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3-D View of Fracture and Reservoir Pressures in Shale Leading to New Approach and More Reliable Predictions*

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Abstract

Fracture and reservoir pressures are vital parameters to optimize drilling and completion and to adequately estimate potential hydrocarbon production from shale. Our study, that includes five shales from three different basins, is shedding a new light on pressure gradients. Whereas traditionally gradients are calculated with respect to a ground level reference, our analysis demonstrates the existence of very well behaved gradients connecting all of the pressure data pertaining to structural blocks, sub-basins and sedimentary packages.

Introduction

Observed shifts between gradients within any sub-basin are interpreted as structurally induced tectonic displacements that can be correlated to apparent vertical fault throw; these tectonic activities only represent tectonic activity posterior to maximum burial. Partial depressurization can locally occur in association with major uplift related unconformities and poor to variable fault sealing capacity; making it difficult to recognize these newly introduced pressure gradients.

Various Case Studies

In a first case study from the Utica and Lorraine shale in the Quebec Saint Lawrence Lowlands, fracture pressures and gradients were studied per area; the data came from hydraulic fractures exclusively taken in vertical wells. Each area and in this case each well was defined by high well-defined gradients backed-up by systematic relationship with isotopic and gas geochemistry (Chatellier et al. 2013). These recently conceived gradients would not have seen the light but for the extensively sampled wells penetrating more than 2500 m of continuous shale without the presence of any conventional reservoir.

Saint David and Leclercville are two wells that are 150 kms apart (nearly 100 miles) and in different parts of the St Lawrence Lowlands. The first well located in a tectonically quiet area, whereas the second one is in a thrusted area with numerous complex folds and fractures. Note that the Ordovician folding and thrusting predate the time of maximum burial. Figure 1 shows newly defined gradients tied to the geochemistry and to pressure increases while drilling. The fracture gradients calculated from the fractures in these wells are incredibly close to each other: (63.37*depth)-59426.5 kPa for Saint David (blue gradient) and (63.49*depth)-68479.2 kPa for Leclercville (green gradient). The slopes have a difference of only 0.19% despite the distance and change in tectonic setting.

The very high gradients of some 63 kpa/meter are internally consistent gradients that do not anchor to ground level. Our study has shown that these gradients are systematically anchored to a geochemically well-defined depth which is the intersection between the lithostatic gradient and the depth of the overpressure domain, the latter is easily identified by the Ethane or propane isotope reversal or by the butane ratio (iC4/nC4) reversal (Chatellier et al. 2013.) Reservoir pressure gradients were calculated using the hydrostatic pressure at the depth of the isotope reversal and the reservoir pressure values from down-hole recorders in Saint David and in Saint Edouard (7 km away from Leclercville).

The reservoir pressure gradients calculated for Saint David and Saint Edouard (replacement for Leclercville as we had a data recording failure on the Leclercville down-hole monitor) are respectively (26.59*depth) -21961.3 kpa and (26.23*depth)-24688 kpa. These gradients are anchored to the same reference depth except that the intersection is now on a hydrostatic reference gradient. The slope difference between the two calculated gradients is only 1.38% despite the large distance between these wells. Reliable, repeatable and useful reservoir and fracture gradients could thus be calculated in the overpressure dry gas domain.

A second case study focusing on the Montney Shale shows the existence of “intrinsic gradients” (not linked to ground level) at a regional scale, the examples chosen for the fracture gradient are taken using the public domain database and has focused on the first fracture from horizontal wells in two separate areas. Very good parallelism between gradients is observed between trends within each of the two studied areas but the trends have different slopes between the two areas (Figure 2), are presently interpreted as structural style, and block tilting geometries.

To complement the Montney shale study with an example of reservoir pressure gradients, DFIT data obtained from the toe of horizontal wells in the Farrell Creek Altares Field was used. Whereas the reservoir pressure data would not adequately contour on maps even when focusing on single horizons, the data was extremely well organized on a depth plot and each of the newly defined gradients were geographically constrained (Figure 3). A single fault direction can be inferred from the analysis and can be substantiated by the existence of fault controlled surficial features such as long linear river stretches and topographical cliffs that controlled some of the pad or access road placement. Note that not one single DFIT data point for the area mentioned has been filtered; the depth graph honors all of the data acquired.

The last case study deals with a series of Devonian shale from North East British Columbia. The tectonic history of the area is complex and reservoir pressure maps generated from the DFIT data do not make sense even when restricted to any particular shale. However, several gradients are well defined on a depth plot and each of these gradients comprise data from wells geographically well constrained (Figure 4).

Conclusions

Prediction of reservoir pressure and fracture pressure can be improved by using a combined 3-D analysis of the pressure data; the gradients may seem less useful at first. However, the newly proposed gradient approach has delivered high precision predictability for the first fracture of horizontal wells in Quebec compared to the expected fracture pressure calculated using the traditional fracture gradient approach.

Acknowledgments

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Reference Cited

Chatellier, Jean-Yves, Pawel Flek, Marianne Molgat, Irene Anderson, Kevin Ferworn, Nabila Lazreg, Larsen Ko, and Steve Ko, 2013, Overpressure in Shale Gas: When Geochemistry and Reservoir Engineering Data Meet and Agree: in Jean-Yves Chatellier and Daniel M. Jarvie (eds), Critical Assessment of Shale Resource Plays, AAPG Memoir 103, p. 45-70.

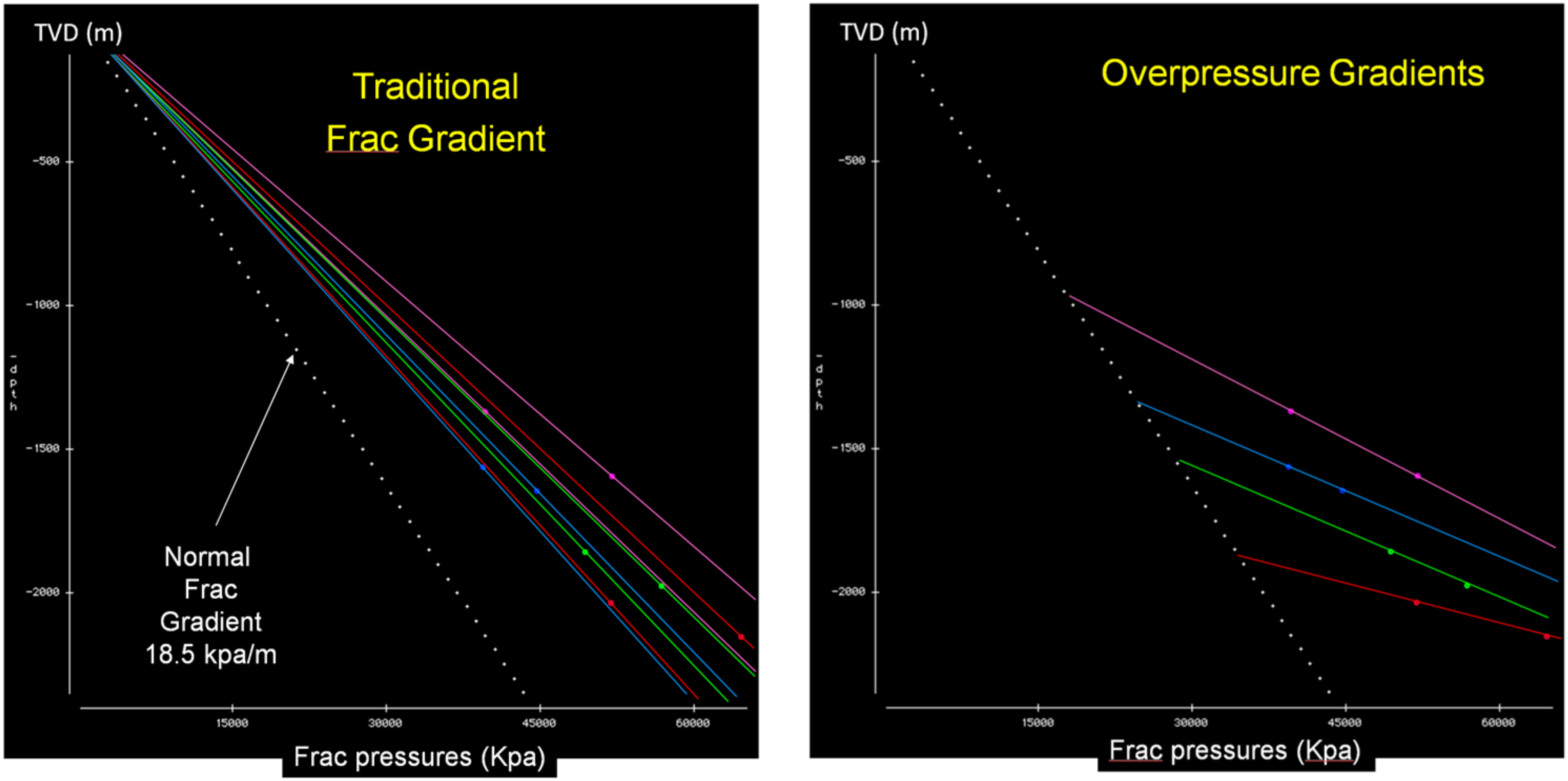

Figure 1. Fracture gradients calculated from fracture pressures from neighboring measurements display well organized patterns – note that the blue and green trends are from areas 150 km apart and from very different structural settings (Ordovician Utica shale, Quebec).

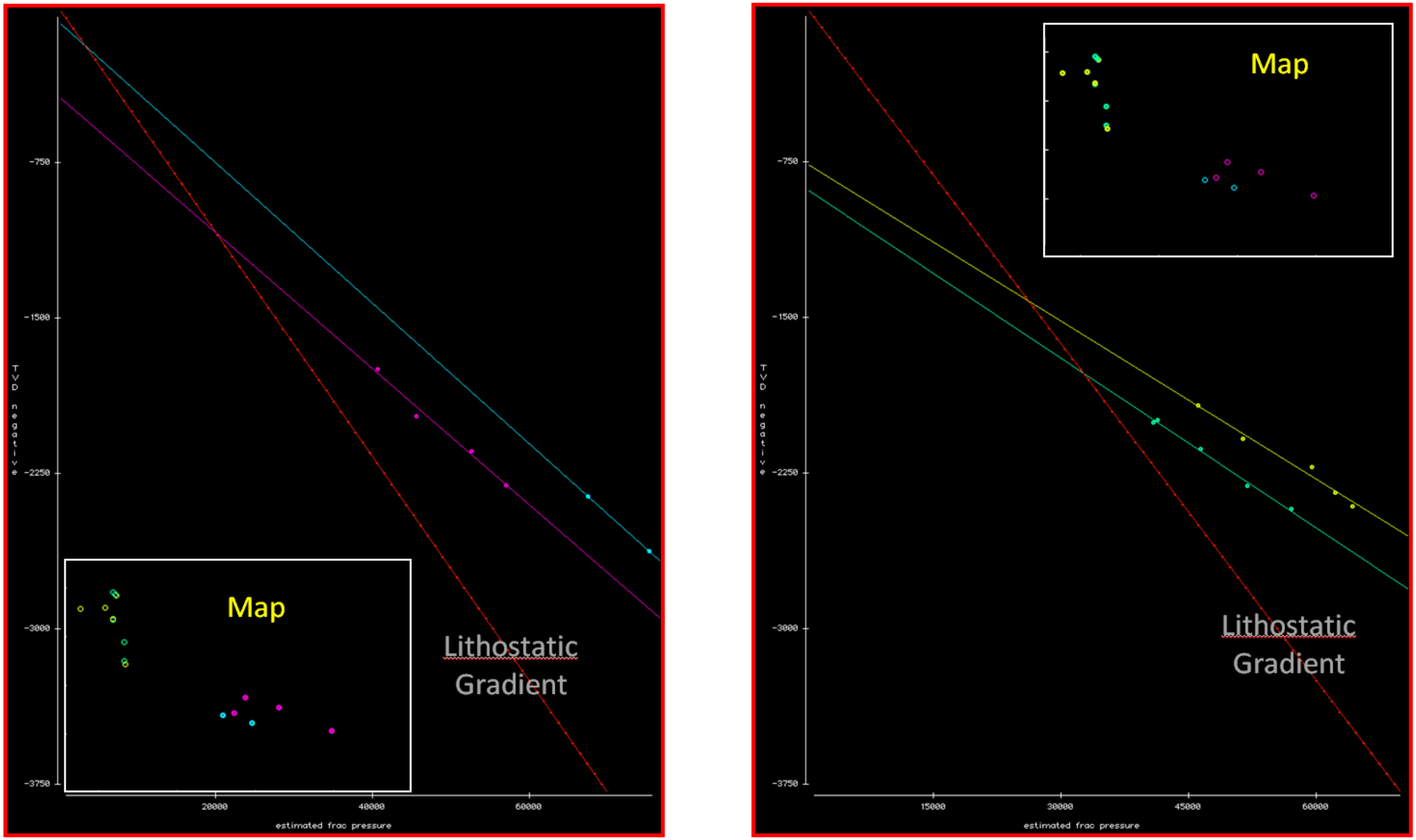

Figure 2. Fracture gradients from the Montney shale using data from first stage fracture only and from two geographically distinct areas (two different plots) – note that the gradients are geographically specific.

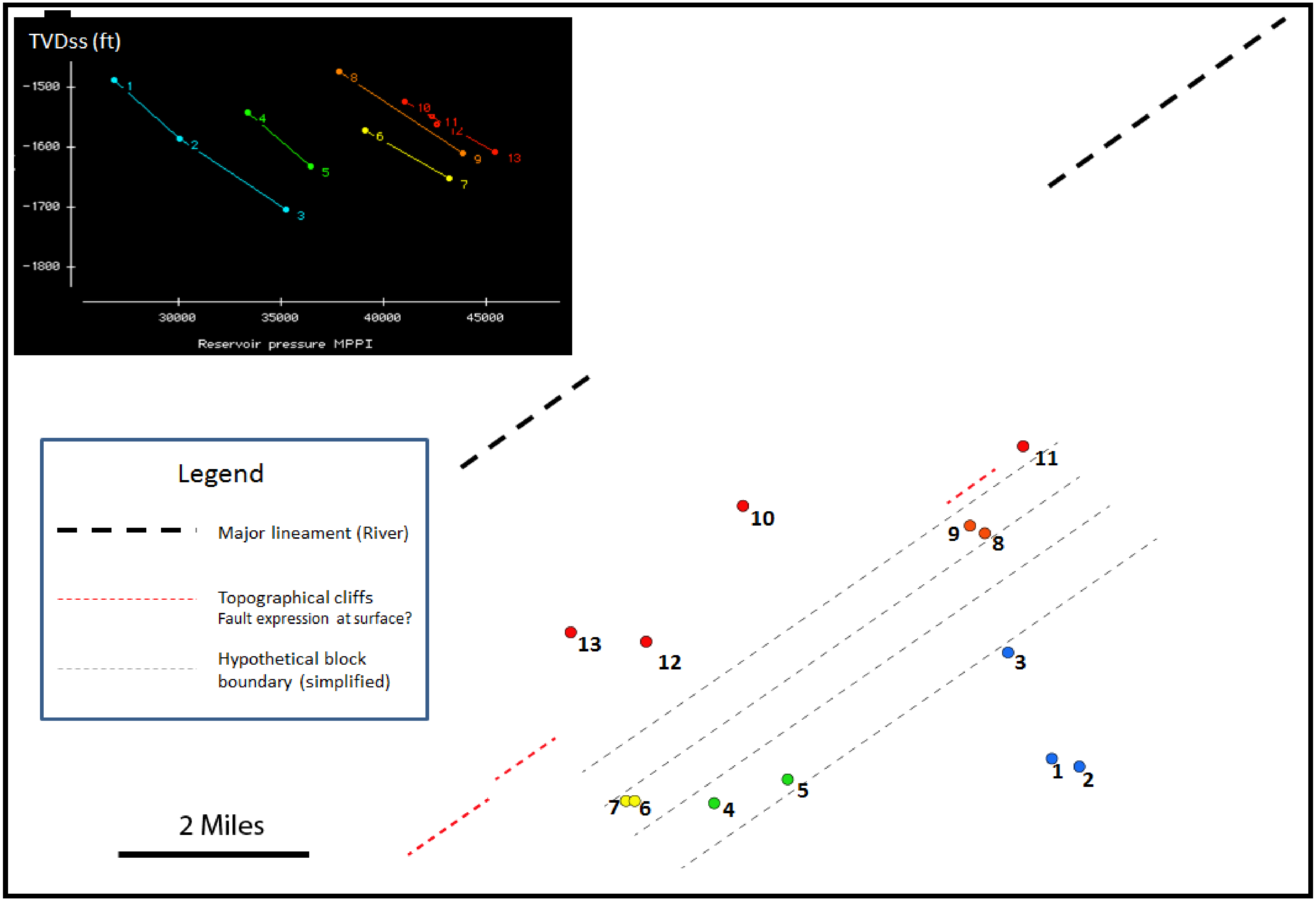

Figure 3. Montney shale DFIT pore pressure – depth plots showing well-defined gradients that are parallel to each other, they are isolated in elongated strips on the map in an orientation reminiscent of the structurally controlled cliffs and straight portions of the local river.

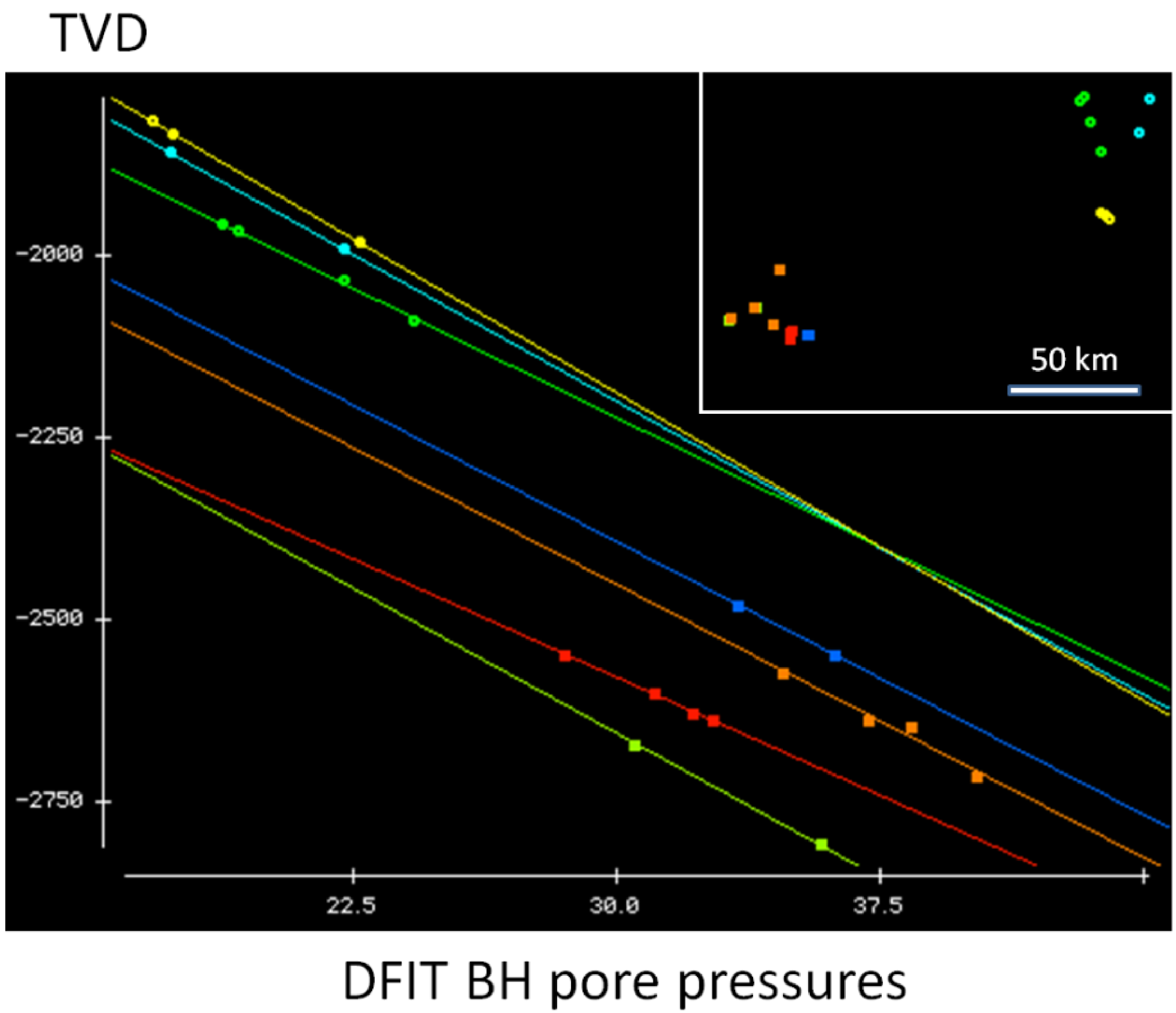

Figure 4. DFIT from various prospective shales in two neighboring basins; all of the gradients are sub-parallel to each other and geographically well confined.