Nonbright-spot AVO: Two examples

Christopher P. Ross* and Daniel L. Kinman‡

ABSTRACT

The use of amplitude variation with offset (AVO) attribute sections such as the product of the normal incidence trace (A) and the gradient trace (B) have been used extensively in bright spot AVO analysis and interpretation. However, while these sections have often worked well with low acoustic impedance bright spot responses, they are not reliable indicators of nonbright-spot seismic anomalies. Analyzing nonbright-spot seismic data with common AVO attribute sections will: (1) not detect the gas-charged reservoir because of near-zero acoustic impedance contrast between the sands and encasing shales, or (2) yield an incorrect (negative) AVO product if the normal incidence and gradient values are opposite in sign.

We divide nonbright-spot AVO offset responses into two subcategories: those with phase reversals and those without. An AVO analysis procedure for these anomalies is presented through two examples. The procedure exploits the nature of the prestack response, yielding a more definitive AVO attribute section, and this technique is adaptive to both subcategories of nonbright-spot AVO responses. This technique identifies the presence of gas-charged pore fluids within the reservoir when compared to a conventionally processed, relative amplitude seismic section with characteristically low amplitude responses for near-zero acoustic impedance contrast sands.

INTRODUCTION

Offset-dependant amplitude variations directly affect the recognition of hydrocarbon indicators by influencing the full-stack amplitude response. For example, bright spots associated with shallow, low acoustic impedance gas sands encased in higher acoustic impedance shales have large normal incidence reflection coefficients, but typically demonstrate a larger full-stack amplitude because of the increase in reflection amplitude with larger incident angles. In other geological areas, moderate to weak normal incidence reflection amplitudes caused by smaller contrasts between encasing media and a gas reservoir may have even smaller full-stack reflection amplitudes because of a possible phase reversal within the common midpoint gather (CMP) gather. Issues to be presented in this paper are concerned with amplitude variation with offset (AVO) responses of these nonbright gas reservoirs, or nonbright-spot AVO.

Various papers have been presented on AVO, and many excellent case histories have been published. However, there appears to be a bias in the literature towards AVO associated with bright spots rather than dim spots or low-amplitude seismic anomalies. The causes of this may be three-fold: (1) lack of confidence in visually identifying nonbright spot reservoirs in reflection seismic data. Bright-spots are easier to identify and subsequently there is a higher frequency of AVO analysis performed on these reservoirs; (2) AVO interpretation of bright spots is straight-forward, making the results appear to be black-and-white; and (3) nonbright-spot AVO measurements are more subject to S/N ratio problems and velocity problems.

Although issue (3) contains some truth, the overall bias is misleading and has led to misconceptions that "AVO only works with bright spots" and "since this is not a bright spot, there is not a need for AVO." These misconceptions diminish the ability of AVO in certain instances to contribute to the exploration and development process. Such misconceptions deny the explorationist the chance to find a new prospect or evaluate an existing one using additional techniques other than conventional seismic interpretation. With the increasing costs for hydrocarbon exploration, finding a new prospect or better assessing an existing prospect prior

*Formerly Oryx Energy Company, P.O. Box 2880, Dallas, TX 75251-2880; presently PGS Tensor, Inc., 10550 Richmond Ave., Suite 300, Houston, TX 77042.
‡Oryx Energy Company, P.O. Box 2880, Dallas, TX 75251-2880.
©1995 Society of Exploration Geophysicists. All rights reserved.
to drilling a well should be major considerations. Therefore it is important to consider AVO, even if there is not a bright spot, to see if it demonstrates an "unconventional" response; i.e., some anomalous behavior relative to background (Castagna, 1992). The procedure in this paper presents a technique to detect elastic gas-charged reservoirs that would otherwise go unnoticed using conventional migrated AGC or RAP sections, or AVO sections. To illustrate the procedure, two AVO examples are presented—one from Indonesia and one from the Gulf of Mexico.

HISTORICAL OVERVIEW

Since Ostrander's work in 1984, many energy companies have devoted intensive manpower and resources to AVO research and fluid detection applications. During this time, a large amount of research was devoted to shallow gas-sands where inconsistent direct hydrocarbon indicator (DHI) technology was problematic. Early AVO analysis over these shallow sands proved beneficial, but the technique had difficulties with deeper and older strata with reduced porosities. Hilterman (1983) demonstrated that velocity and density trends for Gulf of Mexico sediments varied with age, resulting in different AVO and poststack seismic responses, which explained some of the difficulties with older, lower porosity sands.

In 1987, Smith and Guidlow presented a "weighted stacking" approach to fluid detection that has been overlooked by most of the industry until recently. This gas detection procedure appears to be porosity insensitive, yielding "fluid factor" seismic sections that emphasize gas reservoirs. The fluid factor is a weighted stack trace that is near-zero when shear and compressional velocities change in the same direction (across a shale-wet sand interfaces), and is anomalously large in amplitude for shear and compressional velocity changes that are opposite in direction (shale-gas sand interfaces). To our knowledge, this was the first published work of successful AVO analysis for nonbright spots. Castagna and Smith (1993) have most recently explored the work of Smith and Guidlow (1987) and have recommended a more robust measurement of AVO involving a scaled addition of common AVO attribute sections.

We present another AVO procedure that focuses on nonbright-spot AVO that occurs for Class 2 type sands [we use the nomenclature of Rutherford and Williams (1989) as shown in Figure 1]. We make no attempt to compare our technique to those previously discussed except to say that the approach is analogous in improving AVO analysis and gas detection.

BRIGHT SPOTS

Bright spot DHIs are associated with a large acoustic impedance contrast between the gas-charged reservoir and the encasing (shale) media. Reflection amplitude of the full-stack is quite large because of the combination of the normal incident contribution and the generally increasing AVO. For a Class 3 AVO response (in these areas), incorporation of AVO offset information (AVO gradient) has been very useful in separating gas reservoirs from wet sands, shallow calcareous stringers, and coals. Whereas these later lithologies may also appear as large reflection amplitudes (false bright spots), the shale to gas-sand reflection amplitude increases with offset, while the shale to wet sand and the shale to calcareous shale have decreasing AVO. (The decreasing AVO for the shale to calcareous shale is associated with an increase in acoustic impedance and a decrease in Poisson's ratio across the interface, assuming the shales are composed primarily of smectite.)

AVO response differences between bright spots and false bright spots have led to shortcuts in Class 3 AVO analysis. Instead of examining all CMP data for these differences (which can be tedious), AVO attribute sections can be computed and presented in stacked data format. After performing normal moveout (NMO) corrections, the AVO gradients of a CMP are measured automatically over all time samples and curve-fitting algorithms can be implemented to extrapolate normal incidence values. The results of these measurements are a normal incidence trace (A) and a gradient trace (B) for each CMP. Shuey (1985) reduced the AVO response [the P-wave reflection coefficient as a function of average incident angle (θ)] to the addition of A and B*\sin^2(θ). Class 3 (bright spots) are often easily identified on A*B sections, because a large A value has been multiplied by a large gradient value of the same sign. Most other lithologies (in these areas) have A and B values of opposing signs, resulting in negative A*B products. AVO products, and other similar mathematical combinations (attribute sections) of A and B are common for Class 3 AVO anomaly detection.

DIM SPOTS

Dim spots, by definition, are localized decreases in the stacked reflection amplitude resulting from the presence of hydrocarbons. Rutherford and Williams (1989) relegate dim spots to their Class 2 designation—near-zero acoustic impedance contrast sands. However, the Class 2 response is characterized by a range of possible responses as displayed

![Fig. 1. AVO categories proposed by Rutherford and Williams (1989) for clastic gas-charged reservoirs. We propose that Class 2 responses be subdivided into those with phase reversals (Class 2p) and those without phase reversals (Class 2).](image-url)
by two curves shown in Figure 1. The upper curve has a small positive normal incident reflection coefficient, whose reflection amplitude decreases for the low incident angles, and increases for larger incident angles after a phase reversal. The lower curve has a small negative normal incidence reflection coefficient that increases as the incident angle increases. We chose to subdivide the Class 2 designation into those gas reservoirs that exhibit an ordinary increase in amplitude variation with offset (Class 2), and those that exhibit a phase reversal with increasing offset (Class 2p) (See Figure 1). The Class 2p response will behave more like the traditional dim spot, having opposite polarities at near and far incident angles, resulting in a near-zero full-stack amplitude response. The Class 2 response will have a small full-stack reflection amplitude that may not be interpreted as a bright spot nor a dim spot.

NONBRIGHT SPOT AVO RESPONSES

Local velocity, density, and Poisson’s ratio contrasts across an interface determine whether a response will behave as a Class 2 or Class 2p. However, it is important to realize that detection of either type of Class 2 offset response using conventional AVO attribute sections (such as an AVO product) will be difficult, if not impossible. For Class 2p responses, the AVO product would be negative because of the phase reversal, and in the case of Class 2 responses, the near-zero A term reduces the AVO product to a near zero value. Therefore, we propose a different approach to detect Class 2/2p responses.

Recently, it has been suggested that other AVO attributes or formulation of attributes are more robust when encompassing a broader selection of clastic reservoirs and seals than the A*B attribute. Expanding on Smith and Guidlow’s work (1987), Castagna (1992) proposed the use of $R_p - R_s$ as a gas reservoir detector. Castagna and Smith (1993) further demonstrate that

$$R_p - R_s \approx \frac{A + B}{2},$$

where $R_p$ and $R_s$ are the compressional and shear wave reflection amplitudes, while A and B are the normal incidence amplitude and AVO gradient, respectively.

From Figure 1, an empirical relationship can be developed that better expresses the intrinsic AVO nature of the Class 2/2p response. This relationship is a logical extension that many geophysicists have informally investigated—examining observed seismic responses over nearby wells and fields within a specific formation. This procedure should be approached with the intent of minimizing overburden and depositional differences, yielding a clearer expectation of the AVO character that is being sought. It is important to note that the seismic offset response identified as a hydrocarbon response for the particular target may not be unique to the entire seismic section. This is anticipated since deposition and overburden change throughout the geologic section. Finally, the geophysicist needs to ensure that the data, in particular the gradient, have been properly processed. Corrections to the gradient may be required prior to AVO attribute computation (Martinez, 1993; Ross and Beale, 1994) if there are concerns about the data quality. With these caveats in mind, let us now examine two examples from two diverse depositional settings.

DATA EXAMPLES

Gulf of Mexico

Alpha field lies on the northern continental shelf of the Gulf of Mexico in 20 m of water and 20 km off the Texas coastline. Prospective Middle Miocene sands are encountered at 3680 m and are trapped in a faulted roll-over anticline, downthrown (south) from a large (Middle Miocene) expansion fault. Three wells penetrated the reservoir, and all three encountered gas-charged sands. Figure 3 displays a portion of Line A that has been processed to preserve relative amplitudes. It illustrates the roll-over structure, and the gas symbol indicates the 35 m (gross) pay zone in the Alpha well as projected (150 m) into the plane of the seismic section. Note that there is no direct indication of the thick gas reservoir observable in the seismic data. This suggests a near-zero impedance contrast sand and a Class 2 offset response.

Figure 4 shows a section of wireline data (3500–3800 m) obtained from the Alpha well. The gas reservoir is indicated by the increased resistivity response in track 2 as well as by the neutron-density crossover in track 4 between 3680 and 3715 m. Log analysis indicates two gas-charged sands with
FIG. 2. Class 2 (dash) and 2p (solid) schematic showing the effective amplitudes of the far-range stack and the near-range stack as defined by incident angle. Separation of $\theta_n$ and $\theta_f$ away from the angle of phase reversal ($\theta_{np}$) typically increases the dynamic range of the FN attribute. Here, $a_n$ and $a_f$ are the average amplitudes of the near- and far-ranges, respectively.

FIG. 3. Line A through Alpha Field near well Alpha. The line has been processed to preserve relative amplitude. The gas symbol at 3.24 s indicates the hydrocarbon reservoir.
low water saturation and high porosity ($\phi = 30\%$), separated by a 6-m shale stringer. The lowermost sand contains a gas/water contact at 3708 m. Log analysis indicates that the water has a low gas saturation.

The multiwell crossplot in Figure 5 emphasizes the differences between the clean sands and shales in this trend. Sands and shales were separated by using a computed sand percentage curve that incorporates the neutron-density, gamma ray, and the SP logs. Lithologies with a sand percentage greater than 70% are posted as sands in Figure 5, and those lithologies with sand percentages less than 30% are posted as shales. The lithologies separate and cluster very well in this plot. From Figures 4 and 5, the petrophysical concept of Alpha field is: (1) the shales have a significantly slower velocity than any sand encountered (gas or brine); and (2) the shales have a significantly higher density.

Following petrophysical analysis, full-offset synthetic seismic modeling was performed. However, to accomplish this modeling we computed a shear-wave log using a mineralogical end-member analysis (Greenberg and Castagna, 1992) to obtain a Poisson’s ratio log. (Please note that the lack of actual shear-wave data in these rocks increases the potential error in these models.) With the well logs and computed Poisson’s ratio log, full-offset synthetic models were generated using a ray-trace algorithm and a 5–8-40–60 Hz zero-phase wavelet. NMO corrections were applied using the rms velocities from the check-shot corrected sonic log, and a $T^2$ gain correction was applied to the data to correct for spherical divergence amplitude losses. Figure 6 shows the time-based logs with the full-offset synthetic seismogram for the Alpha well with the top of the reservoir annotated.

Examining the full-offset synthetic, it is apparent that most reflectors have strong normal incidence reflection amplitude that decreases dramatically at the far offsets, while the gas reservoir exhibits a small normal incidence reflection amplitude (when compared to the other reflectors) and has an increasing AVO which demonstrates a Class 2 response. Additionally, this AVO response produces a strong trough-peak development on the far traces.

To further demonstrate the reliability of the model, Figure 7 shows a fluid replacement full-offset synthetic seismogram adjacent to the in situ full-offset synthetic seismogram (from Figure 6). In the fluid replacement synthetic, the gas was replaced by brine (water) in the reservoir sections. Examination of the fluid replacement synthetic seismogram shows that there is no trough development on the far traces and that the basal (peak) reflector now exhibits a decreasing amplitude variation with offset. The differences between the in-situ synthetic seismogram and the fluid replacement synthetic seismogram reiterate that the AVO anomaly is related to gas-saturated pore fluids, which reduces Poisson’s ratio, velocity, and the bulk density of the reservoir.

Employing equation (2) with $c_1$ being set to zero, a far-range stack (approximately 15 traces) was created to emphasize the Class 2 response. Figure 8 illustrates the trough-peak character of the Class 2 offset response of the gas reservoir at 3.24 to 3.26 s between CMP 608 and 655. This areal range corresponds to the reservoir limits of the field determined by structural mapping and well log measurements. Figure 8 also illustrates potential reservoir between CMPs 585 and 603, downthrown from the three wells drilled on the crest of the structure. As with the synthetic models,
Fig. 6. Time-based sonic, bulk density, and computed Poisson's ratio logs with the full offset synthetic seismogram of well Alpha with a 5/8-45/65 Hz zero-phase wavelet. A Class 2 offset response is present at 3.24 s. Notice the trough development immediately above the peak on the far traces.

Fig. 7. Full offset synthetic seismogram of well Alpha before (left) and after (right) fluid substitution of brine for gas. Notice the Class 2 offset response is not present after fluid replacement, as manifest by the lack of trough development (right).
the trough corresponds to the top of the gas reservoir and the peak corresponds to the base.

Figure 8, when compared to Figure 3 (the full stack section), illuminates the gas reservoir. In addition, many of the reflectors are now diminished by the lack of near-offset information. Only the event at 3.58 s between CMP 480-550 is bright in addition to the reservoir, but this event does not have a trough-peak character, and is not considered to be associated with gas. Therefore, for this Middle Miocene gas reservoir, the nonbright-spot AVO anomaly can be detected with the FN attribute.

**Indonesia**

Our second example comes from offshore Indonesia. The productive reservoir section of the Beta field occupies the upper portion of a mid-Oligocene-Eocene (MOE) clastic formation with the overlying claystones acting as a reservoir seal. Wireline logs from exploration wells and core information indicate a fluvio-deltaic environment.

Structurally, the present hydrocarbon trap consists of a sand reservoir deposited in a half-graben that deepens to the southwest and thins updip where the sands are bounded by a large right-lateral wrench fault. Gas and oil bearing sands are encountered at measured depth intervals of 2030 m to 2300 m, depending on the well location. These depths correspond to a two-way traveltime window of 1770 ms to 1922 ms. A portion of the relative amplitude processed (RAP) 2-D dip line (Line B) through the Beta well is shown in Figure 9. The MOE formation is bounded by the claystone marker intersecting well Beta at 1.75 s and by basement at 2.20 s. The gas symbol at 1.88 s denotes a thin reservoir containing a gas/oil contact, determined by check-shot and synthetic seismogram data.

A portion of the wireline log suite for the MOE formation is shown in Figure 10 (2130-2335 m). Increased resistivity in track 2 clearly indicates the presence of several thin gas and gas/oil sands, as does the neutron-density crossover in track 4 (shaded). Log analysis denotes sand porosities of 18 to 24%, with the cleaner sands (channel and mouth-bar facies) exhibiting higher porosities.

Thin sands and transitional geology makes determination of accurate petrophysical parameters for geophysics difficult to ascertain, and therefore a multiwell crossplot (Figure 11) was employed to better define the velocities and densities of the key lithologies for AVO modeling and analysis. Using a sand percentage curve, silts and silty sands were discriminated against to enhance the sand claystone/shale differences in the crossplot. The effects of thin lithologies are still apparent in the crossplot, with variation in clay content dispersing the shale and claystone cluster, while hydrocar-

**Fig. 8.** FN AVO section illustrating the Alpha gas sand reservoir on Line A. The updip portion of the reservoir (CMP 608-655) has been tested, while the downthrown section, (CMP 585-603) has not. Notice the predominant trough-peak character of the FN anomaly in both fault blocks.
Nonbright-spot AVO

bon saturation and silt content affect the wet sand and gas sand clusters. Comparing this crossplot to the Alpha example (Figure 5), which has distinct clustering of sands and shales, this environment is more transitional, resulting in some sand/shale cluster overlap. Nevertheless, as with Alpha, the well logs and crossplot data from Beta indicate that: (1) the shales have a slower velocity than do sands (gas-filled or water-wet); and (2) the shales have a significantly higher density.

Since multipole sonic information was not acquired in this prospect area, Poisson’s ratios used for modeling were determined by estimating shear velocities for each lithology using an equivalent mudline equation (Castagna et al., 1985) for shales and Gulf of Mexico analogies for sands. In general, the claystones and sandstones are considered unconsolidated and hence have high Poisson’s ratios (\(\sigma > .34\)), whereas gas-charged sediments have lower values (\(\sigma < .20\)). Recent work by McKnight (1993, personal communication) using ultrasonic techniques supports these estimates.

Therefore, as in our Alpha example, a full-offset, ray-trace synthetic seismogram was generated to determine what response a gas sand would produce. Unfortunately, the sonic data from the Beta well on Line B encountered some environmental difficulties immediately above the top of the MOE, so another well, Beta-2 was used for the seismic modeling. This well encounters the MOE formation along trend at the same relative depth with minimal change in overburden. Figure 12 shows an in-situ full-offset synthetic model from the Beta-2 well. A Class 2p offset response can be seen in the MOE at 1.82 s as annotated. The event is subtle, and begins as a trough on the near trace and ends as a peak on the far trace, with phase-reversing in the mid-offsets. Correlation of this event to the resistivity log indicates that the event is associated with a pay sand, or more likely the combined effects of several thin pay sands. It is unfortunate that there is not a one-to-one correspondence between each thin pay sand and a Class 2p anomaly. However, despite the temporal resolution limitations, the modeled response of these thin sands indicates that hydrocarbons could be detected within the MOE formation.

Whether the event in Figure 12 is associated with the introduction of gas-charged sands is unclear because of the limits in temporal resolution and the nature of near-zero acoustic-impedance responses. To demonstrate that this is a plausible explanation for the MOE AVO response, a constant Poisson’s ratio curve was used with the in-situ sonic and density logs to generate a second full-offset model presented in Figure 13. Since sharp contrasts in Poisson’s ratio are most often associated with gas sands in this area, which in turn result in identifiable AVO responses, a con-

FIG. 9. Line B through Beta Field example near well Beta. The line has been processed to preserve relative amplitude and the gas symbol at 1.88 s is the gas reservoir of interest.

FIG. 12. Full-offset synthetic seismogram for Beta-2 well. Notice the Class 2p offset response at 1.82 s. The event reverses phase midway through the gather. Poisson’s ratio was computed using Castagna’s mudline equation for shales and Gulf of Mexico analogies for sands.

FIG. 13. Full-offset synthetic seismogram for Beta-2 well using a constant Poisson’s ratio. The Class 2p offset response at 1.82 s is not present, indicating that the Class 2p event can be associated with strong contrasts in Poisson’s ratio (i.e., gas-charged pore fluids).

Fig. 10. A portion of wireline logs through well Beta illustrating the thin and variable sands of the fluvio-deltaic MOE reservoir. The resistivity log and neutron-density log crossover (shaded) indicate hydrocarbon reservoirs. 1.88 s corresponds to the package of thin gas reservoirs near 2210 m.

Fig. 11. Sonic velocity and density multiwell crossplot for wells in encountering the MOE formation in the Beta Field. Shales and sands cluster separately, with shales exhibiting larger densities and slower velocities than the sands.
FIG. 14. CMP 140 from Line B illustrating a Class 2p offset response. Offset distances are labeled across the top of the CMP window, with the near trace on the left and the far trace on the right. Incident angles are calculated for each CMP using the rms velocities selected for NMO corrections. These angles have been labeled on the abscissa of the lower graph. Normalized amplitudes for each trace are then plotted as a function of offset (or incident angle). The shaded areas on the CMP window denote the sample selected for analysis.

Examination of CMP 140 from Line B (Figure 9) using an interactive AVO analysis program illustrates a Class 2p response at approximately 1.88 s. (See Figure 14.) This response agrees with the synthetic modeling and shows a trough with low reflective strength at near-offset that reverses phase in the middle of the CMP to become a peak in the far-offset ranges. The event time in Figure 14 (1.88 s) corresponds to the gas-charged reservoir in the inter-MOE at 2210 m in the Beta well. (See Figure 10.)

Subjecting the Line B reflection data to the FN equation [equation (2)] results in Figure 15. For this display c₁ equals unity, and the near-offset amplitude is subtracted from the far-offset amplitude. Comparison of the RAP seismic section (Figure 9) with the FN section in Figure 15 illustrates that the gas sand is now quite visible at 1.88 s, extending down dip.

FIG. 15. FN attribute section for Line B. The gas reservoirs at 2210 m in the Beta well correspond to the peak that is present at 1.88 s on the FN attribute section and which continues down dip from the well to CMP 100 and is also found upthrown to the fault at 1.84 s from CMP 144 to 160.
away from the wellbore, and can also be seen on the upthrown block at 1.84 s between CMP 145-156. The observed FN response is considered to be a combined effect of several thin gas sands. Although some gas reservoirs do not have a one-to-one correspondence to an FN anomaly, (which can be explained by the thin intervals and variable sand geometry/consistency), the occurrence of an AVO anomaly indicates that there are hydrocarbons in the formation that would otherwise go undetected using RAP sections alone. The extent of the 1.88 s FN anomaly on Line B and other seismic data over the MOE formation corresponds to the reservoir extent determined independently from fluid-pressure testing.

CONCLUSIONS

In general, when the density of a shale is greater than the sand density that it is encasing and the velocity of the shale is slower than the sand velocity (regardless if the sand’s pore fluids are gas-charged), the AVO response will behave as a Class 2 offset response. We have subdivided Class 2 offsets into those with phase reversals (Class 2p) and those with ordinary increases in AVO (Class 2). There is no break-over point between the two subdivisions, and determination must be performed locally. This implies the FN attribute should be used as an exploitation tool where well control is abundant. However, with familiarity with a specific formation or system and increased awareness of the pitfalls and caveats, this can be extended into exploration.

Two examples from distinctly different basins have been examined using the FN equation. In both cases, Class 2 offset responses have been modeled, observed, and correlated to well log information, confirming the existence of gas-charged pore fluids and bolstering the confidence in this approach. Even though the Beta example did not have a one-to-one correspondence of gas sand to FN event, the presence of an FN event indicates the presence of gas in the reservoir system. Therefore, incorporating nonbright-spot AVO techniques can be beneficial by emphasizing events that the interpreter or explorationist cannot see with traditional exploration tools.

ACKNOWLEDGMENTS

We would like to express our appreciation to Oryx Energy for the time and resources that were made available for this study and we thank Marathon Petroleum Indonesia, Ltd, Oryx Indonesia Energy Company, Lasmo Indonesia, Ltd., L.L & E Indonesia, Ltd. and Pertamina for permission to publish this data. We also wish to thank Paul Beale for his critical review of this manuscript.

REFERENCES