Fracture Model, Ground Displacements and Tracer Observations: Fruitland Coals, San Juan Basin, New Mexico, CO2 Pilot Test

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Abstract
This study incorporates observations from some of the experiments conducted on the Southwest Regional Partnership (SWP) for Carbon Sequestration’s San Juan Basin pilot test site. This enhanced coalbed methane recovery/carbon sequestration test was conducted in the thick coals of the Fruitland Formation in the high rate production fairway of the San Juan Basin. The pilot test was funded by the U.S. Department of Energy and managed by the National Energy Technology Laboratory. The SWP in collaboration with ConocoPhillips injected approximately 16,700 metric tons of CO2 into the Fruitland coals from July 23rd of 2008 through August 14th of 2009. 3D seismic data from the site revealed that the seismic response of the Fruitland Formation is recognizable as a well defined seismic sequence and that individual coal zones in the formation are generally detectable. 3D seismic data also revealed that structures in the Fruitland Formation and overlying Kirtland Shale are more complex than anticipated. Analysis of well log data revealed that the Fruitland Formation coal zones throughout the area surrounding the site consist of two coal beds, each separated by a shale parting. This observation indicates that the coal reservoirs consist of six separate coal beds rather than three. Perfluorocarbon tracer monitoring revealed early arrival of tracer in a direction roughly orthogonal to that anticipated prior to CO2 injection. Tiltmeter derived ground surface displacements revealed subsidence across the area rather than uplift. The additional information obtained from the studies conducted at the site during its multiyear duration provide the opportunity to revise our models of the reservoir and sealing strata and to obtain new insights into observed reservoir responses to CO2 injection. A model discrete fracture network (DFN) is developed for the Fruitland coals that incorporates results from this multiyear study. Fracture sets incorporated in the model are derived from FMI log observations. Attributes derived from the 3D seismic data over the site are analyzed to obtain insights into larger scale reservoir architecture that may control flow in the vicinity of the CO2 injection well. These attributes are combined with ground displacements observed during CO2 injection to guide the distribution of fracture intensity through the reservoir. Properties of the DFN including porosity, permeability and fracture storage volume are upscaled into a gridded model of the reservoir. The aerial distribution of reservoir parameters derived in this study will improve our understanding of Fruitland coal reservoirs; help develop more effective strategies to enhance coalbed methane recovery combined with CO2 storage; and, help guide future flow simulations of Fruitland coal CO2 floods in this region of the high rate production fairway.

Keywords: carbon sequestration; enhanced coalbed methane recovery; discrete fracture networks; 3D seismic attributes; reservoir model.

1. Introduction and background
1.1 Basic research effort
Efforts undertaken in this study include 1) post stack processing of seismic data to extract and enhance seismic responses that may be associated with fracture systems and small faults; 2) use of seismic attributes to control distributions of fractures in the reservoir fracture network; 3) incorporation of vertical surface displacements observed during CO2 injection into fracture model development; 4) definition of fracture porosity and permeability facies within the reservoir; and 5) evaluation of the relationship between high permeability pathways in the fractured reservoir to the movement of Perfluorocarbon (PFC) tracers between the CO2 injection well and surrounding storage wells.

1.2 Study area
The Southwest Regional Partnership (SWP) on Carbon Sequestration’s San Juan Basin carbon sequestration pilot site is located in the high rate production fairway of the San Juan Basin (Figure 1). The pilot test was undertaken in collaboration with ConocoPhillips as a joint CO2 enhanced coalbed methane recovery (ECBM) test with accompanying CO2 sequestration in deep, unmineable coal seams (see Oudinot et al., 2011; Wilson et al., 2012). The SWP conducted the pilot test in the high permeability...
Upper Cretaceous Fruitland coals in the high-rate fairway southwest of the northwest trending basin hinge (Figure 1). The pilot injection well is located on Pump Mesa at latitude 36.86° N, longitude -107.7° W (center of Section 32, T. 31 N., R. 8 W with WGS84 UTM Zone 13N coordinates of 259401E, 4082156N) (Figure 2).

According to Meek and Levine (2006) the Fruitland reservoirs are divided into four different “type production areas” (TPAs). The injection well was located in TPA 3 and corresponds to the over-pressured “High Rate Fairway”. The coals of the Fruitland Formation have been producing methane for decades. Fassett (2010) noted that production from coal bed methane reservoirs in the San Juan Basin reached about 28 billion cubic meters (BCM) per year with cumulative production from 7,736 wells reaching about 440 BCM. The Fruitland coalbed methane reservoirs are now being considered for enhanced coalbed methane recovery (ECBMR) using CO₂ injection. The use of CO₂ for ECBMR takes advantage of preferential adsorption of CO₂ to the coal matrix. Preferential adsorption of CO₂ makes CO₂ injection attractive for its potential to flush out residual methane from the coal matrix; however, the CO₂ molecules are larger than the methane molecules they displace and their adsorption leads to additional coal swelling and reduction of reservoir permeability (e.g. Sawyer et al., 1990; Levine, 1996; Palmer and Mansoori, 1998; Pan and Connell, 2007).

Swelling results in decreased injection rate at constant wellhead injection pressure. CO₂ induced swelling caused the injection rate to drop from nearly 70,000 m³/day to about 14,000 m³/day during the first half year of injection (Department of Energy, 2010; Oudinot et al., 2011).

1.4 Seismic response
Wilson et al. (2009) noted that the Fruitland seismic sequence is characterized by a well defined zone of high amplitude reflection events that extends from the top of the Fruitland Formation to the underlying Pictured Cliffs Sandstone. Coal zones within the Fruitland also form recognizable events that can be correlated through the area (Figure 2). Resolution limits estimated for the coal zones (Weber et al., in review) ranged from about 10 to 22 ft. This suggested that the thickness of the upper and middle coal zones were near the resolution limits while the lower Fruitland coal zone was thick enough to be resolved.

2. 3D Seismic Analysis
2.1 Depth Conversion
The development of seismic attributes used to control fracture intensity was undertaken using a depth converted 3D seismic volume. Reflection travel times to various reflectors interpreted in the seismic were converted to depth using the velocity function shown in Figure 3.

![Figure 1: Outline of the San Juan Basin and Fruitland high-rate fairway. The pilot site is located southwest of the northwest trending basin hinge near the southwestern edge of the fairway (modified from Heath, 2010).](image-url)
Figure 2: In this 2D seismic display, locally steepened dips are evident across the area. This line trends northeast-southwest. Considerable internal discontinuity of reflection events is evident throughout (from Wilson et al., 2009).

Figure 3: Velocity function used to convert two-way-travel times to depths.
2.2. Discontinuity detection workflows

In this study, the 3D seismic response is used to control the distribution of fractures within reservoir and seal intervals. Wilson et al. (2012) developed a standard workflow to generate and test various approaches to discontinuity detection and enhancement. An assumption made in this approach is that discontinuities represent deformed areas and that regions proximal to these discontinuities will be more highly fractured. This assumption is generally valid in relatively uniform lithologies. In more complex depositional systems, the issue of differentiating between structural and stratigraphic influences is a critical consideration. However, discontinuities of structural and stratigraphic origin can usually be differentiated by their morphological expression.

Post-stack processing workflows developed as part of our pilot site characterization efforts (Figure 4) outline some approaches that might be followed to prepare seismic data for discontinuity identification. In most cases we would start with the seismic amplitude data. This would be the end product delivered by the processor to the interpreter: a 3D migrated CMP stack volume. Depending on interpreter preference, this data may be in a “true amplitude” format: one in which the amplitudes are generally assumed to be proportional to reflection coefficients between subsurface acoustic boundaries imaged in the geologic strata (Path I at left in Figure 4). The amplitude response is generally one that provides a band-limited view of subsurface reflectivity. A simple alternative to working with the amplitudes is to take the absolute value of the amplitude (Path II, Figure 4). The absolute value produces an apparent increase in signal bandwidth. Subtle structures are often enhanced in the visual displays. Statistical correlations are also likely to change in response to changes in spectral bandwidth and spectral shape. Taking the absolute value of the derivative (Path 3 Figure 4) is another approach used to bring out subtle structural and stratigraphic detail in the data (Wilson et al., 2009; Wilson et al., 2012). The process of taking the derivative of a digital data set does more than introduce a simple π/2 phase shift. The derivative produces significant enhancement of the higher frequency components in the data. High frequencies in the data may be dominated by noise making it necessary to design a lowpass filter to reduce the influence of noise introduced by the derivative and absolute value processes. In this study we extract discontinuities from the amplitude data following Path I (Figure 4). Examples of these possible input formats (Figure 5) reveal both obvious and subtle differences in response.

Procedures for extracting discontinuities include additional processing steps designed to measure local variability in dip or signal coherence. The variance approach (van Bemmel and Pepper, 2000) provides a measure of difference relative to the local mean. The number of inline and crossline traces along with the number of vertical samples used to compute local variance can be adjusted to the scale of interest. Areas of high variance are associated with variability in seismic response. High variance zones may result from both stratigraphic and structural variability. Again, the morphology of high variance features usually guides the interpretation of their origin.

Dip deviation is another approach that provides information about local structural variability. Deviation is computed relative to a smoothed estimation of local dip. Patterns of local dip deviation may occur across subtle faults or may be due to local velocity anomalies and travel time differences associated with fracture zones. Chaos is a procedure developed by Randen and Sonneland (2004) that is based on principal components decomposition of local dip and dip azimuth. If the eigenvalue of the first principal component is much larger than the other two, the signal is considered coherent; if their difference is small, then the signal is considered chaotic. Chaotic zones or zones across which there is considerable variability or indefiniteness of event orientation provide another measure that can reveal the presence of structural discontinuity and stratigraphic texture.

The various paths in the workflow lead to Ant Tracking (Figure 4). In this process (Pedersen et al., 2002), zones of seismic variability defined by variance, dip deviation, chaos or other measures of trace-to-trace seismic variability are scanned and evaluated for continuity or persistence through the seismic volume. Numerous parameters can be adjusted in this process to make identification and extension of features more or less restrictive. Less restrictive parameters allow “ant tracks” to continue through regions of less significant signal variability. The output provides a 3D representation of zones of disruption that may be associated with zones of increased fracture intensity.
Figure 4: Flow chart illustrates processing steps used in this study to extract seismic scale discontinuities.
2.3 Fracture intensity drivers

The distribution of seismic discontinuities in the subsurface is interpreted to reflect the distribution of fracture zones and small faults throughout the area. Zones of discontinuity extracted using workflows outlined in Figure 4 provide one possible driver or control on the distribution of fracture intensity throughout the subsurface. The use of Ant Tracking on the dip deviation volume revealed considerable reflection disruption in the vicinity of the injection well and nearby production wells (Figure 6). The intensity of seismic discontinuities decreases upwards from the lower coal zone. This suggests there may be some association between the relative degree of disruption observed in the reservoir to injectivity tests conducted at the site (DOE, 2010), which suggested that 80% of injected CO\textsubscript{2} went into the lower coal interval.

Curvature has also been shown to have direct relationship to fracture intensity (Staples and Marfurt, 2011; Yenugu and Marfurt, 2011). Staples and Marfurt (2011) reported linear correlations between curvature and fracture intensity developed in deformed clay models. Correlation varied from about 72% during extensional deformation to 95% during compressional deformation. Yenugu and Marfurt (2011) made simplified estimates of curvature on amplitudes and time structure. Fractures observed in an image log from a horizontal well showed increased intensity on the hinge of a fold and decreased intensity in the syncline. In this study we calculate maximum volume curvature (Figure 7). Marroquin and Hart (2004) used horizon curvature to identify two dominant structural trends and predict high permeability zones in the lower Fruitland Formation.

The relationship between seismic discontinuities, volume curvature (or surface curvature) and fracture intensity is strain based. Areas of structural disruption and increased curvature are areas of increased strain and as a consequence are likely areas of increased fracture intensity. In this study we also incorporate an additional driver derived from vertical surface displacements that occurred during CO\textsubscript{2} injection. The vertical surface displacements (Figure 8A) were computed from variations in surface tilt during the year-long period of CO\textsubscript{2} injection. Although the surface displacements are quite small, ranging from just over zero to about -17 mm, they represent active present day short term strain. This kind of strain could increase apertures and could enhance permeability. Maximum curvature is computed on the displacement surface and used as an additional control on the distribution of fracture intensity.

Figure 5: Path I, II and III inputs. A) Amplitude; B) Absolute value of filtered amplitude data with 75ms AGC; C) Absolute value of derivative of filtered amplitudes with 75ms AGC.
Figure 6: A) Ant Tracks on the lower Fruitland coal. B) Ant Tracks are superimposed on all 6 coal beds in the Fruitland coal zones.

Figure 7: A) Volume curvature on the lower Fruitland coal. B) Volume curvature superimposed on all 6 coal beds in the Fruitland coal zones.
We develop a composite fracture intensity driver by combining these three attributes. Seismic discontinuities were given twice the weight of volume curvature and curvature on the vertical displacement surface. The composite driver (Figure 9) reveals considerable variability in fracture intensity throughout the region surrounding the injection well.

**Figure 8:** A) Vertical surface displacement. Values range from just over zero to about -17mm. B) Curvature draped on the displacement surface.

**Figure 9:** A) Composite driver on the top of the upper coal zone; B) Composite driver on the top of the lower coal zone.
3. Fracture model

The distribution of fracture intensity through the model is controlled by the composite driver (Figure 9). Based on the background fracture studies conducted at the site and noted in surrounding areas we developed a basic model that consisted of three fracture sets and assumed they were present in roughly equal numbers. The three sets incorporated in the model consist of a N55W set, a N35E set and a NS set. The NW and NE sets are generally consistent with observations in the region although their average orientation varies. The N55W and N35E sets coincide roughly with the regional strike and dip, respectively, of the San Juan Basin in this area. The NS set is reported by Lorenz and Cooper (2003). Lorenz and Cooper (2003) reported pervasive north to north-northeast oriented extension fractures in exposures of the underlying Mesaverde and Dakota sandstones primarily in the northern half of the basin. They suggested these fractures formed in response to an approximately north-south directed stress during the Laramide orogeny. Roughly north-south to north-northeast south-southwest oriented fractures were also observed in the image logs from the injection well. The north-northeast trend is also the prominent fast-shear direction observed throughout the Fruitland coal section (Wilson et al., 2012).

Siriwardane et al. (2012) derived permeability in the vicinity of the injection well that averaged around 135 mD for the face cleats. Laubach et al. (2003) presented a relationship between permeability and aperture derived from productive coalbed methane wells in the San Juan and Black Warrior basins that suggests cleats with this permeability have approximately 70µ aperture. We used a power law aperture distribution that varied from approximately 0.00004 to 0.0004 ft (~12 and 122µ). The majority of the apertures are clustered between about 12 and 30µ. The composite driver (Figure 9) was used to distribute the three fracture sets noted above through the model. A close-up view of the fractures is shown in Figure 10.

The properties of the model fracture network (Fig. 11) were upscaled into the model grid following procedures outlined by Schlumberger (2009). Directional permeability in this study was calculated using the tensor approach of Oda (Oda, 1984; Dershowitz et al., 2000). Porosity is upscaled as total fracture pore volume within a model cell (total fracture area times aperture) divided by the cell volume. The permeability is derived from the combined length, aperture and intensity distributions defined for all fracture sets in the network.

The porosity and permeability distributions associated with this network are shown for the lower A coal bed (Figure 11). The locations of the injection and production wells are shown for reference. High porosity bands extend generally along a N20W trend through the area (Figure 11 A). Patterns appearing in the porosity distribution are similar to those in the driver (Figure 9B). The permeability in the i (or east-west direction, Figure 11 B) is less than the permeability in the north-south (j) direction (Figure 11C). The j permeability is, in turn, less than that in the vertical direction. Overall, the comparison indicates that the patterns of the composite driver are imprinted on the reservoir properties.

Figure 10: Local distribution of fractures in the vicinity of the CO2 injection well.
4. Discussion

Perfluorocarbon (PFC) tracers were injected shortly after the start of CO₂ injection. Tracer injection consisted of three week-long sequential injections (DOE, 2010; Wells et al., in review). A uniform tracer mixing rate was maintained during each injection period. Three nearby methane producing wells were monitored by the SWP for changes in CO₂ concentration and the arrival of the perfluorocarbon tracer (e.g. Figure 7). These wells include the 300 (EPNG Com A 300), FC1(FC State Com 1) and 300S (EPNG Com A 300S) (Figure 7). Initial predictions preceding injection were that CO₂ would first appear in the southwest producer (well 300, Figure 7). This prediction seemed likely since evidence from the nearby NEBU well (Mavor and Close, 1989) indicated that the more permeable face cleats in the region trend N35E (or S35W) roughly along a line connecting the two wells. Distinct breakthrough of CO₂ was not observed in any of the surrounding methane producers. Possible indications of
breakthrough were observed in the FC1 well to the east-northeast, which showed a steady increase of CO₂ from 22% to 25% in the first three months following the start of injection (DOE, 2010). However, distinct arrivals of perfluorocarbon tracers were observed in both the 300 well to the southwest and FC1 well to the east, but arrival times were opposite those expected. PFC tracers were initially observed in the FC1 well to the east in November of 2008, a little over 3 months after injection started. The tracers did not make it to the southwest 300 well until February of 2009 (DOE, 2010; Wells et al., in review).

The reservoir properties maps (Figure 11) reveals that a larger fraction of the reservoir between the injection well and the producing well to the east has relatively higher porosity and permeability than the area between the injection well and the southwest producer. The higher permeability zones to the east suggested by the seismic response and surface displacement curvature may help explain the rapid arrival of tracer in the well to the east. The surface displacement ridge that extends between the injection well and the FC1 well is also a higher curvature area with curvature most likely occurring normal to the ridge and preferentially opening fractures in a direction normal to the ridge axis.

5. Summary and Conclusions
Properties associated with rock strain were extracted from 3D seismic and tiltmeter derived surface subsidence data from the Southwest Regional Partnership for Carbon Sequestration’s San Juan Basin pilot site. Seismic properties associated with rock strain and fracture included seismic discontinuities and volume curvature. Seismic discontinuities are interpreted to be produced by small scale faults and fracture zones. Areas of increased curvature also represent areas of increased strain and may be more intensely fractured. Differential surface subsidence is also likely to produce slight increases in existing fracture apertures. A ridge of relatively less surface subsidence extends between the CO₂ injection well and the FC1 produce to the east. PFC tracers appeared in the eastern producer (FC1) 3 months after injection started. It took an additional three months for tracers to appear in the southwest producer (300). Curvature across this subsidence ridge may have produced some overall enhancement of permeability between these two wells along that ridge.

A discrete fracture network (DFN) was created for the reservoir using observations derived from a variety of data sets available over the site. A composite fracture driver was developed by combining measures of seismic discontinuity obtained from 3D seismic data over the site, volume curvature (also calculated from the 3D seismic data) and curvature associated with surface subsidence during CO₂ injection. The surface subsidence data was obtained from tiltmeter measurements over the site. The composite driver was used to distribute the intensity of fracturing throughout the reservoir intervals. Observations from high resolution satellite imagery, surface fracture mapping, image logs and shear wave polarization in the CO₂ injection well suggested the presence of at least 3 systematic fracture sets. These three sets have roughly average orientations of N55W, NS and N35E. Length and aperture distributions were assigned using power law relationships.

DFN properties were then upscaled into a 100 x 100 x 5 ft grid. Porosity and permeability distributions associated with the discrete fracture network include continuous zones of relatively higher porosity and permeability. These zones are positioned in such a way as to preferentially enhance flow between the injection well and eastern producer rather than the injection well and the southwestern producer. The results suggest that physical properties related to fracture distribution can be extracted from 3D seismic and vertical displacement data. Reservoir porosity and permeability distributions inferred from the DFN help explain differences in CO₂ migration times to surrounding methane production wells.

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