

## Multifocusing 3D diffraction imaging for detection of fractured zones in mudstone reservoirs

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### Summary

Unconventional reservoirs have a unique set of problems. Most production wells are drilled horizontally through the reservoir rock and hydraulic fracturing is applied to increase permeability in the reservoir. The pre-drilling knowledge of natural fracture corridors and small offset faults is very important in this case. Seismic resolution from conventional reflection imaging is generally not sufficient to resolve such small scale rock properties. Diffracted waves are events generated by small scale subsurface heterogeneities and discontinuities (including fractures). Detection and imaging the diffractive component of the total wavefield opens a new perspective to find and characterize fracture zones in carbonate environment.

### Introduction

Detection of natural fractures is important when developing unconventional reservoirs, as they can help production by adding permeability and hydrocarbon storage to the system or hinder production by creating loss zones for hydraulic fracture fluid and blunting hydraulic fractures. Understanding the location and orientation of natural fractures is important for optimal well placement when sweet spotting an unconventional reservoir play.

During the Devonian period (Frasnian-Femmenia) a major sea level transgression, including superimposed high-order sea-level regressions, occurred. These sea level fluctuations resulted in conditions favorable for the growth and subsequent drowning of the reefs and the deposition of the time-equivalent shales. At a later time, isolated pinnacle reefs grew, dividing the basin into sub-basins with reduced oceanic circulation. During an episodic regression, organic-rich mudrocks and basinal limestones were deposited. High concentrations of silica accumulated in the protected sub-basins which created a heterolithic shale reservoir with high total organic content (TOC) and porosity sufficient for hydrocarbon storage in the reservoir. Small scale faulting, with throws less than 30 m, has been observed on the seismic data in this area. Most of the faulting is deeper than the reservoir and related to basement structure although there are some faults that occur at the reservoir level. Faulting has influenced reef growth in the area, as the reefs grow on upthrown fault blocks, and faulting can also create fractures. Figure 1 shows the time structure map of the top reservoir horizon, picked from seismic data, overlain with the fault polygons in black, and the earlier reef and platform edges in blue. The wells used in this study are shown in red.

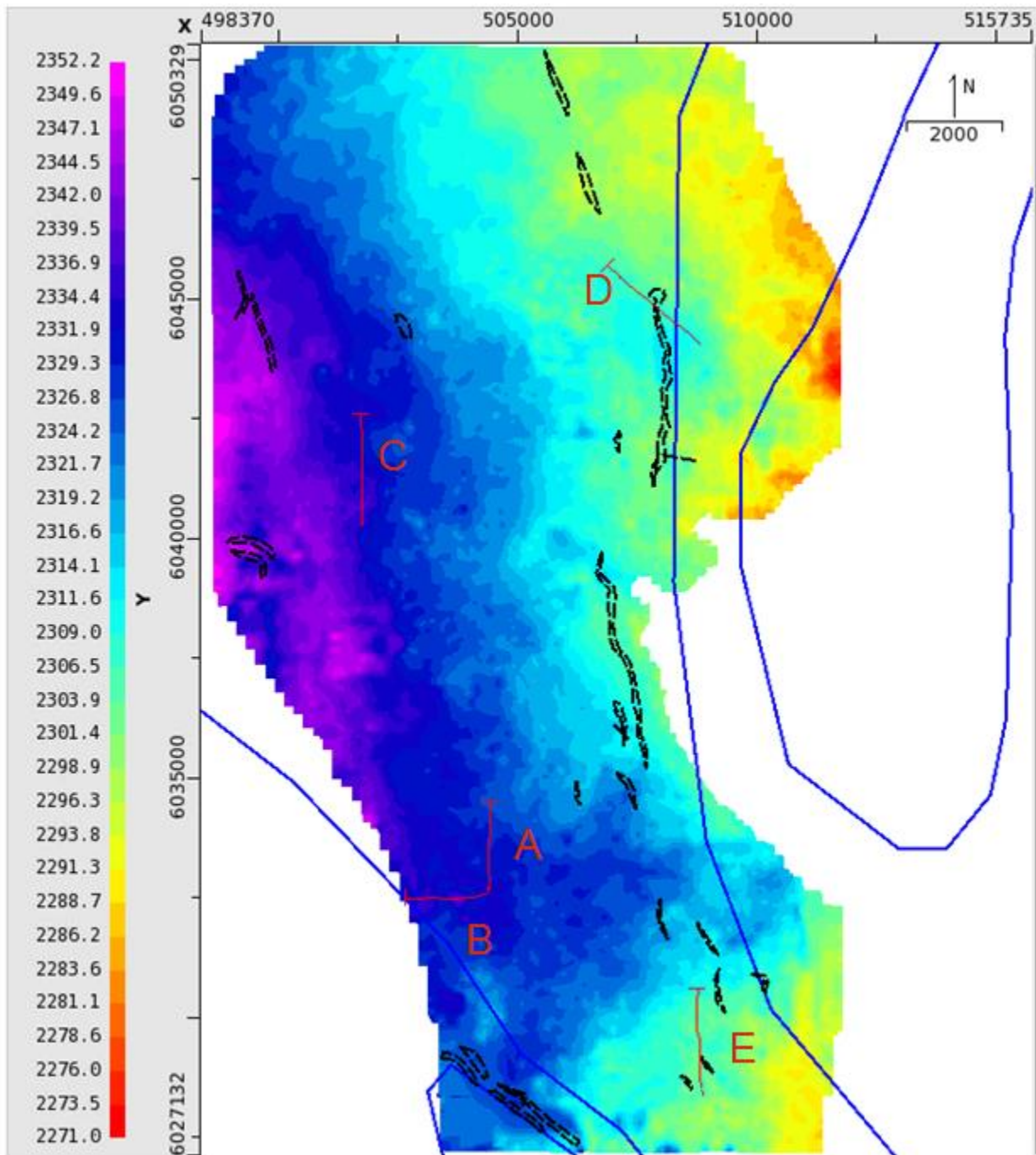


Figure 1: The time structure map of the top of the reservoir is shown with the underlying reefs and platform edges in blue, fault polygons in black and the drilled wells in red.

The reservoir is naturally fractured, as can be measured from core and image logs. The fractures appear to be pervasive throughout the formation however they vary spatially in orientation, aperture

and density. Fractures occur in the reservoir at two different orientations (WNW-WSW and NE-SW), some are cemented closed and others are open with narrow apertures, from 1 to 3  $\mu\text{m}$ . The fracture density also varies within the study area, from small networks to large fracture densities that imply extended network of fractures. The genesis of the fractures is speculative, as the fractures with orientations WNW-WSW, are at oblique angles to the direction of maximum stress angles and seem unrelated to the Laramide orogeny. Possible causes of fracturing may be related to the draping of the reservoir over underlying reefs, small scale faulting or pressure created during catagenesis or hydrocarbon generation. Today, the reservoir is a self-sourced liquids-rich to gas shale play. It is 15 to 60 m thick and exists at depths of 2700 to 3300 m TVD. The average porosity is 4.5% and the average TOC ranges from 2.5 to 4%. We have observed variability in the geologic data related to the density, orientation and aperture of natural fractures. This variability may be related to a combination of factors including the underlying basin structure and lithology of the reservoir. Understanding the heterogeneity of the reservoir and how it relates to hydrocarbon production is the key to maximizing value from the development of the asset.

## **Theory and/or Method**

Seismic diffraction can be used for imaging extended systems of natural fractures. Diffracted waves are generated when the incident wavefield meets small scale objects and discontinuities such as fractures, faults, sharp curvature or edges (Khaidukov et al., 2004). The diffractive component can be extracted from the total wavefield and used to produce images that contain information regarding subsurface scatterers and discontinuities. There are several techniques available to separate and image diffractions. We have used Diffraction Multifocusing Method which consists of an optimal summation of seismic data along in diffraction traveltimes trajectories (Berkovitch et al., 2009). The presented case study shows that diffraction imaging offers a new perspective on finding and characterizing fracture zones in unconventional reservoirs.

## **Examples**

The diffraction multifocusing (DMF) was applied to 3D seismic data acquired above the reservoir resulting in a data volume which highlights discontinuities possibly related to fractures. Figure 2 illustrates an in-line section extracted from the pre-stack time migrated (PSTM) volume and overlain by the DMF data (shown in color).

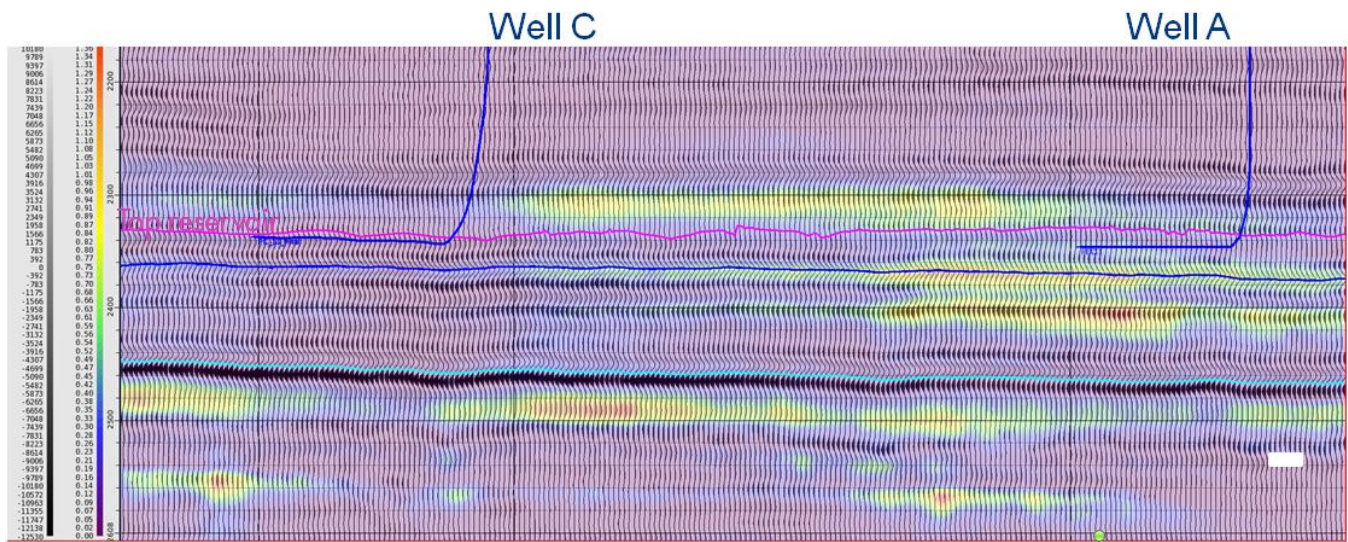


Figure 2. An in-line extracted from the PSTM cube, along the traverse line shown in red on the inset map, is shown in wiggle trace with diffractivity data overlain in color. The two well trajectories show different diffractivity amplitude indicating a change in the presence of subsurface discontinuities. The reservoir occurs at the pink horizon.

Several diffractivity anomalies appear at the reservoir level (the pink horizon in Figure 2). Some of them coincide with geologic features that could be associated with fractures, small-scale faulting or differential compaction of the formation over underlying reefs, as shown in Figure 1. The cause of other amplitudes is not clear and may be related to different fracture mechanisms, such as fracturing owing to pressures building up during hydrocarbon maturation. Fracture swarms of considerable extent may be able to scatter seismic energy and be detectable by diffractivity imaging (Landa, 2011). Figure 3 shows a diffractivity attribute draped on the top reservoir horizon and the positions of the well trajectories.

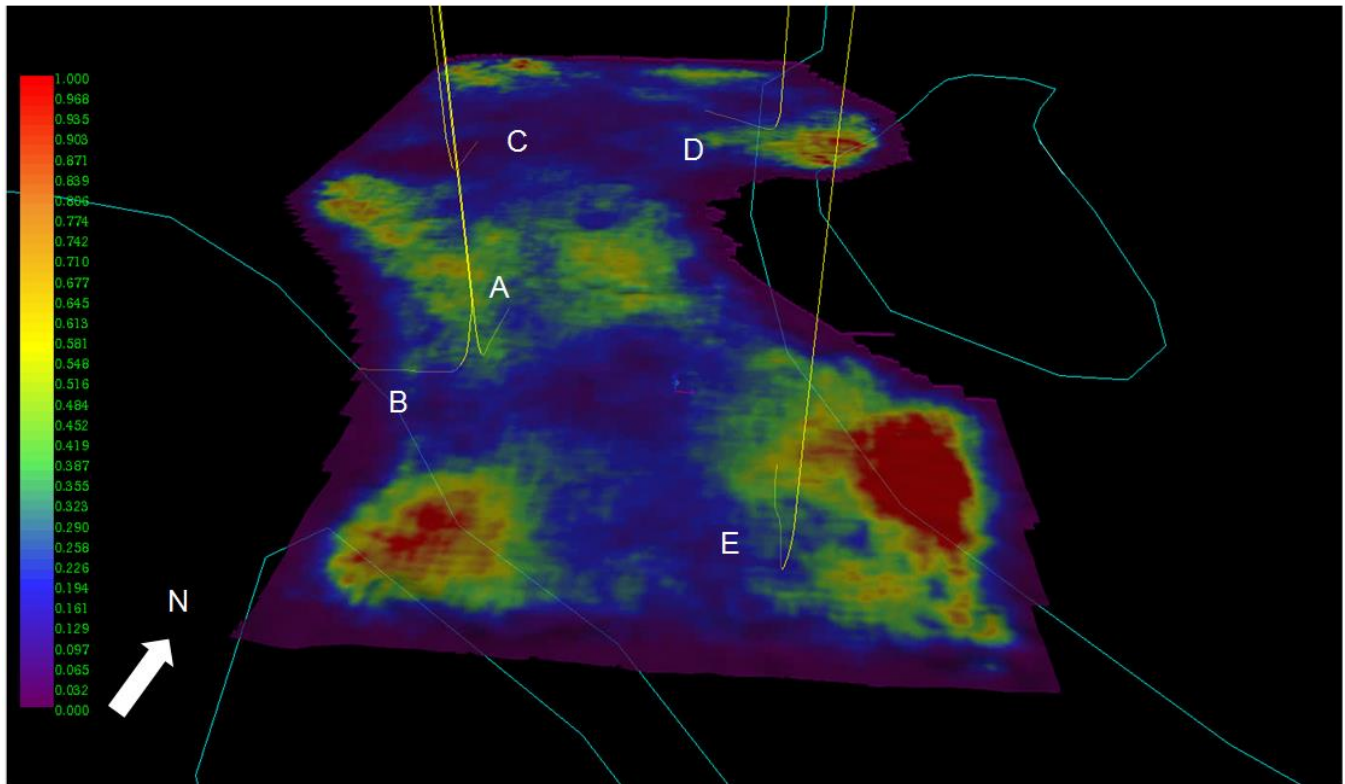


Figure 3. Diffractivity amplitudes draped over the top reservoir surface are shown with the well locations.

Five wells have been drilled into the target formation on the survey area and produced. Their trajectories are shown in 3. Diffractivity attribute data extracted along each well track have been averaged and correlated with initial production (IP) of each corresponding well where production data exists. Results are shown in Figure 4. There is a strong linear trend relating initial hydrocarbon production of 5 days to diffractivity amplitude, independent of the length of the lateral section of the well in Figure 4. There is less data available with 10 days and 40 days of production, however the slope of the graph still indicates that larger diffraction amplitudes relate to higher production. This trend still exists even if the data is normalized by the length of the lateral section of the well. The average porosity in the reservoir is spatially consistent at ~4 to 5% so the extra hydrocarbon storage may come from natural fractures. Although Well A and Well B have been drilled from the same surface location, they have intersected different subsurface conditions as evidenced by the diffraction anomaly (Figure 2) and their production is different. Well A drilled north into the anomaly and Well B drilled parallel to it.

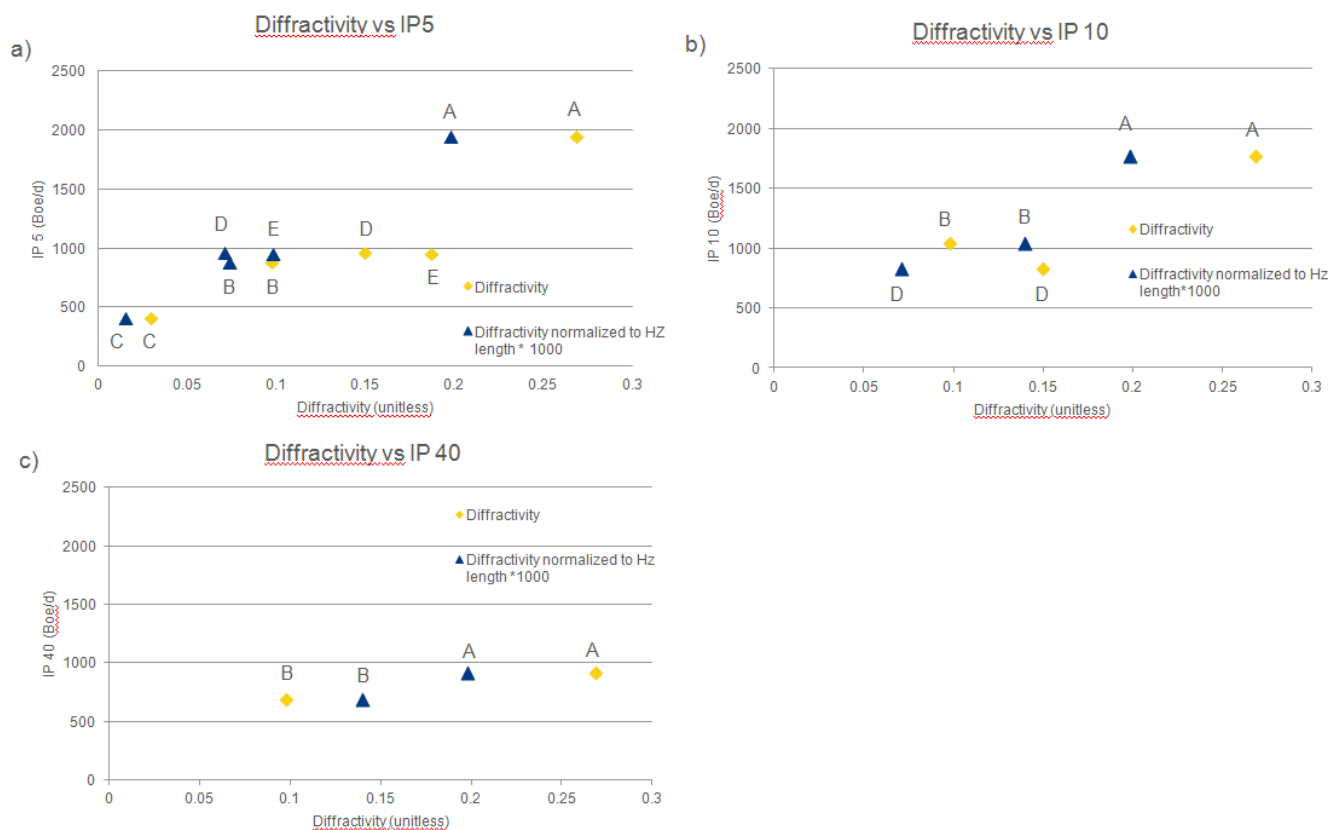


Figure 4. The diffractivity attribute data averaged along each well track are compared with the initial production of each corresponding well. The yellow data points are the diffractivity amplitude values and the blue data points are the diffractivity amplitudes normalized to the horizontal lateral length.

The total gas (normalized by the rate of penetration) recorded during drilling also relates strongly to the diffractivity amplitude along the lateral length (Figure 5). The trend of the diffractivity data is similar to the trend of total gas encountered during drilling for Well A. At Well C, the gas shows are extremely low compared to the other wells and the diffractivity amplitude values are correspondingly low. At Well D, the diffractivity and total gas have a similar shape with a bias in the overall amplitude of the diffractivity data. The diffractivity does not correspond to the gas shows at Well C. Noise generated from multiples, reverberating energy originating shallower in the section, were observed in the seismic data near Well C. This noise may stack coherently during the diffraction imaging process contaminating the diffractivity image.

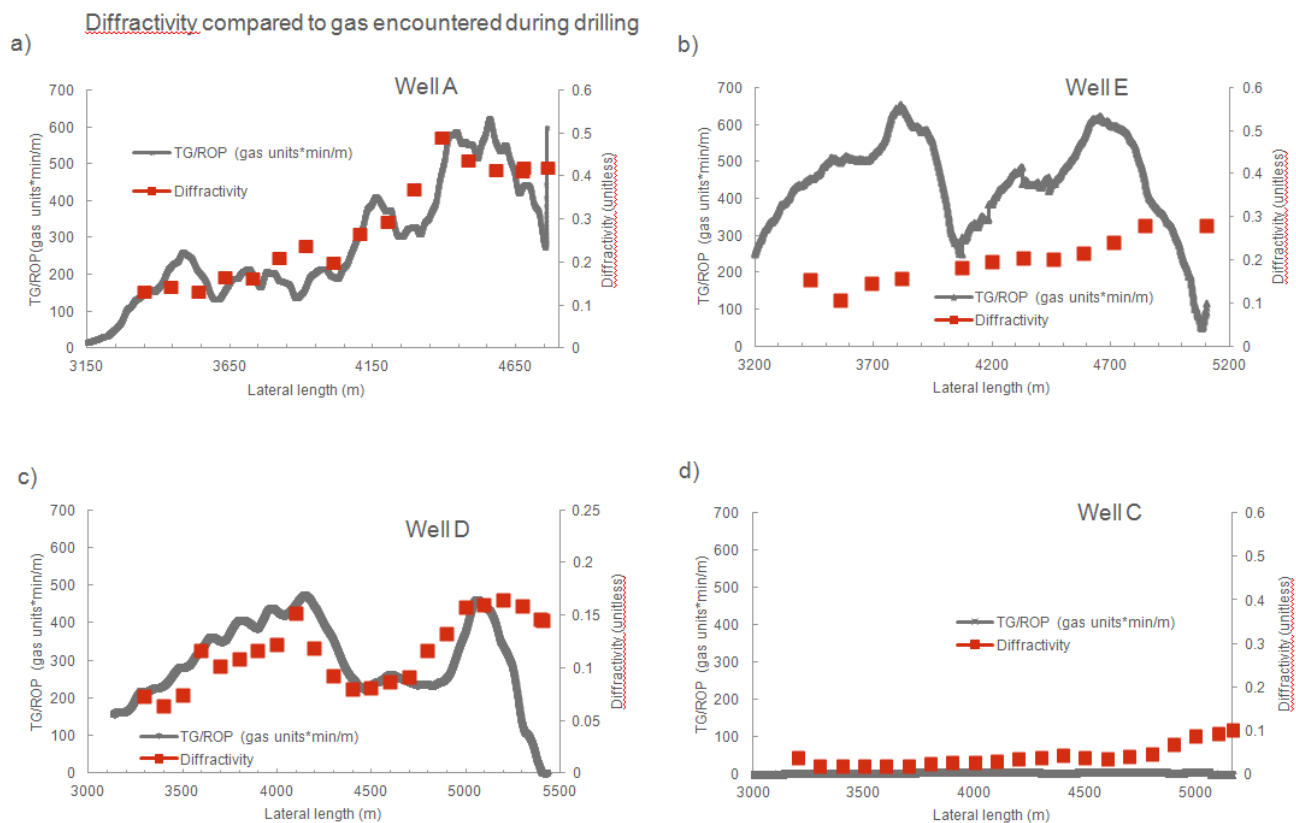


Figure 5. The total gas recorded during drilling (grey) is compared to the diffraction amplitude (red) along the well laterals. The horizontal axis is the length of the well lateral, the left vertical axis is the total gas from the strip logs measured in gas units\*m/min, and the right vertical axis is the diffraction amplitude.

## Conclusions

We have tested diffraction imaging to map the variability of subsurface discontinuities thought to be related to extended networks of natural fractures within an unconventional shale reservoir of the Western Canadian Sedimentary Basin. From the diffraction volume, we have been able to map the location of fracture swarms large enough to scatter seismic energy and relate them to gas shows during drilling and initial production rates. This may allow us to spatially locate well trajectories to target or avoid natural fractures.

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