Geophysical model response in a shale gas

Dhananjay Kumar and G. Michael Hoversten
Chevron USA Inc.

Abstract

Shale gas is an important asset now. The production from unconventional reservoir like shale gas has been possible because of horizontal drilling and hydraulic fracturing technologies. Efficient implementation of both of these technologies needs an accurate subsurface model for horizontal drilling in the target layer, and for understanding of the rock properties to design frac jobs. Shales are very heterogeneous and therefore well data alone may not be sufficient to map the subsurface. Geophysical data can provide accurate 3D subsurface images. For analysis of geophysical data, a set of geophysical models are very important. Synthetic responses can be generated for a set of geological scenarios using a reliable rock physics relationship and forward modeling. This paper presents both seismic and electromagnetic (EM) model responses over 1D earth model for a shale gas reservoir, particularly the Bossier/Haynesville shale from East Texas, USA. Seismic attributes (lower P-Impedance and lower Vp/Vs ratio) can be used to map zones with potential high gas saturation in a shale formation. Laboratory measurements and well logs and field seismic data analysis indicate that shale is intrinsically anisotropic (VTI) and VTI parameters should be considered in rock properties relationships, stress estimation, and seismic analysis. MT data is not well suited for characterizing shales, but CSEM data can be used for mapping high resistivity shale gas reservoir studied here.

Introduction

Traditionally shale has been considered a source rock and hence was not the focus in geophysical exploration. Now in certain cases shale can be considered both a reservoir and a source rock and has received attention in geophysical studies to characterize it. The production from low permeable shale plays has become possible primarily because of two technologies: 1) horizontal drilling that increases rock volume contact with well bore, and 2) hydraulic fracture stimulation that increases permeability. To stay in the target shale layer with horizontal drilling requires detailed subsurface imaging that is possible with active seismic data, and to create desired artificial fractures requires knowledge of rock properties (e.g. Young's modulus) and stress/fracture orientations (using azimuthal seismic anisotropy) that are possible with the active seismic data with wide azimuthal and offset coverage (Schmid et al., 2010). Induced fracture monitoring requires time-lapse passive seismic data (microseismic data) to monitor fracture propagation. Fluid saturation in shale gas can be inferred from electromagnetic (EM) data along with seismic data.

Shales can exhibit large variations in petrophysical and elastic properties (Roth, 2010). All shale gas rocks are intrinsically anisotropic due to the presence of clay minerals; they are typically overpressured due to trapped fluids in pores; they contain organic materials; and they have low porosity and very low permeability. However, seismic anisotropy (Sondergeld and Rai, 2011), mineral composition, TOC (total organic carbon) content, and porosity/permeability in shales are variable from basin to basin and even within a basin. TOC is used as a proxy for gas saturation and is a very important parameter in shale gas exploration.

Variations in anisotropy, mineral composition, TOC and porosity of shale gas plays can significantly influence the geophysical response (Zhu, et al., 2011). It also means that geophysical data can be used to estimate these variations in rock properties. TOC and maturity might be related to seismic anisotropy (Vernik and Liu, 1997; Cheng, 2011). To understand the sensitivity of various rock parameters to geophysical data, first rock physics relationships are used to transform rock properties (earth model) to elastic properties for seismic data modeling and to electrical properties for EM data modeling, and then forward modeling is used to generate synthetic geophysical data. If well data are available we can use well logs to build an earth model for data simulation.

In this study we used well logs from a well in the Bossier/Haynesville shale gas area in East Texas, USA (Figure 1). The Bossier/Haynesville shale has low clay content (unlike conventional shale) and is more like silty mudstone; also it has all the hallmarks of a shale gas play including high TOC, high gas saturation and good porosity (Younes et al., 2010). A marine condensed section marks the top of the Haynesville shale and is coincident with maximum flooding surface (Hammes and Carr, 2009). The maximum flooding surfaces highlight the richest organic zones (Younes et al., 2010). The Haynesville shale reservoir is also overpressured (Parker et al., 2009). We will first discuss rock physics relationships from this well and then simulate seismic and EM responses.

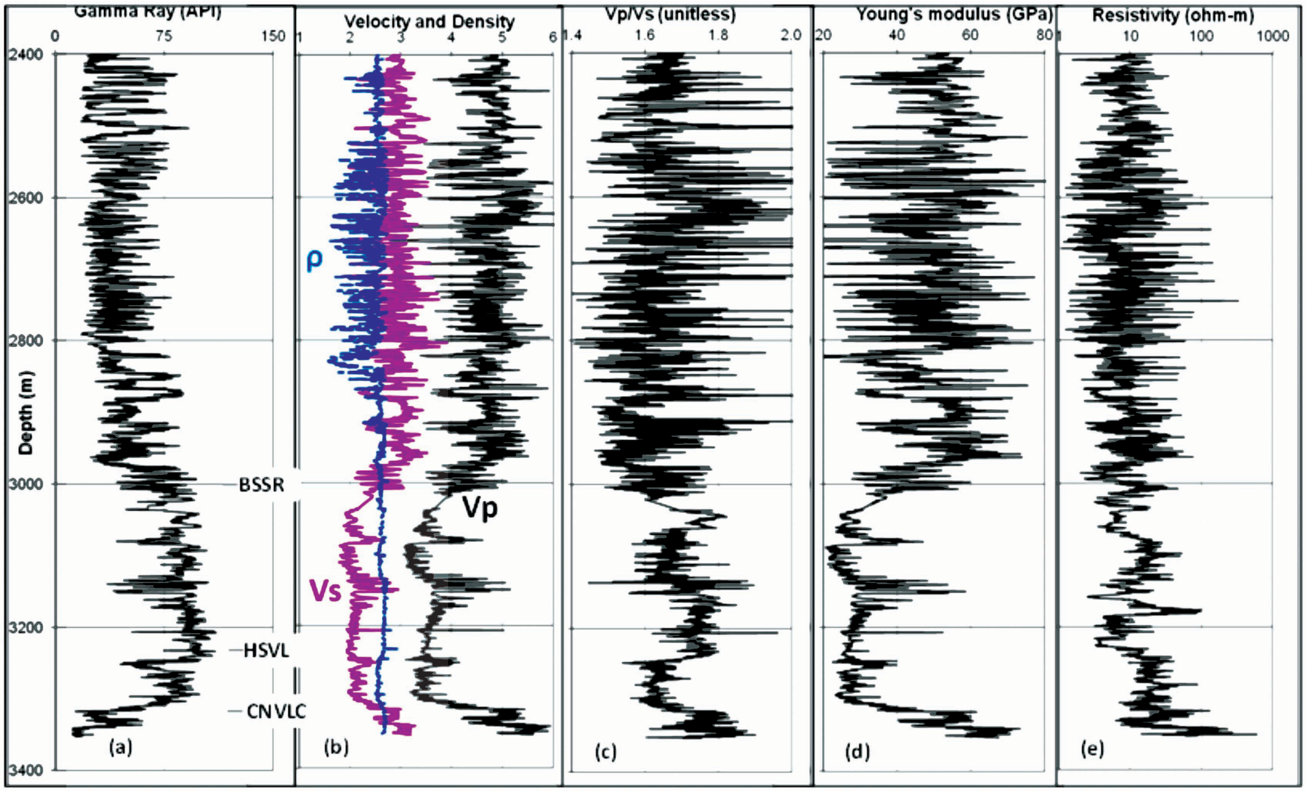

Fig.1 Well data from a well in Bossier/Haynesville shale area in East Texas, USA. Marker BSSR represents the top of Bossier shale, HSVL represents the top of Haynesville shale and CNVLC represents the top of cotton valley limestone. Shale reservoir has high Gamma value, Lower P-impedance, lower Vp/Vs ratio, and higher resistivity value, but it has lower Young's modulus and therefore it might be difficult to induce fractures in this shale.

Rock physics relationships

Shale can be distinguished from other lithology using Vp/Vs ratio and P-Impedance. Also reservoir shale can be separated from non-reservoir shale using Vp/Vs ratio and P-Impedance together, and gas saturation in shale reservoir can be estimated using electrical resistivity along with P-Impedance. Figure 2 shows schematic rock physics relationships for a shale play especially Bossier/Haynesville shale gas relating i) P-Impedance and Vp/Vs ratio and ii) P-Impedance and resistivity. The Vp/Vs ratio for shale gas is lower at about 1.6 compared to non-reservoir shale with Vp/Vs ratio greater than 1.7 (Figure 1, see also Lucier et al., 2011), because the presence of gas reduces Vp but Vs remains relatively unchanged.

3D volumes of P-impedance and Vp/Vs ratio can be derived from AVA (amplitude versus angle) inversion of

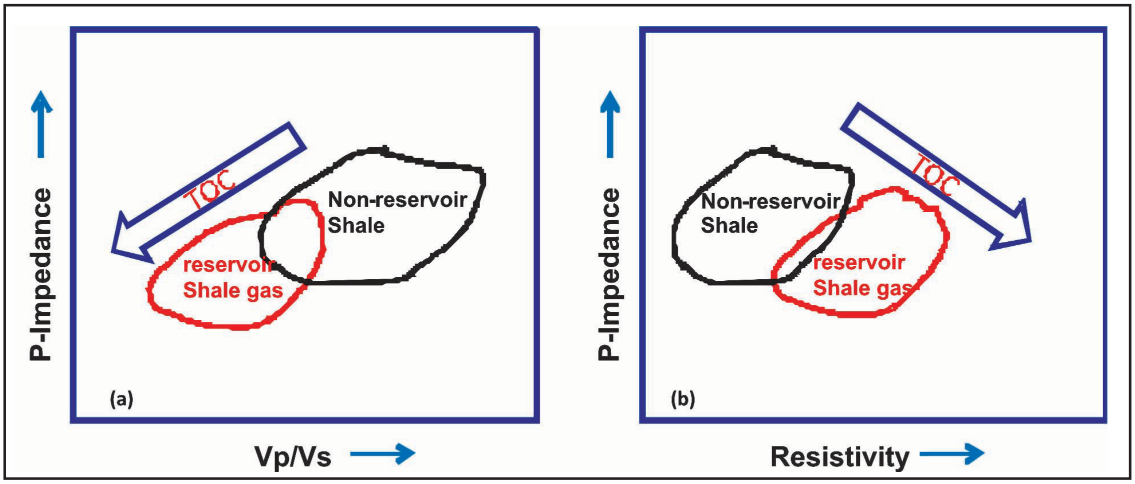

Fig.2 Schematic rock physics relationships between P-Impedance and Vp/Vs ratio (a) and P-Impedance and resistivity (b).

seismic data, and 3D volume of resistivity can be derived from inversion of electromagnetic data, such as, MT (magnetotelluric) data and CSEM (controlled-sourced electromagnetic) data.

Anisotropy

Anisotropy is an important attribute of shale that needs to be incorporated in rock physics and data analysis. Shale is intrinsically anisotropic (of type transverse isotropy with a vertical axis of symmetry, VTI) due to the presence of clay minerals (Banik, 1984). VTI medium is represented by 5 elastic parameters (Thomsen, 1986). Estimating anisotropic parameters from seismic is not trivial (Kumar et al., 2008). In a weak VTI medium, velocity anisotropy is the horizontal velocity minus vertical velocity and divided by vertical velocity. Seismic anisotropy in shale can be up to 60% (Sondergeld and Rai, 2011). In VTI media, Vp/Vs ratio (or Poisson ratio) and Young's modulus will also be anisotropic. Note that Young's modulus helps model rock's fracability. Minimum horizontal stress is an important parameter in frac design, and in VTI it will be a function of vertical and horizontal Poisson ratio and Youngs's modulus (Sayers, 2010). Electrical anisotropy is the ratio of vertical and horizontal resistivities and it can be up to 800% in shale (much stronger than seismic anisotropy). Also there is no clear intrinsic relationship between seismic and electrical anisotropies.

Seismic models

Figure 3 shows a P-wave seismic angle gather for the earth model (well logs) shown in Figure 1 using Zoeppritz modeled P-P reflectivity and a 30Hz Ricker wavelet. We performed Gassmann fluid substitution from insitu (gas bearing) to 100% brine to model sensitivity of fluid on AVA response (Figure 3). Even if Gassmann relation for the shale gas is not appropriate, it gives a first order estimate. Figure 3 shows AVA gather for both insitu and brine models. There is up to 12% increase in P-Impedance from insitu to brine case in this example and this provides detectable difference in two

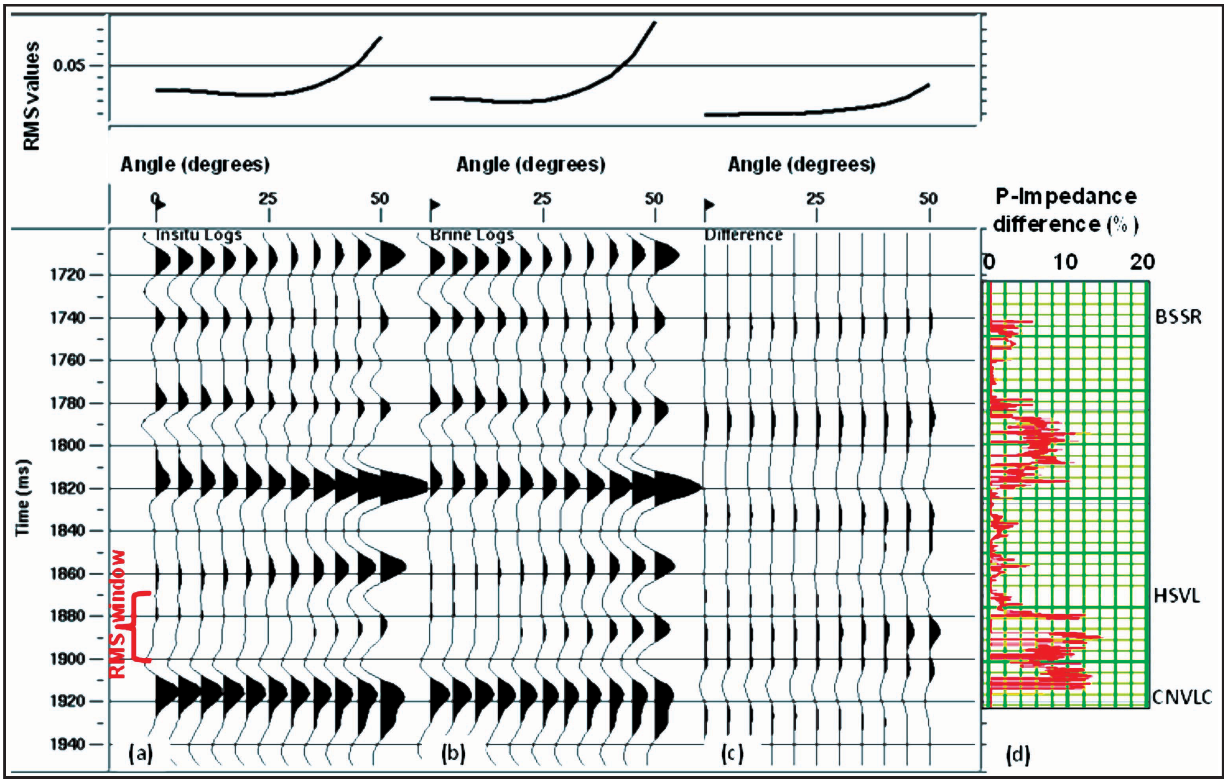

Fig.3 Seismic AVA model for shale gas and brine saturated shale. Gassmann equations (homogeneous saturation) were used to fluid substitute insitu (about 70%) gas saturation to 100% brine saturation in shale. Although Gassmann relation is not suited for shale, it provides first order estimate. For the single mineral matrix moduli used in Gassmann equation, we computed effective mineral moduli combining three dominant minerals: Quartz, Clay and Calcite. The synthetic AVA gathers for insitu (a) and brine saturated rock (b) are based on Zoeppritz P-P wave angle reflectivity and 30Hz Ricker wavelet. The difference in two AVA gathers (b-a) is shown in the third column (c). To quantify the difference in AVA response due to fluid, the root mean square (RMS) seismic amplitude in Haynesville shale (HSVL) zone is shown on the top of gather as a function of angle. The change is fluid has some effect in AVA response especially at far angles. The percentage increase in P-Impedance from insitu gas saturation to 100% brine saturation in this Bossier/Haynesville shale example is up to 12% (d). However if we consider patchy fluid saturation (using Brie or Voigt relationship for computing fluid bulk modulus) in Gassmann equations and substitute fluid from insitu to 60% water saturation (say after 2 years of production) the percentage increase in Haynesville shale is up to 6%.

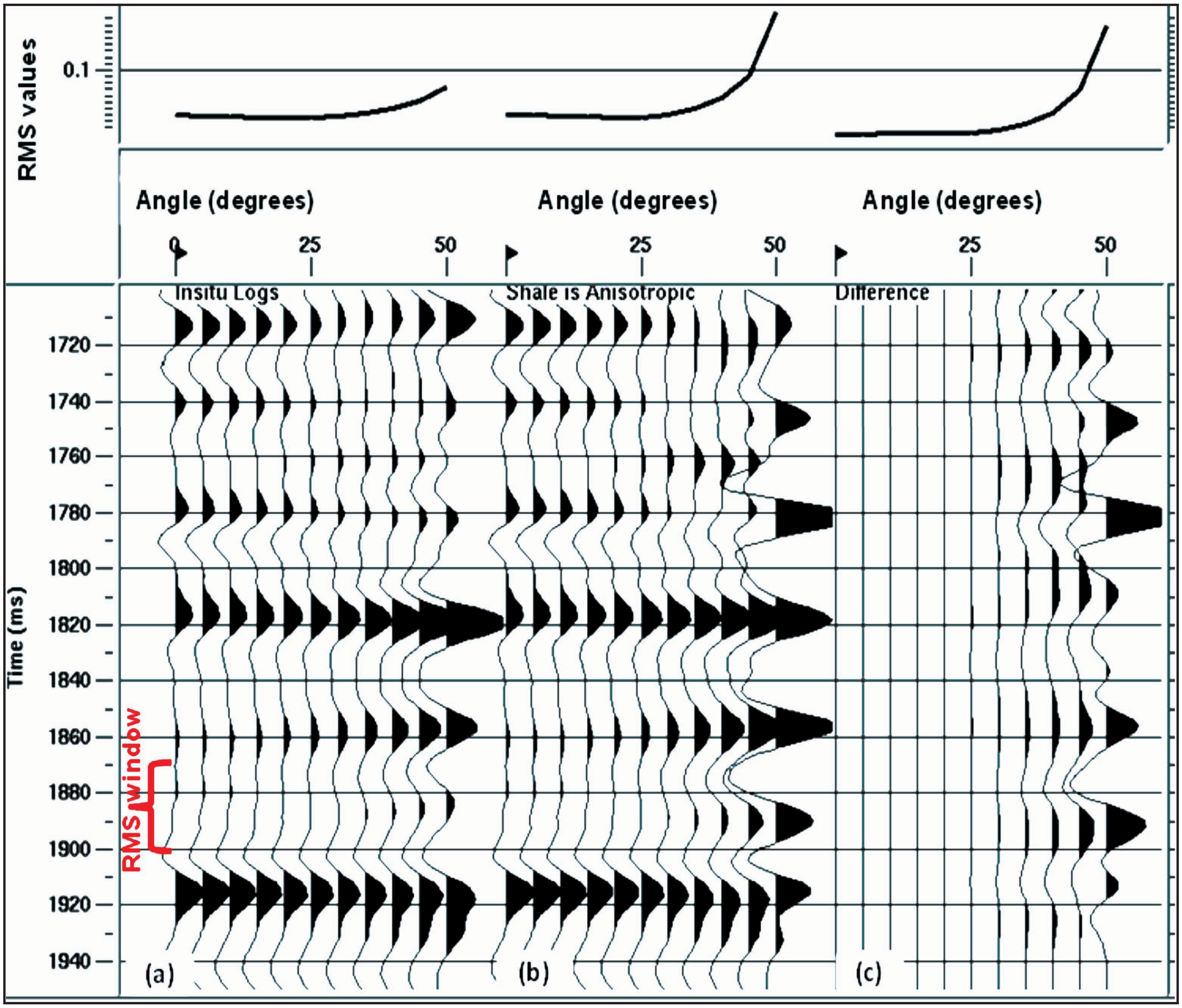

Fig.4 Effect of VTI anisotropy in shale on P-P wave seismic angle gathers: isotropic model (a), VTI anisotropic shale (b) and difference (b-a) between two gathers (c). In VTI model, shales (with Gamma ray log value > 75) are anisotropic and sandstones are isotropic. The Thomsen's VTI parameters for shale (epsilon = 0.256, delta = -0.051) are from Table 1 of Sondergeld and Rai (2011). Zoeppritz equation is used for isotropic medium and anisotropic Zoeppritz equation is used in VTI medium to calculate angle domain P-P wave reflectivity. The reflectivity function was convolved with a 30Hz Ricker wavelet to generate seismic data. Note significant difference in seismic response in Haynesville shale zone (about 1880-1900 ms); especially at far angles. To quantify the difference between isotropic and anisotropic gather, the RMS of seismic amplitude in Haynesville shale (HSVL) zone is shown on the top of gather as a function of angle. It clearly shows that anisotropy in shale can't be avoided in seismic data analysis. The anisotropy in shale gas has been reported much higher than used in this example (Sondergeld and Rai, 2011).

AVA gathers (Figure 3). However, gas saturation can be better estimated by incorporating resistivity information after EM data inversion. AVA inversion can be performed to estimate P-impedance and Vp/Vs ratio, and those can be used to map shale gas reservoir from seismic using appropriate rock physics models (Fig. 2) Seismic in (un-fractured) shale exhibits VTI behavior. Therefore the seismic response will be different in anisotropic shale. VTI parameters can be included in the Zoeppritz equations to compute P-P angle reflectivity in anisotropic medium (Schoenberg and Protazio, 1992). Figure 4 shows comparison of isotropic and anisotropic angle gathers using the well data from the Haynesville as in Figure 1.

EM models

Two types of EM data are studied here: 1) passive EM response with Magnetotellurics (MT) data and 2) controlled source EM (CSEM) data. In general, MT data is suited for thick conductive body (clay) and deeper thick resistive body (salt, basalt) and CSEM data is suited for resistive bodies (hydrocarbon targets). Also a CSEM survey is better suited for shallower target exploration. In the case of shale gas, resistivity is higher than background and is 3km deep in this case study (Figure 1). We performed both MT and CSEM modeling (Constable et al., 1987) over a 1D earth model (Figure 5). As expected the MT response (Figure 6) for the shale gas target compared to background shows very little sensitivity to the However, the CSEM model is promising (Figure 7). Figure 7 shows the CSEM model in both time domain and frequency domain for source and receivers on the surface. There is up to a 15% difference in Ex (horizontal electric field) in time domain and up to a 10% difference in the frequency domain due to a shale gas reservoir compared to the background. Therefore CSEM data has the potential to identify high gas saturation zones in shale reservoir. Note that EM responses in 3D will be less than in 1D, therefore 1D modeling is the first test to pass and it must be followed by 2D and 3D modeling.

Conclusions

Geophysical models are important for better understanding/interpretation of geophysical data. From the rock physics relationships it appears that seismic data is better suited for highlighting high gas potential zones (with lower P-Impedance and lower Vp/Vs ratio) and combined seismic and EM properties (lower P-Impedance and higher resistivity) can be used to infer gas saturation in a shale reservoir. 3D volumes of P-Impedance and Vp/Vs ratio can be estimated from seismic AVA inversion and 3D volume resistivity can be estimated from EM data inversion. Amongst the EM data types, MT data is not suited for deep resistive shale gas but CSEM data is well suited. Anisotropy in shale is significant and cannot be ignored in data analysis.

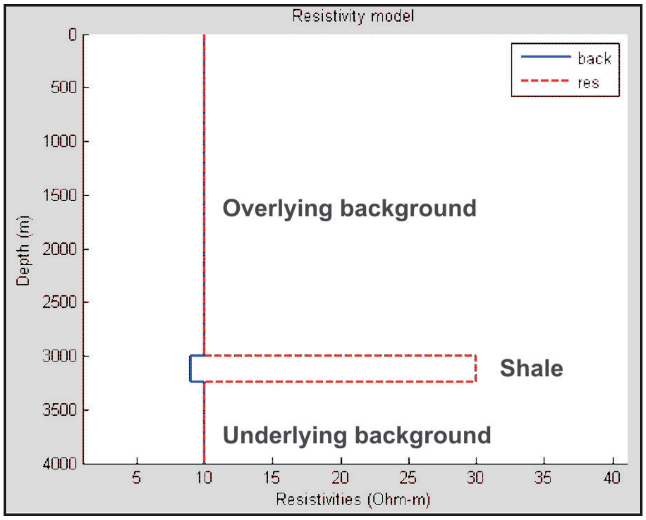

Fig.5 1D resistivity earth model for EM data modeling. This model is based on real well log shown in Figure 1. The background model ('back') is shown by blue solid line and the shale gas reservoir model ('res') is shown by red dotted line. In the shale zone, the background resistivity is 9 ohm-m and shale gas reservoir resistivity is 30 ohm-m in this model. This model represents a resistive shale gas reservoir at a 3km depth.

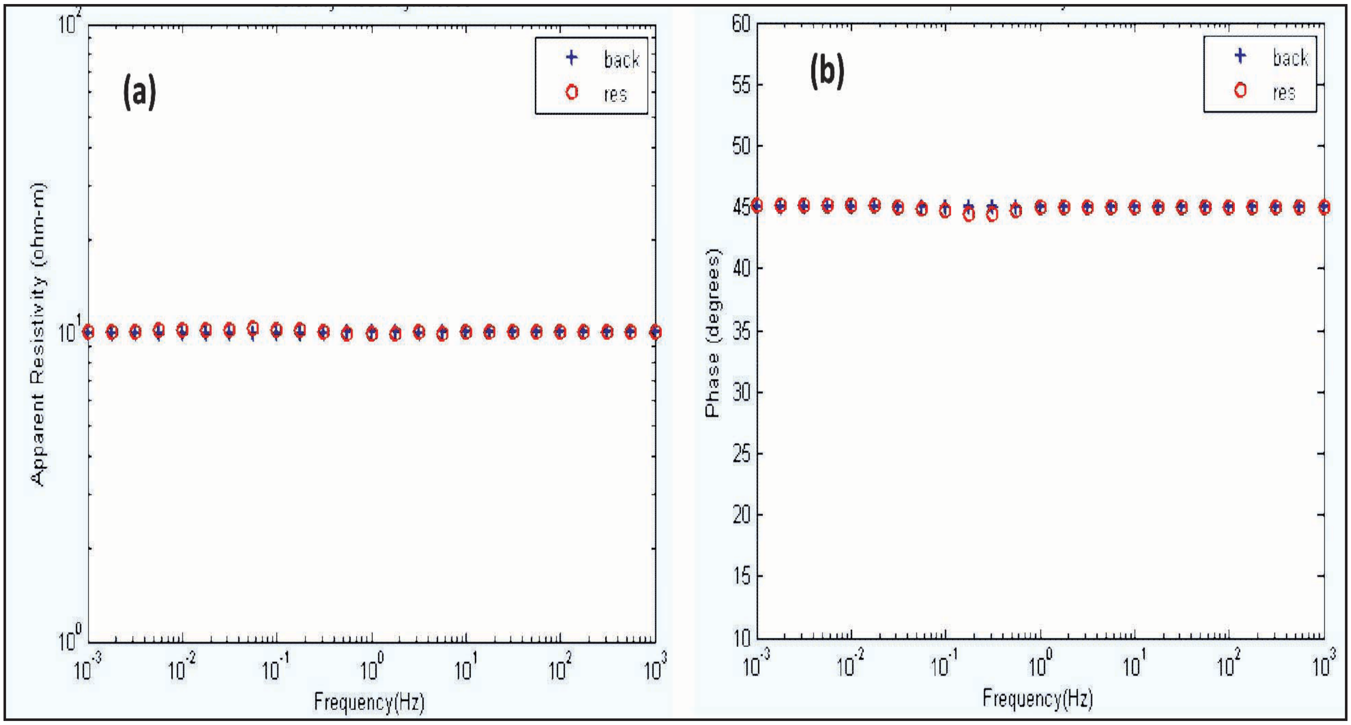

Fig.6 MT response: apparent resistivity (a) and phase (b) for the background model and the reservoir model shown in Figure 5. The X-axis is logarithmic frequency in Hz. There is negligible difference between MT responses for the two models. This implies that MT data is not suitable for the present geological scenario discussed in Figure 5. This MT response was expected and it confirms the statement that MT data is not suited for thin deeper resister.

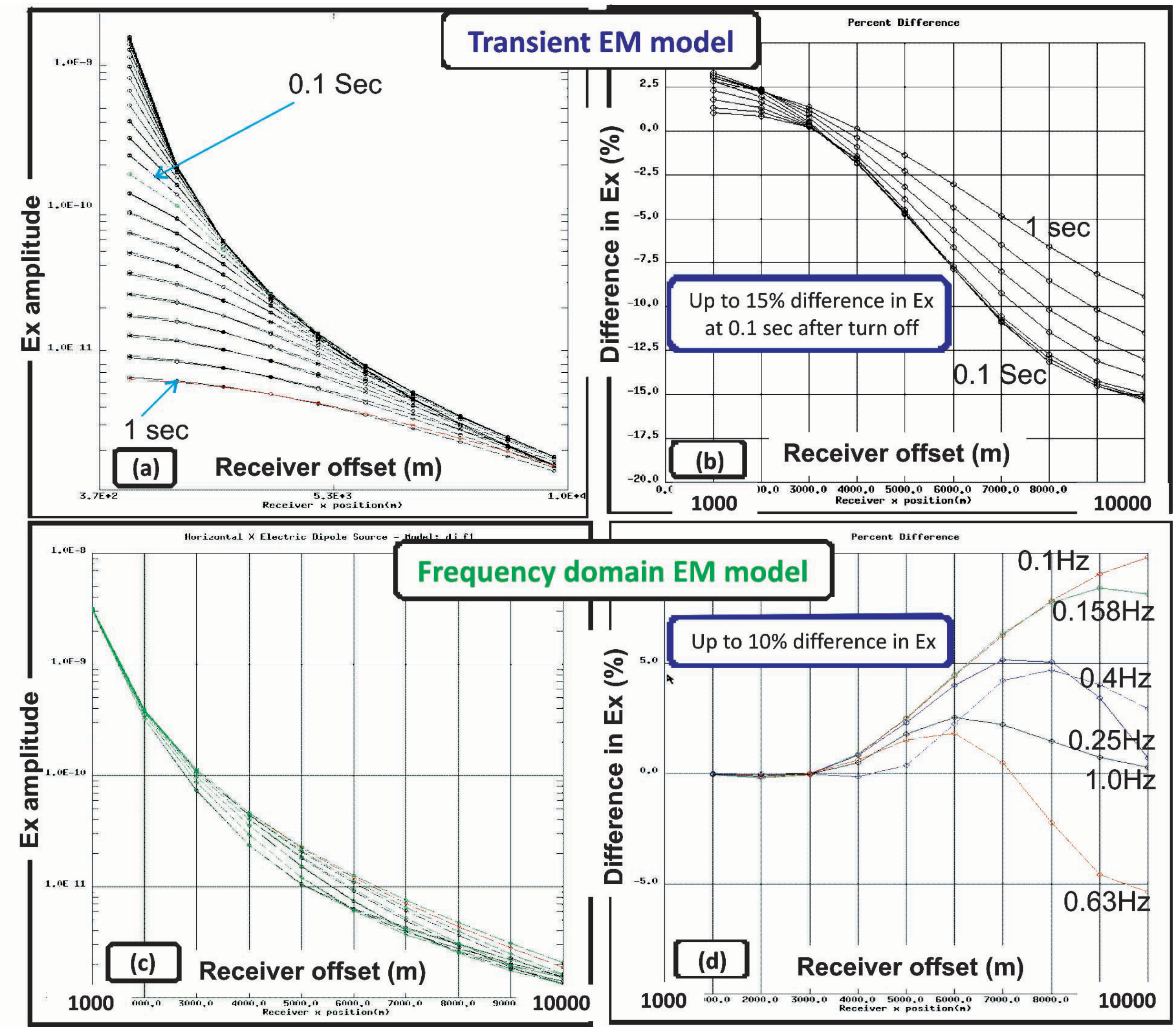

Fig.7 CSEM (controlled source EM) response in time domain (a and b) and frequency domain (c and d) for the 1D model shown in Figure 5. The source is horizontal electric dipole in X-direction on the surface and the receiver is also on the surface. The response is horizontal electric field in X-direction (Ex). Time domain modeling is done for 0.01 to 1 second. The Ex amplitude (in V/m) is plotted for both background and reservoir models (a and c). In time domain (a) both models are in black and the separation between the two models are evident beyond 5km offset, and in frequency domain (c) background model is in black and reservoir model is in green. The difference in Ex response due to the background model and the shale gas reservoir model is up to 15% in the time domain (b) and is up to 10% in the frequency domain (d). In a well processed good quality CSEM data the noise level is around 5%. This difference in Ex response over 1D seems promising to invert EM data for resistivity models and map the increase in resistivity in the shale layer due to the presence of gas. However, the 3D EM response will be less than 1D case and it will also depend on the size of anomaly, and therefore 1D modeling should be followed by 2D and 3D modeling. Time domain CSEM modeling is better suited for land data, because in the field EM data can be recorded after air wave has passed and this can reduce noise in data.

Acknowledgements

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