Using full-azimuth imaging and inversion in a Belarus salt dome tectonic regime to analyze fracturing in Upper Devonian intersalt and subsalt carbonate reservoirs

Aleksandr Konyushenko¹, Valery Shumilyak², Vladimir Solgan², Aleksandr Inozemtsev³*, Vadim Solovyev³ and Zvi Koren³ present the results of a full-azimuth, angle domain, prestack depth migration, and the subsequent assessment (through inversion) of the volumetric distribution of fracturing in Upper Devonian carbonate reservoirs in a typical Belarusian field.

An analysis of recent publications, together with the results of the European Association of Geoscientists & Engineers (EAGE) and EurAsian Geophysical Society (EAGO) exhibitions, reveals an unequivocal trend towards an increase in information content and accuracy of fracture predictions made using full-azimuth seismic acquisition and processing technology. This trend is notable in oil and gas fields in carbonate and terrigenous reservoirs within the countries of the Commonwealth of Independent States (CIS), where major oil companies such as Gazprom, Gazpromneft, Lukoil, Novatek, etc., are already conducting work of this type. This trend has also been observed abroad, but on a larger scale. The number of successfully completed projects is sufficient to confirm a surge in the use of higher density and richer seismic azimuth surveys in the coming decades.

Belorusneft PA RUE places great importance on the modernization of field surveys and on hardware systems that are capable of supporting the implementation of super-dense, full-azimuth imaging and inversion systems. While these surveys are considerably more expensive, they enable a comprehensive full-azimuth study of deep targets and oil and gas reservoirs. However, these surveys require special software technologies that are capable of correctly processing full-azimuth data and extracting the greatest possible amount of information from them.

This article presents the results of a full-azimuth, angle domain, prestack depth migration, and the subsequent assessment (through inversion) of the volumetric distribution of fracturing in Upper Devonian carbonate reservoirs in a typical Belarusian field. In order to assess the quality of the depth images produced, they are compared to depth migration results obtained using the Kirchhoff algorithm, which has been the principal depth imaging tool to date in this region.

The work is based on use of a proven technology from Paradigm, EarthStudy 360, for producing full-azimuth depth images (Koren and Ravve, 2009). The theoretical and practical principles, together with the primary advantages of this technology, were described in detail in an article by the technology’s inventors. We merely note that the technology’s fundamental difference from traditional migrations consists of a new approach to the organization of full-azimuth ray tracing, with a rich set of rays propagated from the subsurface local angle depth domain to the surface, with a uniform increment in aperture angles and azimuths to achieve a full and even illumination of the subsurface. Additionally, the wavefield is decomposed into specular and scattered components. The migration produces two rich sets of full-azimuth directional and reflection angle gathers. The former carry information about elastic energy distribution determined by the reflector spatial orientation, while the latter carry information about the distribution of reflection energy as a function of incident angle and associated azimuth within the imaging aperture.

The basic parameters of the seismic survey include bin dimensions of 10 x 10 m, an orthogonal shot line and receiver line arrangement, a receiver spread in the form of a ‘brick’ configuration, an average multiplicity (fold) of 100, offsets up to 4900 m, and an offset azimuthal distribution histogram that is fairly uniform, with small sinusoidal variations of the envelope.

The targets are intersalt and subsalt carbonates in an oil field located within the confines of the southern downthrown side of a regional fault.

The survey was conducted in order to more precisely define the geological model of the intersalt hydrocarbon field, predict the petrophysical parameters of the field’s

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rocks in the interwell space, and delineate the boundaries of regional, large-amplitude, intermediate subsalt blocks that show promise for hydrocarbon prospecting.

The rock profile within the confines of the field consists of an Archaean-Proterozoic crystalline basement, as well as Upper Proterozoic, Paleozoic, Mesozoic, and Cenozoic sedimentary formations. A characteristic feature of the sedimentary mantle structure is the presence of two salt-bearing strata, Lebedyanskian-Polesian and Evlanovian-Livnian, in which sedimentary complexes (subsalt terrigenous and carbonate, lower salt bearing, inter salt, upper salt bearing, and suprasalt) are of prospective and development interest.

The commercial oil content within the field is linked to the Lebedyanskian (Borichevskian upper salt-bearing) and Petrikovian-Zadonian inter salt and subsalt carbonate (Voronezhian, Semilukian, and Sargayevian) and terrigenous (Lanian) sediments.

The major oil pool is confined to the inter salt complex sediments. Over the surface of the productive inter salt sediments, the oil pool is represented by a semi-dome that is bound from the north by a zone without inter salt sediments and that adjoins the regional fault. The productive Zadonian-Yeletskian-Petrikovian sediments are primarily composed of micro-granular and fine-grained dolomites that are organogenic-algal, argillaceous to different degrees, dense, indistinctly laminated, cavernous, fractured in places, oncolitic, and sometimes calcareous.

The overall thickness of the inter salt sediments varies over a considerable range – from 100 m to 524 m, which is explained by the presence of a biothermal structure that makes up the southern part of the reef complex.

The inter salt complex pool consists of a single-pay roof pool that is stratigraphically bound from the north. It is bound from the south and west by the oil drainage boundary. The inter salt pool reservoirs are of porous-cavernous-fractured type. Their storage capacity consists of pores and caverns, while filtration occurs through the fractures and intergranular channels. Throughout the inter salt pool, the effective porosity value is estimated to be 7.7%. The pool has an elastic water drive. The inter salt pool is in the operation and maintenance phase, and is being developed pursuant to the project.

Limestone, marls, and dolomites with clay bands represent the subsalt carbonate complex sediments of the intermediate blocks. The prospecting reservoirs consist of cavernous-fractured dolomites and less often, limestone of the Upper Devonian Frasnian stage Voronezhian and Semilukian horizons.

Belorusneft PA RUE specialists, together with Paradigm geoscientists, conducted a comparative analysis of the full-azimuth migration results obtained by the Paradaym Geofizikal [Paradigm Geophysical] Limited Liability Company (LLC), and the Kirchhoff migration results obtained by BelNIPIneft. The analysis revealed that the full-azimuth imaging results had more accurate reflection and dislocation focusing, higher boundary resolution and traceability, a much lower level of migration noise, and none of the migration distortions (delays) inherent in the Kirchhoff migration (Figures 1-4). This made it possible to more clearly define the tectonic block boundary and stratigraphic sequence pinchout.

Comparisons of longitudinal depth sections obtained from full-azimuth migration EarthStudy 360 at different maximum frequencies (70 Hz and 100 Hz) are shown in Figures 1, 2 and 3. The depth profile following the traditional Kirchhoff migration is provided on the left for comparison. The migration velocity-depth model and maximum aperture...
were identical in both cases. The reflection intervals reflect a gradual change in the geological profile from the northwest to the southeast along the main oil field. The maximum incidence angles of the reflectors reached 70°.

The main advantages of depth images using full-azimuth imaging as compared to the Kirchhoff migration include an increase in the lateral and vertical resolution of the main reflectors, an increase in the level of detail in delineating the blocks and dislocations, including the principal oil and gas reservoirs, the virtual absence of migration noise in the profiles, and an increase in the accuracy and unambiguous of geological profile and principal reservoir interpretation.
Horizontal transverse isotropy (HTI) analysis of anisotropy and fracturing

Prior to the analysis, we present several important findings that have been published in recent scientific literature. The tectonic origin of the great majority of fractures has been extensively studied and documented. The fractures in the carbonate formations (limestone, dolomites, and dolomitic limestone) are primarily arranged perpendicular to the bedding. The directions of the tectonic structures and faults control the orientation of the principal fracture systems. On the whole, fairly regular geometric systems or networks characterize the fracturing (macro and micro) in the rocks (primarily in the carbonates), which can be in mutually perpendicular and less often diagonal directions. The fractures are open and closed, which facilitate or hinder fluid penetration. It is important to note that the physical property of rock permeability is proportionately linked to the open fracturing of the relevant rocks.

An analysis of data at the reflection gather level near the producing wells revealed the presence of clearly expressed HTI anisotropy in both the three-dimensional image (Figure 5) and the two-dimensional (2D) scans (Figure 6). A surface of reflection (reflection amplitudes) from the HC top of a saturated reservoir is shown in Figure 5, where a bulging effect is observed that is linked to the difference in velocities along the V II fractures and the V I_ fractures. The parameter of velocity anisotropy, Delta2, reflects its intensity and the difference in relative moveout along and across the fractures. Delta2 is a dimensionless quantity and has negative values. The increased values of this parameter or intensity are proportionately linked to an increase in fracturing or fracture thickness, as well as to the decompression zones caused by unidirectional overburden pressure.

The surface of reflection from the top of the fractured reservoir is symmetrically curved and reflects (in the

\[ \text{Delta2} = \frac{dV}{V_{II}} - \frac{dV}{V_{I_2}} \]

Figure 5 Kinematic registration of HTI anisotropy (linked to fracturing) on a surface of full-azimuth reflection from the HC top of saturated carbonate reservoir D3el.

Figure 6 Display of the HTI anisotropy effect on a 3D reflection gather in a 2D image (all azimuths and maximum aperture angle = 30°) near the high oil flow rate well. The reference seismic section and gather location are shown on the left).
Additionally, a Coherence Cube was calculated to highlight the fault zones.

**Analysis of the results**

The well (Figure 7) falls into the central zone of increased fracture density, both inline and crossline. The azimuths of the predominant fracture orientation fall within value limits of 20-40° from the north (a northeasterly direction). At the same time, there are zones in which a mutually perpendicular fracture orientation direction is predominant: 40-60° from the north (a northwesterly direction).

The relationship between seismically derived macro-fracturing and the deep faults (dislocations) calculated using the Coherence Cube is depicted in Figure 8. It is readily apparent from a comparison of the reflection intervals that sub-vertical tectonic fractures and dislocations control the primary fracturing. At the same time, oil saturated fracturing is localized in zones that are not subjected to heavy strains, in zones of relatively low coherence and a negligible distance from the main large, medium and small faults. A great deal of research confirms this fracturing behaviour.

Two examples of the correlation between increased fracture density values and oil well flow rates are presented in Figures 9 and 10, in which the direct relationship between fracture density and oil saturation can be seen, together with the prospective zone of increased fracturing.
Figure 8 Comparison (from left to right) of the full-azimuth amplitude volume, fracture density (intensity), and Coherence Cube in the vicinity of the high flow rate oil well.

Figure 9 Comparison (from left to right) of the depth image volume from full-azimuth imaging and the fracture density volume (AVAZ inversion) near a low flow rate oil well. The oil well falls into a peripheral zone of the region of increased fracture density, both inline and crossline. This may explain, in particular, the decrease in the oil flow rate in the well.

Figure 10 Example of the localization of prospective zones of increased fracturing in the D3 subsalt oil saturated carbonate reservoirs under complex geological conditions in the presence of large reflector dips (up to 70°). The high flow rate oil well falls in the centre of an anomalous fracture density attribute zone.
According to these assessments, a direct dependence is observed between the fracture density attribute and the well flow rate.

The intersalt complex HTI anisotropy axis of symmetry orientation calculated on the basis of seismic data revealed that a minimum of two fracturing systems have developed within the field – from the north-northwest to the north-northeast direction.

**Analysis of the results in context**

Based on the volumes derived, fracturing attribute charts were extracted over a range of field intersalt complex reservoirs (Figures 11 and 12). BelNIPinftBelorusneft PA RUE specialists, together with Paradigm experts, performed a preliminary assessment of the fracturing attributes of the intersalt complex carbonate reservoirs based on a comparison of well flow rates to fracturing attributes.

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**Figure 11** Subsurface contour map, and a map of the density of the fractures and their orientation, extracted for the top of the main carbonate reservoir – D3. On the right – the fracturing direction azimuth scale.

**Figure 12** Subsurface contour map and fracture density map, overlaid by a map of the intensity of fracturing and its orientation in a vector version. Each vector designates the intensity and direction of the fractures in a specific bin. Azimuthal distribution of the main filtration flows and the maximum speed of movement of a tracer fluid from the injection well (dark blue) to the recording wells (black). Comparisons of the trend directions (vectors) of seismic fractures and of the well fluid flow filtration show a good correlation.
Results

Convincing results were obtained about the promising nature of seismic investigations using full-azimuth and inversion technologies under the complex seismic conditions of salt dome tectonics when studying carbonate reservoirs at great depths. The target depth images obtained had a higher resolution and greater detail than those produced using the Kirchhoff migration. For the first time in the territory of the Republic of Belarus, reservoir fracturing was assessed using seismic data. Based on the analysis results, the density distribution of fractures and their orientation are directly linked to productivity and pressure transient test results.

In the findings, it is important to note that full-azimuth data is the key to a detailed understanding of reservoir structure. The full-azimuth imaging and inversion technologies make it possible to obtain more accurate depth images and to extract vital information about reservoir fracturing. The results reveal that the proposed technology can be an essential tool for enhancing the efficiency of seismic surveying in hydrocarbon fields in Belarus with complex geology under conditions of salt dome tectonics.

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