed sequences were defined based on rock properties and gamma ray logs.
2. Since shear sonic logs were not available, shear velocity prediction was carried out using Han's relation (1986) for shale sequences and the Greenberg-Castagna (1993) relation for brine – saturated sandstones.
3. Fluid substitution using Gassmann's equations was conducted using appropriate values for rock properties derived from ultrasonic measurements.
4. Statistical distributions for P-wave velocity (V_p), S-wave velocity (V_s) and density (ρ) corresponding to shale, brine and gas sandstones were performed via Montecarlo simulations to compute AVO intercept and gradient. The use of Montecarlo simulations takes advantage of the vertical variability of rock properties for different fluids. This implies that statistical Rock Physics considers, in some degree, the

geologic and depositional process and events experienced by the cap rock and reservoir rock.

5. To form synthetic CDP gathers, well-log information of a gas sand encased in shale sequences were assumed to be the reflectivity series convolved with a 30Hz Ricker wavelet. The thickness of the gas sand layer was changed from 300ft to 10ft.
6. Estimation of normal incidence amplitude (A) and gradient (B) were computed based on the Zoeppritz's equations in order to obtain the resulting A-B crossplots. These crossplots influenced by thin layer tuning were analyzed for gas sands type class III.
7. Comparisons between AVO response of the reservoir gas sandstone and brine sandstone under tuning condition and under non-tuning condition (thickness higher than $\lambda/2$) were analyzed.

Discussion of the Results

After fluid substitution, applying Gassmann's equations and shear velocity prediction using Han ($V_s = 0.7936V_p - 0.7868$) and Castagna's ($V_s = 0.8042V_p - 0.8559$) relations, we have the necessary input well-log data (V_p , V_s and ρ) for the reservoir gas sandstone and the overlaying layers (Figure 30).

As we explained before, we convolved well-log data, assumed as our reflectivity series, with a Ricker wavelet with a central frequency equivalent to 30Hz. The model parameters used for this forward modeling are presented in Table 1. The only non-fixed parameter is the thickness of the gas sand. Figure 31a and 31b show the effect of differential moveout and thin layer tuning in the constructive and destructive interference of the energy. At near offsets the time difference between reflections from top and base of the gas sand layer is larger than the time difference at far offsets, as theory predicts.

The next stage of the investigation is focused on normal incidence amplitude (A) and gradient (B) amplitude estimation via Zoeppritz's equations. With the intention of knowing the tuning thickness for the reservoir gas sand, following the definition given by Widess (Widess, 1973), we plotted the normal incidence amplitude versus variation in 2004 Fluids/DHI Tuning Effect on A-B Crossplot thickness (Figure 32). From this result, we can conclude that interference of the energy occurs, approximately, at 65 ft (19.8 m) and maximum interference or tuning at 32.5 ft (9.9 m).

A-B Crossplots

AVO interpretation may be facilitated by crossplotting the AVO intercept and gradient. Generally, brine saturated sandstones follow a well defined "background trend in the A-B plane, deviations may be indicative of hydrocarbons, specifically bright spots sands which fall in quadrant III and have negative AVO intercept and gradient.

The above case is similar to ours, when we plot the values of A (intercept) and B (gradient). Gas sands, fall in quadrant III and brine sands follow the background trend (Figure 33). This plot suggests that for gas sands under tuning condition, the classification

A-B discriminate more easily from brine sands, since intercept and gradient become more negative as bed thickness decrease. Another characteristic noticeable in this plot is the wide scatter of the gas sand response. According to Swan (1991), this effect is caused by offset dependent tuning and is minutely manifested for brine and oil sands response due to smaller high-angle reflection amplitude for these sands. Generally, gas sands exhibit lower velocity than brine and oil sands.

For every thickness we have all intercept and gradient values corresponding to every combination of shale and gas sand obtained via Montecarlo simulations. Since these distributions are partially overlapping each other, as we approach zero thickness, we computed the median for every set of thicknesses (300ft, 65ft, 45ft, 32.5ft, 20ft, 15ft, 10ft) in order to gain a better understanding (Figure 34). This result shows that for small values of thickness, A and B become increasingly negative until they approach 32.5 ft (9.9m), which happens to be the point of maximum constructive interference for normal incident amplitude (A). At this point the amplitude decrease in magnitude since destructive interference of the reflection takes place as thickness diminishes until both, amplitude and thickness approaches to zero. This means, for very thin layer thicknesses, gas sands Class III might possibly be interpreted erroneously as a brine sands.

Frequently, it is claimed that when we invert from seismic data to calculate A and B, the separation for gas and brine sands on an A-B crossplots is bigger than when we performed fluid substitution using Gassmann's equations to estimate A and B. To investigate further in this statement, we analyzed the AVO response for brine and gas sandstone with a layer thickness equivalent to 70ft and for brine and gas sandstone of layer thickness equal to 45ft, under tuning conditions. The result shown in Figure 35 implies that one reason for this discrepancy between seismic data response and Gassmann's equations response to be the tuning effect presents on seismic gathers.

Conclusions

AVO analysis is affected by several complications and pitfalls. Tuning effect is one of those sources of error. For gas sands type Class III, the tuning effect causes estimation of AVO intercept and gradient to be more negative than the rock properties of the reflecting interfaces predicts. However, an erroneous classification of gas sands as brine sands could be possible for very minute layer thicknesses. On the other hand, we suggest the tuning effect as one explanation for the discrepancy that is sometimes encountered between estimation of intercept (A) and Gradient (B) from seismic data and fluid substitution via Gassmann's equations.

PARAMETER	VALUE
Thickness of Layer 1	700m
Thickness of Layer 2	Variable
Maximum Offset	700m
Sample Interval	20m
Time Length (max.)	4s
Time Interval	0.001s

Table 4. Parameters used in the forward modeling.

Figure 29. a) Earth model used to show the effect of offset differential moveout for thin gas sands.

b) Offset differential moveout observed in the CDP gather.

Figure 30. Well-log information. After fluid substitution and shear velocity prediction.

Figure 31. a) Synthetic CDP gather with layer thickness of the gas sand equal to 300ft . b) Synthetic CDP gather with layer thickness of the gas sand equal to 45ft

Figure 32.
Thickness vs.
Intercept (A)

Figure 33. A-B
crossplot for gas
and brine sands.
Note the tuning
effect in the
position of the
same gas sand on
the A-B crossplot
as layer thickness.

Figure 34. A-B crossplot of the median of the distribution for every layer thickness. Note the effect predicted by Widess, layers with different thickness present similar amplitude values.

Figure 35. Discrimination on A-B crossplots for brine and gas sands with layer thickness under 0.02 tuning condition is higher than for sands with layer thickness under tuning condition.

Plans

As we enter our final year of this project, we will concentrate on several aspects of research, integration, application, and dissemination.

Our test site environments are largely dominated by complex turbidite sequences. We have constructed several general geologic cross sections characteristic of deep water settings. These have included sections from direct observations in the field (Brushy Canyon formation, Lewis Shale) and from sections derived from Gulf of Mexico seismic and log data (Ursa). We will complete schematic sections for our other deep water areas (e.g. Nansen, Neptune, Viking Graben). We will begin immediately to develop more realistic seismic forward models based on these sections. Because these turbidites will have internal structures with variable thicknesses of sand and shale units, it will be important to develop constraints on the importance of these structures for changing AVO responses. We will continue to investigate the applicability of using Backus average methods for simplifying calculations. We will concentrate at first on building several one dimensional models and combining them into effective two dimensional sections. In addition, we can use the more realistic geologic models to constrain the variability in our A-B plots due to tuning and thin bed effects.

Several recent investigations have shown that attenuation is an important seismic property for reservoir characterization because of its sensitivity to fluid saturation. We expect to complete our ultrasonic measurements on the core samples within the next two quarters. We can then move on to measurement of both velocity and attenuation at low frequencies. At our current stage of understanding, it is not clear how different fluids interact with the rocks to cause attenuation.

Although frequency extraction from seismic data is linked to attenuation, neither the best methods for measurement nor interpretive techniques are yet well developed. We will further develop various forms of wavelet transforms for higher resolution frequency extraction. The study of attenuation is not an easy problem because it links seismic amplitudes and frequency dependence with wave propagation effects, such as tuning. Also, processing artifacts, such as NMO (Normal Move Out) stretch, could distort the frequency and amplitude content severely according to reservoir depths and offset locations, which makes problems more complicated. Thus, our objective here is (1) to study the effects of wave propagation and processing artifacts and (2) to consider or remove those effects for a better characterization and quantification.

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