A METHODOLOGY TO INTEGRATE MAGNETIC RESONANCE AND ACOUSTIC MEASUREMENTS FOR RESERVOIR CHARACTERIZATION

Semi-Annual Report
April 1, 1999-October 31, 1999

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Date Published: January 2001

Work Performed Under Contract No. DE-AC26-99BC15203

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National Petroleum Technology Office
U.S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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for Reservoir Characterization

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SEMI ANNUAL REPORT

TITLE: A Methodology to Integrate Magnetic Resonance and Acoustic Measurements for Reservoir Characterization

DOE CONTRACT No: DE-AC26-99BC15203

CONTRACTOR: Southwest Research Institute
San Antonio, Texas

SWRI PROJECT MANAGER: Jorge O. Parra, Ph.D., Staff Scientist

DOE PROJECT MANAGER: Purna Halder

PROJECT DURATION: Three years

REPORTING PERIOD: April 1, 1999-October 31, 1999

OBJECTIVES

The objective of the project is to develop an advanced imaging method, including pore scale imaging, to integrate magnetic resonance (MR) techniques and acoustic measurements to improve predictability of the pay zone in two hydrocarbon reservoirs. We will accomplish this by extracting the fluid property parameters using MR laboratory measurements and the elastic parameters of the rock matrix from acoustic measurements to create poroelastic models of different parts of the reservoir. Laboratory measurements will be compared with petrographic analysis results to determine the relative roles of petrographic elements such as porosity type, mineralogy, texture, and distribution of clay and cement in creating permeability heterogeneity.

ACCOMPLISHMENTS OF PHASE I

Task 1. *NMR Instrumentation Preparation and Imaging of Core Samples.* The Bruker MSL-300 imaging spectrometer is being prepared and calibrated. This system will be used to image core samples in the second phase of the project.

Task 2. *Conduct nuclear magnetic resonance (NMR) core measurements.* Low frequency measurements and analysis of selected cores will be performed.

Existing NMR core data from a South Florida water reservoir is being reviewed and analyzed. In particular, the data has been processed to determine the pore size distribution of the carbonate rock. Appendix A describes the procedure and gives an example using NMR core data from Florida.

Task 3. *Implement theoretical relations between effective dispersion and stochastic medium properties at the core and borehole scales.* The 2D random medium solution of the heterogeneous wave equation will be implemented to produce attenuation and dispersion 2D images. The images will be used to address the core and borehole scales.

The solution of the stochastic wave equation was extended to examine the role of scattering on multiple length scales and applied in a real sedimentary sequence of the Buena Vista Hills reservoir. We determined that inclusion of multiple length scales in stochastic medium wave theory is straightforward if the transitions associated with each length scale are statistically independent. We also examined the interaction of scattering and the squirt flow attenuation mechanism in a permeable medium. A manuscript describing the results was prepared and submitted for publication. Appendix B includes the manuscript in draft form.

Task 4. *Conduct imaging analysis using existing core and well log data.* Existing data sets of the selected reservoir will be used to address scale issues and verify the theoretical models developed in Task 3.

Existing VSP and sonic logging data from Siberia Ridge is being processed and applied to construct dispersion and attenuation models. The objective is to use the model to correct the total attenuation for scattering effects. The resulting intrinsic attenuation will be related to flow properties (e.g., permeability, porosity, saturation, etc.). Reservoir properties will be determined from the cores and well log data (see Task 6).

Task 5. *Construct dispersion and attenuation models at the core and borehole scales in poroelastic media using real rock and fluid property parameters.* Data gathered in Task 4 will be used to predict attenuation and dispersion associated with fluid flow effects.

We have used the core/well log data from the Buena Vista Hills reservoir to analyze the effects of cracks and fractures on azimuthal attenuation. The attenuation previously computed as a function of depth was related to vertical cracks and fractures observed in the Brown Shale Formation at the Buena Vista Hills reservoir. The results suggested that multi-frequency acoustic/seismic measurements should be used to map cracks and fractures at the Buena Vista Hills field. A manuscript was prepared and it will be submitted for publication to a peer reviewed journal. Appendix C includes this manuscript in draft form.

Task 6. *Petrophysics and catalog of core and well log data.* The petrophysics, core data, and well log data from selected reservoirs will be evaluated and cataloged for the data analysis addressed in Tasks 4 and 5.

We have received core and well log data as well as a VSP data set from Siberia Ridge, Well 5-2. This data was gathered by Schlumberger and GeoQuest for a Gas Research Institute project. The in-kind cost of the data is addressed in the Funding Section of this report. We have over 30 different logging curves, including several resistivity, gamma ray, SP, P velocity from sonic logs, and neutron porosity measurements, as well as several derived parameters like saturation, % shale and % coal by volume, and computed permeability. We also have NMR logging data including the Schlumberger processed

T2 distribution curves, and NMR measured porosity. We are expecting to receive FMI resistivity data and dipole sonic data from this well. The core and well log data were cataloged. Once all the data is received the catalog of the data will be included in the first year annual report. A preliminary catalog of the Siberia Ridge data is given in Appendix B.

Task 7. Technology transfer activities and reports. Poster presentations, peer review papers and reports will be prepared under this task.

The manuscript titled, "Attenuation of Acoustic Waves from Multi-scale Scattering and Pore Flow in Heterogenous Permeable Media," was submitted to the *Journal of the Acoustical Society of America*. The manuscript is given in Appendix A.

WORK TO BE PERFORMED

I. Analysis of Sonic Log and VSP scales

We have VSP data from the 5-2 Well for a single offset. This includes 291 waveforms from 97 three-component receiver locations, extending down to 11,000 feet. Receiver locations are spaced approximately 50 feet apart in the lower part of the well (8000 to 11,000 feet) and are more widely spaced at shallower depths. This overlaps with the primary producing formation and an extensive suite of well logs, which extend from roughly 10,600 feet to 11,000 feet. The VSP data may be analyzed by itself and integrated with the P velocity data from sonic logs to gain additional insight on the acoustic behavior of the rock formations.

Using the VSP data alone, we can pick first arrivals to obtain an estimate of the compressional wave velocity at the VSP frequency (approximately 10-30 Hz). At first glance, the VSP measured compressional velocities appear to be significantly slower at the reservoir depths than the sonic logging velocities. This unusual behavior may arise from several effects, but the most likely at this time is shale anisotropy. The well is deviated at a 45 degree angle through the reservoir, and the high shale content of the reservoir sands and overlying sediments makes it likely that anisotropy in the shale is appearing in the sonic log. To integrate the vertical path VSP data we must be able to correct for the anisotropic velocity variations in the non-vertical sonic log. A log of fractional shale content supplied by Schlumberger/GeoQuest may be helpful here.

The reservoir is deep enough that there is significant uncertainty in the attenuation as measured by observed or spectral amplitude. The combined attenuation includes both scattering effects from the stratigraphic layering and intrinsic effects from rock anelasticity and viscous fluid motion. We will be able to predict the scattering effects as a function of frequency by constructing models from the Vp sonic log and a lithological column for the well (after correcting for anisotropy). The magnitude of the predicted scattering effect can be checked against known plane-wave stochastic medium solutions.

Once the scattering effect is quantified, we can subtract that from the combined attenuation to obtain the intrinsic attenuation as a function of depth. Intrinsic attenuation is often associated with fractures and softer, permeable rocks. Another estimate of intrinsic attenuation may be obtained by

comparing the low frequency VSP velocity and the high frequency sonic log velocity. The dispersion between these two frequencies will be directly related to the attenuation in the rocks. It is important to try to estimate wave attenuation at higher frequencies, because fluid based attenuation is rarely significant at low frequencies.

II. Characterization of Flow Units/Fractures Using NMR, Acoustic, FMI and Petrophysics

A lithological column will be constructed based on well logs and core data from the Siberia Ridge well. Flow units will be identified in the lithology columns using the NMR well log data and core data. Rock physic relationships will be implemented to relate the properties of the flow units (permeability, porosity, fluid saturations, etc.) with acoustic data, V_p , V_s , and attenuation derived from the dispersion analysis addressed in (I). The objective of this task will be to be able to relate V_p , V_s and attenuation with flow units in zones where core data was not recorded. In addition, we will correlate the FMI data with the lithology to identify fractures. We will identify zones where the presence of fractures contributes to the overall permeability. We will attempt to address how the presence of fractures affects the NMR signature, the V_p/V_s ratio, and the attenuation.

III. Analysis of Florida Data

The data set from the South Florida water reservoir is rich in information relevant to our project. It contains monopole/dipole sonic full waveform well logs, NMR well logs, standard well logs, processed Stoneley permeability data, NMR core data, geotechnical core data (permeability, porosity, density, capillary pressure, etc), and the lithology of the carbonate formations. This data set will be used to predict empirical permeability relationships at the core scale that will be used to calculate permeability from NMR well logs. In addition, the NMR core data with the capillary pressure will be used to predict the pore size distribution from T2 distributions. These values will be verified with thin sections and NMR data. The goal of this analysis is to be able to predict the pore size distributions from NMR well logs. In addition, the Stoneley permeability will be compared with the NMR derived permeability. These permeability values will be correlated with the lithology and pore size distributions to determine their origins and scales.

In particular, we will attempt to simulate the effects of the different porosities in the carbonate on attenuation and dispersion using the stochastic solution addressed in Task 3.

FUNDING

The total contract amount for the first year of this DOE project was \$229,000; the present balance is \$170,000. Since we have the data to carry out Phase I of the project, we can proceed and use the project balance to accomplish the proposed work for the rest of the tasks. In addition, the total in-kind contribution from Springfield Exploration (SE) is \$300,000 for three years (see Appendix E). We expect to use the SE in-kind contribution sometime in the second year of the project. However, to accomplish the Phase I tasks, we have obtained a data set from Schlumberger and GeoQuest from a Siberia Ridge project that is sponsored by the Gas Research Institute. The cost of this data set is over \$350,000. A detailed explanation of the cost of this data is given in Appendix F.

APPENDIX A

NMR Core Data Analysis from the South Florida Water Management Project

During this period we processed core data from the Florida Data Set Project. Progress was made as follows:

There are two frequently used permeability models based on NMR. The first (a) is based on the logarithmic mean T_2 , and the second (b) is based on the free fluid index.

- a. One of the empirical models is the Carman-Kozeny model:
$$k = [\phi^3 / \tau (1 - \phi)^2] (S/V)^{-2}$$
and the following equation is used to estimate sandstone permeability:
$$k = c \phi^4 T_{2, LM}^2$$
where $T_{2, LM}$ is the logarithmic mean of T_2 distribution and porosity is in fraction.
- b. The second permeability model is based on the free fluid index from the T_2 relaxation distribution:
$$k = 10^4 \phi^4 (FFI/BVI)^2$$

where porosity is also in fraction. BVI is bound-fluid irreducible and FFI is free-fluid volume from the desaturated and saturated T_2 distributions for the partitions of pore volume, which are the bound-fluid and the free-fluid. The cutoff values (or BVI) are used to estimate the irreducible water saturation from NMR data. The T_2 distributions were obtained from the fully saturated water and the desaturated samples made by centrifuging to remove the free water inside the pores. The cutoff value was determined by best agreement between the T_2 distributions from the saturated and desaturated samples. In general, the results obtained from the formula in part (b) may be better than those in part (a), because the cutoff values depend on lithology and $T_{2, LM}$ is not expected to be universal for all permeability (formula in part a). However, this method is more time consuming.

Nine T_2 distribution data sets were obtained from Florida Water Management Company and permeability was calculated. The comparisons between the two models were made and general conclusions were obtained; that is, the above equations can be applied to relevant core samples.

Additional computational modeling is also under development. For a rock saturated with a fluid, the T_2 relaxation time distribution can be transformed to the pore size distribution of the rock if surface relaxivity is known. NMR T_2 relaxation is known to depend on surface-to-volume ratio with the proportionality of the surface relaxivity constant. The computational modeling for estimating relaxivity that is under development is related to cumulative T_2 distributions and the pore capillary pressure curves. From the obtained data between the capillary pressure and the core water saturation, the estimation of relaxivity of the core sample is also under development. The relaxivity combined with the T_2 relaxation distributions have produced the pore size distribution for one of the samples. We are planning to apply this method to the other eight samples from the Water Management District in Florida.

The attached figure displays an example of the pore size distributions for sample #3.

APPENDIX B

Attenuation of Acoustic Plane Waves from Multi-Scale Scattering and Pore Flow in Heterogeneous Permeable Media

ABSTRACT

Compressional waves in heterogeneous permeable media suffer attenuation from both scattering and induced pore scale flow of the viscous saturating fluid. Stochastic medium theories are used to describe scattering on multiple length scales, and are validated by numerical examples using a dual length scale sedimentary sequence taken from a producing oil reservoir. The highly variable permeability in this sequence also affects the wave attenuation due to pore flow. The numerically observed squirt flow attenuation occurs at characteristic frequencies controlled by the individual permeability of each member instead of the formation average permeability. Depending on the viscosity of the saturating fluid, the magnitude of the flow-based attenuation can dominate or be dominated by the scattering attenuation at typical sonic logging frequencies (~10 kHz). For the moderate attenuating mechanisms considered, the overall attenuation is well approximated by the sum of the scattering attenuation from stochastic medium theory and the volume weighted average of the intrinsic attenuations of the sequence member rocks.

I. INTRODUCTION

Recent advances in understanding the influence of pore-scale flow on seismic wave propagation (Kazi-Azoual, 1988; Parra, 1991; Dvorkin and Nur, 1993; Parra, 1997) have led to the possibility of using measurements of seismic wave attenuation and velocity dispersion to estimate matrix and fluid properties. In many practical cases of interest, however, the material is inhomogeneous and variations exist in the local permeability, density, and compressibility. These variations introduce a scattering-based dispersion and attenuation for propagating waves which exist in addition to the fluid-based and intrinsic dispersion and attenuation. Better understanding of the dispersion mechanisms operating between seismic and ultrasonic frequencies will also lead to better scaling from core measurements to in situ seismic. This can be critical in time lapse seismic applications in which oil reservoirs are monitored for small changes in velocity, e.g., Wang et al. (1998).

The theory of poroelasticity is developed from recognition that a compressional wave propagating through a porous medium forces the pore spaces to alternately expand and contract. This local change in pore volume and pore pressure may cause the saturating fluid to flow from contracting pores to expanding pores in a manner such that the fluid is not at rest relative to the solid. The internal motion of a viscous fluid thus extracts energy from the passing wave, and also affects the rigidity of the porous volume as a whole which in turn alters the wave velocity. Biot (1956, 1962) presented a theory describing the frequency dependent behavior of the attenuation and dispersion for fluid motion parallel to the direction of wave propagation. In contrast, the squirt flow mechanism accounts for fluid motion perpendicular to the direction of wave propagation.

Dvorkin and Nur (1993) presented a unified analysis of the Biot and squirt flow (BISQ) mechanism. An important observation was that the critical frequency for Biot flow is inversely proportional to K/μ , while the squirt flow critical frequency is directly proportional to K/μ . Here, μ is the fluid viscosity, and K the medium permeability. The Biot mechanism characteristic frequency goes to zero in the limit of an infinitely permeable medium, while the squirt flow characteristic frequency goes to infinity in the same limit. For this reason, Biot's mechanism is most often observed in highly permeable media (such as unconsolidated beach sands), while the squirt flow mechanism is more often observed in less permeable media (such as sedimentary rocks).

Akbar et al. (1994) performed a detailed analysis on the effects of fluid saturation on velocity and attenuation in various types of pore structure. Considering both macro- and microscopic patchy saturation, they developed models based on pore and conduit compressibility. Akbar et al. compare the results of their theory to a fairly extensive array of experimental data, including effects of confining pressure, fluid saturation, and frequency of investigation. As part of their development, they presented a formula by which the frequency of an observed flow-based attenuation peak can be related to the squirt flow length scale and permeability of the medium.

Sams et al. (1997) used a suite of measurements from the well-characterized Imperial College (UK) borehole test site to examine wave propagation over frequency changes of four orders of magnitude. By combining measurements from vertical seismic profiles, crosswell seismic, sonic well logs, and core samples, these researchers were able to put together an estimate of the frequency dependent attenuation and dispersion at the test site. Their results show a peak in attenuation in the sonic frequency range, slightly higher than 10 kHz. This result is used with basic squirt flow models to estimate the crack aspect ratio in test site rocks, a result which is related to field permeability.

While fluid motion may dominate the attenuation for wave propagation in porous media over certain frequencies, it is certainly not the only mechanism which reduces wave amplitude. Scattering, in the form of reflections from variations in medium impedance, has long been recognized as a significant contributor to attenuation. O'Doherty and Anstey (1971) provided one of the first attempts to quantify statistically the frequency dependence of scattering from bed boundaries in seismic methods. They showed that scattering attenuation should be proportional to the power spectrum of the reflection coefficient series. Later workers put this result on a sound mathematical basis (e.g., Burridge et al., 1988; Shapiro and Zien, 1993), with applications generally assuming a single dominant length scale for medium transition (e.g., Kerner and Harris, 1994). Hermann (1998) suggests that sedimentary rocks might be considered to have a fractal multiscale, with reflecting surfaces at every point and a varying range of dominating scales.

Gurevich et al. (1997) provided a study considering the effects of scattering and Biot flow. Instead of considering the local squirt flow, however, they considered the global or interlayer flow. The interlayer flow phenomenon is a globalization of the pore scale squirt flow in which a passing pressure wave squeezes fluid out of a thin porous layer into surrounding more compliant material. Because of the relatively large interlayer length scales, this effect is predominantly confined to low frequency waves in moderate to high permeability material, while the Biot effect is generally confined to high frequency waves in high permeability material. The pore scale squirt flow

mechanism, in contrast, is considered the most likely cause of observed attenuation peaks in moderate permeability rocks (see Bourbie et al., 1987) at the intermediate frequencies (1-100 kHz). Nevertheless, the work of Gurevich et al. demonstrated that flow based and scattering-based attenuations are separable in that they can be treated independently at first, and later added to produce the total attenuation.

Shapiro and Müller (1999) demonstrate that heterogeneity in permeability is also important in determining the dispersion and attenuation due to the interlayer flow. As the permeability in the medium changes, the frequencies most strongly affected by the local flow change as well. The overall attenuation of the medium as a whole is thus controlled by those sections in which the dissipation is maximized. For this reason, the effective permeability of a formation for global fluid flow is different from the effective permeability of a formation for seismic attenuation. The first type is given generally by $K_{\text{eff}} = \langle K^{-1} \rangle^{-1}$, while the second may be approximately given (according to Shapiro and Müller) by $K_{\text{eff}} = \langle K \rangle$. Shapiro and Müller present an example in which the difference between the two effective permeabilities is more than two orders of magnitude. Their results are strictly valid only when the permeability heterogeneity is independent of the stiffness heterogeneity. It seems likely that this assumption can be relaxed without harm, as fluid-based attenuation and scattering-based attenuation are fairly independent in mechanism, if not location.

In this paper, we first examine the role of scattering on multiple length scales in the light of stochastic medium theory and a real world sedimentary sequence. We show that inclusion of multiple length scales in typical stochastic medium wave theory is straightforward if the transitions associated with each length scale are statistically independent. Verification of the theoretical development is accomplished using an elastic plane wave program and a known real sedimentary sequence. We next turn to the interaction of scattering and the squirt flow attenuation mechanism in permeable media.

II. PERTURBATION THEORY

A. Outline

This section outlines the development of a one-dimensional stochastic medium wave propagation theory. We follow the development of Parra et al. (1999), but similar results could be obtained using the development of Shapiro et al. (1994). Consider that the density, ρ , and stiffness, α , of a one-dimensional medium have a random variation in such a way that

$$\begin{aligned}\rho(x) &= \rho_o e^{\sigma_R R(x)} \\ \alpha(x) &= \alpha_o e^{\sigma_A A(x)}\end{aligned}\tag{1}$$

where σ_R and σ_A are small parameters, and $R(x)$ and $A(x)$ are stationary Gaussian random fields with zero mean and unit variance. These two fields have a covariance χ , and each has a spatial distribution governed by the spectral density $S(k)$. The spectral density is the Fourier transform of

the autocorrelation function $E(a) = \langle R(x)R(x+a) \rangle = \langle A(x)A(x+a) \rangle$, where brackets $\langle \rangle$ denote expectation value over all x .

The inhomogeneous one-dimensional wave equation is

$$\rho(x) \frac{\partial^2 u}{\partial t^2} = \frac{\partial}{\partial x} \left(\alpha(x) \frac{\partial u}{\partial x} \right), \quad (2)$$

where u is displacement. We will treat the small parameters σ_R and σ_A as perturbations to the linear wave equation. Taking an ensemble average to remove the zero mean fluctuations, and transforming to the frequency wavenumber domain, the 2nd order solution to the perturbed wave equation is given in Parra et al. (1999) as

$$\frac{\omega}{k} = V_o \left[1 - \frac{1}{4} (\sigma_R^2 + \sigma_A^2) (C(\omega) + 1) - \frac{1}{2} \sigma_R \sigma_A \chi C(\omega) \right], \quad (3)$$

where

$$C(\omega) = \int_{-\infty}^{\infty} \frac{k_o}{z - 2k_o} S(z) dz, \quad (4)$$

and k_o is ω/V_o . The attenuation due to scattering effects is

$$\frac{1}{Q} = 2 |\text{Im}(C(\omega))| \left[\frac{1}{4} (\sigma_R^2 + \sigma_A^2) + \frac{1}{2} \chi \sigma_R \sigma_A \right]. \quad (5)$$

The frequency dependent quality factor Q describes wave attenuation in a form proportional to $\exp(-\omega x/2VQ)$, where V is the phase velocity and x is the propagation distance (Aki and Richards, 1980).

B. Results for single dominant length scale

First, we should note that in the limit of σ_R and σ_A going to zero, the phase velocity correctly approaches V_o , the phase velocity in the uniform (unvarying) medium. For finite values of σ_R and σ_A , we must know something about the behavior of $C(\omega)$ to describe how the phase velocity changes. Fortunately, there is an analytic solution for the integral $C(\omega)$ for a common form of the spectral density function. Many sedimentary sequences can be considered to be layered mediums with layer thicknesses given by a Poisson distribution (Velzeboer, 1981). With this type

of spatial distribution, the autocorrelation function E is

$$E(x) = e^{-x/\ell}; \quad (6)$$

and its Fourier transform, the spectral density, is

$$S(k) = \frac{\ell}{\pi} \frac{1}{1 + k^2 \ell^2}, \quad (7)$$

where ℓ is the layer transition length scale. Note this means that the average layer thickness is 2ℓ .

The integral equation (4) for $C(\omega)$ may be evaluated using contour integration. The singularity in the integral is best removed by assuming some intrinsic dissipation in the medium. This is accomplished by having the unperturbed wavenumber k_o be complex. Then the unperturbed wave solution is

$$u(x,t) = U_o e^{j\omega t - jk_o x} = U_o e^{j\omega t - jk_R x} e^{-k_I x} \quad (8)$$

if k_R and k_I are the real and imaginary parts of k_o . Having moved the pole off the real axis, the integral for C evaluates to

$$C(\omega) = - \frac{k_o \ell (2k_o \ell + j)}{4k_o^2 \ell^2 + 1}. \quad (9)$$

The imaginary part of C corresponds to attenuation of the wave due to scattering from the random heterogeneities. This attenuation is maximized for $k_o \ell = 1/2$, corresponding to a wavelength equal to 4π times the length scale of the random structure.

It is easy to show that for this type of structure (or any reasonable structure), $C(\omega)$ approaches zero in the low frequency limit and $-1/2$ in the high frequency limit. Thus, the low frequency limiting phase velocity is

$$\frac{\omega}{k} = V_o \left[1 - \frac{1}{4} (\sigma_R^2 + \sigma_A^2) \right] \quad (10)$$

while the high frequency limiting phase velocity is

$$\frac{\omega}{k} = V_o \left[1 - \frac{1}{8} (\sigma_R^2 + \sigma_A^2) + \frac{1}{4} \sigma_R \sigma_A \chi \right] \quad (11)$$

As demonstrated in Parra et al. (1999), given the definitions of ρ and α above, these limiting velocities are consistent with the known low and high frequency velocities of layered media (Backus, 1962; Marion et al., 1994). Thus, this development satisfies the issues raised by Scales (1993) regarding some forms of the randomly varying medium theory.

III. MULTIPLE LENGTH SCALE RESULTS

A. Incorporation into perturbation theory

Acoustic measurements in rocks have been taken over frequency ranges from a few Hz (in long range seismic experiments) to MHz (in lab scale experiments on core samples). Similarly, length scales which can induce scattering effects can range from sedimentary layers hundreds of meters thick to sub-millimeter pore scale variability. Analysis of well logs by White et al. (1990) indicates that it is not uncommon for the autocorrelation function of velocity well logs to be controlled by more than one length scale. In this section, we show that it is not difficult to include the multiple length scale scattering effect in the perturbation theories of Parra et al. (1999) or Shapiro et al. (1994).

The effect of the length scale occurs only in the spectral density, which is the Fourier transform of the autocorrelation function, E . To include the effect of multiple length scales, we need only to determine the autocorrelation function of a multiple length scale medium. For simplicity, we choose two length scales. For ease of evaluation, we will assume that the variation on each length scale is independent of the other. More complicated forms of the autocorrelation function may be included in the perturbation theory, but will often require numerical instead of analytical integration.

Let $R_1(x)$ and $R_2(x)$ be independent, zero mean, unit variance, normally distributed random fields with exponential autocorrelation functions E of different length scales. If $\sigma_1 R_1(x) + \sigma_2 R_2(x)$ describes the fluctuations in a property like density, then the combined fluctuation has zero mean and variance $\sigma_R^2 = \sigma_1^2 + \sigma_2^2$ (Kalbfleisch, 1985). If $R_1(x)$ and $R_2(x)$ are independent and uncorrelated, then the autocorrelation function of the combined fluctuation is the sum of the individual autocorrelation functions, or

$$\sigma_R^2 E_R(x) = \sigma_1^2 E_1(x) + \sigma_2^2 E_2(x) = \sigma_1^2 e^{-x/\ell_1} + \sigma_2^2 e^{-x/\ell_2} \quad (12)$$

The variability and autocorrelation function used in the perturbation theory will thus be σ_R^2 and E_R , respectively. Similar expressions may be found for the variations in stiffness.

This function (12) is a linear combination of functions of the form Eq. (6), and as such, the resulting spectral density $S(k)$ is a linear combination of functions of the form Eq. (7). This spectral density may be used with the theory of Shapiro et al. (1994) or equations (3) through

(5) above to produce the scattering effect of two length scales in the phase velocity and attenuation. From Figure 1, it may be seen that the effects of each length scale may be observed separately in the attenuation if the lengths are at least an order of magnitude apart. Given that here only linear transforms are made of E , it is apparent that the effects of scattering from different length scales are additive, so long as the variations at each length scale are uncorrelated with the other length scale.

B. Computational investigation of a real sequence

The Buena Vista Hills field near Bakersfield, California includes some oil producing rock formations with very fine structure. The Antelope shale in this field is a high porosity ($\sim 30\%$) but low permeability (50 microdarcy, or $5 \times 10^{-17} \text{ m}^2$) rock. Intercalated with the shale are hundreds of thin (1 mm to 1 m) layers of sand and fractured carbonates. These thin beds have much higher permeability (~ 10 millidarcy, or 10^{-14} m^2) than the host shale, and are believed to significantly contribute to the oil production from the formation. For this reason, it is important to be able to identify and characterize this fine structure, which mostly falls below the resolution of typical sonic and density logging tools. Given the high permeability contrast between the shales and sands, it may be possible to use dispersion and attenuation measurements to identify the thin bed density.

Figure 2 shows the lithology of a typical section of the Antelope formation, along with the corresponding velocity and density logs. There are 255 alternating shale, sand, and carbonate layers in this 30 m region. The lithology is here determined to approximately 3 mm resolution by visual inspection of rock cores removed during the drilling of the well. The logging tools typically used to obtain the velocity and density information in the well sample over a coarser interval and essentially average the rock properties over a vertical distance of 30 to 60 cm. Standard well logging therefore does not capture much information about these thin beds, and core removal and storage are often prohibitively expensive and time consuming. The lithology of this section is used to construct a plane layered poroelastic model which is then used as input to a plane wave propagation program (Parra et al., 1997). This program includes the effects of the Biot and squirt flow (BISQ) mechanisms, and so the influence of the variable permeability between layers can be taken into account.

While the two carbonate layers (at 13 m and 26 m depth) provide the most striking contrast in the density and velocity logs of Figure 2, this is somewhat misleading because they actually comprise only about 1% of the formation volume. For simplicity then, the carbonates will be replaced by sands in the layered model. (It is not significantly more difficult to create a three medium model, but because of the small volume of carbonates there is little advantage gained.) Since the actual velocities and densities are not resolved by the well logs, the shale and sands are assigned constant properties given in Table 1. The autocorrelation function E of the layered model is used to provide input to the random medium theory, and is shown in Figure 3 along with two possible fits. Because the shale layers are generally significantly thicker than the sand layers, the autocorrelation function has the double exponential (two length scale) form discussed previously.

The best least squares fit using a single exponential function [Eq. (6)] is found to have a correlation length of 4.5 cm. A far better fit is found using a double length scale function [Eq. (12)] with correlation lengths of 1.2 cm (66% weight) and 18 cm (34% weight). Here, the smaller length scale corresponds to the sand layer half-thickness, while the larger length scale corresponds to the shale layer half-thickness. Interestingly, these two length scales are more than an order of magnitude apart, implying that there will be some visible multi-scale scattering effects.

1. Elastic behavior

This prediction of visible multi-scale scattering is confirmed by applying an elastic plane wave computer program (Parra et al., 1997) to the 255 layer lithologic sequence shown in Figure 2. This program, operating in the frequency domain, applies a normally incident plane wave to a stack of planar sand/shale layers with properties given in Table 1. By including no effects of intrinsic attenuation in the layered model, the frequency dependent scattering attenuation may be simply determined by measuring the transmission coefficient on the far side of the layered model. The observed attenuation may be transformed into a Q value by taking into account the distance traversed and the frequency of measurement. The resulting scattering attenuation is shown in Figure 4, along with the scattering attenuation prediction of the stochastic medium model. Agreement is quite good, although by necessity the actual "realization" of the random medium causes fluctuations around the predicted mean value. Further numerical experiments show that the magnitude of the fluctuation can be reduced by extending the propagation length in the random medium, increasing the number of layers traversed. This follows the ergodic hypothesis that as the size of a particular random sample increases, the resulting behavior will regress to the ensemble average properties. For this sequence, the frequencies of peak scattering attenuation (1 kHz to 12 kHz) overlap the frequencies used by borehole sonic logging tools (2 kHz to 20 kHz).

It is of practical interest to note that even though there are more than 250 reflecting surfaces in the 30 meter study section, the actual attenuation due to scattering is quite low. Peak attenuations correspond to Q values on the order of 200 - 400. This is partly because the sands only comprise 11% of the study section and the actual statistical variance of the medium properties is far lower than the contrast between sand and shale might at first indicate. Adding intrinsic attenuation to the medium in the form of a frequency independent Q of 100 for all layers provides a background attenuation ($1/Q = 0.01$) and now the scattering attenuation shows as an additional attenuation of up to 30% increase, possibly creating a measurable fluctuation. The stochastic medium theory slightly overpredicts the attenuation at high frequencies. This may be due to the high skew (89% shale) and kurtosis (binary medium assumption) in the lithology statistics.

2. Poroelastic behavior

Finally, we examine the effects of including the poroelastic BISQ mechanism into the 255 layer model. The poroelastic plane wave program (Parra et al., 1997) operates in the

frequency domain by computing the frequency-wavenumber relations for fast and slow P waves in each layer. Boundary conditions requiring continuity of stresses and displacement at the layer interfaces have recently been demonstrated to be rigorously correct for poroelastic media by Gurevich and Schoenberg (1999). The saturating fluid is assumed to be oil, with viscosity $\mu = 1$ g/cm/sec. In Figure 5, the dashed and dotted lines show the attenuation due to BISQ flow in unbounded sands and shales, respectively, assuming the medium properties from Table 1. The peak attenuation in the sand is at about 2 kHz, covering roughly the same range of frequencies as the scattering peak attenuation. The magnitude of the BISQ attenuation is significantly higher than the scattering only attenuation examined earlier, showing that fluid-based attenuation has the potential to entirely dominate scattering

attenuation. The BISQ attenuation in the shale exists at higher frequencies due to the low permeability and short squirt flow length. The scattering attenuation from Figure 4 is reproduced here as a dot-dash line, for comparison of magnitudes.

The actual attenuation, given by the poroelastic plane wave program, is shown by the light line. This is well approximated by the sum of three terms: the scattering attenuation, 11% of the sand attenuation, and 89% of the shale attenuation. In other words, the attenuation response of a poroelastic medium over this frequency range is given by the volume weighted average of the individual lithology responses, plus the scattering attenuation. This may be contrasted with the global flow results reported by Shapiro and Müller (1999), in which they show the global flow in a heterogeneously permeable media is well approximated by the direct average permeability $\langle K \rangle$, and not the individual permeabilities or the effective permeability $\langle K^{-1} \rangle^{-1}$. This result is expected as the global flow is a low frequency effect requiring the interaction of multiple permeable layers while the BISQ flow is a local effect occurring independently in the pore space of each layer.

The formations of the Buena Vista Hills reservoir, however, are not completely saturated with oil. The saturations determined from core measurements are in the general range of 80% water and 20% oil. This presents a difficult physical situation, since water is a wetting fluid and oil is a non-wetting fluid. In practice, this means that the water probably occupies the pore space adjacent to the rock, while the oil exists as dispersed droplets at the centers of the larger pores. While the mechanical response of this uneven two fluid saturation is unknown, we can examine the effects of complete water saturation, and these are shown in Figure 6. While oil and water have roughly similar densities and compressibilities, the viscosity of water is much less, only 0.01 g/cm/sec. This reduced viscosity moves the squirt flow effects to significantly higher frequencies. The shale body is now essentially non-attenuating over this frequency range, while the sand body has its attenuation peak at about 200 kHz. This leaves the scattering attenuation as the dominant attenuation mechanism in the sonic frequency range of 1 - 20 kHz, at least in the absence of other attenuating effects. Again the combined response of the heterogeneous poroelastic medium is well approximated by the sum of the scattering attenuation and the volume weighted average of the BISQ attenuations for the two rock types.

IV. CONCLUSIONS

Real sedimentary lithological sequences have been shown to have more than one dominant length scale. An elastic plane wave model is used to demonstrate the ability of stochastic medium theories to successfully address scattering on multiple length scales. While the scattering attenuation for the particular sequence examined is fairly low, it is important to recall that the scattering attenuation is proportional to the variance of the medium modulus and density. This variance could be increased dramatically by examining a sequence with a more even split between sand and shale (i.e., 50% - 50% instead of 11% - 89%), or by examining a sequence with greater contrast between components (i.e., shale and limestone). In any case, the acoustic scattering for the Buena Vista Hills formation has its strongest effect in the frequencies typically employed by sonic logging tools. Sequences with thicker laminations will have scattering effects at lower frequencies.

Localized intrinsic attenuation, such as the BISQ mechanism, adds directly to the scattering attenuation. The very different rock types in the Buena Vista Hills reservoir lead to quite different behavior in the BISQ mechanism and spread the effects of pore flow attenuation over a large range of frequencies (two orders of magnitude). In contrast to the global flow, the characteristic frequencies of BISQ flow attenuation are controlled by the local properties of each formation member, and not by the average properties of the formation as a whole. Thus the influence of the sand and shale can be observed separately in the frequency dependent attenuation profile of the test section. This will complicate efforts to determine formation permeability by attenuation measurements as there may not be a well defined peak attenuation in heterogeneous media. This is of particular import in fractured media, where a network of discrete, localized fractures may comprise a significant fraction of the medium permeability. The viscosity of the saturating fluid is also shown to have a dramatic effect on the BISQ attenuation, and more work is needed on understanding the flow response of saturation with two immiscible fluids to compressional waves.

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List of Tables and Figure Captions

Table 1

Properties of Buena Vista Hills sediments for layered model. The volume weighted average is based on the actual lithology prevalence of 11% sand by volume. The squirt flow length is estimated as 20 times the pore throat radius (based on mercury porosimetry measurements) for each lithology.

<i>property</i>	shale	sand	weighted avg.	Std. Deviation
uniaxial modulus	11.3 GPa	16.5 GPa	11.9 GPa	14%
density	1.90 g/cm ³	2.20 g/cm ³	1.93 g/cm ³	5%
permeability (x 10⁻¹⁵ m²)	0.05	10		
porosity	27 %	27 %		
squirt flow length	0.01 mm	1 mm		
solid grain modulus	26.8 GPa	37.9 GPa		

LIST OF CAPTIONS

- Figure 1: Theoretical scattering based group velocity dispersion (solid line) and attenuation (dashed line) for a random medium having variability on two length scales separated by one order of magnitude (50 cm and 5 m). The assumed variability is 20% in each of the density and compressional modulus.
- Figure 2: (a) Actual shale/sand/carbonate sequence for an oil reservoir near Bakersfield, California. Black areas represent sands and carbonates while white areas represent shales. This 30 meter interval contains 255 separate layers, based on visual inspection of cores recovered from wellbore. The interval contains 11% sands and carbonates by volume. Density (b) and velocity (c) logs for the same interval as (a) are also presented. These logs are unable to represent the true structure of the medium because they have insufficient resolving power.
- Figure 3: Autocorrelation function of the lithological sequence in the study interval. The solid line is the actual autocorrelation function. The dashed line is a single length scale fit, while the dotted line is a fit using two length scales.
- Figure 4: Attenuation of compressional waves in the study interval. Lower set of curves is scattering attenuation only. Upper set includes an intrinsic attenuation of $Q=100$ in both sand and shale. Heavy line denotes prediction of stochastic medium theory. Light line with symbols is computed with elastic/anelastic plane wave model using the observed layer sequence.
- Figure 5: Attenuation of compressional waves including flow effects using oil saturation. Dashed line: BISQ attenuation in an unbounded sand body having properties as in Table 1. Dotted line: BISQ attenuation in an unbounded shale body having properties as in Table 1. Dash-dot line: scattering attenuation from stochastic medium theory. Heavy solid line: combined fluid and scattering attenuation for study interval. Light solid line with symbols: attenuation from poroelastic plane wave program.
- Figure 6: Attenuation of compressional waves including flow effects using water saturation. Dashed line: BISQ attenuation in an unbounded sand body having properties as in Table 1. Dotted line: BISQ attenuation in an unbounded shale body having properties as in Table 1. Dash-dot line: scattering attenuation from stochastic medium theory. Heavy solid line: combined fluid and scattering attenuation for study interval. Light solid line with symbols: attenuation from poroelastic plane wave program.

Figure 1

Figure 2

Figure 3

Figure 4

Figure 5

Figure 6

APPENDIX C

Analysis and Interpretation of a Fractured Low Q Zone in the Buena Vista Hills Reservoir

ABSTRACT

Attenuation of high-resolution interwell seismic and acoustic waves based on dispersion analysis is related to fluid flow effects in fractured and shale-sand sequence formations at the Buena Vista Hills reservoir, California. A fractured low Q zone in the Brown Shale formation correlates with a system of cracks having permeability of the order of 1 md and dimensions between 0.5 to 1 cm. Vertical cracks oriented at azimuths of 0-40 degrees were detected in the frequency range of 1-10 kHz. To relate the low Q in the Brown Shale Formation with the presence of cracks we used a poroelastic model based on the Biot/squirt flow mechanism (BISQ). Since the Brown Shale does not have sands it is an ideal location at which to evaluate the response of a crack system to attenuation. The BISQ mechanism, recently adapted to simulate a crack system, is characterized by the permeability and squirt flow tensors. The elements of these tensors provide the flow properties parallel and perpendicular to the cracks, as well as the crack sizes in permeable media. The model assumes the principal axes of stiffness constant tensor are aligned with the axes of the permeability tensor and the squirt flow tensor, and the fluid filled cracks form an interconnected network. To simulate the system of cracks two scales are considered: (1) squirt flow length of the order of centimeters to represent cracks, and (2) squirt flow length less than 1 mm to represent grain scales. The model analysis suggests that fractures greater than 1 cm can be sensitive to attenuation for a frequency range of 200-1000 Hz. In addition, the analysis infers that isolated fractures observed in cores of the order of 5 to 10 cm are unconnected, so fluid flow will not occur between them and the shales. As a result, these fractures may not be sensitive to attenuation.

I. INTRODUCTION

A. Location of the Buena Vista Hills Reservoir

We studied the characteristics of seismic waves in the Antelope siliceous shale formation at the Buena Vista Hills field. This site is 25 miles southwest of Bakersfield, in the southern San Joaquin Valley of California (Figure 1). Chevron conducted a reservoir characterization program in the Antelope shale at the Buena Vista Hills field to establish the viability of CO₂ enhanced oil recovery. That study focused on a new infill well (653Z) and the four 1950s vintage wells that surround it. The five wells were used for a CO₂ pilot flood program, with the new well serving as the injector. At this field, the shale-sand sequence is characterized by layering, which is finer than that typically resolvable by sonic logging. In some sections the vertical resolution ranges from a fraction of a cm to tens of cm, while in others zone bed thicknesses can vary from centimeters to meters. These thin beds are associated with turbidite deposition and contribute to the apparent anisotropy in the sonic to seismic frequency range.

B. Geological Setting

Buena Vista Hills consists of a northwest-southeast trending doubly plunging anticline with two structural highs (Toronyi, 1997). The study area is located on the west high, which is called West Dome. The producing interval is a 1300 foot thick section of the Upper

Miocene Monterrey Formation. Locally, the interval is referred to as the Antelope shale, and is divided into three units: the Brown shale (upper quarter), the Upper Antelope shale (middle half), and the Lower Antelope shale (lower quarter). Geochemical analysis of the produced oil suggests that most of the present production comes from the Brown and Upper Antelope shales (Morea, 1998).

The Antelope shale is an unusual reservoir rock. Approximately 95 percent of the rock consists of thin (1 to 5 cm) graded, clay-free, siliceous shale beds. Very thin (1 mm to 25 cm) clayey sand laminae and carbonates are intercalated with the siliceous shale. The cores of the new infill well, 653Z, contain 748 sand laminae; all but one are in the Upper Antelope shale. The porosity averages 28 percent, but the formation permeability averages only 70 microdarcies, mostly due to low permeability in the siliceous shale. The rock was deposited in a restricted basin as distal turbidite and hemipelagic siliceous beds. Diagenetically altered diatom tests are the source of the silica. Petrographically, the siliceous shale is a silty, dolomitic, opaline mudstone. Very finely crystalline dolomite is dispersed in a matrix of isotropic opal-ct. Detrital grains are feldspar, clay, quartz, pyrite, and dolomite (Morea, 1998).

Thin section analysis of the shale reveals that most of the porosity is matrix microporosity. Moldic and fracture pore types are also present, but interconnectedness of all pore types is poor. Pore throat radii in the shale are less than 0.5 micron, and range from 2.5 to 10 microns in the sands (Morea, 1998). Mercury porosimetry tests indicate that at reservoir conditions only the sands are capable of producing oil (Morea, 1998). The sands, however, consist of only 5 percent of the rock, so fractures may be contributing significantly to hydrocarbon production.

The extent of fracturing within the Antelope shale and the significance of the fractures for fluid transport is a subject of debate. Pressure build up analyses indicate that the fracture system is not pervasive (Toronyi, 1997). Cores and FMI logs, however, indicate that fractures are widespread in the borehole, and occur on a variety of scales.

The objective of this paper is to explore the use of directional attenuation to characterize fractures at the Buena Vista Hills reservoir. Work by Hackert et al. (1999) has produced the quality factor as a function of depth in the region between 4100- 4300 ft of infill well 653Z. The quality factors have been determined from velocity dispersion analysis based on sonic and crosswell seismic data. The profile exhibits two low quality factor anomalies. The shallow anomaly is in the Brown Shale Formation and the bottom anomaly is in the Antelope Shale Formation. Hackert et al. (1999) demonstrated that the low quality factor in the Antelope Shale Formation is due to scattering/intrinsic attenuation and fluid flow effects in the sands.

In this paper we analyze the fractured low Q zone in the Brown Shale Formation. Since the Brown Shale does not have sands it is an ideal location to evaluate the response of a crack system to attenuation. Specifically, we attempt to answer two questions: (1) Can cracks and fractures contribute to attenuation at the Buena Vista Hills reservoir? and (2) Can we predict the fracture characteristics of the fracture system that will affect that attenuation?

To answer these questions we use petrophysics and the dispersion results from Hackert et al. (1999), together with a poroelastic model that relates the P-wave attenuation with the

tensor permeability. This model is based on the work given by Parra (1999) and Dvorkin and Nur (1993). We simulate the crack system by assuming that the horizontal x-axis is the axis of symmetry. To relate the attenuation with the presence of cracks embedded in a porous medium, we define the plane of the cracks (yz) as a plane of large permeability and the plane perpendicular to the cracks (xz) as a low permeability porous medium. In addition, the model assumes that the principal axes of the stiffness constant tensor (c_{11} , c_{12} , c_{13} , c_{44} , c_{33}) are aligned with the permeability tensor (k_x , k_z), and the fluid-filled cracks form an interconnected network. To simulate the crack system we consider two scales: (1) squirt flow length (s_z) of the order of centimeters to represent cracks, and (2) squirt flow length (s_x) less than or equal to 1 mm to represent grain scales. These scales add some degree of heterogeneity to the simulations that include directional attenuation.

II. DATA ANALYSIS AND INTERPRETATION

A. Analysis of fractures

Analysis of the core photographs and FMI logs of the 653Z well revealed information regarding fractures and faults in the interval from 4100 to 4300 feet. The following description is a compilation of the FMI analysis, core description, and review of the core photographs. All depths are measured depths referenced to the log depths (Figure 2).

Core photographs reveal numerous en echelon fractures perpendicular to bedding. Their length ranges from less than 1 cm to approximately 9 cm. They terminate at bedding planes and have a width of 0.01 mm. The interval from 4056.5 to 4267.4 feet contains the highest concentration of these fractures in the entire borehole. The only other intervals in which they are present are at 3985.4 to 3986.6 and at 3987.2 to 3987.4 feet.

In addition, two types of fractures have been identified on the FMI log: Fracture A and Fracture B. Fracture A types cross the entire borehole, are conductive, and are probably open. Fracture B types do not cross the entire image, are conductive, and are probably open. Attitudes of Fracture A types do not have a consistent orientation in the borehole. Attitudes of Fracture B types generally strike SW-NE, dipping SE. Two Fracture A types and two Fracture B types were identified from 4100-4300 feet (Figure 2). The Fracture A types are parallel to bedding in this interval. Fracture B types are perpendicular to bedding in this interval, and generally are perpendicular to bedding in the rest of the borehole.

Faults and microfaults were also identified with the FMI. Most faults strike SW-NE and dip to the SE. Microfaults are not as consistent in their orientation as the faults, but generally have the same attitude. One fault was identified in the FMI log from 4100-4300 feet. It trends SW-NE, is parallel to bedding, and dips north. Five microfaults were identified in the FMI log of this interval.

Large fractures, microfaults, and faults with an attitude perpendicular to bedding are scattered throughout the entire cored interval. The most common fractures perpendicular to bedding in this interval are the short, vertical en echelon fractures. Movement in the zone from 4100 to 4300

feet may be attributed to horizontal fracturing or faulting of adjacent beds. Because this is the only zone in the entire cored interval with vertical en echelon fracturing, it is believed that this feature is one reason for the attenuation of the acoustic signal in the Brown Shale Formation.

B. How to relate horizontal and vertical attenuation to fluid flow effects at the Buena Vista Hills reservoir

We attempt to relate the intrinsic attenuation to fluid flow effects in a vertical crack system of siliceous shales at the Buena Vista Hills field. The horizontal attenuation due to the siliceous shales and shale-sand sequence was addressed by Hackert et al. (1999). The attenuation was determined via velocity dispersion by integrating crosswell seismic data (Guan et al., 1998) with well logs and cores. The resulting attenuation profile represents the horizontal attenuation between the 653Z and 564 wells at the depth of interest as given in Figure 3. This figure also shows the correlation between the quality factor as a function of depth and the lithology. A low quality factor zone between 4000 - 4100 ft correlates with the fractured Brown Shale Formation. The second low quality factor zone between 4150 and 4300 ft correlates with the Antelope Shale Formation that is formed by a sequence of carbonates/sands and siliceous shale. The quality factor profile was determined from dispersion data measured at 1000 Hz (crosswell data) and at 10,000 Hz (sonic data).

The quality factor low associated with the Antelope Shale was interpreted by fluid flow effects in the sands. The attenuation of the sands was represented by the Biot/squirt flow mechanism (Parra, 1997). This suggests that, in the Antelope region between 4150 and 4300 ft the horizontal attenuation is controlled by the flow in the sands. That is, the results show that shales have a relatively low intrinsic attenuation compared to those layers that include the permeable portions of the reservoir. In addition, the vertical attenuation (in the region between 4150-4300 ft) associated with the siliceous shales was computed using a poroelastic layered model addressed by Hackert and Parra (1999). In this case the contribution of the scattering attenuation was determined assuming a layered shale-sand sequence model based on rock physical properties of shales and the sands from cores and well logs. The rock physical properties for the sand are: (1) uniaxial modulus ($\lambda + 2\phi\mu$) = 16 GPa; (2) density (ρ_s) = 2.2 g/cm³; (3) porosity (ϕ) = 27%, permeability (k) = 10 md; and (4) solid grain modulus (K_s) = 37.9 GPa. A summary of the rock/fluid properties used for the shale is given in Table 1. The intrinsic attenuation was modeled using the Biot/squirt flow mechanism representing the flow in sands saturated with oil. For the sands the squirt flow length was $s = 1$ mm; and the viscosity (η), density (ρ_f) and velocity (v_f) of the oil were 1.8 poise, 0.88 g/cm³, and 1449 m/s, respectively. The result of the modeling and analysis demonstrated that the attenuation in the vertical direction is associated with combined scattering and fluid flow effects (Figure 4). That is, the vertical attenuation is controlled by the average permeability of the siliceous laminated shales (which is in the order of the microdarcy range) and the boundaries of the sand-shale sequence in the Antelope Shale Formation. In this zone the number of cracks is small and fractures are thin and perpendicular to the stratifications, so the vertical propagation along the fractures does not contribute to the vertical attenuation (Parra, 1999).

In the next step we evaluate the low quality factor observed between 4000-4100 ft in profile shown in Figure 3. In the lithological column given in Figure 2, several type of fractures were characterized using cores and FMI logs. In particular, vertical fractures were observed and

characterized in the Brown Shale Formation. These fractures are called echelon fractures (see the lithology column with containing these fractures). To relate the presence of vertical cracks and fractures in the siliceous shale to seismic wave attenuation, we selected the range of frequencies used in crosswell and sonic logs at the Buena Vista Hills field. We also developed computer models based on rock physical parameters and well logs as well as fracture information determined from the cores and FMI data (see Table 1). The model to simulate dispersion and attenuation is based on the Biot/squirt flow mechanism. The model assumes that the axis of anisotropy and the permeability (k_x , k_z) and squirt flow tensors (s_x , s_z) have the same orientation. In addition, the model assumes that the cracks are interconnected.

Furthermore, to simulate a system of cracks we assume that the cracks are oriented in the zy plane (perpendicular to the zx plane of symmetry), which represents the maximum permeability. In this case the permeability is about 1 millidarcy (see Figure 2). Alternatively, permeability in the direction of the plane of symmetry (perpendicular to the cracks) is about 50 microdarcy. These two permeability values are obtained from cores. The vertical fractures observed in cores vary between less than 1 cm to about 9 cm. To predict the effect of the fractured siliceous shale on the attenuation we simulate cracks having dimensions between 0.5 cm to 5 cm.

Rock physical parameters such as stiffness constants, permeability, porosity and fluid properties are used to produce attenuation and dispersion curves for different azimuthal angles. The azimuthal angle (Ω) is measured from the horizontal x-axis, and the incident angle (Φ) or propagation angle is measured from the vertical z-axis. In this case we varied the vertical squirt flow length (or the crack length). Since the oil saturation of the study region is very small, the total attenuation is calculated assuming water as fluid. Figures 5-7 show the attenuation curves calculated by considering these squirt flow lengths at azimuthal angles between 0 and 60 degrees. Since we are interested in the frequency range of 1000 to 10,000 Hz, we calculate the quality factors in this frequency range. In general, as the crack diameter increases the attenuation peak is shifted towards the low frequency, and for azimuthal angles perpendicular to the system of cracks the attenuation is maximum. In the range of the frequency under study the average Q value is between 18 to 120. For cracks of 0.5 cm, the attenuation is close to the average attenuation observed in the range of 4000-4100 ft of the profile shown in Figure 3. The average Q values are determined directly from the graphs given in Figures 5-7. According to the modeling results, we can predict attenuations similar to those observed in the Brown Shale Formation (see Figure 3), by simulating cracks of dimensions 0.5 to 1 cm, oriented at azimuth angles between 0 and 40 degrees relative to the plane of symmetry.

The observed horizontal attenuation in the interval between 4000 to 4100 ft can be correlated with the presence of cracks in the siliceous shale. For cracks greater than 2 cm the effect on the attenuation is small. In fact, for these cracks the quality factors are of the order of 100 or greater. Since the large fractures or cracks may be isolated or unconnected, the squirt flow model may not work. The squirt flow model assumes that the cracks must be interconnected. That is, the low quality factor Q appears to be caused by a system of interconnected vertical cracks having lengths of about 0.5 cm to 1 cm.

The above analysis of the attenuation curves gives the range of Q values versus crack dimensions and the frequency range for detecting fractures. For example, cracks of about 0.1 cm-3

cm can be characterized by analyzing dispersion data derived from crosswell and sonic measurements. Alternatively, fractures having lengths greater than 5 cm may be detected using dispersion data derived from lower frequency measurements. This suggests that multiple scale seismic/acoustic measurements should be considered for characterizing fractures and cracks at the Buena Vista Hills field. Thus, different fracture lengths can be mapped using sonic logs, RVSP and surface seismic.

The above interpretation suggests that the smaller cracks (0.5 cm-3 cm) are the cracks most likely to be interconnected in the study formation. Larger, high Q cracks could also be present, but would not be observed. Therefore, the interconnected system of cracks is formed by the fractures that contribute the most to the observed attenuation. Also, these fractures must be very thin or partially closed to have permeabilities of the order of 1 millidarcy. The thin fractures justify the fracture network permeability of 1 millidarcy.

Finally, we address the contribution of the fractured laminated siliceous Brown Shale to the vertical attenuation. Hackert and Parra (1999) developed an approach to model the effect of either the laminated shale or a sand-shale sequence associated with the Buena Vista Hills formation. We apply the Hackert and Parra approach to model the laminated Brown Shale Formation in the interval between 4000 to 4100 ft. In this case the total contribution of the laminated shale is equivalent to an attenuation of 0.001 (or a Q equal to about 1000). Since this interval does not have sand and carbonate layers, we expect its contribution to the vertical attenuation to be less than the scattering contribution of the Antelope Shale Formation to the vertical attenuation, as shown in Figure 4. In addition, in the interval between 4000-4100 ft. the isolated vertical fractures and vertical cracks may not contribute to the vertical attenuation for waves traveling perpendicular to the laminated siliceous shale. Therefore, the vertical attenuation in the Brown Shale is controlled by the laminated siliceous shale.

III. CONCLUSIONS

We have integrated the lithology with the quality factor profile that was previously determined via velocity dispersion at the Buena Vista Hills reservoir. We demonstrated using the Biot/squirt flow mechanisms that the horizontal attenuation in the Brown Shale formation is associated with a system of vertical cracks, and that the vertical attenuation is associated with the laminated siliceous shale. The vertical cracks should have permeabilities on the order of 1 millidarcy and lengths of 0.5-1 cm. Also, the model results suggest that larger vertical fractures on the order of 5 cm to 9 cm do not contribute to the attenuation in the frequency range of sonic and high-resolution crosswell seismic. One way to contribute to the observed quality factor in this frequency range is to have permeabilities much greater than 1 millidarcy. This suggests that there is no flow between large fractures in the Brown Shale Formation. The small flow associated with 1 millidarcy occurs in the crack system formed by cracks of the order of 0.5-1 cm. Such a system of cracks is approximately oriented at the azimuthal angles between 0-40 degrees relative to the vertical plane of the boreholes. We correlated the lithology with Q values to derive the squirt flow models (or crack models). We selected the theoretical Q values that are close to the observed Q values to infer the azimuthal angles of the system of cracks. In general, the results suggest that the attenuation is sensitive to the presence of vertical fractures in the Brown Shale Formation. Since we know the permeability values from the core analysis, we can relate the permeability of about 1 millidarcy to

the presence of the cracks in the shales. We have found that vertical cracks can produce attenuations between 0.06 -0.1 (i.e, in the range of Q_s from 10-17), depending on crack diameter, permeability, viscosity, frequency range and azimuthal angle.

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LIST OF CAPTIONS

Figure 1. Map of Buena Vista Hills field near Bakersfield, California

Figure 2. The petrophysics and fracture log of a selected interval in the Antelope Shale Formation (4100- 4100 ft), Buena Vista Hills field, Kern County, California.

Figure 3. Quality factor profile based on dispersion data between 1000-10000 Hz.

Figure 4. Attenuation of compressional waves including flow effects using oil saturation. Dashed line: BISQ attenuation in an unbounded sand body. Dotted line: BISQ attenuation in an unbounded

shale body. Dash-dot line: scattering attenuation from stochastic medium theory. Heavy solid line: combined fluid and scattering attenuation based on the poroelastic theory.

Figure 5. The effect of frequency and azimuth angles on attenuation illustrating the average quality factor in the interval of 1000 to 10,000 Hz at each azimuth, for a crack of diameter $s = 0.5$ cm and a propagation angle of $\Phi = 90^\circ$.

Figure 6. The effect of frequency and azimuth angles on attenuation illustrating the average quality factor in the interval of 1000 to 10000 Hz at each azimuth, for a crack of length $s = 1$ cm and a propagation angle of $\Phi = 90^\circ$.

Figure 7. The effect of frequency and azimuth angles on attenuation illustrating the average quality factor in the interval of 1000 to 10,000 Hz at each azimuth, for a crack of length, $s = 2$ cm and a propagation angle of $\Phi = 90^\circ$.

Table 1.
Properties of the siliceous shale in the interval between 4000-4300 ft at the Buena Vista Hills field.

Parameter	Unit	Formation Values
c_{11}	(GPa)	11.3
c_{13}	(GPa)	5.65
c_{33}	(GPa)	11.3
c_{44}	(GPa)	2.82
c_{66}	(GPa)	2.82
ϕ	%	27
K_s	(GPa)	26.76
ρ_s	(g/cm ³)	1.9
v_f	(km/s)	1.5
ρ_f	(g/cm ³)	1
η	(poise)	0.01
k_x	Darcy	50. e-6
k_z	Darcy	0.001
s_x	(mm)	0.01
s_z	(mm)	10

Figure 1

WELL 653Z PETROPHYSICAL AND FRACTURE LOG OF A SELECTED
INTERVAL IN THE ANTELOPE SHALE (4100-4300')
BUENA VISTA HILLS FIELD, KERN COUNTY, CALIFORNIA

Figure 2

Par097

Figure 3

Figure 4

Par094

Figure 5

Par095

Figure 6

Par096

Figure 7

APPENDIX D

Siberia Ridge Data

We have received the following data on Siberia Ridge well 5-2 from Schlumberger/GeoQuest with the permission of GRI. This is a well recently drilled in the tight gas sands of the Green River Basin, Wyoming. To maximize contact between the well and the fracture network, the well deviates at about 48 degrees from vertical in the producing Almond formations. The Almond sandstones are generally about 10% porosity, with permeability around 20 microdarcies.

I. WELL LOG DATA

We have over 30 different logging curves, including several resistivity, gamma ray, SP, P velocity from sonic logging, and neutron porosity measurements, as well as several derived parameters like water saturation, % shale and % coal by volume, and computed permeability. We also have NMR logging data including the Schlumberger processed T_2 distribution curves, and NMR measured porosity. From the given T_2 values we can use several techniques to obtain the NMR permeability. Additional information includes a fracture log and the well deviation path.

All well logs cover the Almond formation in this well, at approx. 10,600 feet to 11,000 feet in depth. Some well logs cover part of the overlying Lewis shale and include about 2000 feet of wellbore (9000 - 11,000 feet in depth). We are also expecting to receive FMI resistivity data and dipole sonic data from this well.

II. CORE DATA

Cores were obtained from the 5-2 well over a distance of about 24 feet, and an extensive analysis of these cores led by Schlumberger/GeoQuest was undertaken. Core plugs were taken at one foot intervals. Some of the analysis is available for all cores, and some for a subset of cores.

A. Data from all cores

This includes photographs, porosity, permeability, and grain density. The lithology covered by the 24-foot cored section was analyzed and found to cover several types of sandstone deposition environments and to span several fractures.

B. Data from a subset of cores

Generally, the same subset of core plugs is used for each test, but occasionally nonoverlapping or different subsets are used. Data here includes:

- SEM images
- formation factor for resistivity, including regression vs. porosity
- formation resistivity index vs. brine saturation
- mercury porosimetry, including capillary pressure curves and pore throat radius
- point count data, including minerology, porosity, permeability, compaction, etc.
- Stress dependence of porosity and permeability

- NMR from cores, including T_2 distribution, surface relaxivity, and FFI/BVI cutoff

The core NMR data is courtesy of Dr. George Hirasaki of Rice University.

III. SEISMIC DATA

We have VSP data from the 5-2 well for a single offset. This includes 291 waveforms from 97 three-component receiver locations, extending down to 11,000 feet. Receiver locations are spaced at approximately 50-foot intervals in the lower part of the well (8000 to 11,000 feet) and are more widely spaced at shallower depths. This overlaps with the primary producing formation and an extensive suite of well logs, which extend from roughly 10,600 feet to 11,000 feet. The VSP data may be analyzed by itself and integrated with the P velocity data from sonic logs to gain additional insight on the acoustic behavior of the rock formations.

Using the VSP data alone, we can pick first arrivals to obtain an estimate of the compressional wave velocity at the VSP frequency (approximately 100 Hz). We can also apply the spectral ratio method to compare the signals at neighboring VSP stations and obtain an estimate of the local combined attenuation. The combined attenuation includes both scattering effects from the stratigraphic layering and intrinsic effects from rock anelasticity and viscous fluid motion. We will be able to predict the scattering effects as a function of frequency by constructing models from the V_p sonic log and a lithological column for the well. The magnitude of the predicted scattering effect can be checked against known plane-wave stochastic medium solutions.

Once the scattering effect is quantified, we can subtract that from the combined attenuation to obtain the intrinsic attenuation as a function of depth. Intrinsic attenuation is often associated with fractures and softer, permeable rocks. Another estimate of intrinsic attenuation may be obtained by comparing the low frequency VSP velocity and the high frequency sonic log velocity. The dispersion between these two frequencies will be directly related to the attenuation in the rocks. It is important to try to estimate wave attenuation at higher frequencies, because fluid-based attenuation is rarely significant at low frequencies.

IV. FIGURES

The attached figures show examples of the available data. Figure 1 is a lithological column interpreted from the core data by Schlumberger/GeoQuest. This is in the main producing member of the Almond formation, and consists of some of the most permeable and highest porosity sands. Figure 2 shows sample well logs through the entire Almond formation. Figures 1 and 2 are not depth matched, so the cores in Figure 1 actually come from the section in Figure 2 extending from about 10,600 to 10,630 feet measured depth. Figure 3 compares three permeability measurements: computed permeability from log porosity, permeability from core plugs, and NMR log permeability from standard sandstone correlations. All three measurements show significant differences.

Figure 1. Lithological environment of cored area. Depths are not matched to well logs; see Figures 2 and 3.

Figure 2. Sample well logs. Logs are Vp: P wave velocity (ft/sec), RHOB: bulk density (g/cc), PHIE: effective porosity (fraction), VSH: volume of shale (fraction), VCOAL: volume of coal (fraction), PERM: computed permeability (millidarcy), and WATSAT: water saturation (fraction). Cores were taken from the relatively high porosity, high permeability sandstones slightly deeper than 10,600 feet.

Figure 3. Comparison of permeability measurements. Red: computed permeability based on well log porosity and water saturation calibrated to field core measurements. Green: actual core measurements. Black: NMR well log permeability, using standard SDR method and total NMR porosity. The permeability estimates span roughly two orders of magnitude, but are reasonably consistent in trend.