

Integrating seismic derived rock properties with horizontal well induced fractures in the Duvernay Formation

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ABSTRACT

The Duvernay formation is a major zone of interest for unconventional oil production. It is the stratigraphic equivalent of the lower Leduc, and is commonly believed to be the source rock for most of the Devonian age production in Alberta. Microseismic Techniques have been used to evaluate the efficiency of hydraulic fracture stimulations. The Duvernay has been drilled horizontally, and hydraulic fracturing has been deployed to enhance oil production. Microseismic surveys have been carried out in a number of areas to determine fracture length, height, and general efficiency of the completion. In this paper, a method of using seismic attributes is proposed to optimize drilling programs. Seismically derived geological attributes can be used in the well placement and fracture stimulation intervals to optimize recovery. To date, most Duvernay drilling patterns have been laid out in a uniform pattern, orthogonal to the regional stress, or parallel to the boundaries of the oil lease. Localized geological rock properties are used in the initial planning stage, but not in well placement; a common assumption is the rock is uniform, and fractures will occur governed by the regional stress regime. Seismic derived attributes can provide valuable information with respect to well placement, and what facies are favorable to hydraulic fracture stimulation, fracture length, and direction. Seismic attributes can and should be used to direct horizontal well placement, as well as completion programs. Some completions perform well, whilst others fail. Fracture patterns and induced seismicity may preferentially follow geologic depositional patterns; this should be considered in well planning.

INTRODUCTION

The Duvernay Formation (equivalent to the Muskwa Formation) is a major resource play in the Western Canadian Sedimentary Basin. With the development of horizontal drilling, and multi stage hydraulic fracturing, the Duvernay is a desired exploration target. The Duvernay is commonly believed to be the source rock for the Leduc reef, Nisku, and Wabamun carbonate plays. The rock type varies in accordance with its position in the basin. Near Leduc buildups, there is reef debris, away from the reef it is a carbonate bank. It is rich in organic matter, and depending where it is situated in the basin, produces gas, natural gas liquids, or oil. Vertical wells and cores are evaluated for rock properties and total organic hydrocarbon content and evaluated for suitability for further development. Common production practice has been to drill a pattern of horizontal wells, and hydraulically fracture these wells in a number of stages. The lithology is often assumed to be uniform, affected only by the overall stress regime. Microseismic surveys are often performed to evaluate the effectiveness of fracturing the Duvernay. The microseismic data gives information as to the depth, penetration and direction of the induced fracture, however it is recorded during the fracture stimulation, and analyzed after the completion is finished. Once the completion program has commenced, it is too late to significantly change the completion program based on the Microseismic results. Micro seismic, used in this manner can aid the program by defining fracture lengths, height and efficiency of a

zone. Microseismic in itself cannot explain why a certain program worked and another did not. If a horizontal program works in one area, the same program may not work in nearby areas due to variations in geology. Seismic-derived reservoir characteristic is valuable in designing future drilling completion programs.

In the forward planning of a horizontal program data such as well logs, core and seismic data can provide valuable information on horizontal well placement and fracture positioning. Seismic data can provide lithologic parameters on the Duvernay such as Young's Modulus, Poisson's ratio, brittleness, and other rock parameters. If the more brittle rocks are more susceptible to fracturing, then it follows that seismic data providing these data would provide valuable information in designing drilling and completion programs.

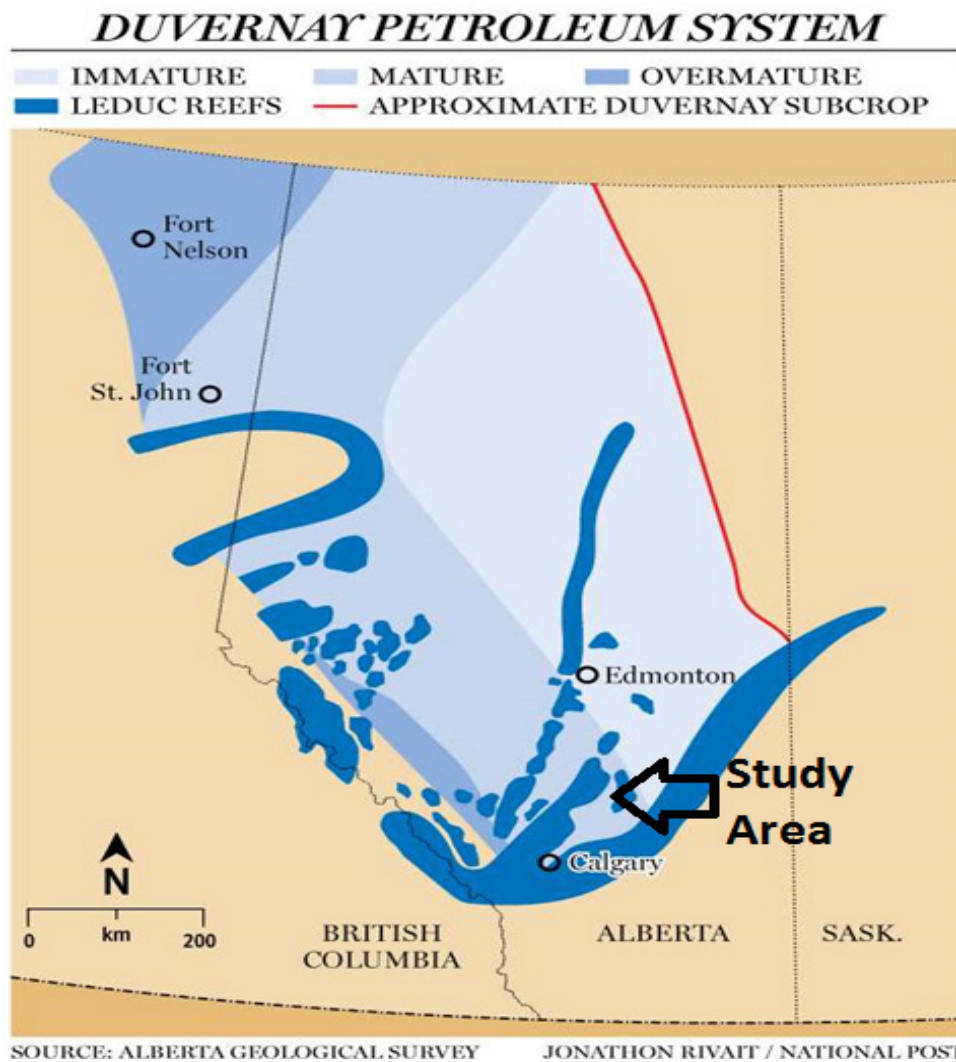


FIG 1. Duvernay source maturity map, the Rangeland study area is highlighted. Note, the study area falls within the mature oil window, Map Courtesy Alberta Geological Survey.

Microseismic work to date

Wuesfield et al (2012) published a paper regarding the current state of microseismic monitoring and stimulation effectiveness. A lot of work and research has gone into how and why fractures propagate in certain directions, how far and how high they go. The basic model is that fractures develop along a single azimuth, controlled by regional stress. In reality, fractures frequently develop asymmetrically, and are far more complicated than predicted by the original assumptions and models. Asymmetry in fracture growth is attributed to structure, regional stress, pre existing fractures, and faults, but rarely to the depositional facies.

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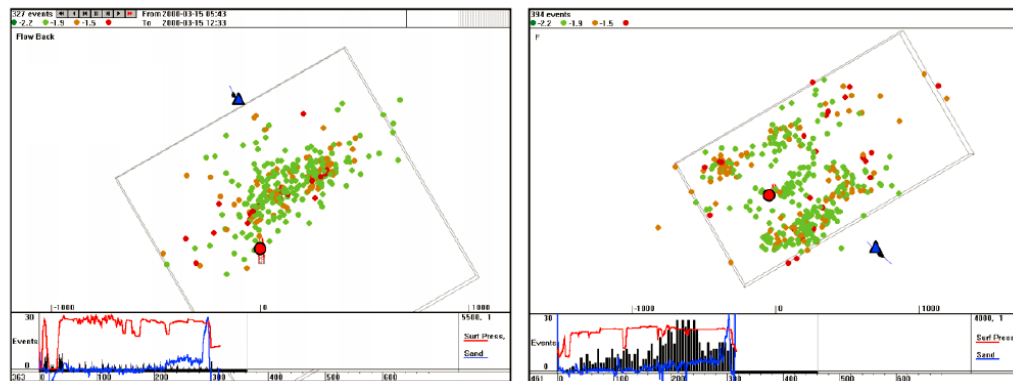
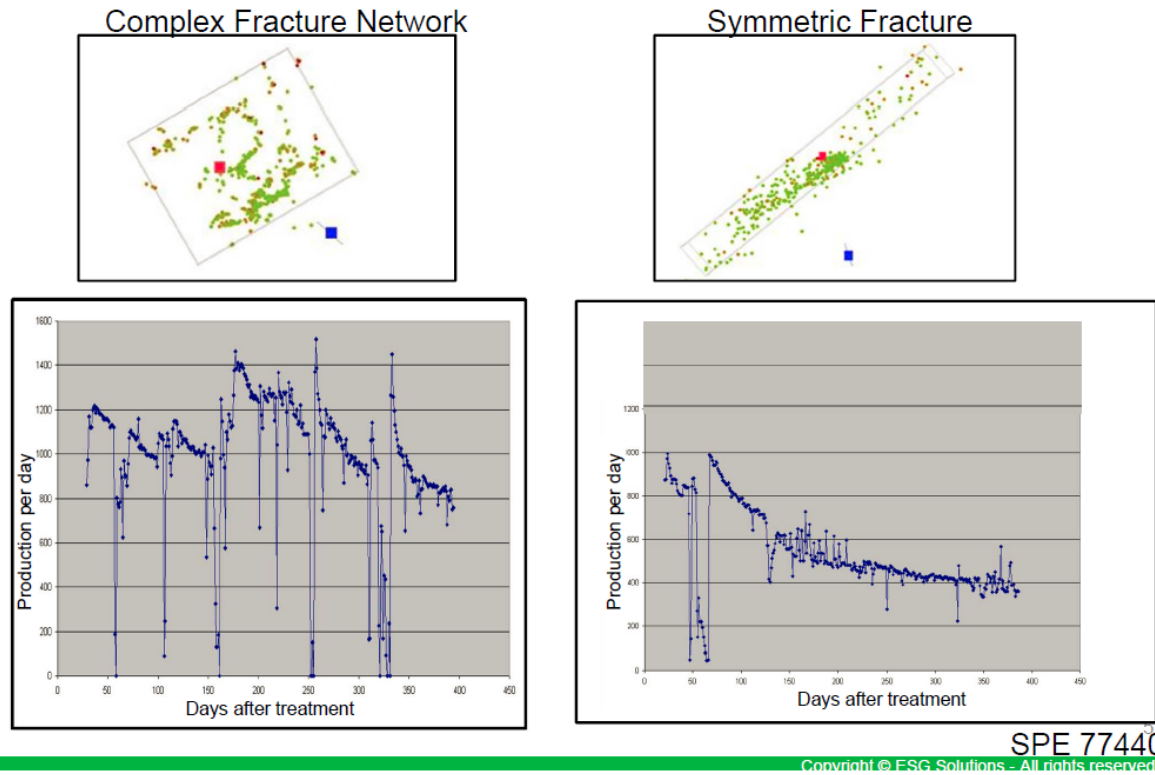


FIG. 2 Courtesy of Maxwell 2002, this is an example from the Barnett shale in Texas. The different fracture patterns observed on the Barnett Shale are often assumed to be pre-existing fractures. The variance in fracture patterns could also be defined by lithology. Soft, less brittle rocks would tend to deform, and not fracture. This formation is commonly considered to be homogeneous.

Wuesfield goes to further state fracture height, width, length, orientation and growth vary from formation to formation, and within each formation. Seismic Moment tensor inversion, desecrate fracture analysis, enhanced fluid flow is all discussed. Pre existing structures, fractures, and stress regimes are also mentioned.

Wayne Camp et. al., (2013) proposed a methodology using prestack seismic rock attributes in conjunction with core and well logs could be helpful in developing unconventional plays. He proposed that data such as well logs, cores, prestack seismic inversions should be included in the evaluations of unconventional resource plays, but no actual case studies were provided. A method of using prestack seismic inversion is discussed here, and how it would be deployed.

Role of Structure in Production



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FIG 3. Courtesy of esg Solutions The variance in recorded microseismic events in this example are attributed to structure.

To date, many assumptions are made with respect to how fractures propagate, the key ones being reservoir homogeneity. The difficulty with this assumption is that reservoirs are almost never homogenous. Observations of modern day analogues such as the comparison of the Duvernay to the Great Barrier Reef demonstrate that this is not correct.

Bowman, 2011, makes the following statement:

- *Early assumptions:*
 - *Rock is a homogeneous mass with no pre-existing structure*
 - *Hydraulic stimulation nucleates fractures which propagate through the rock*
 - *Fractures grow asymmetrically about the treatment zone*
 - *Fractures are vertical to sub-vertical*
- *Introduction of Microseismic monitoring in ~2000 challenged a number of*

these assumptions

- *Fractures do not always grow symmetrically*
- *Changes in treatment programs and completion styles can affect fracture*

Growth

- *Not all fractures are vertical*
- *Pre-existing structures such as natural fractures exist in many geological formations.*

What is missing in this analysis is the depositional pattern and lithology of the reservoir. Less brittle rocks will tend to deform and not fracture, more brittle rocks will fracture more often. Geological factors such as brittleness based on depositional patterns and hydrocarbon generation could be as much a factor as structure. Instead of following pre existing fractures and faults, it is likely the fracture pattern is following geological features in addition to the stress gradient. The hydraulic fracture would tend to follow the regional gradient if the reservoir was homogeneous, but microseismic surveys suggests a more complex fracture pattern.

Another consideration is that if the measured fracture length is recorded to be 100 meters (for argument sake) at one location in a given formation, assuming it will be 100 meters in all the nearby wells may not be accurate. If in subsequent wells the effective length changes, and even varies in length along the well bore, the homogeneous reservoir assumption may not be valid.

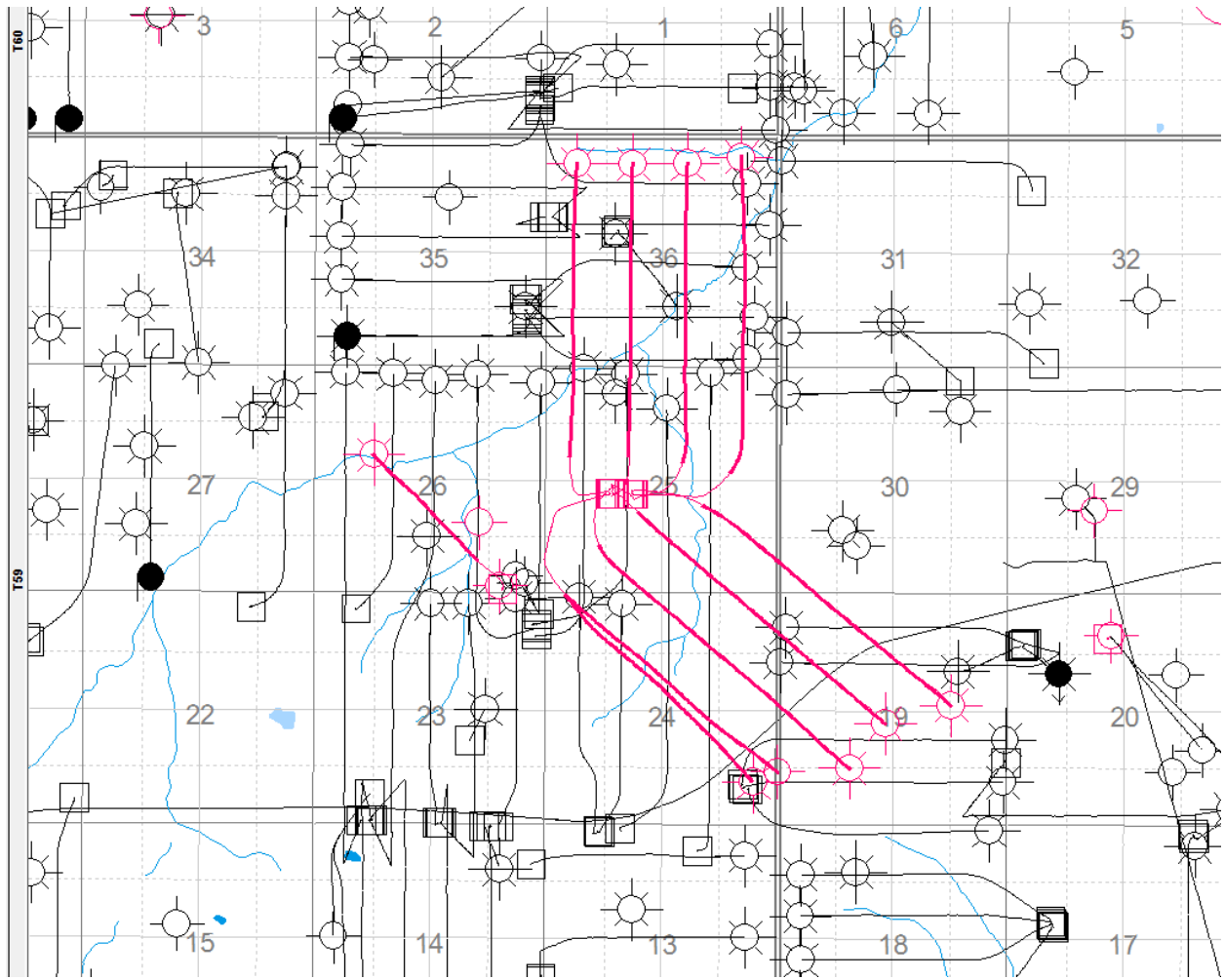


FIG 4, Duvernay horizontal development, T59 R20 W5, Kaybob, 2014 drilling program. This pattern is typical of Duvernay development to date. Well alignment is either orthogonal to the regional stress, or aligned to the land ownership. Duvernay horizontals are highlighted in red. (Courtesy Geoscout)

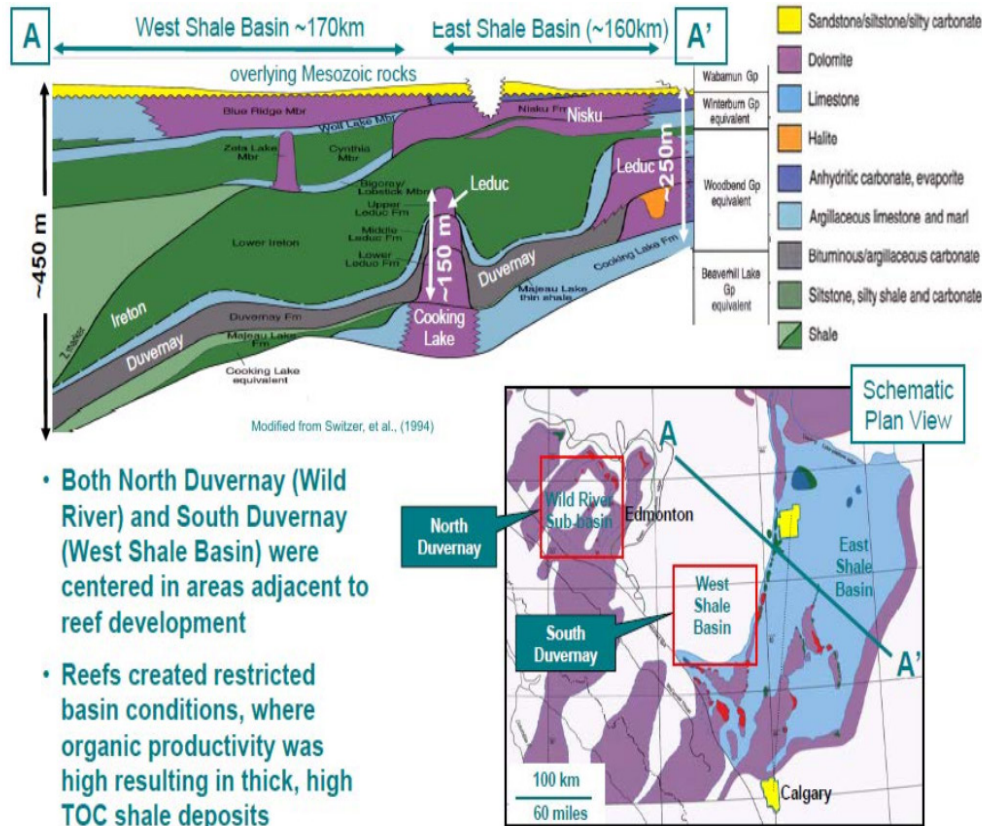
The next two sections will discuss how geological and geophysical derived parameters could be used to explain the distribution of fracture patterns in the Duvernay, and how these parameters can be derived.

Duvernay Geology

The Duvernay is the stratigraphic equivalent of the Leduc formation. The Leduc and Duvernay have received considerable attention from an exploration and development point of view. According to Switzer, the Alberta Geological Survey describes the deposition of the Duvernay as a period of great accumulation of organic carbon. The Duvernay is believed to be the source rocks for most of the Leduc, Nisku, and Wabamun oil pools in Alberta (Alberta Energy Regulator Chapter 12, 2016). Adjacent to Leduc reef complexes, the Duvernay contains a large portion of reef detritus. Further out from the reef, the deposition gradually thins, still remaining rich in organic matter. There is depositional mixing of the Ireton and Duvernay and the lower energy, distal portions of the reef. Low

energy deposition can also occur near the reef in protected low energy areas. This results in silica clay mixing with the Duvernay. The high silica clay content and the high total organic content increase the brittleness of the formation (Scoltanzadeh and Fox 2014).

At the key well tie, the 10-15-038-21 sonic and density curves identified Duvernay interval on seismic. At Duvernay depth, 46 meters of section equates approximately to 25 ms. of isochron thickness.



- Both North Duvernay (Wild River) and South Duvernay (West Shale Basin) were centered in areas adjacent to reef development
- Reefs created restricted basin conditions, where organic productivity was high resulting in thick, high TOC shale deposits

FIG 5. Schematic cross section Leduc, Duvernay, Switzer et al, 1994

Reefs, both modern and ancient, are organic, and grow due to live reef building organisms; they are affected by tides, storms and sea level changes. Based on reef geometry, the deposition changes by energy and source type. During the Devonian the sea level rose, causing the Leduc Reef complex to grow. Reef talus shed off into the off-reef areas and deposited what is now called the Duvernay. The Duvernay is now a highly variable reservoir, with variations in lithology and hydrocarbon content, ranging from reef

detritus, to distal organic rich clays. Hydrocarbon generation occurred as the reef mass was buried from the deposited organic matter. Hydrocarbon generation has changed the rock properties, the high TOC Duvernay has been demonstrated to form a more brittle. (Fox 2015)



FIG 6. Australia great Barrier Reef marine park image, Michaelmas Cay The Great Barrier Reef is considered to be a modern analogue to the Devonian Leduc reef. The areas between the reefs are a modern analogue to Duvernay deposition.

The Great Barrier Reef is considered to be a modern analogue to the Leduc (Lines, Newrik, 2005) The large reef masses are several tens of kilometers across, with a number of outlying smaller pinnacle reefs. Organic rich material is deposited between the reefs. The depositional environment varies enormously from the near reef detritus, to the distal carbonates, all rich in organic matter.

The depositional environment of the Duvernay varies enormously depending on its proximity to the reef. The implications for this in hydrocarbon extraction in the Duvernay is significant. Figure 6 shows a map of the Great Barrier Reef, the inter reef areas are where the modern equivalent of the Duvernay carbonates, organic matter, and silica is deposited.

Significant stratigraphic variations were observed among both lab and log based mechanical properties manifesting the dissimilarities in geomechanical responses of different lithological zones in the study area (e.g., Figure 1). In the case of Young's modulus, strong relations between static and dynamic values measured in the lab were observed. Inconsistencies between the lab and log based data seemed to be related to sampling frequency and the difference between in situ and laboratory conditions (e.g., stress, pore pressure, temperature). Figures 1a and 1b show significant variations in log based dynamic elastic properties (particularly Poisson's ratio) in different zones especially between the Duvernay and

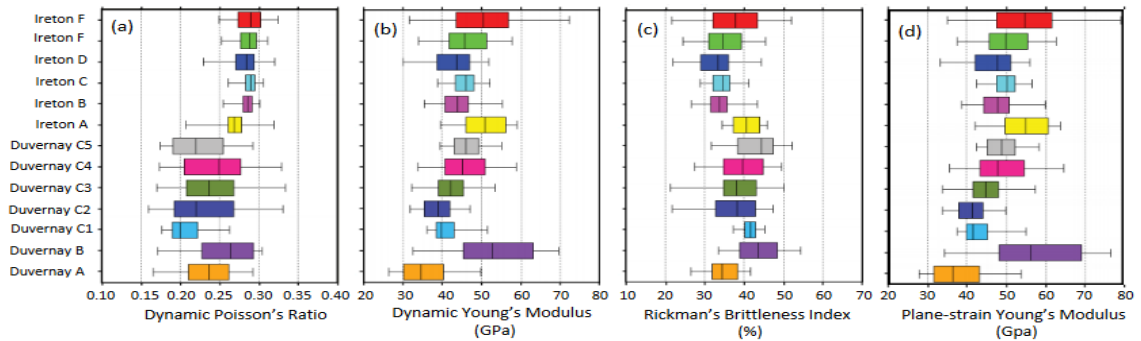


Figure 1. Mechanical properties calculated based on sonic logs for 26 wells for the Duvernay and Ireton formations: (a) dynamic Poisson's ratio, (b) dynamic Young's Modulus, (c) Rickman's brittleness Index, and (d) plane-strain Young's modulus.

FIG 7. Mechanical properties variance in the Ireton and Duvernay. Soltanzadeh and Fox published this in 2014. It shows significant variability in the Duvernay rock properties over their study area in NW Alberta. The brittleness of the Duvernay and Ireton using core.

Soltanzadeh and Fox (2015) published a paper at the 2015 geo convention analyzing the and well derived rock properties.is based on an analysis of 29 wells; they proposed that clay content plays a significant role in the “brittleness” of the Duvernay and Ireton. Brittleness was identified as a key indicator in identifying sweet spots in unconventional plays, areas that are desirable to horizontally drill and complete with hydraulic fracturing.

Dunn and Schmidt gave a paper in the 2012 GeoConvention regarding the Duvernay sedimentology and reservoir characterization. They looked at 302 wells 14 cores, and 2200 square km of seismic data across the basin. Five component lithofacies were identified, in core:(i.) argillaceous mudstones, (ii.) bioturbated limestones, (iii.) organic rich siliceous mudstones(iv.), siliceous organic rich mudstone and (v.) mixed siliceous mudstones. The organic rich mudstones are interpreted as the most basal deposits mixing with the Ireton clay during deposition. Dunn and Schmidt report that a strong correlation exists between quartz content, total organic carbon (TOC) and brittleness. This indicates that the source of the mudstone is biogenic. The high TOC and silica content make this lithofacies quite brittle and highly “fracable.” The higher silica content of the Duvernay

comes from deposition at the more distal, low energy areas. The clays are believed to be Ireton, that has mixed with the Duvernay during low energy sediment deposition.



FIG 8, Great Barrier Reef, public domain photo, West of Hamilton Island, Australia. This aerial photograph shows the reef, an intra reef channel, and off reef in the distance.

Seismic Analysis

The Leduc / Duvernay trend in the Western Canadian Sedimentary basin is extensive (figure 1). In the study area, Pulse Seismic Inc. provided Line 16XBB_B2E59 for analysis (line 16). This area, Rangeland, has producing Leduc reefs, producing Wabamun carbonates, and the potential for Duvernay development. There is a deep, Precambrian direct well tie, as well as a large database of logs and production information (courtesy Geoscout). The Duvernay is the source rock for both the Leduc and Wabamun pools, making this area ideal for seismic attribute analysis. The producing Leduc pool is situated in Two 38 R 20 W4 (figure 9). The pool is a porous Leduc reef buildup. A Wabamun pool exists in Twp. 38 R 21, developed using horizontal wells and acid stimulation. Underlying the entire area is the Duvernay formation., commonly believed to be the source rock for the Devonian.

The seismic line (16) was acquired in February 1982 and is now owned by Pulse Seismic Inc.; it is 1200 % Vibroseis® oriented SW-NE. The deep well tie is at the NW end of the line. The SW end of the Line intersects a producing Wabamun pool. The data was reprocessed to preserve AVO effects, stacks and gathers were output. The stacked data was tied to 10-15-038-21 W4 Using the Precambrian well tie, a time – depth velocity relationship was established. The top and base of the Duvernay were identified, correlated

on the sonic log, and converted to time. A prestack F-K filter was applied to reduce the coherent noise. The CMP gathers were re sorted into angle gathers, with a maximum usable offset of 40°.

The seismic line (16) was correlated and interpreted in the conventional manner on the Seisware interpretation software. The Duvernay interval is approximately 25 ms. (46 meters) thick. Several additional horizons were picked, the critical ones being the top and base of the Duvernay. There were deep seated faults observed on this lie, which were taken into account during the inversion process. At Duvernay depth (~ 1800 meters) and time, the data was good quality, with useable offsets up to 40 degrees for prestack inversion.

The deep Precambrian well did not have a dipole sonic, only Sonic and density. The shear wave was initially estimated using a $V_p/V_s=2$. This was the initial estimate for the shear log model; the model was then perturbed for 10 iterations during the inversion process to obtain a best match to the prestack seismic data. The objective here was to observe relative changes in lithology (V_p/V_s , ρ) across the map area, it was not the absolute values.

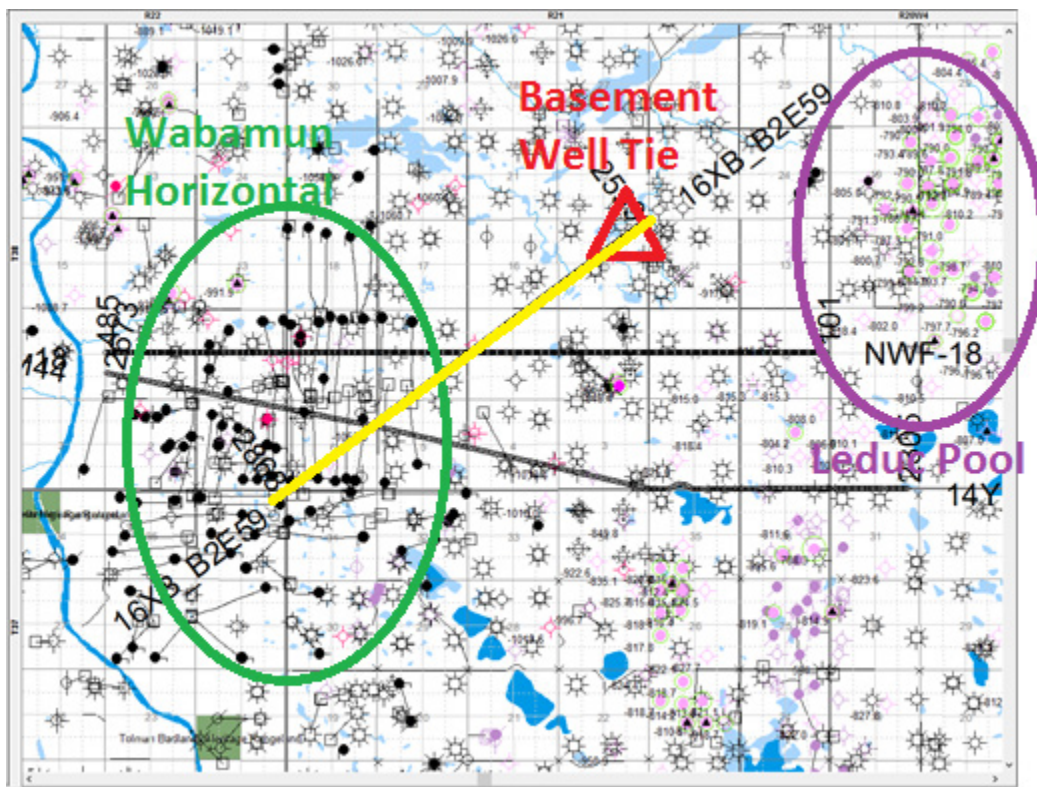


FIG 9. A 2-D seismic line was acquired west of the Leduc reef, with a deep well tie. The seismic line is shown in yellow, the deep well tie is in red, the Leduc pool is in purple; the Wabamun pool is circled in green. This area may be prospective for future Duvernay development.

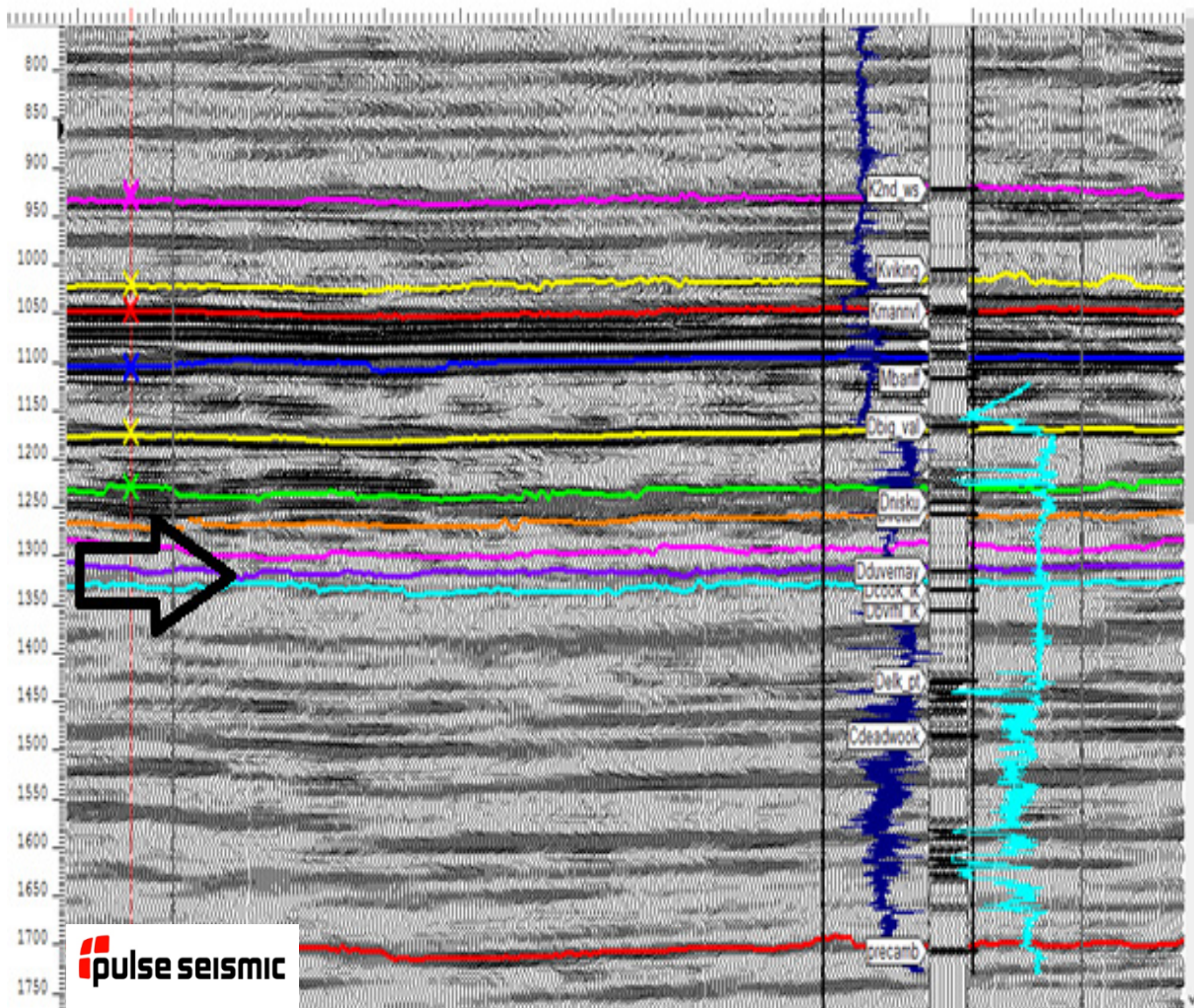


FIG 10. Line 16 showing the deep sonic and density synthetic seismogram tie. The Duvernay target zone is highlighted with the arrow, the red event is the Precambrian. Refer to figure 25 for the expanded scale.

Seismic Processing

Surface consistent scaling was used to reduce source to source and geophone amplitude fluctuations due to source strength, geophone coupling, surface conditions, and noise. The instantaneous amplitude for each input trace was calculated over a specified window from 250 -2200 ms. at 75 m of offset and 950-2300 ms. at 1845 m of offset for this data. The instantaneous amplitude was then decomposed into source and receiver terms in a best-fit sense by using the Gauss-Seidel algorithm (Millar 2004). Traces that fall outside a specified DB range around the reference mean are automatically edited. The reference amplitude chosen for scaling purposes was 2500.

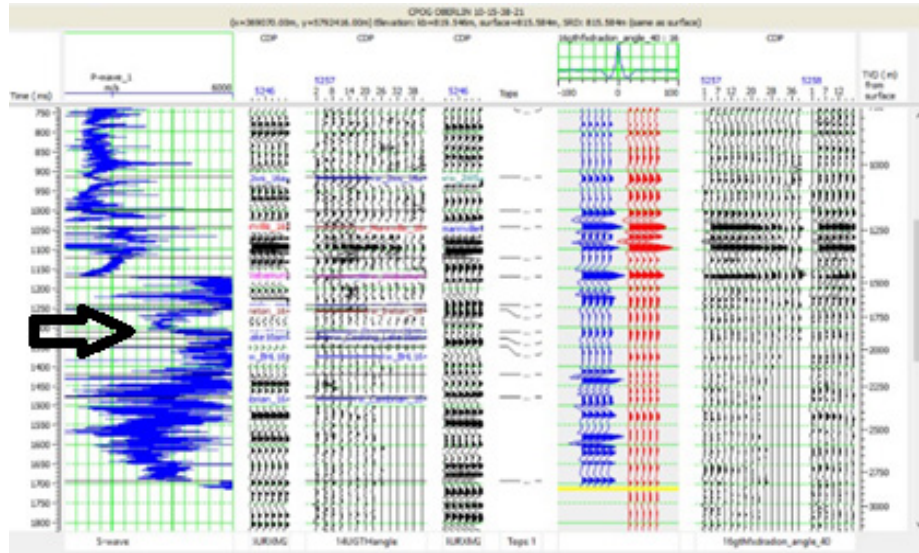


FIG 11. Synthetic Tie to stack data and CDP gathers

AVO THEORY

Pre Stack Inversion

A post stack seismic inversion was processed on line 16. The results for the post stack were similar to those derived from the conventional seismic interpretation (Figure 12). The post stack inversion was used to set up the parameters for the prestack simultaneous inversion. This sets up the time to depth correlation, the zone of interest, and the extracted wavelet. The inversion used here is simultaneous, solving for V_p , V_s , and ρ (density). The prestack gathers have horizons picked based on the original seismic correlation, which further constrained the inversion (figure 11). Figure 12 shows the conversion of incident p waves to shear, and the relationship to the incident angle. The data used in this study was p wave only, so the shear wave, Poisson's ratio and other attributes were derived from AVO seismic data.

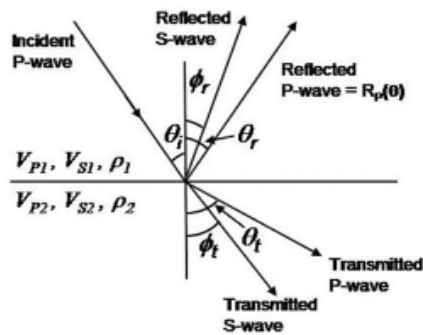


FIG12. Angle dependent components and mode conversion. (Weir, Russell 1988)

Elastic impedance inversion

- (1) Optimally process the seismic data (2) Build model from picks and impedances

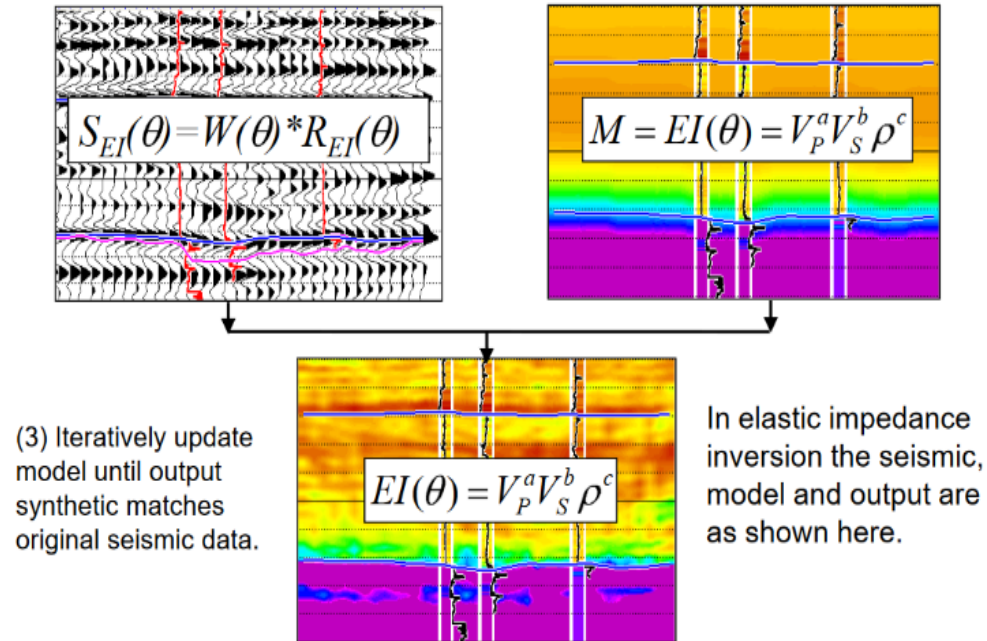


FIG 12. Prestack inversion process

We start with Fatti's version of the Aki-Richards' equation. This models reflection amplitude as a function of incident angle:

$$R_{PP}(\theta) = c_1 R_P + c_2 R_S + c_3 R_D$$

where:

$$\begin{aligned} c_1 &= 1 + \tan^2 \theta \\ c_2 &= -8\gamma^2 \sin^2 \theta \\ c_3 &= -\frac{1}{2} \tan^2 \theta + 2\gamma^2 \sin^2 \theta \\ \gamma &= \frac{V_S}{V_P} \end{aligned}$$

$$\begin{aligned} R_P &= \frac{1}{2} \left[\frac{\Delta V_P}{V_P} + \frac{\Delta \rho}{\rho} \right] \\ R_S &= \frac{1}{2} \left[\frac{\Delta V_S}{V_S} + \frac{\Delta \rho}{\rho} \right] \\ R_D &= \frac{\Delta \rho}{\rho} \end{aligned}$$

FIG 13. Fatti's equation (Weir and Russell, 2016 CREWES presentation)

Normalised Equation

This changes Fatti's equation to:

$$R(\theta) = \tilde{c}_1 W(\theta) D L_p + \tilde{c}_2 W(\theta) D \Delta L_s + c_3 W(\theta) D \Delta L_D$$

where:

$$\tilde{c}_1 = (1/2)c_1 + (1/2)kc_2 + mc_3$$

$$\tilde{c}_2 = (1/2)c_2$$

$W(\theta)$ = wavelet at angle θ

D = Derivative operator

$$L_p = \ln(Z_p)$$

FIG 14. Normalized equation (Weir and Russell 2016 CREWES presentation)

Relationship of Variables

We want to use the fact that the basic variables, Z_p , Z_s , and ρ are related.

We start with two relationships which should hold for the background "wet" trend:

$$V_s / V_p = \gamma = \text{constant}$$

$$\rightarrow \ln(Z_s) = \ln(Z_p) + \ln(\gamma)$$

Constant γ

and:

$$\rho = aV_p^b$$

$$\rightarrow \ln(\rho) = \frac{b}{1+b} \ln(Z_p) + \frac{\ln(a)}{1+b}$$

Generalized Gardner

Figure 15. Variable constraints (Weir and Russell CREWES 2016 presentation)

Model constraints

Both these relationships lead us to the more general model for the background trend:

$$\ln(Z_S) = k \ln(Z_P) + k_c + \Delta L_S$$

$$\ln(\rho) = m \ln(Z_P) + m_c + \Delta L_D$$

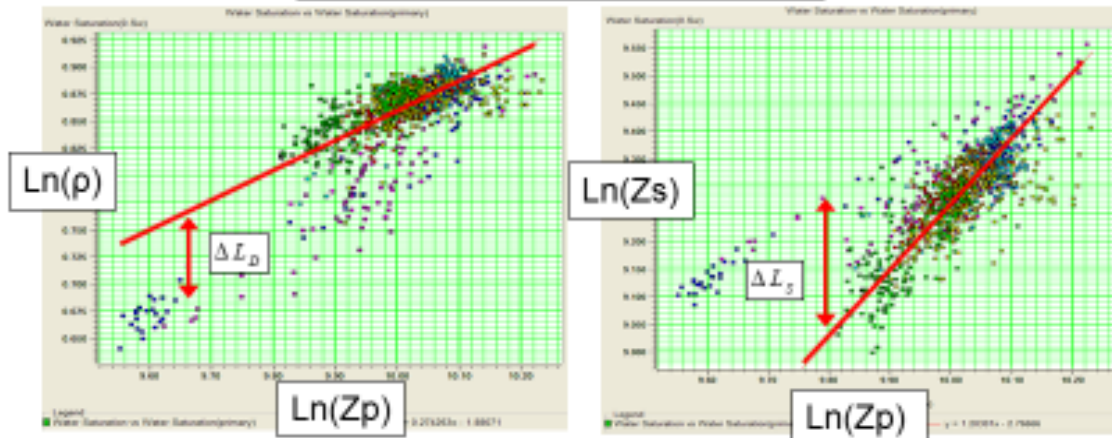


FIG 16. Model constraints, log -log constraints

The basis of the inversion is the normalized Fatti equation (Figure 13, 14, 15), (Hampson et.al 2005). The prestack inversion is a simultaneous process; it iteratively updates the model until the synthetic traces. We start with Fatti's version of the Aki-Richards equation. This models the reflection amplitude as a function of incident angle. The following equations were published by Brian Russell, and are part of a CREWES presentation given in March 2016 by Weir, R. and is available on the CREWES website.

The model is generated by the user, sonic density and shear wave logs are tied to the seismic data. Seismic events (horizons) are correlated on the stack data. A wavelet is extracted to apply to the seismic data to ensure the data is zero phase. The model accounts for the low frequency (0 to 15 Hz) component by blocking the logs in time, constrained by the user using a series of horizon picks.

The inversion is constrained by interpreted seismic (geological) boundaries. The model is perturbed a number of times until a best fit is found with the prestack seismic data. This process is stable in that V_p/V_s ratio is constrained to a set limit range of values. There are also limits to how far density and sonic can deviate from theoretical, based on the general Gardner Equation. The outputs from the inversion process is Z_p , and Density ρ the (acoustic inversion), and V_p , V_s , and Density (elastic, offset dependant). V_p/V_s are calculated as is Poisson's ratio.

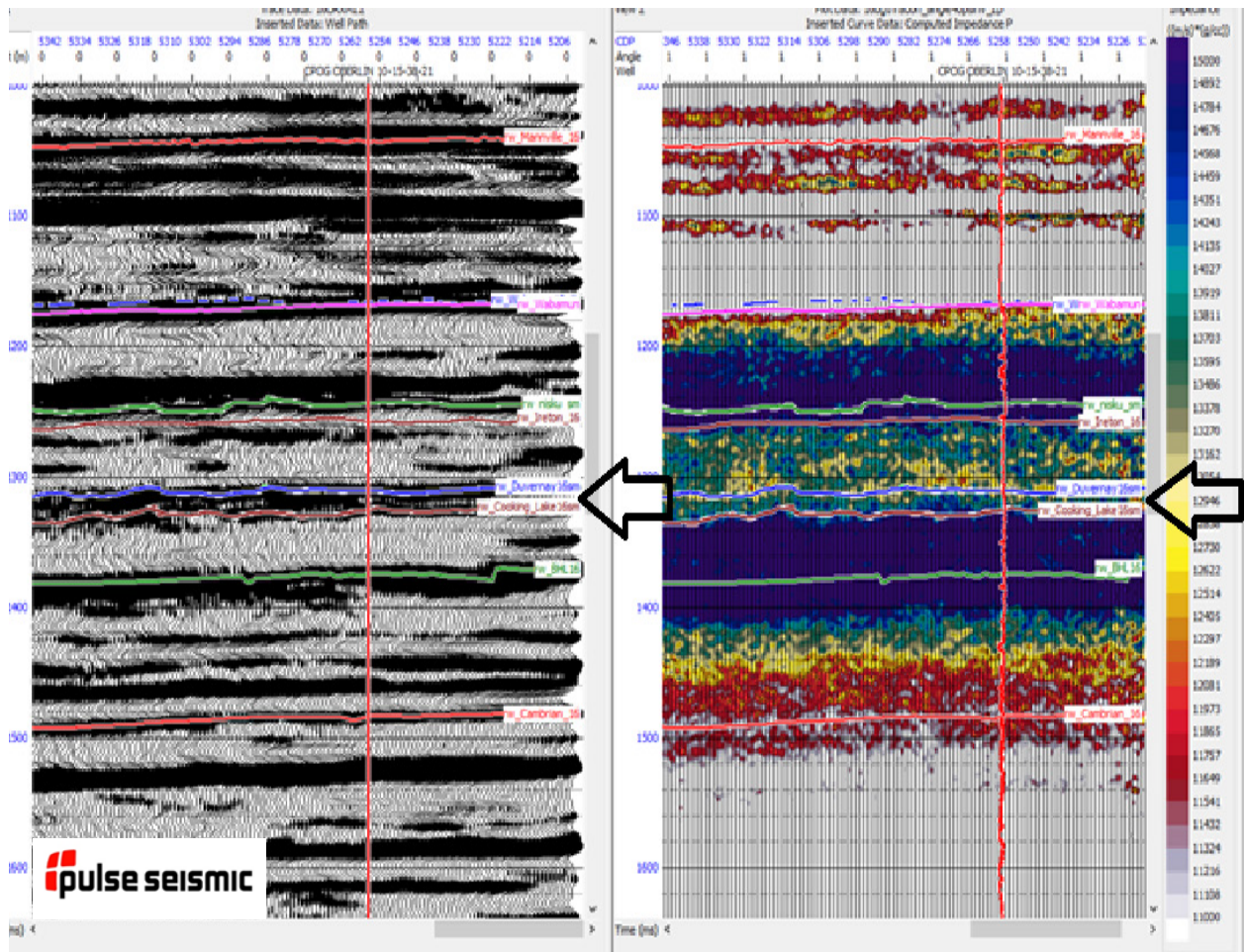


FIG 17. Initial seismic data and inverted PP display. The input stacked section is on the left, the pp elastic inversion is on the right. Once the inversion is output, it is a straight forward process to calculate the Young's Modulus and Brittleness. Brian Russell provided a set of equations to derive these numbers (figure 18), which were used here to generate Young's modulus and Poisson's ratio. inversion derives V_p, V_s and ρ (density), and calculates Young's Modulus, and the Poisson's Ratio from the inverted data. Rock properties were derived from the equations in figure 18.

Related equations are defined as follows:

$$\text{Poisson's Ratio: } PR = \frac{0.5 * \left(\frac{Vp}{Vs}\right)^2 - 1}{\left(\frac{Vp}{Vs}\right)^2 - 1}; \text{ Closure Stress Ratio: } CSR = \frac{PR}{1 - PR}$$

$$\text{Young's Modulus: } E = \frac{2 * Z_s^2 * (1 + PR)}{\text{Density}}; \rho E = 2 * Z_s^2 * (1 + PR)$$

$$\text{Brittleness : } BRI = 100 * \left(w * \frac{(PR_{max} - PR)}{PR_{max} - PR_{min}} + (1 - w) * \frac{(E - E_{min})}{E_{max} - E_{min}} \right)$$

$$\text{Brinell Hardness Number : } BHN = 75.156 * E + 18.21$$

The default impedance unit used in the equation is (m/s)*(kg/m³);
Default velocity unit is (m/s); Default density unit is (kg/m³).
Input values in other units will be converted automatically.

Figure 18. Rock properties equations to convert from Vp, Vs, and density the above equations are used. Brittleness, Young's Modulus and Poisson's Ratio are calculated directly from the inversion output. (Brian Russell 2015). Note, "w" is a weighting factor for brittleness with respect to E and PR, the default is 0.5.

Rock Properties

According to Cho et. Al., 2014, the optimal conditions for a formation is the ability to easily fracture, and the ability to hold a fracture open with proppant. A lower Poisson's Ratio translates to more favorable conditions for fracture failure; a low Young's Modulus will be favorable for failure (and subsequent fracture collapse), but a higher Young's Modulus in a rock represents its ability to maintain its fracture, and not collapse back on itself. Higher porosity and quartz content are significant when predicting suitable places to induce fracturing. The distal areas of the Duvernay are higher in quartz content, with high TOC. The cross plot in figure 23 displays the derived data from the Duvernay interval in terms of Poisson's Ratio vs. Young's Modulus.

The cross plots were used to analyze the rock properties of the Duvernay. Values from the inversion were output over the Duvernay interval. The relationship of E (Young's Modulus) Vs. P (Poisson's ratio) were plotted and show a linear relationship (Figures 19, 20). A small number of values fall outside theoretical possibility; these values were caused by the inversion attempting to match noisy data points. A histogram of the points was also calculated showing the number of values outside theoretical was relatively small.

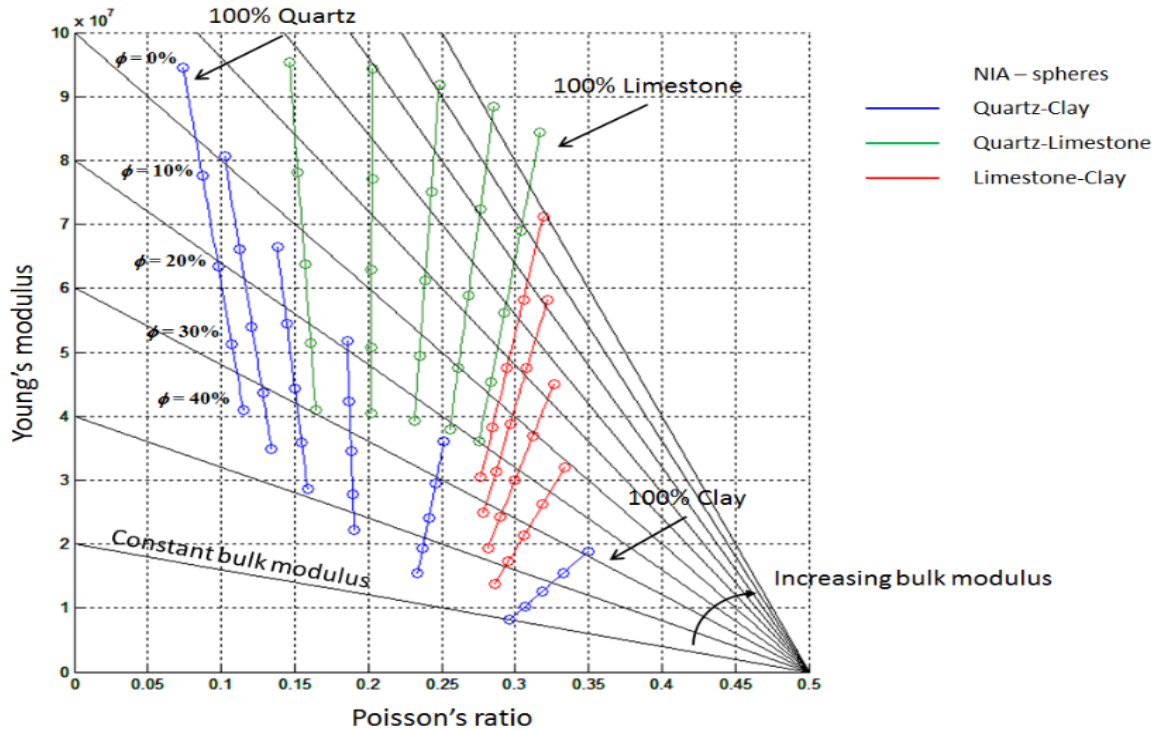


FIG 19 (Cho and Perez, GeoConvention 2014) An increase in quartz content will lower the Poisson's ratio and increase the Young's modulus. In addition, an increase in porosity will lower the bulk modulus and hence the Young's modulus (Cho et. al. 2014). The upper left quadrant would be where the desired combination of fracture failure, and the ability to hold a fracture open.

As a quality control check, Young's Modulus and Poisson's Ratio was extracted from the top of the Cambrian interval. The cross plot trend was quite different, with most of the values clustering around a single value, with a different overall trend (Figures 21, 22.). This exercise verified that the inversion process was not influenced by data acquisition or processing artifacts, and reflects actual geological changes. In contrast, the top 40 meters of the Cambrian show little variation in Poisson's Ratio and Young's Modulus. Two polygons were drawn on the cross plot (Figure 23), separating more brittle (blue) from less brittle (red) conditions. A plot of line 16 was created, coloured matched to the conditions defined by the cross plot (Figure 24). Significant variations were observed on the seismic line over the Duvernay interval. This would imply that a hydraulic fracture performed at the Precambrian well tie would perform well, the areas to the West (in red) would perform poorly.

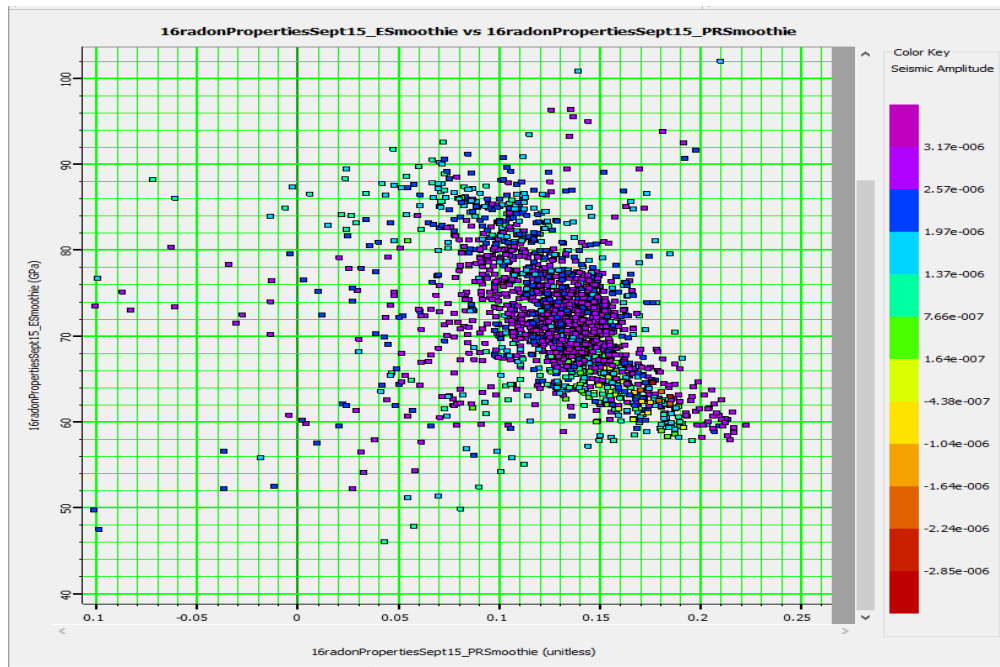


Figure 20. Duvernay cross plot, Poisson's Ratio vs. Young's Modulus The slope of the data lines up from bottom right to upper left. A few points line up outside what is theoretically possible. This is due to noise, and the inversion attempted to match noise.

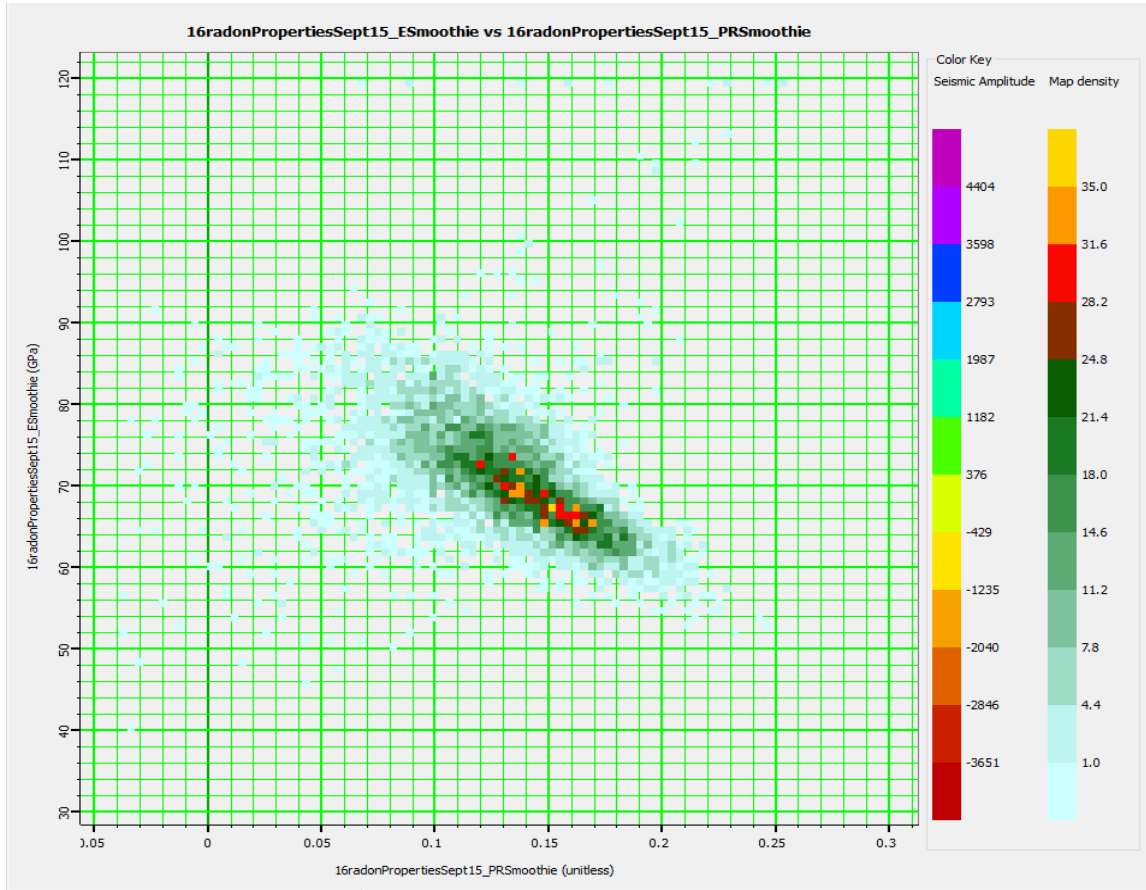


FIG 21. Histogram Duvernay cross Plot, Poisson's Ratio vs. Young's Modulus. The number of out of range data points is relatively small; the linear data trend is evident. The majority of the points are aligned on a lower right to upper left axis. This is the same data as shown in figure 20, colour coded with a histogram. In figure 20, the colour bar is the Duvernay seismic amplitude from the pp inversion, figure 21 is a histogram of the same data. This is equivalent to the modeled cross plot displayed in figure 19.

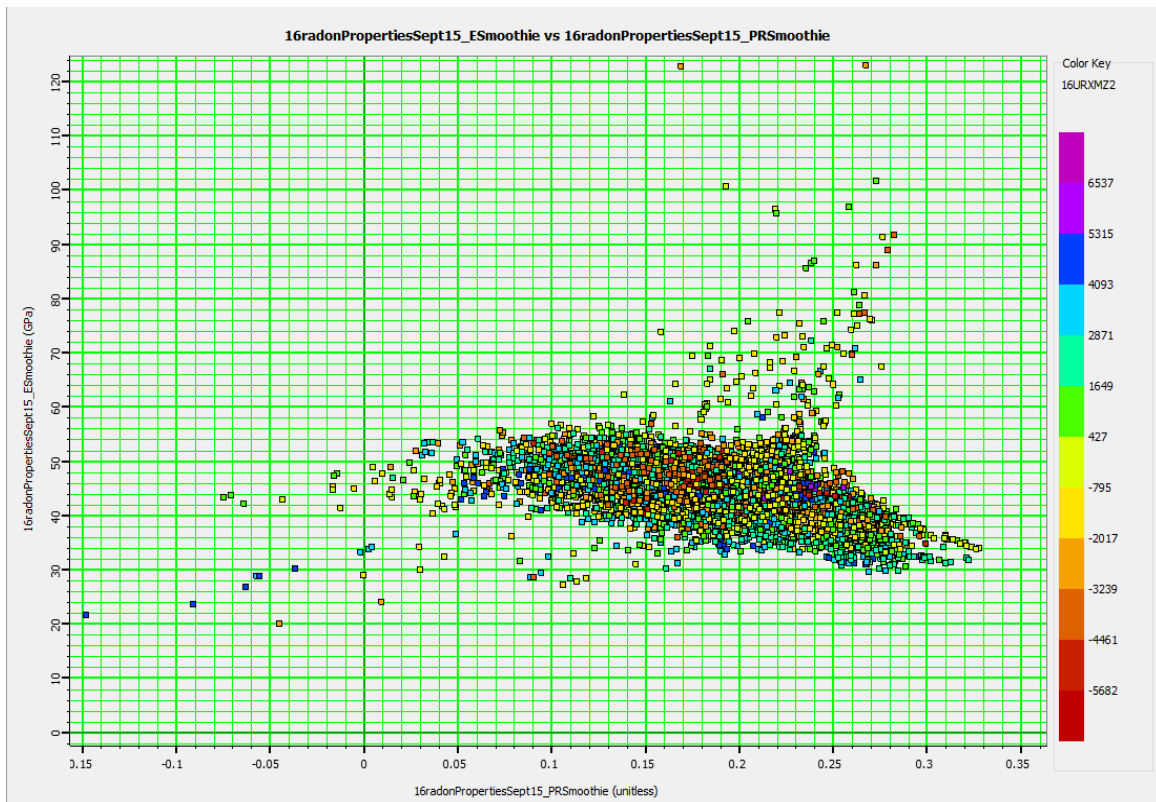


FIG 22. Baseline comparison, the same cross plot on the Cambrian surface, Young's Modulus Vs. Poisson's Ratio. This is Cambrian cross plot that shows quite a different trend than that shown for the Duvernay. The cross plot from the Duvernay is showing lithological effects, and is not data dependant. A small number of points fall outside of the allowable data range, due to data noise.

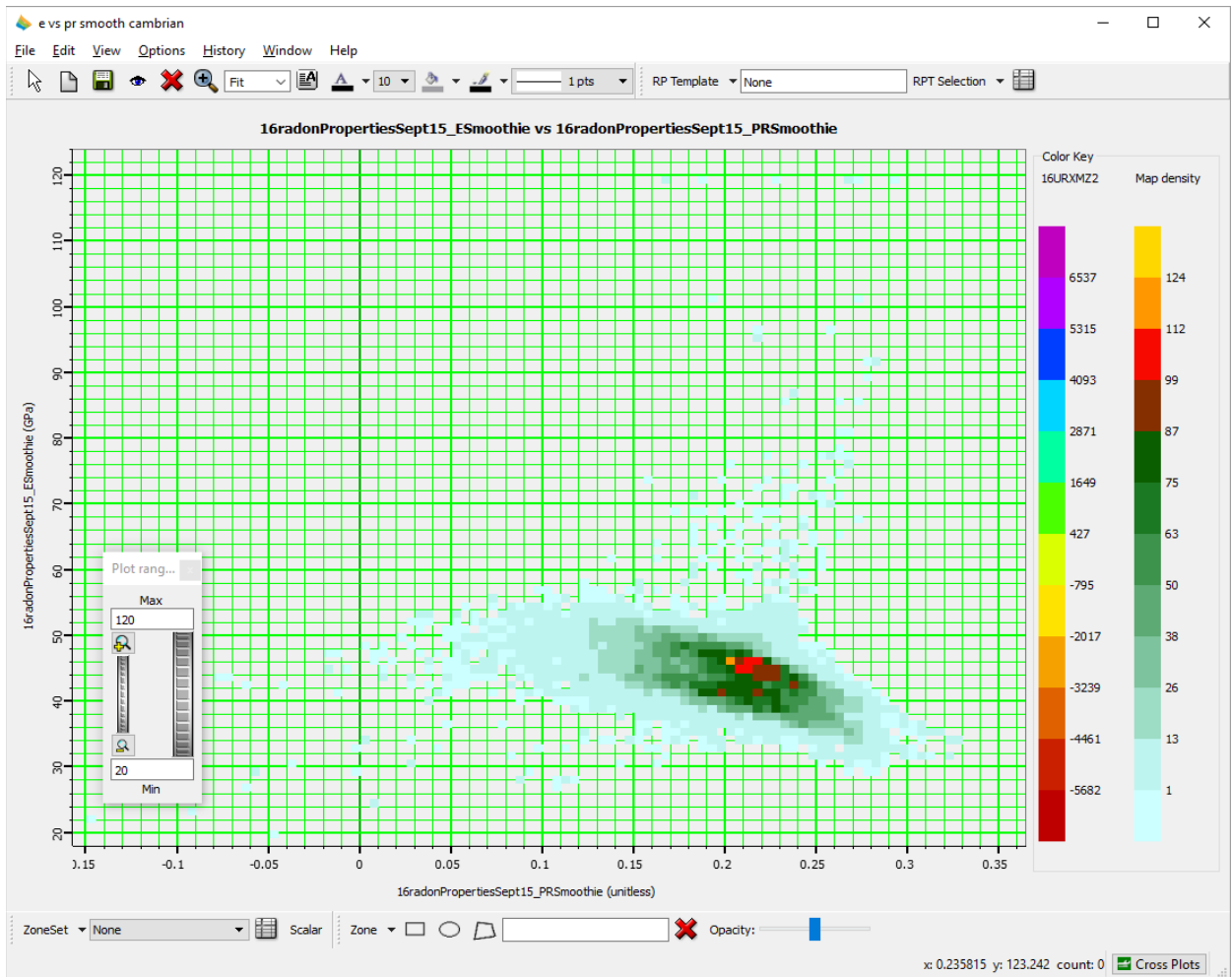


FIG 23. Histogram cross plot of Poisson's Ratio Vs Young's Modulus over the Cambrian interval. This plot was created for quality control. Most of the values are clustered around a small region or single point. This indicates that the Cambrian surface has a relatively uniform lithology.

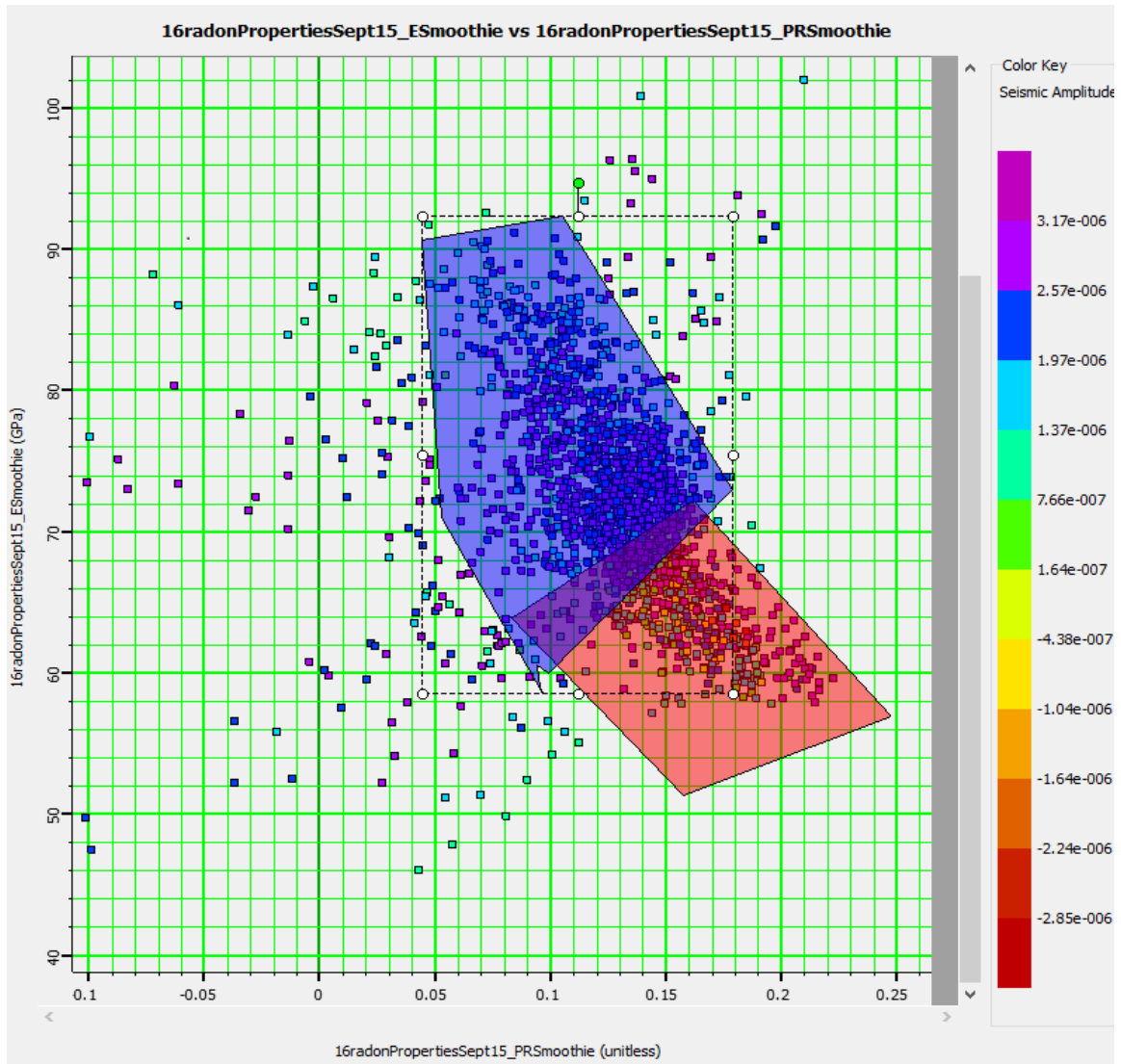


Figure 24. Cross plot of Poisson's ratio (x) vs Young's Modulus (y) This is a summation of all the Poisson's data points inside from the seismic Duvernay interval. The seismic plot in figure 57 shows all points on the seismic line that meets these conditions. The data in red is less brittle, the data in blue is more brittle and capable of maintain a fracture. The boundaries between red and blue are user defined. Figure 19 illustrates the reason for the division of the data into two populations (red and blue colour attributes, figure 25).

Analysis and Recommendations

Extracting seismic attributes is a technique available to most seismic data, given well control and seismic data with sufficient offsets. This analysis can be extended to 3-D if one is available; the methodology is identical using well ties and correlations to prestack data. Ideally, a dipole sonic would be available, as well as multi component seismic data. The ground proofing of this concept is to perform prestack inversion over a known Duvernay pool with brittleness fracture prediction used in conjunction with microseismic data. If geological brittleness is the defining factor in fracture propagation, microseismic events would align themselves with geological trends such as depicted in figures 26, 27.

The Duvernay cross plots (figure 20, 21) show a trend showing information similar to that displayed in Cho's diagram in figure 19. Here, the inversion output shows indication of enhanced brittleness near the deep well (Figure 25), decreasing to the West. This would imply that within the Duvernay interval, the area highlighted in blue would be desirable for fracture stimulation. This variability is an expected result, given the Duvernay was predicted by Dunn and Schmidt to have five distinct facies. The location of the seismic line is where the Duvernay in this area has sourced a lot of oil to the adjacent Leduc and overlying Wabamun pool (figure 9). The presence of abundant TOC in the Duvernay is a major factor in brittleness (Fox, Mehrdat, 2016). Significant hydrocarbon generation has occurred in the study area based on the abundant hydrocarbon production in the nearby Wabamun and Leduc pools.

The Cambrian display of the same attributes shows a different trend, and a cluster of values around a single point (figure 22, 23). This display confirms that the Duvernay rock parameter extraction is not an artifact of the seismic data processing or acquisition. The Cambrian brittleness plots, produce significantly different results.

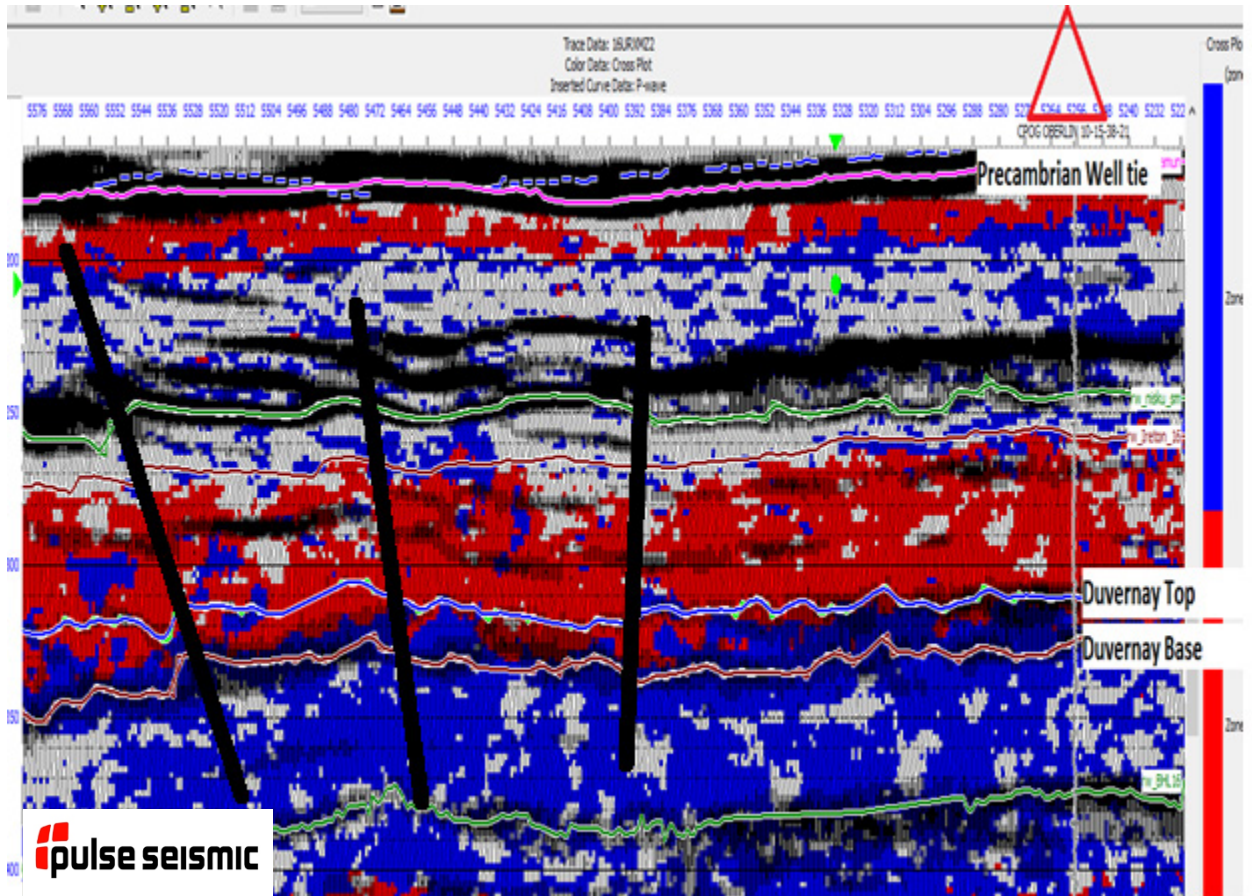


FIG 25. Seismic display of Young's Modulus Vs Poisson's Ratio. The colours are derived from the E (Young's Modulus) vs. Poisson Ratio Cross Plot. The zone of interest, The Duvernay is marked at 1325 ms. Note the variance from NE to SW. in the Duvernay interval. The Blue zone indicates more brittle rock, the red, less. According to this, a hydraulic fracture at the well bore would perform well; an induced fracture at 5426 (red colour) would perform poorly. (three deep seated faults have been interpreted on this 2-D line cutting the Duvernay).

The red – blue attributes seen on the cross plot can be displayed in plan view depth, and displayed with the microseismic events on a 3-D survey, if available. If lithology is a major factor in induced fracture propagation then it follows that a seismic inversion and core derived facies analysis would be critical in developing an accurate fracture propagation prediction model. Figure 22 shows what may be encountered if lithology, regional stress, or a combination of the two factors is taken into account. The question to be asked is “does brittleness affect the induced fractures more than the stress regime?” “If so how much?” The blue area in figure 26 would represent the desired combination of Poisson's Ratio and Young's modulus (upper left corner of figure 19).

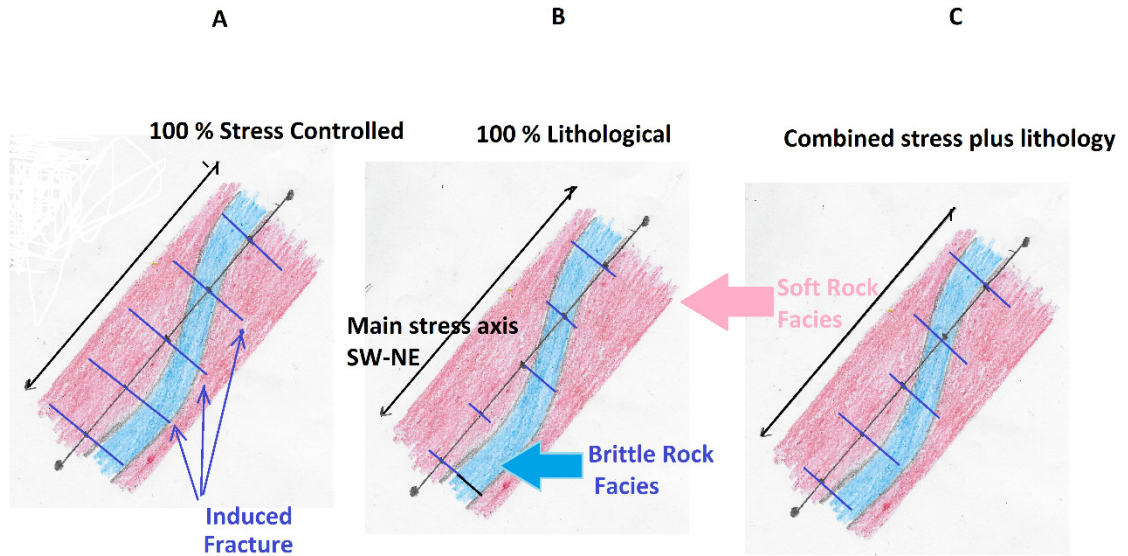


FIG 26. A qualitative prediction of fracture patterns The expected fracture pattern only taking into account the regional stress regime. The expected fracture pattern from lithology only The expected fracture pattern from a combination of A and B.

Figures 26 and 27 show what could be observed on a microseismic survey if the blue (brittle) and red facies were drilled and fracture stimulated. The diagrams are a concept of what a 4-D inverted volume would look like in plan view. Fractures would preferably follow the brittle paths depicted in the drawings.

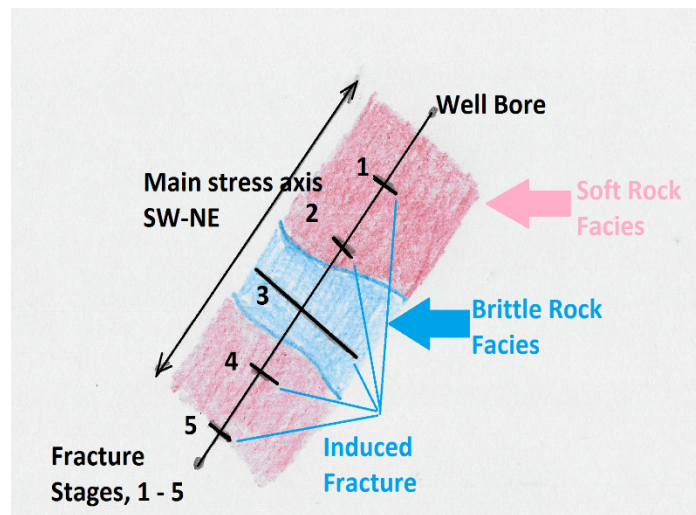


FIG 27, A proposed scenario from a hydraulically induced fracture stimulation. Given the scenario depicted here, the question would be asked as to why stimulation # 3 performed so much better than 1,2,4, or 5. This type of unpredictable behavior is commonly observed on microseismic surveys over what is believed to be homogeneous rocks. (Figure 2, Maxwell 2002). This behavior is often attributed to pre existing fractures.

The proof of concept is to acquire 3-D survey, a corresponding microseismic survey over a hydraulic fracture program and compare results. Lithology, regional stress, structure, and pre existing faults and fractures contribute induced fracture orientation and size. To what extent does geological deposition and hydrocarbon contribute to the induced seismicity and fracture pattern?

Organically rich shales become more brittle with increased total organic hydrocarbon content (THC). They also become more brittle with increased silica content. This study area, Rangeland, as of yet, has had no Duvernay horizontal drilling activity. There is very little core work, and very few deep control wells. Given the quantity of oil generated by this zone, and produced from the nearby Leduc and Wabamun formation, and given the variation in brittleness, the study area is likely a candidate for Duvernay production.

SUMMARY AND CONCLUSIONS

In order to prove the concept of lithologic controlled fracture patterns, a 3-D seismic survey should be acquired over an existing Duvernay pool in conjunction with a Microseismic survey. Young's modulus and the Poisson's Ratio (and several other attributes) can be derived from the data and displayed on a 3-D seismic interpretation system. The microseismic data can also be displayed, in conjunction with the fracture patterns and compared to the lithology. This may explain why there are often unpredictable behaviors in hydraulic fracture patterns, in formations that are often assumed to be homogeneous. The drawings in figures 26 and 27 may explain the non uniform microseismic events that occur in a formation that is considered to be homogeneous.

The seismic inversion data can also identify areas with rock properties that are likely to hold the fracture open, and not collapse shortly after the fluid and proppant is pumped into the formation. The seismic inversion suggests that there are significant variations in lithology in the Duvernay in Rangeland. This is consistent with the findings by Fox et al using core analysis and logs in NW Alberta. Prestack inversion can identify these variations. In order to prove this concept a 3-D survey would be processed over a known hydraulic fracture program, and Microseismic events observed to follow seismically mapped brittleness trends.

Post Script

I have made contact with Pulse Seismic, the owner of a large 3-D data base in the Kaybob area. The data is available under the University of Calgary's master licensing agreement. As a follow up to this paper, I will try to acquire this 3-D data set, the core analysis, and the microseismic data over an existing horizontal fracture stimulated pool in the Duvernay. It is my belief that Induced fractures will follow geologically/ seismically defined paths of brittleness.

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TECHNICAL SOFTWARE USED

Geoview (HRS), pre and poststack inversion
Geosyn, 2-d modeling and petrophysics
Geoscout, Well grid and culture data base, LAS files, production and perforation information
Seisware, Conventional seismic interpretation
Vista, prestack data preparation.

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Dr. Brian Russell, technical advice and consultations
Roy Lindseth, technical edits

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