An Assessment of Compressive Seismic Reconstruction in the Delaware Basin, Lea County, New Mexico

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Summary

This study assesses the validity of compressive seismic reconstruction (CSR) on 3D seismic data collected in Lea County, New Mexico. These data are dual processed from field records to a PSTM image. However, one dataset is decimated to simulate a compressive seismic acquisition (CSA) design and uses CSR to populate back to the original acquisition geometry. The datasets are compared using well-to-seismic ties, horizon interpretations, and a post-stack simultaneous inversion to acoustic impedance to assess similarities and differences associated with CSR.

Introduction

Wells in the Permian Basin, spread across West Texas and Southeastern New Mexico, are experiencing steeper decline curves (Eaton & Morenne, 2023). Better subsurface control from 3D seismic data can improve the placement of future wells. However, the near-surface geologic complexity in the Delaware Basin proves to be a geophysical challenge that requires high trace density seismic surveys to overcome. Furthermore, as development of the Delaware Basin continues, there is an increasing amount of surface infrastructure. CSA and CSR technologies have the potential to help provide an economic solution to these challenges (Tianjiang et al., 2019, Jiang et al., 2018).

Compressive sensing applications to geophysical methods such as surface seismic acquisition, processing, and imaging are gaining considerable attention. Compressive sensing theory suggests that there is a high probability to recover signal beyond traditional limits of sampling theory using non-uniform sampling, sparsity, and optimization (Mosher, et al. 2017). This study assesses the validity of CSR on a 55 square mile subset of a 2017 vintage 3D seismic survey acquired in Lea County, New Mexico.

The seismic data are decimated to simulate a CSA design as closely as possible given the original acquisition geometry. Both the full and compressive seismic (CS) datasets are processed through a pre-stack time migration (PSTM) image. Well-to-seismic ties are used to characterize similarities and differences in bandwidth, amplitude, and phase between the Full and CS PSTM stacks. Key reservoir horizons are also interpreted to provide comparisons of both structure and amplitude. Then each PSTM dataset is inverted for acoustic impedance and compared to each other and to available well control.

Data and Methods

The 3D seismic data used in this study is a subset from a 2017 vintage survey. These data were acquired with evenly spaced 825' orthogonal source and receiver lines and evenly spaced 165' source and receiver stations. The bin dimensions are 82.5' x 82.5' with a nominal fold of 396. A 133 square mile subset of this survey is used as input to processing. After PSTM, a halo area of two miles is removed from the CS assessment resulting in a full fold 55 square mile area of investigation.

These data are taken through a typical land seismic data processing workflow. To simulate a real-world scenario, multidimensional mutual coherence maps are used to optimize the decimation of the raw input gathers for CSR (Figure 1). This results in a CS dataset with approximately 70% of the original shots and receivers (Figure 2). All the following steps are conducted in parallel on both Full and CS datasets, including first break picking and statics. The two workflows merge after all pre-processing and just before migration, with the reconstruction to the Full geometry from the CS dataset. This workflow mimics the limited information of a CS survey. Specifically, the Full and CS datasets have different statics solutions. This becomes a key part in the assessment of the performance of the CS PSTM compared to the Full PSTM dataset.

A first assessment of the validity of the CSA decimation and CSR is driven by well-to-seismic ties. Ten wells with both sonic and density curves through the stacked reservoir zone are used to generate zero-offset synthetic seismograms to tie to both the Full and CS PSTM stacks. The same events on both Full and CS PSTM stacks are used as tie points to each

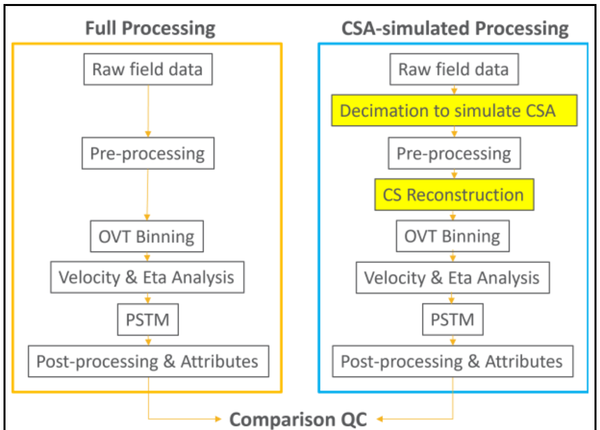

Figure 1: Generalized processing flows of the Full and CS Datasets.

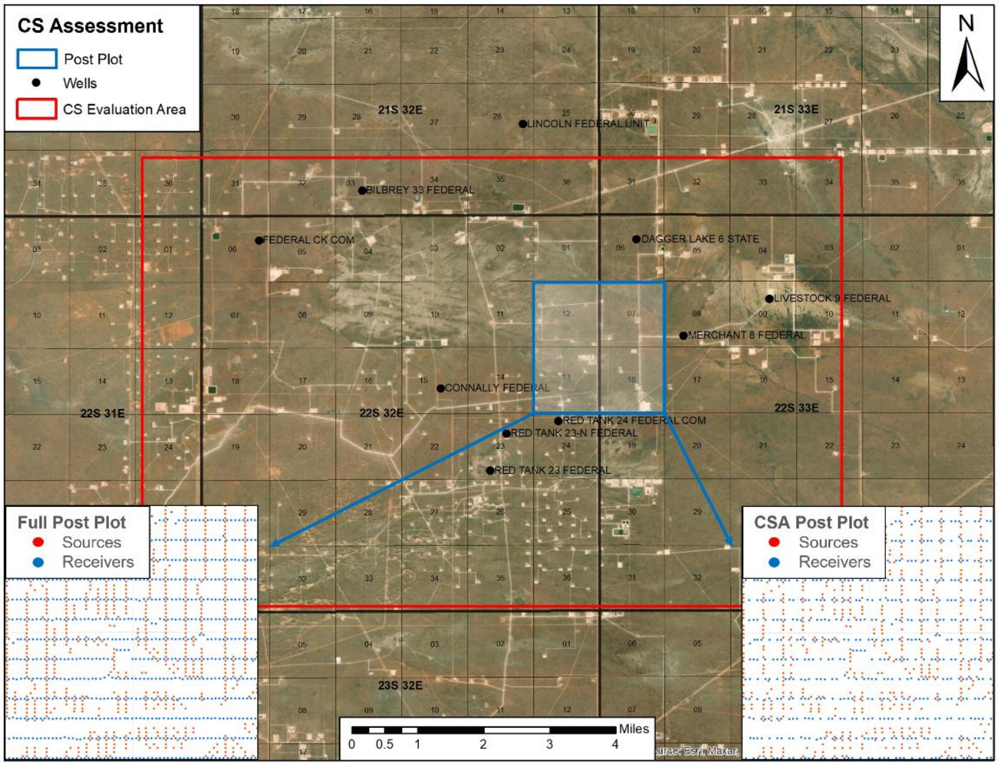

Figure 2: Map of the study area with post plots of the Full dataset and the CSA decimation over four square miles.

well synthetic. The correlation windows are the same for both Full and CS well-to-seismic ties. Each well-to-seismic tie covers similar geology over the Bone Spring and Upper Wolfcamp formations. Once the wells are tied, a Roy-White wavelet estimation is used to assess the similarities and differences of bandwidth, amplitude, and phase between Full and CS datasets (Walden & White, 1998). The cross-correlation values of each well-to-seismic tie are also compared.

The next phase in the CS assessment involves the interpretation of key horizons within the stacked reservoir zone. Because the statics solutions of the Full and CS datasets are different, a statics conversion map is needed. The conversion map is derived by meticulously interpreting the same high signal-to-noise ratio event deep in the seismic section on each dataset and taking a difference between them. Then key horizons in the reservoir are interpreted on the CS dataset and shifted to fit the Full dataset. From here, structure maps and short-window RMS amplitude profiles of each horizon are compared.

The final stage of this CS assessment integrates the well-to-seismic ties and horizon interpretations when both datasets are taken through a post-stack simultaneous inversion to acoustic impedance. Apart from the horizon conversion, the background models for both Full and CS datasets are built identically. The wells are then used to compare the cross-correlation values between the Full and CS acoustic impedance estimates.

Results

Upon completion of the PSTM processing workflow, the stacks and frequency spectrums of each dataset are compared (Figure 3). While the stacks are very similar, the difference in statics solutions is subtly evident. The CS stack seems to have a slightly higher signal-to-noise ratio than the Full stack. The frequency spectra extracted over the stacked reservoir interval are nearly identical to one another. In this case, the Full stack has slightly broader high frequency content, and the CS stack has slightly broader low frequency content. Both stacks have a high signal-to-noise ratio from about 10 Hz to 60 Hz.

After this initial qualitative comparison, well-to-seismic ties are used as a more quantitative assessment of these datasets (Figure 4). Generally, the wells tied to the CS PSTM stack

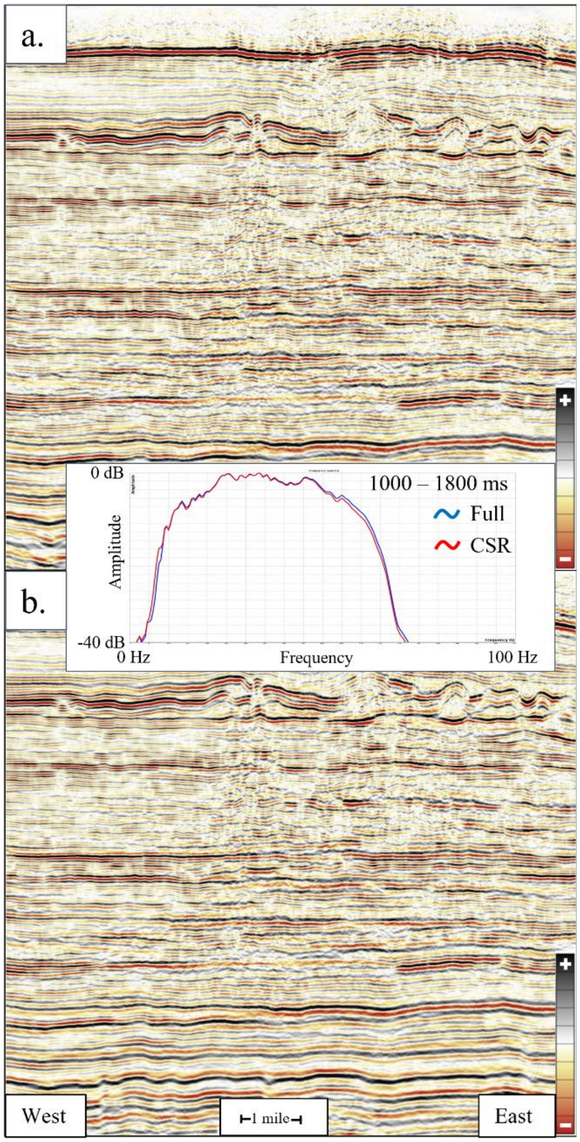

Figure 3: A comparison of (a.) Full PSTM Stack and (b.) CS PSTM Stack and their respective frequency spectra.

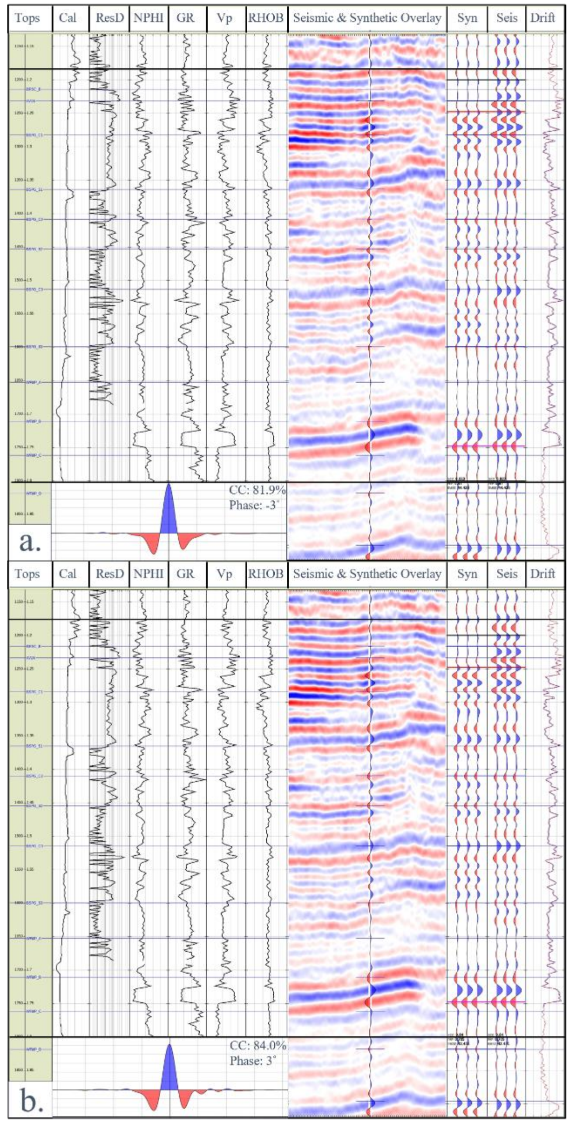

Figure 4: A comparison of well-to-seismic ties between (a.) Full PSTM Stack and (b.) CS PSTM Stack.

have slightly higher cross correlation values. The bandwidth, amplitude, and phase from the extracted Roy-White wavelets are very similar for each well between Full and CS well-to-seismic ties. The amplitude and phase do somewhat vary from well-to-well across the assessment area. However, when the ensemble of wavelets extracted from each dataset are averaged and compared, they are nearly identical.

The interpreted horizons provide structural and amplitude comparisons between the Full and CS datasets. Structural differences between these datasets are due to different statics solutions. While most differences across the assessment area are less than 2 ms, there can be differences of up to about 4 ms in two-way time. The horizon-based short-window RMS amplitude maps are very similar between a given horizon on each dataset. The main assumption in this analysis is that the horizon conversion map is accurate.

Similarly, acoustic impedance estimates from both CS and Full datasets are very similar (Figure 6). The CS dataset generally has a slightly higher cross correlation from

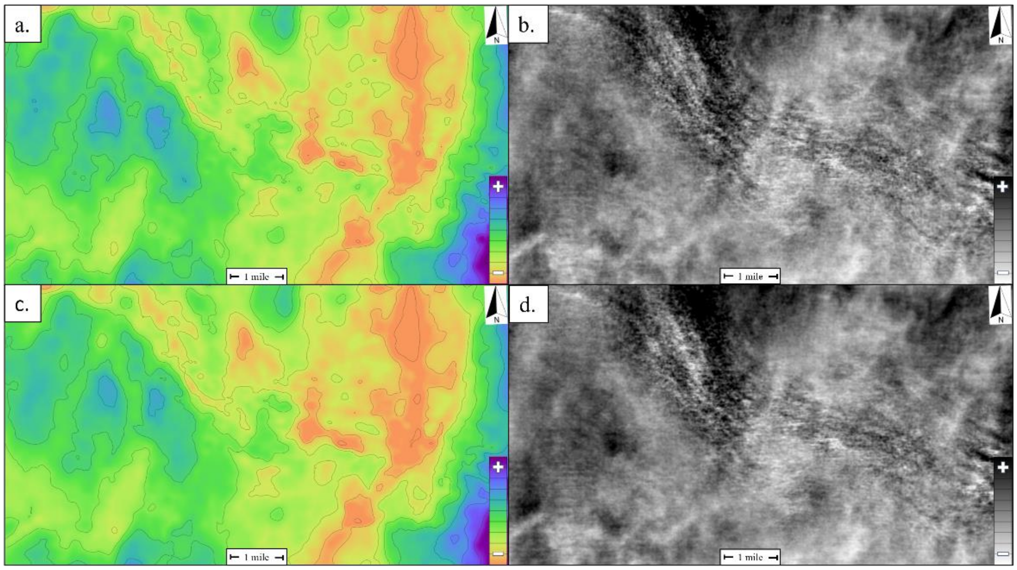

Figure 5: The Bone Spring Lime horizon (a.) converted to fit the Full PSTM image (b.) ± 4 ms RMS amplitude extraction over the Full horizon (c.) interpreted on the CS PSTM image (d.) ± 4 ms RMS amplitude extraction over the CS horizon.

well-to-well. The difference in statics is subtly noticeable when comparing these volumes.

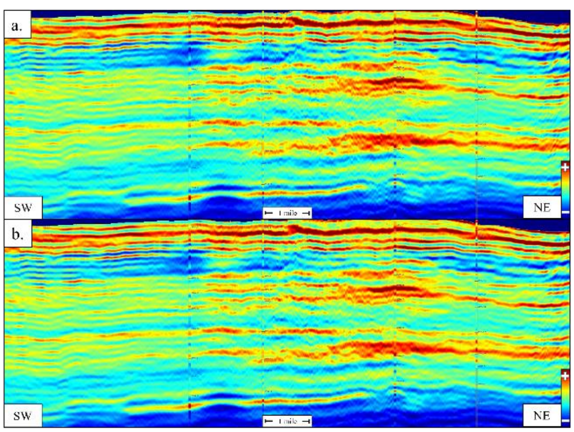

Figure 6: Acoustic Impedance extracted on a southwest to northeast arbitrary line with wells overlaid on (a.) Full and (b.) CS datasets.

Conclusions

One limitation of this test is that the 3D seismic data was not acquired with a compressive seismic design in mind. Therefore, the decimation and subsequent reconstruction are not optimal due to the regular nature of this acquisition design. In general, while the two volumes are very similar, the CS dataset seems to have a slightly higher signal-to-noise ratio. Despite this minor limitation, the results are encouraging.

The correlation coefficients from each well-to-seismic tie confirm this observation, as they are generally slightly higher on the CS dataset. Furthermore, the wavelet analysis shows that the Roy-White wavelets extracted at each well are nearly identical between datasets. The slightly higher signal-to-noise ratio on the CS dataset is possibly due to the CSR algorithm's utilization of the coherency of seismic signals.

The difference in statics solutions between these datasets is subtly evident. While these differences are generally quite small, an extreme case of a 4 ms shift in TWT between these datasets could account for approximately 30 ft of depth. Future work should include depth imaging of both datasets to assess how tomography and well calibration can minimize the structural differences due to statics in the time domain.

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