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Enhanced surface seismic data processing using simultaneous acquired DAS-VSP data

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ABSTRACT

Distribute Acoustic Sensor (DAS) is increasingly recognized as a viable alternative to geophone arrays for the acquisition of borehole seismic data. Borehole seismic data can provide higher resolution structure image around the borehole as its receivers are located inside a borehole and near the reservoir. Apart from its own structure imaging capabilities, the formation velocity, absorption attenuation, anisotropy parameters and other information around the well to a certain range can be obtained directly from the VSP data.

The formation velocity, absorption attenuation, anisotropic parameters and other information obtained from the DAS-VSP data around the well can be used to enhance the surface seismic data processing. It includes velocity model calibration and modification, exacting deconvolution operator, demultiple processing, anisotropic migration, and Q compensation or Q migration, etc. The borehole driven seismic data processing especially the Q-migration in this project has significant enhanced both imaging quality and time slice with accurate Q-field data volume that obtained from the joint inversion of both the near surface 3-D Q-field data volume from micro logging data and the mid-deep layer Q-filed data volume from VSP data. The Q-migration results show much sharp and focused faults and fracture zones. A new 3-D structural model was built with much more fine details based on the Q-migration data, and 3 new oil zones were recommended to the client. The final perforation results on these 3 new oil zones are very successful with high volume of commercial oil flow.

Introduction

Fiber optic Distribute Acoustic Sensor (DAS) is a novel technology that uses an optical fiber cable as a sensor for acoustic signals and increasingly recognized as a viable alternative to geophone arrays for the acquisition of borehole seismic data. The ability to deploy optical fibers into a well, either as a cable-based intervention or as part of a completion string, allows for the entire wellbore to be surveyed with every source activation. This can dramatically reduce the operating time required to complete a normal survey as well as offering the opportunity to achieve much higher spatial coverage than is typical of current technologies. Downhole armored optical fiber cable can be used to acquired simultaneously 3-D surface seismic and borehole seismic data using the same surface seismic sources. The borehole 3-D DAS-VSP data can also provide enhanced VSP imaging and enhance surface seismic data processing significantly. Seismic imaging and time-lapse reservoir monitoring can give us critical reservoir information to guide the placement of production and water flood injection wells in our high-value reservoirs.

Because 3D VSP detectors are located near the reservoir, the formation average and interval velocity, absorption, attenuation, deconvolution operator, anisotropy and other information around the well in a certain range can be obtained directly. At the same time, it is possible to obtain a high-resolution reflection imaging near the well with a higher number of folds. The 3-D VSP can also be used for AVO analysis, reservoir fracture prediction, anisotropy analysis and reservoir characterization (Chen et al., 2012; Jiang, 2016).

DAS is a sensing system which utilizes optical fiber as a sensing element and transmission signal medium. DAS-VSP has the advantages of full well coverage, high density sampling, high efficiency, high temperature resistance, high pressure resistance and low cost. It has become an important development direction of the borehole seismic technology (Li et al., 2010 and Sun, 2009).

A 3-D seismic data acquisition project was conducted simultaneously with 2 borehole seismic data acquisition in Dagang Oilfield near Bohai Bay of China. The 3-D seismic data acquisition project covered an area of 192.49 km2, and 2 boreholes (B-01 and B-02) were used to acquire the borehole seismic data simultaneously when the crew was acquiring the 3-D seismic data.

Joint 3-D seismic data and borehole seismic data acquisition

The 3-D seismic data were acquired with the bin size of 10m x 20m, source and receiver line spacing of 200m, receiver spacing of 20m, shot spacing of 40m, and the minimum offset of 22m and the maximum offset of 4,646m. The 1st borehole B-01 and 2nd borehole B-02 have a depth of 3,500m and 2,770m respectively. An armoured single mode optical cable was deployed inside the casing of borehole B-01 from wellhead to TD and an 80-level 3-C downhole geophone array was deployed inside the casing of borehole B-02 from 500m to 2,080m. A total of 8,167 surface shots were recorded by the armoured optical cable inside borehole B-01 and covered the source area of 73.92 km2, and the surface shots of 7,913 were recorded by the 80-level 3-C downhole seismic array and covered an area of 53.88 km2. The downhole armoured optical cable inside borehole B-01 has a receiver spacing of 2m (total 1,750 levels) and the 80-level 3-C downhole seismic array has a level spacing of 20m (total 80 levels). The total downhole seismic data covered the source area of 127.8 km2 with the total effective surface shots of 16,080.

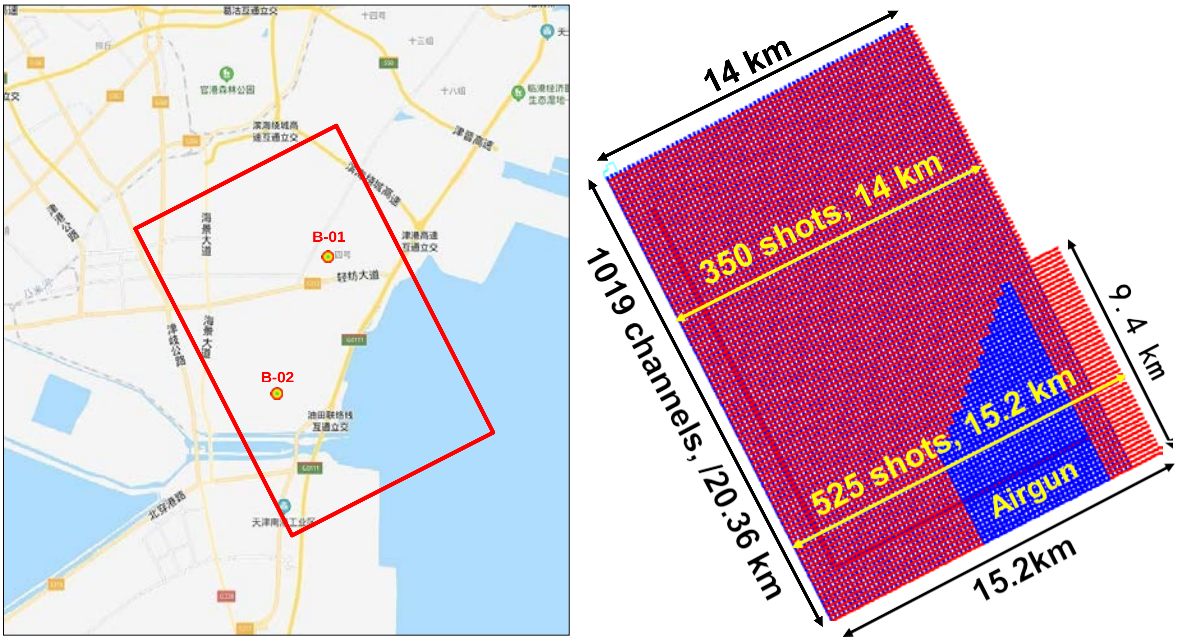

Figure 1. 3-D seismic and borehole seismic simultaneous survey area map and well locations (top) and designed 3-D seismic survey source distribution map (bottom).

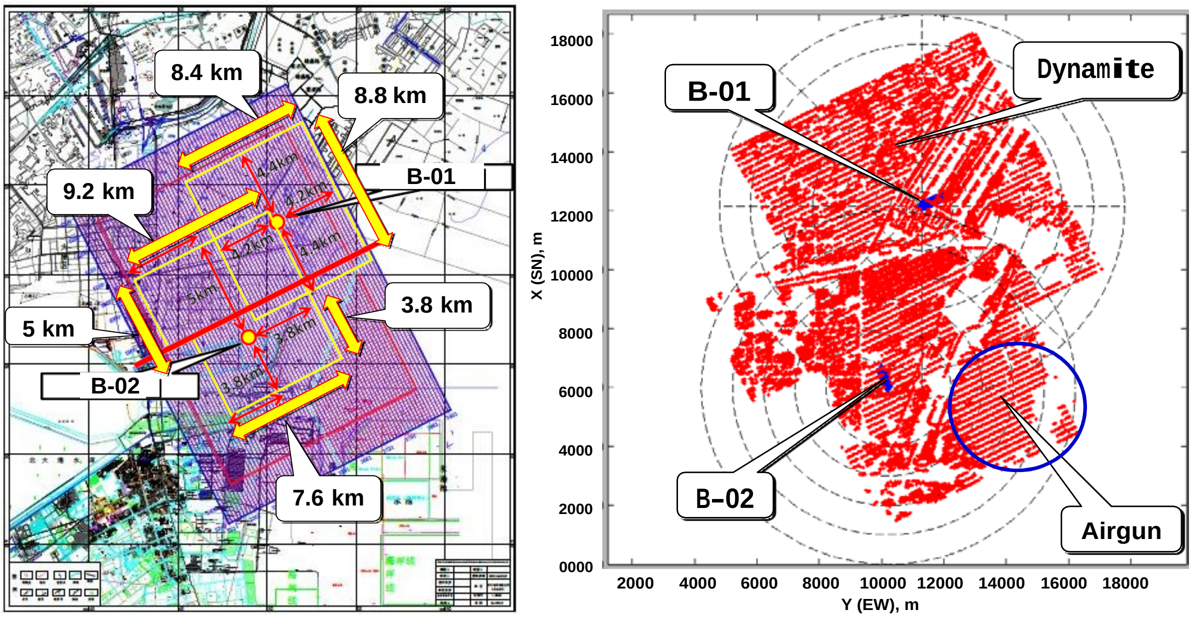

Figure 2. Designed 3-D VSP survey area map (left), and actual source distribution map (right).

Figure 1 is the 3-D seismic and borehole seismic simultaneous survey area map and well locations (left) and designed 3-D seismic survey source distribution map (right). About 75% survey area is onshore and 25% area in the shallow water (Bohai Bay), therefore, both the dynamite and airgun sources were used to acquire the 3-D seismic and borehole seismic data simultaneously. The dynamite sources are located onshore, and the lower right corner is the airgun source locations. The total shots for the 3-D seismic survey were 41,990 including offshore airgun shots of 12,580 (left in Figure 1).

The designed 3-D VSP survey area map and the actual source distribution map is shown in Figure 2. The dynamite sources are located onshore, and the lower right corner is the airgun source locations. For the VSP survey, the borehole B-01 covered the source area of 73.92 km2 and only 8,167 shots were recorded, and the borehole B-02 covered the source area of 53.88 km2 and only 7,913 shots were recorded (Figure 2). About 25% of sources in the centre were recorded by both borehole receiving sensors (optical cable and 3-C geophone geophones).
After the review and analysis of the recorded borehole seismic data, we can draw following conclusions:
（1） The borehole seismic data recorded by the 80-level 3-C downhole geophone array in borehole B-02 have high S/N and broad frequency range, and it can be used for VSP imaging processing;
（2） The borehole seismic data recorded by the armoured optical fibre cable in borehole B-01 have lower S/N but clear first arrival on the downgoing wave, and can be used for anisotropic velocity calculation;
（3） The DAS-VSP data from borehole B-01 have background noise, cable oscillation noise and abnormal channel, etc. and need to remove during the subsequent data processing stage;
（4） The 3-C downhole seismic data from borehole B-02 have rich wavefield information and need to conduct the wavefield separation with effective amplitude preserved processing steps.

3-D seismic data processing and Q migration

Borehole seismic data can provide higher resolution structure image around the borehole as its receivers are located inside a borehole and near the reservoir. Apart from its own structure imaging capabilities, the formation average and interval velocity, absorption, attenuation, deconvolution operator, anisotropy parameters and other reservoir information around the wellbore in a certain range can be obtained directly from the VSP data.

Since DAS-VSP data is different from the VSP data recorded by 3C downhole geophone array, the data processing workflow shall be different between two data sets. Because the DAS-VSP data are in fact the fibre displacement not the velocity at each depth location, the following special data processing procedures were applied: (1) conversion of displacement data to velocity data; (2) optical cable slapping and ringing noise removal; and (3) group forming to increase signal-to-noise ratio. After the above special processing steps on the DAS-VSP data, the typical VSP data wavefield separation and imaging processing steps can be conducted.

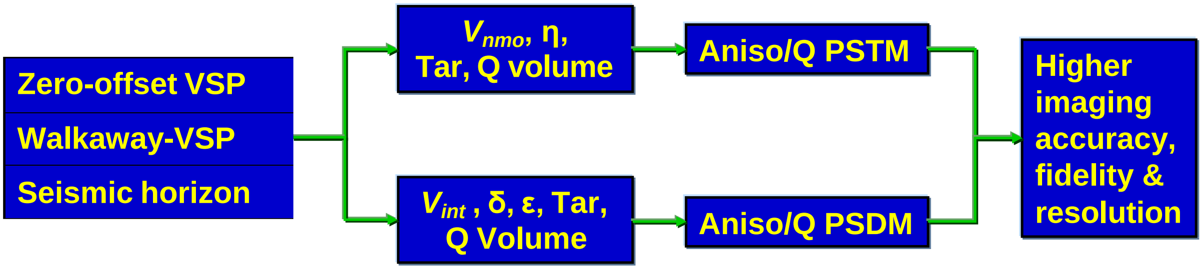

Figure 3. Workflow for borehole driven surface seismic data processing enhancement using parameters extracted from the borehole seismic data.

The formation average and interval velocity, absorption, attenuation, deconvolution operator, anisotropy parameters and other information obtained from the VSP data around the well can be used to enhance the surface seismic data processing, and we call this step ‘borehole driven 3D surface seismic data processing’. It includes velocity model calibration and modification, statics correction, deconvolution processing, demultiple processing, high frequency restoration, anisotropic migration, and Q-compensation or Q-migration, etc. The workflow of the ‘borehole driven 3D surface seismic data processing’ using parameters extracted from the borehole seismic data is shown in Figure 3. The most noticeable enhancement of the surface seismic data processing is to use the correct anisotropic parameters and Q volume as well as more accurate velocity model for the 3D anisotropic and Q migration.

Figure 4 shows the surface seismic PSDM image (left), downhole geophone array walkaway VSP data image from Well B-02 (centre) and walkaway DAS-VSP data image from well B-01 (right). The frequency range of the 3 different imaging results is increased from 60 Hz of surface seismic PSDM data to 70 Hz of Well B-01 downhole geophone array Walkaway VSP imaging, and further to 85 Hz of Well-B-02 Walkaway DAS-VSP imaging. We can easily identify sub-seismic fault and pinch out structure from the DAS-VSP imaging due to the high frequency and high-resolution imaging from DAS-VSP data. But these fine structures are not visible from the surface seismic and downhole geophone array VSP images.

Seismic exploration practice shows that the elastic media rarely exist in the subsurface and subsurface media exhibit viscoelastic behaviour. The viscosity of the subsurface medium consumes the energy of the seismic wave, attenuates the amplitude of the seismic wave, distorts the phase of the seismic wavelet, and reduces the resolution and imaging accuracy of the seismic data. Absorption decreases the amplitude of waves propagating in the earth. In addition, it narrows the bandwidth and modifies the phase. Obtaining true-amplitude migration and acceptable resolution in dissipative media requires a migration algorithm that corrects these effects (Caussen and Ursin, 2000). The earliest viscoelastic compensation appeared in a one-dimensional form. This is the reverse Q filtering technique that still widely used in industry.

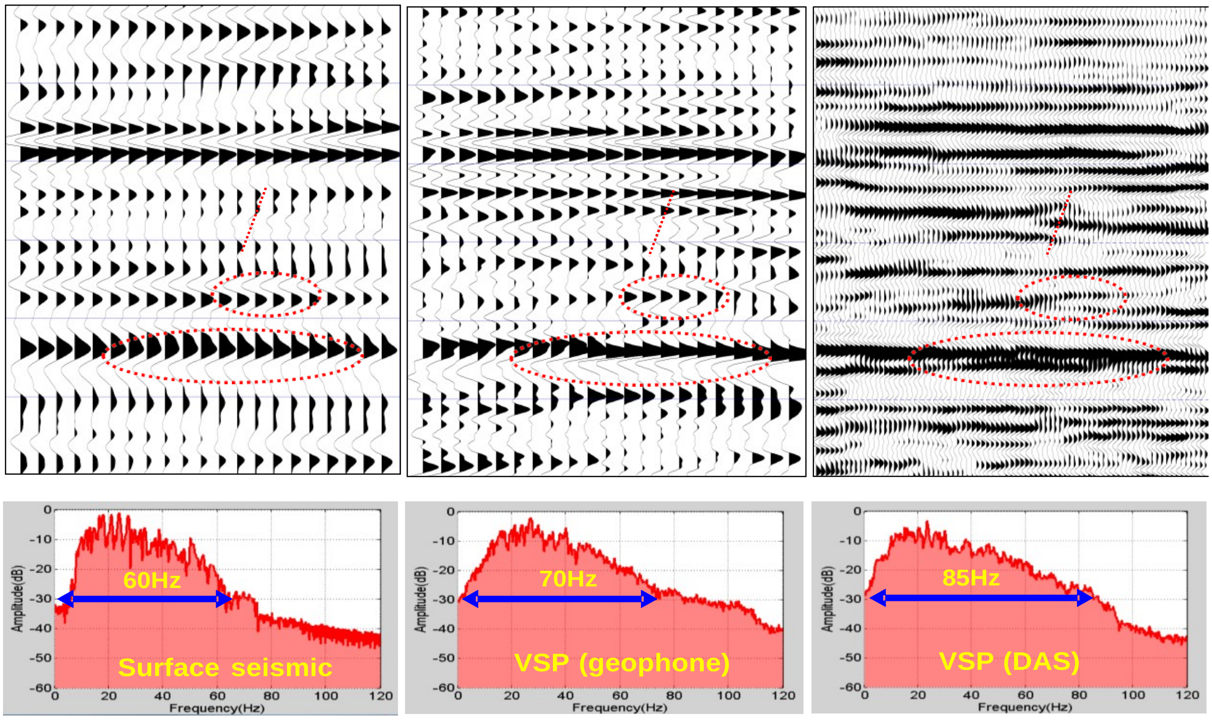

Figure 4. Surface seismic PSDM image (left), downhole geophone array walkaway VSP data image (center) and walkaway DAS-VSP data image (right).

However, the attenuation of viscoelastic seismic waves is not only related to the propagation time, but also to the frequency of the wavelet, the distribution of the velocity field, the ray path, and the subsurface geological structure. Obviously, one-dimensional compensation cannot fully restore the original subsurface characteristics of the seismic wave field.

Dai and West (1994) proposed an inverse Q-migration method to image subsurface structure from seismic reflection data in an anelastic media. The downwards extrapolation of surface seismic data is based on a highly accurate numerical solution for a wave system in the space-frequency domain in an inhomogeneous viscoacoustic medium. They used a pseudospectral method to complete the poststack depth migration of viscous acoustic waves and developed viscoelastic compensation from one dimension to two dimensions. Mittet and Sollie (1995) used explicit convolution filtering in the frequency space to complete the prestack depth migration of the viscous acoustic waves, and analysed numerically the sensitivity of the macro Q model error based on the migration results. They presented a method for accommodating absorption and dispersion effects in depth migration schemes. Extrapolation operators that compensate for absorption and dispersion are designed using an optimization algorithm. The design criterion is that the wavenumber response of the operator should equal the true extrapolator. To better adapt to lateral changes in velocity and better suppress the evanescent wave energy, Caussen and Ursin (2000) used a reverse-time migration to complete the prestack depth migration of the viscous acoustic wave. They used a stable amplifying finite-difference wavefield extrapolation that compensated for the attenuating propagation of the wavefields in the real earth. Numerical tests on synthetic VSP data illustrated how dissipation destroyed the amplitude, phase and resolution in the migration images, and how their algorithm corrected these effects. The tests also showed that the method was stable with respect to noise and did not require a very detailed macro-model for dissipation.

However, the above research work mainly focused on migration methods and modelling experiments, and few examples of viscoelastic migration technique have been applied in the industry. There are two main factors hindering the industrial application of viscoelastic migration technology. One is that it is difficult to estimate a relatively accurate attenuation parameter model using actual seismic data. There are currently at least ten methods known to the authors to estimate attenuation parameters from seismic data, but the noise immunity and stability of these methods cannot meet the requirements of commercial seismic data processing. The second is the effect of high-frequency noise on viscoelastic migration. The viscoelastic migration is a process of high-frequency energy amplification. When the high-frequency signals are amplified, the high-frequency noise is also amplified at the same time. The effect of this situation is especially serious on deep layer imaging. When the viscoelastic wave field is extended, the high-frequency noise in the deep layer is often amplified by tens of thousands of times, which seriously reduces the signal-to-noise ratio of seismic records after viscoelastic migration.

To avoid the influence of high-frequency noise on the practical application of viscoelastic migration, and to make this method better inherit the processing results of high-precision imaging in the past, and better connect with the previous processing flow and results, we used a viscoelastic migration imaging strategy.

The spectral ratio method is the most commonly used approach to estimate the Q factor from DAS-VSP data. Dean and Correa (2017) described a methodology that can be used to correct the frequency spectra and thus successfully estimate unbiased Q values from DAS-VSP data. For both wells B-01 and B-02, the spectral ratio method was used to derive the Q value from the surface to TD. The zero offset DAS-VSP data and geophone recorded zero offset VSP data were used to calculate the Q value for wells B-01 and B-02 separately. Since well B-01 is far away from the coastline, the armored optical cable in this well did not record any 3D DAS-VSP data from the offshore airgun source. As the gauge length in the DAS method has an attenuative effect on the high frequencies of the DAS-VSP data, the Q value from longer gauge length DAS-VSP data is the average Q value within the formation of the longer gauge length. In practice, one would prefer to use short gauge length DAS-VSP data to calculate the Q value if possible. Since we only recorded the DAS-VSP data using 8 m gauge length, the choice of using the short gauge length DAS-VSP data to calculate Q value was not available.

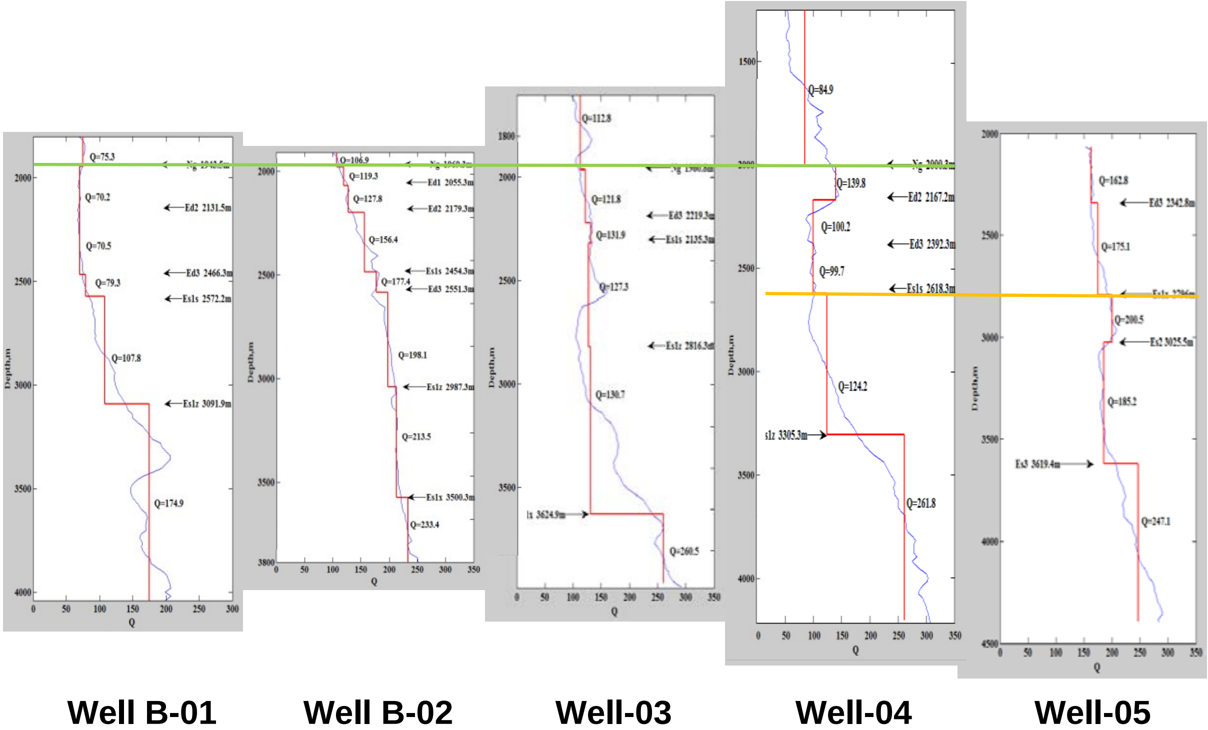

Figure 5. VSP data derived Q values (thin blue curve) and horizon tops (thick green and orange lines) in five wells within the 3D surface seismic survey area.

VSP data from five existing wells within the 3D surface seismic survey area were used to derive the Q values from wellhead to TD along each borehole (Figure 5). These Q values were used to build the mid-deep layer Q-field data volume for the entire 3D seismic data coverage area, whilst uphole data were used to establish the near surface 3D Q-field data volume (Figure 6). The near surface Q field and VSP data constrained Q field are matched to form the initial Q field of reverse Q filter compensation factor of the whole work area. Then we use our tomographic inversion code Qfit to optimize the initial Q-field. The basic principle of Q tomographic inversion is to invert the Q value according to the frequency anomaly of seismic data. From the perspective of inversion, this method seeks the relative Q variation of anomalies against a background rather than the true absolute values, for example where there are gas clouds in the data. From the perspective of migration, because there are many causes of energy loss, Q migration is one of the means for amplitude compensation, but not the only method. Our tomographic inversion code Qfit has the inversion function of quality factor (attenuation factor) for 2-D and 3D isotropic media. The "essence" of Q inversion is to find Q anomaly according to frequency anomaly. After prestack depth migration, the frequency has changed a lot, but the relative relationship of frequency still exists. Therefore, the algorithm can only find the existence of areas of Q outliers and cannot obtain the real absolute Q value completely.

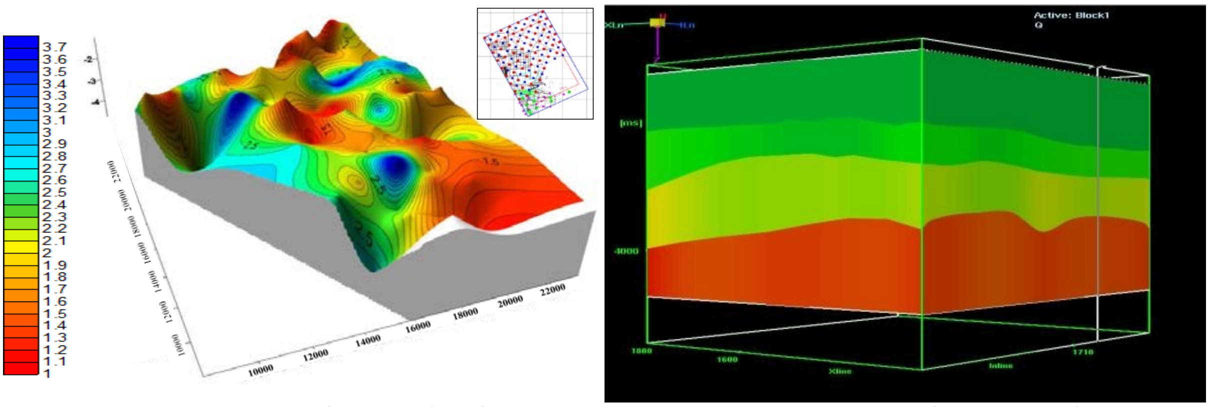

Figure 6. Coloured Q value of near surface formation and the Z-axis is the thickness of the near surface low velocity zone (left panel). The mid-deep formation Q-field data volume from 3 VSP wells (right panel).

Our tomographic inversion code Qfit has the inversion function of quality factor (attenuation factor) for 2-D and 3-D isotropic media. The "essence" of Q inversion is to find Q anomaly according to frequency anomaly. After prestack depth migration, the frequency has changed a lot, but the relative relationship of frequency still exists. Therefore, the algorithm can only find the existence area of Q outliers and cannot obtain the real Q value completely.

The process of establishing the Q field is shown in Figure 3. This migration used the method of using uphole data to establish the near-surface Q field and VSP well constraints to establish the mid-deep layer Q field to invert jointly the whole formation Q field to obtain the initial Q volume data.

The key to viscoelastic migration is to obtain the Q field. To obtain the accurate Q field data volume, following borehole driven 3-D seismic data processing steps were performed on the surface and borehole seismic data:

1. Using the uphole data to establish the near surface 3-D Q-field data volume covering the whole survey area (left panel of Figure 6);
2. Using downgoing VSP data to calculate the Q value along the borehole trajectory for both boreholes;
3. Using the Q value from VSP well as the constraints to establish the mid-deep layer Q-field data (right panel of Figure 6);
4. Obtaining the initial full Q-field data volume by performing joint inversion of both the near surface 3-D Q-field data volume and the mid-deep layer Q-filed data volume.

Finally, we matched the near-surface Q field with the VSP well constraint to obtain the Q field and obtained the initial Q field of the inverse Q filter compensation factor for the entire work area. Then we use the tomographic inversion code Qfit to optimize the initial Q field. The basic principle of Q tomographic is to invert the Q value according to the frequency anomaly of seismic data.

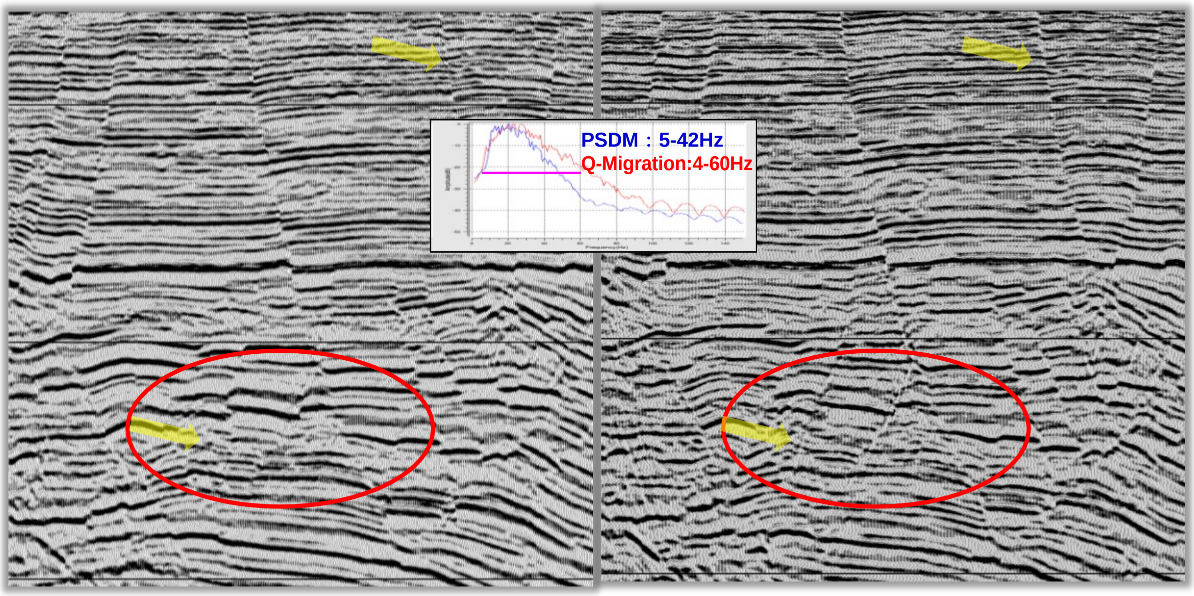

Figure 7. Comparison between the conventional migration (left) and the Q-migration (right).

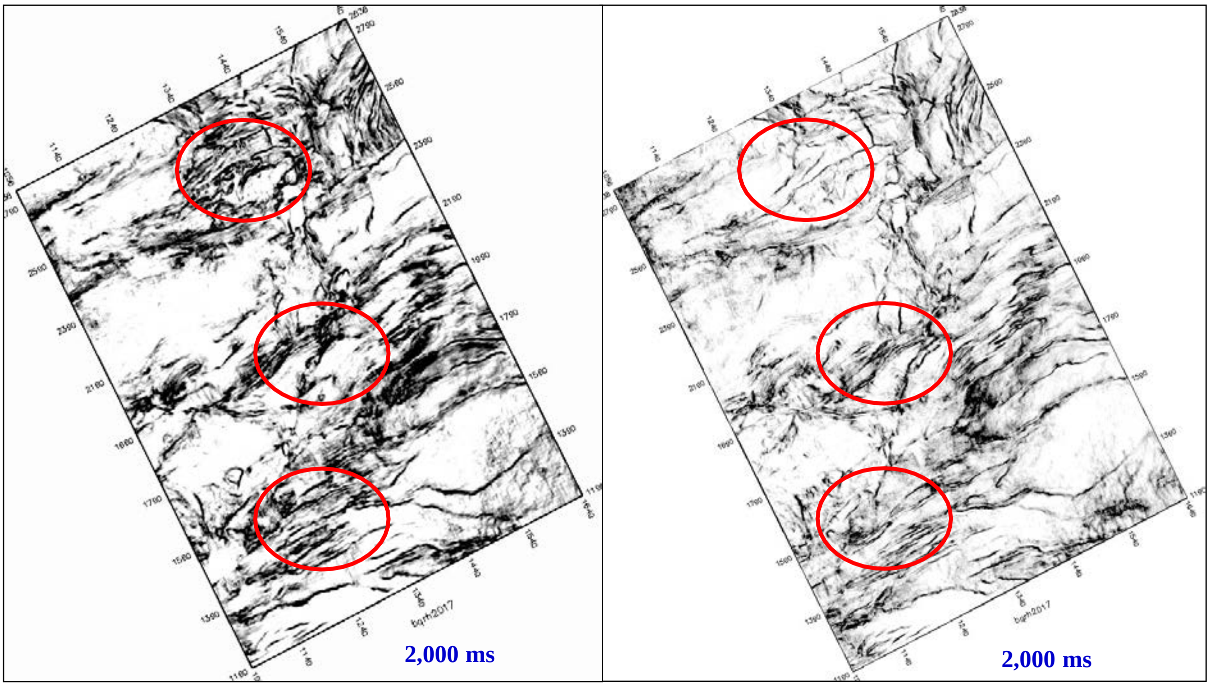

Figure 8. Comparison between the 2,000 ms time slice of the conventional migration (left) and the 2,000 ms time slice of the Q-migration (right).

The comparison between the conventional migration and the Q-migration is shown in Figure 7. After the Q-migration, it can eliminate the influence of formation attenuation on vertical and horizontal formation resolution and improve imaging accuracy. The comparison between the 2,000 ms time slice of the conventional migration (left) and the 2,000 ms time slice of the Q-migration (right) is shown in Figure 8.

From figures 7 and 8, we can see the significant enhancement of the both imaging quality and time slice after the Q-migration with accurate Q-field data volume that obtained from the joint inversion of both the near surface 3-D Q-field data volume from micro logging data and the mid-deep layer Q-filed data volume from VSP data. Both figures show much sharp and focused faults and fracture zones. We built a new 3-D structural model with much more fine details based on the Q-migration data (Figure 9) and recommended 3 new oil zones to the client. The final perforation results on these 3 new oil zones are very successful with high volume of commercial oil flow.

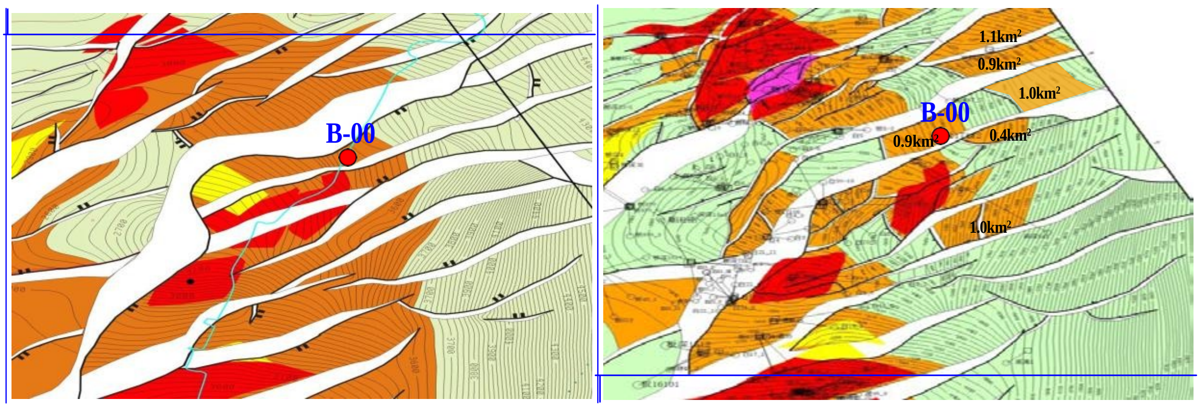

Figure 9. Old reservoir top structural map (left) and new reservoir top structural map (right).

Conclusions

Distribute Acoustic Sensor (DAS) is increasingly recognized as a viable alternative to geophone arrays for the acquisition of borehole seismic data. DAS-VSP data can provide enhanced VSP imaging and enhance surface seismic data processing significantly. The 3D VSP detectors are located near the reservoir, the formation average and interval velocity, absorption, attenuation, deconvolution operator, anisotropy and other information around the wellbore in a certain range can be obtained directly. At the same time, it is possible to obtain a high- resolution reflection imaging near the well with a higher number of folds. The 3D VSP can also be used for AVO analysis, reservoir fracture prediction, anisotropy analysis and reservoir characterization. The information obtained from the VSP data around the well can be used to enhance the surface seismic data processing. It includes velocity model calibration and modification, exacting deconvolution operator, demultiple processing, anisotropic migration, and Q compensation or Q migration, etc. The borehole driven seismic data processing especially the Q-migration in this project has significant enhanced both imaging quality and time slice with accurate Q-field data volume that obtained from the joint inversion of both the near surface 3-D Q-field data volume from micro logging data and the mid-deep layer Q-filed data volume from VSP data. The Q-migration results show much sharp and focused faults and fracture zones. A new 3-D structural model was built with much more fine details based on the Q-migration data, and 3 new oil zones were recommended to the client. The final perforation results on these 3 new oil zones are very successful with high volume of commercial oil flow.

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