4D Seismic Feasibility Study using well Logs in Sienna gas Field, West Delta Deep Marine concession, Egypt

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Abstract: 4D (time-lapse) seismic has become a powerful technology for oil companies to manage their reservoirs. Time-lapse seismic has been proven to be very effective for monitoring not only gas production but also injection process. The process of gas production causes variations in reservoir parameters. The aim of this feasibility study is to give a better imaging about the change in seismic parameters due to gas production by using well logs and core data. In this paper, We determining the petrophysical parameters for sienna reservoirs rocks using wireline logs over the reservoir interval. The products of petrophysical parameters used as in-situ parameter in the rock physics model. The rock physics modeling can explain variations in reservoir parameters using the changes in seismic properties, several theories link seismic properties of reservoir rock to pore spaces, pore fluids, effective pressure and other reservoir parameters. It is primarily based on core measurements and well logs. The fluid substitution model used to detect the change of the water saturation in the seismic parameters using Gassmann's equation. The friable sand model used to detect the change of the pore pressure in the seismic parameters using the Hertz-Mindlin and lower Hashin-Shtrikamn equation.

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1. Introduction

(4D) seismic if the repeated surveys are 3D, becomes to play an important role in reservoir management, since time-lapse seismic has been proven to be very effective for monitoring not only gas production but also injection process. The process of oil or gas production causes variations in reservoir parameters such as fluid types, fluid saturation, pressure and reservoir thickness and thus changes seismic properties of saturated reservoir rock. Repeating 3D seismic surveys over production time can detect changes in seismic response (which can be interpreted as the variations in reservoir parameters) to monitor changes in fluid flow due to gas production or an injection process. With repeatability of seismic surveys, reservoirs that have weak rocks, large amount of pore fluid and large change in rock compressibility are often good candidates to apply time-lapse seismic monitoring.

For the monitoring, variations in reservoir parameters over production time must be large enough for repetitive surveys to detect the differences. Therefore, it is crucial to the success of 4D seismic projects to make a feasibility study determining how we can properly design 4D seismic surveys for a reservoir under consideration. The feasibility study begins with determining the petrophysical parameters (porosity, effective porosity, hydrocarbon and water saturation, shale content) for sienna wells and then make rock physics modeling at each production stage, which explain changes in seismic properties due to the variations in the reservoir parameters during production.

Geologic Setting

The Nile Delta is one of the world's classic deltas (Figure 1). Offshore exploration using high-quality 3D seismic-amplitude data in the last decade has resulted in the discovery of significant reserves. Using a geology-based assessment method in 2010, the U. S. Geological Survey estimated the undiscovered oil and gas resources of the Nile Delta Basin Province. It estimated an average of 1.8 billion barrels of recoverable oil, 223 trillion cubic feet of recoverable gas, and 6 billion barrels of natural-gas liquids in the Nile Delta Basin Province.

The West Delta Deep Marine (WDDM) concession covers 6150 km² and lies approximately 50 to 100 km offshore the northwest margin of the Nile cone. It includes the Pliocene sienna gas field (Figure 1).Sienna Field is believed to be a slope channel complex deposited on the Nile delta slope in the late- Pliocene within Kafr El Sheikh package (figure 2).

The reservoir has been deposited in many stages, starting with a great incision, then followed by depositing amalgamated and laterally extensive system, then as the slope gets flatter, sinuous channels begin to develop, then the story ends with channel abandonment with very distal and weak energy deposits on top before the background deposition dominates.

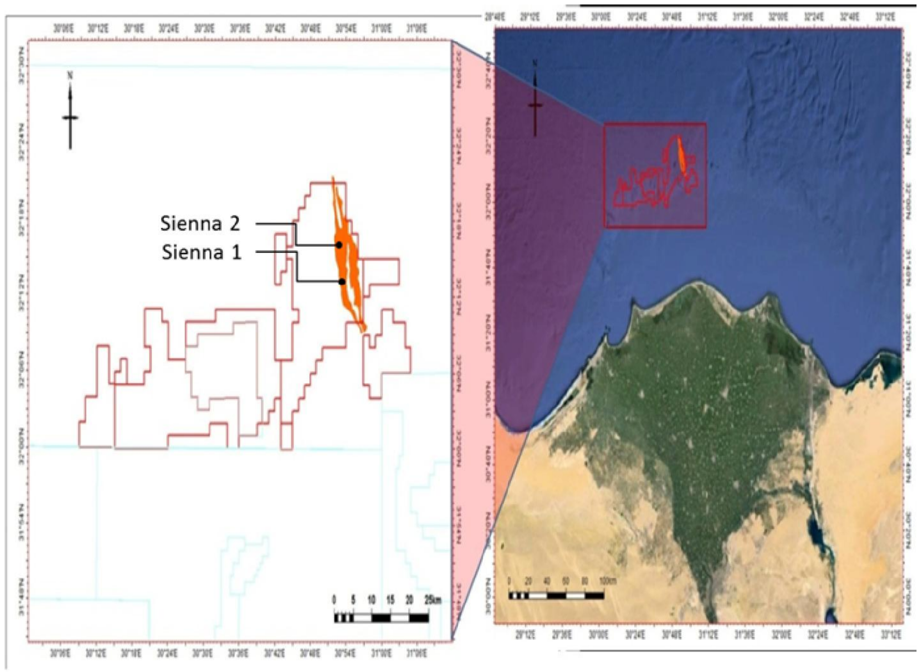

Figure 1: sienna location map.

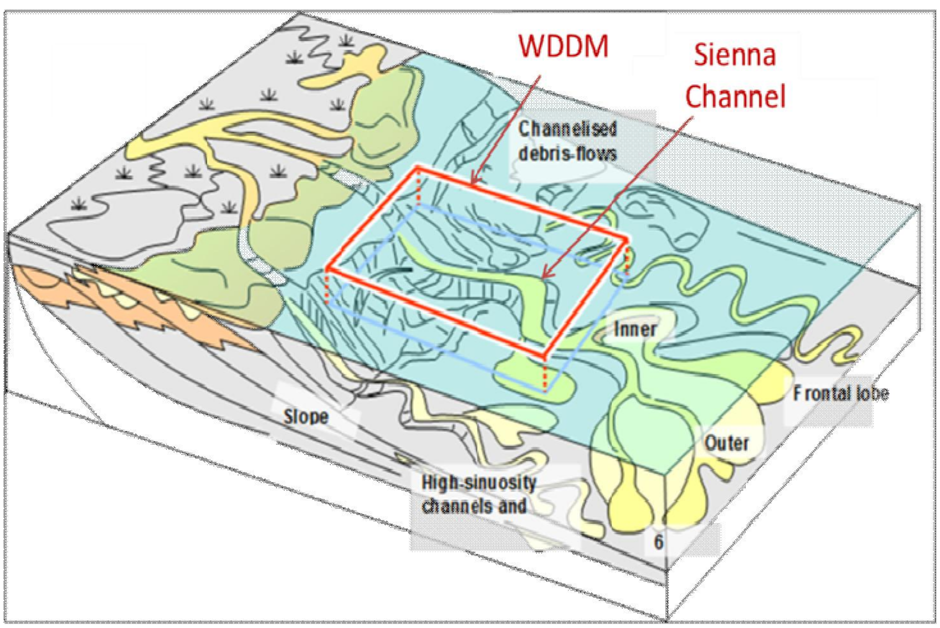

Figure 2: 3D schematic diagram showing the depositionalmodelofturbidite slope channels (After Reading and Richards 1994).

2. **Methodology**

Well Logging Analysis and Interpretation

Two wells in the Sienna field. The wells are near vertical and have a full suite of wireline logs over the reservoir interval.

The volume of shale (Vsh) is calculated through GR as a single indicator and through neutron – density as a double indicator. The gamma ray has a lower resolution than the density - neutron logs and gives higher shale volume in the thin bed but the neutron-density logs affected by the gas, this makes a false estimation of the shale volume in shaly sand zone (make the shaly sand zone is aclean zone) so, we use The shale volume from the gamma ray.

The rock porosity (Φ) was calculated by density as a single indicator and neutron –density as a double indicator. But we used the density calculation due to the over estimation of the neutron –densitylogs. The porosity was determined after applied gas correction.

The determination of fluid saturations is carried out for shalys and zones in sienna reservoir by using Indonesian equation and the Archie equation didn't applied because we didn't have a clean sand zone in sienna reservoir.

The lithology of the sienna reservoir rock was studied using NPHI – RHOB Cross plot. This plot shows the reservoir rock is mainly composed of sandstone with considerable amount of shale and silt, the effect of the gas shift points to upward (figure 3), the effect of the shale shift points to downward (figure 4).

The mineralogy of the sienna reservoir rock was studied using Th-K Crossplot.Th-K cross plot for sienna-1 well Figure (5) shows the clay minerals lie between mixed layer clay, mica, illite, montmorillonite and glauconite. Th-K crossplot for sienna-2 well Figure(6) shows the clay minerals lie between mixed layer clay, montmorillonite, illite and mica. Th-K Crossplot of sienna wells show that sienna wells didn't have feldspars in reservoir zone so, Gr log didn't affected by the feldspars.

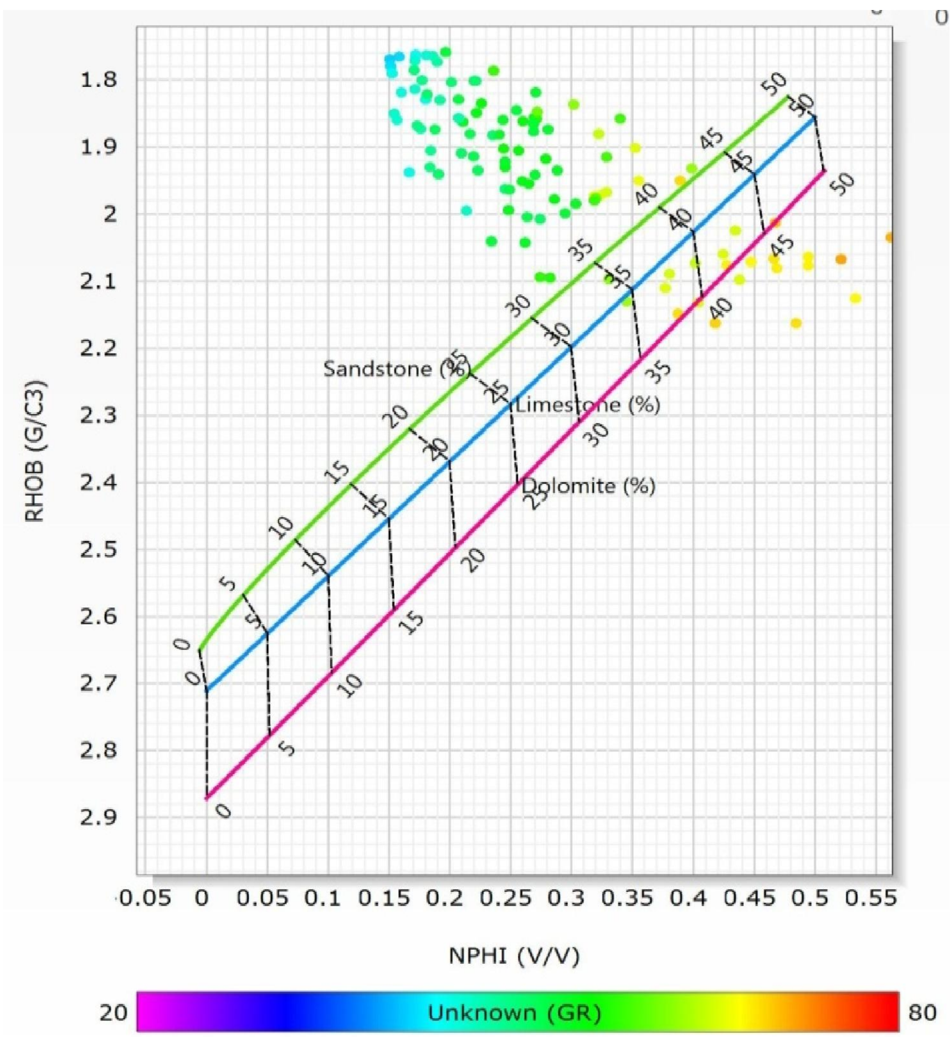

Figure 3: RHOB-NPHI Cross Plot for sand-1 zone in Sienna-1 Well

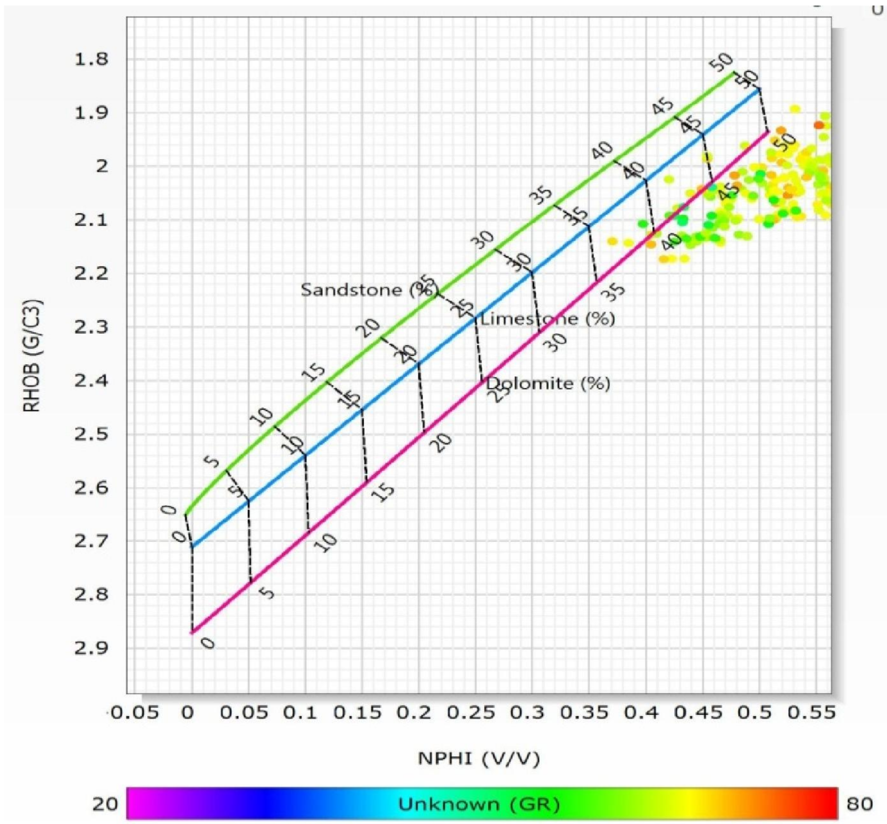

Figure 4: RHOB-NPHI Cross Plot for shale zone in Sienna-2 Well

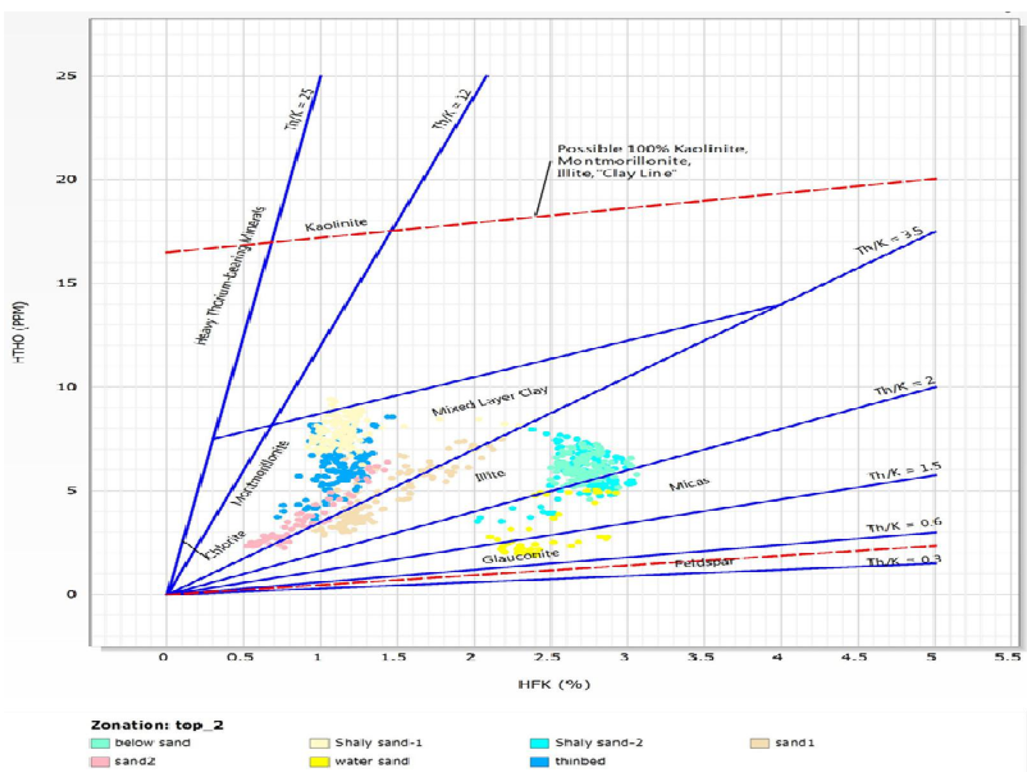

Figure 5: TH-K Cross Plot for Sienna-1 Well

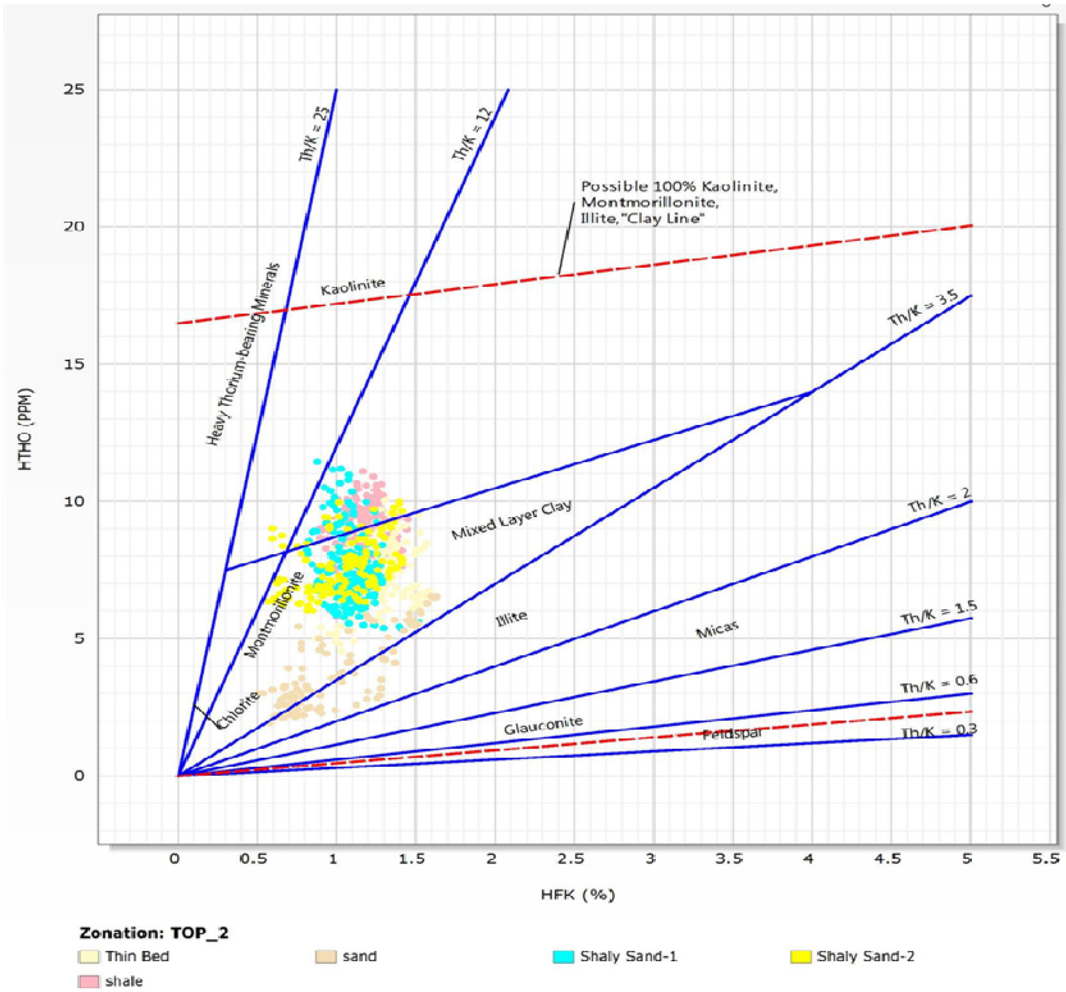

Figure 6: TH- K Cross Plot for Sienna-2 Well

The shale volume value of 60% cut off value was used to identify the reservoir and non-reservoir beds (according to SCAL data from Rashid Petroleum Company).

In this paper, we applied a consistent methodology for better understanding the optimum cut off parameters of sienna reservoir using the well log data. The Equivalent oil Column (HPVH) versus effective porosity and water saturation cut offs crossplots were generated for sienna wells and by calculating the sum total of product of gas saturation (Sg), effective porosity (Φe) and net thickness (H) at different porosity and water saturation cut offs.

The cut offs were chosen at the minimum hydrocarbon pore volume reduction due the cut off value used. These are beyond the inflexion point. The 10% effective porosity and 50 % water saturation cut-off were used to define net reservoir and the net pay (respectively) are fairly arbitrarily and optimistic. Figure (7).

RockPhysicsModeling

The rock physics modeling forms the basis for determining the feasibility of seismicity detecting the combined total effect of all the change in the reservoir and it also provides the much-needed link between the seismology and reservoir engineering by transforming seismic properties to reservoir properties (Wang, 1997).

After production, the water saturation increase, the pore pressure decrease and reservoir thickness decrease and this reservoir parameter make change in the seismic Properties.

In this paper, we study the effect of increasing water saturation using the fluid substitution model and study decreasing pore pressure and reservoir thickness using friable sand model.

The parameter used for one point in the reservoir thickness that best represent the unconsolidated sand reservoir.

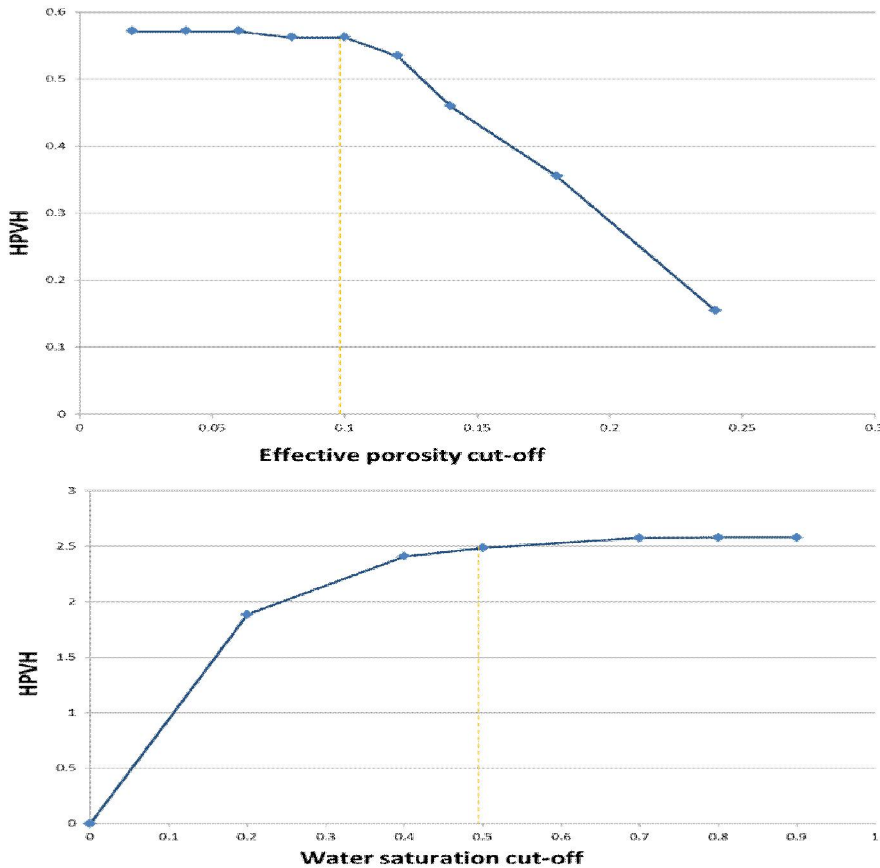

Figure 7: Hydrocarbon pore volume sensitivity plots for effective porosity (top) and water saturation (bottom) cut off validation

Fluid substitution modeling

Fluid substitution is a prediction of fluid saturation effects on seismic properties. It uses Gassmann's equation to calculate elastic properties at the desired saturation, from either the dry rock or a rock saturated with another fluid (Sheriff, 2006).

Gassmann fluid substitution is used for calculation of elastic properties of clean sands with uniform water saturation for different saturation values, and for porosities from zero to initial/critical porosity, and is expressed as:

$$Ksat = Kdry + \frac{\left[1-\frac{Kdry}{Kmin}\right]^2}{\frac{\emptyset}{Kfluid}+\frac{1-\emptyset}{Kmin}-\frac{Kdry}{Kmin^2}} \qquad (1)$$

$$\mu sat = \mu dry \qquad (2)$$

where Kdry is the effective bulk modulus of dry rock, Ksat, effective bulk modulus of rock with pore fluid, Kmin, effective bulk modulus of mineral material making the rock, Kfl, effective bulk modulus of pore fluid, μdry, effective shear modulus of dry rock, μsat, effective shear modulus of rock with pore fluid and Φ is porosity.

Fluid density (ρfl) is a mixture of fluids weighted by saturation - the amount of pore space filled with particular fluid type, and it is defined using equation:

$$\rho fl = Sw\rho w + (1 - Sw)\rho hc \qquad (3)$$

Where SW is water saturation,ρw, density of formation waterandρhc is density of hydrocarbon.

The fluid modulus is given by Wood's equation:

$$Kfl = \left(\frac{Sw}{Kw} + \frac{(1-Sw)}{khc}\right)^{-1} \qquad (4)$$

Where Kw and Khc are bulk modulus of brine and hydrocarbon, respectively.

The mass balance equation is used to calculate the bulk density of the rock as a function of porosity and mixed fluids:

$$\rho b = \rho g(1-\emptyset) + \rho fl\emptyset \qquad (5)$$

Where ρbis bulk density of the formation, ρg, density of the grains comprising the formation (sand grain density 2.65 g/cc), ρfl= density of fluid and Φis porosity.

The compressional (Vp) and shear velocity (Vs) are calculated for the new/desired saturation using the following equations:

$$V_P = \sqrt{\frac{K+{}^4/_3\,\mu}{\rho}} \qquad (6)$$

$$V_S = \sqrt{\frac{\mu}{\rho}} \qquad (7)$$

The friable sand model

The friable-sand model, describes how the velocity-porosity relation changes as the sorting deteriorates. The "well-sorted" end member is represented as a well-sorted packing of similar grains whose elastic properties are determined by the elasticity at the grain contacts. The "well-sorted" end member typically has a critical porosity. The friable sand model represent poorly sorted sands as the, well-sorted, end member modified with additional smaller grains deposited in the pore space. These additional grains deteriorate sorting, decrease the porosity, and only slightly increase the stiffness of the rock.

The elastic moduli of the dry well sorted end member at critical porosity are modeled as an elastic sphere pack subject to effective pressure. These moduli are given by the Hertz-Mindlintheory (Mindlin, 1949) as follows:

$$KHm = \left[\frac{n^2(1-\emptyset c)^2\mu^2}{18\pi^2(1-v)^2}P\right]^{\frac{1}{3}} \quad (8)$$

$$\mu Hm = \frac{5-4v}{5(2-v)}\left[\frac{3n^2(1-\emptyset c)^2\mu^2}{2\pi^2(1-v)^2}P\right]^{\frac{1}{3}} \quad (9)$$

Where KHM and MHM are the dry rock bulk and shear moduli, respectively, at critical porosity Øc, P is the effective pressure, μ and v are the shear modulus and Poisson's ratio of the solid phase and n is the coordination number (the average number of contacts per grain).

The Poisson's ratio can be expressed in terms of the bulk(K) and the shear(μ) moduli as the follows:

$$v = \frac{3K-2\mu}{2(3K+\mu)} \quad (10)$$

The coordination number (n) of the granular assembly is defined as the average number of contacts per grain (Mavko et al., 1998). The relationship between coordination number and porosity can be approximated by the following empirical equation:

$$n = 20 - 34\emptyset + 14\emptyset^2 \quad (11)$$

The other end member point in the friable sand model is at zero porosity and has the bulk(K) and shear(μ) moduli of the mineral.moduli of the poorly sorted sands with porosities between 0 to Øc are interpolated between the mineral point and the well sorted end member using the lower Hashin-Shtrikamn (1963) bound.

The bulk and shear moduli of the dry friable sand mixture are:

$$Kdry = \left[\frac{\emptyset/\emptyset c}{KHM+4\mu HM/3} + \frac{1-\emptyset/\emptyset c}{K+4\mu HM/3}\right]^{-1} - \frac{4}{3}\mu HM \quad (12)$$

$$\mu dry = \left[\frac{\emptyset/\emptyset c}{\mu HM+z} + \frac{1-\emptyset/\emptyset c}{\mu+z}\right]^{-1} - z \quad (13)$$

Where

$$z = \frac{\mu HM}{6}\left(\frac{9KHM+8\mu HM}{KHM+2\mu HM}\right)$$

Due to the over estimation of the dry shear moduli, so we could compute the new value of dry shear moduli μ using the following equation:

$$\mu new = \mu insitu\frac{Kdrynew}{Kdryinsitu} \quad (14)$$

The saturated elastic moduli, Ksat and Msat, can now be calculated from gassmann´s equation (equations (1) and (2) and the density calculated using the equation (5).and we can calculate the critical porosity and the effect of increasing the effective pressure in porosity using Special core analysis (SCAl) data.

3. Results

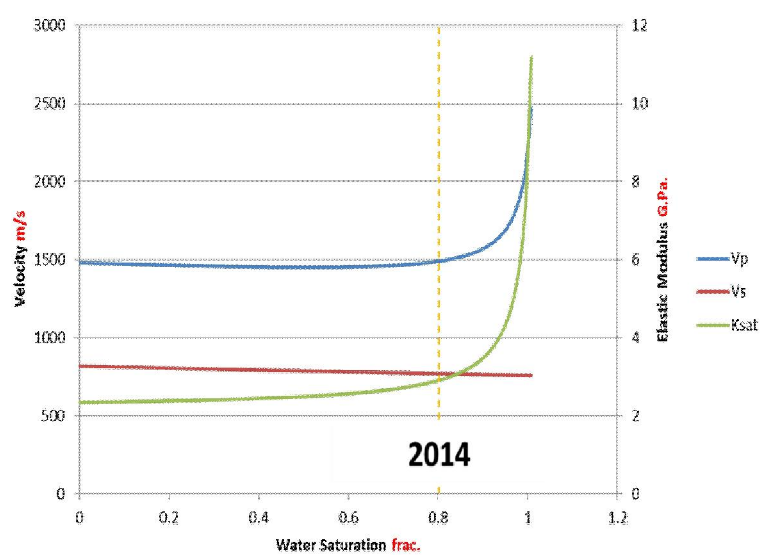

Figure 8: The change in the elastic and seismic properties with different water saturation in sienna- 1

According to the reservoir engineer, the expected water saturation in 2014 became 80 % in flooded area and expected pore pressure in 2014 became 100 bar.

We used well logging analysis results as in-situ parameters and then we choose one point in the reservoir thickness that best represent the unconsolidated reservoir.

The figure (8) shows that elastic and seismic properties change slightly with different water saturation and the figure (9) show that the AVO class still class III with different water saturation.The figure (10) show that the elastic and seismic parameters have great change with different pore pressure and the figure (11) shows that the AVO class change from class III to class II with different pore pressure. The figure(12) shows the maximum drop in the reflectivity will be less than 50% with different water saturation and the drop in the reflectivity with different pore pressure can reach 100%. The figure (13) shows the reservoir thickness in the seismic section can be drop from 50ms to 30ms.

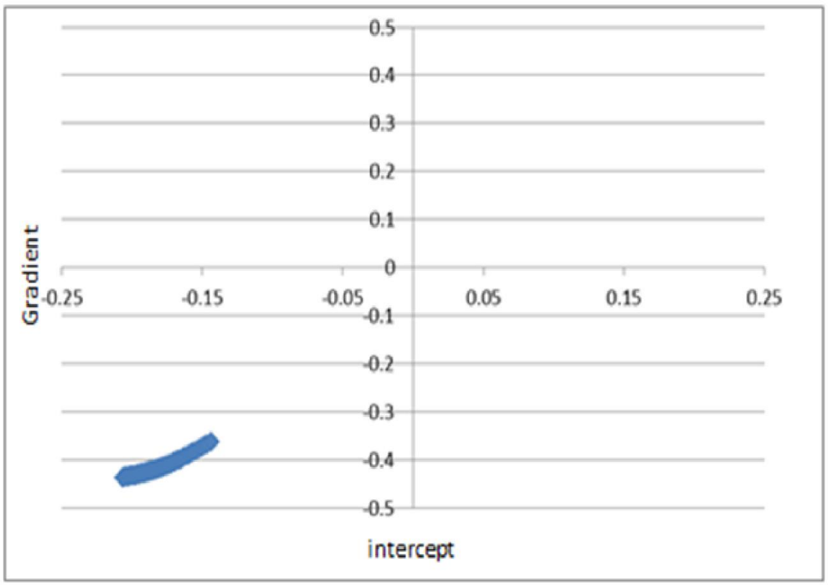

Figure 9: Intercept versus gradient crossplot displaying the water saturating effect at sienna-1.

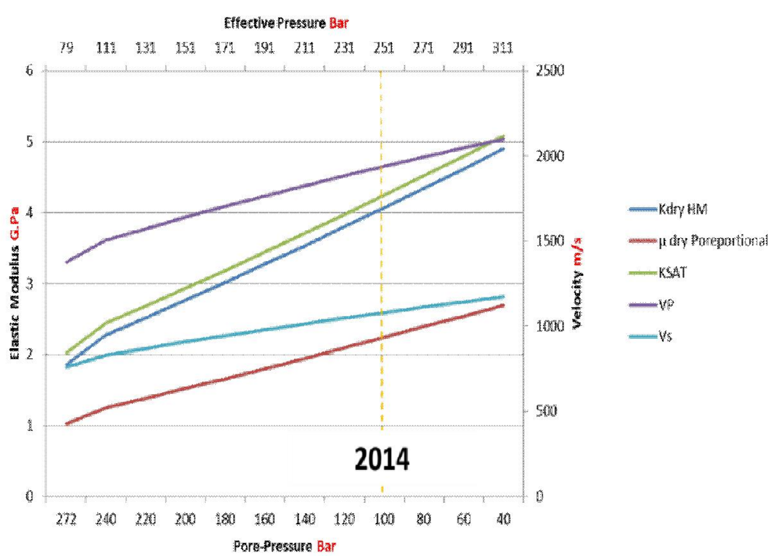

Figure 10: The change in the elastic and seismic properties with different pore pressure in sienna-1

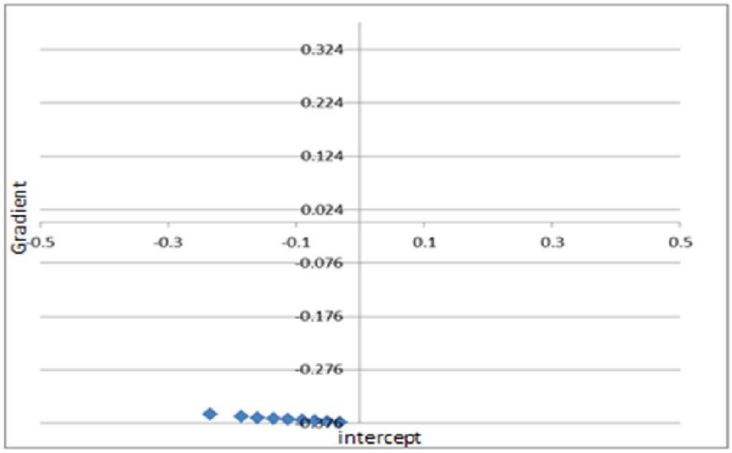

Figure 11: Intercept versus gradient crossplot displaying the pore pressure effect at sienna-1.

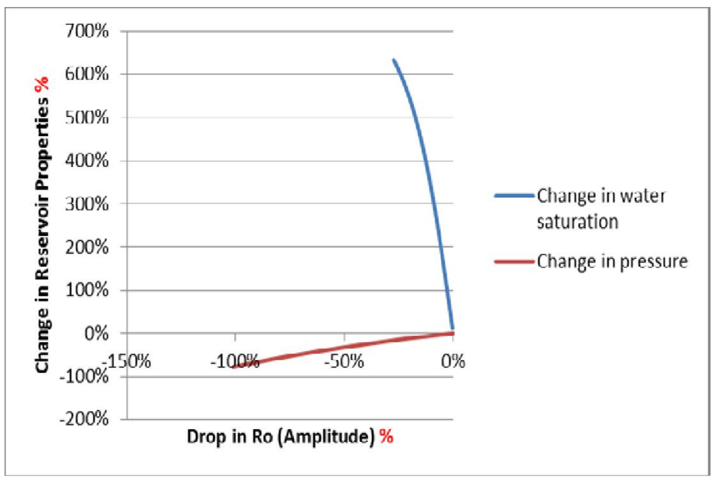

Figure 12: The drop in reflectivity with different pore pressure and water saturation in sienna-1

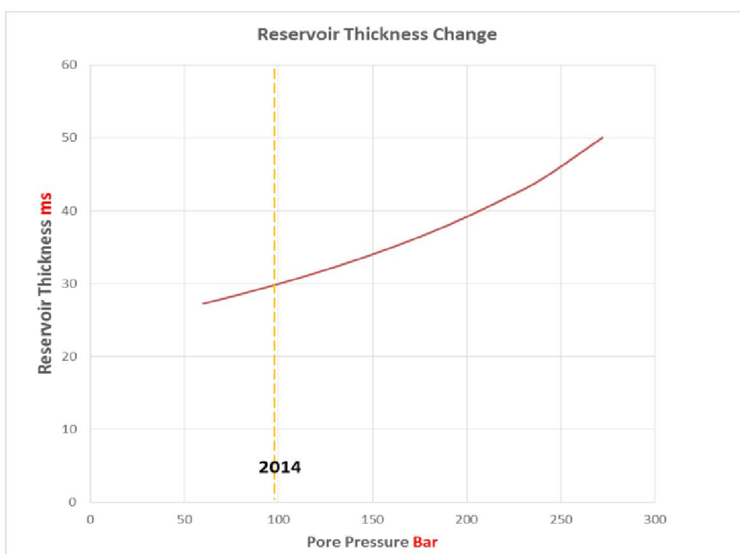

Figure 13: The change in the reservoir thickness with different pore pressure in sienna-1

Conclusion

As the cost implications of 4D projects are substantial, it is important to conduct a feasibility study based on rock physics and forward modeling to analyze the types of changes that may take place due to production and assess if these changes are sufficient enough to be observed seismically. Therefore, seismic-based reservoir monitoring holds significant promise for adding value to reservoirs and reservoir management. The value thus added can be realized through enhanced recovery as well as reduced development cost.

Rock physics modeling explains crucial relations between reservoir parameters and seismic properties of reservoir rock and we used two models for constructing the rock physics modeling, which are fluid substitution model and the friable sand model. Fluid substitution model show that with different water saturation, the seismic parameters change slightly, reflectivity dropped to less than 50% and AVO class didn't change. The friable sand model show that with different pore pressure, the seismic parameters have great change, reflectivity dropped to 100% and AVO class change from class III to class II.

Acknowledgments

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