An Integrated Workflow for Shale Gas in the Western Canadian Sedimentary Basin: Surface Seismic to Stimulation*

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Abstract

In lockstep with increased North American and global shale gas activity over the last decade there have been advances in technology and operational efficiency, primarily in completion and stimulation engineering. More recently there have also been advances in geological and geophysical characterization of these 'resource plays'. Currently, there is much interest in integrated geological, petrophysical, geomechanical and geophysical workflows for shale gas characterization, with different degrees of scientific sophistication evident amongst different operator and service companies.

In this paper we present a case study from an active shale gas play in the Triassic age Montney Formation, Western Canada, which integrates surface seismic amplitude and elastic property volumes with petrophysical data and micro-seismic monitoring results. The integration of reflection seismic data and appropriate attributes brings more geophysical rigor to a traditionally engineering dominated play type.

Introduction

For the geophysicist, mapping major structures and looking for closure becomes less imperative in tight gas and shale gas plays, where in-situ permeabilities are typically sufficiently low that there is no mobile gas. Geophysics can, however, provide significant uplift in reservoir characterization studies of shale gas. The heterogeneity in shale composition subtly alters its seismic response. Experience and modeling results suggest that stack data is minimally sensitive to the heterogeneity, and to provide maximum uplift pre-stack simultaneous AVO inversion for elastic parameters (Vp/Vs ratio, Poisson's ratio and/or Lame parameters Lambda-Rho and Mu-Rho) is necessary. Geophysicists can also help identify subtle structural trends using seismic attributes sensitive to discontinuities and reflector geometry.

Integrated workflows for shale gas reservoirs have received increased attention following the step changes achieved in operational efficiency over the last decade. Du et al. (2009) presented such a workflow for the Barnett Shale play in Texas; however, a crucial link missing in their workflow was analysis and inversion of pre-stack seismic data. In Western Canada an increasing number of major leaseholders exploring and exploiting the Horn River Basin and Montney Formation are utilizing pre-stack amplitude variation with offset (AVO) inversion data to assist in well placement and field development planning.

It is known from well log analysis that the ratio of compressional to shear sonic velocities (Vp/Vs) is a good indicator of sand-shale or quartz-clay ratios in shales and/or tight siltstones (Figure 1). Qualitatively and empirically, an increased sand-shale ratio correlates to increased porosity, lower breakdown pressures for stimulation, and enhanced relative production (Miller et al., 2007). AVO inversion of 3D seismic data allows for the creation of Vp/Vs volumes and maps of the reservoir interval that can be utilized for exploration and field development, which reflect the reservoir quality based broadly on the sand-shale ratio. Inversion data and other attributes derived from pre- or post-stack seismic data require corroboration from independent sources to confirm its utility. Data that can provide such calibration for these seismic based properties includes log data, micro-imaging data, production log data, production data, and micro-seismic monitoring data.

Geological Setting

The Triassic Montney Formation of the Western Canadian Sedimentary Basin (WCSB) is a marine clastic rock deposited in a continental margin basin. The Formation comprises fine-grained (silt to shale) rocks with morphologically controlled interbedded sandstones. Carbonate content varies and can be locally abundant in similar proportions to quartz content. The Upper Montney comprises stacked sections of distal shoreface to shelf siltstones up to 150 m thick with laminae of pyrite bearing organic material (Hayes, 2009). Broadly, grainsize decreases to the west and north from western Alberta into eastern British Columbia.

Petrophysical and Geological Data

A total of 8 wells with density and sonic logs that penetrate the Lower Doig and Upper Montney formations were utilized in this study. The zone of interest in this area averages around 40 to 50 metres in thickness. Analysis of these wells through the zone of interest (Figure 2) illustrates the varying rock quality and thickness. The porosity-height values for the combined interval from the

Lower Doig to the Base Upper Montney and for the Upper Montney only are included in Figure 2; note that only for Well A does the Lower Doig make a substantial contribution to the porosity-height.

The petrophysical model utilized to convert standard log suites (i.e., triple-combo data) to the mineral models illustrated in Figure 2 is calibrated with advanced log data (such as natural gamma-ray spectroscopy and elemental capture spectroscopy) and core data. Core data is critical to calibrate petrophysical data and to provide quantitative measures of mechanical properties, which are needed to model hydraulic fracture propagation. Image log data can be utilized to provide estimates of natural fracture density and aperture, properties that can be difficult to measure in extracted core due to the changes in confining pressure associated with recovery.

Reservoir Geophysics and Seismic Inversion

Using the ISIS simultaneous inversion algorithm four angle stacks (0-12°, 12-18°, 18-25°, and 25-30°) were inverted for acoustic impedance, Vp/Vs ratio, and density. The angle ranges for the four angle stacks were selected to optimize the fold in each angle stack over the zone of interest. Results of the inversion for acoustic impedance and Vp/Vs ratio are illustrated in Figure 3, where they are compared to well log data from that location. These results confirm that the inversion is capable of predicting these properties. To test the hypotheses that the Vp/Vs ratio is a good indicator of reservoir quality, horizon or stratal slices extracted through the Vp/Vs ratio volume are compared to porosity-height maps (Figure 4).

Stimulation and Monitoring

Micro-seismic data are available in the study area from a horizontal well with an ~1100 metre lateral section in the north of the study area (Figure 4). The well was stimulated in five stages using a Packers Plus open-hole completion and monitored in a vertical well close to the centre and slightly to the north of the lateral section. The micro-seismic data recorded for stages 1 and 2 varies markedly from that recorded for stages 4 and 5 (Figure 5). No data were recorded for stage 3 as no fracture could be initiated, which is assumed to be a result of either a failure with the completion mechanism (although there was no conclusive evidence of this) or of changes in reservoir properties that increased the break-down pressure of the formation.

Figure 5 illustrates that relatively few micro-seismic events are recorded from stages 1 and 2 relative to stages 4 and 5, and additionally the distribution of the points is also markedly different. The concentration of micro-seismic events measured during pumping stages 1 and 2 to the north of the lateral suggest an asymmetric fracture propagation that has failed to create a complex, interconnected swarm of induced fractures from which to produce. The events from stage 2 also concentrate in the same area as stage 1, which indicates that new reservoir is not being stimulated during stage 2. In contrast, a greater number of events, which on average have a larger amplitude, were measured during stages 4 and 5. The alignment of events from stages 4 and 5 is also much closer to the expected orientation based on knowledge of regional stresses.

The stimulation stages were designed to be approximately equivalent in terms of total fluids and proppant pumped, the assumption being that induced fracture networks should be very similar for each stage. Although it is certainly possible that stimulation design and implementation practice, and not reservoir related properties, could explain the observations regarding the micro-seismic event patterns discussed above, we consider that changes in formation properties underpin the variable micro-seismic response. The increased Vp/Vs ratio indicated by the AVO results around the stage 3 frac port suggests that a higher breakdown pressure would be expected due to increased clay mineral content, and this may explain the failure to initiate a fracture for this stage. Stages 4 and 5 are located in a more extensive area of lower Vp/Vs ratio (Figure 5), which explains, at least in part, the improved stimulation results.

The stimulation detailed in this case study utilized gelled frac oil, which is perceived by some reservoir engineers to result in less damage to the formation as laboratory tests on core suggest the recovered permeability is greater for oil based fluids. Theory and field results, however, indicate that the differential is short-lived and although the flow back of stimulation fluids may occur slightly more rapidly, the overall producibility of the reservoir is not improved by more expensive oil based fluids relative to slickwater or foam. The stimulation plan for this well called for each stage to pump ~50T of proppant; however, stages 4 and 5 ultimately pumped greater volumes due to the failure to place any proppant into the formation during stage 3.

Conclusions

Geophysics and specifically AVO inversion can bring significant uplift to tight gas and shale gas reservoir characterization studies. Variations in Vp/Vs ratio can be used to investigate and understand heterogeneity in reservoirs related to facies variations and changes in grain size and mineralogy. The AVO results presented here are correlated to both petrophysical modeling results from a number of wells and micro-seismic monitoring data from a single well. The continuation of the workflow presented here is to integrate production data and decline curve analysis with volumetrics predicted from reservoir models based on log data at well locations and AVO inversion data between the wells.

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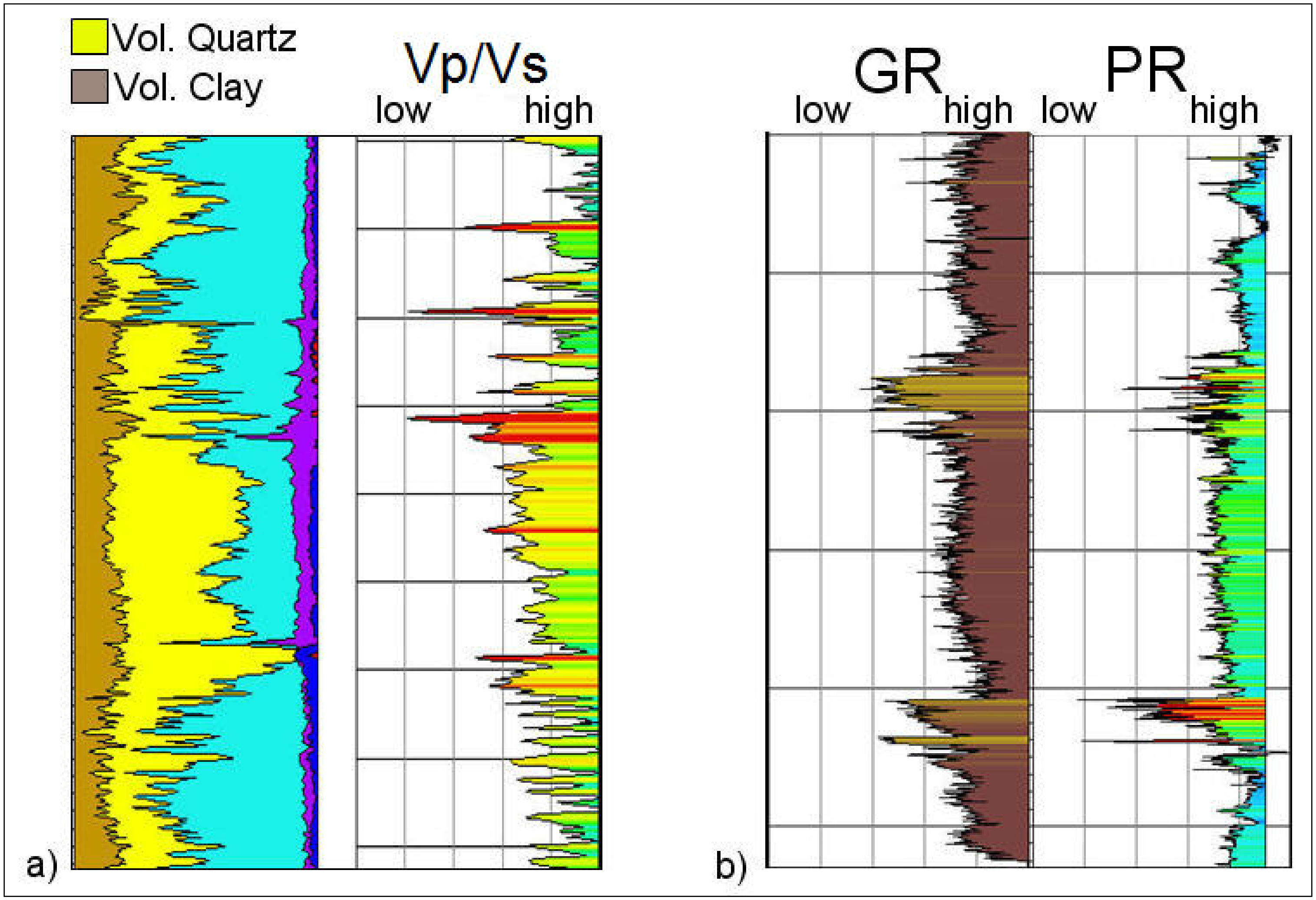

Figure 1: Log data that illustrate the correlation between low Vp/Vs ratio and/or Poisson's Ratio (PR) with increased sand-shale content, from a) a Western Canadian shale gas play, and b) a South Texas tight gas play where low gamma ray (GR) is taken as a proxy for increased quartz content.

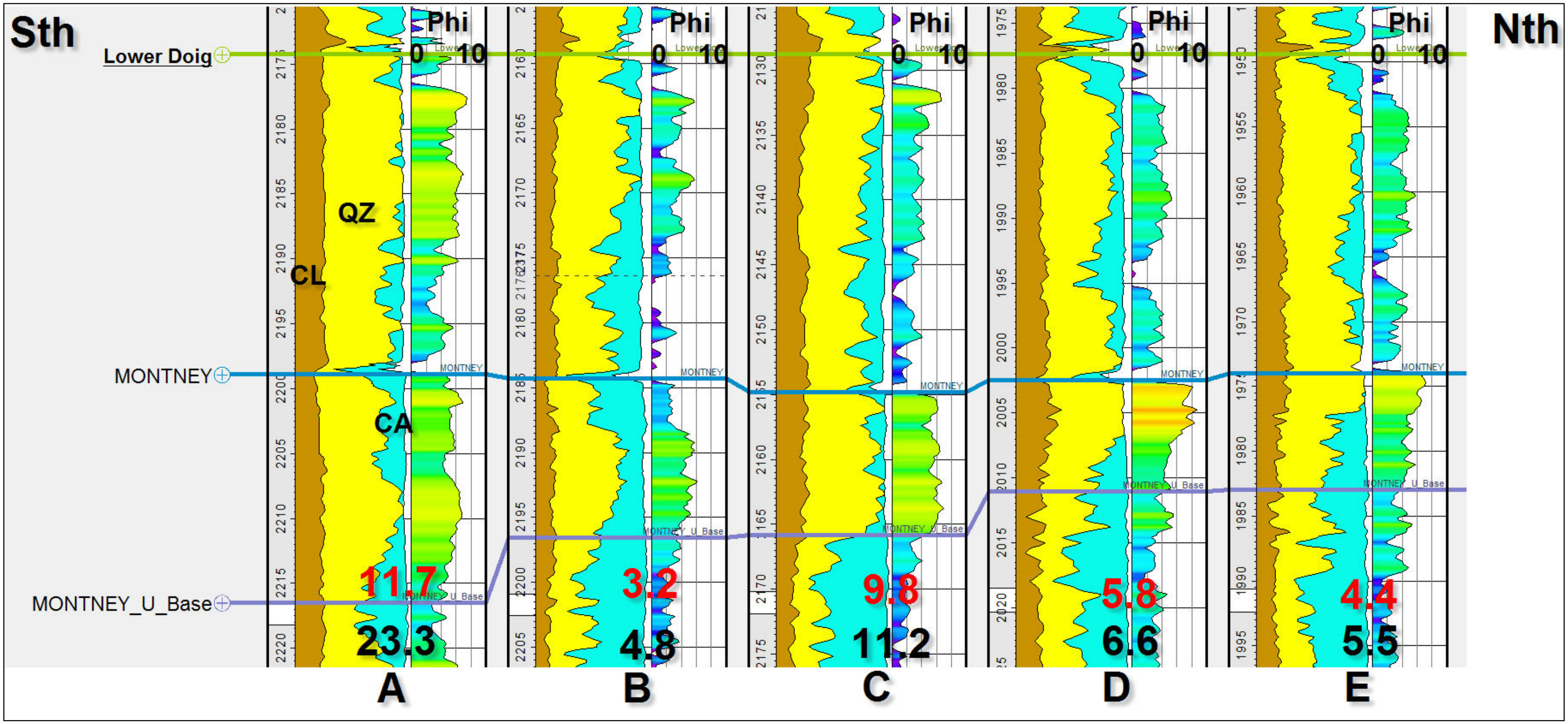

Figure 2. A north-south section through five wells over the zone of interest. Bold numbers at the bottom of each well panel indicate porosity-height: red values for the Upper Montney only and black for the combined Lower Doig and Upper Montney. QZ=Quartz, CL=Clay, CA=Carbonate.

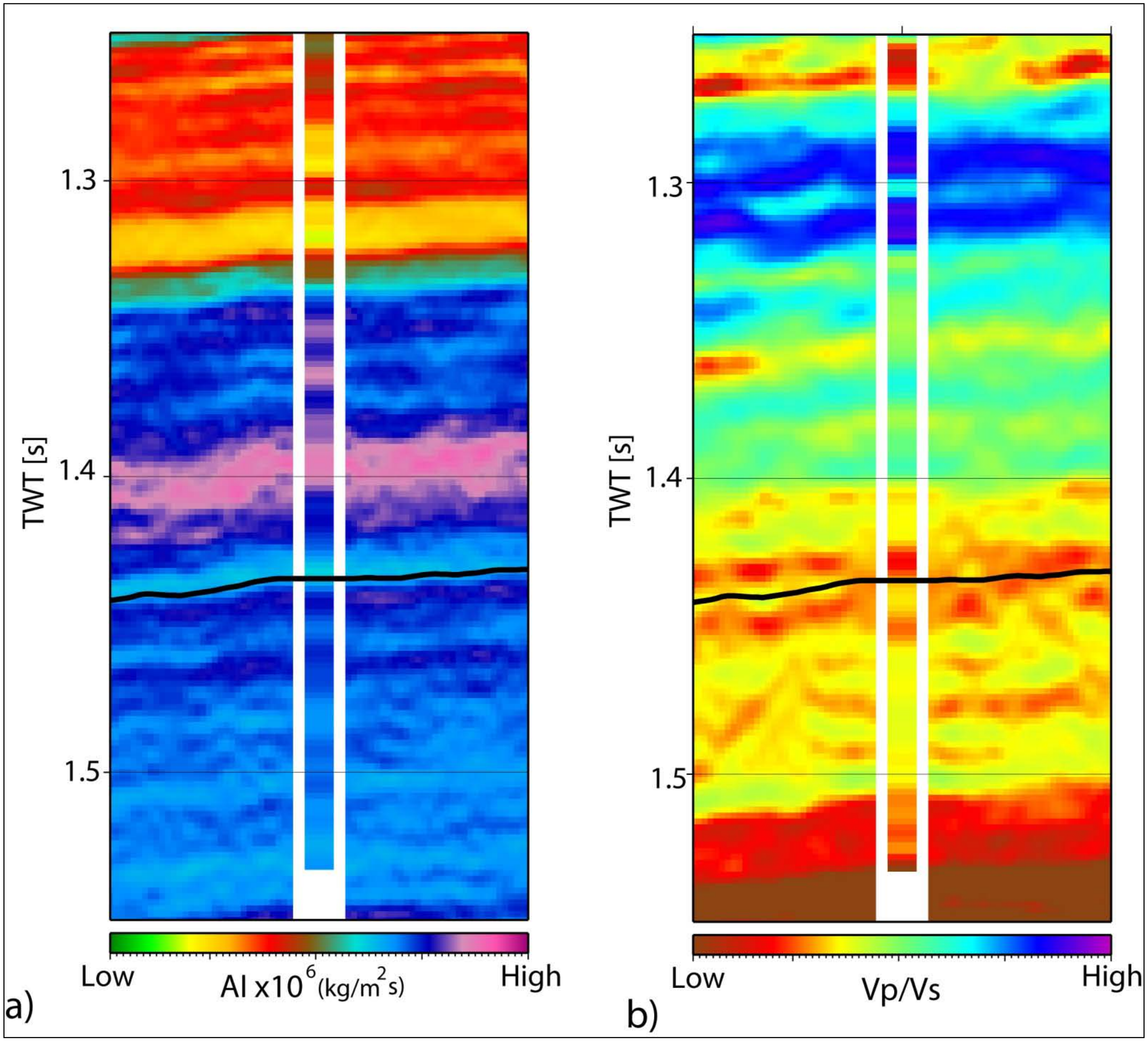

Figure 3: Pseudocolour a) acoustic impedance, and b) Vp/Vs ratio logs inserted into their respective inversion volumes. The zone of interest is illustrated by the bold dark horizon at ~1.425 s TWT.

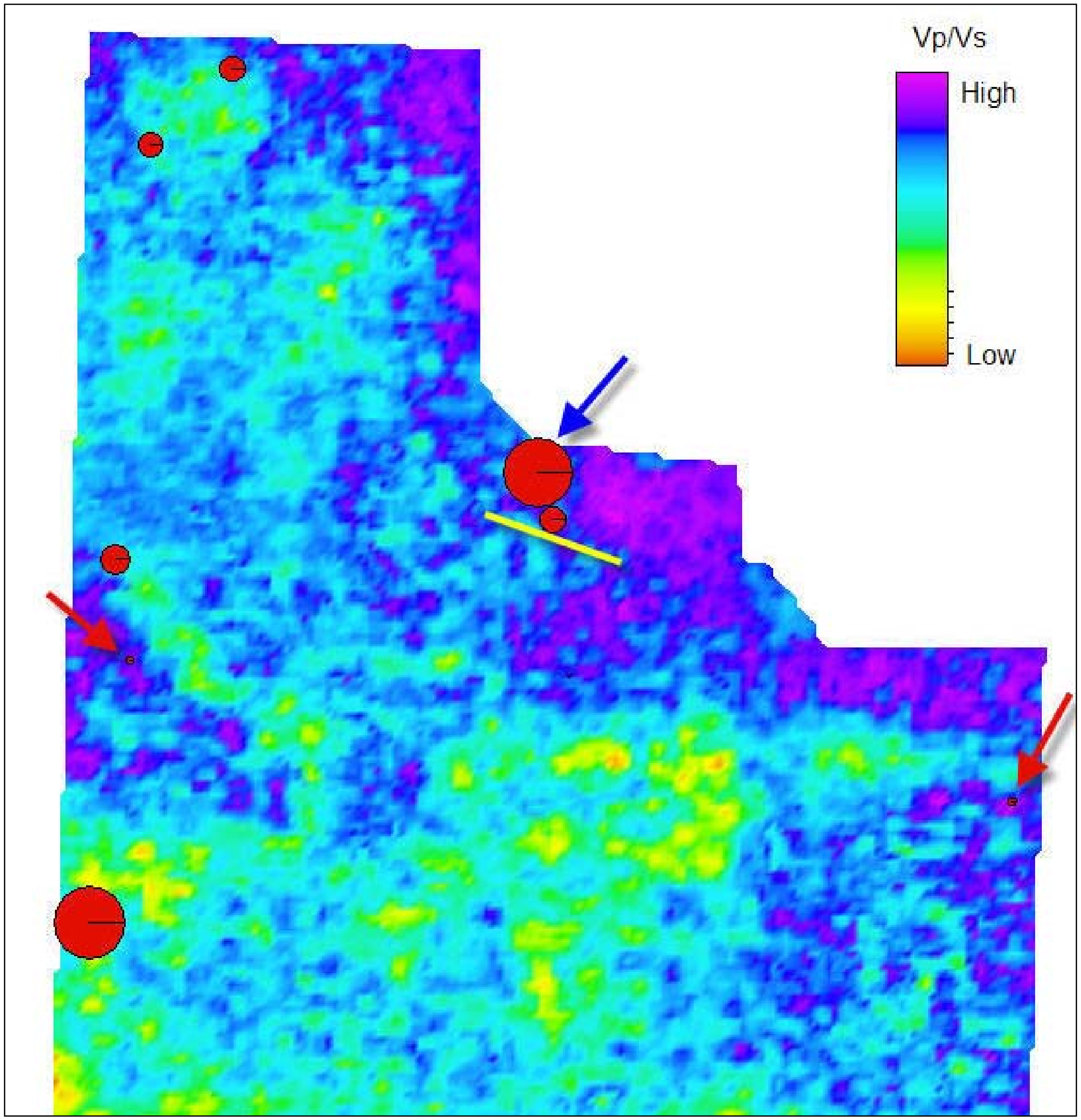

Figure 4: Map of median Vp/Vs ratio and porosity-height from 8 wells through the Lower Doig and Upper Montney. The red arrows highlight wells with very small porosity-height values and correspond in general to areas of higher Vp/Vs ratio. The blue arrow highlights a well with a large porosity-height at the edge of the seismic data where the inversion is adversely affected by decreased fold. The yellow line is the approximate location of a horizontal well where micro-seismic data were recorded.

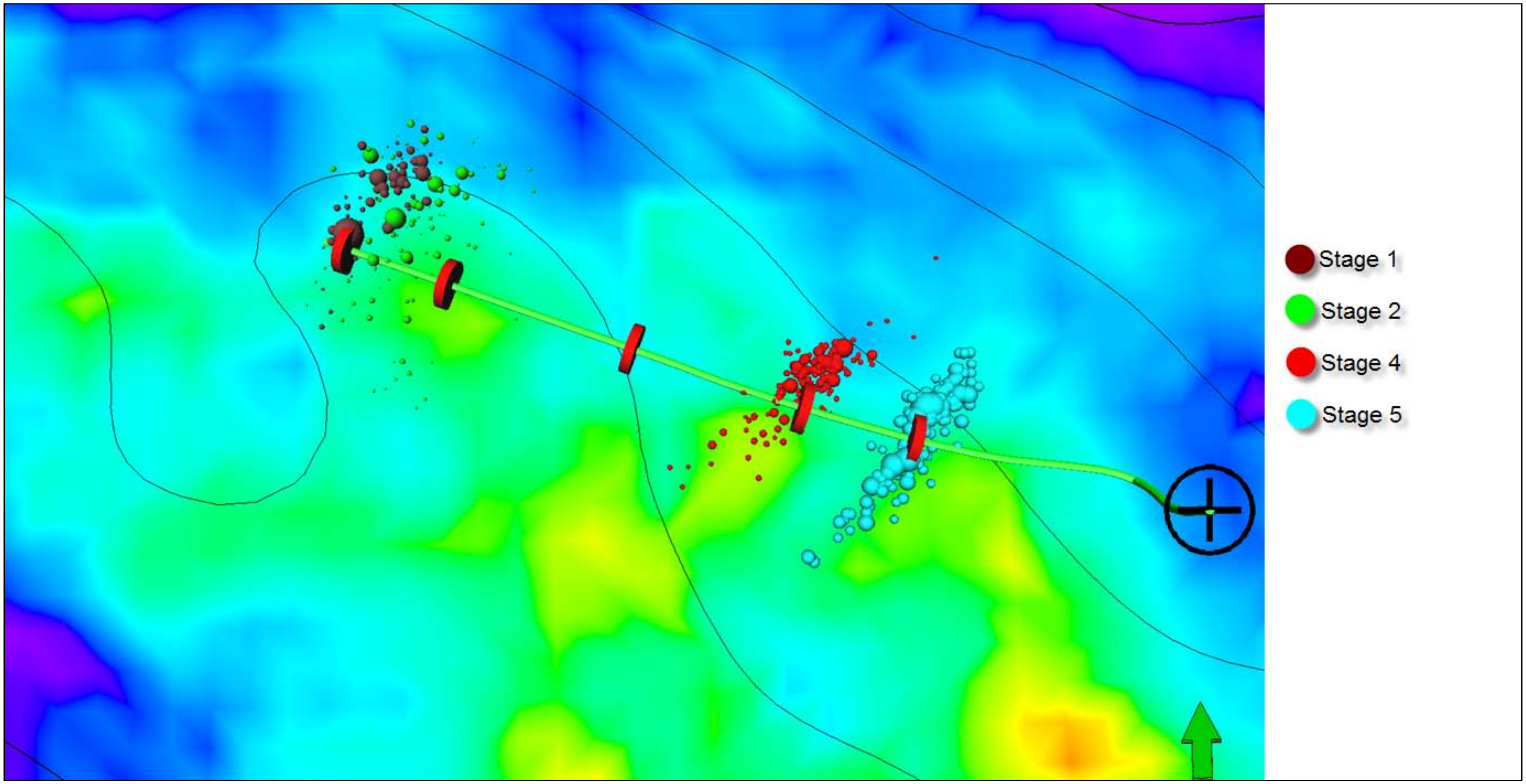

Figure 5. Micro-seismic monitoring data overlain with a Vp/Vs ratio map from AVO inversion. Fracture stimulation ports (frac ports) are located as red disks along the lateral.