Quantitative interpretation using conventional and facies-based pre-stack inversion — A thin dolomite reservoir case study in Cabin Creek Field, Williston Basin

Paul El Khoury1, Ehsan Zabihi Naeini2, Thomas L. Davis1 apply the conventional simultaneous pre-stack inversion method and the newly developed facies-based inversion technique to the reservoir characterization of a thin deep dolomitic interval, planned to undergo CO₂ enhanced oil recovery, in the Cabin Creek Field, Williston Basin.

Introduction
Cabin Creek Field, on the southwestern flank of the Williston Basin, is one of 14 hydrocarbon fields within Cedar Creek Anticline. The field was initially discovered in May 1953 and developed by Shell starting with primary production followed by water flooding beginning in the late 1950s. In 1999, Encore purchased Shell’s interests and focused on infill drilling. In 2010, Denbury Resources acquired Encore giving it the potential to undertake enhanced oil recovery operations in the Rockies. Production is from the Ordovician Red River, Silurian Stony Mountain, Interlake, and Mississippian Mission Canyon Formations.

The objective of the Cabin Creek reservoir characterization is to document reservoir heterogeneity within the target reservoirs and to facilitate development of the CO₂ flood. The goal of this integrated case study is to generate a representative reservoir model that combines the structural framework and porosity prediction within the Red River Formation. This paper focuses on utilizing and comparing conventional and facies-based pre-stack inversion methods to characterize the porosity at the reservoir level.

Geologic setting
The Ordovician Red River Formation conformably overlies the Winnipeg Formation and is overlain by the Stony Mountain Formation and Interlake Formation. The Red River reservoirs are typically subdivided into A, B, C and D units (from youngest to oldest). They represent a period of six million years of cyclic depositional packages that grade from highly burrowed, open marine limestones through laminated dolomite mudstone into bedded anhydrites (Longman and Haidl, 1996). The development of porosity in the Red River Formation is owing to the dolomitization of these beds. According to Longman and Haidl (1996), the early dolomitization in the Red River Formation was generated because of subtidal downward seepage reflux migration of magnesium-rich brines. In this paper, the Red River Formation is subdivided into nine petrophysical units, U1 through U9 within the A through D zones. The limestone and anhydrite intervals are U1, U3, U5, U7, and U9 while U2, U4, U6 and U8 indicate the porous dolomite intervals.

Available data
A P-wave 3D seismic survey was acquired in July 2014 over the Cabin Creek unit covering approximately 114 km² (44 miles²) (Figure 1). Figure 2 shows interpreted events across the seismic survey along with the corresponding formations. In addition, the Cabin Creek well dataset includes a suite of borehole measurements from...
17 wells; of which 13 wells are within the seismic survey and 4 are in close proximity (Figure 1). The well logs suite includes gamma ray, density, neutron porosity, and resistivity with sonic and some with photoelectric factor (PEF). The northwest wells outside of the seismic dataset contain dipole sonic logs that are used to invert for fracture density and nuclear magnetic resonance (NMR) logs for porosity cross validation with inverted porosity.

**Target reservoir: RRU4**

Red River Formation is an important reservoir interval at an approximately 2740 m (9000 ft below sea level in the Cabin Creek Field. Production is mainly from the porous dolomitic zones (RRU2, RRU4, RRU6 and RRU8). CO₂ EOR operations target RRU4 that contains the most remaining oil in the Red River Formation, estimated to be 71 million barrels of recoverable oil. RRU4 reservoir thicknesses range between 19 ft to 25 ft across the Cabin Creek Field based on interpreted zone thickness from available wells.

**Rock physics model**

A representative rock physics model (RPM) developed for the Red River Formation shows that the largest variations of compressional and shear velocities are owing to porosity followed by fractures, pressure, and mineralogy. The petrophysical sensitivity analysis indicates that impedance variations within dolomite-rich zones affect the P-wave signal amplitude of the over- and under-burden layers, while impedance changes in the calcite-rich zone impact the adjacent layers’ signal amplitude. The RPM workflow utilizes the Voigt-Ruess-Hill mixing approximation, the modified differential effective medium theory, Hudson’s model for cracked media, and Gassmann’s fluid substitution equation for anisotropic rock to represent horizontal transverse isotropic (HTI) in a reservoir rock (see El Khoury et al. (2017) for details). Figure 3a plots trends of constant mineralogy for a dolomite/calcite mix at various porosity values for an isotropic water saturated model. Figure 3b illustrates the sensitivity trends at 12.5% porosity by varying the porosity, pressure, mineralogy, saturation, and fracture density over its expected range. As mentioned previously, compressional velocity is barely sensitive to the fractures. A probabilistic approach is considered during the quantitative interpretation to accommodate any possible distribution from fractures, pressure, or saturation effects.
Rock composition logs are used to classify facies based on the dominant mineral content. The five determined facies are:
1. Shale Facies: corresponding to calcareous shales or argillaceous limestones characterized with high gamma ray response (> 40 API),
2. Anhydrite Facies: mainly present above the Mission Canyon Formation with volume of anhydrite 70% or more,
3. Dolomite Facies: porous rock with good reservoir properties containing 70% or more dolomitic minerals,
4. Calcite Facies: non-porous, non-reservoir rock, mainly calcitic with volume of calcite 70% or more,

The calcite/dolomite facies mix overlaps the remaining facies and cannot be resolved using the seismic scale. Hence we only consider the high-quality facies for inversion later in this study (facies 1 to 4) and combine facies 5 into 3 and 4. In addition, 2D probability density functions are defined in the velocity ratio (Vp/Vs) versus acoustic impedance cross-plot for facies 1 to 4.

Data preparation
The preliminary step prior to the pre-stack inversion is to condition the well logs and seismic data. The data preparation phase included seismic pre-processing of raw gathers, angle stack, log conditioning, wavelet extraction, and the well-to-seismic tie.

Angle stacks
Cabin Creek seismic gathers required additional pre-processing steps including multiple suppression using radon transform, wavelet deconvolution, and time-variant trim statics to improve data quality. Five angle stacks were extracted between 8° and 46° centered at 12°, 20°, 28°, 36° and 43°, respectively.

Log conditioning
All wells drilled within the Cabin Creek seismic survey were logged between the Mission Canyon and the Red River Formation spanning approximately 914 m (3000 ft) Shear data from two out of the three wells northwest of Cabin Creek Field were used in conjunction with the remaining logs (GR, density, porosity, and mineral content) to train a neural network and predict synthetic sonic logs for the wells available within Cabin Creek seismic survey. The third well with a sonic log is used to cross-validate the neural network analysis.

Well tie and wavelet extraction
Zabihi Naeini et al. (2016) discussed in detail the considerations around the seismic bandwidth and subsequently wavelet estimation for seismic data. Following their proposed workflow, we found that the parametric constant phase method introduced in their paper yields the optimum results. Constant phase wavelet estimation has an empirical basis in which the phase of the seismic wavelet should be approximately constant across the seismic bandwidth, as attempted during seismic processing. This approach is especially suitable when only a short log length is available as, in practice, allowing the phase to vary with frequency would be unreliable for such wells. The constant phase is estimated using a least-squares method in which the well logs, 200 to 300 ms on average in this case, are incorporated. The amplitude spectrum is obtained over a long but multi-tapered interval of seismic data (in this case 1200-2200 ms) using multiple traces around available wells. Figure 4 shows the average wavelets for the corresponding angle stacks.

Seismic inversion
Model-based inversion
The model-based pre-stack inversion here utilizes the Smith, Gidlow, and Fatti approximation (Smith and Gidlow, 1987; Fatti et al., 1994) to solve for acoustic impedance (Al), shear impedance (Sl),
and density. The inversion is an iterative process between building the low-frequency model, optimizing the inversion parameters, and blind well testing. The final low-frequency model is constructed using four wells evenly distributed across the seismic survey and QC’ed at two blind wells. In addition, the Winnipeg Formation is characterized by a sharp decrease in elastic properties compared to the Red River. Therefore, to capture the impedance contrast into the background low-frequency model to eliminate residual side lobes at the inversion boundary, elastic properties (Vp, Vs, density) are spliced from well 24X-15A into well 31-18 that penetrates up to RRU9. The bandwidth frequency filter is 10 to 15 Hz for the low-frequency cut and 80 to 100 Hz for the high-frequency cut. The selection of the frequency cuts is based on the seismic frequency content. Figure 5 shows the low frequency model, real and inverted elastic properties at Well 31-18. Figure 6 shows the extraction of seismic amplitude, acoustic impedance, and Vp/Vs velocity ratio at RRU4 surface. Converting from interface property (seismic) into layer property (acoustic impedance) we observe similar anomalies appearing at RRU4. However, Vp/Vs appears to be constantly high across the field and does not follow the anomaly patterns. From the RPM model, the best reservoir rock would have high acoustic impedance (dolomitic) and low Vp/Vs ratio.

**Facies-based inversion**

Facies-based seismic inversion, in which the low-frequency model is a product of the inversion process itself, was introduced by

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**Figure 5** Well 31-18 simultaneous inversion elastic properties results. Low Frequency model in blue, log data in black, and simultaneous inversion results in red.

**Figure 6** Simultaneous inversion elastic volumes exact extractions at RRU4 horizon. (a) seismic amplitude, (b) inverted acoustic impedance, and (c) inverted Vp/Vs.
Kemper and Gunning (2014). The low-frequency model is constrained by per-facies input, depth-trended Rock Physics Models (describing the depth dependent Vp, Vs and density behaviour for each facies), the resultant facies distribution, and the match to the seismic. Zabihi Naeini and Exley (2017) discussed in detail the differences with classic simultaneous inversion. The per facies depth-trended RPM’s are at the heart of facies-based inversion and ultimately lead to the optimum construction of a low-frequency model which becomes an output of the inversion (rather than an input). The per facies depth-trended RPM’s are constructed by fitting a compaction curve to the impedance log data belonging to that facies, complete with an assessment of uncertainty. The depth is relative to a datum (e.g. ground level). Then, the inversion first derives models of impedances (from the seismic data) given facies, and then facies (from the impedances) at each iteration of the optimization loop. The main outputs of the inversion are the most-likely elastic properties and facies given by so-called maximum aposteriori (MAP) estimation.

Figure 7 shows the facies-based inversion result at Well 31-18. The facies profile (track 1) is an output of the inversion and correlates to the original facies classification (track 2). Thin shale layers are identified from the inversion. Inverted elastic impedances are comparable to the input logs, and low residual synthetic seismic is obtained. Furthermore, elastic properties are identified throughout the inversion window with no edge effect (LFM approaching zero at inversion window) as observed in the Winnipeg Formation (see Figure 5 and 7). Finally, all wells in facies-based inversion are treated as blind wells since the low-frequency model was built from depth trends and not from the elastic impedance logs at the wells.

Figure 8 displays the inline facies across Well 31-18. Individual Red River intervals cannot be resolved at the seismic frequency; consequently, the upper Red River Formation is mainly dolomitic with few calcite intervals and the lower Red River Formation is mainly calcite. We are able to identify continuous anhydrite layers (Mission canyon – shallow section) and continuous shale intervals.
heterogeneities. A Bayesian classification using the 2D probability density functions per facies is applied to transform simultaneous inversion elastic volumes into a facies volume. The 2D PDFs are not a function of depth and prior probability needs be adjusted for target layers. The most probable facies at RRU4 is the reservoir facies (dolomite facies) with patches of non-reservoir facies (calcite) using simultaneous pre-stack inversion elastic volumes (Figure 10b).

On the other hand, using the facies-based inversion, the most probable facies volume is a by-product of the inversion as mentioned before. Thus, an automatic extraction at RRU4 surface displays the interval mainly as reservoir rock (dolomite facies), as illustrated in Figure 11b.

**Seismic-derived facies**
Quantifying anomalies detected on the acoustic impedance and velocity ratio maps is vital to understanding the reservoir spatial heterogeneities. A Bayesian classification using the 2D probability density functions per facies is applied to transform simultaneous inversion elastic volumes into a facies volume. The 2D PDFs are not a function of depth and prior probability needs be adjusted for target layers. The most probable facies at RRU4 is the reservoir facies (dolomite facies) with patches of non-reservoir facies (calcite) using simultaneous pre-stack inversion elastic volumes (Figure 10b).

Finally, Figure 9 shows maps of seismic amplitude, inverted acoustic impedance, and inverted Vp/Vs velocity ratio at the RRU4 surface for the facies-based inversion. Unlike simultaneous inversion, anomalies are consistent between seismic amplitude, acoustic impedance, and Vp/Vs maps. In general, high seismic amplitude corresponds to high-acoustic impedance (AI) dolomitic zones and low Vp/Vs.
Well logs and core analysis shows RRU4 as mainly dolomitic. Thus, the presence of calcite facies is attributed to either 1) overlap of dolomite/calcite facies 2D PDFs and their sensitivity to the prior user input, 2) resolution of the seismic with respect to the thin approximately 22ft dolomite interval, 3) pressure effect that might cause the AI and Vp/Vs to shift (El Khoury et al., 2017).

However, facies-based inversion provides a more consistent facies distribution at RRU4 with it being more dolomitic.

**Seismic-derived porosity**

Porosity is the main driver for compressional and shear variations in the reservoir rock. In addition, characterizing the lateral porosity variation helps in identifying potential flood pathways (water or CO₂) or potential bypassed pay. Therefore, given the acoustic impedance and velocity ratio (Vp/Vs) in conjunction with the Red River RPM model (Figure 3), the operator can determine the porosity distribution of any formation of interest. Consequently,

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**Figure 11** Facies-based inversion quantitative interpretation using exact extractions at RRU4 horizon. (a) seismic amplitude, (b) most probably facies from facies-based inversion, and (c) porosity using RPM model between 50% dolomite trend and green dashed line (see Figure 3a).

**Figure 12** Vp/Vs versus AI plot comparing inverted seismic properties at RRU4 and data from well logs. (a) Simultaneous pre-stack inversion, (b) facies-based inversion, (c) overlay of a and b crossplots, and (d) data from well logs in TWTT for dolomite and calcite.
Figure 13 RRU4 seismic-derived porosity versus porosity from well data. Red dots represent nine wells within Cabin Creek Unit. Porosity value at each well corresponds to the mean log value (red dot) for RRU4 interval and uncertainty bar (horizontal) is the standard deviation. Seismic-derived porosity is extracted at the corresponding well location with 2.5 p.u. uncertainty bar width (vertical). Blue line represents the 1:1 line.

Figure 10c and 11c shows the porosity distribution at RRU4 given 50% or more dolomite volume (expected reservoir facies) using simultaneous and facies-based inversion, respectively. The upper bound for porosity extraction is identified by the dashed green line (Figure 3). Porosity appears to be patchy or not identified at the entire RRU4 from simultaneous inversion elastic volumes owing to the identification mainly of non-reservoir rock. On the other hand, porosity appears to be fully defined at RRU4 for the facies-based inversion method (note that porosity has been quantified but is not released because of confidentiality).

Inversion method comparison

Given the exact same seismic angle stacks, wavelets, and well log data but using two different pre-stack inversion methods, distinct answers are reached for the same reservoir. Thus, evaluating which method provides the accurate solution is vital to be able to proceed with the design and optimization of any future EOR development plans. Acoustic impedance was relatively close between both inversion methods. However, Vp/Vs was significantly lower in the facies-based inversion, as illustrated in Figure 12 a-b. Knowing that RRU4 contains mainly dolomite facies, and comparing the inversion results to information obtained from well logs, shows that the facies-based inversion is more accurately predicting the expected facies while the simultaneous inversion is under-predicting the solution.

The final quality check is to compare seismic-derived porosity to well data, as shown in Figure 13. From the porosity log of all wells, the mean and standard deviation porosity is extracted within the RRU4 interval and plotted on the horizontal axis. The porosity from the seismic inversions is extracted at the corresponding well location and plotted on the vertical axis with a constant 2.5 p.u. standard deviation based on the RPM bin size with 50% or more volume of dolomite as lower bound and dashed green line as the upper bound (Figure 3). It is clear that facies-based inversion was able to predict porosity values closer to the real data from logs while simultaneous inversion under-predicted porosity significantly (and indeed classified the dolomite reservoir facies as non-reservoir).

Conclusion

Conventional and facies-based inversion methods are evaluated and compared in this paper to delineate dolomite (reservoir) and calcite-rich (non-reservoir) zones and quantify porosity at RRU4 using the Cabin Creek seismic dataset. The simultaneous inversion method is relatively straightforward to apply with no prior knowledge of the litho-facies needed. However, an additional method is required to extract the litho-facies from inverted elastic volumes. The facies-based inversion is a robust technique that incorporates prior facies knowledge into the inversion process to concurrently invert for elastic and litho-facies volumes. The latter method is independent of traditional low-frequency related issues and takes advantage of facies-based seismic inversion. Therefore, the facies-based inversion generates an improved result in quantifying porosity compared to a conventional simultaneous pre-stack inversion method.

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