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Geophysical model response in a shale gas

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Summary

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 geophysical 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 in Bossier/Haynesville shale from East Texas, USA. Seismic attributes (lower P-Impedance and lower Vp/Vs ratio) can be used to map high gas potential zones in a shale reservoir. Considering EM data, MT is not suited, but CSEM data is well suited for mapping high resistive shale gas reservoir in this example.

Introduction

Traditionally shale has been considered a source rock and hence was not the focus in geophysical exploration. Now in certain cases shale is considered as reservoir as well as 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 images 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 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 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. 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 applied to generate geophysical data. If well data are available we can use well logs to build an earth model for simulation of data.

In this study we used well logs from a well in Bossier/Haynesville shale gas area in East Texas, USA (Figure 1). 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, 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 highlights 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.

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 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.

Seismic models

Figure 3 shows a P-wave seismic angle gather for the earth model (well logs) in Figure 1 using Zoeppritz modeled 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 gathers 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 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 (Figure 2).

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 body (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 1D earth model (Figure 4). As expected MT response (Figure 5) for the shale gas target compared to background is almost same, meaning there is very little sensitivity of target and we can't reliably use MT data for mapping shale gas. However, CSEM model is promising (Figure 6). Figure 6 shows CSEM model in both time domain and frequency domain for source and receiver on surface. There is up to 15% difference in Ex (horizontal electric field) in time domain and up to 10% difference in frequency domain due to shale gas reservoir compared to background. Therefore CSEM data can be used 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 seems seismic data is better suited for highlighting high gas potential zones (with lower P-Impedance and lower Vp/Vs ratio) and seismic and EM properties combined (lower Vp/Vs ratio and higher resistivity) can be used to infer gas saturation in 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. In EM data types, MT data is not suited for deep resistive shale gas but CSEM data is well suited.

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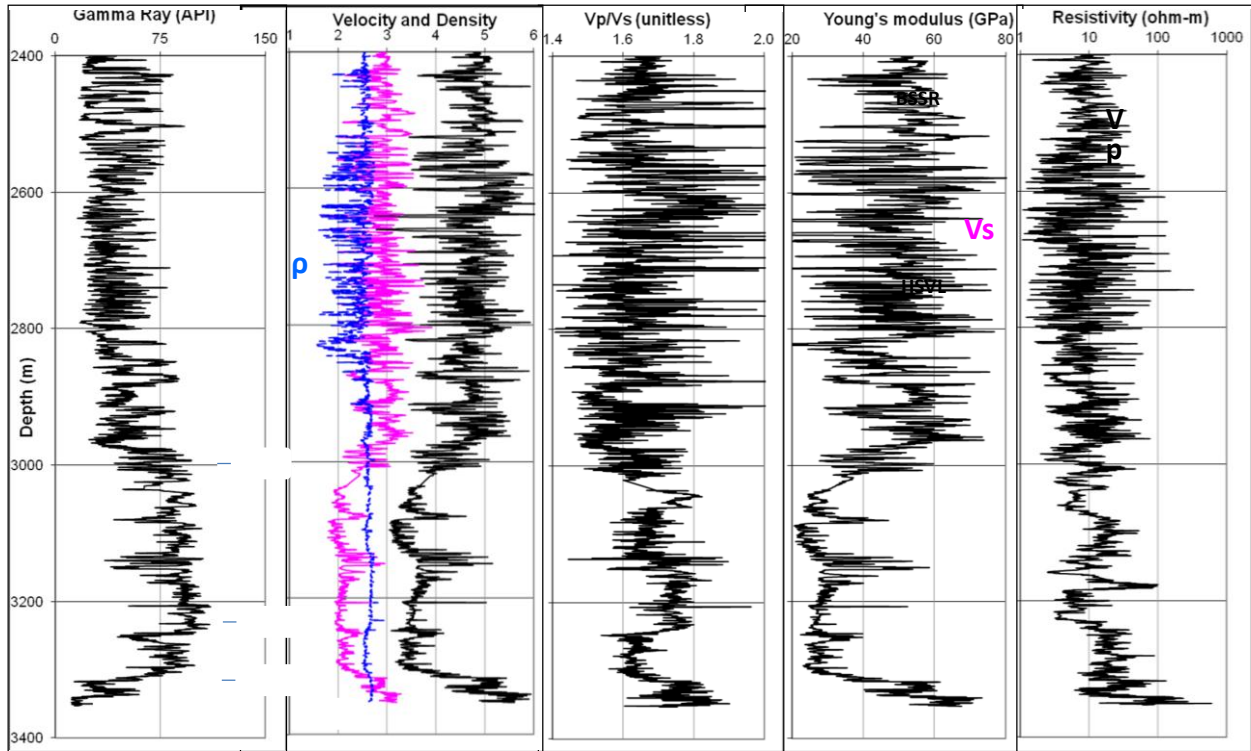


Figure 1: Well data from a well in Bossier/Haynesville shale area in East Texas, USA. Marker BSSR represents the top of Bossier shale, HSVL represents the top of Haynesville shale and CNVLC represents the top of cotton valley limestone. Shale reservoir has high Gamma value, Lower P-impedance, lower Vp/Vs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

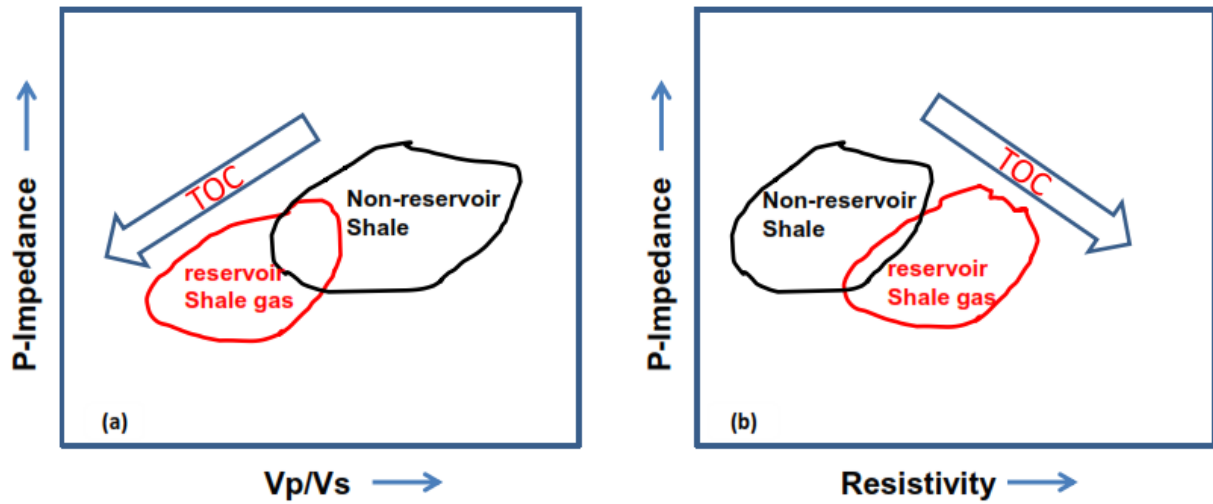


Figure 2: Schematic rock physics relationships between P-Impedance and Vp/Vs ratio (a) and P-Impedance and resistivity (b).



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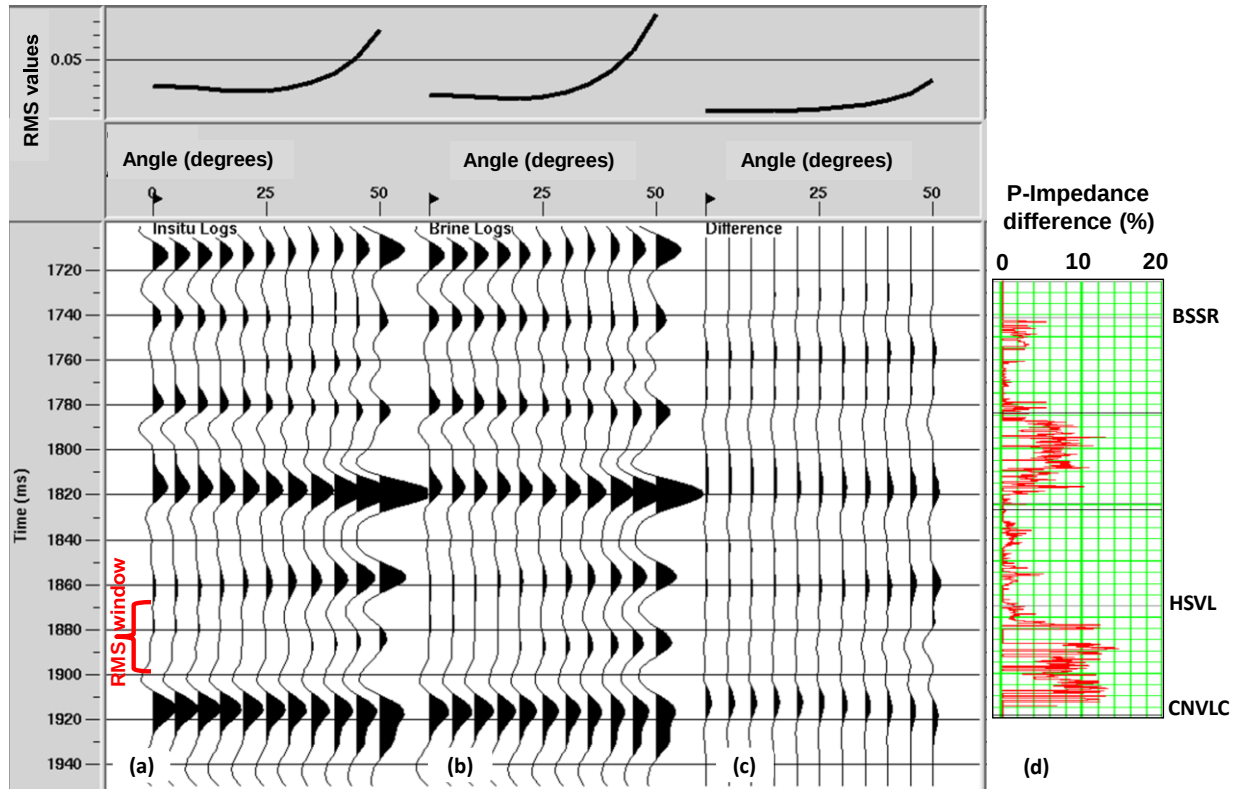


Figure 3: Seismic AVA model for shale gas and brine saturated shale. Gassmann equations (homogeneous saturation) were used to fluid substitute insitu (about 70%) gas saturation to 100% brine saturation in shale. Although Gassmann relation is not suited for shale, it provides first order estimate. For 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 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 (HSVLC) zone is shown on the top of gather as a function of angle. The change in 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) using homogeneous saturation model. However in the shale gas model patchy saturation is probably more suitable; and 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%. We think the AVA gathers can be inverted for P-Impedance and V_p/V_s ratio and those volumes can be used to highlight shale gas reservoir in 3D using appropriate rock physics relationships.



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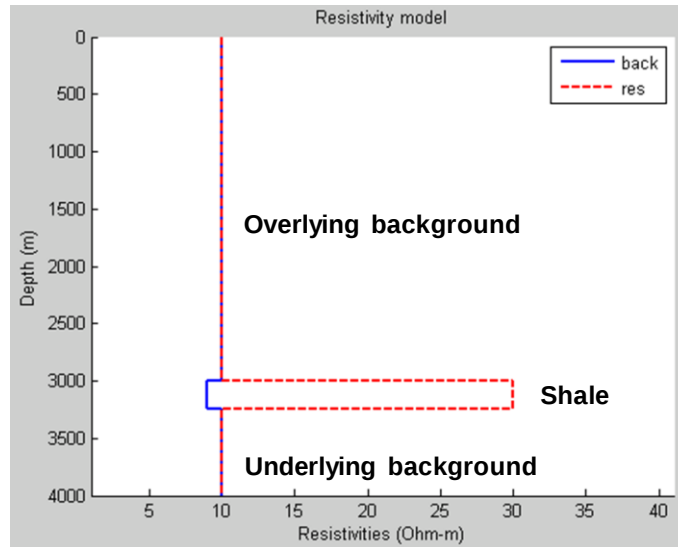


Figure 4: 1D resistivity earth model for EM data modeling. This model is based on real well log shown in Figure 1. The background model ('back') is shown by blue solid line and the shale gas reservoir model ('res') is shown by red dotted line. In the shale zone, the background resistivity is 9 ohm-m and shale gas reservoir resistivity is 30 ohm-m in this model. This model represents a resistive shale gas reservoir at a 3km depth.

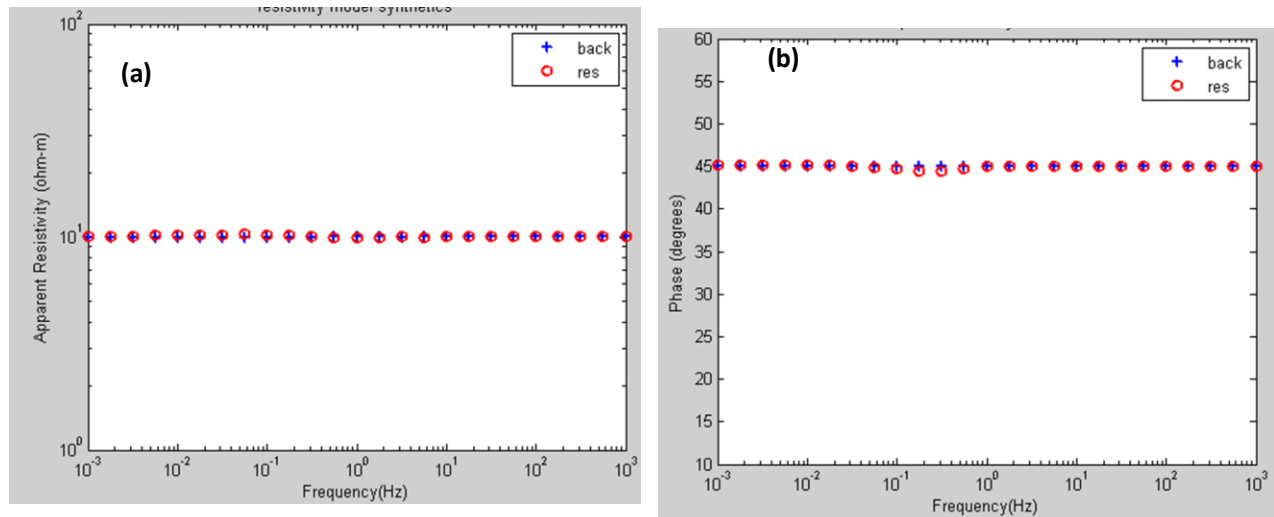


Figure 5: MT response: apparent resistivity (a) and phase (b) for the background model and the reservoir model shown in Figure 4. The X-axis is logarithmic frequency in Hz. There is negligible difference between MT responses for the two models. This implies that MT data is not suitable for the present geological scenario discussed in Figure 4. This MT response was expected and it confirms the statement that MT data is not suited for thin deeper resister.

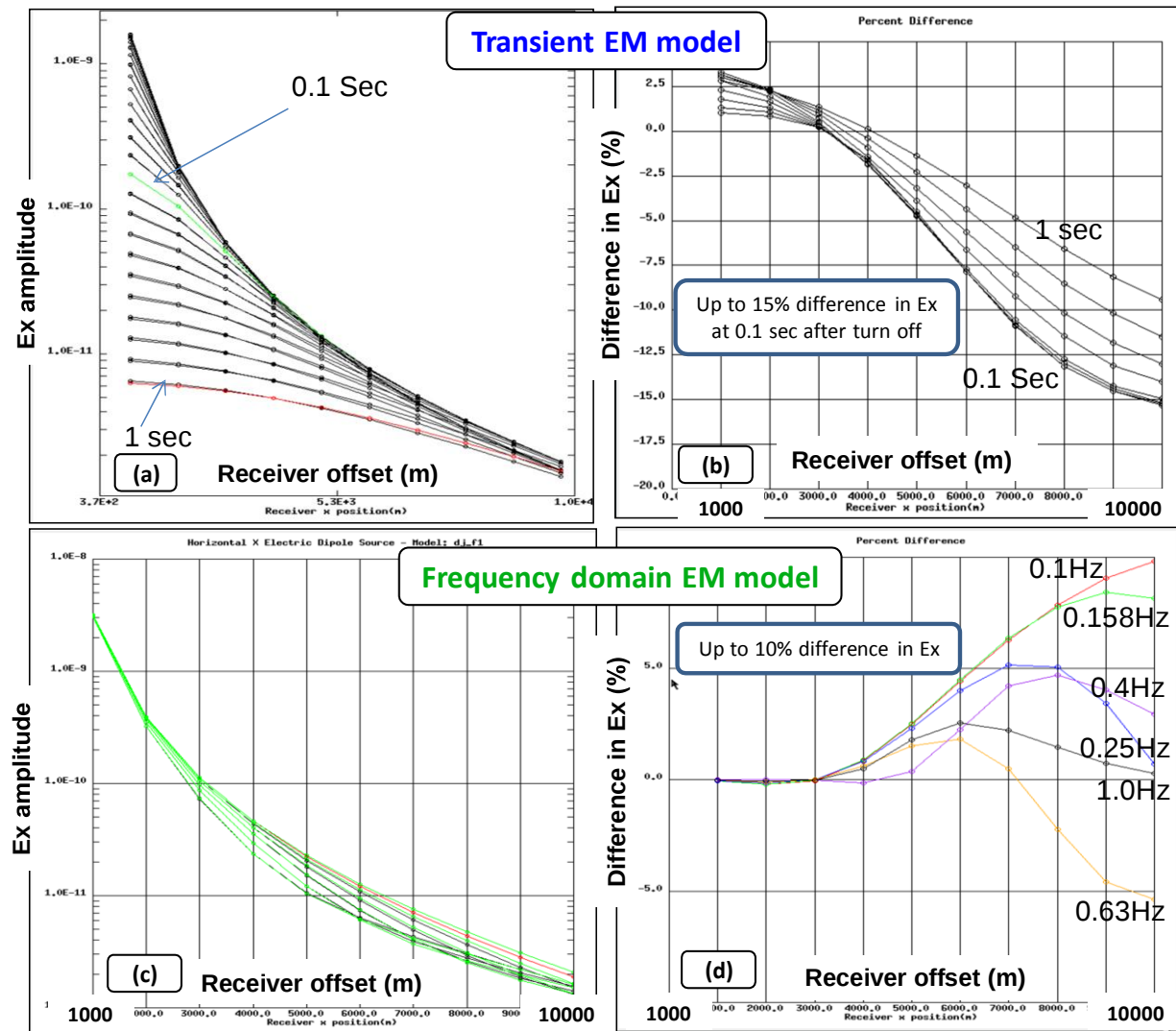


Figure 6: CSEM (controlled source EM) response in time domain (a and b) and frequency domain (c and d) for the 1D model shown in Figure 4. The source is horizontal electric dipole in X-direction on the surface and the receiver is also on the surface. The response is horizontal electric field in X-direction (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.