Carbon Capture and Sequestration and CO$_2$ Enhanced Oil Recovery in the Monterey Stevens Sandstone at North Coles Levee, San Joaquin Valley, California

By

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ABSTRACT

Depleted oil and gas reservoirs in the petroliferous San Joaquin Basin are attractive starting points for geologic carbon storage efforts in the southern San Joaquin Valley of California. An added benefit of such carbon storage is that, in addition to curbing carbon emissions presuming capture from an anthropogenic source, new oil can be produced through carbon dioxide enhanced oil recovery (CO₂ EOR). CO₂ EOR has been used successfully in the Permian Basin of west Texas for over two decades. The main reason it has not been employed in the San Joaquin Basin is the lack of a cheap source of carbon. If local power generating facilities are retrofitted to capture and compress CO₂ emissions, then oil and gas operations would have an affordable source of CO₂ in the region and some of the cost of the carbon capture process would be offset.

This study examined the reservoir architecture, pressure characteristics, and production history of the Monterey Formation Stevens sandstone at the North Coles Levee oil field in order to ascertain whether it could serve as a viable carbon dioxide storage reservoir. The results of this work indicate that additional analysis needs to be carried out before the field’s viability as CCS site can be confirmed. Pressure response to fluid production and very little water production indicate the field behaves as a closed system and the most recent pressure data suggests that the Stevens reservoirs are at, or near hydrostatic pressure. Compartmentalized or closed system, reservoirs typically have significant pressure increase when a large volume of fluid is injected into them. This can be problematic for both seal integrity and the amount of fluid that can be injected. Methods that allow for estimation of total carbon storage capacity in compartmentalized systems before overpressure occurs are available but, unfortunately one of the necessary inputs into the storage calculation is the total pore volume, which due to the limits of the available data, this study does not provide.

The field would likely benefit from CO₂ EOR. A successful pilot test in the early 1980s showed increased oil recovery over a two year period when CO₂ was used for EOR. We estimate that with a well-planned CO₂ EOR program, a minimum of 60 million additional barrels of oil could be recovered from the Stevens sandstone reservoirs at North Coles Levee.
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Introduction

Carbon Capture and Sequestration (CCS) is a promising new technology that can help to mitigate the climate change effects of fossil fuel burning (Burruss et al., 2009). This research sets out to test the feasibility of carbon storage technologies that could have a profound impact on the San Joaquin Valley and will serve as a model for other regions around the country and the globe. The West Coast Regional Carbon Sequestration Partnership (WESTCARB) is one of seven regional organizations in partnership with the United States Department of Energy (DOE) tasked with identifying and characterizing CCS opportunities. Initial studies focused on sedimentary basins with particular focus on depleted oil and gas reservoirs due to their known trapping capability, in place infrastructure, and proximity to carbon emission sources. Additional work at Lawrence Berkeley National Laboratory, funded by California’s Public Interest Energy Research Program (PIER), focused on the highly prolific oil fields of the southern San Joaquin Basin (SJB) where local power plants produce 27% of California’s total CO₂ emissions (American Lung Association, 2011).

North Coles Levee (NCL) is one of several depleted or near-depleted oil fields in the SJB that meets basin screening criteria set forth by WESTCARB, the DOE, and the USGS (Gillespie, 2011). Publicly accessible well history reports, production data, and electric logs are the main inputs for this study of the Stevens reservoir at NCL. The primary goals of this project are to determine, (a) the reservoir architecture of the field and the lateral extent of sealing units for the express purpose of identifying any potential fluid migration pathways that
may endanger local freshwater aquifers, and the degree of reservoir is compartmentalization, (b) the total pore volume, cumulative fluid production, and viability of CCS at NCL, and (c) the potential amount of tertiary oil recovery utilizing CO$_2$ EOR methods.

**Carbon Capture and Sequestration**

From the onset of the Industrial Revolution and subsequent increase of fossil fuel burning, the concentration of atmospheric CO$_2$ has been rising and the trend is likely to continue. CO$_2$ and other greenhouse gases aid in the trapping of infrared radiation in the upper atmosphere by acting as an insulator around the planet, thereby increasing global temperatures (Downey and Clinkenbeard, 2006). Coal and natural gas supply as much as 85 percent of global energy consumption and that trend is not expected to change significantly over the next 25-50 years (Herzog and Golomb; Kaldi et al., 2009). CCS has been proposed as a viable solution to allow continued fossil fuel consumption at large facilities while mitigating greenhouse gas emissions (IPCC, 2005).

Geologic carbon storage and sequestration in deep saline reservoirs and mature oilfields is one proposal to help mitigate the effects of fossil fuel burning (Figure 1). Saline aquifers are by far the most voluminous targets and, if CCS is to have a significant impact on lowering atmospheric CO$_2$, they must be utilized. However, the cost of storing CO$_2$ in saline formations is prohibitive at this time, characteristics of most aquifers are poorly known, and the necessary infrastructure is not in place (Downey and Clinkenbeard, 2006). Depleted oil and gas reservoirs offer less storage capacity but, due to decades of production and observation they are much better understood. Therefore depleted oil reservoirs are the most economic starting point for CCS projects with the hope that, once in place, they will lead to CO$_2$ injection into the more widespread saline formations (Figure 1) (Downey and Clinkenbeard, 2006).
Figure 1. Diagram of CCS sources and sinks from the U.S. Department of Energy showing anthropogenic CO$_2$ sources, deep geologic storage reservoirs, enhanced oil recovery potential, and CO2 market opportunities. Carbon capture technologies separate CO$_2$ from industrial plant exhaust streams prior to atmospheric release then compress and transport CO$_2$ to suitable locations for injection or industrial use (From U.S. Department of Energy, 2012).
In 2007, the USGS, working with the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE), was authorized to conduct a nationwide assessment of carbon storage potential in geologic resources. Burruss et al., (2009) set forth three constraints for potential reservoirs:

1. Formation water salinity cannot be less than 10,000 mg/L TDS. Although most drinking water TDS is in the 500-1500 mg/L range, the EPA has deemed any water with less than 10,000 mg/L TDS to have potential to be remediated in the future. (U.S. EPA, 2008)

2. Minimum depth of the reservoir is 3000 feet. CO\textsubscript{2} is a supercritical fluid at pressures and temperatures found deeper than 3000 feet (Figure 2). CO\textsubscript{2} density in supercritical phase is similar to oil and less dense than water so it will behave in similar manner to oil at reservoir conditions.

3. Minimum reservoir size must be 2 million cubic meters (12.5 MMbbl oil). This is equivalent to approximately 1-1.4 million metric tons of CO\textsubscript{2} at typical reservoir pressure and temperature conditions
Figure 2. Pressure Temperature diagram showing phase characteristics of CO$_2$. At pressure and temperature conditions higher than the critical point, CO$_2$ is a supercritical fluid. At typical subsurface temperature gradients (red line) this occurs at depths near 3000 feet (From Burruss et al., 2009)
Initially, basins screened for CCS focused on the storage potential of oil and gas reservoirs due to their previously mentioned positive attributes and the following:

(a) Oil and gas fields possess proven trapping mechanisms having contained buoyant hydrocarbons for thousands to millions of years. In order for CO$_2$ to stay in the subsurface long enough so that there are no adverse effects to the atmosphere, CO$_2$ must remain trapped for thousands of years. In most cases this requires the presence of an extensive stratigraphic sealing unit. Transgressive units are most desirable in that they are regionally extensive and composed of impermeable shale (Downey and Clinkenbeard, 2006).

(b) CO$_2$ density at reservoir pressure and temperature conditions is very similar to oil so it will behave like oil at those conditions; rising buoyantly until it encounters a sealing unit (Burruss et al., 2009).

(c) Supercritical CO$_2$ and crude oil are generally miscible at the previously defined storage depth, and under such conditions CO$_2$ actually lowers oil viscosity allowing for tertiary production of the previously unrecoverable hydrocarbons.

(d) Oil and gas reservoir records contain large amounts of publicly accessible data pertaining to production through time, reservoir petrology, well summary reports, core data, well logs, and reservoir geometry.

Recent regional studies of the southern San Joaquin basin (SJB) have noted potential environmental impacts to ground water resources from CO$_2$ sequestration (Birkholzer et al., 2008). Although CO$_2$ projects will occur in formations much deeper than local aquifers, there is potential for saline aquifers at reservoir depth to be in hydraulic communication with shallower freshwater aquifers used for domestic and commercial purposes (Birkholzer et al., 2008). When CO$_2$ is injected into the reservoir it radiates outward in a plume. Within and adjacent to the plume is an area of elevated pressure. The concern is that this pressure front could force brackish reservoir brines upward through faults and abandoned boreholes and bring them into hydraulic communication with freshwater aquifers (Figure 3) (Birkholzer et al., 2008). This is of special concern in the
NCL region due to its proximity to the Kern Water Bank, a large groundwater storage resource that is vital to the region’s agriculture industry and domestic supply (http://www.kwb.org/index.cfm/fuseaction/pages.page/id/36). Reservoirs that are compartmentalized (encased in shale or other permeability barriers and not connected to an extensive saline aquifer) are less likely to be in hydraulic communication with freshwater aquifers near the basin margin (Benson et al., 2005).

Figure 3. Diagram showing adverse pressure effects on local brines and freshwater aquifers (From Birkholzer et al., 2008)
Carbon Dioxide Enhanced Oil Recovery

Higher hydrocarbon prices combined with state and federal funding, tax incentives, and carbon credits have made CCS through CO₂ EOR an attractive starting point for larger CCS storage projects in saline aquifers (Alvarado and Manrique, 2010). Oil and gas reservoirs are excellent candidates because they have proven sealing mechanisms, and in many instances, costly infrastructure like wells and pipelines are already in place and can be retrofitted for CO₂ EOR provided there is a nearby source of anthropogenic carbon to mitigate the cost of transportation whether it is through pipeline or over the road (Downey and Clinkenbeard, 2006; Burton et al., 2008; National Energy Laboratory, 2009). Not all mature reservoirs are ideal candidates for CO₂ EOR and various studies have put forth reservoir screening criteria for potential CO₂ EOR candidates (Kaldi et al., 2009; National Energy Laboratory, 2009). In order for CO₂ to be most effective in EOR operations it must be at the right pressure and temperature conditions so that the CO₂ will behave as a supercritical fluid and be miscible in the oil. Desirable characteristics include depths between 2000 and 9800 feet, pressure greater than 1200 psi, permeability greater than 5 millidarcies, a minimum of 27 API gravity, and at least 25% residual oil saturation after water flooding (National Energy Laboratory, 2009). If these conditions are met, CO₂ can be injected into mature reservoirs where it becomes soluble with residual crude oil. The supercritical CO₂ causes the oil to expand and become less viscous. This increases the mobility of the oil phase as well as the relative permeability to oil allowing the trapped hydrocarbons to escape pore throats and flow to producing wells. At the surface, the oil and gas are separated from CO₂ and produced water. The CO₂ is recaptured, compressed, and injected back into the reservoir (Figure 4). The produced water may be injected as part of a water alternating gas drive, or disposed of by a variety of other conventional means (National Energy Laboratory, 2009; Alvarado and Manrique, 2010). CO₂ EOR can improve recovery of the original oil in place by 6 to 15 percent making it a worthwhile endeavor when the above screening criteria are met (Downey et al., 2006; Burton et al., 2008; National Energy Laboratory, 2009; Smith et al., 2009).
Figure 4. Cross section showing how injected water and CO$_2$ are used to flush residual hydrocarbons from a mature reservoir (From The National Energy Laboratory, 2009)

Many SJB fields are amenable to CO$_2$ EOR but the lack of nearby CO$_2$ sources and the cost of transporting CO$_2$ into the region has historically made CO$_2$ EOR unattractive to SJB petroleum operations (Burton et al., 2008; Knepp et al., 2009). This trend may soon change if local CO$_2$ generating facilities, several of which are within 20 miles of NCL, are retrofitted or if new facilities are optimized for carbon capture (Figure 5) (http://gif.berkeley.edu/westcarb/explorer2/index.html).

California’s new cap-and-trade legislation incentivizes California greenhouse gas (GHG) generating industries to reduce emissions to 1990 levels by the year 2020 by setting limits on the amount of GHG’s each
facility can emit. Each GHG generating facility’s emissions are capped and permits for any additional emissions must be bought at auction or from other facilities whose emissions fall below the cap. This means that energy providers that employ carbon capture technologies will have GHG emissions that fall far below the cap and could sell their excess carbon credits to other facilities. In addition SJB oil and gas operations could then purchase the locally captured CO$_2$ and inject it into nearby reservoirs for EOR (Figure 4) (California Environmental Protection Agency Air Resources Board, 2013, Burton et al., 2008, Myers and Wagoner, 2011).

![Figure 5. GIS map showing the proximity of North Coles Levee to electricity and CO$_2$ generating facilities (blue circles). The dark green shapes are oil fields (major fields are named) identified by WESTCARB as potential carbon sequestration sites (from WESTCARB, http://gif.berkeley.edu/westcarb/explorer2/index.html).](image-url)
North Coles Levee: Location and Field History

The North Coles Levee (NCL) oil field is located approximately 25 miles southwest of Bakersfield in the petroliferous southern San Joaquin Valley (Figure 6). NCL is bordered by the Elk Hills field to the west, the South Coles Levee field to the south, the Canal field to the northeast, and the Ten Section field to the east (Figure 6). The NCL field was discovered in the late 1930’s using recently introduced seismic reflection surveys that detected the NCL structural feature; a 4 mile-long, 2 mile-wide, east-plunging anticline (Figure 7). The discovery well drilled at the apex of the dome initially produced 805 barrels of 49 API gravity oil per day in 1938 and, after recompletion in early 1939, as much as 1400 barrels of oil and 8900 mcf of gas per day from the Stevens sandstone of the Monterey Formation (Hardoin, 1962).
Figure 6. Location map of North Coles Levee and surrounding fields.
Initial reservoir pressure at 8500 feet was 3990 psi and the temperature was 230 degrees F (Table 1) (Davis, 1952). The field was produced by gas cap expansion until 1942 when a gas injection program was initiated due to a rapid loss of reservoir pressure. All produced gas along with gas from external reservoirs was injected back into the reservoir gas cap (Davis, 1952; Hardoin, 1962). In 1965 a gas blow down was initiated and reservoir pressure dropped to less than 1000 psi. In 1967 a waterflood project was initiated and field wide waterflooding was established by 1970. The waterflood effort re-energized the reservoir and pressures returned to, and sometimes exceeded, pre-discovery levels (MacAllistar, 1989).
A CO₂ EOR pilot project was conducted at NCL from 1981 to 1983. The project delivered mixed results. Overall tertiary recovery from the production wells in the pilot project area did not improve but when performance was analyzed on a well by well basis, it became clear that some of the wells did show a marked increase in tertiary recovery. The inconsistency in recoveries between the different producers was ultimately attributed to bad injector/producer pilot patterns, gravity override issues leading to CO₂ loss to upper zones, mechanical difficulties in some of the producing wells, and permeability heterogeneity. After the project was halted, radioactive tracers were injected into the reservoir. The paths taken by the tracers indicate that in the test area, a northwest permeability trend influences fluid flow (Figure 8 and 9) (MacAllistar, 1989).
Figure 8. Location map of the 1981 North Coles Levee CO₂ EOR pilot. After two years of CO₂ injection, a surveillance test using radioactive tracers was employed and the results indicate that a NW, SE flow pattern (red arrows) is prevalent in the pilot test area. Green hachured areas indicate the swept area (Modified from MacAllister, 1989).
Figure 9. Production graph of NCL Well CLA 87-29. Oil Production from 1978-mid 1981 shows a linear production decline. Upon breakthrough of CO$_2$ after the pilot test was initiated, production stabilizes for the duration of the test until three years after breakthrough suggesting that, properly managed, CO$_2$ EOR can be successful at North Coles Levee (Modified from MacAllistar, 1981).
Geology

Tectonics

The SJB originated in Mesozoic time as the southern half of the Great Valley forearc basin (Bandy and Arnal, 1969). Eastward subduction of the Farallon plate under North America induced arc magmatism along the eastern boundary of the SJB giving rise to the Sierra Nevada magmatic arc complex (Atwater, 1970). During the middle Tertiary, the plate tectonic regime shifted from a convergent system to a transform system when the Pacific-Farallon ridge encountered the trench and initiated right lateral movement on the San Andreas Fault (SAF) system (Atwater, 1970). As the Pacific plate migrated northwestward along the SAF boundary it carried granitic terranes northward along the western margin of the San Joaquin embayment (Figure 10) (Bartow, 1991). One of these terranes, referred to as the Salinian block or Gabilan Range, lay along the western margin of the southern SJB and, in late Miocene time, acted as a clastic provenance for western Stevens sand reservoirs at the Midway Sunset, Elk Hills, and Buena Vista oil fields among others (Figure 5) (Graham and Williams, 1985). During the same period, the dissection of the Sierra Nevada magmatic arc provided clastics for eastern SJB Stevens sands including those found at NCL (MacPherson, 1978). Beginning in the Miocene and continuing to the present day, a component of compressive stress along the SAF oriented normal to the North American plate boundary initiated basinward directed thrust faulting and folding; building large anticlinal structures like the one found at Elk Hills which is still growing to this day and may control the structural architecture at North Coles Levee as well (Namson and Davis; 1988; Medwedeff, 1989).
Figure 10. Paleogeographic reconstruction of the San Joaquin basin during late Miocene time. Granitic terrains like the Salinian block served at times as granitic source provenance and during highstands, as a submarine sill allowing for anoxic conditions which led to the preservation of organic material. The present day location of NCL is in the red box (Modified from Bartow, 1991)

Sedimentation

The Stevens sandstones, which constitute the principle reservoir rocks at NCL, are found in the upper part of the Miocene age Monterey Formation and were deposited as in a deep marine turbidite system between 8.7 Ma and 6 Ma (McPherson, 1978; Webb, 1981; Hewlett and Jordan, 1994; Harrison and Graham, 1999). Rapid uplift of the Sierra Nevada combined with increased precipitation related to late Miocene atmospheric cooling contributed to greater erosional rates and increased sediment supply to the basin (Graham and Williams, 1985; Graham et al., 1988). To the northeast, shallow marine sediments of the Santa Margarita Formation were
deposited along the western edge of the Sierra Nevada in a series of coalescing fans and deltas which accumulated on a narrow offshore shelf while, during marine highstands, biosiliceous shales accumulated in the moderately deep (200-600 meters) ocean basin (Figures 11 and 12) (Hewlett and Jordan, 1994). These shales, along with the Stevens sandstones, form one of the major petroleum systems (Antelope-Stevens) in the SJB (Figure 11) (Magoon et al., 2007). The Stevens sands at NCL were deposited as turbidity flows during sea level regressions in three sequences known as the Coulter, Gosford, and Bellevue lowstand system tracts. These sequences were sourced by exposure and erosion of the shallow marine Santa Margarita sediments on the shelf (Figure 12 and 13) (MacPherson, 1978; Webb, 1981; Hewlett and Jordan, 1994; Harrison and Graham, 1999). The major reservoirs at NCL are part of the Bellevue and Gosford sequences with only minor production from Coulter sands (Figure 13) (Clark et al., 1996).
Figure 11. Generalized stratigraphic section of the Southern San Joaquin basin. Red arrow points to Stevens sand position (Modified from Scheirer and Magoon, 2007)
Figure 12. Upper Miocene sand distribution in the southern San Joaquin basin; the red arrow is pointing in the southwest transport direction of the majority of the Stevens sands at North Coles Levee. Sands were derived from the ancestral Sierra Nevada from approximately the same location that the modern Kern River does today. The Santa Margarita shelfal and deltaic sands were subsequently eroded during lowstands and redeposited in the deep basin as Stevens turbidites. See figure 13 for cross section A-A’.
(Modified from Webb, 1981)
Figure 13. Cross section A-A' (Figure 12) depicting the Rosedale, Coulter, Gosford, and Bellevue low stand sequences. These sequences were deposited as deep marine turbidite fans during the upper Miocene. The Rosedale sequence did not reach the North Coles Levee depocenter and production from the Coulter sequence (68-29 zone) is minor there. The majority of production and all of the storage space reported in this study is from the Bellevue and Gosford sequences. (Modified from MacPherson, 1978).

**Stevens Zones at North Coles Levee**

Hardoin (1962) recognized 3 principal Stevens zones and four pools at NCL (Figures 13 and 14);

1. The 300 foot thick 21-1 zone on the northeast flank is the youngest Stevens zone at NCL and produces in the 21-1 pool (Figure 14 and 15).

2. The *Upper Western* zone is generally unproductive due to low permeability and lateral discontinuity except for in portions of sections 31, 32, and 33 in the Main Western pool (note: the *Lower Western* zone is also productive in the Main Western pool (see below), and a portion along the eastern flank of the structure in sections 34 and 35 in the Western-35 pool (Figure 14 and 15).
(3) The *Lower Western* zone is a massive 550-foot thick sand found throughout the field that produces in the Main Western and the Western 29 pools. The Lower Western zone is the oldest Stevens sand examined in this study and is responsible for the greatest amount of production at NCL (Figure 14 and 15) (Davis, 1952). The 21-1 and Upper Western zones are part of the Bellevue sequence and the Lower Western zone is part of the Gosford sequence (Clark, 1996) (Figure 13).

(4) A deeper Stevens pool known as the 68-39 pool, a part of the middle Coulter sequence, was not examined in this study due to a lack of data (Figure 13) (Clark, 1996).
Figure 14. Type log shows 21-1 (blue), Upper Western (purple, green, and red), and Lower Western (yellow) Stevens zones recognized by Hardoin (1962) at NCL. Colors reflect those used for well correlations in this project. The Upper Western zone contains 3 distinct sand bodies found in this project: 1. Purple – Western 35, 2. Green – Upper Western Meander/Overbank, 3. Red–Upper Western A. The 68-29 zone was not analyzed in this study. Note; the “N” electric marker, also known as the N-Chert or N-Point as is used in this study (Modified from Hardoin, 1962).
Figure 15. North Coles Levee Map showing Stevens pools. Note separation of the stratigraphically equivalent Main Western and Western 29 Pools. The permeability barrier is likely caused by cementation within the sands (Modified from Hardoin, 1962).

It is important to note that none of the Stevens sands at NCL are contained entirely within the field. The 21-1 and Upper Western sands can be correlated to equivalent, although differently named, sands found in the Canal (Upper Stevens) and Ten Section (Upper Stevens) fields to the east (Walling, 1939; Hluza, 1967). Upper Western sand equivalents can also be found south of NCL in the South Coles Levee field (F1 zone) (Dosch, 1962). Lower Western sands have no boundaries within the study area at all. Lower Western sands can be correlated into all the above mentioned fields (Canal –Middle Stevens, Ten Section – 53 and 76-24 zones, South Coles Levee – F2 zone) and also into the Elk Hills field (Main Body B and Western 31S) to the west (Carter et al, 1975)

**Trapping Mechanisms**

Structure and stratigraphy are the main trapping mechanisms at NCL (Hardoin, 1962; Clark et al., 1996). The 21-1 zone Stevens sands pinch out against the northeastern flank of the structure suggesting that the anticline was present at the time of deposition (Figure 16). The only significant productive portion from the
Upper Western zone (besides in the sands in the Western 35 pool which also pinch out against the southeastern flank of the structure) is located on the southern flank of the structure and appears to trap fluids due to up dip permeability loss (Figure 16) (Davis, 1952; Hardoin, 1962). A permeability barrier that exists in the Lower Western Zone and separates the Western 29 pool from the Main Western pool is likely due to differential cementation (Figure 15) (Hardoin, 1962).

![Figure 16. North-South cross section of NCL is showing 21-1 sands (blue) pinching out against the structure along the northern flank and productive Upper Western sands losing permeability up dip into unproductive Upper Western sands (green) on the southern flank. The dashed line at the bottom of the Lower Western zone is representative of the original oil water contact and not the base of the Lower Western zone sands. The inset structural contour map (200' interval) is built on the N-Point marker (Modified from Hardoin, 1962).](image_url)

The entirety of NCL is overlain by the N-Chert (N-Point) and Reef Ridge shale. These shales are hundreds of feet thick and serve as a field-wide seal (Figures 11 and 14). Although there is no significant faulting observable through well correlations or core analysis within NCL, MacPherson (1978) observed a large growth fault to the east of the field that may serve as a permeability barrier between NCL and the Canal and Ten Section fields (Figure 17). The NCL structure is an anticlinal dome; however the overall four-way structural
closure is minor (less than 100 feet on the western end of the structure) and is not the main trapping mechanism between NCL and Elk Hills to the west. Instead, differing oil water contacts suggest that there is a seal between NCL and Elk Hills (Davis, 1952).

Figure 17. Structural contour map over Bakersfield Arch oilfields built on the N point marker. Red lines highlight growth faults. The westernmost growth fault may serve as a permeability barrier between NCL and Ten Section/Canal (Modified from Macpherson, 1978).
**Facies Recognized at North Coles Levee**

MIDFAN: All of the productive (21-1, Western 35, Main Western, and Western 29) pools at NCL appear to be high energy mid-fan or suprafan facies deposited in unleved braided turbidite distributary channels and lobes. Productive sands are massive, medium to coarse grained with occasional pebbles. Mid-fan sands have barrel-shaped spontaneous potential electric log characteristics that can rapidly fine up, or coarsen up, (Figure 18) (Mutti and Ricci-Lucchi, 1978; McPherson, 1978; Webb, 1981; Lowe, 1982; Hewlett and Jordan, 1994; Clark, 1996; Harrison and Graham, 1999). Harrison and Graham (1999) interpreted curvilinear features found on time slices from a 3-D seismic survey of Stevens sands at Ten Section (northeast of NCL) to represent a series of deep sea braid plain channels. Typical sizes for these channels are 500 feet wide and 1-3 miles long. It is likely that these braid plain channels continue southwest into NCL.
Figure 18. A typical electric log at NCL with Upper Western zone meandering channel or overbank facies (green) characterized by spiky fining up log signatures. Lower Western zone midfan facies log characteristics (yellow) are blocky and barrel shaped and it is difficult to interpret individual events.
MEANDERING/CREVASE SPLAY FACIES: Much of the Upper Western Zone consists of meandering channel sands or overbank crevasse splays. Webb (1981) noted that in some modern turbidite system analogs like the La Jolla Canyon system, higher energy/gradient midfan braided depositional facies are preceded up gradient by lower gradient meandering facies where muddy slopes are incised by sinuous channels (Figure 19 A and B). Meandering log signatures are bell-shaped, fining-up sequences surrounded by shales (Figure 18). Due to the migratory nature of meandering channel point bar sands, they are not laterally extensive and extremely difficult to correlate. Webb (1981) notes that, on the Bakersfield Arch, meandering Stevens sands can be observed farther east in the Rosedale and Greeley fields. Webb did not recognize them in NCL, but log signatures in much of the Upper Western zone seem to support this facies model (Figure 17). The Upper Western sands that produce in the Main Western pool on the southwest flank of the NCL anticline, have a barrel-shaped log character indicative of a midfan type deposit that could indicate a facies change downstream from meandering channel to midfan facies (Figures 18, 19A and 19B) (Davis, 1952, Hardoin, 1962). An alternative idea is that Upper Western zone sand deposition was deflected into topographic lows along the flanks of the structure and the poor quality sands found along the crest of the NCL structure are overbank or crevasse splay deposits. This would explain the thick sands found in the Western 35 pool and the productive portion along the southern flank of the NCL structure. Regardless of which model (meandering channel or overbank) is correct, the Upper Western zone sands are generally impermeable and are not good targets for CCS except for sands along the southern flank of NCL and in the Western 35 pool. (Figure 14, 15, and 16) (Davis, 1952; Hardoin, 1962).
Figure 18. (A) Webb’s (1981) Miocene paleobathymetric illustration of the SJB during the late Miocene modified and juxtaposed against (B), a Google Earth™ image of the modern day analog LaJolla submarine turbidite system off the San Diego California coast. In both of these systems a muddy slope meandering channel facies (M) is upstream of a steeper gradient, higher energy, sand-rich midfan facies (B) (Buffington, 1964; Webb, 1981).
Methods

Well Correlations and Mapping

This project utilized IHS Petra™ software for well log analysis, well correlation, mapping, volumetrics, production analysis, and reservoir analysis. Well correlations were performed using depth registered raster logs consisting of SP and resistivity log curves. The method of well to well correlation was based on the findings of MacPherson (1978), and Webb (1981). Cross sections were oriented parallel and perpendicular to the northeast to southwest direction of deposition. Sand body nomenclature was based on the pools and zones of Hardoin (1962). One of the goals of the correlations was to provide a reliable net pore volume of the various pools. To this end, sand bases were picked in order to exclude all shale intervals except those within the Upper Western zone where, due to extreme heterogeneity, lateral continuity of sands was not observed. Structural maps of all tops and bases of the zones picked during well log correlations were created and used to build isochore, or true vertical thickness (TVT), grids.

Volumetrics

The main focus of the initial volumetric calculations was to ascertain the total pore space minus the irreducible water saturation. The reported values are in tons of CO₂ and barrels of oil. To be clear, these values are illustrative only, meaning if the pore space were completely full of fluid, that volume of fluid would be equivalent to the reported tons of CO₂ or barrels of oil. Additionally the reported volumes do not represent the total available CO₂ storage space as there is likely to be formation water and/or residual hydrocarbons occupying a large proportion of the pore volume.

The isochore grids were used to calculate volumetric reports for pore volume within the Petra program. Initial inputs into the volumetric calculation within the Petra software were limited to porosity, isopach isochore
grids, and the lease boundaries of the NCL field. Once those values were gathered, they were entered into an Excel spreadsheet where additional values for water saturation and net to gross (N/G) sand ratios (gathered from well log observations) were applied. Values of 0.20 for porosity and 0.39 for water saturation (original field value) (Table 1) were gathered from public records available from the DOGGR. The pore volume calculation uses an equation (1) which is modified from Smith et al. (2009).

\[ Q = \frac{A \times T \times N/G \times \Phi \times \rho_{CO2} \times (1 - S_{wirr})}{2000} \]  

- \( Q \) = storage capacity of CO\(_2\) (tons)
- \( A \) = area of the zone (ft\(^2\))
- \( N/G \) = net sand amount divided by the gross interval (decimal)
- \( T \) = zone thickness (ft)
- \( \Phi \) = average porosity (.20) (Table 1)
- \( \rho_{CO2} \) = average density of CO\(_2\) at initial reservoir pressure and temperature (40lb/ft\(^3\)) (Figure 20)
- \( 1 - S_{wirr} \) = gross pore space minus the irreducible water saturation.
- 2000 = converts pounds to tons (lb)
Figure 20. Pressure and temperature and CO$_2$ density diagram. The red x is positioned at the intersection of Stevens initial reservoir pressure and temperature conditions of 3990 psi and 230°F (Table 1) where CO$_2$ density is 40 lb/ft$^3$. That value was used in the volumetric calculations to convert cubic feet of pore volume to cubic feet of CO$_2$ storage at reservoir pressure and temperature conditions (Modified from Jordan, 2008).

It should be noted that using isochore or TVT grids as inputs to the volumetric calculation result in outputs of greater volumetric values than are actually present in the subsurface. A better input for this is an isopach or true stratigraphic thickness grid but unfortunately, in order to build a reliable isopach grid, dipmeter logs must be available and they were not for this project.

**Pressure Data**

In order to determine whether the various pools at NCL are compartmentalized, pressure data was analyzed to determine how the reservoir pressures are affected by fluid withdrawal and injection. If the reservoir is
connected to a large aquifer with a strong water drive, the reservoir pressures should show little change over time as the field is produced. However if the reservoirs are isolated and compartmentalized, the pressures will fall rapidly with production.

Formation test data from drill stem tests (DST) can give information about what the reservoir pressure is at various times throughout the life of the field. DST tools seal off a portion of the reservoir in order to test the flowing capabilities of the formation. The shut in (initial shut in (ISI) and final shut in (FSI)) periods halt the flow of fluids to the surface by closing a valve and allowing pressure to build up in the tool. Reservoir pressure conditions are observed when the pressure reaches a point of equilibrium. If the shut in period is too short, equilibrium will not be reached and the pressure measurement will be less than the true value.

Idle well fluid levels also can be used to determine the reservoir pressure. Idle well fluid heights can be converted to reservoir pressure by multiplying the height (height of the fluid column from the top of the highest open well perforations) by a pressure gradient (Table 2). According to Schlumberger’s Oilfield Glossary (2013), the pore pressure gradient for distilled water is 0.433 psi/ft. The pore pressure gradient for water with 100,000 ppm total dissolved solids (TDS) has a 0.465 psi/ft pore pressure gradient (http://www.glossary.oilfield.slb.com/en/Terms/p/pore-pressure_gradient.aspx). Using these values a pore pressure gradient of 0.4416 psi/ft was calculated for the 26,912 ppm (Table 1) formation waters at NCL and used in the pressure calculations for idle well fluid heights.

Approximately 10 percent of the field has DST data available from records acquired at the DOGGR. Idle well fluid levels are available for 146 wells spanning a period between 1990 and the 2005 provided by DOGGR.
### Example of an Idle Well Pressure Calculation

<table>
<thead>
<tr>
<th></th>
<th>Measurement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top of perforated interval</td>
<td>8225 ft (measured depth)</td>
</tr>
<tr>
<td>Pore pressure gradient</td>
<td>0.4416 psi/ft</td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td>8225 ft*0.4416/ft = 3632.16 psi</td>
</tr>
<tr>
<td>Top of fluid</td>
<td>500 ft</td>
</tr>
<tr>
<td>fluid height</td>
<td>7025 ft (top of perforated interval - top of fluid (8225 - 500) ft)</td>
</tr>
<tr>
<td>Idle well reservoir pressure</td>
<td>7025 ft*.4416 psi/ft = 3175.3 psi</td>
</tr>
<tr>
<td>Percent of initial reservoir pressure</td>
<td>idle/hydrostatic = 3175.3 psi/ft/3632.16 psi/ft = 0.87 or 87% of hydrostatic</td>
</tr>
</tbody>
</table>

Table 2. Example of an idle well pressure calculation.

### Production Data

Assessing the total pore space available for storage is contingent on knowing the total amount of produced fluids (oil, gas and water) throughout the field’s history. The DOGGR, part of the Department of Conservation, houses a wealth of oil field data including well history reports, field summary reports, electric logs, GIS data, and production records. Online monthly well specific production records are available at the DOGGR website in spreadsheet form dating back to 1976 ([http://opi.consrv.ca.gov/opi/opi.dll](http://opi.consrv.ca.gov/opi/opi.dll)). Monthly production records prior to 1977 are available on microfilm in the DOGGR division 4 office in Bakersfield, California. The microfilm data was scanned and converted to pdf files by Interstate Gas Services. Production data in the pre-1976 pdf files were tabulated, combined with post 1976 records, and entered into the Petra™ database along with well perforation, pressure tests, and cementing data gathered from well files available from the DOGGR. Cumulative production was limited to 1938–2005.

The last pressure measurements available from idle well fluid levels are from 2005 and, since one of the goals of this study was to compare pressure response to production, it was decided that post-2005 production would not be analyzed.

One discrepancy was observed in the pre-1977 records. Water injection totals were absent from well-specific monthly production records (Figure 21). Fortunately field wide water injection totals are available on a year by year basis. These field wide totals are useful for cumulative production analysis but unfortunately limit
our ability to analyze water injection patterns on a well by well basis. For data entry into the Petra program, yearly field-wide water injection totals from 1963 to 1976 were divided equally and allocated to water injection wells.

\[ V = (P_o \times B_o) + P_w + P_g - I_w - I_g \]  

\( V \) = total volume of produced fluids at reservoir temperature and pressure (reservoir bbl)  
\( P_o \) = volume of oil produced at the well head (stock tank barrel)  
\( B_o \) = oil formation volume factor (unitless) (Table 1)  
\( P_w \) = volume of produced water (bbl)  
\( P_g \) = volume of produced gas (reservoir bbl)  
\( I_w \) = volume of injected water (bbl)  
\( I_g \) = volume of injected gas (bbl)
\( P_g \text{ and } I_g \text{ volumes are reported in production records in mcf units and must be converted to bbls at reservoir temperature and pressure conditions. The volume of gas produced converted to reservoir bbls is calculated as (3):}

\[
P_g \text{ (or } I_g) = \frac{B_g \ast V_{sc}}{0.17810761}
\]

\( P_g \) = volume of gas at reservoir temperature and pressure (bbl)

\( B_g \) = gas formation volume factor (unitless)

\( V_{sc} \) = volume of gas at surface conditions (14.7 psi and 60° F) (ft\(^3\))

0.17810761 converts ft\(^3\) to barrels of oil

The gas formation volume factor is calculated as (4):

\[
B_g = \frac{Z_r \ast T_r \ast P_{sc}}{P_r \ast T_{sc}}
\]

\( Z_r \) = gas compressibility at reservoir conditions (unitless)

\( T_r \) = reservoir temperature

\( P_{sc} \) = standard surface pressure condition (14.7 psi)

\( P_r \) = reservoir pressure (psi)

\( T_{sc} \) = standard surface temperature condition (520° Rankine)

The gas compressibility at reservoir conditions \( (Z_r) \) can be estimated using the pseudocritical method (Figure 22) if the gas specific gravity is known.
The following examples use values from NCL data from the DOGGR and this study (Table 1):

\[ T_r = 690^\circ R (230^\circ F + 460) \]

\[ P_r = 3405.86 \text{ psi (Idle well fluid level average field wide pressure in 2005)} \]

\[ S_g = \text{NCL gas specific gravity} = 1.1 \]

Figure 22. Pseudocritical pressure and temperature properties of miscellaneous natural gasses and condensate well fluids chart. Values for pseudocritical pressure \((P_c)\) and temperature \((T_c)\) are found by drawing a vertical line up from the specific gravity of gas. NCL specific gravity = 1.1 (Table 1). In this case \(P_c\) (orange) = 649 psia, and \(T_c\) (green) = 516° Rankine (Modified from Craft and Hawkins, 1959)

The ratio of reservoir conditions and pseudocritical properties gives the pseudo reduced pressure and temperature \((P_r\) and \(T_r\)) (equations 5 and 6).
\[ P_r = \frac{P_r}{P_c} = \frac{3405.86 \text{ psi}}{649 \text{ psi}} = 5.25 \]  

\[ T_r = \frac{T_r}{T_c} = \frac{690^\circ R}{516^\circ R} = 1.33 \] 

\( P_r \) and \( T_r \) are then used in a Standing and Katz chart (Figure 23) to find the gas compressibility at reservoir conditions \( (Z_r) \).
Figure 23. Standing and Katz chart for acquiring Values for $Z_r$. In this example a $P_r$ value 5.25 (yellow) and a $T_r$ value of 1.33 (green) were used to find a $Z$ value of .745 (red) (Modified from Craft and Hawkins, 1959).
With the gas compressibility at reservoir conditions factor \((Z_r)\), the gas formation volume factor \((B_g)\) is calculated (equation 4):

\[
B_g = \frac{Z_r T_r P_{sc}}{P_r T_{sc}} = \frac{(0.745 \times 690^\circ R \times 14.7 \text{ psi})}{(3405.86 \text{ psi} \times 520^\circ R)} = 0.0042667
\]

With the gas formation volume factor the volume of gas produced at the surface may be converted to a volume equivalent to barrels of oil in the subsurface.

**Results**

**Well correlations and isochore maps**

**21-1 Sand:** The 21-1 sand is the uppermost Stevens sand at NCL. The structural cross sections and isopach map clearly show southwest thinning of this sand onto the structure (Figure 24 and 25). This indicates that, at least at the time of the uppermost Bellevue lowstand deposition, the structure was a seafloor topographic high (Figure 13, 14, 16, 24, and 25). The 21-1 SP log character is barrel shaped with no indication of significant shale intervals (Figure 24). The log character is consistent with a braided mid-fan/suprafan facies. The total 21-1 pore volume within the NCL lease boundaries is equivalent to 40.6 million tons of CO₂ or 362 million barrels of fluid (equation 1) (Table 3).
Figure 24. West-East (A-B, vertical exaggeration 3X) and South-North (C-D, vertical exaggeration 1X) cross sections depicting Stevens sands at NCL. Depths are sub-sea level. See results section for sand geometry explanation.
Figure 25. 21-1 sand isopach map in blue and type log. SP and resistivity curves (shaded blue) on the 25-28 well log show the barrel shaped log characteristics of the 21-1 sands. Horizontal lines on the log equal 10 feet. Structural contours on the N-Point marker.
Table 3. Total Stevens pore volume at North Coles Levee reported in barrels of fluid (MBF) and tons of CO$_2$ (equation 1). See text for discussion.

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Storage Volume - MBF</th>
<th>Storage Volume – CO$_2$ tons</th>
</tr>
</thead>
<tbody>
<tr>
<td>21-1</td>
<td>361,687.78</td>
<td>40,614,523.58</td>
</tr>
<tr>
<td>Western 35</td>
<td>342,980.93</td>
<td>38,513,899.70</td>
</tr>
<tr>
<td>Upper Western</td>
<td>200,261.30</td>
<td>22,487,674.42</td>
</tr>
<tr>
<td>Upper Western A</td>
<td>148,075.52</td>
<td>16,627,643.17</td>
</tr>
<tr>
<td>Lower Western</td>
<td>3,140,367.71</td>
<td>352,620,926.36</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4,193,373.25</strong></td>
<td><strong>470,864,670.23</strong></td>
</tr>
</tbody>
</table>

**Western 35 Sand**: Stratigraphically the Western 35 sands occupy much of what is considered the Upper Western Zone. However, most of the Upper Western zone is impermeable and has never produced. For this reason the Western 35 sands were considered a separate reservoir by field operators and will be considered as such in this study as well. The Western 35 sand thickens to the southeast and pinches out to the northwest along the southern flank of the NCL structure (Figure 26). Western 35 sands are older and stratigraphically below 21-1 sands but, in the southern portion of section 21 and the northern portion of section 35, the two sands coalesce forming one thick, blocky sand body. Western 35 sands interfinger with Upper Western A sands (see Upper Western A discussion below) in the southern portions of sections 32 and 33, and the south western corner of section 34. In most of the Western 35 area, two thick shale intervals divide the Western 35 into three sand packages. The total pore volume within the NCL lease boundaries is equivalent to 38.5 Million tons of CO$_2$ or 343 million barrels of fluid (equation 1) (Table 3).
Figure 26. Western 35 sand isopach map in purple and type log. SP and resistivity curves (shaded purple) on the 14-35 well log show the barrel shaped log characteristics of the Western 35 sands. Horizontal lines on the log equal 10 feet. Structural contours on the N-Point marker.
**Upper Western meandering sands** – Except for a portion along the southern flank of the NCL structure, the Upper Western zone is extremely difficult to correlate. Over 9 different sand and shale packages were correlated within the Upper Western sands but confidence in their connectivity is low. Literature describes these sands as impermeable and non-productive (Hardoin, 1962). However, in sections 29 and 30 some wells are perforated in Upper Western intervals giving rise to the possibility that they may have produced. Unfortunately perforations in the much more prolific Lower Western sands (see Lower Western discussion below) were open in the same wells over the same time period so the extent of the Upper Western’s contribution to overall production is unknown. Although unlikely to be a viable CO$_2$ storage reservoir for the above mentioned reasons, volumetric calculations were performed on the nine Upper Western sand intervals. The total pore volume within NCL lease boundaries is equivalent to 22.5 Million tons of CO$_2$ or 200 million barrels of fluid (equation 1) (Table 3).

**Upper Western A sands** – The southern portion of the Upper Western zone shows a barrel shaped SP log character similar to those mentioned in the 21-1 and Western 35 discussions which is easily correlatable (Figure 27). Upper Western A sands interfinger with Western 35 sands (see Western 35 discussion above) in the southern portions of sections 32 and 33, and the south western corner of section 34. The total pore volume within NCL lease boundaries is equivalent to 16.6 Million tons of CO$_2$ or 148 million barrels of oil (equation 1) (Table 3).
Figure 27. Upper Western A sand isopach map in red and type log. SP and resistivity curves (shaded red) on the 76-32 well log show the barrel shaped log characteristics of the Upper Western A sands. Horizontal lines on the log equal 10 feet. Structural contours on the N-Point marker.
**Lower Western Sands** – The Lower Western zone is by far the largest and most continuous sand body at NCL. The sand is a continuous massive sand package which is over 500 feet thick throughout the field (Figures 24 and 28). There is some uncertainty concerning the sand thickness because many of the wells were not drilled to the base of the sand since much of the zone is below the oil water contact. In total, only 19 of 242 wells have logs to the base of the upper western zone. However, sand thickness does not vary significantly across wide distances so confidence in volumetric calculations remains high if not as high as it is for other sands with closer well to well correlations. The total pore volume within NCL lease boundaries is equivalent to 352 million tons of CO₂ or 3.1 billion barrels of fluid (equation 1) (Table 3).
Figure 28. Lower Western sand isopach map in yellow and type log. SP and resistivity curves (shaded yellow) on the 68-29 well log show the barrel shaped log characteristics of the Lower Western sands. Horizontal lines on the log equal 10 feet. Structural contours on the N-Point marker.
Pressure

Publically available pressure data from DSTs and idle well fluid levels is sparse. North Coles Levee DST data was found in 30 percent of well records, but upon closer inspection only a few of these records have any meaningful measurements (Table 4).

<table>
<thead>
<tr>
<th>WELL</th>
<th>ZONE</th>
<th>ISI (psi)</th>
<th>FSI (psi)</th>
<th>DEPTH (Ft)</th>
<th>YEAR</th>
<th>ISI TIME (min)</th>
<th>FSI TIME (min)</th>
</tr>
</thead>
<tbody>
<tr>
<td>74-34</td>
<td>Western 35</td>
<td>2740</td>
<td>2340</td>
<td>9620</td>
<td>1945</td>
<td>35</td>
<td></td>
</tr>
<tr>
<td>15-28</td>
<td>Lower Western</td>
<td>3425</td>
<td></td>
<td>9420</td>
<td>1958</td>
<td></td>
<td></td>
</tr>
<tr>
<td>46-32</td>
<td>Lower Western</td>
<td>3413</td>
<td>3037</td>
<td>9020</td>
<td>1963</td>
<td></td>
<td>165</td>
</tr>
<tr>
<td>46-32</td>
<td>Lower Western</td>
<td>3551</td>
<td>3210</td>
<td>9075</td>
<td>1963</td>
<td></td>
<td></td>
</tr>
<tr>
<td>35-33</td>
<td>Lower Western</td>
<td>3221</td>
<td>3066</td>
<td>9125</td>
<td>1963</td>
<td></td>
<td>45</td>
</tr>
<tr>
<td>55-33</td>
<td>Lower Western</td>
<td>3269</td>
<td>3042</td>
<td>9250</td>
<td>1963</td>
<td></td>
<td></td>
</tr>
<tr>
<td>48-28</td>
<td>Lower Western</td>
<td></td>
<td></td>
<td>3075</td>
<td>1970</td>
<td></td>
<td></td>
</tr>
<tr>
<td>53-32</td>
<td>N-Chert</td>
<td>3609</td>
<td>3279</td>
<td>7813</td>
<td>1977</td>
<td>60</td>
<td>94</td>
</tr>
<tr>
<td>53-32</td>
<td>N-Chert</td>
<td>3542</td>
<td>3212</td>
<td>7895</td>
<td>1977</td>
<td></td>
<td></td>
</tr>
<tr>
<td>53-32</td>
<td>N-Chert</td>
<td>3601</td>
<td>3306</td>
<td>7890</td>
<td>1978</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4. North Coles Levee DST data.

A 1945 Western 35 zone DST result shows that reservoir pressure is low (2740 psi), but the shut in time is also only 35 minutes which may not be enough time for the pressure to reach equilibrium (Table 4). Pressure measurements from several Lower Western zone DSTs in 1963 show pressure values closer to original field pressure (Table 4). A DST performed in a sandy interval of the N-Chert zone (not analyzed in this study) from 1973 shows pressure values that are actually greater than hydrostatic pressure (Table 4).

Idle well fluid level measurements were recorded in 165 wells from 1990 – 2005. The wells were evenly distributed throughout the field. Through the period of 1992-1995, eleven wells show anomalously low pressure readings (Figure 29). Upon further examination, these measurements were deemed false for the following reasons that:

(a) Additional readings taken in many of the same wells both before and after the anomalous measurements reveal reservoir pressures that are at or near hydrostatic pressures, (Table 5).
(b) There was no significant injection or production from nearby wells prior to or after the anomalous measurements that could cause such vast pressure changes (Figure 30). For this reason the anomalous measurements were removed from the data set for pressure vs. production analysis. Overall field pressure averages increase from around 70 percent of hydrostatic in the early to middle 1990’s to 90 percent of hydrostatic near the end of 2005.

Figure 29. Idle well fluid level measurements, converted to reservoir pressure values (Table 2), are shown as a percentage of hydrostatic (red diamonds). Note the unusually low values from the period spanning 1992-1995 (highlighted blue). Field-wide average pressures, represented along the green line, show the overall trend of increasing pressure from 1990-2005.
<table>
<thead>
<tr>
<th>DATE</th>
<th>WELL</th>
<th>% Hydrostatic Pressure</th>
<th>ZONES WITH OPEN PERFS</th>
<th>Other Pressure Measurements</th>
</tr>
</thead>
<tbody>
<tr>
<td>12/18/92</td>
<td>47-32</td>
<td>29</td>
<td>UWA</td>
<td>0</td>
</tr>
<tr>
<td>03/05/93</td>
<td>12-33</td>
<td>49</td>
<td>UW, LW</td>
<td>0</td>
</tr>
<tr>
<td>07/03/81</td>
<td>57-28</td>
<td>42</td>
<td>LW</td>
<td>1996-98%</td>
</tr>
<tr>
<td>03/16/95</td>
<td>26-28</td>
<td>29</td>
<td>LW</td>
<td>1999-69%, 2001-71%, 2005-98%</td>
</tr>
<tr>
<td>03/16/95</td>
<td>45-28</td>
<td>11</td>
<td>21-1</td>
<td>0</td>
</tr>
<tr>
<td>03/22/95</td>
<td>24-29</td>
<td>26</td>
<td>UW, LW</td>
<td>0</td>
</tr>
<tr>
<td>08/01/95</td>
<td>36-33</td>
<td>-2</td>
<td>W35, UWA</td>
<td>6/1995-87%, 1999-83%, 2001-83%, 2004-76%</td>
</tr>
<tr>
<td>11/27/95</td>
<td>51-32</td>
<td>11</td>
<td>LW</td>
<td>3/1995-83%</td>
</tr>
<tr>
<td>11/30/95</td>
<td>85-31</td>
<td>-6</td>
<td>UWA, LW</td>
<td>8/1995-83%, 1999-100%, 2001-100%, 2004-70%</td>
</tr>
</tbody>
</table>

Table 5. Eleven wells with anomalously low pressure values, 1992-1995 (Figure 29). Each well’s perforation data was examined to see if the pressure anomalies could be tied to a specific zone (UW-Upper Western, UWA-Upper Western A, W35-Western 35, LW-Lower Western). Except for NCL 45-28, all of the anomalous wells have open perforations in multiple zones making zone specification impossible. The fifth column “Other Pressure Measurements” includes all additional pressures found in these wells at times before and/or after the low values were recorded. All of the before and after measurements are within 30 percent of hydrostatic pressure values, and cast further doubt upon the validity of the anomalously low readings.
Figure 30. Pie bubble map showing net fluid production at North Coles Levee from March 1995-November 1995. In 1995 reservoir pressure values measured in four NCL wells (triangles) dropped an average of 85 percent. Very little production took place over the time period near three of the effected wells. NCL 51-32 is in close proximity to a significant amount of water injection (compared to water production), but pressure should increase with injection rather than as the November measurement indicates. Therefore, the idle well fluid level values for these wells were discarded from the dataset. The size of the bubbles indicate the relative amount of fluid production/injection for each well. The pie graphs within the bubbles show the relative proportionality of each produced/injected fluid. Structural contours are on the N-Point marker.
Figure 31. Graph of pressure response and net fluid production, 1990-2005. Net fluid production from 1991-1994 is positive (more production than injection) and reservoir pressure is approximately 70 percent of hydrostatic. From 1995-2005, the net fluid production is negative (i.e. more injection than production) and the pressure value increases to 90 percent of original. Note the slight pressure drop in response to a short peak in positive fluid production in 1999.

Recent idle well pressure measurements from 2005 show that the highest pressures in the field found are in the Lower Western zone while the lowest are found in the Western 35 (Table 6).

<table>
<thead>
<tr>
<th>ZONE</th>
<th>AVERAGE PRESSURE</th>
<th>PERCENT OF HYDROSTATIC</th>
</tr>
</thead>
<tbody>
<tr>
<td>21-1</td>
<td>3546.6</td>
<td>88.0</td>
</tr>
<tr>
<td>Western 35</td>
<td>3046.2</td>
<td>77.5</td>
</tr>
<tr>
<td>Upper Western A</td>
<td>3266.3</td>
<td>88.5</td>
</tr>
<tr>
<td>Lower Western</td>
<td>3600.8</td>
<td>92.9</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td><strong>86.7</strong></td>
<td></td>
</tr>
</tbody>
</table>

Table 6. Pressure data from 21-1, Western 35, Upper Western A, and Lower Western zones showing that reservoir pressure conditions are close to hydrostatic conditions (see table 2 for example calculation).
Production

In order to keep reservoir pressure above the bubble point both gas injection and waterflooding efforts were employed throughout the production history at NCL (Figure 32). Cumulative total fluid production reveals that more fluid has been injected into the Stevens reservoirs than has been extracted (Figure 32) (Table 7). The volume of water injection is much greater than the volume of produced oil and water combined (Table 7) (Figures 32 and 33). Gas production is greater than gas injection but when converted to volume in barrels at field-wide average 2005 reservoir conditions; the total volume occupied is insignificant compared to that of oil and water (equations 3-6) (Table 7) (Figure 34).

Figure 32. North Coles Levee production and injection graph. All produced gas is re-injected from 1942 through 1965 when a controlled gas blow down was initiated because of favorable gas economics. In the middle 1960’s, waterflooding begins and continues to the present. Note that prior to the initiation of waterflooding, the field produces almost no water at all. Water production during the 1970s and 1980s is likely due to the breakthrough of previously injected water. Because the amount of water injected far exceeds the amount of produced water, the additional injected water came from other aquifers—mainly water supply wells in the Tulare Formation (http://owr.conservation.ca.gov/WellRecord/029/02945327/02945327_DATA_03-30-2011.PDF).
<table>
<thead>
<tr>
<th>North Coles Levee Cumulative Production (reservoir MMbbl) 1938-2005</th>
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<tbody>
<tr>
<td>Oil*</td>
</tr>
<tr>
<td>Water</td>
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<tr>
<td>Water Injected</td>
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<tr>
<td>Gas** (produced-injected)</td>
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<td><strong>Total</strong></td>
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</tbody>
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Table 7. North Coles Levee cumulative production (reservoir MMbbl) 1938-2005. *converted to reservoir bbl at 2005 temperature and pressure conditions. **converted to reservoir bbl at 2005 and pressure conditions. (equations 2-6)
Figure 33. Pie bubble map showing net fluid production at North Coles Levee, 1938-2005. The size of the bubbles indicates the relative amount of fluid production/injection for each well. The pie graphs within the bubbles show the proportion of each produced/injected fluid. The majority of production is centered on the apex of the structure and water injection far outweighs the sum of oil and water produced. Gas production is not included in this map because, once gas is converted to barrels at reservoir temperature and pressure its contribution to overall production is insignificant. See Table 7 for NCL gas volume in barrels at 2005 reservoir conditions. Structural contours are on the N-Point marker.
Figure 34. Pie bubble map showing cumulative gas produced and gas injected. All of the gas produced at NCL from 1942 – 1969 was re-injected primarily into the apex of the structure in order to support the gas cap drive and keep the reservoir pressure above the bubble point. Structural contours are on the N-Point marker.
Discussion

Reservoir compartmentalization

Well correlations and isochore maps do not definitively prove that the Stevens reservoirs at NCL are compartmentalized. All of the sand zones are continuous and correlatable outside of the field boundaries and to truly understand their lateral extent additional studies, similar to this one, should be performed on all of the surrounding fields. Previous studies indicate that the field is surrounded by low permeability zones which serve to isolate the Stevens reservoir at NCL; effectively making it a closed system (Davis, 1952; Hardoin, 1962; MacPherson, 1978).

A better indication of compartmentalization of the Stevens at NCL is the reservoir’s pressure response to production. Rapid pressure loss occurred early in the production life of the Stevens reservoir while it was producing under a natural gas cap expansion drive (Davis, 1952). Gas injection efforts helped to keep reservoir pressures stable until the gas cap was blown down in the early 1960’s. At that point, pressure decreased rapidly again until it was re-stabilized by a waterflood program (MacAllistar, 1989).

NCL fluid production behavior is another good indicator of reservoir compartmentalization. The Stevens reservoir fluid production did not include a significant amount of water until shortly after the waterflood program was initiated in the middle 1960’s. It is likely that the water cut is representative of the breakthrough of injected water and not from formation brines. Waterflooding continues to this day and helps to keep reservoir pressure stable and close to initial discovery values. Because the Stevens reservoir doesn’t produce sufficient water to inject, water supply wells were drilled into the Tulare Formation. This aquifer is the main source of irrigation water in the SJB.

Unfortunately most of the wells at NCL were perforated through multiple zones. This means that assessing the pressure response of individual zones within the Stevens reservoir is not possible.
The rapid decline in reservoir pressure during the brief periods when injection was halted, and lack of water production prior to the initiation of the waterflood demonstrates that the Stevens reservoirs at NCL are not supported by a strong water drive and are not likely to be in hydraulic communication with shallower fresh water aquifers. It is unlikely CO₂ injection would endanger these local aquifers unless the leakage occurred due to mechanical or wellbore integrity problems.

**CCS at North Coles Levee**

Calculations indicate a total pore volume at NCL equivalent to over 4.1 billion barrels of oil or 470 million ton of CO₂. This is enough storage space to sequester 42 years of CO₂ emissions from the ten electricity generating facilities within a 20 mile radius of the field (http://gif.berkeley.edu/westcarb/explorer2/index.html, http://gif.berkeley.edu/westcarb/explorer2/index.html). However, the total pore volume is not void of fluids. In fact, there is more fluid in the Stevens reservoirs at NCL today than there was upon discovery of the field in 1938 (Table 7) (Figure 30).

The overall pressure at NCL as of 2005 is around 90 percent of hydrostatic. If the reservoir is a closed system, as this study suggests, then the reservoir’s response to fluid injection needs to be analyzed in more detail. A significant amount of pressure build up can be expected when large a large volume of CO₂ is injected into a compartmentalized reservoir. The rapid increase in reservoir pressure may lead to the fracturing of sealing units, thereby restricting the amount of storable CO₂ to amounts to very small amounts. For this reason it is recommended that additional studies pertaining to pore and brine compressibility at NCL are implemented before the feasibility of large scale CCS at NCL is ascertained (Zhou et al., 2008).

**CO₂ EOR**

The Stevens pools at NCL are generally good candidates for CO₂ EOR (Table 1). The depth of the reservoir insures sufficient pressure and temperature conditions so that CO₂ will behave as a supercritical fluid and be miscible with oil. An average permeability of 115 millidarcies and an oil API gravity value of 33-39 surpass
the minimums set forth by the National Energy Laboratory (NETL) (2009) for CO$_2$ EOR to be viable (Table 1). The recovery factor for the Stevens reservoirs at NCL is between 15 and 20 percent (Kevin Beacom, MHA Petroleum Consultants LLC, personal communication, 2013) which means that there is at least 85 percent of the original oil in still in place. This amount surpasses the minimum of 25 percent residual hydrocarbons left in the reservoir after water flooding stipulated by the NETL guidelines (2009). According to The California Division of Oil, Gas, and Geothermal Resources (CA DOGGR) (2009), NCL has produced over 164 million barrels of oil to date and, with the recovery factor at 15-20 percent; the original oil in place would have been nearly 1 billion barrels. Therefore, at a 6 percent recovery factor, a CO$_2$ EOR project at NCL could improve field recovery by at least 60 million barrels.

**Conclusion**

This study set forth to assess the feasibility of CCS and CO$_2$ EOR at the North Coles Levee oil field. The results suggest that additional studies must be done before any definitive answer to the question regarding CCS feasibility is answered. Pressure response to production and injection give good indication that the field behaves as a closed system. There are methods (see Zhou et al., 2008) available that allow for a reasonable estimation of the amount of CO$_2$ that can be stored in a closed system, but the total pore volume must be known and that has not yet been determined at NCL. Pore volumes reported in this study are limited to the lease boundaries, and therefore do not reflect the true pore volume that actually exists within the Stevens reservoir.

Studies of the surrounding fields should help determine the size of the pools outside the field boundaries. Additional pressure data may provide an indication of the reservoir limits outside of NCL boundaries and provide a more accurate estimate of storage capacity.
If nearby electricity generating facilities are retrofitted to capture carbon, CO$_2$ EOR will be economically feasible at NCL. The field operators could purchase compressed CO$_2$ from the nearby generators and, combined with cap and trade credits, offset part of the cost of the capture process. The compressed CO$_2$ could then be injected into the Stevens reservoirs at NCL with the potential to recover as much as 60 million additional barrels of oil.
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