New advances in passive seismic tomography from instrumentation to data processing and interpretation – some examples

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Passive, Tomography, Earthquakes

Summary

Passive Seismic Tomography (PST) in recent years has become a well established technique in the upstream hydrocarbon industry specifically for regional hydrocarbon exploration. Significant advantages have been achieved not only in instrumentation but in data de-noising, processing and interpretation. Some of these advantages will be presented with case histories.

Introduction

PST has been applied successfully in regional hydrocarbon exploration, demonstrating its potential to map large areas for a relatively low cost compared to conventional 1D seismic surveys (Kapotas et al., 2003). Valoroso et al. (2008) use 4D passive seismic tomography to detect space-time dependency in response to fluid pressure. Tselentis et al. (2006) show that PST can even be applied at a local scale. Although the number of such applications is limited at the moment, with improvements in instrumentation, data acquisition and processing technology, the use of PST as a tool for hydrocarbon exploration and characterization is likely to flourish.

The rationale for applying PST as a complementary imaging tool has several important advantages. First, tomography is a cost-effective means of imaging a large area with difficult terrain in which conventional seismic exploration is expensive and can be of poor quality because of seismic penetration problems. Second, PST can provide an accurate 3D velocity model that can be used to improve (i.e., PSDM) existing or lower-quality reflection seismic data. Third, the technique is environmentally friendly, an important consideration in all operational activities. Finally, PST can provide parameters related directly to reservoir properties, such as $V_P=V_S$ and Q_P. These parameters are very difficult to derive from conventional seismic techniques because they require large-amplitude shear waves.

Processing of PST data at a local scale for hydrocarbon exploration is more complicated than applying off-the-shelf 3D inversion algorithms. To get the best resolution of the geologic formations at the lowest cost, we tap an arsenal of techniques, including initial-velocity model selection, simultaneous earthquake hypocenter and 3D velocity models, Q_P inversion, synthetic and real-data checkerboard tests.

Data de-noising and phase identification

During a PST investigation, we use small magnitude earthquakes which often are hard to detect since they can be corrupted by noise. Therefor, identification of the weak P- and S-wave arrivals is important for obtaining accurate PST results.

For high resolution PST applications, we need as many as possible small magnitude events which can be characterized as point sources. These small events, especially if acquired in urban areas are often strongly affected by noise, so we also require procedures that allow a reliable first arrival picking, without losing important information. During the last years various methodologies have been developed.

Thus an important step in the processing is to attenuate the energy of the seismic noise while not only preserving the energy from the event but also avoiding altering the arrival times of the seismic phase. A number of algorithms have been proposed for automatic event detection and seismic phase identification and can be divided in the following categories:

Automatic Microseismic Event Detection

i. **Energy Based Algorithm (**recommended for high seismicity records**)**
  - Improved STA/LTA algorithm.
  - Dynamic threshold based on the statistical properties of the STA/LTA "ratio".
  - Simple and fast, demands low computational resources.

ii. **Algorithm Based on Statistical Methods (**recommended for noisy records**)**

Two – stage procedure, based on a non-strict hypothesis testing scenario:

- First stage: Estimation of the empirical *pdf* of the seismic noise (using statistical methods such as sampling, modeling, clustering).
- Second stage: Use of a thresholding scheme in order to detect the microseismic events, in a non-strict hypothesis testing framework.

iii. **Algorithm Based on Signal's Polarization Attributes in Time-Frequency domain (**recommended for extremely noisy records**)**

- Fourier analysis on different frequency sub-zones.
- Evaluation of the polarization differences among the three components.
- Regression analysis technique in order to correct errors due to sensor's interference.
- Development of a characteristic function based on the above differences, for the microseismic event detection.

Automatic P&S Phase detection

i. P-phase picking:

- The kurtosis criterion is applied on the segment of the record that includes a seismic event.
- The maximum slope of the kurtosis curve is assigned to the P-onset time.

ii. S-phase picking:

- Eigenvalue analysis on 3C data.
- Development of a characteristic function, based on the maximum eigenvalues of the above analysis.
- Kurtosis criterion on the characteristic function

Recently LandTech developed an integrated Algorithm (AYTOPSI©) for seismic events detection, signal enhancement and automatic P- and S-phase picking. This method is comprised by a Chi-squared based test statistical test for the event detection, filtering in the S- transform domain, for de-noising and an automatic picker based on the Kurtosis criterion. The performance of the method has been applied successfully to various datasets and seems to solve the problem of automatic processing of seismological data of large PST networks. Automatic picks were compared against manual reference picks, resulting in mean residual time of 0.051 s. Moreover, this new technique was subjected to a noise robustness test and sustained a good performance. The mean residual time remained lower than 0.1 s, for noise levels between −1 up to 8 dB. Figure1 depicts the various stages of this method

Passive instrumentation

The magnitude (Richter Scale) of the recorded events during a PST survey, range from –2R to 3R. For the recording of such small events, the sensor must be very having sensitivity at least 1500V/m/sec.

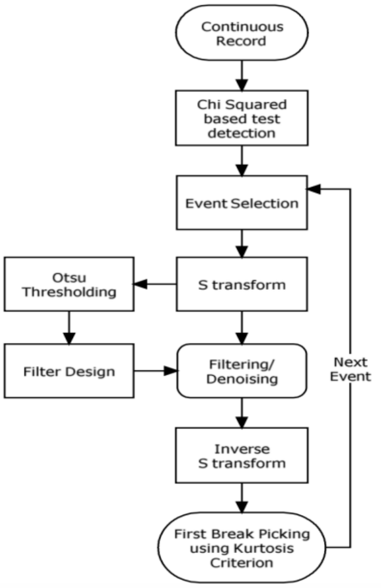


Figure 1: AYTOPSI algorithm.

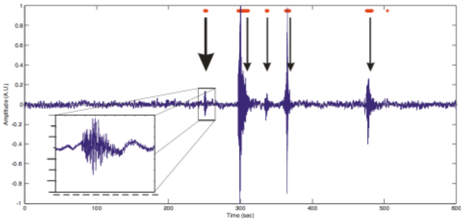


Figure 2: Zoomed area shows the event selected to apply the methodology. Vectors indicate the detected events and the red dots indicate the presence of the seismic events.

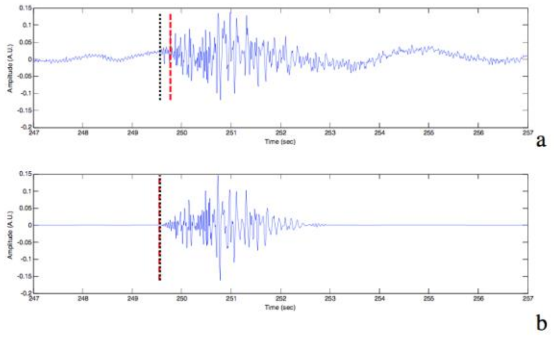
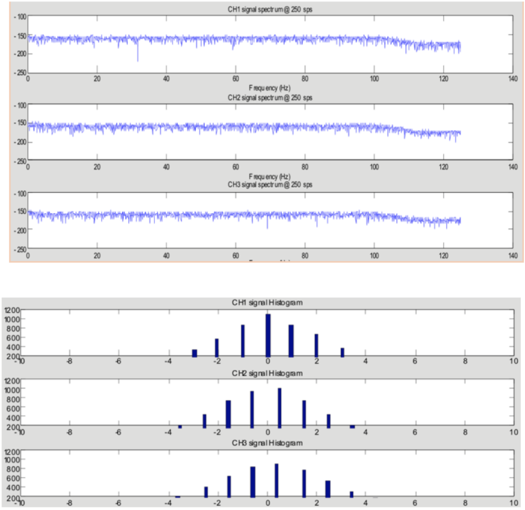


Figure 3: The event selected from (a)the real data and (b) the filtering in the time-frequency domain. The red dashed line is the automatic pick as calculated using the kurtosis criterion and the black doted line is the actual position of the first arrival.

The resolution of the digitizer is one of the most important parameters of the seismic instrumentation. 24bits digitizers are mostly used in seismotectonic studies and rot suitable for PST investigations. These surveys require 4rd generation 32bit digitizers, with dynamic range at least 138dB at 250sps and 142dB at 1000sps



(a)

(b)

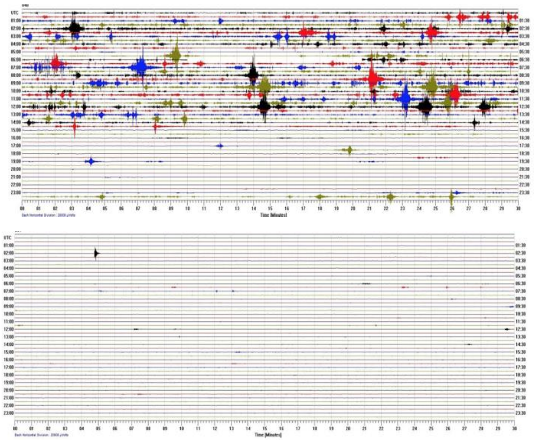
Figure 4: (a) Noise spectrum of the Sr32 LandTech digitizer, (b) corresponding noise histogram.

Another issue is the autonomy of the PST seismic stations. Given that are powered from a simple 12V lead acid battery, the power cycle must be as many days as the seismic crew needs to visit the seismic station. Seismic networks consisted of 150 seismic stations, spread in an area of 3000 – 5000 Sqm2 placed in accessible terrain, usually takes two weeks to twenty days from the seismic crew to visit them. So the power autonomy of each seismic station (recorder + sensor) must be enough for at least 20-25 days. There should be also enough storage capacity for store the data of the above period.

Figure 5: Photo of a new generation 32bit PST seismograph developed by Landtech-Geophysics and Geobit. It is powered by a motorcycle battery for more than a month.

The seismic events obtained during a PST exploration usually have frequency spectrum into the band 2Hz to 20Hz. So a wide band seismometer with the range of below 1Hz up to 30 Hz is necessary. Ideally PST sensors with bandwidth from 0.1Hz to 98Hz are preferred in order to record these seismic events with the maximum quality. The low frequency response gives also the ability to calculate moment tensors as well.

PST sensors must be of borehole type, so they can be installed in a few meter depth, depending on noise. The noise level at this depth is much less than the surface. The borehole can be easily (opened with a drilling machine with low cost. Small diameter boreholes can be opened by hand in rough areas where no vehicles can access.



(a)

(b)

Figure 6: (a) recording at the surface, (b) recording at 10m depth.

Processing

Processing of PST data at a local scale for hydrocarbon exploration is more complicated than applying off-the-shelf 3D inversion algorithms. To get the best resolution of the geologic formations at the lowest cost, we tap an arsenal of techniques, including initial-velocity model selection, simultaneous earthquake hypocenter and 3D velocity models, Q_P inversion, and synthetic and real-data checkerboard tests.

Figure 7: The stages of PST data processing.

A hydrocarbon reservoir tends to be acoustically softer than regions that are full of an incompressible fluid such as water. Thus, a seismic wave should suffer more attenuation in a hydrocarbon reservoir than in surrounding materials.

One of the geophysical parameters that correlates best with the physical state of the rocks and the percentage of fluid content is the intrinsic quality factor Q_P of the compressional body waves. As an exploratory tool, attenuation effects have only recently attracted attention (e.g., Tselentis et al., 2010). The Q_P can prove useful in two ways: as a means of correcting seismic data to enhance resolution of conventional imaging techniques and as a direct hydrocarbon or geothermal indicator. The reconstruction of Q_P imaging is considered to be a powerful tool for establishing the distribution of fractured systems characterized by fluid circulation.

Until recently, most attempts to extract attenuation on a local scale have been restricted to active seismic data recorded at the surface. This approach encounters significant difficulties because the amplitude spectrum of the seismic record contains the imprint of the amplitude spectrum of the earth's reflectivity as well as the amplitude spectrum of the seismic wavelet.

A method based on the inversion of the rise times is expected to provide the most reliable estimates of intrinsic attenuation. In fact, because only a very limited portion of the seismogram is used, the effects of multiple waves generated in thin layers around the recording site are usually minimized (de Lorenzo et al., 2006).

A mathematical model for realistic pulse broadening in an in homogeneous medium has been suggested by Gladwin and Stacey (1974) and Stacey et al. (1975). These studies show experimentally that the rise times of acoustic signals propagating linearly in elastic media with frequency-independent quality quotient Q is described by

$$\tau = \tau_0 + \mathrm{C}\int_{\mathrm{ray}} \frac{ds}{V_p Q} = \tau_0 + \mathrm{C}\int_{\mathrm{ray}} \frac{\Delta T}{Q},$$

where s is the pulse rise time, τ_0 is the original pulse rise time at the source, C is a constant, ds is an arc segment along a ray-path, and ΔT is the incremental travel time.

Figure 8: Measurement of rise time and pulse width broadening.

For a medium with constant V_P, where $Q = Q_0$, the above equation can be written in a linear form:

$$\tau = \tau_0 + \frac{CT}{Q_0}.$$

The ratio T=Q is usually referred as t* in the literature. The constant C was determined experimentally for ultrasonic acoustic pulses to be 0.5 (Gladwin and Stacey, 1974)

The following figure presents an example of a 3D mapping of Qp below an exploration block.

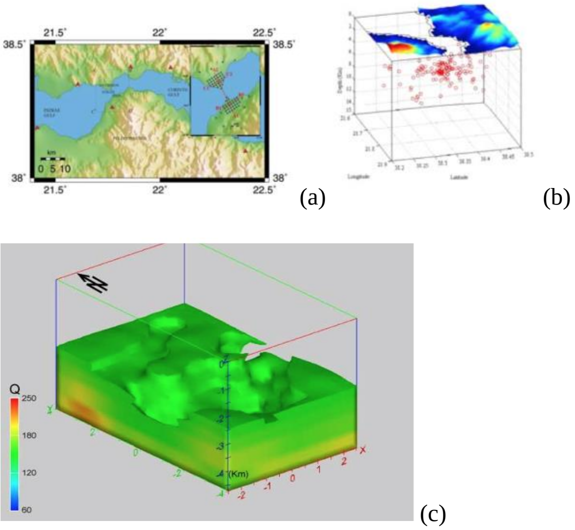


Figure 9: (a) Seismic station layout, (b) 3D distribution of recorded hypocenters, (c) 3D Qp structure of the investigated area. Lower Qp regions have been removed revealing the basement.

Evaporite identification

Evaporite identification from geophysical data is an important task for oil prospecting in new regions where few or no wells have been drilled. In this paper, we propose to approach the problem of evaporite identification through the use of a two step procedure. Initially estimating seismic parameters such as P and S wave velocities and Poisson ratio for the area of interest through the use of passive seismic tomography and then using Kohonen neural networks techniques to perform data clustering, pattern recognition and classification.

To further analyze the clustering of the data and reveal the major lithological units in the region, we use Kohonen neural networks or self organizing maps (SOMs). These are unsupervised artificial neural networks developed by Kohonen (1982), who intended to provide ordered feature maps of input data after clustering. That is, SOMs are capable of mapping high-dimensional similar input data into clusters close to each other on a n- dimensional grid of neurons (units).

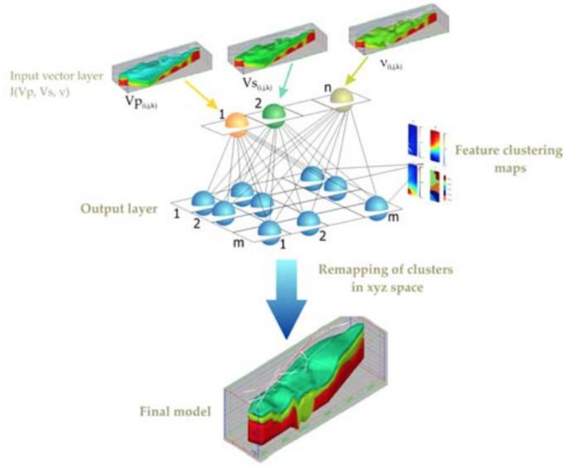
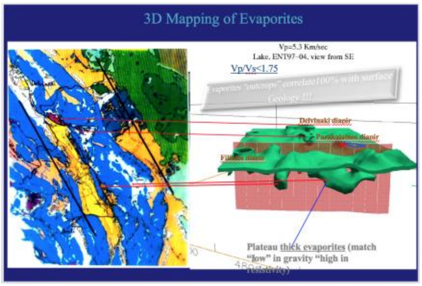


Figure 10: Vp,Vs and Poisson’s ratio are used to “train” the neural network.



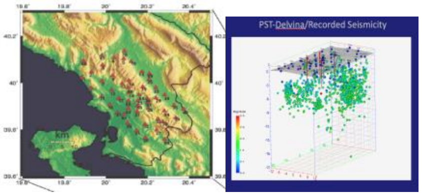


Figure 11: Example of 3D evaporate delineation below an entire exploration block. Not the match with the surface outcrops.

A 3D delineation of the evaporitic cup of a gas reservoir in Albania which was derived from a PST survey is depicted in the following picture.

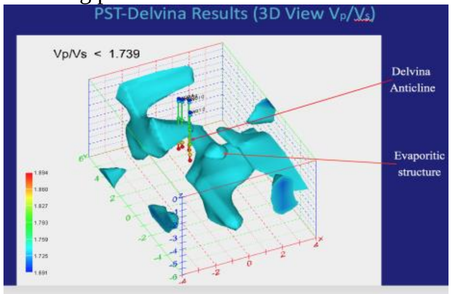


Figure 12: Delineation of the evaporitic cap of a reservoir using the 3D distribution of the Vp/Vs parameter.

Gas identification

Low V_P/V_S values characterize gas-bearing rocks (i.e., those with a high fluid compressibility), whereas higher values of V_P/V_S indicate liquid-bearing formations (i.e., those with a low fluid compressibility). Furthermore, pore-fluid pressure may also play a role by inducing a fluid-phase transition and by keeping pores and cracks open. As a consequence, velocities are further affected. Laboratory measurements show that crack opening induced by increasing pore pressure leads to a strong reduction in V_P/V_S in gas-bearing rocks.

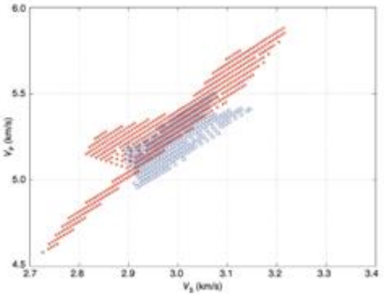


Figure 13. Relation between V_P and V_S, at the producing depths 2204 of the gas (blue circles) and oil (red stars) fields.

The figure above, presents the relationship between V_P and V_S values, which were obtained from the passive survey but only for the corresponding production depths of the gas and oil reservoir. Despite the overlapping region, there is a tendency for the oil and gas values to separate from each other on the cross-plot.

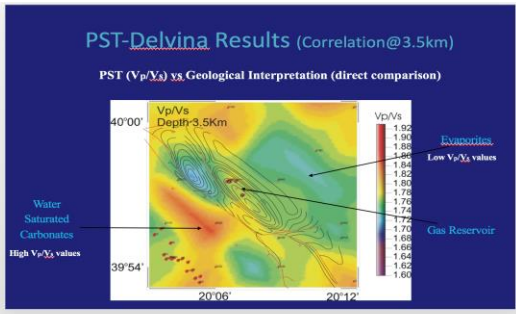


Figure 14: Successful delineation of water saturated carbonates, evaporates and gas reservoir from Vp/Vs values obtained during a PST survey.

Drilling sites

Although a PST survey provides mainly, structural and lithological information below the entire block of interest and cannot be considered as a direct hydrocarbon indicator, in certain cases we can provide maps that depict sub-regions within the investigated block that possess a high probability for a successful well. This is due to the fact that one of the products of PST is the Poisson's ratio, which strongly depends on the fluid content within the pore space. Furthermore, the mapping of the Q parameter all over an exploration block could reveal regions of high porosity, fracture zones and help differentiate gas and oil in the pore space.

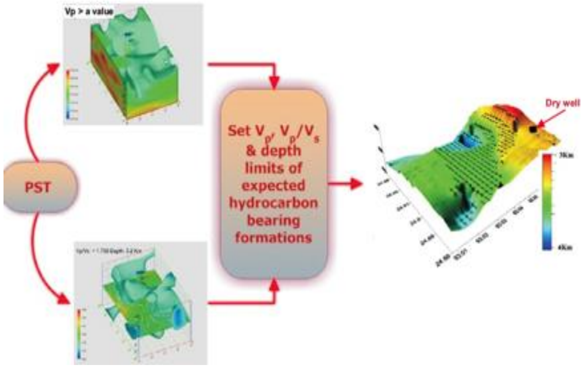


Figure 15: Setting certain limits on the derived parameters we can locate sites (+) possessing high probabilities for a successful well.

Conclusions

PST can provide a wealth of information for areas where conventional 2D seismic surveys do not work. PST is the most appropriate method for regions with severe seismic penetration problems and difficult topography as well as regions with environmental restrictions. Recent advantages in instrumentation and processing methodologies have significantly increase the resolution of PST methodology which can now be applied at a reservoir scale. Some of these advances are presented in the present paper.

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Advances in passive seismic tomography