frontiers | Frontiers in Earth Science

TYPE Methods
PUBLISHED 27 November 2025
DOI 10.3389/feart.2025.1624435

OPEN ACCESS

EDITED BY
Jidong Yang,
China University of Petroleum (East China), China

REVIEWED BY
Shikai Jian,
China University of Petroleum (East China), China
Feilong Yang,
Xi'an Shiyou University, China
Yalong Fan,
China University of Petroleum, China

*CORRESPONDENCE
Xinwei Wei,
jinseismic@outlook.com

RECEIVED 07 May 2025
REVISED 15 October 2025
ACCEPTED 31 October 2025
PUBLISHED 27 November 2025

CITATION
Wei X and Gao Q (2025) Wide-azimuth anisotropic inversion based on rock physics model and its application in fractured reservoirs prediction in tight sandy conglomerate.
Front. Earth Sci. 13:1624435.
doi: 10.3389/feart.2025.1624435

Wide-azimuth anisotropic inversion based on rock physics model and its application in fractured reservoirs prediction in tight sandy conglomerate

Xinwei Wei* and Qiuju Gao

Shengli Oilfield Geophysical Exploration Reasearch Insitute, Sinopec, Beijing, China

The study area is located in the north of an oil field in eastern China. Most of the middle and shallow sandy and gravelly rock mass development areas in this region have been identified, while the western section of the middle and deep sandy and gravelly rock mass development area has a large amount of reserves awaiting upgrading, and there is a reserve blank area of nearly 150 square kilometers in the central and eastern parts. The daily oil test output of the target layer section of the key well in the study area reached over 20 tons, confirming that the middle and deep layers still have good exploration potential. However, there are challenges such as deep burial depth, dense physical properties, rapid lateral variations, strong heterogeneity, and difficulty in seismic identification of nearshore fan and turbidite fan sandy conglomerate reservoirs. Conventional inversion methods struggle to precisely identify effective reservoirs under these conditions. Therefore, it is essential to conduct research on seismic anisotropic inversion method for tight sandy conglomerate reservoirs. This study aims to precisely delineate the distribution of effective reservoirs to address critical issues in integrated reserve enhancement. This paper proposes an improved consolidation index model. This method not only takes into account the consolidation degree in sandstone but also incorporates the influence of porosity on the consolidation index. It exhibits higher parameter stability and stronger calculation accuracy. Through rock physics analysis, a rock physics template suitable for the quantitative characterization of such reservoirs is constructed, with anisotropic parameters integrated into it, laying a foundation for prestack inversion. Using wide-azimuth offset vector tile (OVT) data, elastic parameter volumes across different azimuths are inverted. Through elliptical fitting, anisotropic parameters for compressional and shear waves are obtained. This approach quantitatively describes porosity distribution and fracture networks within the study area, offering guidance for the comprehensive evaluation of high-quality tight sand-gravel reservoirs.

KEYWORDS

tight sandy conglomerate, fractures, rock physics modeling, pre-stack inversion, anisotropy

1 Introduction

Numerous scholars have characterized and predicted anisotropic properties of tight reservoirs through the lens of rock physics theories and pre-stack inversion techniques.

1.1 Characterization of the reservoir fracture development based on the rock physics model

Fractures are extensively developed in sandy conglomerates, with their development controlled by lithology, stratum thickness, sedimentary microfacies, tectonic structures, and stress conditions (Zeng, 2004). In low-permeability sandy conglomerate reservoirs, fractures are predominantly composed of tectonic fractures, along with bedding-parallel diagenetic fractures and detachment fractures (Li et al., 2015; Wang and Zeng, 2007). Many scholars have conducted foundational research from the theoretical perspective of rock physics. Backus (1962) proposed the equivalent anisotropy model of layered media to describe the anisotropy produced by the directional arrangement of clay. Crampin et al. (1984) quantitatively described the anisotropy induced by fractures, providing theoretical guidance for fluid identification. Thomsen (1986) systematically defined weak anisotropic parameters, laying the theoretical foundation for the inversion of VTI(Transverse isotropy with a vertical axis of symmetry) media. The rock physical modeling of fractured media and analysis of seismic response characteristics serve as a critical foundation for fractured reservoir prediction using seismic data. The rock physical modeling enables the establishment of effective seismic inversion and reservoir characterization methods. Li et al. studied the variation patterns of anisotropic parameters under different fluid-filling characteristics through fracture reservoir rock physical modeling. They also analyzed the relative content of fracture porosity using rock physical models to identify fracture development zones (Li et al., 2019). Yang et al. categorized wells to delineate single-well fracture development characteristics in the area and established a fracture model accordingly. Through analyzing rock physical influencing factors for fracture prediction and conducting forward modeling attribute analysis, the study identified key attributes sensitive to fracture-scale prediction (Yang et al., 2014). Chen et al. applied an extended soft porosity model to derive fracture-related porosity from conventional well logs for quantitative characterization of fracture intensity, which was validated through FMI (Formation MicroScanner Image) image log interpretation and core analysis to confirm the reliability of fracture porosity quantification (Chen et al., 2017). Conventional fracture prediction technologies face certain limitations in addressing the challenges of predicting complex reservoirs where actual formations often contain various developed fractures. Chen et al. (2017) used the Voigt–Reuss–Hill (VRH) bound and Self-Consistent Approximation (SCA) theory to integrate non-clay minerals, clay minerals, pore spaces, and fluid inclusions as rock matrix constituents. Incorporating actual fracture geometry parameters and genetic mechanisms, the Chapman multi-scale fractured rock physics model was implemented with bedding-parallel fractures, and seismic responses were simulated through propagation matrix-based forward modeling (Chen et al., 2020). Incorporating fracture occurrence patterns and Chapman's multi-scale fracture rock physical model, they introduced bedding-parallel fractures and simulated seismic responses through propagator matrix method. Xu et al. (2019) conducted systematic research on orthotropic fractured reservoir prediction technology based on orthotropic media anisotropy theory. Through fractured rock physics modeling of the orthotropic media, implementation of orthotropic media pre-stack anisotropic inversion, and advancement of orthotropic media fracture parameter quantification techniques, the study achieved refined parameter characterization for complex reservoir systems. Based on experimental data and electronic scanning results, Luo et al. (2024) established a rock physical model of shale anisotropy, quantitatively characterizing the anisotropy of shale and revealing its laws.

1.2 Azimuthal anisotropy inversion

Yang et al. proposed that anisotropy inversion for seismic data primarily utilizes post-stack seismic attributes from wide-azimuth seismic datasets, including stacked amplitude, attenuation, P-wave impedance, as well as pre-stack P-wave amplitude and AVO (Amplitude Versus Offset)gradient attributes (Yang et al., 2021). Fracture density can be derived through azimuthal anisotropy inversion (Xue et al., 2017; Pan et al., 2020). Yang et al. successfully predicted the fracture orientation and density in the carbonate reservoir of Tahe Oilfield using P-wave anisotropy (AVA-Amplitude Versus Azimuth) technology (Yang et al., 2006). Liu et al. employed P-wave azimuthal anisotropy technology to conduct fracture detection in the Huawa area. Through high-quality azimuthal gather processing and amplitude-preserved workflows, they successfully predicted fracture distribution in the Fu-2 Member shale oil and gas reservoir (Liu et al., 2014). Li et al. (2020) proposed a wide-azimuth seismic OVT (Offset Vector Tile) -domain azimuthal anisotropy correction technology based on a coherent spectrum picking method. By inverting anisotropy parameters on post-migration offset vector gather (OVG) datasets, they mitigated the impact of azimuthal anisotropic time differences on imaging quality, thereby providing high-quality data for reservoir prediction and fluid identification. Li et al. successfully predicted fracture-developed zones by applying pre-stack P-wave azimuthal anisotropy technology. Ma (2020) estimated the changes in seismic velocity and anisotropy parameters caused by production by using the third-order elasticity theory, and linked the geomechanical model and fluid parameters to the seismic properties. Xie et al. (2022) performed approximate simplification of the Rüger equation and derived theoretical models for fluid-saturated fractured reservoirs. The method's effectiveness and applicability were demonstrated through both theoretical modeling and field data applications, providing a feasible technical approach for fracture prediction using wide-azimuth pre-stack seismic data. Zhang et al. (2023) proposed an anisotropic Markov Random Field (MRF) model based on anisotropic diffusion methods and a corresponding pre-stack nonlinear inversion approach. An optimization scheme for diffusion factors and auxiliary models was established, which significantly enhanced the lateral continuity and vertical resolution of the results. Building upon Elastic Vector Angle (EVA) inversion, Lian et al. (2023) introduced an anisotropic total-variation multi-trace inversion method with Lp-norm constraints. The inversion performance was validated through both forward modeling tests and practical field data applications. Based on the assumptions of the TTI model, Zhao et al. (2025) inverted the fracture density and fluid indicator factors in the study area through the anisotropy theory, effectively improving the accuracy of reservoir prediction. Liu et al. (2025) determined the anisotropic intensity and azimuth of the target layer in the study area using four distinct azimuthal anisotropy inversion methods. Through qualitative and quantitative analyses, the feasibility and reliability of these methods for predicting mesoscopic-scale fractures were verified.

Based on the integrated methodological framework, this study employs rock physics analysis as its guiding foundation. Through wide-azimuth anisotropic pre-stack inversion, we partition azimuthal sectors to derive elastic parameters across different orientations. Utilizing elliptic fitting equations, we calculate P-wave and S-wave anisotropy to predict reservoir properties and fracture development intensity, thereby providing guidance for comprehensive evaluation of the study area.

2 Study area overview

The study area is located in the northern steep slope zone of an oilfield in eastern China and is a critical reserve potential area (Figure 1). While the sandy conglomerate bodies in middle-shallow layers have been largely explored, the western segment of the middle-deep sandy conglomerate development zone contains substantial reserves awaiting classification upgrades, with a nearly 150 km^2 undrilled resource gap identified in the central-eastern sector. The multi-stage fracturing test in a key well targeting the lower third member of the Shahejie Formation (Es3x) sandy conglomerate achieved a maximum daily production rate of 24.3 cubic meters, it is an important direction for middle-deep reserve enhancement. The buried depth of the sandy conglomerates reservoir is over 3500 m, the effective thickness is over 10 m, and the mean value is 24.4 m. Average porosity: 7.68%; permeability: <5 mD.

The mid-deep conglomerate complexes in the northern belt of the Bohai Bay Basin develop two genetic types: nearshore fans and turbidite fans. Vertically, they are distributed in two stratigraphic intervals: the Es4 (Shahejie Formation Member 4) and Es3 (Shahejie Formation Member 3). The eastern segment of the fault zone, previously underexplored due to significant burial depth, represents a key target for future reserve growth. The hydrocarbon accumulation in the northern belt sandy conglomerates complexes is dominantly controlled by reservoir properties. Areas with favorable rock physical characteristics—specifically the mid-fan to distal fan zones and fault-proximal regions—exhibit high hydrocarbon enrichment, forming structural-lithologic reservoirs. In the western sector, sandy conglomerates units have reported contingent reserves (Lower Es3 + Upper Es4). Conventional well testing yielded non-commercial results (“non-oil or dry”), while fracturing tests achieved moderate productivity of 5–8 t/d.

Integrated with exploration insights of sandy conglomerates complexes, structural transition zones can provide enhanced sediment supply. Paleogeomorphic reconstruction and reservoir prediction analyses indicate that the hanging wall of the middle Es3 (Shahejie Formation Member 3) frontal zone within the Chengdong-Chengnan fault transition zone exhibits substantial accommodation space, hosting a large-scale turbidite fan system sourced from northern provenances (Figure 2). To address current challenges—such as deep burial depths, tight rock physical properties, and seismic identification difficulties in nearshore fan and turbidite fan sandy conglomerates reservoirs—it is imperative to advance seismic prediction techniques for effective tight reservoirs. This involves phased, high-precision characterization of internal fan microfacies architecture and detailed delineation of effective reservoir distribution, thereby resolving critical issues in integrated reserve growth.

3 Rock physical modeling and analysis of tight sandy conglomerates

3.1 Rock physical modeling of tight sandy conglomerates

The cementation of minerals during different sedimentary stages in tight sandy conglomerate significantly affects rock elastic properties. Traditional rock physical modeling methods present several limitations: empirical relationship-based approaches lack physical significance and exhibit poor generalization capability, hindering the acquisition of P/S-wave velocity ratios; conventional rock physical model-based methods require complex parameters and computations while being susceptible to complex lithology impacts; artificial intelligence-based methods demonstrate weak generalization and unsatisfactory practical performance. This study establies a rock physics model applicable to tight sandy conglomerate reservoirs by considering variations in cementation degree (Yu, 2022). The rock physics modeling process based on the improved consolidation index is as follows. The Voigt–Reuss–Hill averaging mixing method is adopted to calculate the elastic modulus of the mixed rock matrix. The Gassmann fluid substitution equation is utilized to fill the mixed fluid into the dry rock matrix so as to obtain the saturated rock modulus and calculate the longitudinal wave velocity. The consolidation index is improved and a prediction equation (Yu, 2021) is established, and then the shear wave velocity can be predicted:

$$V_{pre} - V_p = A(1+\gamma\phi)^2 + B(1+\gamma\phi) + C = 0$$

Among them, $Vpre$ represents the predicted longitudinal wave velocity, and Vp represents the measured longitudinal wave velocity. Solve the above formula to obtain the improved consolidation index coefficient γ, and then substitute it into the generalized expression of the dry rock shear modulus.

$$\begin{cases} \mu_d = \dfrac{\mu_m(1-\phi)}{1+\gamma\alpha\phi} \\ \gamma = \dfrac{1+2\alpha}{1+\alpha} \end{cases}$$

Among them, γ is the coefficient of the improved consolidation index. Finally, the shear wave velocity is obtained through the relationship between the shear wave and the shear modulus.

The improved method based on a modified consolidation index, which considers not only the consolidation degree in

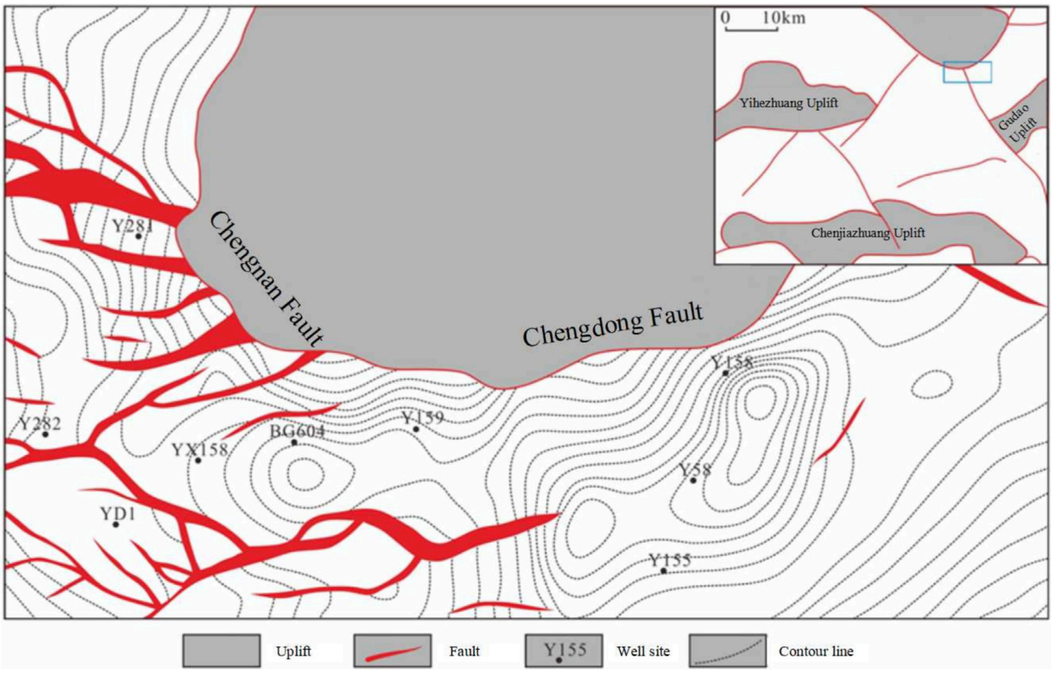

FIGURE 1
Regional overview.

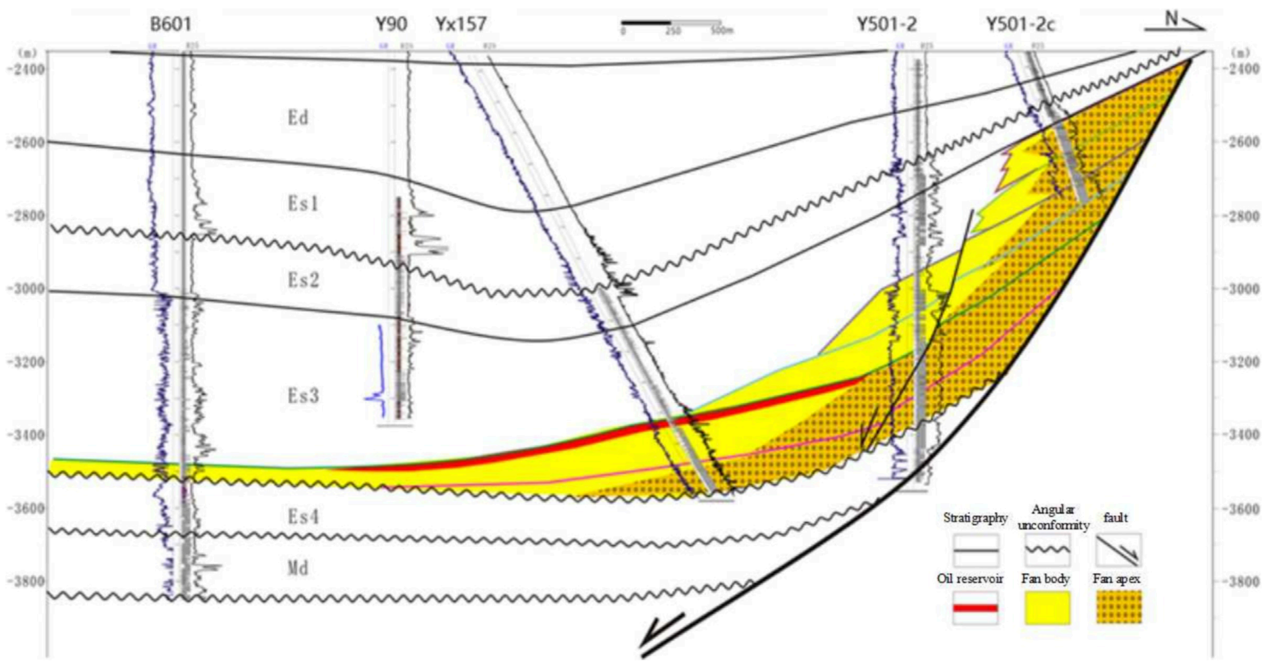

FIGURE 2
Reservoir profile.

sand, but also the porosity effect on the consolidation index, demonstrates enhanced parameter stability, higher computational accuracy, and better adaptability to complex lithology. Its most significant advantage lies in direct solving without requiring optimization algorithms, while maintaining high precision.

Taking Well Yi 288 as an example, the S-wave velocity was predicted by inputting parameters including P-wave velocity

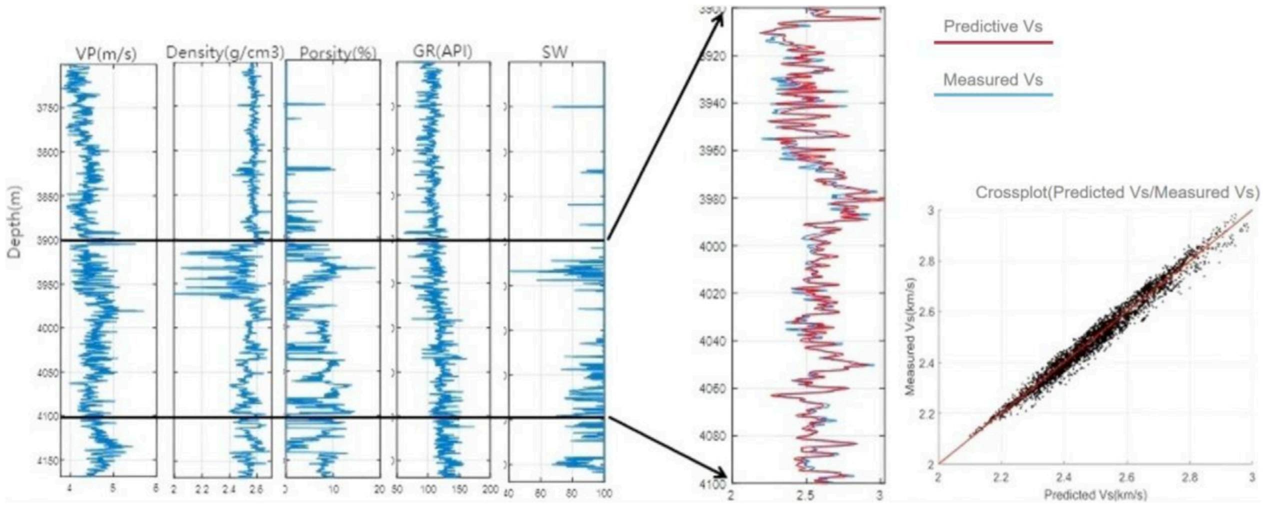

FIGURE 3
Rock physics model predictions and crossplot of predicted and measured S-wave velocities for Well Yi 288.

(Vp), density, porosity, gamma ray (GR), and water saturation (Sw). In the zoomed-in depth interval of 3,900–4,100 m, the predicted velocities (red curve) show high overlap with measured velocities (blue curve) as illustrated in Figure 3, demonstrating good agreement between modeling results and field measurements. While the empirical or SCA model provide unreasonable results lie out of the true values range. This is because the traditional method ignores the consolidation degree and the porosity effect.

3.2 Rock physical analysis of tight sandy conglomerates

A perturbation analysis was conducted based on the established rock physical model, where model predictions were performed by individually varying reservoir parameters such as oil saturation and porosity. A quantitative analysis was performed to evaluate the sensitivity of predicted logging curves (including elastic parameters and anisotropy parameters) to reservoir parameter variations.

Taking Well Yi 288 as an example, a porosity model perturbation analysis was conducted by systematically varying porosity and quartz content to observe corresponding changes in logging curve responses. In Figure 4, the blue curve represents original data, the black curve corresponds to a 10% porosity increase with proportional 10% quartz reduction, the purple curve indicates a 5% porosity increase with 5% quartz reduction, and the red curve reflects a 5% porosity decrease with 5% quartz enhancement. Quantitative evaluation of sensitivity to porosity variations reveals that epsilon (ε) and bulk modulus exhibit significantly greater magnitude changes compared to other elastic parameters, as demonstrated in Figure 5.

A fluid perturbation analysis was conducted on Well Yi 288 by replacing the original fluid with fully gas-saturated (blue curve), oil-saturated (black curve), and water-saturated (red curve) conditions to observe variations in logging curve responses. The results demonstrate significant changes in P/S-wave velocity ratios and Poisson's ratio, indicating high sensitivity of these parameters to fluid substitution.

Given the dominant lithology of mudstone and sandy conglomerate in the study area, along with interbedded layers at certain depths, lithology differentiation is critical. The Vp-Vs crossplot (Figure 6a) demonstrates that sandy conglomerate intervals exhibit higher P-wave and S-wave velocities compared to mudstone intervals. Furthermore, the crossplot of P-wave impedance *versus* anisotropy parameter (epsilon) (Figure 6b) shows reduced anisotropy and a deteriorated linear correlation between anisotropy and impedance in sandy conglomerate intervals.

Following lithology differentiation, sensitivity analysis was specifically conducted on sandstone intervals using epsilon (ε) and P-wave impedance to discern porosity variations. The results demonstrate that epsilon values exhibit similar covariation trends with P-wave impedance, where the crossplot between these parameters effectively discriminates porosity variations, as evidenced in Figure 7.

A rock physics template was established based on the distinct correlation pattern observed in the P-wave impedance *versus* epsilon (ε) crossplot (Figure 8) to quantitatively differentiate porosity variations within conglomerate intervals. This template integrates data from four wells (Yi-50, Yi-288, Yi-501_1, and Yi-501_2), demonstrating a progressive porosity increase trend from the upper-right to lower-left regions. Notably, most sandstone interval data points are effectively discriminated by this template. The developed rock physical template will guide optimal selection of porosity inversion methodologies in subsequent workflows.

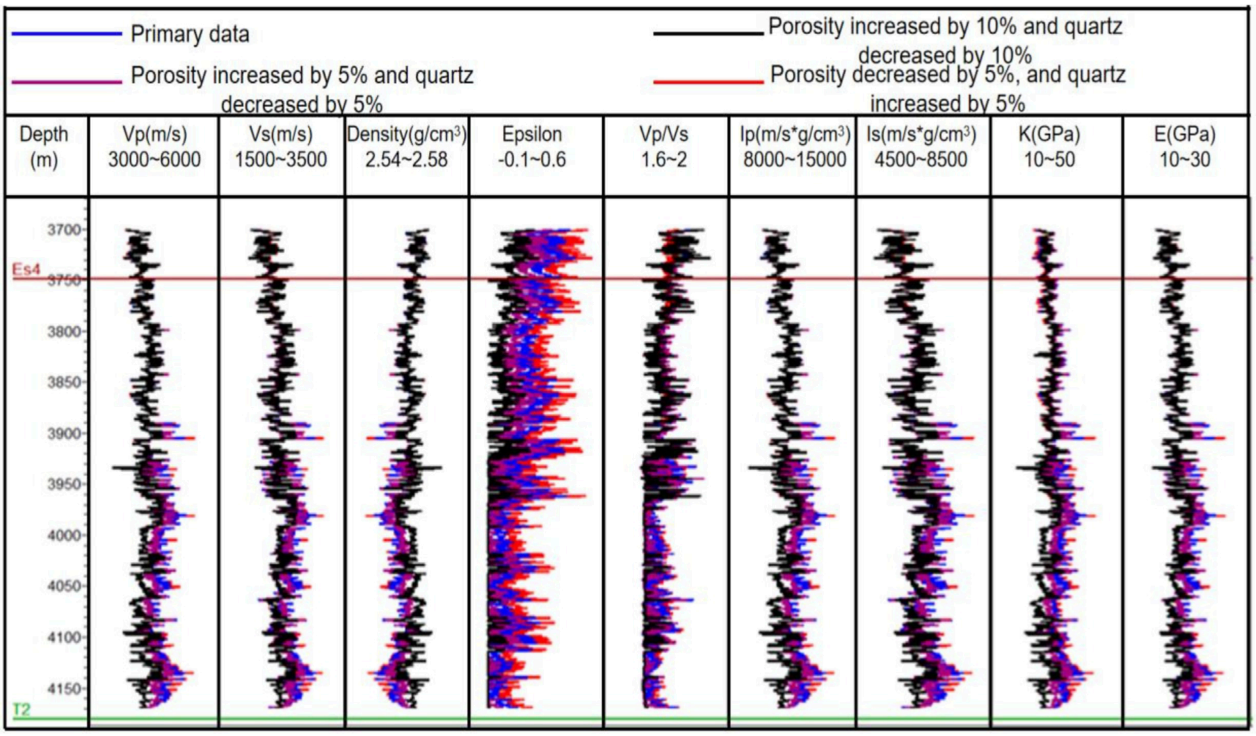

FIGURE 4
Porosity sensitivity analysis diagram for Well Yi 288.

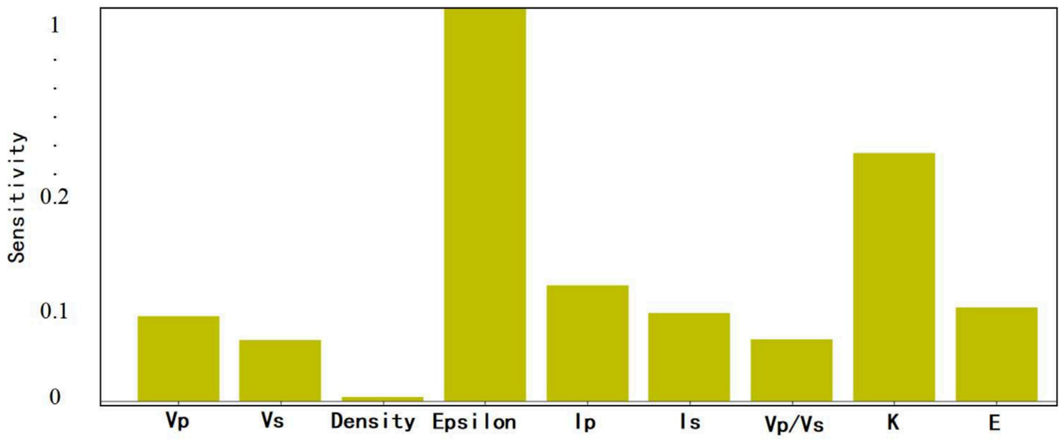

FIGURE 5
Schematic diagram of mean sensitivity gradient for porosity perturbation analysis in Well Yi 288.

4 Tight sandy conglomerate pre-stack inversion

4.1 AVO response analysis based on rock physics perturbation

Comparative analysis of AVO response characteristics induced by porosity variations in Well Yi 502 reveals systematic changes at the target strong reflection interface. The interface predominantly exhibits Class I AVO response. With increasing porosity, velocity decreases lead to attenuation of Class I AVO characteristics, manifested as diminished reflection amplitude energy, reduced complex wave phenomena, and emergence of dual-peak reflection signatures (Figures 9, 10). This demonstrates that porosity variations not only alter elastic parameters at the logging scale but also induce distinct seismic response modifications at the seismic scale. The dual-peak reflection pattern can be interpreted as a diagnostic seismic signature associated with porosity variations.

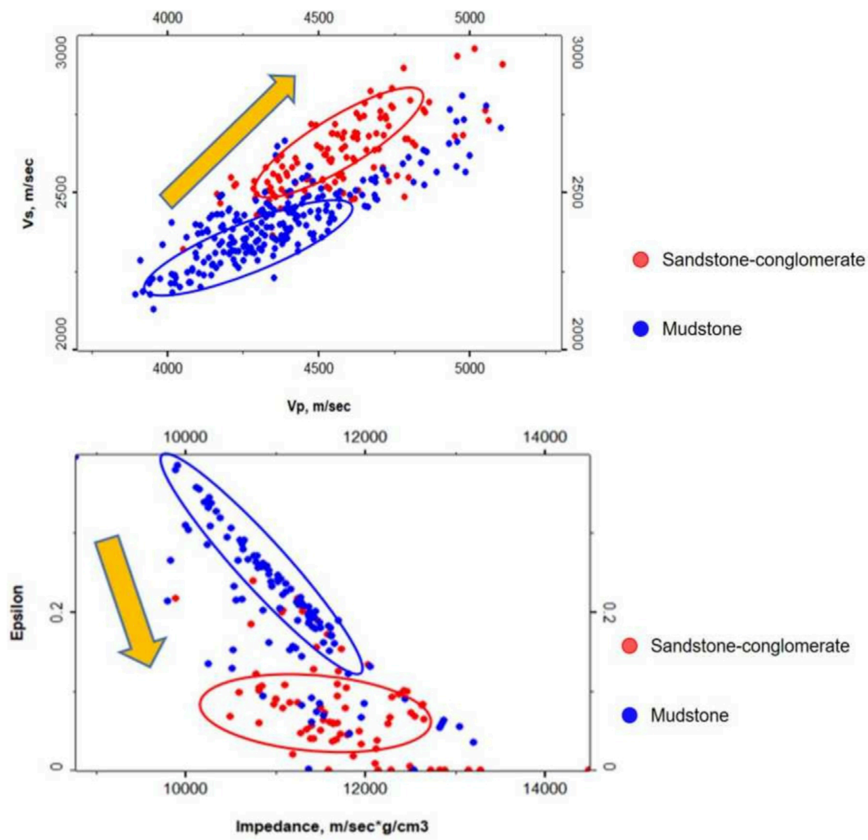

FIGURE 6
Crossplot of P-wave impedance versus anisotropy parameter (epsilon) and Vp versus Vs for Well Yi 288.

4.2 Pre-stack anisotropic inversion

Rock physics analysis reveals that sandy conglomerate reservoirs are characterized by low P-wave impedance and low Vp/Vs ratios. By applying pre-stack inversion techniques to predict sandy conglomerate reservoirs and establishing a regression relationship between P-wave impedance and porosity, porosity prediction is thus achieved.

4.2.1 Azimuthal sector division

Azimuthal anisotropic inversion typically utilizes wide-azimuth seismic data. Current industry practice for wide-azimuth seismic data processing predominantly adopts the OVT (Offset Vector Tile) method.

The OVT (Offset Vector Tile) bin extraction process involves selecting traces with approximately similar offsets and azimuths from each Common Midpoint (CMP) gather, reorganizing them into small rectangular bins. Each OVT bin thereby contains traces sharing nearly identical offset and azimuth attributes. Individual OVT bins are subjected to pre-stack migration. Post-migration traces retain their original offset and azimuth metadata. If OVT processing is not applied to wide-azimuth data, an azimuth division-based pre-stack migration method may be adopted to reduce computational costs. Both OVT processing and azimuth division migration necessitate systematic azimuth sector partitioning as a foundational preprocessing step.

To investigate medium azimuthal anisotropy using shear wave splitting theory, azimuthal sector partitioning of full-azimuth seismic data is required. To ensure optimal imaging for each sector while minimizing anisotropic differences caused by non-azimuthal factors, the division of azimuth sectors should adhere to the following two principles.

1. Each sector must ensure a certain number of coverage times (usually no less than 35), and the number of coverage times for each sector should be roughly equal. It is advisable to have 5 to 6 azimuth sectors, too few will not guarantee the accuracy of elliptical fitting, while too many will fail to ensure sufficient coverage times, leading to low signal-to-noise ratio and poor imaging quality in pre-stack inversion results.
2. Ensure that each sector contains near, medium and far offset data sets, and the maximum offset is roughly the same to avoid anisotropy differences between different sectors due to different far offsets.

The azimuthal sector division scheme is illustrated in Figure 11.

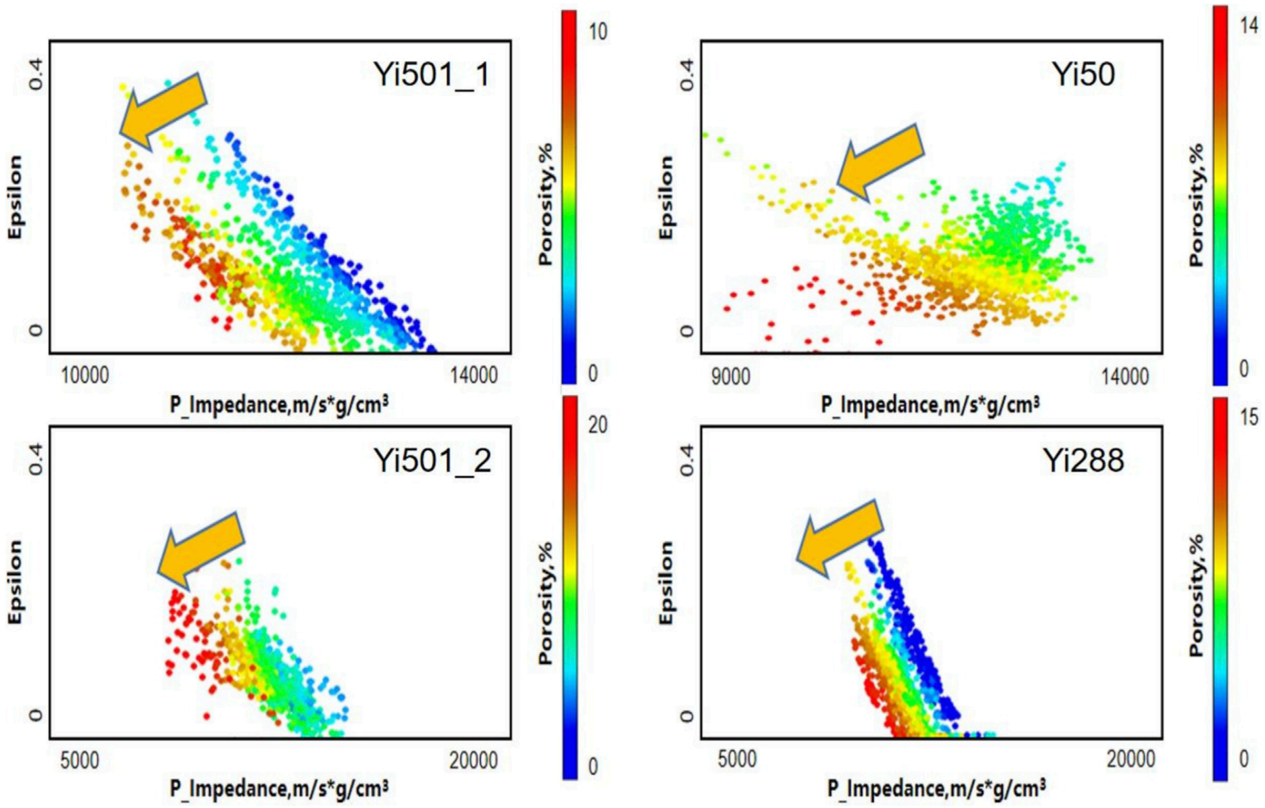

FIGURE 7
Crossplot of P-wave impedance versus epsilon (ε).

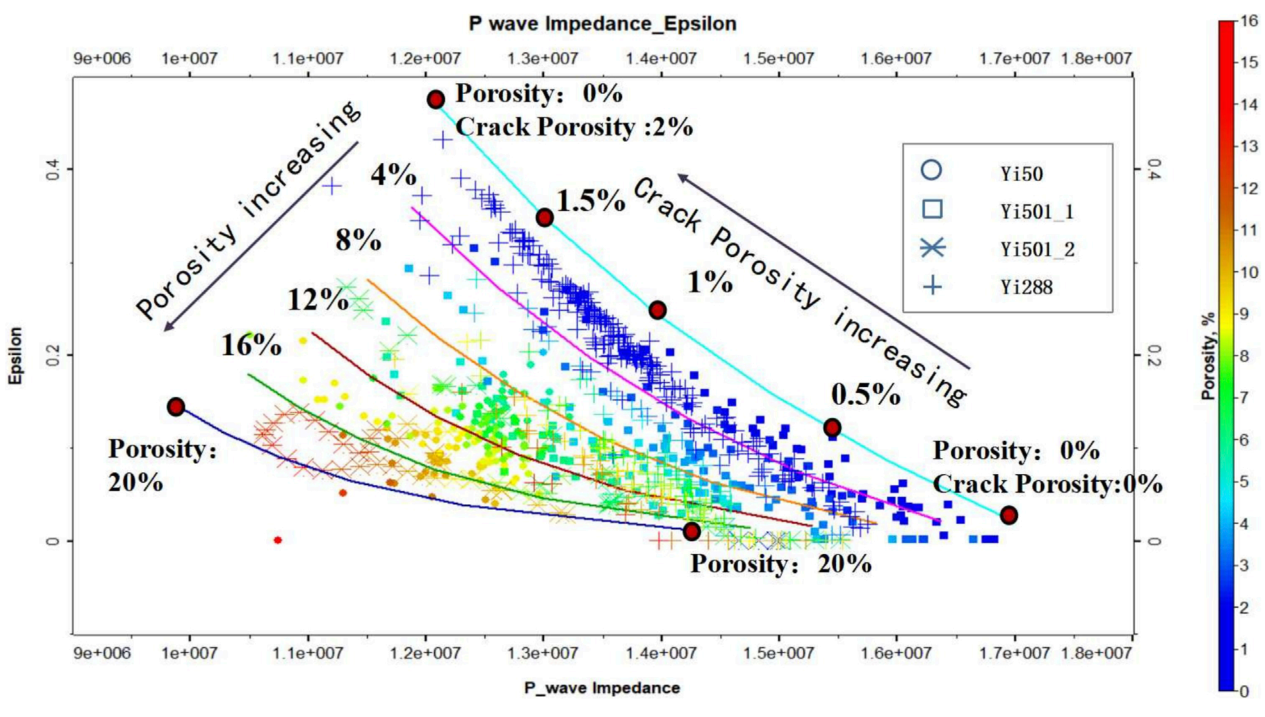

FIGURE 8
Rock physics template (RPT).

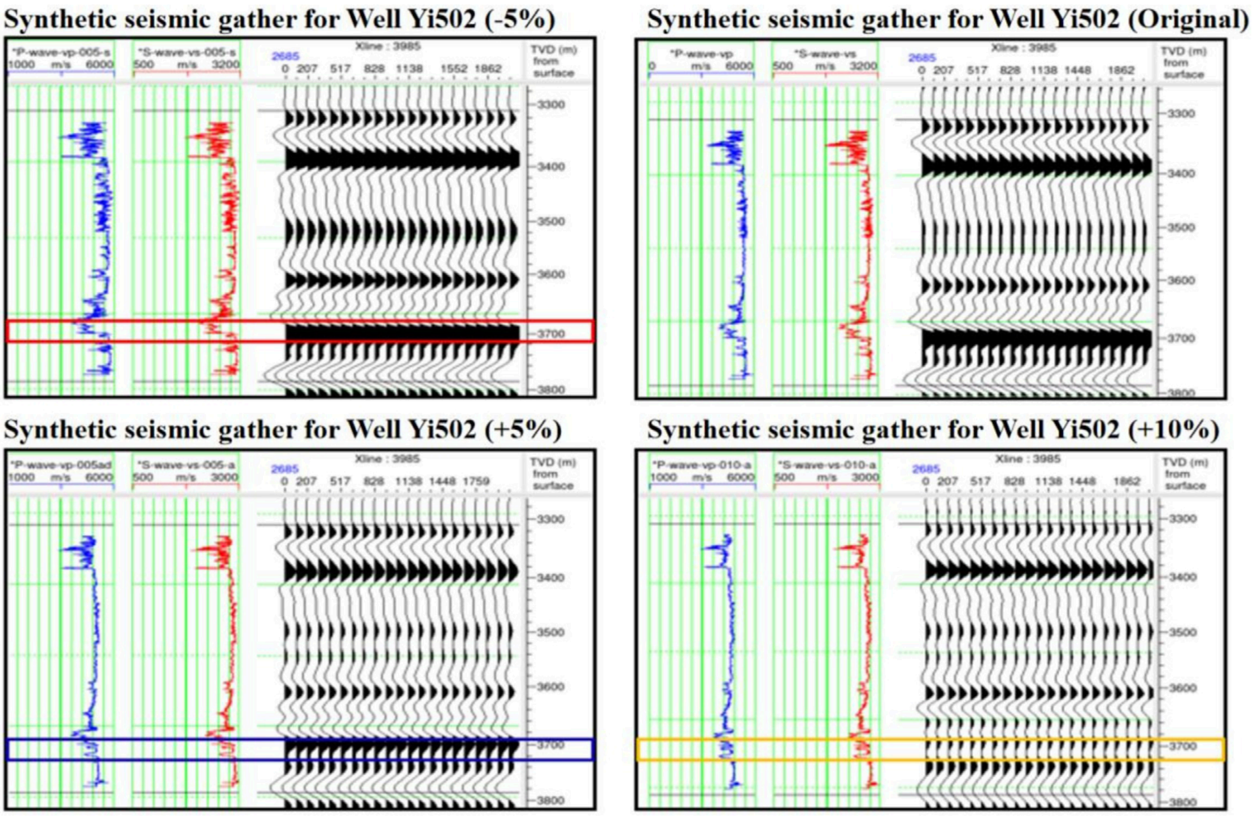

FIGURE 9
Synthetic seismic gather for Well Yi502.

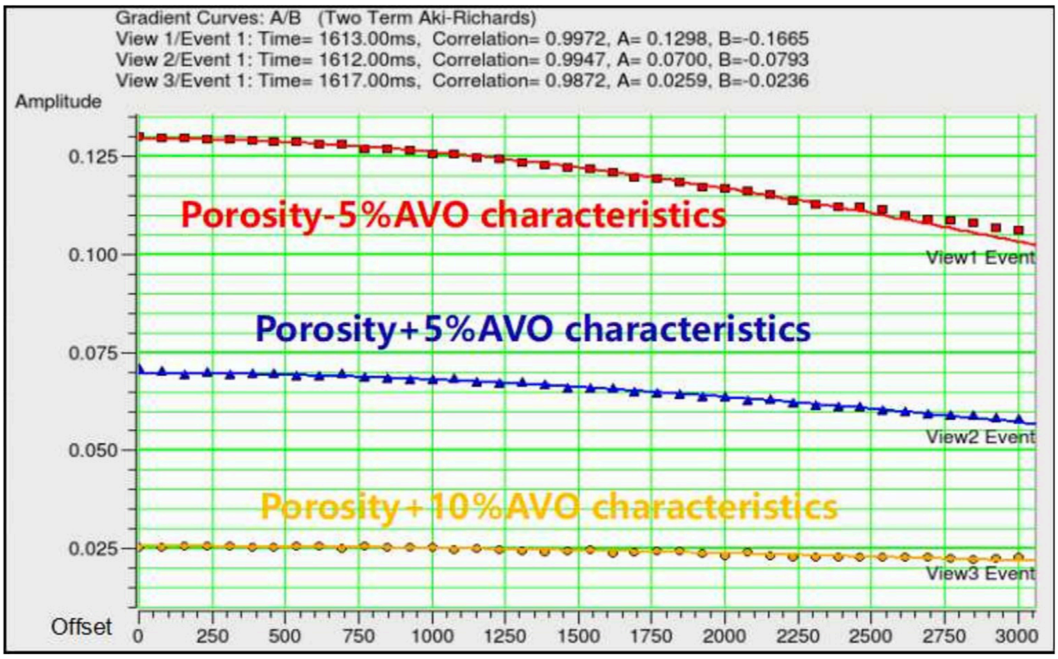

FIGURE 10
AVO characteristic analysis of the synthetic seismic gather for Well Yi502.

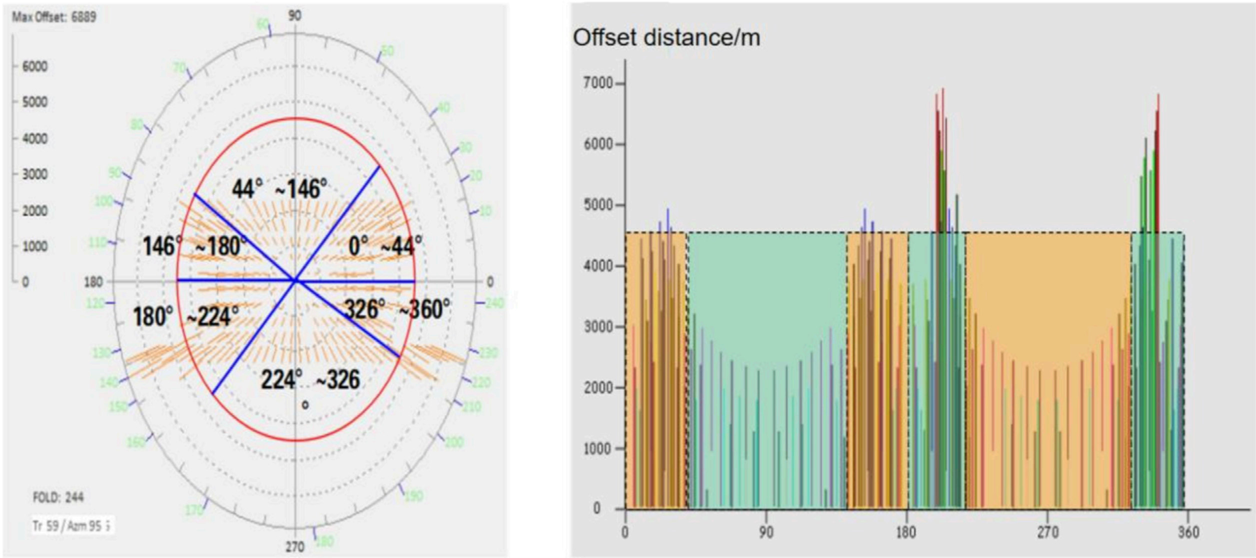

FIGURE 11
Rose diagram and histograms of azimuth-offset distribution for seismic gathers.

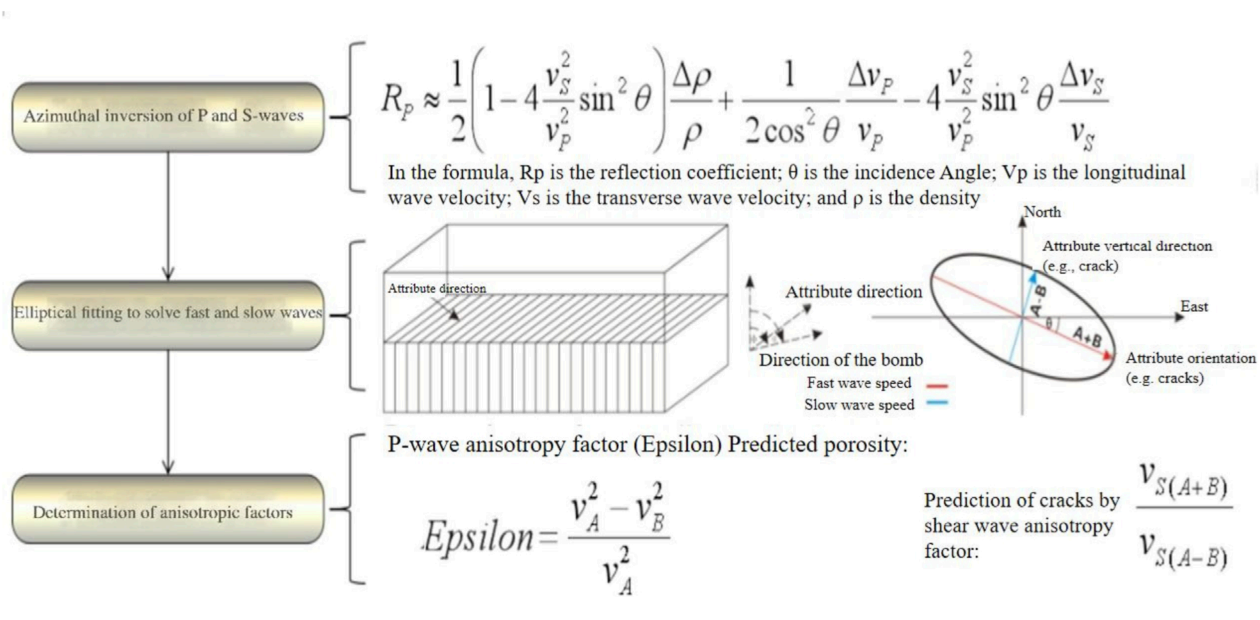

FIGURE 12
Anisotropy Parameter Estimation Workflow.

4.2.2 Joint anisotropic characterization via well-unconstrained seismic inversion and elliptical fitting

Utilizing six-sector OVT gather data and seismic velocity information (including root mean square/stacking velocities), we implement robust AVO tri-parameter inversion based on the Zoeppritz linear approximation to derive compressional (P-wave) and shear (S-wave) velocity volumes. An elliptical fitting method is subsequently applied to resolve orthogonally oriented fast/slow shear-wave velocities, thereby obtaining P- and S-wave anisotropy factors, with the workflow detailed in Figure 12.

4.2.2.1 P-wave well-unconstrained seismic inversion and elliptical fitting

Through statistical analysis of the target interval's acoustic interval transit time logs, a mean P-wave velocity of 4,300 m/s as the constant low-frequency component and an extreme relative value of 500 m/s. Well-unconstrained seismic inversion of P-wave velocity

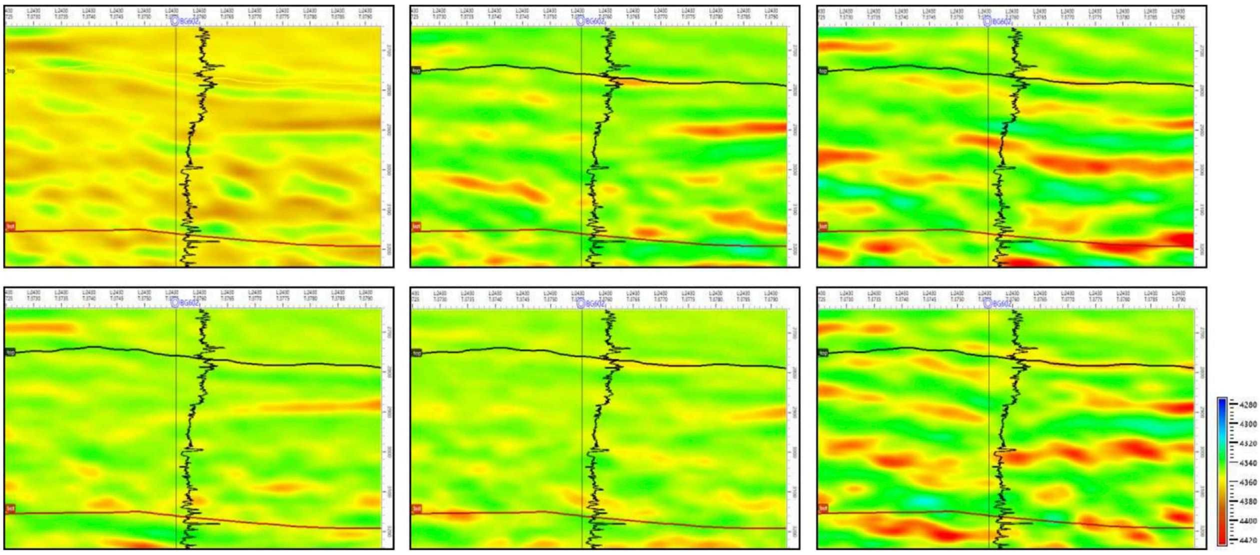

FIGURE 13
Non-well-constrained P-wave inversion results for gather2 dataset.

was conducted for each sector, yielding six sector-based P-wave velocity datasets.

Taking gather data Gather2 as an example, sector-wise well-unconstrained seismic inversion of P-wave velocity was conducted, yielding six sector-based P-wave velocity data. Since each sector is assigned an identical constant low-frequency component, the original shear wave velocity differences between sectors are preserved. The P-wave velocity can also be obtained by using the well-constrained seismic inversion method, but it should be noted that the inversion results are not too strongly constrained by the well data, so as to avoid the convergence of the inversion results of the P-wave velocities in six different sectors, which will flatten their differences and thus cannot complete reasonable elliptical fitting processing, nor can the direction and magnitude of fast and slow P-wave velocities be determined. Figure 13 shows the results of well-unconstrained inversion of P-wave velocity in six azimuthal sectors in the data set Gather2. The longitudinal variation law of P-wave velocity in each sector target segment (2,700–3200 ms) is consistent with the variation trend of logging P-wave velocity curve.

The elliptical fitting method serves as an important method in wide-azimuth seismic data interpretation for determining fracture orientation and fracture density. This approach is applicable to both post-stack seismic attribute data and pre-stack inverted elastic parameter data. Typically, 2-6 different azimuthal sections of post-stack attributes or pre-stack inversion elastic parameters are used to obtain an ellipse representing post-stack attributes or elastic parameters by using the elliptical fitting method. The major axis (fast-direction) of the ellipse indicates the principal orientation of azimuthal anisotropy at each trace and time sample (spatial location).

Previous rock physical studies demonstrate that P-wave anisotropy effectively reflects reservoir porosity variations. In the study area, because the P-wave velocity has advantages in reflecting the azimuthal anisotropy of subsurface porosity, that is, the azimuthal anisotropy of the P-wave velocity is the strongest, the inversion method of the azimuthal anisotropy of the P-wave velocity is reliable and effective. The elliptical fitting was carried out according to the inversion results of the P-wave velocity of 6 sectors, and the P-wave fast and slow wave data were obtained as shown in Figure 14. The well-unconstrained inversion of P-wave data using six different azimuthal sectors is performed, and an ellipse representing the anisotropy of P-waves is obtained by elliptical fitting. The long axis represent fast P-wave velocity and orientation, while the short axis represents slow P-wave velocity and direction. The fast and slow P-waves obtained in the future will be used to predict porosity based on the established rock physics template.

4.2.2.2 Shear-wave well-unconstrained seismic inversion and elliptical fitting

4.2.2.2.1 Azimuthal S-wave inversion. The mean velocity of the S-wave is 2,500 m/s, and the limit relative value is 500 m/s.The well-unconstrained seismic inversion of S-wave velocity was performed for each sector, yielding six sector-based S-wave velocity datasets.

Taking gather data Gather2 as an example, the S-wave velocity inversion was performed for each sector well-unconstrained, yielding six sector-based S-wave velocity data. Since each sector is given a constant low frequency component, the original difference in the velocity of the S-wave in each sector is preserved. The S-wave velocity can also be obtained by using the well-constrained seismic inversion method, but it should be noted that the inversion results are not too strongly constrained by the well data, so as to avoid the convergence of the inversion results of the S-wave velocities in six different sectors, which will flatten their due differences, thus failing to complete reasonable elliptical fitting processing and determine the direction and magnitude of fast and slow -wave velocities. The well-unconstrained S-wave velocity inversion results

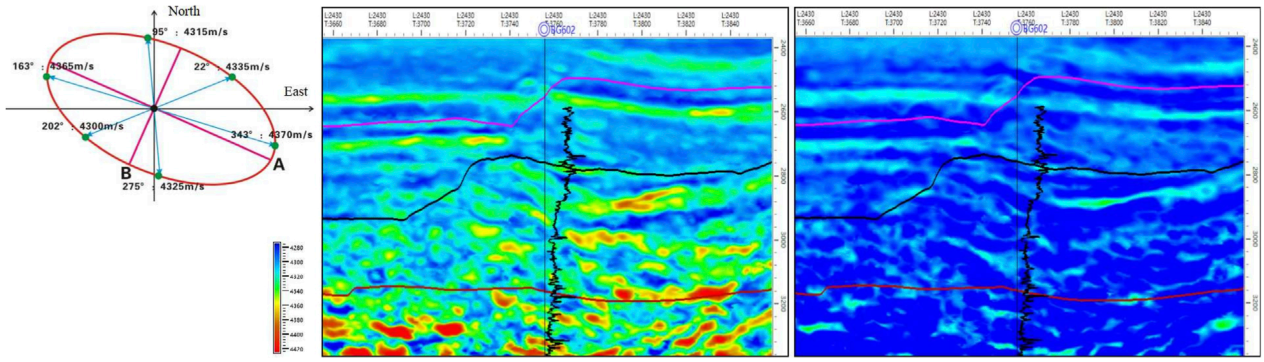

FIGURE 14
Well constrained free inversion profiles of fast and slow P waves.

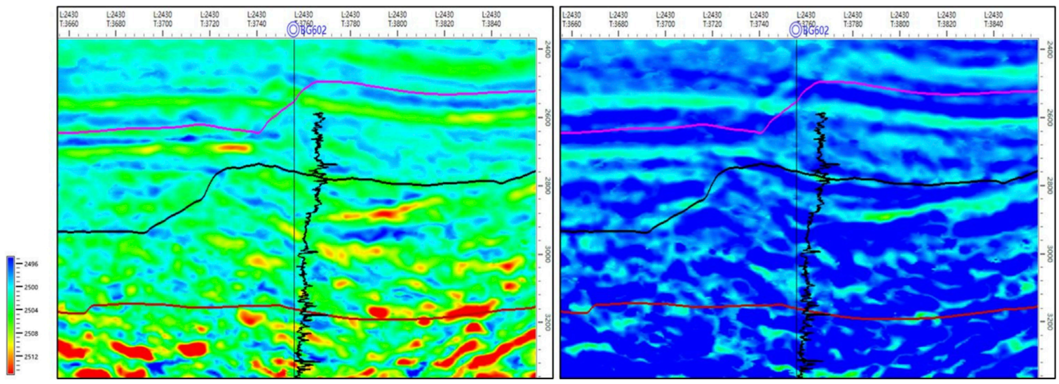

FIGURE 15
Well constrained free inversion profiles of fast and slow S waves.

from six azimuthal sectors in gather data Gather2 demonstrate that the vertical velocity variations within the target interval (2,700–3,200 ms) of each sector align with the trends observed in wireline P-wave velocity logs.

4.2.2.2.2 Obtain fast and slow S-waves. The elliptical fitting method serves as an important method in wide-azimuth seismic data interpretation for determining fracture orientation and fracture density. This approach is applicable to both post-stack seismic attribute data and pre-stack inverted elastic parameter data. Typically, 2-6 different azimuthal sections of post-stack attributes or pre-stack inversion elastic parameters are used to obtain an ellipse representing post-stack attributes or elastic parameters by using the elliptical fitting method. The major axis (fast-direction) of the ellipse indicates the principal orientation of azimuthal anisotropy at each trace and time sample (spatial location), while the ratio of the major axis to the minor axis indicates the strength of anisotropy at that location (fracture density).

Due to the advantages of S-wave velocity in reflecting azimuthal anisotropy of subsurface media, that is, the strongest azimuthal anisotropy of S-wave velocity, the inversion method for azimuthal anisotropy of S-wave velocity is reliable and effective. Based on the inversion results of S-wave velocities from six sections, elliptical fitting was performed, ultimately obtaining the fast and slow S-waves used for predicting fracture density and fracture direction (Figure 15).

4.2.2.2.3 P-wave anisotropy predicts the porosity. The obtained fast and slow P-wave data bodies were used to calculate the P-wave anisotropy factor. Based on the results of rock physics modeling, the relationship between the P-wave anisotropy factor and reservoir porosity function was further fitted, and the P-wave anisotropy factor body was transformed into the porosity body (Figure 16).

4.2.2.2.4 S-wave anisotropy to predict cracks. The velocity of S-waves is the strongest in reflecting the azimuthal anisotropy of underground media and can be used to determine the direction and density of fractures. As shown in Figure 17, the fitted ellipse major axis represents the main direction of azimuthal anisotropy (fracture trend), and the ratio of the major axis to the minor axis represents the intensity of azimuthal anisotropy at that location (fracture density).

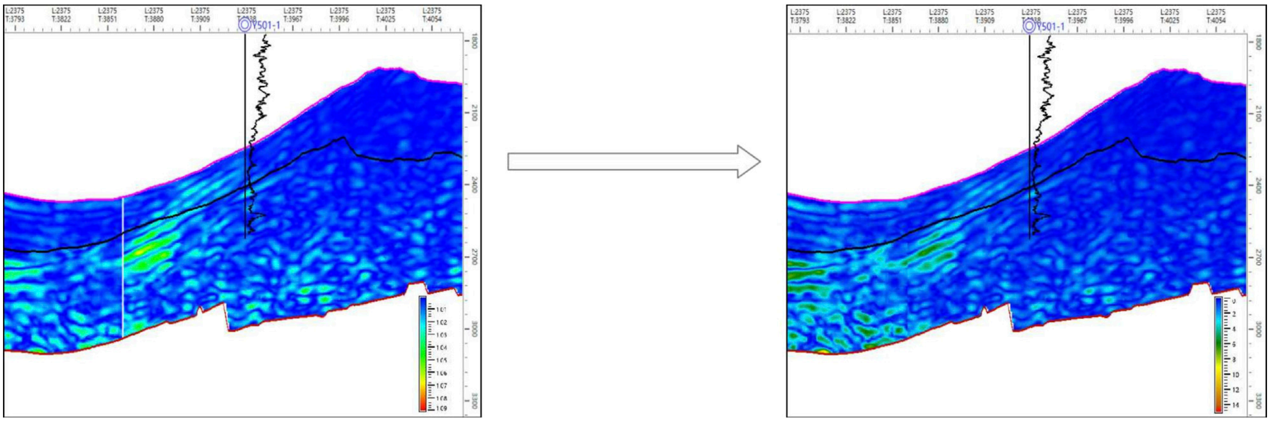

FIGURE 16
P-wave anisotropy volume to porosity conversion.

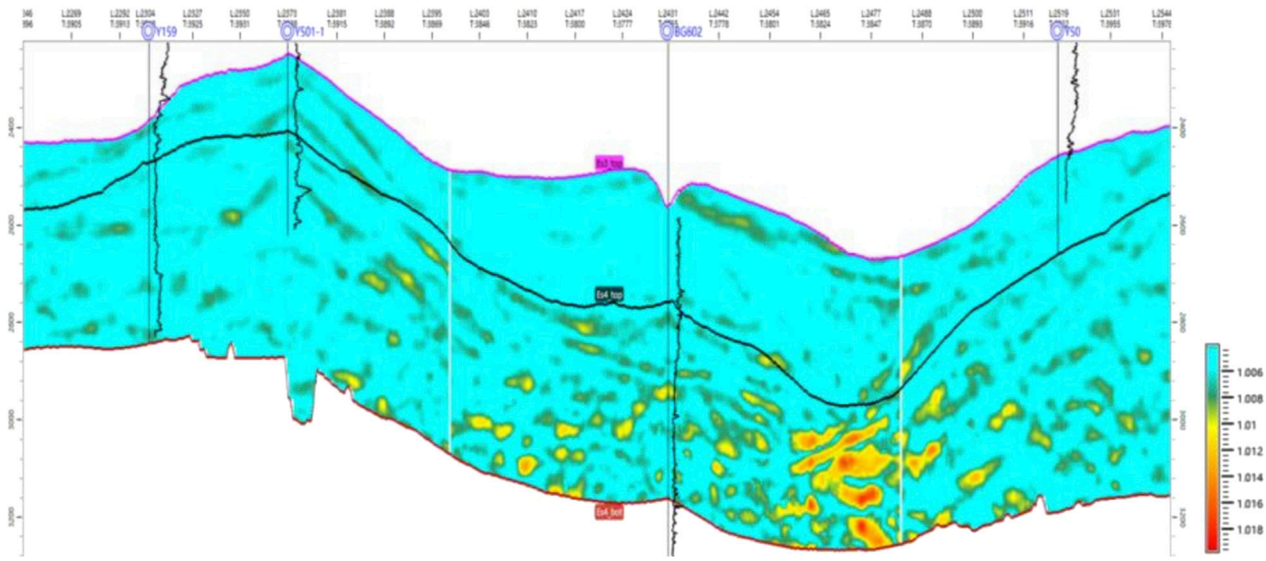

FIGURE 17
Well-tie fracture density profile.

5 Conclusion

This study investigates the influence of minerals composition and fractures in tight sandy conglomerates on rock physics modeling. An improved rock physics modeling method, based on a consolidation index, is proposed, offering an alternative to traditional empirical approaches. Cross-plot analysis of sandstone and conglomerate intervals from analogous wells demonstrates a strong correlation between P-wave impedance and the Epsilon parameter, which effectively reflects porosity variations. Based on this relationship, a rock physics template is constructed. An integrated pre-stack reservoir prediction workflow, specifically designed for the depositional characteristics of tight sandy conglomerates, is established. This workflow incorporates four key technologies centered on anisotropic inversion, enabling the quantitative characterization of porosity distribution and fracture networks within fan bodies. Consequently, this framework provides a basis for the comprehensive seismic evaluation of effective reservoirs in such formations. Based on this study, the following key findings are established.

1. Improved Consolidation Index Rock Physics Model. The improved consolidation index rock physics model established in this study features robust calculation and accurate results, and has been successfully applied to the characterization of tight reservoirs in the study area. This model not only enhances the reliability of traditional methods, but also effectively overcomes the limitations

of traditional sensitivity analysis—such as low efficiency in identifying porosity changes and the resulting overlap and ambiguity of logging curves—by introducing crossplot analysis between P-wave impedance and ε (reservoir parameter). Consequently, it achieves clear characterization of porosity changes.

1. OVT-Based Anisotropic Inversion. The OVT data are superimposed in different directions, and the elastic parameter volume is obtained through the inversion of the three parameters before superimposition. Elliptic fitting is performed on the data volumes in different directions. Elliptical fitting using OVT data successfully inverts anisotropic parameters for compressional (P) and shear (S) waves. However, inversion accuracy critically depends on the signal-to-noise ratio, resolution, and aspect ratio of pre-stack gathers. Inadequate data coverage in certain azimuths may introduce significant errors.
2. Fracture Prediction Challenges. Utilizing S-wave anisotropy for fracture prediction benefits from calibration with borehole image logs at well locations, reducing certain errors. Nevertheless, due to the limited frequency bandwidth of seismic data, seismic-scale fracture predictions cannot perfectly match logging or core-scale observations, warranting further research.
3. Rock Physics Template Application. The rock physics template constructed from P-impedance *versus* epsilon (ε) provides effective guidance for predicting physical properties through pre-stack inversion.
4. Porosity and fractures of tight sandy conglomerate bodies are key factors for characterizing effective reservoirs. Through anisotropic inversion, the prediction of porosity and fractures in sandy conglomerate fan reservoirs has been realized, addressing the difficulties that restrict the development and evaluation of the study area.

Data availability statement

The original contributions presented in the study are included in the article/supplementary material, further inquiries can be directed to the corresponding author.

Author contributions

XW: Methodology, Investigation, Conceptualization, Writing – original draft, Formal Analysis. QG: Data curation, Conceptualization, Validation, Funding acquisition, Supervision, Writing – review and editing.

Funding

The author(s) declare that financial support was received for the research and/or publication of this article. This research is financially supported by the National Science and Technology Major Project (Oil and Gas Major Project 2024ZD1400102), Scientific and Technologigical Project of Sinopec (P23068), Scientific and Technological Project of Shengli Oilfield Company (YKS2503).

Acknowledgements

Thanks for useful suggestions from assistant professor Ziqi Jin of Northeast Petroleum University.

Conflict of interest

Authors XW and QG were employed by Shengli Oilfield Geophysical Exploration Reasearch Insitute, Sinopec. The authors declare that this study received funding from the Shengli Oilfield Geophysical Research Insitute of Sinopec. The funder had the following involvement in the study: study design, data collection, data analysis, data interpretation, and manuscript preparation.

Generative AI statement

The author(s) declare that no Generative AI was used in the creation of this manuscript.

Any alternative text (alt text) provided alongside figures in this article has been generated by Frontiers with the support of artificial intelligence and reasonable efforts have been made to ensure accuracy, including review by the authors wherever possible. If you identify any issues, please contact us.

Publisher's note

All claims expressed in this article are solely those of the authors and do not necessarily represent those of their affiliated organizations, or those of the publisher, the editors and the reviewers. Any product that may be evaluated in this article, or claim that may be made by its manufacturer, is not guaranteed or endorsed by the publisher.

References

Backus, G. E. (1962). Long-wave elastic anisotropy produced by horizontal layering. *J. Geophys. Res.* 67 (11), 4427–4440. doi:10.1029/JZ067i011p04427

Chen, Y. H., Hu, J., Jiang, L., and Hu, D. (2017). Quantitative prediction of fractured porosity using conventional well logs. *Special Oil Gas Reservoirs* 24 (6), 7–11. doi:10.3969/j.issn.1006-6535.2017.06.002

Chen, S. Q., Zhong, Q. L., Li, Z. P., Zhang, M., Zhao, X., and Li, X. Y. (2020). Horizontal lamination fractures rock physical modeling and seismic response characteristics. *Oil Gas Geol.* 41 (6), 1273–1281. doi:10.11743/ogg20200613

Crampin, S. (1984). Effective anisotropic elastic constants for wave propagation through cracked solids. *Geophys. J. Int.* 76, 135–145. doi:10.1111/J.1365-246X.1984.TB05029.X

Li, S. H., He, W. S., and Wu, Y. P. (2015). Fracture characteristics and controlling factors in low-permeability sandy conglomerates reservoirs. *West-China Explor. Eng.* 27 (1), 73–74. doi:10.3969/j.issn.1004-5716.2015.01.025

Li, H. X., Zhang, G. Z., and Zhou, Y. L. (2019). Research on rock physical modeling of fractured tight clastic reservoirs. In: *Proceedings of the 2019 geophysical exploration technology symposium*. Beijing, China: Chinese Petroleum Society. p. 791–793.

Li, A., Zhang, L. Y., and Yang, J. G. (2020). Azimuthal anisotropy correction technology in wide-azimuth seismic OVT domain. *Oil Geophys. Prospect.* 56 (1), 62–68.

Lian, Z., Kai, L., and Xiaotao, W. (2023). Anisotropic total variation pre-stack multitrace inversion based on Lp norm constraint. *J. Petroleum Sci. Eng.*, 220. (PB).

Liu, L. M., Chen, X. F., and Fu, B. (2014). Application of P-wave azimuthal anisotropy technology in fracture detection in the Huawa area. *Complex Hydrocarb. Reserv.* 7 (3), 37–41.

Liu, E. L., Ding, P. B., and Zhang, F. (2025). Verification of fracture prediction method based on azimuthal anisotropy using physically modeled seismic data. *Chin. J. Geophys.* 68 (7), 2684–2702.

Luo, K., Zong, Z., Yin, X., Ji, L., and Yang, Y. (2024). Shale anisotropic rock-physics model incorporating the effect of compaction and nonplate mixtures on clay preferred orientation. *Geophysics* 89 (6), MR309–MR323. doi:10.1190/geo2023-0591.1

Ma, Y. (2020). Time-lapse inversion of anisotropic velocity linked to geomechanics. *Pet. Eng.* 000 (000), 140.

Pan, X. P., Li, L., and Zhang, G. Z. (2020). Multiscale frequency-domain seismic inversion for fracture weakness. *J. Petroleum Sci. Eng.* 195, 107845. doi:10.1016/j.petrol.2020.107845

Thomsen, L. (1986). Weak elastic anisotropy. *Geophysics* 51 (10), 1954–1966. doi:10.1190/1.1442051

Wang, Z. G., and Zeng, L. B. (2007). Fracture characteristics and conventional well identification methods in ultra-low permeability sandstone reservoirs. *World Well Logging Technol.*, 14–18.

Xie, R., Yan, J., and Chen, Q. (2022). Pre-stack anisotropic parameter inversion and its application in fracture prediction. *Geophys. Geochem. Explor.* 46 (4), 968–976.

Xu, K., Wang, S. X., Tang, J. L., Cao, H. L., and Liang, Z. Q. (2019). Research on fracture prediction technology in orthorhombic media. In: Proceedings of the 2019 annual conference on petroleum geophysics. p. 345–348.

Xue, J., Gu, H. M., and Cai, C. G. (2017). Model-based amplitude *versus* offset and azimuth inversion for estimating fracture parameters and fluid content. *Geophysics* 82 (2), M1–M17. doi:10.1190/geo2016-0196.1

Yang, Q. Y., Zhao, Q., and Wang, S. X. (2006). P-wave azimuthal anisotropy and its application in fracture detection. *Geophys. Prospect. Petroleum* 45 (2), 177–181.

Yang, P. F., Liu, Y. F., She, Z. C., Xia, W. J., and Guo, C. (2014). Rock physical modeling and attribute sensitivity analysis of carbonate fractures. *China Petroleum Chem. Stand. Qual.* 34 (2).

Yang, J. L., Gao, L. J., and Li, J. (2021). Shear-wave velocity azimuthal anisotropy inversion based on shear-wave splitting theory. *Geophys. Prospect. Petroleum* 60 (2), 261–271.

Yu, B. (2022). *Geostatistical reservoir characterization method based on multi-source information fusion*. Doctoral dissertation. Beijing, China: China University of Petroleum.

Zeng, L. B. (2004). Fractures and seepage characteristics in low-permeability sandstone oil and gas reservoirs. *Geol. Sci.*, 11–17.

Zhang, L., Zhang, H., and Xu, K. (2023). Seismic nonlinear inversion and gas reservoir identification based on anisotropic markov random field. *Geophys. Prospect. Petroleum* 62 (6), 1088–1100.

Zhao, Y., Wen, X., Xie, C., Li, B., Pan, X., Zhou, X., et al. (2025). Corrections to seismic inversion of anisotropic and isotropic fluid indicators and fracture density in the TTI medium. *IEEE Trans. Geoscience Remote Sens.* 63, 1–2. doi:10.1109/TGRS.2025.3570029