TIME-LAPSE PP SEISMIC TO CHARACTERIZE STIMULATION AND PRODUCTION BEHAVIOR IN THE NIOPRARA AND CODELL RESERVOIRS WATTENBERG FIELD, COLORADO, US

by

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ABSTRACT

The primary source of present-day, on-shore oil and natural gas production in the United States is within unconventional, tight reservoirs. Recovery factors in unconventional reservoirs are typically 5-15%, and substantially less than in conventional reservoirs. Current hydraulic fracturing and completion efforts are directed to improving recovery, where even a 1% increase could substantially impact the economics of the field.

The Wattenberg Field is among the most successful unconventional fields in the United States, targeting the Niobrara and Codell formations. The Reservoir Characterization Project in conjunction with the field operator, Anadarko Petroleum Corporation, acquired three multi-component, time-lapse seismic surveys over a four-square mile area to study the stimulation and production effects associated with 11 horizontal wells. The baseline survey was acquired prior to drilling the wells. The first monitor was acquired during completion of these wells, and the second monitor acquired after two years of production to observe dynamic changes to the reservoir. Time-lapse, pre-stack seismic inversion of the compressional wave data was performed to analyze the changes to the reservoir at these two pivotal instances. Observing changes from monitor one (during completion) to the baseline has provided an understanding of the effectiveness of the hydraulic stimulation, and the opening of existing and new fracture networks. There is no in-situ free gas in the reservoir; however, after 90 days of production, near-wellbore reservoir pressures drop below bubble point and gas is released from solution. During the two-year interval between the acquisition of the first and second time-lapse seismic data, the 11 wells experienced an increased gas production and increasing gas-oil-ratios over time. The inversion result from the second monitor with reference to the baseline survey provides information about the influence of gas on the system, thereby indicating the effectiveness of the completion and contributing reservoir volume.
Time-lapse seismic inversion has allowed for a self-consistent interpretation of the oil and gas production, directly correlating to the stimulation and production, in addition to in-situ stress and structure as it relates to a change in compressional velocity. The results of this study will assist in understanding these variables to help guide future field operations and completion strategies.
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CHAPTER 1
INTRODUCTION

The Colorado School of Mines (CSM) Reservoir Characterization Project (RCP) has been supported by Anadarko Petroleum Corporation (APC) for Phases XV and XVI. The RCPs primary objective is to provide recommendations to enhance recovery and operations by providing an analysis of the dynamic changes to the Niobrara and Codell formations within the Denver-Julesburg (DJ) Basin, Colorado. The study area is 1 square mile, referred to as the Wishbone Section, located in the southern core area of the Wattenberg Field, Colorado, USA. The Wishbone Section is owned and operated by APC, and was used as a test section for well spacing, formation targets, and completion design to determine key variables that would enhance recovery and improve operational efficiency.

Time-lapse seismic has been used in the conventional reservoir (sandstone, high porosity/permeability) setting for decades tackling a variety of dynamic mechanics that influence the ultimate recovery (EUR via enhanced oil recovery (EOR)), compartmentalization (fractures/traps) and prolonged reservoir integrity (subsidence). History of time-lapse seismic has proved dynamic changes in acoustic waves being most sensitive to porosity. More specifically, as a reservoir is depleted there is a decrease in porosity directly associated with a pore pressure decrease creating an acoustically faster media that is observable in a time-lapse study. Time-lapse seismic has not been widely implemented to characterize unconventional tight-rock reservoirs as they are a magnitude less in porosity than their conventional sandstone counterparts. This has caused wide-spread hesitation by industry to economically risk time-lapse acquisition and study. Hydraulic fracturing is key to developing tight-rock reservoirs with the sole intention of increasing permeability in the reservoir in relation to the wellbore(s). Hydraulic fracturing would provide the inverse effect on conventional applica-
tions for time-lapse seismic, where an effective increase in permeability and pore pressure would cause a slowing of the reservoir. A time-lapse study acquired during stimulation in a tight-rock reservoir would provide a more accurate estimation of completion effectiveness, in addition to quantifying uncertainties specific to other geoscience data such as microseismic, when interpreting a stimulated rock volume (SRV).

Conventional time-lapse seismic applications are also used to detect gas influence on a given reservoir system. An miscible/immiscible gas-flood would increase reservoir pressures and assist the release of by-passed hydrocarbons contained in the reservoir’s porosity. Candidates for this application have retained only formation water and liquid hydrocarbons, but no presence of gas. Injecting immiscible gas increases reservoir pressures and influences liquids to producing wells. A miscible injection would result in a mixing of the solution, increasing reservoir pressure and occupy pore space originally occupied by the liquids. Both of which have been successfully monitored via time-lapse seismic due to the dramatic increase of compressibility resulting from even the smallest influence of gas (Ostrander, 1984).

The Niobrara and Codell reservoirs in the RCP study area are overpressured and saturated by hydrocarbons because of a protruded thermal anomaly along Colorado’s mineral belt creating an ideal kitchen window for the local and inter-bedded source rock (Sonnenberg and Underwood, 2013). Pressure, Volume and Temperature (PVT) analysis performed near the RCP study area indicates that gas is being released from solution after roughly 90 days of production where there is no free gas initially in the system. The acquisition of a time-lapse survey after a given production period greater than 90 days would capture the increase in compressibility of the reservoir, associated with a slowing effect on both compressional and shear velocities. The ”softening” observed in the seismic data will be explained by increased gas saturations indicating areas structurally or lithologically compartmentalized. These observations will directly apply to the effectiveness of the stimulation, and thereby
have a direct influence to future completion design and field operations.

Current operations and completions in the Niobrara and Codell reservoirs are economic, but average only 8% in recovery factor between the two. RCP and APC are implementing dynamic reservoir characterization in order to bridge the gap in recovery factor between unconventional reservoirs and conventional reservoirs. Time-lapse seismic technology can advance the current understanding of unconventional reservoirs by providing a three-dimensional representation of changes over time.

Time-lapse, multi component (9C/4D) seismic surveys were acquired over the Wishbone Section to observe completion and production effects to the reservoir. The RCP has been involved in with Anadarko in the Wattenberg Field since the Fall of 2013. Figure 1.1 illustrates the RCP’s involvement between project Phases XV and XVI. The baseline survey was acquired over initial reservoir conditions after drilling, first monitor survey (Monitor 1) acquired during/after completion and second monitor (Monitor 2) after two years of production. This study will cover the stimulation and production effects to the reservoir with a multidisciplinary focus to aid in enhancing recovery and operations.

Figure 1.1: Timeline of Phase XV and XVI, providing RCP involvement and available data via Anadarko Petroleum Corporation.
1.1 Objectives

This thesis will focus on the time-lapse response of the compressional (PP) seismic data in the Wishbone Section in association with the stimulation and production of the Niobrara and Codell formations. Several intermediate goals were achieved during this process including:

- Cross-equalized pre-stack PP 3D volumes for both Monitor 1 and Monitor 2 surveys with respect to the Baseline survey as input to future time-lapse studies
- Time-lapse, pre-stack inversion of Baseline and cross-equalized Monitor surveys, gaining accurate compressional impedance (Ip) volumes and their differences
- P-velocity ($V_p$) changes from increasing pore pressure after stimulation (Monitor 1)
- Modeled changes in $V_p$ for a combined pore pressure increase after two-years of production and gas out of solution (Monitor 2)
- Integrated interpretations associating this study with previous RCP work to constrain reservoir simulation iterations

1.2 Data Overview

The data used in this study was provided by both RCP and Anadarko Petroleum Corporation with its relative location in the Wattenberg Field in Figure 1.2, with an enhanced view of this location and the data available to RCP shown in Figure 1.3. The data behind the focus of Phase XV and XVI is three time-lapse (4D), multicomponent (9C) seismic surveys (Turkey Shoot) that are roughly 4 square miles, centered over 11 horizontal wells in the Wishbone Section provided in Figure 1.4.

Figure 1.4 provides a map overview of the Turkey Shoot location with the 11 horizontal wells and the nine wells used in the PP pre-stack inversions. There are eight preexisting vertical wells in the Turkey Shoot (Blind Wells A-B and Wells B-G), none of which had real sonic logs. A neural network was used to calculate synthetic sonic logs for all of the wells.
Figure 1.2: Map of Northeast Colorado highlighting the RCP study area with respect to a rough outline of Wattenberg Field (green).

Figure 1.3: Overview of the seismic data, sonic data and core data in available to the RCP.
within the survey bounds. There is only one well near the Turkey Shoot that had dipole sonics acquired and was transposed into the survey, avoiding structure variations, and maintaining consistent impedance through the entire reservoir interval shown in Figure 1.5.

1.3 Geologic Overview

The Denver-Julesberg (DJ) Basin is located directly east of the Rocky Mountains in Colorado and extends to Wyoming, Nebraska and Kansas. The basin extends over 70,000 square miles, but the most prolific portion of the basin is located within the Wattenberg Field, roughly 1600 square miles, in Northeast Colorado (Figure 1.2). The DJ is an asymmetric foreland basin, steeply dipping to the west and gently to the east Figure 1.6.

The Wattenberg Field was discovered in 1970 by Amoco Production Company with gas completions in the J Sandstone. Future development of the field led to multiple pay zones considered to be unconventional plays requiring hydraulic fracturing stimulation. Since the unconventional boom in the early 2000’s, the Niobrara formation has grown to be one of
Figure 1.5: A P-impedance extraction through the entire reservoir interval, showing the original location of Well A within the Anatoli survey and its transposed location into the Turkey Shoot survey boundary. Its new location was supported by the similarity in structure and consistent geology.

Figure 1.6: Cross section of the DJ basin from west to east, from the foothills of the Rocky Mountains to the borders of Kansas (Sonnenberg and Underwood, 2013)
the most profitable unconventional discoveries in the United States. The Niobrara includes two members: the Smoky Hill and Fort Hays. The Smoky Hill is the main interval of interest, consisting of inter-bedded limestones and calcaerous shales. For simplicity, they are commonly referred to as oscillating chalks and marls that are labeled in sequence A-C, Figure 1.7. The Wishbone section however, does not have the A interval as it is thought to be eroded due to a paleo-high. The Fort Hays member is a tight Limestone that vastly differs in character. Having almost no permeability or porosity, it acts as a barrier to reservoirs below. The Sharron Springs and the Pierre Shale are a regional seal for the Smoky Hill member of the Niobrara. It is also important to note that the individual marl benches are also thought to be a local, restrictive seals, allowing for more hydrocarbons to be trapped in the chalks.

The Niobrara ranges 200 to 400 feet in total thickness, where the individual benches are 30 to 50 feet thick at total depths of 7200 to 8000 feet below surface in the Wattenberg Field. The chalks and marls are inter-bedded and can be difficult to interpret on log data as provided in Figure 1.8. The chalks are separated from the marls with higher resistivity (>30 ohmm), lower gamma ray, higher porosity, and higher permeability. Mineralogically, the chalk and marl interfaces are gradational, and typically do not have a distinct interface (Matthies, 2014). This is significant because seismic data cannot distinguish these individual benches. The inter-bedded nature of the Niobrara is also thought to be the reason for its continued success throughout the field, as the formation could be penetrated anywhere in the field and withdraw hydrocarbons with well designed completion.

The Codell Sandstone is the other reservoir of interest, and lies directly beneath the Fort Hays member of the Niobrara. The Codell is anywhere from 10-20 feet thick, at roughly 7400 to 8200 feet of depth from the surface in Wattenberg Field. It is a sandstone that is comprised of cross-stratified and bioturbated, clay rich siltstone. Beneath the Codell is a more malleable and clay rich Carlile shale which is known to be a drilling hazard; it is
Figure 1.7: Generalized stratigraphic column of the Denver Basin with multiple pay intervals identified with the black asterisks. The RCP study area does not have an A Chalk unit, as it was eroded during a paleo-high. Modified from Sonnenberg and Underwood (2013).
Figure 1.8: Type log for the RCP study area from a well located in the Anatoli survey (Mabrey, 2016).
rubilized and can dramatically increase rig-time associated with low rates of penetration on the drill bit. There are 11 total horizontal wells in the Wishbone section with seven Niobrara wells and four Codell wells (Figure 1.9)

Figure 1.9: Cross section showing the target and kickoff intervals in the Wishbone Section. Well spacing tightens from East to West also better overall production (oil/gas) to the West.

1.3.1 Depositional History

The Niobrara formation was deposited during the Late Cretaceous in what was the Western Interior Seaway. This time period consisted of fluctuating sea-level and climate resulting in multiple transgressive and regressive shore faces. This ever-changing sea-level is the reason for the oscillating chalk and marl benches mentioned in Section 1.3.

The Western Interior Seaway is thought to have covered the larger part of North America which included cold (Boreal) water from the North (present day Arctic Ocean), and warm
(Tethyan) water from the south (present day Gulf of Mexico) portrayed in Figure 1.10 and Figure 1.11. This seaway had adjacent bordering landmass that provided a large clastic input source for the basin. The Wattenberg Field at the time of deposition was positioned to the more southern portion of the seaway. During times of transgression, there was more influx and circulation of warmer currents ideal for the coccolith-rich carbonate chalks to be deposited. During times of regression, warmer currents would retreat and create suitable conditions for anoxic marl deposition at higher rates.

Figure 1.10: Paleo-reconstruction during the Late Cretaceous, providing the WIS from the present day Arctic Ocean to the Gulf of Mexico (Blakey, 2014).
Figure 1.11: Detailed map of deposition during the Late Cretaceous Niobrara. Showing colder currents flowing from the Arctic and warmer currents from the Gulf (?).
1.3.2 Tectonic History

Exploiting unconventional reservoirs has entailed hunting for conglomerated fracture networks, with the intention of gaining higher permeability in these tight reservoirs. Hydraulic stimulation of these zones is thought to increase this effective permeability further by building even greater networks and more local fracture density. Particularly in the Wattenberg Field, it has been proven that these fracture networks have been sought out and utilized to increase recovery (Vincelette and Foster, 2011). In doing so, these networks are likely to establish conduits allowing hydrocarbons to more easily flow back to the wellbore (Warpinski et al., 2014). These natural fractures are associated with the tectonics of the area and can be either open or calcite filled.

In the Niobrara, the simultaneous deposition of chalks and marls create planes of weakness as they bind together during deposition. These planes of weakness fail when stressed, creating these natural fracture networks. The Niobrara has been exposed to two major tectonic events which are pivotal when building an understanding of how the resulting fractures aid in production.

The Laramide orogeny is the first of these two major tectonic events, resulting in basement controlled, right lateral wrench faulting which strikes southwest/northeast. This compressional tectonic event caused many of these open fracture networks in our study area Figure 1.12. Secondary faulting is also associated with these wrench faults, striking east/west and northeast/southwest and are situated appropriately with the maximum compressional stress in the field. None of the major wrench fault zones intersect the RCP study area, but associated compressional fault networks and the associated secondary faulting can be easily interpreted. This observed stress is understood to be the current paleo-stress in the Niobrara observed from microseismic, image logs and azimuthal shear-wave amplitudes (Motamedi, 2015).
The second major tectonic event, during the mid-Tertiary, is potentially more important when aiding recovery, generating post-Laramide fractures (Vincelette and Foster, 2011). This extensional stress pulled the previously compressed basin apart, causing resettling and subsidence of the previously mentioned flower structures. This has effectively created a series of grabens abundant through the field which can be widely observed in the RCP study area. The interior (subsided) area of these grabens are complex which is observed from drilling many wells intersecting dominant structural features. It is also important to note that there is also perpetuating structure around the perimeter of the grabens that are parallel in strike. In the Wishbone section these faults and fractures are typically calcite filled, seen in the core and interpreted on image logs Figure 1.13.

Studies such as Sonnenberg and Underwood (2013) and Sonnenberg et al. (2016) suggest that there are three fault styles in the DJ Basin: wrench, polygonal and salt dissolution. There are also faults that are slightly listric in nature prevalent within the Cretaceous section of the DJ. These listric-type faults (Figure 1.14) can be seen in Lower-Pierre shale and usually truncate in the Niobrara to Greenhorn interval (Davis, 2011). After looking at the seismic, these faults have high inclinations (20 to 50 degrees) supporting the listric geometry and interpretations. The recurrent movement through tectonic history could also potentially hinder production if sufficiently healed by calcite (Davis, 2011).
Figure 1.12: Wrench faulting and their relative locations in the Wattenberg Field with respect to the RCP study area. The color data is the estimated ultimate recovery (EUR) regarding gas production in Wattenberg Field. Modified from (Higley et al., 2003).
Figure 1.13: Rose diagrams associated with FMI interpretation providing the open and sealed fractures associated with the Mid-Tertiary event, faults from the Laramide compressional event, and the drilling-induced fractures (Dudley, 2014). The fractures that are "open and sealed" are indicative of the paleo-maximum horizontal stress and the "induced" fractures is the current maximum horizontal stress.

Figure 1.14: Schematic showing listric faults and the associated increase in fracture density with normal faulting (Davis, 2011).
CHAPTER 2
SEISMIC DATA OVERVIEW AND CONDITIONING

This chapter of the study will provide a brief overview of the new co-processing completed by Vecta Oil and Gas after the Phase XVI, Monitor 2 acquisition. It will also cover the preliminary data conditioning necessary for the pre-stack PP, time-lapse inversion.

2.1 Seismic Data

The data used in this study was provided by Anadarko Petroleum Corporation and is noted as “Turkey Shoot” outlined in Figure 1.4. The data consists of three surveys, all of which are 9 component and shot with the intention of a time-lapse study. The first of the three surveys (Baseline, BL) was shot after drilling the 11 horizontal Niobrara and Codell wells in the section. The first Monitor survey (Monitor 1, M1), was shot during the completion of these Wishbone wells, in order to measure the stimulation effects to the reservoir. Lastly, the second monitor survey, (Monitor 2, M2) was acquired to measure the production effect and thereby gain perspective on the contributing reservoir volume. These surveys are all four square-miles in size, centered over the Wishbone section as the main study target. Fold is highest over the Wishbone horizontals provided in Figure 2.1. Data was delivered from Vecta Oil and Gas as both pre-stack time migrated (PSTM) gathers and stacks Figure 2.2 and Figure 2.3. This study incorporates the pre-stack data, which will be further discussed in Section 2.3. Section 2.2 will follow to discuss key aspects pertaining to the data consistency and repeatability, which is paramount for any time-lapse seismic study.

The time-lapse seismic surveys were all acquired by Paragon Geophysical to maintain consistency in acquisition using INOVA’s cableless system (Hawk). Each survey had different influences on data quality due to changes in surface conditions. The BL survey was
acquired at the end of summer with relatively dry conditions but a noteworthy amount of field noise attributed to operational activity within the Turkey Shoot survey area. The M1 survey was acquired after a 100-year-flood that occurred in Northern Colorado, heavily saturating the surface with water. The final, M2 survey was acquired during the winter two years later with frozen surface conditions.

Figure 2.1: Fold coverage in the Turkey Shoot survey ranging from 40 to over 100. Wells with respect to Figure 1.4 provided in addition to the 11 horizontal Niobrara and Codell wells.

The PP data is fairly good quality for a small land survey, however the data does not have high-enough fold to observe higher incidence angles at the reservoir interval. It was necessary to analyze the extent of the angle coverage in the far traces moving towards the perimeter of
Figure 2.2: Section view of the full-fold gathers with their interpreted Niobrara (blue) and Greenhorn (green) horizons to provide location of reservoir.
Figure 2.3: Section view of the full offset range stack and its interpreted Niobrara (blue) and Greenhorn (green) horizons to provide location of reservoir, faulting (yellow).
the survey and lower-fold data in order to determine the seismic AVO predictive capability for inversion (Simmons and Backus, 1996). In order to observe this, the RMS migration velocities provided with processing were applied to the gathers to overlay incidence angle. Incidence angles for a gather in a high fold location stretch to $45^\circ$ at the reservoir interval (Figure 2.4). The dominant frequency of the data is roughly 23 Hz and the bandwidth ranges from 10 Hz to 60 Hz shown by Figure 2.5.

![PP Offset Gathers Colored by Incident Angle](image)

Figure 2.4: Incidence angle colored over pre-stack gathers from the BL survey. The top of the Niobrara peak spans from $0^\circ$ to $45^\circ$ in high fold areas.
2.2 Time-Lapse Co-Processing

Acquisition of these data were held as constant as possible to ensure the time-lapse repeatability of these surveys. With the new acquisition of Monitor 2 (M2) in Phase XVI, the previous surveys Baseline (BL) and Monitor 1 (M1) were co-processed with M2, further increasing their repeatability. The data underwent simultaneous processing of the time-lapse volumes to ensure repeatability further explained in (Lumley et al., 2003). In conventional processing sequence, the surface locations are labeled consistent but via Lumley et al. (2003), the sources and receivers are regarded consistent. The direct benefit of simultaneous processing is implementing a single near surface velocity model for refraction statics. This will be a major process to consider during Section 2.4. The simultaneous processing also allows for monitoring repeatability metrics throughout the workflow. Mismatched traces between volumes were eliminated from the process. Phase and time shifts were also observed regularly after each processing step from 500 - 1500 ms in the PP data. The phase differences ranged from -20 to +20 degrees and the time shifts from -4 to +4 ms on average. These values were considered negligible so phase and time shifts were not applied. Again, this will be important to remember for Section 2.4. Cross-spread noise attenuation was also applied, but provided little change as the geometry between surveys was very consistent.

Figure 2.5: Frequency of the BL survey from an 800ms window from all traces.
2.3 Data Conditioning

Onshore, pre-stack data is typically never perfect after processing and delivery. The data was fairly noisy to begin with, so a radon filter was applied as a first conditioning step to clean up the signal as shown in Figure 2.6.

![Figure 2.6: Radon parabolic filter applied to the raw CDP gathers. Image show the raw, high fold gathers(left), the gathers after filter applied (middle) and the noise gather-volume generated (right) to ensure no coherent signal was removed from the data. The horizons (Niobrara/Greenhorn) are from the flattened gathers and included as a visual reference for the reservoir interval.](image)

These data all suffered from a curving upward trend in the far offsets that were residual effects from NMO corrections. Trim statics were applied to fix migration move-out issues and flatten far offset amplitudes. This process performs cross-correlations on the traces itera-
tively, moving from the near to far offsets and aligning respectively. To maintain consistency in previous studies (White, 2015), a maximum time shift of 8 ms was implemented. This process was done equally for both M1 and M2 surveys as well. Figure 2.7 provides a look at the PSTM radon-filtered gathers before and after trim statics was applied.

After appropriating the gathers, it was important to observe the amplitudes vs offset angles (AVA) to better understand the quality of the data going into cross-equalization and inversion. Modeling your near and far angle (or offset) traces is effectively interchangeable but Hampson-Russell\textsuperscript{TM} will only allow for a pre-stack inversion in the angle domain. Figure 2.8 is the amplitude vs. angle model for the top of the Niobrara peak horizon. From the model, it can be observed that the near-angle amplitudes vary greatly with overall low amplitudes compared to the modeled curve. When ignoring the near-angle amplitudes, the Niobrara peak response is classified as Type I AVO (Castagna and Swan, 1997). The near-angle (0°-10°) low amplitudes are likely caused by ground roll during acquisition and common in seismic around the Rockies. Regardless, they were removed from the gathers as input to future work flows. These observations were seen in both in M1 and M2 surveys as well with the same low amplitudes at near angles.

The next step in preparation for time-lapse inversion is cross-equalization (XEQ). Hampson-Russell\textsuperscript{TM} has restrictive inputs for XEQ and can only accept stacked volumes for this process. After determining the angle ranges best suited for the data, these ranges were then stacked into three consecutive ranges: 10°-20°, 20°-30° and 30°-40°. This was justified from gaining an even distribution of incident angle range in attempt to extract more accurate wavelets for the partitioned data. Per Figure 2.8, the increasing angle-range stacks have lower amplitudes respectively. These stacked data for the BL survey are shown in Figure 2.9, but each survey set of angle-stacks for also M1 and M2 are abundantly referenced in Section 2.4.
Figure 2.7: Image provides the radon-filtered gathers (left) and the gathers after trim statics applied (right) to flatten the far offsets. The horizons (Niobrara/Greenhorn) are from the flattened gathers and included for reference to the reservoir, but the pink line shows the inflection of the amplitudes before and after the correction.
Figure 2.8: AVA modeling against the response from a full-range, full-fold pre-stack gather located in the middle of the survey. Observe that the near traces that do not follow the AVA signature but the remaining offsets follow the curve with little deviation indicative of a class I AVA (AVO) response (Castagna and Swan, 1997).

Figure 2.9: The three resulting angle stacks from Section 2.3. From left to right, stacks 10°-20°, 20°-30° and 30°-40° as prerequisite to pre-stack cross-equalization in Hampson-Russell™. Also interpreted horizons are shown including the upper and lower limits of the reservoir (NIO-GRHN) and two key Lower Pierre shale horizons in the overburden (LP2-LP3).
2.4 Pre-Stack, Cross Equalization

This section will discuss the background and theory of cross-equalization (XEQ) along with its application to this time-lapse study.

2.4.1 Background and Theory

Collectively observed in previous studies (Lumley, 2001; Rickett and Lumley, 2001; Sarkar et al., 2003), cross-equalization (XEQ) is a pivotal step in time-lapse analysis. XEQ is performed to increase the repeatability of seismic volumes and minimizes the altering effects of processing and acquisition between the respective volumes. XEQ is performed on an assumed, unaffected layer in the overburden to effectively normalize the data and observe solely signal variability in the target area. Vecta Oil and Gas co-processed these volumes again after acquiring M2 for Phase XVI. They processed this data with iterative analysis regarding the volumes’ repeatability discussed in Section 2.2. XEQ was performed on these data to build further fidelity of the new co-processing and ensure the repeatability between these volumes.

XEQ typically involves a variety of steps to match the data appropriately and effectively enhance the signal to noise ratio (SNR) around the area of interest. These processes include phase and time differences and frequency matching between the respective volumes to make the overburden consistent through analysis. To quality check (QC) the alterations to the data, NRMS volumes are observed throughout the process to appropriately normalize the overburden. The process and analysis following in this chapter was performed in the Hampson-Russell Software suite.
2.4.2 Cross Equalization of Monitor 1

The XEQ work flow performed followed the 4D work flow tree in Hampson-Russell\textsuperscript{TM}. The process was iterative, making sure NRMS difference volumes and slices progressed constructively. As these steps were rearranged slightly to reflect better results, this section explains the direct order of processes leading to the final volumes used for inversion.

The three ranges of angles discussed in Section 2.3 were stacked respectively (Figure 2.9) in order to cross-equalize because Hampson-Russell\textsuperscript{TM} is limited to the post-stack domain for XEQ. After stacking, there is a difference in the frequency content between the two volumes in each angle range. This is likely attributed to variety of factors, but there were varying surface conditions during acquisition for the Baseline (BL) and Monitor 1 (M1). The BL survey was acquired on a dry, unaltered surface, whereas M1 had been acquired following a massive 100-year flood in Northern Colorado.

XEQ and the NRMS difference QC were iteratively preformed on a 200ms centered window on the LP2 horizon, being roughly 400ms above the reservoir shown in Figure 2.10. The ”4D Calibration” work flow provided in Hampson-Russell\textsuperscript{TM} is as follows:

1. Slices of Correlation Coefficients and Shifts
2. Slices of Predictability
3. Estimate Phase and Time Shifts
4. Build and Apply Shaping Filter
5. Estimate and Correct for Shallow Statics
6. Estimate and Apply RMS Factors
7. Create and Apply Time-Variant Shifts
8. Create Slices of NRMS Difference
It was important to test and understand these processes before building my own workflow, applying only corrections that would not be redundant or counterproductive. Many of these corrections were observed during the new processing (Section 2.2) but were important to QC before building a modified workflow. The goal of XEQ was to minimize the NRMS difference in the overburden to below 0.3; an appropriate NRMS to ensure repeatability as stated in Sarkar et al. (2003). It was critical to make these observations after each step. After iteratively testing the discrepancies in the overburden, only shaping filters were needed to be applied to these data for minimized NRMS differences. A simpler workflow was generated to reduce processing time:

1. Create Slice of NRMS at LP2 horizon (Control)
2. Build and Apply Shaping Filter
3. Create Slice of NRMS at LP2 horizon (QC)
4. QC NRMS at LP3 horizon
5. Trace time-variant time shifts volume estimation
6. Trace time-variant time shifts application

It was important to understand the magnitude of the initial differences, and observe how the overburden differed before any process. As such, NRMS difference slices were generated observing the bulk differences through the 200ms LP2 window (Figure 2.11). Per Johnston (1997), the desired difference in a normalized overburden is 0.3, thereby making it the upper limit on these color-scales in this chapter.

Before observing any phase and time shifts that needed to be applied, it was important to apply a shaping (frequency) filter to match the bandwidth of the BL. This was a step that moved up to the beginning of the work flow after testing various approaches. This step alone had the most significant impact in the NRMS differences. The amplitude spectrum of each volume before and after shaping filter is provided in Figure 2.12. Although relatively minor adjustments were made after filtering the bandwidth, the resulting NRMS extractions over the same 200ms LP2 window were much improved (Figure 2.13).

Two additional QC steps were also implemented to ensure the effectiveness of the global shaping filter applied from the LP2 window. First, an additional NRMS difference extraction was made on another 200ms window at the LP3 horizon (Figure 2.14). This was done to make sure the 200ms window length was appropriate enough to apply as a global bandwidth filter, and constructively be applied through the rest of the data below. Figure 2.14 shows an improvement in NRMS values down section, and provides more confidence in the adequacy of reducing to the simplified XEQ work flow. The second QC was to then look at the overall NRMS differences through the data by generating a volume of NRMS difference (Figure 2.16). This allowed for a look at the changes restricted to the reservoir interval assuming there would be a somewhat abrupt change in NRMS difference moving down into the Niobrara formation (Figure 2.15).
Figure 2.11: Initial NRMS differences extracted from the LP2 window shown in Figure 2.10 between M1 and the BL survey with each stack labeled by angle range. NRMS values well above 0.3 observed in all stacks seemingly dependent on structure through the upper section of the Lower Pierre shale.
Figure 2.12: Bandwidth of each M1 angle-stack before and after building a global shaping filter to match frequency content of the BL. Each plot is titled with respect to its associated angle stack. Consistent through these the BL bandwidth (blue), original bandwidth of M1 (green) and final bandwidth of M1 after shaping filter applied (pink). Extractions were made in the 300ms window in the overburden.
Figure 2.13: NRMS differences after shaping Figure 2.12 extracted from the LP2 window shown in Figure 2.10 and modified from Figure 2.11. NRMS values have been significantly reduced in the three angle stacks to a consistent overburden.
Figure 2.14: Further modified from Figure 2.10 to show the progression of the NRMS window extraction extending up and down using conformable geometry from the LP3 horizon intended for QC purposes.

The last steps of the modified workflow also incorporate time-shifts that will align amplitudes for each trace in a perpetuating analysis window in time. Time-shifts are also a valuable tool to remember during interpretation. Observed in Figure 2.17, negative time shifts are indicative of a "softening" in the reservoir, representing slower velocities (Stammeijer and Hatchell, 2014). Further work could include dissecting the time shifts to learn more about the reservoir's dynamic behavior. After applying the time-shifts, the volumes are ready for a coupled time-lapse inversion. The volumes after all corrections have proven repeatable by reducing the acquisition differences observed in the overburden over time.
Figure 2.15: Quality check to provide insight on the shaping filter’s broader application through deeper signal. NRMS differences are noticeably better than that of extractions at the LP2 horizon, yielding average differences below 0.2.
Figure 2.16: Volume of NRMS difference calculated for the two volumes showing almost no differences in the overburden, and increased differences at the reservoir interval. The map on the right is an average difference extraction from the Niobrara Top to the Greenhorn horizon.
Figure 2.17: Volume of time variant time shifts calculated for each trace (middle). (Left) Image shows NRMS volume difference before time-shifts applied and (right) NRMS difference after time shifts reducing the small difference observed in the overburden and the magnitude in the reservoir interval.
2.4.3 Cross Equalization of Monitor 2

After isolating a consolidated work flow from the M1 XEQ, the same work flow was applied with the M2 volume. M2 initially had much higher data quality overall than both M1 and the BL survey. Similar to what was observed in Section 2.4.2, this was an effect from the surface conditions during acquisition. M2 was shot on a frozen winter surface as opposed to the dry summer conditions of the BL. Higher signal to noise ratio and higher frequency content have resulted from this better coupling of geophones and should be considered for future acquisition.

Incorporating the process iteratively mentioned in Section 2.4.2, it was again critical to understand the initial differences NRMS difference slices through the 200ms LP2 window (Figure 2.18). It was observed that these initial difference maps were better resolved, supporting the better overall data quality in M2.

Before observing any phase and time shifts that needed to be applied, it was important to apply a shaping (frequency) filter to match the bandwidth of the BL. This was a step that moved up to the beginning of the work flow after testing various approaches. This step alone had the most significant impact in the NRMS differences. The amplitude spectrum of each volume before and after shaping filter is provided in Figure 2.19. Although relatively minor adjustments were made after filtering the bandwidth, the resulting NRMS extractions over the same 200ms LP2 window were much improved (Figure 2.20).

The same QC iterations were performed on the M2 XEQ, taking an additional window in a lower Upper Pierre horizon (LP3) (Figure 2.14). Figure 2.21 shows an improvement in NRMS values down section, and significantly better values than that of the M1 XEQ. The second QC was to then look at the overall NRMS differences through the data by generating a volume of NRMS difference between BL and M2. This allowed for a look at the changes
Figure 2.18: Initial NRMS differences extracted from the LP2 window shown in Figure 2.10 between M2 and the BL survey with each stack labeled by angle range. NRMS values well above 0.3 observed in all stacks seemingly dependent on structure through the upper section of the Lower Pierre shale.
Figure 2.19: Bandwidth of each M1 angle-stack before and after building a global shaping filter to match frequency content of the BL. Each plot is titled with respect to its associated angle stack. Consistent through these the BL bandwidth (blue), original bandwidth of M2 (green) and final bandwidth of M2 after shaping filter applied (pink).
Figure 2.20: NRMS differences after shaping Figure 2.19 extracted from the LP2 window shown in Figure 2.10 and modified from Figure 2.18. NRMS values have been significantly reduced in the three angle stacks to a consistent overburden.
restricted to the reservoir interval assuming there would be a somewhat abrupt change in NRMS difference moving down into the Niobrara formation (Figure 2.22).

The NRMS differences were deemed appropriate for the overburden, but were still a bit noisy and inconsistent even through the reservoir. Figure 2.22 shows a fairly significant cloud of differences in what would be the Sharon Springs and even in the Lower Pierre shale. Time-lapse seismic in a production phase in a conventional sense, will observe gas evacuation, compaction, and subsidence that will result in a "hardening" effect in the reservoir interval (Barkved and Kristiansen, 2005). It was important to observe the time-shifts in M2 that would best correlate with the BL. Figure 2.23 provides the estimated time shifts as the last step in the XEQ. There are significant negative shifts in the reservoir interval, indicating that there is an overall decrease in velocity. Interpretations for the observed negative shifts will be further discussed in Section 5.1. These time-shifts were applied to the gathers and NRMS volume analysis was generated again to see if it improved the unwanted differences in the overburden. Figure 2.24 is the NRMS values before and after the time shifts were applied, indicating that application of the time-shift volume significantly reduced the NRMS in the overburden and condensed the more dramatic NRMS differences at the reservoir. The resulting gathers were ready for the time-lapse inversion (Section 3.3).
Figure 2.21: Quality check to provide insight on the shaping filter’s broader application through deeper signal. NRMS differences are noticeably better than that of extractions at the LP2 horizon, yielding average differences below 0.2.
Figure 2.22: Volume of NRMS difference calculated for the two volumes showing almost no differences in the overburden, and increased differences at the reservoir interval. The map on the right is an average difference extraction from the Niobrara Top to the Greenhorn horizon.
Figure 2.23: XLine in the middle of the Turkey Shoot survey showing significant positive and negative shifts in the overburden to reduce NRMS differences. It is also important to note the overall negative shifts that were then applied to the reservoir interval.
Figure 2.24: Volume of time variant time shifts calculated for each trace (middle). (Left) Image shows NRMS volume difference before time-shifts applied and (right) NRMS difference after time shifts reducing the small difference observed in the overburden and the magnitude in the reservoir interval.
This chapter of the study will discuss the theory, processes and uninterpreted results of the time-lapse, pre-stack inversion.

3.1 Pre-Stack Inversion Theory

Pre-stack seismic inversion is a key tool for building interpretations regarding higher resolved rock-properties and fluid concentrations. This simultaneous inversion is referred to as such, because it effectively solves for P-Impedance ($I_P$), S-Impedance ($I_S$) and Density ($\rho$) at the same time. One of the most significant aspects of successful inversions is enhancing vertical resolution. As inversion effectively will deconvolve the wavelet from the seismic data, it removes most biases associated with conglomerated reflection coefficients (Hampson et al., 2005). Not applicable in the Turkey Shoot survey, but wavelets can cause problems because they are time and spatially variant and usually incur complex shapes from side lode energy (MacFarlane, 2014).

Throughout seismic exploration history, many studies that isolate reflection coefficients as a function of the Earth’s elastic properties Aki and Richards (1980); Ruger (1998). The elastic properties are needed for high level interpretation, isolation, and classification of petroleum reservoirs and source rocks. Hampson Russell™ Software utilizes Aki and Richards (1980) derivation for PP reflectivity, assuming a linear relationship between the logarithm of $Z_P$, $Z_s$, and $\rho$. This also introduces two constants ($k$ and $m$) that will appropriate the relationships between the well based rock properties. The specific advantages of this are a more stable system reliant on three independent variables, and known linear relationships between rock properties from the wells. The pre-stack inversion algorithm is explained below:
1. Given angle gathers, wavelet(s), and initial models for \( Z_p \), \( Z_s \), and \( \rho \).

2. Derive the optimal values for constants \( k \) and \( m \) which appropriately scale logarithmic relationships between variables using log data from wells that overlap adequate seismic coverage.

3. Use the following to build the initial guess, where "L" are the previously mentioned relationships between impedance and density including the background trends:

\[
(L_p \quad \Delta L_s \quad \Delta L_D)^T = (\log(Z_p) \quad 0 \quad 0)^T
\]  

(3.1)

4. Solve equation 3.1 using conjugate gradients.

5. Calculate the final estimations of \( Z_p \), \( Z_s \), and \( \rho \).

3.2 Baseline PP Pre-Stack Inversion

There are initially 8 vertical wells provided in the Turkey Shoot survey area, none of which have real sonic curves. Synthetic sonic curves were generated for each of the wells in the section using neural networks performed by a former RCP student, Pitcher (2015). It was important to also move a well from just outside the survey bounds into the Turkey Shoot to aid in a more reliable representation of the reservoir discussed in Section 1.2, making the total well count nine. All of these wells have been tied to the survey, however only four were included when building the low frequency model (LFM), shown in (Figure 3.1). Reducing the amount of wells to four for the LFM was supported by the P-impedance extraction over the reservoir interval from the pre-stack inversion of the Anatoli dataset Figure 3.2. The extraction shows that there is not a tremendous amount of variability looking at the reservoir (Niobrara to Greenhorn) within the Turkey Shoot survey. Well A is the transposed pseudo well, incorporating the real sonic data. The other 3 wells (B, F, G), were incorporated to provide a perimeter distribution for the anticipated low frequency model construction. Blind wells A and B were intentionally left out for QC against the inversion results because they were near the high fold area of the survey and the Wishbone section and would be powerful
to validate the model and the inversion. The unlabeled remaining wells were iteratively applied but eventually removed as they created too much variability in the distribution of the LFM characteristics.

Figure 3.1: Modified from Figure 1.4, providing all of the wells in the Turkey Shoot survey. The labeled wells (A, B, F and G) being the only wells in the construction of the LFM. The remaining green wells were applied and removed iteratively, and the blind wells (red) were left out from the initial stages to give a representation of the LFM and inversion near the Wishbone survey.

The gathers generated from the three angle stacks discussed in Section 2.3 were used to generate statistical, angle dependent wavelets for each angle range respectively. These wavelets were generated using the seven wells previously mentioned over an 800ms time window, and grouped for each angle gather volume (Figure 3.3). Wavelets were also statistically generated for each well independently and tested with no phase control in order to quantify and support creating a universal phase. Roughly half of the wells resulted in zero phase wavelet groups from unconstrained estimations along traces at their locations. The wells that did not effectively extract zero phase wavelets typically experienced less than 6 degrees of suggested rotation. With strong similarities, the final wavelets were 110ms in length and zero phase assumption was supported and implemented moving forward.
Figure 3.2: The Anatoli P-impedance extraction from a pre-stack inversion running from the Niobrara top to the Greenhorn showing the consistent character through the Turkey Shoot survey. Figure 1.4 also transparently applied to this map to show its position respectively.

Figure 3.3: Statistical wavelets generated for each angle range using all of the wells in the Turkey Shoot survey (Wells A-G in Figure 1.4). Each wavelet is 0 phase, and 100ms in length.
Well A is provided as an example well tie shown in Figure 3.4. All twelve wells in the section were tied to the BL data, to be incorporated later in blind well analysis of the inversion results. As expected, the four wells selected for the inversion tied with the highest correlations (above 80%) between the synthetics generated and the seismic data. This is because the wavelets were statistically extracted using these four wells. The remaining wells in the Turkey Shoot were tied with these same wavelets and still maintained viable correlations averaging 75%, with the lowest being 63%.

Figure 3.4: Example well tie at Well D nearly within the Wishbone section. Well tie shows the five key horizons used in the inversions labeled with their respective colors and listed in Table 3.1. This well tie and the provided correlation of 86% accounts for the entire 800ms window covering 600ms above the reservoir and 100ms below.

From Figure 3.4, there were five horizons picked that appropriately represented the target interval across the survey explained in Table 3.1. Four of the five horizons represent specific formation tops, the fifth noted as ”Middle Niobrara” because the heterogeneity and subtle differences of the Niobrara and the seismic resolution does not allow for a specific representation of a given bench. Because of this, the Middle Niobrara was not incorporated into the inversion process, but simply used for analysis and interpretation. Figure 3.5 provides a section view perspective of the horizons within the Turkey Shoot.
Table 3.1: Horizons reference to tops from well tie, notation and color. The table lists these horizons in consecutive order from shallow to deep.

<table>
<thead>
<tr>
<th>Formation Top</th>
<th>Horizon Abbreviation</th>
<th>Color</th>
</tr>
</thead>
<tbody>
<tr>
<td>Niobrara Top</td>
<td>NIO</td>
<td>Blue</td>
</tr>
<tr>
<td>Middle Niobrara</td>
<td>MNIO</td>
<td>Yellow</td>
</tr>
<tr>
<td>Fort Hays</td>
<td>FRHS</td>
<td>Pink</td>
</tr>
<tr>
<td>Codell</td>
<td>CDLL</td>
<td>Orange</td>
</tr>
<tr>
<td>Greenhorn</td>
<td>GRHN</td>
<td>Green</td>
</tr>
</tbody>
</table>

Figure 3.5: Horizons in Table 3.1 provided in section view on stacked seismic. The yellow (Mid-Niobrara) horizon is shown, but not included in the generation of the LFM.

The velocity model used for the inversion was the RMS migration velocity volume provided by the processor, Vecta Oil and Gas. This was consistent with the data conditioning of the gathers, discussed in Section 2.3.

The low frequency model (LFM) provides an input to the inversion that represents the missing low frequency seismic data. This model is an estimation that uses well log information to control distributions of P-impedance, S-impedance, and density, but can also
incorporate other logs depending on the purpose for the inversion. For this study, only P-impedance, S-impedance, and density models were built to support the pre-stack inversion. Typically for larger or lenticular targets, an abundance of well data is important to build an effective LFM. Even though the Niobrara’s heterogeneity is very complex, it is impossible to resolve with the seismic data. Using four of the twelve wells to generate the LFM was appropriate considering the well data filtered at low frequencies would not resolve any significant vertical or lateral variation in the reservoir. The dominating high impedance character from the Niobrara Top to the Greenhorn Limestone reflector would only gradually change throughout the four square mile survey.

After using the given sonic and density curves to generate impedances for the four wells, the calculated curves are then filtered to a low frequency bound 1 to 20Hz (high-cut filter 15-20Hz) to effectively fill the void of bandwidth provided by the seismic. The synthetic curves in wells B, F and G were tested for artifacts and checked for any anomalous representation of the overburden and the reservoir. All of the curves in the study area end following the Greenhorn Limestone, so the LFM was generated for the entire 800ms window used for the well-ties, but was eventually truncated to immediately below the Greenhorn horizon (25ms) shown in Figure 3.6. The vertical section of the model was reduced because a significant amount of log data did not extend below the Greenhorn formation. The model generated is further validated with a cross plot in Figure 3.7, where the modeled low frequency impedances have a direct linear relationship with the filtered log impedances calculated from the P-sonic and density curves. Data from all wells in the Turkey Shoot survey are included in the Figure 3.7 against the distributed properties in 3D.

The generated models have less than 10% difference across the four square mile survey area within the reservoir, which is a great result and effectively minimizes the LFM effect on the inversion. When looking specifically at the LFM over the Wishbone horizontal wells, the
Figure 3.6: XLine of the Ip low frequency model across the middle of the Turkey Shoot survey.
Figure 3.7: Cross plot of the modeled P-impedance against the filtered log P-impedance showing an ideal linear relationship increasing with time. The trend line in red is also provided to show minimal deviation in this relationship. This cross plot provides a necessary QC to the generated model to ensure appropriate representation with the low frequency P-impedance to be later used in the inversion.
distribution dropped to less than 6% providing even more confidence in the isolated AOI, both shown in Figure 3.8.

Figure 3.8: Low frequency model P-impedance extracted from the Niobrara top to the Greenhorn horizons in the Turkey Shoot survey. Map view shows the increasing impedance toward the North and an even distribution through the center of the survey where the horizontal wells are located. Histogram provided to show less than a 10% variation in Ip across the survey.

Before running the inversion process on the entire BL volume, it was essential to modify inversion parameters based on results at the wells to reduce iterative computation time. The resulting and most ideal parameters were:
- Background Vp/Vs iteratively calculated automatically at 60ms from the log curves
- Covariance pre-whitening based off of regression separation for Ip, Is and \( \rho \)
- Exclusion of a trace if it has less than 80% of volume samples
- Maximum of five iterations to not overestimate logs tested through iterative inversions at the wells
- Angle range is 10\(^\circ\) to 40\(^\circ\)

The pre-stack inversion analysis outputs for P-impedance and S-impedance prove to be very good prior to the volume inversion provided in Figure 3.9 and Figure 3.10. It should be noted that there is inadequate far-offset/angle range (Section 2.3) to estimate density. Density results from a deterministic pre-stack inversion with insufficient far offsets are typically unusable because the density is manipulated inaccurately in order to effectively estimate P and S impedances. Density estimation results are also provided in Figure 3.11. Only the P-impedance results are desired for the purpose of this study, although the Is and density results will be key to appropriate as a low-frequency model input to the M1 and M2 coupled inversions. The Is results are also QC’d to provide the best representation from the inversion.

Inversion results are very good, and both Ip and Is correlate to the three wells discarded in the inversion but left in the overall analysis observed in Figure 3.12 and Figure 3.13. Furthermore Figure 3.14 provides the section view over the Blind Well A, left out of the inversion and the analysis stage with a strong representation of both Ip and Is. Because blind well 1 was left out of the analysis from the beginning, a generic high-cut filter (60Hz-70Hz) has been applied to compare the log’s Ip and Is but are not the exact bandwidth of the inversion.
Figure 3.9: Baseline pre-stack inversion analysis of P-impedance estimation over the wells implemented in the LFM and inversion (A, B, F and G). Provided is the original P-impedance log (blue), the P-impedance LFM (black) and the inverted P-impedance log (blue). The inversion matches very well over the original (filtered) curves and the inversion synthetic seismic yields a 99% correlation to the original volume.

Figure 3.10: Baseline pre-stack inversion analysis of S-impedance estimation over the wells implemented in the LFM and inversion (A, B, F and G). Provided is the original S-impedance log (blue), the S-impedance LFM (black) and the inverted S-impedance log (blue). The inversion matches very well over the original (filtered) curves and the inversion synthetic seismic yields a 99% correlation to the original volume.
Figure 3.11: Baseline pre-stack inversion analysis of density estimation over the wells implemented in the LFM and inversion (A, B, F and G). Provided is the original density log (blue), the density LFM (black) and the inverted density log (blue). The inversion uses the density to best represent a $\frac{V_p}{V_s}$ relationship hence its strong mis-match.

Figure 3.12: Wells that were included in the analysis of gaining appropriate inversion parameters but not included in the low frequency model. Their filtered Ip curves in relation to the inversion results over the well.
3.3 Time-Lapse, Monitor 1 Inversion

Following the process explained in Sections 2.4.2 and 2.4.3, the data is ready for the inversion. The deterministic approach is specific to the given parameters from the well logs in the Turkey Shoot survey however, inversions are still inherently non-unique. The result from the BL inversion will be incorporated in both M1 and M2 inversions using the BL P-impedance, S-impedance and density outputs as the LFM. This process is referred to as a coupled time-lapse inversion (Sarkar et al., 2003). Performing a coupled inversion eliminates much of the preparation work required for an independent and uncoupled time-lapse inversion as all parameters used or resulting from the BL inversion will be used again for the inversion of M1 and M2. Coupled inversion can also reduce unexplained impedance differences between volumes, because if a model is built for each seismic volume, there will be a inherent bias in rock property estimation with each pair (Sarkar et al., 2003).
Figure 3.14: Blind Well A excluded from both the low frequency model and the inversion analysis, showing its correlation to a XLine out of the inversion volume. The Ip result on the left and the Is result on the right.
After building the work flow and parameters used in the BL inversion, the M1 angle gathers simply needed to be included and ran using the same parameters used for the BL inversion. In order to compare the two volumes, the percent difference was calculated between the two providing overall negative P-impedance changes in the reservoir. The Ip results for the M1 inversion are shown against the BL results along with the percent difference volume in Figure 3.15 and Figure 3.16. The time-lapse (M1, M2) Is and density volumes were not be analyzed for all intensive purposes of this study.

![Figures 3.15 to 3.19](image)

Figure 3.15: The results from the coupled inversions showing the BL results(left), M1 results(middle) and percent difference volume (right). The percent differences are negative near the well deviations showing a ”softening” response and slightly positive in the upper intervals of the Niobrara indicating a hardening effect.

Both M1 and M2 negative anomalies coincide with deviated well locations in the modeled subsurface. Below in Figure 3.17, Figure 3.18 and Figure 3.19 are a few maps showing the character of negative percent differences in the M1 time-lapse P-impedance volumes with
Figure 3.16: The results from the coupled inversions showing the BL results(left), M2 results(middle) and percent difference volume (right). Again, the percent differences are negative near the well deviations showing a "softening" response and slightly positive in the upper intervals of the Niobrara indicating a hardening effect.
respect to the BL. Average extractions are provided in these initial results and interpretations to illustrate a fair representation of both positive and negative differences should they interfere. The M1 data shows that percent differences in the upper portion of the Niobrara result in a positive 3-5% and negative 3-5% in the lower portion of the Niobrara, near the well placement. Additionally, more of the negative percent differences in Ip are located to the North and West in the section. The M2 differences are at a lesser magnitude overall (positive and negative 1-3%) but with the same polarity in roughly the same locations vertically.

Figure 3.17: Map view zoomed in over the Wishbone section with an average of the P-Impedance percent differences from the Niobrara Top to the Greenhorn horizon. Because the mean extraction only provided negative differences, the scale runs from cooler (0% change) to warmer (-3% change).

Below in Figure 3.20, Figure 3.21 and Figure 3.22 are a few maps showing the character of negative percent differences in the M1 time-lapse P-impedance volumes with respect to the BL. The M2 differences in the reservoir interval are similar spatially over the Wishbone section as M1, but have more overall changes to the North particularly over the toe sections of the 2N and 3C. More advanced applications and interpretations for these distributions are discussed later in Sections 5.1 and 5.2.
Figure 3.18: Map view zoomed in over the Wishbone section with an average of the P-Impedance percent differences from the Mid-Nio to the Fort Hays horizons respectively. A line sample highlights the interval extraction on the left. This P-impedance percent difference extraction supports the overall large changes in the north and in the west of the section.

Figure 3.19: Map view zoomed in over the wishbone section with an average of the P-Impedance percent differences from the Codell to Greenhorn (base of reservoir) horizons. A line sample highlights the interval extraction on the left. This P-impedance percent difference extraction supports the overall large changes in the north and in the west of the section.
Figure 3.20: Map view zoomed in over the Wishbone section with an average of the P-Impedance percent differences from the Niobrara Top to the Greenhorn horizon. Because the mean extraction only provided negative differences, the scale runs from cooler (0% change) to warmer (-3% change).
Figure 3.21: Map view zoomed in over the Wishbone section with an average of the P-Impedance percent differences from the Mid-Nio to the Fort Hays horizons respectively. A line sample highlights the interval extraction on the left. This P-impedance percent difference extraction supports the overall large changes in the north and in the west of the section.

Figure 3.22: Map view zoomed in over the wishbone section with an average of the P-Impedance percent differences from the Codell to Greenhorn (base of reservoir) horizons. A line sample highlights the interval extraction on the left. This P-impedance percent difference extraction supports the overall large changes in the north and in the west of the section.
CHAPTER 4
FORWARD MODELING METHODS AND APPLICATION

This chapter will provide modeling theory and application to justify the negative impedance changes from the Baseline to both Monitor 1 and Monitor 2 within the reservoir. Explanation will include the methods used to generate well-based model from a cross-dipole sonic log and XRD analysis located roughly 11 miles to the northeast of the Wishbone section (Figure 4.1). Models from Sayers (2010) and Mavko and Bandyopadhyay (2009) are used to estimate changes in $V_p$ regarding pore pressure after stimulation and production. Explicitly for M2, fluid substitution was modeled after the applied pressure differences to the P-velocity and slowness curves (Mavko and Bandyopadhyay, 2009) for an anticipated gas effect.

Figure 4.1: Location of Well N which contains cross-dipole sonic logs and XRD analysis on core samples from the Niobrara and Codell reservoir intervals. The well is roughly 11 miles to the northeast of the Turkey Shoot survey.
4.1 Fracture Compliance and Pore Pressure

Reservoir pressure has been a proven critical variable controlling time-lapse seismic response and are well published however, these successes are typically in a conventional reservoir setting (20-40\% porosity). Compressional wave time-lapse studies observing pore pressure changes are typically performed to assess well-bore and reservoir integrity as substantial depletion and decreasing pore pressure will inevitably result in subsidence. These reservoir changes cause significant velocity increases and relative time displacements in the reservoir that are observable on the seismic. Time-lapse seismic has been utilized to mitigate these risks before becoming detrimental to field development.

The unconventional Niobrara and Codell reservoirs have proven to be very different than a typical conventional application. These reservoirs are in the same relative interval as their source rock, tightly bound between their respective seals. When hydrocarbons are expelled there can be an increase in pore pressure in this interval and a proportional decrease in effective pressure above and below these seals. Figure 4.2 provides a schematic of the overpressured nature of the Niobrara and Codell interval in the DJ basin. The overpressured strata is a direct result of the expulsion of hydrocarbons by which increases pore pressure, reducing the load of the abiding stratigraphy in addition to compaction (Ransom, 1986). During stimulation, fluids are injected into the reservoirs at substantial pressures to fracture the media, further reducing the load on the reservoir, and effectively increasing pore pressure. This is the theory behind modeling a change in P velocity as a result of change in pore pressure during stimulation of the 11 horizontal wells in the Wishbone section.

(Sayers, 2010) established the relationship between pore pressure and fracture compliance as a means of incorporating a degree of anisotropy in stress effects. Compliance, being the inverse of stiffness of a given media, is devoted to stress sensitivities both vertically and horizontally. To make a more reasonable case for the in-situ stress sensitivities, the compliance
Figure 4.2: Schematic showing the overpressured interval of the DJ basin where both the Niobrara and Codell reservoirs are located (Robert J. Weimer, 1996).
of fractures are added to this stiffness matrix to broadly represent the overall (background) compliance of a given media. Fracture compliance in this particular case does not represent one single fracture, but a conglomeration of fractures in that particular media (Hobday and Worthington, 2011). Fracture compliance is directly related to a fracture’s height, width and aperture. This quality is nearly impossible to appropriately estimate when considering the complexity of structure influencing a given reservoir, but the assumption is that the fractures are parallel, planar and equidistant from one another (Hobday and Worthington, 2011).

As a change in pore pressure is directly sought after, Equation 4.1 shows the relationship between fracture compliance ($Z_n$) and effective stress, where $Z_0$ is the initial fracture compliance, $\sigma_n$ is the normal confining stress, and $\sigma_c$ is a characteristic stress (Sayers, 2010). These initial values are calculated via core experiments measuring the variation of velocity from the rock stress sensitivities. For all intensive purposes regarding application for this study, stress sensitivities were taken from Niobrara core of an unknown field location in a recently published thesis out of the Colorado School of Mines’ Center for Rock Abuse consortium (Panfiloff, 2015). Figure 4.3 provides a graphical representation of this relationship showing increasing compliance with a decrease in effective stress which is proportional but inversely related to pore pressure. This relationship already includes with the previously mentioned Niobrara core measurements as input.

$$Z_n = Z_0 e^{-\sigma_n/\sigma_c}$$

(4.1)

The modeling of changes in $V_p$ for this study use VTI assumptions with weak anisotropy for the generation of stiffness matrices and Thomsen parameters from (Mavko and Bandyopadhyay, 2009) and (Saberi and Ting, 2016). VTI is used to attribute heterogeneous complexity known to be present in the Niobrara and Codell reservoirs. $V_p$, $V_{s,fast}$, $V_{s,slow}$ and $\rho$
Figure 4.3: Fracture compliance in relation to effective stress. Increasing effective stress (decreasing pore pressure) decreases the compliance of fractures. The equation is also listed as an exponential fit to the relationship.

can provide estimations of these values at each sample in the dipole sonic logs provided in Well N (Figure Figure 4.1).

Well N has cross-dipole sonic curves to immediately estimate two constants in the stiffness matrix (Equations 4.2 and 4.3). With VTI implied in this model, Equation 4.4 provides the identical relationship for the S-wave terms.

\[
c_{33} = \rho \cdot V_{p}^{2} = M \tag{4.2}
\]

\[
c_{23} = \rho \cdot V_{s1}^{2} = \mu \tag{4.3}
\]
With VTI media:

\[ c_{44} = c_{55} = c_{66} \]  \hspace{1cm} (4.4)

The stiffness tensor is still under determined as a VTI medium requires five independent elastic constraints. The remaining constraints required can be approximated with the main assumption that pore space is sufficiently connected (Mavko and Bandyopadhyay, 2009). This could be an inherent pitfall of this modeling because of the commingled and heterogeneous chalks and marls associated in the Niobrara (discussed in Section 1.3). Considering this modeling will only be applied to the targeted, chalk dominant intervals of the Niobrara and the Codell Sandstone the concern was noted, but ignored.

Because the model is assuming a weakly anisotropic VTI medium, from Gassmann (1951), \((c_{2323}^{sat})\) and dry \((c_{2323}^{dry})\) are equivalent, where the shear modulus does not change in the pore fluid in an anisotropic medium. Continued from Mavko and Bandyopadhyay (2009), Thomsen (1986) parameters can then be estimated using Equations 4.5, 4.6 and 4.7.

\[ \epsilon = \frac{c_{11} - c_{33}}{2 \ast c_{33}} \]  \hspace{1cm} (4.5)

\[ \gamma = \frac{c_{12} - c_{23}}{2 \ast c_{23}} \]  \hspace{1cm} (4.6)

\[ \delta = \frac{(c_{13} + c_{23})^2 - (c_{33} + c_{23})^2}{2 \ast c_{23} \ast (c_{33} - c_{23})} \]  \hspace{1cm} (4.7)
The remaining independent stiffness (Equations 4.8, 4.9 and 4.10) elements for a VTI medium can be inverted for using the Thomsen (1986) parameters estimated in Equations 4.5, 4.6 and 4.7 ((Mavko and Bandyopadhyay, 2009)).

\[ c_{11} = M \ast (1 + 2 \ast \epsilon) \]  
(4.8)

\[ c_{12} = \mu \ast (1 + 2 \ast \gamma) \]  
(4.9)

\[ c_{21} = M \ast (1 + 2 \ast \epsilon) \ast 2 - 2 \ast \mu \ast (1 + 2 \ast \gamma) \]  
(4.10)

After estimating all of the components for the stiffness tensor provided in Equation 4.11 we can then invert this matrix to its respective background compliance provided in Equation 4.12.

\[
C_{ij}^{B} = \begin{bmatrix}
c_{11} & c_{12} & c_{13} & 0 & 0 & 0 \\
c_{21} & c_{22} & c_{23} & 0 & 0 & 0 \\
c_{31} & c_{32} & c_{33} & 0 & 0 & 0 \\
0 & 0 & 0 & c_{44} & 0 & 0 \\
0 & 0 & 0 & 0 & c_{55} & 0 \\
0 & 0 & 0 & 0 & 0 & c_{66}
\end{bmatrix}
\]  
(4.11)
Inverted to background compliance, where subscript b is the background shear modulus:

\[
S_{ij}^B = \begin{bmatrix}
S_{11} & S_{12} & S_{13} & 0 & 0 & 0 \\
S_{21} & S_{22} & S_{23} & 0 & 0 & 0 \\
S_{31} & S_{32} & S_{33} & 0 & 0 & 0 \\
0 & 0 & 0 & \frac{1}{\mu_b} & 0 & 0 \\
0 & 0 & 0 & 0 & \frac{1}{\mu_b} & 0 \\
0 & 0 & 0 & 0 & 0 & \frac{1}{\mu_b}
\end{bmatrix}
\]  

(4.12)

A new representation for the effective elastic compliance can now be made from combining the background compliance \((S_b)\) and the fracture compliance \((S_f)\) as a product of Equation 4.13 ((Schoenberg and Sayers, 1995)).

\[
S_{total} = S_b + S_f
\]

(4.13)

The addition of \(S_f\) is strictly the compliance of the fractures which will only have normal and tangential compliances effectively adding the terms to the \(S_{11}, S_{55}\) and \(S_{66}\) as seen in Equation 4.14. Equation 4.15 represents the matrix result of the combined effective compliance in Equation 4.13.

\[
S_f = \begin{bmatrix}
Z_n & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & Z_t & 0 \\
0 & 0 & 0 & 0 & Z_t
\end{bmatrix}
\]

(4.14)
4.1.1 Monitor 1 Modeled Pore Pressure Differences

No pressure data is provided in our data, so initial and input pressures were inferred from literature (Sonnenberg and Underwood, 2013). Increases in pore pressure were tested in two separate cases. The pore pressure was increased by 2000 psi and 4000 psi for two cases previously mentioned. As some of the assumptions in Section 4.1 were clear about more consistency of an even distribution of "interconnected" pores, the changes in compliance were only modified in the Chalk intervals of the Niobrara and separately, the Codell. With increasing pore-pressure, the effective stress proportionally decreases. The initial pore pressure is assumed to be 4000 psi, just as when the logs were acquired. Figure 4.4 shows the base-case (assumed starting point) and the two locations on the curve where different compliance values were tested. The two tests yielded a compliance of \(0.0046 \frac{1}{\text{psi}}\) for a difference of 2000 psi, and the maximum possible compliance \(0.25 \frac{1}{\text{psi}}\) for the 4000 psi pore pressure increase.

Per Schoenberg and Sayers (1995), there are two different assumptions to be made when applying a given fracture compliance to the model, the modeled interval can either be assumed to be predominantly liquid filled fractures (\(Z_n = .1Z_t\)) or gas filled fractures (\(Z_n = Z_t\)) respectively.

Proprietary PVT (Pressure, Volume, Temperature) analysis was performed on an undisclosed well in the field but within an acceptable distance to the RCP study area. PVT experiments
Figure 4.4: Fracture compliance and pore pressure relationship curve, showing the starting effective stress (Case 0) and the two tested increases in pore pressure (Case 1 and 2).
are done to evaluate the produced hydrocarbons under a certain variety of in-situ variables regarding pressure, volume and temperature. It was concluded that roughly 90 days after flow back, the near-wellbore reservoir pressures dropped below bubble point pressure and gas was being released from solution. This would mean that there was no free gas initially in the system. With this knowledge, the predominantly fluid-filled fractures assumption \((Z_n = .1Z_t)\) was applied to the pore-pressure versus fracture compliance relationship for the M1 modeling. A work flow was generated to assess these differences in attempt to make direct correlations to the percent difference P-impedance results from the time-lapse inversion shown in Figure 4.5.

![Workflow](image)

Figure 4.5: Workflow for evaluating fracture compliance behavior and its effects on P-velocity.

Code in Microsoft Excel™ was written to take the input logs and apply all of the math discussed in Section 4.1 at each sample along the well where there was sonic log data. In addition to this, the application of a change in pore-pressure via change in fracture compliance could be applied by outputting a new and modified sonic curve. These are the modeled sonics that are input to analysis and compared to the 4D inversion difference volumes.
Additional code was implemented to gain a perspective on the overall differences and effects on $V_p$ (second step Figure 4.5). The changes in Case 1 resulted in an inadequate comparison to the magnitude of the 4D differences. The results of Case 1 (2000 psi increase in pore pressure), proved to change $V_p$ at most a negative tenth of a percent (-0.1%), and in the majority of the vertical section, less than a negative five one-hundredths of a percent (0.05%). However, there was an immediate reason for such a poor magnitude difference in $V_p$. When referring back to Figure 4.4, Case 1 at a 2000 psi increase in pore-pressure (drop in effective pressure) creates virtually no displacement up the fracture compliance axis. In addition to this, the fluid-filled fractures assumption means that only 10% of the estimated compliance is applied to the calculation. This case was concluded and as such, provided differences in $V_p$ would be negligible.

Case 2, testing a maximum change in fracture compliance, was not much more promising than Case 1. Applying the maximum increase in fracture compliance, yielded a maximum of a -1% change in $V_p$. A difference of a -1% change along a substantial portion of the reservoir could potentially produce similar P-impedance differences when convolved with a wavelet and inverted (Figure 4.6).

The results from modeling such a large increase in pore pressure was deemed insignificant with a maximum of 0.25% velocity change. The results shown in Figure 4.6 show differences that do not surpass the effective error range assumed on the Turkey Shoot percent difference volumes. Although the outcome of these models was relatively unsuccessful, it still provided a vector where velocities would change. The negative difference in $V_p$ shows that there would be an effective decrease in velocity with an increase in pore pressure.
Figure 4.6: Result of fracture compliance influence on P-velocity with a change in pore pressure (sonic track). The inversion results to compare to percent difference volumes is provided on the right. There is a maximum difference of about 0.25%.
Fracture compliance alterations on compressional velocity are very minimal when assuming a weakly anisotropic VTI medium. Additionally, $V_p$ is only dependent on the $c_{11}$ and $c_{33}$ terms of the stiffness tensor and the (inverted) compliance tensor. The estimated values for the $S_{11}$ term when taking the inverse of the stiffness matrix relies on the fast shear polarization calculated from the cross-dipole sonic. Well N has almost no separation from the two polarizations and therefore has virtually no HTI anisotropy affecting the initial background compliance. This observation presents a potential pitfall of this analysis because even though there is a negligible difference in $S_{h \text{min}}$ and $S_{h \text{max}}$, the compliance has no way of determining the anisotropic stress sensitivity of the rock with VTI assumptions, currently being investigated by Tom Bratton (RCP). This is extremely valuable information that would directly impact the changes in $V_p$. Future work in modeling the dynamic changes in $V_p$ that are apparent on the time-lapse inversion should include HTI assumptions in addition to anisotropic stress sensitivities. If these parameters are modeled correctly they would be fairly intuitive to apply as additional modifications in the compliance matrix. This would not only account for normal and tangential compliances of an inferred fracture set, but could also account for stress sensitivities between grain boundaries. The heterogeneity of the Niobrara would make the application of this modified workflow and assumptions very applicable to the study.

4.1.2 Future Considerations for Modeling Pressure Response on a Hydraulically Fractured Reservoir

There are alternative means to identify a decrease in P-impedance between M1 and the BL, but would require an understanding of the geomechanical influences during stimulation. The increase in pore pressure during stimulation is known, but we do not know how it interacts with virgin reservoir properties or how it is distributed. An alternative work flow to address a pressure difference would be to perform the identical time-lapse analysis, but instead use M1 as a baseline survey. This would include XEQ with respect to M1 and could provide information specific to the highest magnitude pressure change, moving from
the highest pore pressure (stimulation), to the lowest (production). These effects intuitively should be visible in the reservoir, in addition to the stress distributions above and below in vertically adjacent strata.

If the Sayers (2010) model accurately estimates a difference in $V_p$ with a large change in pore pressure from hydraulic stimulation, then it is important to consider alternate reasons for the -3% to -5% changes in the time-lapse inversion difference (M1-BL). Another study that would deviate from the assumptions incorporated for this study is one from Sammonds et al. (1989). He concluded that there is a reduction in $V_p$ after a given pressure on a more brittle medium. Figure 4.7 shows the results of a rock at "peak stress" becoming more compliant and collapsing on internal microcracks (Sammonds et al., 1989). This could be an alternate explanation for the negative differences in the time-lapse. Additionally, a significant negative difference in the Wishbone section occurs in the Fort Hays limestone horizon. The Fort Hays is a more brittle formation and would likely succumb to a similar response in $V_p$ if pushed to its peak stress.

It is also important to mention potential pitfalls in the Sayers (2010) model. Modeling a decrease in pore pressure using fracture compliance with weakly anisotropic VTI assumptions could prove problematic. Similar to the uncertainties discussed in Section 4.1.1, there is an even larger gap in understanding on the rock’s anisotropic stress sensitivities over two years of production. Both the Niobrara and Codell have undergone a tremendous amount of varied stress after completion and during production. It will be important to understand the geomechanics of the reservoir under such differential stresses which would allow for more understanding regarding the rock’s sensitivities.

There is still a lot unknown regarding the completion of these wells and the anticipated effects that would influence observations in a time-lapse seismic study. Rather than attack-
Figure 4.7: P-velocity after "peak stress" is applied to a core sample similar in reservoir properties to the Niobrara and Codell (Sammonds et al., 1989).

ing the problem blindly, three-dimensional geomechanical modeling is currently underway on the Wishbone wells. Gaining an understanding of how the reservoir and the comple-
tions behave during stimulation allows for testing various parameters that could point to a
dynamic P-impedance response for M1. The time-lapse pre-stack inversion results will be
implemented to constrain correlations to the geomechanical inputs to the simulation model.

4.1.3 Monitor 2 Modeled Pore Pressure Differences

Similar to Section 4.1.1, the M2 pore-pressure modeling undertook the same work flow.
Only one case was tested to understand the vector (direction and magnitude) of a $V_p$ change
using the fracture compliance versus pore pressure relationship. Based on the results from
M1 models, there was not a tremendous amount of anticipated change especially when in-
troducing a negative compliance as input for the M2 models. However, there are a few
key differences that were implemented from the M1 models. First, Turkey Shoot M2 was
acquired after two years of production. Gas has been introduced to the system, with rising
GOR in every well over two-years production. Reservoir simulations suggest gas saturations in the reservoir could be as high as 40% near wells from stimulation or structure that is inferred to have higher permeability. The structural influence was interpreted from seismic, geosteering, and image logs. Because of such a dramatic phase change, a gas-filled fracture assumption has been applied to the input compliance, where $Z_n = Z_t$. The second difference between the M1 and M2 models is a different initial starting case, Case 0. This was to get a sense on both the magnitude and direction of fracture compliance influence on velocity with a pore pressure decrease (effective pressure increase) both Case distributions are provided in Figure Figure 4.8.

![Fracture Compliance vs. Effective Stress](image)

Figure 4.8: Case 0 is the initial fracture compliance and Case 1 is the modified compliance to understand the largest possible variation fracture compressibility with a decrease in pore pressure.

The time-lapse analysis on the M2 Turkey Shoot data is with reference to the BL survey, so if the model for M2 is consistent with that of M1, Case 0 is still sitting on the curve at
4000psi. The Case 1 scenario for the M2 modeling holds to this to maintain consistency between models starting from the associated fracture compliance at 4000psi and expending to the maximum effective stress provided on the curve distribution (5000psi and 0.0000001 \( \frac{1}{\text{psi}} \) fracture compliance).

The Case 1 analysis for M2 has a different Case 0, in order to model a large (maximum) increase of effective stress (decrease in pore pressure). Reservoir simulations show a change in pressure of almost 3000psi after two years production. It is nearly impossible to quantify that large of a decrease in pore pressure via Sayers (2010) fracture compliance methods with the additional influence of control from the Niobrara core sensitivity analysis. The fundamental reconstruction of Case 1 is done to understand the magnitude and direction of a P-impedance or more specifically, a \( V_p \) change. Case one had a drop in compliance and an increase of 6000psi in effective stress. The results for a modeled velocity change is provided in Figure 4.9.

The modeled results after accounting for a pore pressure decrease is relatively insignificant in \( V_p \). However, this slight difference could have a critical influence for the initial P-velocities moving into fluid substitution. There are a few other considerations worth mentioning before moving forward with the M2 models that would support a relatively insignificant change in velocity. The Niobrara and Codell as unconventional reservoirs have small recovery factors in comparison to producing from a conventional sandstone or high porosity carbonate play. If recovery is only 5% to 12% of the resource in place, it is likely that the pore pressures immediately along the well are not able to represent the entirety of the targeted interval and an observable pressure difference with seismic. If the reservoir has effectively ”resettled” changes in pressure might be lower but not at a large enough displacement to notice a compressional velocity change.
Figure 4.9: Result of fracture compliance influence on P-velocity with a change in pore pressure (sonic track). The inversion results to compare to percent difference volumes is provided on the right. Synonomous with 4.1.1, the fracture compressibility has little affect on sonic changes.
4.2 Unconventional Fluid Substitution

This section will discuss the application of Mavko and Bandyopadhyay (2009) fluid substitution modeling as it applies to unconventional reservoirs. The M2 impedance results were the only data considered for fluid substitution as the stimulation fluids were not thought to provide any observable differences in compressional velocity. Furthermore, the stimulation fluid would not present a bulk density change either; the Niobrara and Codell reservoirs had liquid-filled pores before being produced, creating no apparent impedance change in the reservoir.

Compressional wave time-lapse studies are abundantly successful to observe fluid and gas effects in conventional applications because the phase differences and varying saturations are heavily dependent on the porosity of the reservoir (Brie et al., 1995). However, gas has a very strong influence on a reservoir’s compressibility. Figure 4.10 graphically explains an acoustic response from fluid or gas and the influence it has on compressibility even with a <5% saturation.

Figure 4.10: Showing the immediate compressibility as gas enters a system (Ostrander, 1984).
Before walking through the work flow implemented for the fluid substitution in association with M2, it is important to understand the choice of estimating these dynamic saturation changes in an unconventional reservoir like the Niobrara. Previous work has addressed the complications associated with modeling fluid/gas substitution in tight reservoirs; (Sava et al., 2000) explains the inaccuracy with the conventional Gassmann’s fluid substitution in anisotropic media. (Sava et al., 2000) has published laboratory experiments that show a significant over and under prediction of velocity changes when modeling crack and thin-layer anisotropy, respectively. The study concludes that Gassmann’s fluid substitution model is more likely to illicit greater errors in media composed of stiff isotropic background with thin intercalation of a softer media (Sava et al., 2000). Operationally speaking, the Niobrara is targeted in its respective chalk intervals with the intention of stimulating the stiffer, more brittle lithology to enhance conductivity in low porosity and permeable rock. As mentioned in Section 1.3, these chalks are never assumed to be homogeneous and will have varying influences from clay minerals vertically and horizontally. This directly relates to the problematic case presented by (Sava et al., 2000), eliminating the application of the conventional, isotropic Gassmann’s approach to fluid substitution.

To properly represent a certain degree of anisotropy, unconventional fluid substitution methods illustrated in (Mavko and Bandyopadhyay, 2009) were implemented to generate imposed gas effects on P-velocities. Well N, the same well used in Section 4.1 was used for this modeling and incorporated the modeled logs as a base case. In addition to the stiffness matrices already generated for changes in pore pressure, the data preparation was already complete with modified stiffness matrices, slightly increased velocities and Thomsen (1986) parameters as inputs to the (Mavko and Bandyopadhyay, 2009) unconventional fluid substitution. These components can be carried over into this model because the assumption for a weakly anisotropic VTI medium is also incorporated. Mineralogy and saturation inputs were still required before observing any dynamic $V_p$ changes.
Well N had a standard ELAN (Elemental Log Analysis) formation evaluation applied (Figure 4.11) by RCP PhD Candidate, Tom Bratton. The ELAN is an inversion performed using the provided suite of logs to create mineralogy distributions and quantities of kerogen content required as inputs for fluid substitution. This inversion is performed by establishing a series of linear relationships between the known log curves to effectively solve for the unknown differences in mineralogy. The mineralogy is then tied back to X-Ray Diffraction (XRD) results at given samples through the reservoir interval placing a control on the inversion results. Independent rock models were used for the Niobrara chalks and marls and the Codell sandstone. Figure 4.12 shows the distribution of minerals along the well, generated through the Niobrara to the Greenhorn. Generalized mineralogies would suffice for fluid substitution, but the data in Well N provides more confidence in the modeling results. The minerals (summing to unity) are required for fluid substitution and include the following minerals in its distribution: illite, smectite, quartz, calcite, k-feldspar, n-feldspar, kerogen, and pyrite. These distributions are provided from left to right respectively in Figure 4.12.

The next big input to model the acoustic response of the saturation changes in the reservoir, were the saturations themselves. RCP has a working reservoir simulation model which has been tried and tested over the Wishbone section. Simulations have determined that gas saturations had risen to 40% surrounding the major structure in the section, and 30-45% in the rock matrix seen in an averaged slice in Figure 4.13. The simulation model was used to quantify a modest input of a 30% gas saturation with the intention of iteratively applying more to quantify the given anomalies in the real time-lapse inversions.

There are many different perspectives which attest to the stimulated and producing volume in the Niobrara and Codell reservoirs. Any operator developing unconventional reservoirs would like to entertain the idea that stimulation effectively induces and props con-
Figure 4.11: The ELAN formation evaluation that includes gamma ray, resistivity (shallow-deep induction), mineralogy, oil saturation(green)/immovable-water(blue)/movable-water (orange), density with XRD, porosity and spectral gamma ray curves from left to right.
Figure 4.12: Mineralogy curves through the entire Niobrara to Greenhorn interval. These include: illite, smectite, quartz, calcite, k-feldspar, n-feldspar, kerogen, and pyrite from left to right. Additionally, the black dots are the XRD results from the core as a tie to real data.
ductivity through all benches of the Niobrara, producing uniform capacities from stimulated fractures. This is a common and most likely mis-represented interpretation, that is widely accepted as a result of microseismic data interpretation in the field.

Studies done by (Duenckel et al., 2011) and (Vincent, 2011) suggest that when using sand proppants to maintain open fractures, will actually be slowly swallowed and/or crushed over a six month period losing 55% of the stimulation’s conductivity (Handren and Palisch, 2009). This interpretation would therefore rely on the resettled reservoir to have an increase in effective permeability while it resettles. Conceptually this occurs with grains, microfractures and even fractures that settle in different orientations after being agitated. This realignment creates a new aperture strictly controlled by regional or localized stresses as the reservoir is produced.
After having all of the inputs required to implement (Mavko and Bandyopadhyay, 2009) unconventional fluid substitution model, RokDoc™ software interface was used to organize and apply the substitution algorithm. There were two separate cases that were tested to quantify the anomalies observed in the inversion difference volumes discussed in 5.

Using the the components generated from Equations 4.2 to 4.10 in Section 4.1, Mavko and Bandyopadhyay (2009) provides an approximation for P-wave modulus ($c_{33}$) with a modified saturation input shown in Equation 4.16. $K_{dry}$, $K_{sat}$, $K_m$ and $K_{fl}$ are the elastic bulk moduli if the dry rock, saturated rock, solid mineral and saturating pore fluid respectively.

$$c_{33}^{dry} \approx c_{33}^{sat} - \frac{(K_{fl}/K_m) \cdot [K_m - K_{sat}^{iso} - (2/3) \cdot c_{33}^{sat} \cdot \delta]^2}{\phi \cdot (K_m - K_{fl}) - (K_{fl}/K_m) \cdot (K_m - K_{sat}^{iso})}$$

(4.16)

The anomalies of lower impedance differences in the M2 volume seemingly reside in the Mid-Niobrara to Fort Hays horizons and also between the Codell to Greenhorn horizons. These intervals are the target intervals for all wells with the exception of the 11N (B Chalk). Both of the previously mentioned interpretations were utilized in constructing two cases that would best correlate to the percent differences in the P-impedance. First, the more probable case, explained by (Duenckel et al., 2011) and (Vincent, 2011), was reflected on the model by only applying saturation changes to the C-Chalk and Codell intervals shown in Figure 4.14.

Additional modeling was also tested observing gas saturations as a higher (less probable) case, including the B Chalk provided in Figure 4.15. These results are not as dominant as in (Figure 4.14), but show a more distributed negative difference in the reservoir interval.
Figure 4.14: Modeled percent difference (M2-BL) volume from a well near the Wishbone section with dipole-sonic logs. Monitor 2 being synthetic, generated from modeled P-sonic changes "producing" from the C-chalk and Codell intervals. Percent differences coincide with actual inversions. The "hardening" effect both above and below the negative change is assumed to be from a residual time shift in amplitudes from the slowing of the C Chalk and Codell formations, however, this still needs to be investigated.
Figure 4.15: Modeled percent difference (M2-BL) volume from a well near the Wishbone section with dipole-sonic logs. Monitor 2 again, synthetic, generated from modeled P-sonic changes "producing" from the B-chalk, C-chalk and Codell intervals. Percent differences correlate with actual inversions. Results are not nearly as dramatic without including the B Chalk velocity change, but are distributed more in the reservoir.
CHAPTER 5
TIME-LAPSE INTERPRETATION AND DISCUSSION

This chapter will discuss the more detailed interpretations created regarding the pre-stack time-lapse inversion results and its associated models from Sections 3 and 4. It will also review alternative perspectives that could be studied in future work to continue quantifying the time-lapse results.

5.1 Monitor 1 Interpretation

Although the M1 to BL differences in Ip could not be appropriately correlated or quantified, there are some observations that are supported with other data. The microseismic acquired during the completion of the Wishbone wells presents a direct correlation with the Ip percent difference at the reservoir from M1 to the BL. Figure 5.1 shows a map providing event density above a given threshold overlain on the average Ip difference from the top of the Niobrara to the Greenhorn horizon. The microseismic density of events outlines the Ip negative anomalies almost bordering the higher magnitudes entirely.

These analyses were only made from a map perspective because similar correlations in depth provide a tremendous amount of uncertainty. The analysis of the impedance differences in depth and combining uncertainty associated with two different velocity models could lead to incorrect observations and correlations. The maps provide further confidence regarding the M1 repeatability and that Ip differences are attributed to a metric of conductivity established by stimulation and not completely arbitrary.

A petroleum engineering graduate Dang (2016) published her study with the tracer data provided to RCP in Phase XV, and acquired during the completion of the Wishbone section. Much of the tracer information supports what is observed in the time-lapse inversion for M1. Specifically observations against mass of recovered tracers in the Wishbone wells. Figure 5.2 and Figure 5.3 are plots showing the displacement of tracers injected by 5C and 6N along the
Figure 5.1: Map showing event density overlain on the average Ip difference (M1-BL) from the top of the Niobrara to the Greenhorn. The density of events are normalized into polygons similar to a heat map, to provide better perspective on the correlation between the two maps.
graben recovered by other wells in the Wishbone section. The average Ip percent difference isolated in the area with the most relevant wells is also included.

Figure 5.2: The average Ip percent difference (M1-BL) (left) extracted from the Mid-Niobrara to the Greenhorn representing the total interval of negative difference in the reservoir. The mass percent recovered versus distance (right) (Dang, 2016) showing the amount of the tracer 1700 injected at well 5C in the Northern portion of the graben and recovered at other wells in the section. A barrier (labeled) was interpreted in the Ip difference extraction potentially limiting western conductivity away from the graben. Wells of importance are outlined in bold and circled on the plot to focus attention to the anomalies potentially coincide with conductivity.

The mass percent recoveries show that in both injector wells (5C and 6N) maintained greater conductivity between the wells in the East. Wells 7N and 8C both have limited tracers produced from the 5C and 6N from tracers injected into the graben. This could be indicative of a barrier features interpreted on the map. Dang (2016) had made her interpretations based on seismic structure maps, FMI logs and tracer injection locations indicating that
Figure 5.3: The average Ip percent difference (M1-BL) (left) extracted from the Mid-Niobrara to the Greenhorn representing the total interval of negative difference in the reservoir. The mass percent recovered versus distance (right) (Dang, 2016) showing the amount of the tracer 1500 injected at well 6N in the Northern portion of the graben and recovered at other wells in the section. The same barrier (labeled) potentially limiting western conductivity away from the graben. Wells of importance are outlined in bold and circled on the plot to focus attention to the anomalies potentially coincide with conductivity.
the central West-East graben delivered the majority of the tracer mass to the Eastern wells. If this negative percent difference is indicative of any conductivity metric, it would provide further interpretation power as a significantly more negative difference lineation spanning from the interpreted barrier in the West moving though the 3C well in the East. The tracer data is real, quantifiable data which, if correlated to time-lapse results, could be immensely powerful in continued understanding of the seismic contributions. A last look at the tracer information with respect to the M1-BL time-lapse results is provided in Figure 5.4. This figure shows the NRMS values in the reservoir over the Wishbone section. It seems that the major differences begin at a line that almost cuts perfectly perpendicular to the induced fracture orientation and principal stress direction interpreted from FMI logs (Dudley, 2014). The black-dotted lines give two perspectives of where the significant NRMS changes begin in order to show that the larger differences are more conglomerated to the Northern portion of the wells. The total mass percent recoveries from Dang (2016) are partitioned by location of injection (graben/toe section/heel section) and their range of distance traveled. The plot summarizes that the graben is the most conductive area, transporting injected tracers the furthest distance. More importantly, the second largest displacement of tracers occurs in the toe sections of the wells (from the graben, north) which correlates to the largest NRMS difference body.

The inversion results show greatest negative P-impedance percent differences in the western and northern areas of the Wishbone section from the inversions and supported by previous studies. With the underestimation from the modeling in Section 4.1.1 the following discussion will relate observations leading into future work and alternative considerations regarding the negative differences between M1 and the BL surveys.

The pre-stack study provided a more plausible vertical distribution of negative differences contained within the reservoir (Mid-Niobrara to Greenhorn). The positive and nega-
Figure 5.4: NRMS extraction from the Mid-Niobrara to the Greenhorn (left) with a plot showing the mass percent recovered in a generalized location (right) (Dang, 2016). The data points plotted differ in geometric shape referring to the location of injection, separated into the heel, graben and toe. The plot shows that the graben carried tracer the furthest, toe second and heel third. The overall NRMS difference map shows a larger amount of normalized differences between M1 and the BL covering a larger area to the north. The black dotted lines are a guides for where the transition from small to large NRMS values begin. The induced fracture orientation interpreted by Dudley (2014) is also included as they match fairly well with the orientation of the NRMS differences.
tive oscillations observed throughout the vertical section in the post-stack inversion (White, 2015) were reduced to only the upper section of the Niobrara and just above the Greenhorn formation. The abiding strata (marl/shale) above and below the reservoir could be more susceptible to stress. (David et al., 1994) proves that even though shales are more ductile, they are more sensitive to stress with a direct application to compressional and shear velocities shown in Figure 5.5. The marl intervals were not manipulated when modeling for pressure changes, but the difference volumes for M1 show a strong increase in Ip within the Upper Niobrara (A Marl) and below the Codell Sandstone (Carlile Shale).

Figure 5.5: A variety of core samples with diverse reservoir properties underwent permeability tests under increasing stress. The Rothbach is a shale formation against all other displayed sandstones, with a greater stress sensitivity (David et al., 1994).

5.2 Monitor 2 Interpretation

The time-lapse analysis for M2 has resulted in negative impedance differences over time which can be attributed to a gas effect from modeling saturation changes in the Niobrara and Codell reservoirs. Immediate observations can be made specific to the production differences in the Wishbone section over a two year period. There is also a direct relationship with well spacing: Tighter well spacing in the west correlates spatially with the greatest
negative differences in M2. No immediate recommendations can be made at this point as these observations must be applied to simulations in order to build specific conclusions and thereby implement changes to operations in the Wattenberg Field. This section will provide an interpretation specific to the current understanding of these time-lapse differences, address discrepancies observed in the results, and provide some perspective to the application of these results in a multidisciplinary setting.

Gas out of solution is considered to be the main driver in negative Ip differences (M2-BL). However there is a significant amount of negative differences that surround the Wishbone wells in adjacent sections. Wattenberg Field is one of the most prolific unconventional fields in the United States and there has been significant activity before and after this study. It was important to understand the production before and after development of the Wishbone wells in order to account for anomalous time-lapse responses that could occur in the surrounding area. Figure 5.6 shows the gas production before and after the Wishbone wells began flow back. There were two wells with significant gas production to the west of the Wishbone section prior to the BL survey acquisition. This must be considered when observing time-lapse variations near this area. More importantly, it is imperative to observe the gas production after the Wishbone wells were began production, where horizontals have been producing substantial amounts of gas in the same reservoir intervals and a similar time line. This will undoubtedly complicate an isolated time-lapse interpretation specific to the Wishbone section.

When considering the production in adjacent sections, the more problematic areas of the survey are identified to be the entire perimeter with exception to the direct North, Northwest, South and Southwest sections. In any other direction, wells could be as close as 1000 feet to a Wishbone laterally and likely interfere in some capacity.

In order to further understand the power of the time-lapse regarding a producing volume, a series of statistical well extractions were made in attempt to correlate production versus
Figure 5.6: Gas production inside and surrounding the Turkey Shoot survey after the Wishbone section flow back. The wells and gas production shown here all occurred within six months of the Wishbone wells.
a varying degree of time-lapse difference along the wellbores. Production spinner logs were acquired for the 2N and 6N- however, they were seemingly dominated by flow from major structure during flow back (Motamedi, 2015). Extractions along the horizontal wellbores were made to assign negative differences to the wells production. When extracted, each well had a "log" representing the average at each 5 foot sample. To narrow these down even further, the logs were averaged again to consolidate negative impedance values for each stage. To effectively correlate well head production, these averages per stage were combined again to represent an average impedance along the wellbore. The cross plot in Figure 5.7 shows the relationship between the average negative impedance difference versus the normalized gas production at the well-head.

![Figure 5.7: The relationship between the average negative differences extracted along the wellbores in the Wishbone section against their normalized production. There is a 70% percent correlation with all wells included in the analysis (blue). If one outlier is removed, then the correlation jumps 17% to 87% (orange).](image)

With all Wishbone wells included in the analysis, there is a 70% percent correlation with negative difference and the gas production. Removing one of the outliers leaving ten of the eleven wells in the cross plot, there is an 86% correlation with these values. When creating the same cross plots for the oil production (Figure 5.8) the distribution is scattered and no discernible relationship. Gas production showing a 70% correlation, the fluid substitution
modeling with similar negative impedance changes, and the non-correlation of oil production isolates gas as being the dominant effect on the time-lapse seismic data. With only simple analyses performed on this data, it will be important to test more statistical relationships for even better correlations.

![Oil Production vs Negative Difference](image)

Figure 5.8: Negative Ip differences extracted along the Wishbone wells plotted against the cumulative oil production. There is no discernible relationship, further supporting a gas effect on the PP time-lapse seismic.

After further support of the negative differences correlating with gas production, it was important to observe the representation of these differences in section view. To provide a maximum and minimum representation along the wells in the Wishbone section a section line along the zipper-frac’d wells (7N, 8C, 9N- higher producers) was compared against the lowest producer in the section (4N) shown in Figure 5.9 and Figure 5.10. The color scales on each Figure are equivalent and the time-lapse sections are both clipped to represent only the differences that are greater magnitude than what is observed in the overburden.
Figure 5.9: (Top) Overall NRMS change in section view near the zipper-frac’d wells (7N, 8C, and 9N), relatively high gas producers as a unit in the Wishbone section. (Bottom) The Ip percent difference volume (M2-BL) showing a high magnitude differences along the well, compared to Figure 5.10 and the lowest gas producer in the section.
Figure 5.10: (Top) Overall NRMS change in section view near the well 4N, the lowest gas producer in the Wishbone section. (Bottom) The Ip percent difference volume (M2-BL) showing a reduction in magnitude differences along the well, compared to Figure 5.9 and the zipperfrac.
The major negative differences are somewhat stratified into the lower interval of the Niobrara, which also supports a gas effect. During production, the wells are causing a pressure depletion more significantly near the well where gas would be attracted. Furthermore, intervals that consist of more dominant marl lithologies are much more malleable and maintain lower porosity and permeability. Conceptually, the marl intervals of the Niobrara would be the first to heal any conductive paths back to the wellbore(s) and limit prolonged hydrocarbon flow vertically in the Niobrara. This would further support a compartmentalized reservoir driven by natural fractures, also indicating a smaller influence of stimulated fractures through the life of these wells.

Structural complexity observed in the Wishbone section also plays a pivotal role in compartmentalization and the overall contributions from the Niobrara and Codell reservoirs. The tighter-spaced wells are located in the Western portion of the Wishbone section, but so is the greatest structural complexity. Two major grabens interact with each other in the West, and will undoubtedly introduce a greater density of natural fractures where they interact. This statement is abundantly supported by previous RCP work Davis (2011); Davis and Weimer (1976); Dudley (2014); Motamedi (2015); Mueller (2016); White (2015) and also supported by the M2 negative differences that are indicative of greater gas saturations in the West (Figure 5.11).
Figure 5.11: Negative Ip differences in the Wishbone section with faults detectable by seismic traced over the map. The incoherence attribute isolates faulting that is observable in the seismic data, identifying large changes in amplitudes trace to trace.
CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

This study has provided substantial observations from the P-impedance inverted from time-lapse compressional wave surveys over the Turkey Shoot dataset. A variety of comparisons between the differences of the volumes have been made which correlate both with modeling in addition to current and previous studies in Phases XV and XVI. These observations will continue to provide a well-rounded interpretation and application to the dynamic understanding of the reservoir. The main deliverables from this study are:

- Cross-equalized pre-stack PP 3D volumes for both Monitor 1 and Monitor 2 surveys with respect to the Baseline survey as input to future time-lapse studies
- Time-lapse, pre-stack inversion of Baseline and cross-equalized Monitor surveys, gaining accurate compressional impedance (Ip) volumes and their differences
- P-velocity ($V_p$) alterations from increasing pore pressure after stimulation (Monitor 1)
- Modeled changes in $V_p$ for a combined pore pressure increase after two-years of production and gas out of solution (Monitor 2)
- Integrated interpretations associating this study with previous RCP work to constrain reservoir simulation iterations

6.1 Conclusions

Following the time-lapse analysis and deliverables, the conclusions that result from this study follow:

- The time-lapse PP Turkey Shoot surveys are repeatable and residual differences in the overburden are appropriately minimized through cross-equalization (XEQ). A more
efficient XEQ work flow was constructed for application in future XEQ processes to enhance repeatability between surveys. The modified work flow was consisted of applying a trace by trace shaping filter to match frequency content and resolvable limitations, in addition to trace specific time variant time shifts.

- There are significant Ip differences that are observable from inversion results in both M1 and M2 time-lapse analyses. The M1 differences range from 0% to -4% and the M2 slightly less, from 0% to -3% in the reservoir interval. The greatest Ip differences coincide with the distributions of NRMS amplitude differences to the Northern and Western portions of the section. This areal distribution also directly relates to the results of the microseismic and conductivity during stimulation from the tracer experiments.

- Rock physics models show little sensitivity to pore pressure change through stimulation and production, but large and more dominant influence from gas out of solution during the producing life of the reservoir. Both models have appropriately incorporated weakly anisotropic VTI assumptions necessary for estimating changes in P-velocity in unconventional reservoir applications.

Differences in seismic are not only sensitive to dynamic characteristics of producing reservoir, but also subtle differences in acquisition and processing (Johnston, 1997). The cross-equalization performed in this study isolates the key methods addressing discrepancies in the time-lapse volumes. The modified work flow outlined in this study increases the overall repeatability between surveys to gain the best possible perspective regarding dynamic changes to the reservoir during stimulation and production. The cross-equalized Monitor volumes maintain NRMS differences effectively reduced below .15, half the value considered appropriate for land-acquired seismic data.

Both modeling of pore pressure and saturation changes were designed to estimate the sensitivity of the reservoir to a change in compressional velocity for M1 and M2. The pore
pressure models observed maximum possible variance resulting from changing compliance ±1%. These models would not independently account for the magnitude differences in P-impedance for M1 but both negatively affect P-velocity. The combination of a pore pressure decrease ($V_p$ increase) in combination with gas saturations estimated a closely matched difference to that of the M2 time-lapse analysis. This is the first study with practical interpretation regarding the M2 data for Phase XVI.

### 6.2 Recommendations

The M1 data set and time-lapse differences with respect to the BL survey have not been appropriately justified due to a mismatch of negative impedance magnitudes in the modeling. Future work should include modeling the sensitivities of the Niobrara and Codell reservoirs along with their surrounding stratigraphy. More complex assumptions regarding the mineralogy (grain boundaries), stress sensitivities, and structure may better justify the differences in P-velocity observed in the seismic analysis. Further analysis of the core data near the RCP study area could be performed as a minimum constraint on dynamic observations on moduli. More specifically, these core should be taken beyond failure to observe the velocity differences at peak strength (Sammonds et al., 1989). Destructive measurements could further validate the softening/slowing that is occurring in the time-lapse observations as the rock condenses on its own microcracks after failure. The observations from core experiments could lead to new modeling methods to better appropriate for the changes in P-velocity. The associated modeling could also lead into work flows for the dynamic (4D) multicomponent (9C) seismic data at the Turkey Shoot.

The change in P-velocity associated with gas out of solution allows for simulations to be constrained by a three dimensional distribution of negative differences indicative of gas presence and saturation. An interpreted volume of gas saturation after two years production would help better understand other inputs to the simulation that might be weakly modeled,
thereby reducing the amount of compounded uncertainty. In association with other data inputs and educated assumptions from RCP studies, a gas saturation volume will empower RCP and APC’s ability to gain a statistical understanding of unknown optimization questions regarding both recovery and operations:

- Contributing lithology to production:
  - What is the ideal target formation for horizontal wells?
  - Based on an economic evaluation, the value of rig time spent steering wells, maintaining accurate placement in the target formation
  - More confident acquisition of more acreage in the field with respect to sweet spots

- Structural contributions to production:
  - Utilizing large multi-client seismic datasets to isolate more (probable) productive areas with respect to faulting and stress geometries
  - Azimuth of wells be placed with respect to the localized stress regimes to maximize conductivity over a given production period

- Well length, geometry and spacing- how to efficiently maximize and place wells for a given section, maintaining higher production

- Are there certain wells worth sacrificing to lesser production in order to get more out of a fewer wells

These are major industry concerns that can be supported with continued time-lapse seismic understanding and dynamic reservoir characterization in the Wattenberg Field. This would not only assist in increasing recovery factors, but also operational efficiency. The initial success in this study and the continued efforts from RCP should influence more time-lapse seismic studies in unconventional reservoirs. Multidisciplinary expertise and data will
provide a statistical advantage on the critical operational questions mentioned above.

The lack of gas saturation in the Wishbone section from the time-lapse seismic could also isolate bypassed pay. This is extremely powerful because the time-lapse seismic would be the only tool to characterize "under-produced" areas or intervals at a given time period. Additionally, utilizing this volume and engineering data at the well could isolate candidates for re-fracturing (a second stimulation in preexisting perforations) or re-completion (drilling out casing, implementing new perforations and injection strategy). A more immediate application to the study area would be infill drilling strategies to maximize production over existing acreage, avoiding the operational complications with re-completion design.

The single most important recommendation would be the continued inversion work with the multicomponent data. Utilizing the converted shear (PS) seismic will allow for a more accurate density model for the three seismic volumes over time. A dynamic density model could accurately estimate the changes to reservoir rock properties and moduli over time. Estimating changes to dynamic moduli is going to be a key integration factor for all scales of geoscience from the finite core scale to the up-scaled simulation model.

A substantial amount of uncertainty still exists regarding the behavior of unconventional reservoirs during stimulation and production. The heterogeneity of the Niobrara and Codell reservoirs cannot be adequately represented using geophysical estimation methods at the surface, or even with densely spaced down-hole data. The Wattenberg Team in the RCP is working to minimize these unknown variables using a variety of multidisciplinary constraints to better understand the dynamic reservoir behavior.
REFERENCES CITED


