Diagnosis of "fizz-gas" and gas reservoirs in deep-water environment

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Introduction

"Fizz-water" or "Fizz-gas" is a rather ill-defined and misused concept. For some, it refers to gas in solution with brine; for others, it is defined as small amounts of free gas phase. This small, uneconomic gas content then gives rise to seismic bright-spots or other Direct Hydrocarbon Indicators (DHIs). Unfortunately, it is often the culprit of choice when no other reason can be found. However, progress has been made in assessing the problem. We have systematically examined physical properties of fluid and rock, and fluid interaction with rock to examine gas saturation effect on acoustic velocities, especially in deep-water sands of the Gulf Mexico . Furthermore, we have reviewed the current AVO and Rock physics interpretation techniques to propose optimum DHIs. Several promising techniques of seismic evaluation of gas saturation are in development.

Gas and water properties

Han and Batzle (2003) have systematically studied gas effects on fluid modulus. Measured data show that dissolved gas has negligible effect on water velocity, modulus, and density. In addition, gas bubbles exsolving from either water or oil have only a small effect on bulk fluid properties at pressures higher than about 20 MPa (about 3000 psi). Gas properties progressively transit to those of light oils with increasing pressure. Gas effects on fluid modulus depend on two factors: gas has to be in free phase and gas pressure has to be low (less than 20 MPa).

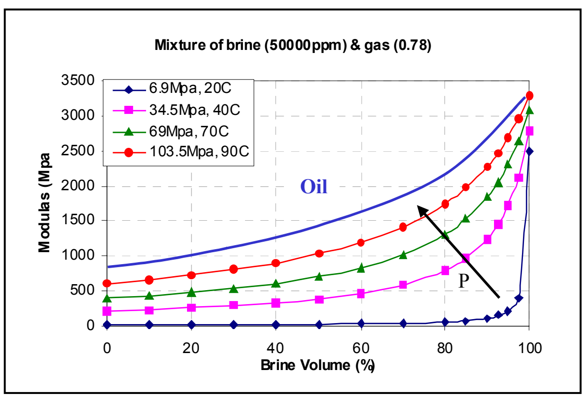

Figure 1. Modulus of Gas-water mixture depends on gas and water modulus and pressure and temperature conditions.

Figure 1 shows that modulus of gas-water mixture at iso-stress condition is calculated with Reuss bound (Wood, 1955) and mainly controlled by pressure. At low pressure (shallow depth < 2000 m), gas modulus is much less than 0.1 GPa. Even few percent volume fraction of gas can drastically reduce the modulus of gas-water mixture. However, at a high pressure condition, modulus of gas-water mixture shows progressive decrease with increasing gas saturation and results in differentiable DHI attribute. Fluid modulus depends on composition, distribution and reservoir conditions, which are a result of complicated geological processes which form a reservoir.

Phenomenon associated with strong DHI anomalies for "fizz-gas "should correlate with both low fraction (<30%) and low pressure (<20 MPa) gas. The "fizz-gas" should also be correctly termed as "residual-gas".

Fluid saturation effect

Surface seismic data are a measure of impedance contrast of sediment (shale and sand) interface. Fluid saturation effects on seismic velocities can be described by the simplified Gassmann's equation for high porosity sands (Han and Batzle, 2004).

$$\begin{aligned} K_s &= K_d + \Delta K_d; \quad \mu_d = \mu_s \\ \Delta K_d &= G(\phi) * K_f \end{aligned} \tag{1}$$

where subscript d and s are for dry and saturated rock respectively; f is for pore fluid and ϕ is porosity. The *G (ϕ)* is the gain function of dry rock frame given as

$$G(\phi) = (1 - K_d / K_0) / \phi \tag{2}$$

The Gassmann's equation suggests that there is fluid effect on the bulk modulus but not on shear modulus. And the portion of fluid contribution into the bulk modulus is approximately proportional to pore fluid modulus K_f and the gain function *G (ϕ)*, which is a dry rock frame property. We rewrite the above equation with P-wave modulus as

$$\begin{aligned} M &= \rho * V_P^2 \\ M_s &= K_d + 4/3 * \mu_d + \Delta K_d \\ &= M_d + G(\phi) * K_f \end{aligned} \tag{3}$$

Diagnostic "fizz-gas" and gas reservoirs

The fluid effect on the P-wave modulus depends on sensitivity of P-wave modulus M_s to variation of fluid modulus K_f. The fluid saturated P-wave modulus M_s is dependent on pore fluid modulus K_f as well as dry frame P-wave modulus M_d and dry frame gain function $G(\phi)$. In this relation, the K_d and μ_d are correlated and constrained by $G(\phi)$ through the Gassmann's equation. To evaluate fluid saturation, we have to know both rock and fluid properties.

The sensitivity of P-wave modulus to fluid modulus

The minimum of M_s of reservoir rock is equal to the M_d with pore fluid modulus K_f equals zero (vacuum) and the maximum of M_s is assumed as that with (background) water saturation. Here, the modulus of water depends on salinity and reservoir conditions and assumed to be higher than that of hydrocarbon (it may not be true for a heavy oil reservoir). We define the relative sensitivity of P-wave modulus to pore fluid as

$$\Delta_f = 1 - {(M_d + G(\phi) * K_f)}\big/{M_w} \qquad (4)$$

The maximum sensitivity is $\Delta_{\max} = 1 - {M_d}\big/{M_w}$. The sensitivity to differentiate fizz from gas reservoir

$$\Delta_{f-g} = {G(\phi) * (K_{fizz} - K_g)}\big/{M_w} \qquad (5)$$

To differentiate the "fizz" gas from gas reservoir it mainly depends on difference of the modulus of the "fizz" and gas fluids. The sensitivity also depends on the gain function and the P-wave modulus of background water zones.

Gain function of deep-water unconsolidated sands

Deep-water gas reservoirs in the Gulf of Mexico are often hosted in young, unconsolidated turbidite sands. We have measured velocities of core samples. The measured data suggest that the bulk modulus is very sensitive to water saturation at in situ conditions as shown in Figure 2. It is interesting that the calculated gain function based on measured data on those porous sands tend to approach a constant of 2.5 as shown in Figure 3. The Gain function tends to decrease with decreasing porosity and increasing cementation. Using the gain function, we can derive fluid modulus using the differencel of the fluid saturated and the dry modulus of rock.

$$\begin{aligned} \Delta K_d &= \Delta M_d = M_s - M_d = G(\phi) * K_f \\ K_f &= \Delta M_d / G(\phi) \end{aligned} \qquad (6)$$

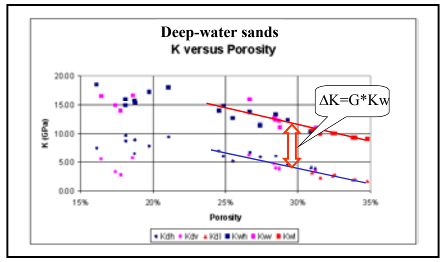

Figure 2. Measured dry and water saturated bulk modulus for deep-water sands show water saturation effect.

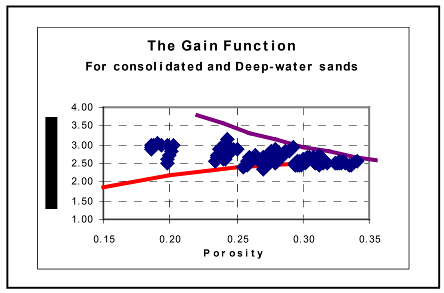

Figure 3. Gain function for deep-water sands

Optimum hydrocarbon indicator

Many indicators are now being developed to address residual-gas discrimination. Russell et al. (2003) summarized the DHI techniques associated with AVO technique. The indicators can usually be reduced to a form dependent on the difference between the compressional and shear impedances: $Z^2_p - CZ^2_s$, where C is a calibration constant. We (Batzle et al., 2001) have suggested that C should be equal to square of dry Vp/Vs ratio. Goodway (1997) has suggested $\lambda-\mu$ method (equivalent C=2) and Hadlin (2000) has adopted $K/\mu=0.9$ (equavilent C=2.23). Dillon et al. (2003) pointed out that the value of this constant C is important in maximizing the hydrocarbon discrimination, and is often larger than the values of C=2.33 suggested by Batzle et al., (2001). For deep-water unconsolidated sand reservoirs, modulus and density of gas tend to be high, but can vary over a wide range. We actually have a chance to differentiate a gas reservoir from a residual-gas zone, if we can carefully calibrate the seismic parameters. Figure 4 shows relative attributes of "fizz-gas" and gas cases normalized by the values with water saturation. Attributes such as modulus K, fluid factor ΔK, $\lambda\rho$, $\rho*\Delta K$, $\rho*K_f$, and K_f, illustrate significant differences between residual-gas and gas reservoirs. All these attribute show similar sensitivity and are mainly controlled by fluid modulus K_f.

Diagnostic “fizz-gas” and gas reservoirs

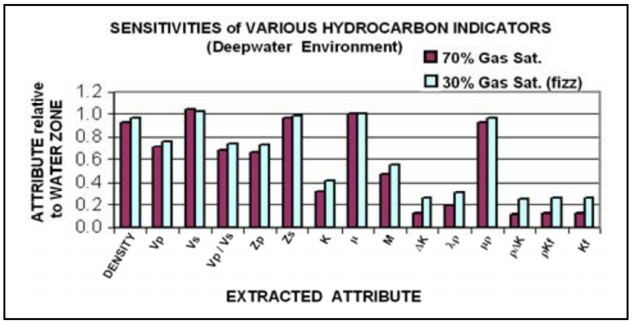

Figure 4. Sensitivity of 15 different hydrocarbon indicators in deep-water fizz and gas reservoirs.

In comparison to the shallow case, normal reflectivity appears to be the best residual-gas indicator as shown in Figure 5.

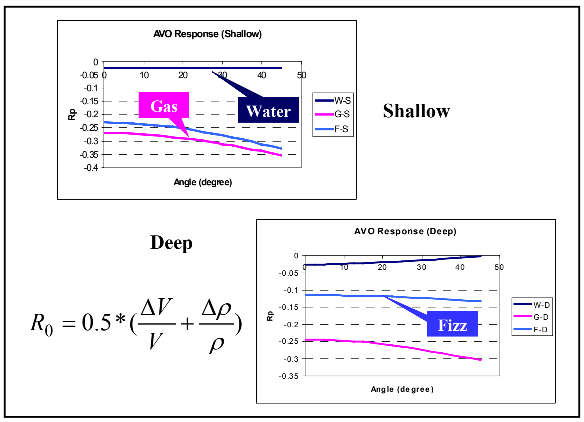

Figure 5. AVO responses for deep- and shallow sands.

We need better methods to calibrate seismic attributes not only on gas zones, but equally important brine zones to give us background calibration. Forward modeling, with accurate rock and fluid properties, and reservoir structure (include fluid distribution), is also a powerful tool to quantify hydrocarbon indicators.

However, in practice seismic attributes are not only affected by rock and fluid properties, but also by scattering and intrinsic dispersion and attenuation due to property heterogeneity and different frequencies (wavelength). Question is how we can separate the scaling effects to make sure that seismic attributes are proper to be used for rock and fluid property inversion.

Scaling effects on seismic attribute

Forward modeling often starts with well logging data, building synthetic seismogram to compare with near-by seismic gather. Seismic parameters such as velocity can be significantly affected by scale dependent heterogeneity. For two material layer model, effective velocity (as well as impedance) can vary in wide range depending on wavelength/layer thickness ratio as shown in Figure 6 (Mavko et. al., 1998).

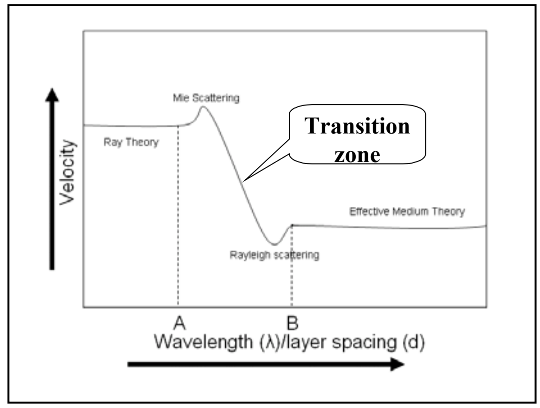

Figure 6. Velocity dispersion due to layer structure

Unfortunately, seismic properties in sedimentary basin are often located in the transition zone, and seismic attributes are hard to obtain. For example, AVO attributes (Figure 7) can be affected by both fluid properties and thin layer tuning.

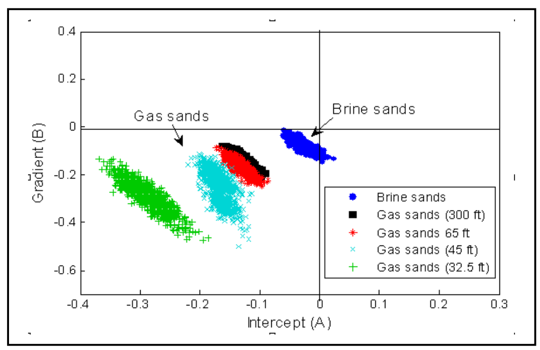

Figure 7. AVO attributes A and B for typical deep-water sands with different thin layer tuning effect.

Therefore, we may have to apply wave propagation model to include scattering dispersion and attenuation effects. Furthermore, we may have to develop inelastic model to include intrinsic dispersion and attenuation into synthetic seismogram to evaluate the seismic wave propagation effects on seismic attribute. Eventually, we may be able to separate the wave propagation effects on seismic attributes, before which can be then be used for quantitative evaluation of gas saturation.

Residual gas reservoirs

Forming a gas reservoir is a result of many geological processing, such as hydrocarbon resources, maturation, migration (gas resolves in, or exsolves out of water and hydrocarbon, equilibrium between capillary trap, gravity force and chemical diffusion), trap and accumulation (seal and leak equilibrium) with back ground of sedimentary processing. The gas distribution can be ranged in many phases from gas layer with good trap, or poor accumulation with leaking trap, or continue seep to surface as gas chimney. Each phase can be in different scale from micro-size in pore space to mega-size in hundred meters. Residual gas reservoir often associates to leaking trap or poor resources.

We are suspicious that very thin gas layer (a foot thick?) along top of lithology interface may generate shape impedance contrast, which may be able to block seismic wave to generate a bright reflection, but invisible for conventional log tools.

Potential techniques

In the future, attenuation (1/Q), or frequency content, might prove a helpful attribute as revealed in measured data shown in Figure 8 (Kumar, et al., 2003). Less is understood of 1/Q, but several researchers recently have reported success in using frequency content as a discriminator of hydrocarbons. In this case, fluid properties, distributions, and mobility all contribute. However, the in situ fluid distribution and mobility are often unknown. In addition, even the controlling mechanisms of attenuation are not well understood.

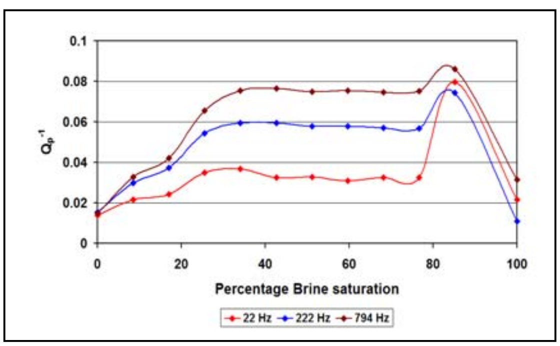

Figure 8. Measured attenuation versus gas saturation reveals that low gas saturation may be related to high attenuation.

Acknowledgments

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