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CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

NBU CCS Site

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1.0 Project Background and Contact Information

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CapturePoint Solutions, LLC (CPS) is a privately owned Texas based company with a focus on developing large scale carbon dioxide capture and sequestration projects with an emphasis on deep geologic storage of CO_2 in saline formations. CPS is a fully owned subsidiary of CapturePoint LLC, which has over one million tons of anthropogenic CO_2 capture, over 300 miles of CO_2 pipelines and multiple CO_2 EOR floods including two EPA approved MRV plans, two Administratively Complete Class VI permit applications (EPA Region 6) and existing projects that benefit from Federal 45Q tax credits. CapturePoint LLC is also a licensed oil and gas well operator in the state of Oklahoma. Standard Industrial Codes for this project are 4619 (Pipelines, not elsewhere classified) and 7389 (Business Services, not elsewhere classified).

The proposed carbon dioxide (CO_2) storage site is in northwestern Osage County, Oklahoma (**Figure 1-1**). The site is approximately 21 miles northeast of Ponca City, Oklahoma. The small community of Shidler, Oklahoma is located 5 miles southeast of the proposed sequestration site. This site is located approximately 455 feet beneath the North Burbank Unit (NBU), an ongoing tertiary flood in a Lower Pennsylvanian age sandstone reservoir (Burbank), and thus will be called the NBU CCS site.

The sequestration project will consist of 2 injection wells, 1 above zone monitoring well, 1 in-zone monitoring well, and 2 shallow groundwater monitoring wells that are completed above the uppermost confining interval. The site is in Township 27 North Range 5 East, Sections 11 and 14. The expected maximum daily injection rate for the site is 28.7 mmcfd (1,495 metric tonnes per day (19.2 metric tonnes per mcf)). The maximum injection pressure was set at 90 percent of fracturing pressure at the top of injection interval to avoid fracturing of reservoirs near the injection interval. The injection interval is set to be 200 ft above the top of the underlying basement rocks to avoid significant pore pressure changes within basement rocks in order to minimize induced seismicity risk. The depth to the basement is expected to be at approximately 4,500 feet and the entire injection interval is ~900 feet thick.

Permanent geologic storage of CO_2 is intended to occur beneath NBU and in the Arbuckle Formation at depths between 3,500 and 4,300 feet. A series of competent (20' to 120') confining layers separate shallow (0' to 300') groundwater resources from the deeper injection zone. The storage of CO_2 is intended to occur beneath private lands primarily used for agriculture and oil and gas production.

It is anticipated this site will last for 20 to 25 years and will cumulatively sequester between 11 and 14 million metric tonnes over the life of the project. CPS will use the site to capture and store CO_2 from industrial emitters in northeast Oklahoma. Storage capacity for this site is estimated to be approximately 100 million metric tonnes of CO_2. Injection is projected to begin in 2025. A second-Class VI application for a sequestration site north of the NBU CCS site is expected to be submitted in the fourth quarter of 2023. The NBU site has a pipeline for CO_2 transportation for the tertiary operations at NBU. Facilities infrastructure will be developed in parallel based on the initial progress and feedback on NBU's Class VI permit application. The CO_2 will be transported to the site via the Coffeyville pipeline network. All surface facilities for the site will be constructed on CapturePoint property leased by CPS.

The preliminary Area of Review (AoR) represents the area of critical pressure within the injection zone as determined by modeling and computational simulation. The preliminary size of the AoR for the NBU

CCS site is 11,325 acres. The AoR was calculated using the base of the Vanoss freshwater zone at approximately 280 feet in depth. There are no Underground Sources of Drinking Water (USDW) at the NBU CCS site. This is based on freshwater zones having limited deliverability. Although there are no USDWs, the Vanoss is being treated as such for permitting purposes, including determination of the AoR. Based on modeling and simulation results, the expected maximum subaerial extent of the CO_2 plume within the Arbuckle Formation is approximately 3,530 acres and the expected critical pressure boundary (AoR) encompasses approximately 11,320 acres (**Figure 1-2**). Following the drilling, coring, sampling and logging of a stratigraphic test well, the geologic model and computational simulation will be updated and revised to provide a better estimate of the AoR.

The proposed project site was selected based on a culmination of factors deeming it to be an ideal candidate for a commercial CCS project. Both the confining layers and the targeted injection zone are regionally extensive and possess the necessary properties that serve to safely contain the injected CO_2 and displaced formation fluids. Furthermore, there is no faulting and a limited number (16) of artificial penetrations (APs) that penetrate the primary confining unit within the AoR. Another advantage of locating facilities and operations on CapturePoint owned lands is that it guarantees access to the site and significantly reduces permitting requirements for pore space agreements and for right of way easements.

The APs within the AoR will be evaluated and if necessary, mitigated through appropriate corrective action. Well plugging, well construction and operational parameters for this project are designed to protect freshwater zones being treated as Underground Sources of Drinking Water (USDWs), prevent surface releases and inject at rates that will not fracture the storage reservoir or the confining units and/or induce any seismic events. Available data indicate that this area is rooted in igneous granites of Precambrian age and there are no known transmissive faults within the AoR and that the site is in an area of Oklahoma where seismic events have not been detected.

Though the proposed site is not positioned on any recognized aquifers by the State of Oklahoma, the site's location is positioned between two aquifers in Oklahoma. To the west is the Arkansas River Alluvial aquifer and to the east is the Vamoosa-Ada Bedrock aquifer. Groundwater withdrawals within the AoR are from 4 shallow groundwater wells that range in depth from 100 to 231 feet. These wells service livestock tanks. Per Oklahoma Water Resources Board there are not any water wells in northwest Osage County that provide water for human consumption. Currently, CapturePoint operates 75 ground water monitoring wells, 59 of which are located within the AoR. Depths of these monitoring wells range from 123 to 302 feet.

The general topographic relief within the AoR is at an elevation between 1,000 and 1,100 feet above sea level. The area is mainly grasslands with minimal relief and few trees. Facilities for the site are located entirely on private land owned by CapturePoint.

A schematic cross section diagram (**Figure 1-3**) illustrates the two proposed injection wells, an in-zone monitoring well, an above zone monitoring well and shallow ground water monitoring wells that are to be completed at the site.

The AoR encompasses an area on private lands that are owned by CapturePoint LLC, the parent company of CapturePoint Solutions LLC. This guarantees full access to the site for the duration of all phases of the proposed injection project.

The injection zone is the Upper Cambrian / Lower Ordovician age Arbuckle Formation. Without site specific conventional core data, minor amounts of CO_2 storativity was modeled for the Simpson Group. However, the Simpson is comprised of interbedded sands and shales, with these shales providing additional confinement. The Simpson will not be targeted for injection. The Arbuckle is capped by the

Silurian and Devonian shales along with the lower Mississippian impermeable carbonates and the Pennsylvanian age Cherokee Shales. The stratigraphy in descending order are the Pennsylvanian Cherokee Shales, Upper Mississippian Chat limes (Upper Mississippi Formation), Lower Mississippian impermeable limes (Lower Mississippi Formation), Woodford Shale, Simpson shales and sands, Arbuckle dolomites and the Cambrian age Reagan sands on top of basement. The primary confining unit is the regionally extensive Woodford Shale. The secondary confining unit is the Lower Mississippi Formation. Together these confining units have an average thickness of approximately 80 feet. Higher up in the section and above the Mississippi Formation is the 30-foot-thick Savannah Shale; this unit also has the necessary properties to serve as an additional confining unit. The Upper Mississippian aquifer monitoring well will monitor pressure and the geochemical make up of formation fluids to confirm the Woodford and Lower Mississippi formations are not breached or compromised due to injection operations. The in-zone monitoring well will be located in Township 27 North Range 5 East, Section 11 and will be used to monitor pressure and geochemical make up of formation fluids in order to monitor the CO_2 plume and pressure front during the injection and the post injection phase of the project.

There are two proposed injection wells for the NBU CCS site; the volumes per well were modeled at 14.37 MMCFD (~747 metric tonnes per day). The injected CO_2 will be collected from anthropogenic sources including ethanol, fertilizer and ammonia plants from eastern Oklahoma and southeastern Kansas.

Permitting and oversight for this project will be through the US Environmental Protection Agency (USEPA) in coordination with the Osage Minerals Council and the State of Oklahoma. The site will be owned by CapturePoint Solutions, LLC (CPS) and operated by its parent company CapturePoint LLC. As part of the permitting and oversight, CPS will continuously monitor operations at surface facilities and at each of the injection wells and provide collected data to the USEPA in semi-annual reports.

Although the site is located entirely on privately held lands in Osage County, the area does reside within the borders of tribal lands belonging to the Osage Nation. Contact information for Osage Minerals Council and State of Oklahoma are provided below.

Osage Minerals Council – (918) 287-5346

Oklahoma Corporation Commission – (405) 521-2211

Amended plans or demonstrations per this permit application shall be submitted to the UIC Program Director as follows:

1) Within one year of an Area of Review (AoR) reevaluation
2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the AoR, on a schedule determined by the UIC Program Director, or
3) When required by the UIC Program Director.

GSDT Submission - Project Background and Contact Information

GSDT Module: Project Information Tracking
Tab(s): General Information tab; Facility Information and Owner/Operator Information tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

2.0 Site Characterization

A detailed Site Characterization report was prepared and accompanies this permit application in Section 2.0 pursuant to 40 CFR 146.82(a)(2), (3), (5), and (6). This Site Characterization provides information including regional and local geology, geohydrology, hydrology, geologic structure, characterization of the confining and injection zones of interest and discussion of freshwater zones that are being treated as USDWs within the AoR. Maps, cross sections and other pertinent figures are included as attachments to this narrative. References to figures and tables are included in the narratives. References to rules, sections and figures are listed in **Table 2-1**.

Table 2-1. Site Characterization Sections, Rules and References

Section and Rules	Reference
Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]	Sections 2.1 through 2.4
Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]	Appendices A and B
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]	Section 2.2.4
Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]	Section 2.3
Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]	Section 2.6
Seismic History [40 CFR 146.82(a)(3)(v)]	Section 2.5
Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]	Section 2.4
Geochemistry [40 CFR 146.82(a)(6)]	Section 2.7
Other Information	Section 14

Site Characterization: List of Appendices:

Appendix A Figures Regional Geology Cross Sections and Maps

Appendix B Figures Local Geology Cross Sections and Maps

Appendix C Well Logs used in Cross Sections

Appendix D Tabulation of Wells in the AoR

Site Characterization Narrative

The geologic suitability of a specific stratigraphic interval for the injection and confinement of carbon dioxide (CO_2) is determined primarily by the following criteria:

- Lateral extent, thickness, porosity, and permeability of the Injection Zone;
- Lateral extent, thickness, porosity, and permeability of the overlying Confining Zone;
- Faulting or fracturing of injection zones, overlying freshwater zones and USDWs, or confining zone; and
- Seismic risk analysis.

The above criteria can be evaluated based on the regional and local depositional and structural histories of the geologic section. In making such evaluations, the depositional and structural framework of the stratigraphic section for the sequestration of CO_2 for CapturePoint Solutions at the NBU CCS site are outlined in the following sections of this report.

The primary focus of this narrative is the regional and local geology and geohydrology of this proposed carbon capture and sequestration (CCS) site. The principal confining unit is the Devonian – Mississippian age Woodford Shale. The secondary confining unit is the Lower Mississippi that rests directly above the Woodford. The targeted injection zone is the Cambrian – Ordovician age Arbuckle Formation, although minor storage was also modeled in the overlying Late Ordovician thin sands within the Simpson Group. A site-specific stratigraphic section is shown in **Figure 2-1**.

A comprehensive review of information was made from publicly available sources, including reports, maps and data repositories. Furthermore, public records requests were also made as part of the information gathering effort. In addition to publicly available sources, information such as well records, geophysical well logs and 2D seismic were purchased and used for the preparation of this application.

Figure 2-2 is a composite type log from the NBU No 1542, (504'-4263), NBU No 15-41, (504'-300') and the MW #3C, (9'-300'). All wells are in T27N R5E Section 11 with the No. 1542 located 3,675' west of the proposed northern sequestration well. This composite type log shows the various log responses and interpretation of the formations beneath the NBU CCS site. The type log was constructed utilizing the second nearest offset electric log that penetrates the formations of interest. The key regulatory intervals represented on the type log are reported in true vertical depth (TVD) and subsea elevation (SSL).

A detailed map of the AoR is contained in **Figure 2-3** per 40 CFR 146.82(a)(2). Due to the large number of well locations associated with operations at the North Burbank oil field, a series of associated maps keyed to the primary AoR map are provided. These maps are shown in **Figures 2-3-1** through **2-3-24**. These associated maps show locations for groundwater wells, monitoring wells, injection wells and oil wells within the AoR. Wells penetrating the upper confining zone are also displayed on the maps. Each map is keyed to an index map shown in the upper right of each figure. The size of the grid used to delineate each associated map is 1 mile by 1 mile. The map scale for each map is 1:6,500. These maps were created using ArcGIS.

2.1 Regional Geology

The regional geology of northeastern Oklahoma and southeastern Kansas is comprised of the Cherokee Platform which is bound on the east by the Ozark Uplift, on the west by the Nemaha Ridge/Uplift, on the south by the Arbuckle Uplift and Arkoma Basin and on the north by the Bourbon Arch. Charpentier, 1995, described the Cherokee Platform as an area that extends from southeastern Kansas and part of southwestern Missouri to northeastern Oklahoma. This feature is 235 miles long (north-south) by 210 miles wide (east-west) having a total area of 26,500 square miles.

Located primarily in Southeast Kansas and within the Cherokee Platform is a small elliptical basin known as the Cherokee Basin. This Paleozoic sag is primarily a function of the Burbon Arch to the north and the Osage High to the south. The proposed sequestration site is located on the southwestern flank of the Cherokee Basin and the northwestern platform of the Osage High (**Figure 2-4**). The Ozark Uplift is a large asymmetrical structure, wherein the core of the dome contains exposed Precambrian rocks known as the St. Francis Mountains. This uplifted region creating the eastern side of the Cherokee Platform covers more than 40,000 square miles and occurs in portions of Missouri, Arkansas, northeast Oklahoma, and southeast Kansas.

Figure 2-4 highlights the physiographic provinces of Oklahoma, and **Figure A-1** illustrates where the two regional cross sections are in proximity to the proposed sequestration sites that are found in **Appendix A** – "*Regional Maps and Cross Sections*" (See Section 2.2.1 for further information). Cross section **Figure A-2** runs west to east and illustrates that the Paleozoic rocks in northeastern Oklahoma dip to the southwest away from the central axis of the Ozark Uplift/ Dome. Cross section **Figure A-2** has a north to south axis and defines a significant area of the Cherokee Platform with a gradual dip to the south where dip reversal occurs due to basement uplift and formation of the Arbuckle Mountains. Stratigraphically, both cross sections illustrate the areas of Paleozoic depositional history with minimal sedimentation since Permian time.

Figure 2-5 is a low-resolution residual Bouguer Gravity map wherein four prominent gravity anomalies within Oklahoma are shown. These anomalies are the southern margins of the Nemaha Uplift, Southern Oklahoma Aulacogen, Arbuckle Uplift and the Osage High. The Mid-Continent Rifting stage coincides in timing with the with the emplacement of intrusive and extrusive rocks of the Osage High at 1.1 billion years ago. The Mid-Continent Rift extends for more than 2,000 miles across the Upper Midwest and represents one of the longest failed continental rift systems in the western hemisphere. However, the Mid-Continent Rifting's increased density is primarily from the rift being underplated with early plateau basalts.

On a significantly smaller scale, and centrally located within the Cherokee Platform is the Osage High or "Precambrian Hills". The Osage High is represented by a significant gravity anomaly. This feature developed in late Precambrian time from igneous intrusions and rhyolite volcanics. These Precambrian Hills strongly influenced deposition through the Cambrian, Ordovician and Silurian periods and also facilitated the development of post depositional karsting during significant eustatic drops in sea level during late Cambrian and Ordovician Periods

Denison for his 1966 dissertation analyzed twenty samples from wells that penetrated basement rocks across Oklahoma, Kansas, Missouri, and Arkansas. Based on the results from the analysis of the samples, basement rocks in northeastern Oklahoma were subdivided into four groups. These include the Central Oklahoma Granite Group, Washington Volcanic Group, Spavinaw Group and the Osage Granite Group (**Figure 2-6**). The basement beneath the Cherokee Platform and specifically the Osage High was formed during the creation of the supercontinent Rodina between 1.4 and 1.1 billion years ago. Personal communication with Shane Matson indicates over 1,230 wells have drilled into basement in Oklahoma.

These basement tests are primarily located in northeast Oklahoma and in southern Oklahoma on the Arbuckle and Wichita uplifts (**Figures 2-5** and **2-9**).

The Southern Oklahoma aulacogen is much younger at 550 million years and represents the initial stages of the breakup of the Pangea Supercontinent. The Nemaha Ridge/Uplift is associated with a series of faults and is referred to as the Nemaha Fault Zone. The long-term uplift along the ridge has been attributed to isostatic uplift due to the anomalously thick crust adjacent to the Mid-Continent Rift. The present Nemaha Uplift occurred during the Ouachita Orogeny during Late Mississippian or early Pennsylvanian time (~320 mya). Berendsen and Blair, 1968 and Amsden, 1975 have both suggested left lateral movement from crustal response to plate collision along the continental margins.

Work by Denison (1966, 1981) determined that the Osage High's core is composed of the Osage Microgranite and flanked with the Central Oklahoma Granite (COG) Group. Compositionally, the Osage Microgranite is the most uniform unit in Osage County (**Figure 2-6**). This unit was probably intruded as a sill. Denison, 1966 interprets the COG as the youngest basement rock unit within northeast Oklahoma. The emplacement of COG lithospherically rooted batholiths add to the overall crustal thickness and has helped to stabilize the area seismically. It is important to note there have been no recorded seismic events related to the core and flanks of the Osage High. The basement rock under the proposed sequestration site is the Washington Volcanic Group. Generally, the isotopic age of these basement rocks are 1.4 to 1.2 billion years old. The seismicity of the area is discussed in Section 2.5 of this narrative.

Surrounding the Osage High are two additional Precambrian extrusive and intrusive groups that are petrographically related. They are defined as the Washington Volcanics and the younger Spavinaw Granite Group. The Washington Volcanic Group is dominantly rhyolite but does contain andesite locally. Rhyolites have been converted to meta-rhyolites across significant areas along the margins of the Northeast Oklahoma Province. The majority of these rhyolites were probably extruded as welded tuffs. (Denison, 1966). Generally, the Spavinaw Group is composed of micrographic granite porphyrite. The intrusions are considered to be mostly sills on textural evidence and further supported from outcrop study. **Figure 2-6** shows the distribution and composition of basement rocks. Denison in 1966, named the Labette Fault, an inferred basement fault that strikes east- northeast from Pawnee County, Oklahoma to Labette County, Kansas. Per Denison, the best evidence of a fault is the occurrence of meta-rhyolites along the north and west flank of the Labette fault and a high gravity gradient parallel to the fault. Shane Matson, per personal communication, suggested the fault or structural lineament could have been activated during the dominate batholitic intrusion of the Central Oklahoma Granite Group after the emplacement of the Washington Volcanics and Spavinaw Granite Group. Based on general consensus from Denison and others, the Labette fault did not have any movement during or after Paleozoic time. The Wild Creek 3-D in southwestern Osage shot by Chevron in the late 90's shows little displacement over the projected strike of the fault. Over the last hundred years significant volumes of salt water have been disposed into the Arbuckle along the inferred Labette basement fault trace without any historically reported seismicity events occurring.

More than 3,400 feet of sedimentary rocks overlie the basement complex of Precambrian granite and other igneous and metamorphic rocks in the area of the proposed carbon capture site in Osage County. The rocks in the eastern half of the county have been folded into many domes, anticlines, structural basins, and synclines, but in the western half, very few such features are present. Regional dip is on average westward at 39 feet to the mile or approximately 0.25 to 0.5 degrees (Bass, 1942).

During Paleozoic time, the Cherokee Platform experienced at least one major tectonic event which resulted in the subsequent uplift of both the Nemaha Ridge and Ozark Uplift. These two structural features are thought to have developed as the result of multiple orogenies that occurred during the Pennsylvanian period. During this time, a broad, north-south trending arch rose above sea level from central Oklahoma to Kansas (Nemaha Ridge). The Nemaha Ridge became a notable positive feature during early Pennsylvanian time. Deformation is associated with a similarly aged plate convergence along the Ouachita Mountain orogenic belt in Arkansas (Newell et al., 1989). This uplift and erosion locally affected the Arbuckle strata, especially on structural highs. Concurrently, a broad uplift also formed to the east in the Ozark region of Oklahoma, Missouri, and Arkansas, termed the Ozark Uplift.

Near the end of the Late Cambrian/Early Ordovician, a falling sea level left the Cambro-Ordovician carbonates and Precambrian basement rocks exposed. The Late Cambrian/Early Ordovician Arbuckle Formation is part of the craton-wide Sauk Sequence. Weathering and erosion above and below the Sauk Sequence produced regional erosional unconformities and an associated karst system over most of the North American Craton. This karsted interval occurs within the lower portion of the Arbuckle Formation.

2.1.1 Regional Maps and Cross Sections

Table 2-2 lists maps and cross sections used for this regional evaluation. These figures are contained in **Appendix A** – "*Regional Maps and Cross Sections*". These maps were compiled from a search of publicly available literature and illustrate the current understanding of the regional geology. These published maps and figures that are referenced in the regional stratigraphic and structural review are included. Additional figures and tables within the narrative are contained as "**Figures**" or "**Tables**" and are referenced within their respective section.

2.1.2 Regional Stratigraphy

The general stratigraphy of the region is shown on a stratigraphic column (**Figure 2-1**). The regional stratigraphy is well documented throughout northern Oklahoma. The present-day geologic nature of Oklahoma is characterized by a west to east progression of increasingly older geologic formations that are exposed at the land surface. The exposed bedrock geology of Oklahoma is shown in **Figure 2-7** and a more detailed bedrock geologic map for Osage County is shown in **Figure 2-8**. In Northwest Osage County both maps illustrate the dendritic drainage to the southeast over the eastern flank of the Osage High and the north to south drainage around the western flank of the Osage High. These Paleozoic Groups and Formations possess gentle dip rates less than 1.5 degrees to the west/southwest in the central and eastern portions of the state. A location map **Figure A-1** in Appendix A shows the locations of two regional cross sections, A-A` and B-B` along with the proposed northwest Osage County sequestration site. on. Cross section A-A` (**Figure A-2** in Appendix A) illustrates the relationship and interpretation of the stratigraphy across northern Oklahoma. This west to east cross section shows the regional structural relationship of the sedimentary sequence and crystalline basement as affected by the Anadarko Basin Shelf, and the Nemaha and Ozark uplifts within this portion of the Cherokee Platform. Overall, the entire geologic section dips between 0.25 and 0.5 degrees to the west-southwest over the Cherokee Platform. **Figure A-3** in Appendix A is a north (B) to south (B') cross section across eastern Oklahoma illustrating the compressional tectonics of the Ardmore Basin/Arbuckle Mountains up onto the Cherokee Platform. The proposed NBU sequestration site is approximately 14 miles east of the cross section transect.

During the early Paleozoic era, over a period of 100+ million years, Osage County was covered by shallow, warm regional seas. These were optimum conditions for the deposition of carbonate sediments. Carbonates were deposited around the North American Craton creating the great American carbonate bank during late Cambrian to earliest Middle Ordovician. In the central midcontinent, this formation was named the Arbuckle, and in Texas and New Mexico the equivalent section is defined as the Ellenberger. Note the equator dissected the middle of the North American craton at early Ordovician time. Sea level fluctuations would eventually expose these carbonate banks to erosion creating both internal unconformities and unconformities that juxtaposed rocks deposited millions of years apart. In addition, the subaerial exposure of the Arbuckle sediments would help to create areas of karsting which would enhance porosity and permeability in the formation. As Paleozoic time progressed, continued burial of these Arbuckle rocks during Late Ordovician occurred, though local unconformities are present on uplifts. This was followed by Devonian and Silurian deposition; erosion was assisted by multiple episodes of meteoric flushing that created and promoted Arbuckle karsting. The shallow seas of the Early Mississippian deposited the sediments that created the regional confining zones of the Woodford and the Lower Mississippi argillaceous lime. It is important to note, the late Ordovician strata, specifically the Tyner Shale interval, will be cored to examine and confirm its subregional confining characteristics in northwestern Osage County. Approximately 4,500 feet of sedimentary rocks overlie the basement complex of Precambrian crystalline rocks in the area of the proposed CCS site.

The following sections only describe the regional formations that may be penetrated at the NBU CCS site. These formations are described in ascending order beginning with the Precambrian.

The primary confining unit is defined as the Devonian-Mississippian age Woodford Shale. The secondary confining unit is the Lower Mississippi Limestone. These confining units developed from the deposition of shallow marine and marginal marine sediments. The basal confining zone is determined to be the Washington Volcanic Group basement rocks of Precambrian age. Details on the proposed confining and injection zones are discussed in Section 2.3.

2.1.2.1 Precambrian – Cambrian

Precambrian rocks underlie all local strata and form the basement in Osage County. **Figure 2-9** shows the location of wells that are drilled into the basement. This basement is composed primarily of granite and other igneous and metamorphic rocks and possesses an age of at least 1 billion years (Denison, 1981). The depth of basement varies greatly across the county. **Figure A-4** in Appendix A is a structure map that illustrates the nature of the top of the Precambrian basement. In the southeast and northeast areas of Osage County, the basement shallows to less than 2,200 feet, and along the western margin of the county the basement is at depths of greater than 3,700 feet (Bass, 1942). These structural variations represent 23 local paleotopographic highs on the granite surface. Shallower areas of the basement are a result of topographic highs, or domes, of Precambrian strata resulting in a thinner overlying section. The composition of the crystalline basement varies throughout northeastern Oklahoma; this variation is illustrated in **Figure 2-4**. The crystalline basement below the NBU CCS site is comprised of the Washington Volcanic Group (WVG).

Overlying the Precambrian basement in some areas is the Cambrian - Ordovician aged Reagan Sandstone. The time-transgressive Reagan Sandstone is the basal clastic unit that lies atop the Precambrian basement. The Reagan Sandstone fills the topographic low portions of northeastern Oklahoma on the Precambrian erosional surface (Reeves et al., 1999). The sandstone is older in areas of low Precambrian relief and younger on the basement topographic highs. It is a fine-grained, well-sorted sandstone with an average thickness of approximately 30 feet with maximum thickness of around 60 feet (Thorman and Hibpshman, 1979). Reagan deposition began when the sea level advanced and basal sandstones were progressively deposited to the north along with the overlying sandy, dolomitic Arbuckle (Dille, 1956). The Reagan sandstone generally has high porosity and permeability that makes it an excellent reservoir in many parts of the south-central Midcontinent but is sporadic and very thin in portions of Osage County (Reeves et al., 1999). Stratigraphic testing at the NBU CCS site will confirm its presence.

2.1.2.2 Arbuckle Formation

The target injection zone for Carbon Sequestration at the NBU CSS site is the Arbuckle Formation. The Arbuckle was deposited during the Mid-Cambrian through middle Ordovician time and lies directly above the Reagan Sandstone (if present); otherwise, with no Reagan it sits directly on the crystalline basement rock. The Arbuckle is part of the "Great American Carbonate Bank" of the mid-continent (**Figure A-5** in Appendix A) and occurs regionally and extends as far east as the Arkoma Basin in Arkansas and as far west as the Anadarko Basin in Oklahoma. A structure map of the Arbuckle is presented in **Figure A-6** in Appendix A. The Arbuckle is part of the Sauk Sequence and occurs between regional unconformities. The Arbuckle is a carbonate formation, comprised mostly of dolomite and is the thickest sequence of lower Paleozoic strata throughout Oklahoma. The Arbuckle thickness fluctuates throughout Osage County. In areas of basement highs, the Arbuckle can be absent, whereas, in other areas, such as western Osage County, the Arbuckle Formation is greater than 1,400 feet thick (Beckwith, 1928). **Figures A-7** and **A-8** in Appendix A shows two isopach maps: one of the Arbuckle Formation over the south-central plains and the second over northeastern Oklahoma. Both maps confirm the proposed carbon capture site will contain approximately 1,100 feet of Arbuckle thickness.

Carbonate sediments were deposited in present day northeastern Oklahoma on a shallow shelf setting. Late Cambrian-Ordovician equivalent lithostratigraphic units are the El Paso Group of southwestern Texas, the Ellenburger Group of central and north Texas, the Knox group of the eastern United States, and the Beekmantown Group in the northeastern United States. In southern Oklahoma's Arkoma Basin, the stratigraphic units of the Arbuckle, which in some places is considered a Group, are the Bonneterre Dolomite, Fort Sill Dolomite, Signal Mountain Member, McKenzie Hill Member, Cool Creek Member, Kindblade Member, and West Spring Creek Member (Ham, 1973). However, based on previous investigations, the Arbuckle Formation in northern Oklahoma is more comparable to the Arbuckle facies of the Ozarks (**Figure A-9** in Appendix A). These dolomite units have been typed and mapped on percentage of magnesium content. They are from base to top the Bonneterre Dolomite, Potosi Dolomite Member, Eminence Dolomite Member, Gasconnade Member, Roubidoux Member, Jefferson City Member, and Powell Dolomite Member. The dolomite units in the Arbuckle Formation are common reservoir rocks throughout Oklahoma for both oil and natural gas. The formation varies in color from white to brown and varies from dense to coarsely crystalline in texture (Beckwith, 1928). In some cases, the lowermost Arbuckle beds, which were deposited on the shores of Precambrian islands, are rich in feldspar and quartz (Reeves et al., 1999). These units contain a large volume of granite fragments ranging from fine to coarse grains that were derived from the old monadnocks (Reeves et al., 1999). In northeastern Oklahoma, the major regional unconformities are found near the base of the Arbuckle, near the Gasconade Member, and near the top of the Arbuckle.

Reservoir development within the Arbuckle primarily occurs along sequence boundaries, especially where facies have strong diagenetic overprints from dolomitization and dissolution associated with paleokarstic events (Fritz et al., 2012). Wellington Field in Sumner County Kansas was studied through DOE funding and found baffles, or subregional confining zones, within the Arbuckle (Watney and Holubnyak, 2017). Younger sediments deposited above the Arbuckle include numerous impermeable formations. These units serve as reliable barriers that prevent the vertical migration of fluids out from the Arbuckle.

2.1.2.3 Simpson Group

The Ordovician Simpson Group unconformably overlies the Arbuckle. Thin sandstones within the Simpson have been modeled for additional storativity, although there are no plans to perforate them. The Simpson Group subcrops in Osage County and was deposited during a regressive sequence. Regionally, the Simpson Group is defined into three formations. The Lower Simpson is defined as the Burgen sand and is normally a tight quartzose sandstone. The Tyner is dominantly green shales that are interbedded with thin shallow marine limestones lenses and occasional tight sands. Therefore, the middle Simpson could provide additional confinement for sealing injection into the Arbuckle. The Upper Simpson is defined as the Wilcox sandstone and subcrops to the west of the proposed CCS site. The Wilcox is often porous and can be productive to the south and west of the proposed CCS site (**Figures A-10** and **A-11** in

Appendix A). The Simpson is thickest in southern Osage County at approximately 200 feet and thins rapidly to the north (Bass, 1942). Within the AoR the Simpson is approximately 70 feet thick. Each of these units represents large-scale eustatic changes of Simpson seas across the low relief platform (Thorman and Hibpshman, 1979). These formations were formed in a shallow marine environment over a period of 25 million years, concluding with the withdrawal of the sea (Denison, 1997).

2.1.2.4 Woodford Shale

The Woodford Shale, also known regionally to the east as the Chattanooga Shale, was deposited during the late Devonian Period and early Mississippian Period on an unconformity surface. In Osage County, it is classified as being early Mississippian (Bass, 1942; Beckwith, 1928). A structure map of the Woodford Shale is presented in **Figures A-10, A-11** and **A-12** in Appendix A. This structure map shows the Woodford to be absent along the northern margins of Osage County. The Simpson through Woodford interval will be cored in more than one well in order to confirm confinement and identify any compositional change within the Woodford interval in northern Osage County. The shale is strongly radioactive due to high amounts of organic matter that gives a distinct marker on gamma ray logs. It is a fissile and carbonaceous shale, dark to black in color. Local pyrite concretions occur within the formation (Beckwith, 1928). Deposition of the shale began during the first stage of the Oklahoma Aulacogen and was deposited upon predominantly carbonate sediments of the first stage of the Southern Oklahoma Aulacogen. In the Anadarko Basin, it reaches a thickness in excess of 600’. The Woodford thins on to the Cherokee Platform with an average thickness of 20 feet to 50 feet. (Thorman and Hibpshman, 1979). An isopach map of the Woodford Shale is presented in **Figure A-13** in Appendix A.

2.1.2.5 Mississippian Age Sediments

Sitting conformably above the Woodford Shale is the Mississippian Limestone, sometimes called the Mississippi Lime. The Mississippi Formation is widespread and occurs throughout Oklahoma. Members of this unit in ascending order include the St. Joe, Lower Mississippi, Upper Mississippi, the Mayes Member, and the Mississippi Chat. The top of the Mississippian is another unconformity surface. The Lower Mississippi Formation has little to no permeability and is defined as the secondary confining unit for the NBU CCS project. In northeast Oklahoma, (**Figure A-14** in Appendix A) the top of the Mississippi is reached at a subsea depth of 1,000’ at the Arkansas state line to 3000’ in northeast Noble County. At the proposed NBU sequestration site subsea depth for the Top of the Mississippian is 1900’ or 3000’ TVD. The Mississippian Limestone is a term given to the collection of formations consisting of the Kinderhook, Osage, Meramec, and Chester series, (the Chesterian sequence sub-crops to the southwest of Osage and Kay counties). During the Mississippian period, northeastern Oklahoma was covered by shallow seas with warm aerated climates. These favorable conditions in northeastern Oklahoma (**Figure A-15** in Appendix A) resulted in the deposition of a thick 200-to-350-foot sequence of carbonate sediments that later became limestone, cherty limestone, chert, and sometimes argillaceous layered carbonates. The formation is characterized as light to dark brown siliceous and dolomitic and medium to fine crystalline limestone (Clare, 1963). The Mississippian is also the formation host rock for the zinc and lead ores in the Tri-State mining district and is also an important oil producing formation in central and north-central Oklahoma (Dott, 1952).

A unit called the Mississippian Chat occurs at the Mississippian-Pennsylvanian unconformity. The Chat consists of upper Mississippian rocks intermixed with large fragments of sandstone and shale from the lower Pennsylvanian sections. The fragments usually consist of angular to subangular brecciated chert, tripolitic chert, unaltered limestone, sandstone, and shale lying in a mud matrix (Jennings, 2014). The Chat is most likely the result of paleotopographic highs that were the result of weathering combined with meteoric groundwater (Manger, 2014). The Chat appears on well logs as a low resistivity zone having low density and high porosity (Rogers, 2001).

2.1.2.6 Pennsylvanian Age Sediments

The Pennsylvanian System uncomfortably overlies the Mississippian and spans a time range from 330 to 290 million years before present (Suneson, 2000). **Figure 2-10** is a map that shows the geologic provinces that occurred during the Pennsylvanian period. Pennsylvanian packages are typically composed of alternating sandstones, marine and non-marine shales, conglomerates, and limestones. These alternating sediment packages are called cyclothems. Cyclothems are characteristic of the Pennsylvanian and Early Permian Systems and are a primary result of marine transgressive-regressive cycles (Suneson, 2000). The Pennsylvanian is composed of three series: Desmoinesian, Missourian, and Virgilian. Overall, the sedimentary section is relatively thin, with maximum thickness of about 4,000 feet in western Osage County (Thorman and Hibpshman, 1979). Because of this, these zones can be difficult to differentiate and are again known by various local names. Dott (1927) conducted a study in oil and gas in Oklahoma regarding Pennsylvanian paleogeography throughout Oklahoma, illustrating the distribution of seas throughout the Pennsylvanian and their relation to neighboring tectonic events. During the middle and upper Pennsylvanian, when shales, sandstones, and limestones were being deposited, a shallow sea with a continually oscillating shoreline covered eastern Oklahoma and Kansas, and west-central Texas. The axis of the basin extended in a northeast-southwest direction.

In western Osage County, the Desmoinesian Series is considered Middle Pennsylvanian in age, roughly 305-311 Ma, and is divided into two groups: the Cherokee and the younger Marmaton. The Desmoinesian rests atop the eroded rocks of the Mississippian. During this time, the seas were advancing and retreating with maximum sedimentation taking place predominately south of Osage County in the Arkoma Basin (Thorman and Hibpshman, 1979). The Cherokee Platform was a depositional shelf during the Middle Pennsylvanian, while the basin was a depositional sink (Krumme, 1981). The Cherokee and Marmaton groups are predominately packages of sandstones and limestones with some interbedded shales.

The Cherokee Formation represents the lower Pennsylvanian in Osage County. The Middle Pennsylvanian is characteristic of thicker packages of strata that resulted from increased neighboring tectonic activity surrounding the Mid-Continent. In Osage County, the Cherokee consists of (in ascending order) the Savannah Shale, Burgess Sandstone, Bartlesville Sandstone, Inola Limestone, Red Fork Sandstone "Burbank Unit sand", Red Fork Shale, Pink Limestone, Skinner Sandstone, Verdigris Limestone and Prue Sandstone members. The Red Fork sandstone member is widely distributed across most of Oklahoma. At NBU, it is called the Burbank Unit sand and is the productive sandstone along with the Bartlesville Sandstone. North Burbank Unit has original oil in place of 780 million bbls and is currently undergoing tertiary recovery. The field's reservoir drive was pressure depletion with pressure maintenance from waterflood beginning with unitization in 1950. Regionally, the Red Fork represents fluvial and deltaic channels that are due to a steady sea level rise across the Mid-Continent (Shelton, 1996). However, at the NBU area in western Osage and eastern Kay counties, a significant delta progradation occurred onto a low relief shelf from southeast to northwest during the regional rise in sea level (**Figure B-17**, Appendix B). This Red Fork member is a common reservoir rock in eastern Osage County typically yielding small reserves (Bass et al., 1942). In western Osage County, the Red Fork sandstone has gamma ray values between 35-95 API units. Photoelectric effect (PE) values sit around 2 barns/electron and neutron, and density porosity logs display sandy signatures. Description of the Red Fork in mudlogs is that of gray and brown sandstones with shows of fluorescence and odor, indicating the faint presence of hydrocarbons. In northwest Osage County area, the thickness of the Red Fork member averages approximately 150 feet; this unit trends north and dips to the west. In western Osage County, overlying the Red Fork is the Red Fork Shale and the Pink Limestone member. The Red Fork Shale and the Pink Limestone is the seal for the North Burbank Field. North of the NBU site, the Savannah Shale and Red Fork Shale coalesce to become a 150' shale package that would also serve as an effective confining unit for the proposed second sequestration site north of NBU. The Skinner member is described in mudlogs as a thin gray sandstone unit. The overlying Verdigris limestone and Prue cap the Cherokee. The Verdigris is 30 feet thick and is described as a brittle brown limestone. The Prue is defined as gray shale with sporadic interbedded sands averaging around 60 feet in thickness. This package represents deposition during transgressive conditions with higher frequency sea-level fluctuations coexisting, resulting in the interbedded shales within the larger limestones.

The younger Marmaton is Middle Pennsylvanian in age and features thin carbonate cycles representing carbonate supratidal, intertidal, subtidal, shallow-marine, and shelf-break depositional environments. In northern Oklahoma, these carbonate cycles are commonly limestone banks; however, to the south, rocks of the same age can be sand and shale facies (Krumme, 1981). In western Osage County, the Marmaton Group consists of four members: the Oswego Limestone, Labette Shale, Big Lime, and Cleveland sands. Regionally, the Oswego Limestone member is a carbonate bank serving as the basal Marmaton. It was deposited during a transgressive systems tract and is seen consistently throughout the northern Oklahoma area. In western Osage County, the Oswego is regularly seen in wireline data due to its unique carbonate character. In gamma ray logs, the Oswego has values of 20-45 API units. Photoelectric values average 5 barns/electron and mudlogs describe this member as being a flaky tan to gray colored limestone. In the proposed carbon capture site area, the dip of the Oswego is to the west–northwest. The average thickness is approximately 205 feet with the thickest of the Oswego located in the southern portion of Osage County.

Overlying the Oswego is the Labette, a shale unit separating the Oswego and Big Lime carbonate banks. In parts of northern Oklahoma, the Labette contains channel filling small sand lenses known as the Peru Sand (Bass, 1942; Oakes, 1952) However, these sand lenses are absent in western Osage County. The Labette is easily seen in wireline, as it is the shale member separating the significant limestone packages. Gamma ray values average 115 API units and photoelectric values average 3 barns/electron. Neutron and density porosity logs show high separation exhibiting typical shale character. In the northwest Osage County, the average thickness of the Labette is roughly 35 feet The Big Lime member overlies the Labette and is the second largest carbonate bank making up the Marmaton Group (Visher, 1996). The Big Lime is widespread and can be found in the subsurface data throughout much of Oklahoma. The upper 25 to 50 feet of the Big Lime is a known reservoir rock in Oklahoma, yielding both oil and gas (Bass, 1942). Oakes (1952) classifies the Big Lime as having three distinct zones: a lower limestone zone, a calcareous shale-limestone zone, and an upper limestone zone. In this area, the Big Lime is easily recognizable in wireline data. It overlies the large Oswego carbonate package and is separated by the thin Labette shale member. Gamma ray values for the Big Lime average 30 API units and photoelectric values fluctuate between 4 and 5 barns/electron. The Big Lime is described in mudlogs as being a brittle, tan to light brown colored limestone with shows of fluorescence. In Osage County, the Big Lime dips to the west and strikes to the north-northeast. The thickness of the Big Lime in western Osage County ranges from 90 to 120 feet and has an average thickness of approximately 100 feet. Overlying the Big Lime are the Cleveland sands. The Cleveland represents the top of the Desmoinesian Series and the base of the Missourian Series. It contains transgressive clastic channel-fill facies overlying the highstand Big Lime interval. Visher (1996) characterizes the Cleveland delta type as being riverine-fan. Oakes (1952) describes the Cleveland as regionally consisting of three zones: a lower and upper sandy zone and a middle shale-coal zone. The coal zone is absent from western Osage County. In the area around the proposed NBU CCS site, the Cleveland features inconsistent gamma ray values between 80 and 130 API units and has photoelectric values between 2.5-3 barns/electron. Neutron and density porosity curves indicate shale facies with interbedded sands. Mudlogs in western Osage County commonly refer to the Cleveland as predominately being gray shale with interbedded sandstones. The local dip of the Cleveland is to the northwest and an average thickness in this area for the Cleveland is 90 feet with the thickest Cleveland being on the western flank of Osage County.

Overlying the Desmoinesian is the Missourian Series. The Missourian is composed of two formations, the Skiatook and the younger Ochelata. The age of the Missourian Series is approximately 300-305 Ma (Visher, 1996) and is considered the beginning of the Late Pennsylvanian. Major tectonic events active during the Missourian were the Arbuckle and Wichita-Amarillo uplifts. Deformation and uplift of the Ouachitas occurred during the Desmoinesian and the first evidence up on the Cherokee Platform of the rise of the Ouachitas is seen in Missourian strata. West, 2015 considered the depositional environment for the Late Missourian sandstone and shale facies.

The Skiatook Group forms the basal Missourian and predominately consists of sandstones and limestones with sporadic interbedded shales. In western Osage County, the Skiatook exhibits the common Pennsylvanian cyclothem pattern of fluctuating sea levels and thin alternating facies. Regionally, the Cleveland sands transition into the Skiatook and represent the basal Skiatook. In the Skiatook, the Cleveland represents clastic sequences overlying the high stands of the Big Lime. The other members making up the Skiatook include: the Checkerboard Limestone, Layton Sandstone, and the Hogshooter Limestone.

The Checkerboard Limestone overlies the Cleveland sands and is one of the most persistent beds in northern Oklahoma (Krumme, 1981). Due to the consistent nature of the Checkerboard, this limestone represents a period of clear waters with uniform depths, after a maximum flooding event occurred across the Cherokee Platform. In this area, gamma ray values for the Checkerboard average between 30 and 60 API units with interbedded shales reaching values in excess of 235 API units. Photoelectric values for the Checkerboard average 5 barns/electron. The mudlog used in Wests' study, (2015) describes the Checkerboard as a buff-tan colored limestone with fluorescence shows and interbedded shales. In western Osage County, the Checkerboard dips to the West and has an average thickness of 70 feet.

The Layton overlies the Checkerboard Limestone and is primarily composed of shale and sandstone from highstand conditions following the transgressive conditions of the Checkerboard. Visher (1996) classifies the Layton as riverine deltaic sandstone sequences in northern Oklahoma. In wireline data from western Osage County, the Layton alternates between shale and sandstone. Gamma ray values for the sandstone packages average 45 API units and photoelectric values are around 2-2.5 barns/electron. The larger shale packages have gamma ray values most commonly between 120-150 API units and PE values of around 3 barns/electron. The maximum flooding event of the Checkerboard can be identified by the high gamma ray spike at the boundary between the Checkerboard and Layton members. The Layton represents progradation during highstand conditions. This is recognized by the coarsening upward sequence on the gamma ray curve, following the maximum flooding event atop the Checkerboard. In western Osage County, the Layton dips to the west and has an average thickness of roughly 230 feet. The thickest section of the Layton can be found in the south-southeast portion of western Osage County at around 260 feet. The Layton sands are described as being white to gray, well-sorted sandstones and the shales as being dark gray to black in color with micro-micas.

Presence of the Hogshooter varies around the area and due to this inconsistency, it was only briefly examined. If present, the Hogshooter represents the youngest formation of the Skiatook Group with gamma ray values fluctuating between 35 and 70 API units and photoelectric values around 4.5 barns/electron. These values, in addition to characters of density and neutron porosity curves, indicated the Hogshooter to be a limestone with interbedded shales during a transgressive systems tract.

The overlying Ochelata Group is Upper Missourian in age and is approximately 300 Ma, and outcrops at the surface throughout many areas in Osage County. In western Osage County, the Ochelata is composed of four formations: the Osage Layton Sandstone, Avant Limestone, Perry Gas Sandstone, and Okesa sands. Tectonic activity occurred south of Osage County as the Wichita and Arbuckle uplifts, as well as active sedimentation from the Ouachita orogeny to the southeast. These events contributed to marine and continental Ochelata sedimentation throughout northern Oklahoma.

The Osage Layton sands are sometimes referred to as the Cottage Grove sands. These sediments represent the shift from highstand to transgression capped off by a maximum flooding event. Bass (1942) describes the Osage Layton as being a sequence of sandstones and shales with some interbedded limestones. Oil and gas have been recovered from lower portions of the Osage Layton in northern Oklahoma; however, there has been very little petroleum recovered from these beds in Osage County.

In wireline data from the project area, the Osage Layton is easily recognizable. On gamma ray curves it has API units around that range from 30 to 60 for the sand beds and 90 and 150 for the interbedded shale units. The gamma ray curve shows the boundary between the Osage Layton and the overlying Avant shale with API units of 195. This shale represents the capping of a transgression by a maximum flooding surface. Photoelectric values range from 2-2.5 barns/electron for the sands and 3-3.5 barns/electron for the shales. The Osage Layton is described as an off-white colored, well-sorted sandstones with medium to coarse sized grains, and interbedded shales. The mudlog also notes the absence of fluorescence and odor in the lower section of the Osage Layton. In Osage County, the dip of the Osage Layton is to the west-northwest and the average thickness is 240 feet. The thickest Osage Layton is found to the southeast of the project area at 260 feet and then thins in the northwest to about 205 feet. Overlying the Osage Layton is the Avant Limestone. In western Osage County, the Avant represents sediments deposited during highstand conditions. The Avant is predominately shale with the presence of sandstone and limestone in the Upper Avant. In the project area, the Avant has gamma ray values ranging from 35-135 API units. The average gamma ray values for the Avant are 110 API units, indicating shale. A coarsening upward character is recognized by the gamma ray curve through the Avant. This character signifies a prograding sediment sequence during highstand conditions. The photoelectric effect values average 3 barns/electron; however, the limestone sequences average 4.5 barns/electron. Neutron and density porosity curves indicate shale with interbedded sands and limestone capping the Upper Avant. Mudlog descriptions classify the Avant as being a medium to light gray shale with brachiopod trace fossils. Cream-colored limestones and sandstones are described in the Upper Avant. In western Osage County, the dip of the Avant is to the northwest. The average thickness of the Avant is 250 feet with the thickest part of the section being in the southeast portion of the project area. This indicates that sedimentation took place toward the northwest, along dip.

The Virgilian Series is the youngest Pennsylvanian strata found in Osage County and is considered Late Pennsylvanian. The Virgilian overlies the Ochelata Group of the Missourian Series and is composed of three groups: Douglas, Shawnee, and Wabaunsee. Virgilian aged strata outcrops at the surface in the project area; however, a lack of material in wireline and literature for western Osage County made Virgilian subsurface stratigraphic interpretation difficult. The Ouachitas continued to supply sediments to areas north and east of the Anadarko Basin during the Virgilian. The Late Virgilian is considered as being a mixed marine and continental depositional environment with interchanging marine and fluvial-deltaic sequences. In western Osage County, the Virgilian is composed of alternating continental-marine limestone, shale, and sandstone facies.

The Douglas Group is upper Pennsylvanian age deposit and overlies the youngest formation in the Missourian Series. The Douglas is a relatively thin formation consisting of alternating shales and sandstones with interbedded limestones. These sediments represent fluvial-deltaic depositional environments, indicating that the basins to the south were at maximum capacity and sedimentation was sourced from nearby uplifts. The Douglas Group consists of four members: the Tonkawa, Haskell, Lovell, and Endicott.

The Tonkawa marks the change from Late Missourian to Early Virgilian aged strata. The Tonkawa is a fluvial-deltaic reservoir rock throughout Central and western Oklahoma. These clastics have been producing oil and gas for over 90 years. Regionally, anticlines associated with basement-rooted faults have been common hydrocarbon traps in the Tonkawa (Campbell, 1997). In western Osage County, the Tonkawa appears in wireline data as shale and sand with interbedded limestones. Gamma ray values averaged between 35 and 50 API units for the sand units and range between 75 and 120 for the more organic shales. These alternating sediments represent a fluctuating shoreline across the area during high stand conditions. Photoelectric values for the sands averaged 2-3 barns/electron and the Tonkawa is characterized as being a white to light gray, well-sorted, sandstone with interbedded gray brittle shale. In the project area, the dip of the Tonkawa is to the northwest and the thickness averages 190 feet.

Overlying the fluvial-deltaic Tonkawa sediments are the Haskell, Lovell, and Endicott formations of the Douglas Group. Directly overlying the Tonkawa sands is the Haskell carbonate deposited during transgression in the area and topped by a maximum flooding interval. The Lovell is a sand deposited during highstands atop the Haskell. The interpretation of the Haskell and Lovell were uncertain, so they were treated as part of the overlying Endicott in wireline studies. Overlying the Lovell is the Endicott. It was deposited in highstands like the underlying Lovell. The Endicott is primarily in the Shawnee Group; however, the Early Endicott sediments are Late Douglas age. Sequences of fluvial and deltaic sandstones and shales make up the Endicott. In wireline data from the project area, the Endicott has gamma ray values around 30 API units for the sands and 105 API units for the shales. PE values fluctuate between 2-3.5 barns/electron depending on being a clastic or mud rich unit. Mudlogs describe the shales as being gray to greenish gray in color and the sandstones as being gray to tan in color with well sorted quartz grains.

Overlying the Douglas is the Shawnee Group. Shawnee members outcrop sporadically throughout western Osage County and consist of sandstone, shale, and limestone sequences (Beckwith, 1928). Multiple sandstones found within the Douglas and Shawnee groups are believed to be of fluvial-deltaic origin and are targeted oil and gas reservoirs in northern Oklahoma (Beckwith, 1928). In western Osage County, the Shawnee consists of the Endicott, Oread, Carmichael, Elgin, Hoover, and Pawhuska members. There is little literature for the Shawnee Group in Osage County, making interpretation of these sequences in western Osage County difficult.

The Endicott was previously mentioned as being a part of both the Douglas and Shawnee Groups. Overlying the Endicott is the Oread Limestone. In the project area, the Oread features limestone with interbedded shales. Gamma ray values for the Oread fluctuate between 35 and 105 API units. The limestones were described as being light gray-to-grayish brown in color. These limestones represent transgressive conditions in western Osage County. The Carmichael overlies the Oread and is a thin sandstone-shale unit with interbedded limestones. The mudlog used in for report describes the Carmichael section as being gray colored sandstones with gray interbedded shales. The sands and shales of the Carmichael represent small shoreline fluctuations resulting in prograding clastic and mud rich sequences atop the carbonates produced in the Oread.

Overlying the Carmichael is the Elgin. In the project area, the Elgin is a thick sandstone package with thin interbedded shales. These sands are from a fluvial-deltaic depositional environments. The gamma ray values for the Elgin average 35 API units, indicating sand. The thin interbedded shales have gamma ray values in excess of 90 API units. Photoelectric values for the Elgin clastics average 2-2.5 barns/electron. Mudlogs describe the Elgin as comprised of gray colored sandstones with well-sorted quartz grains and thin interbedded brittle shale units. The dip of the Elgin is to the northwest and the average thickness is 150 feet with the thickest part of the section being in the south-southwest part of the project area.

The final formation in the Shawnee Group is the Pawhuska. Regionally, the Pawhuska features multiple limestone members separated by shales (Beckwith, 1928). These carbonates were produced during transgressive settings with slight falls in sea-level taking place during Late Shawnee time. In the project area, the Pawhuska includes 3 or 4 limestone packages with interbedded shales. Because of this unique characteristic, it is easy to identify in wireline data. Gamma ray values for the Pawhuska limestones ranged from 15 to 45 API units and the 55 photoelectric values were consistently between 4-5 barns/electron. The mudlog described the Pawhuska as a brown to white colored limestone with interbedded dark gray shale featuring some trace fossils. In western Osage County, the Pawhuska dips to the west-northwest and has an average thickness of 160 feet. The thickest section of the Pawhuska is found in the northeast region of the area, indicating that deposition was along strike.

The Wabaunsee Group overlies the Shawnee Group and makes up the youngest sediments in the Virgilian Series. It outcrops across central Osage County in a general north-south belt. The facies of the Wabaunsee are predominately fluvial and deltaic sediments that are sourced from the south-southeast. Numerous thin, alternating shale and limestone formations that are often fossiliferous can be traced from northern Oklahoma into Kansas, Nebraska, and Iowa.

2.1.2.7 Permian Age Sediments

Permian age sediments in ascending order include the Admire, Council Grove and Chase formations. Of note are the groundwater resources within the Council Grove and Chase formations. Within the Council Grove Formation there are a series of sands containing fresh waters within the Vanoss member. The sands of the Oscar member of the Chase Formation are classified as the other freshwater zone in the area. The groundwater resources within these shallow freshwater zones are currently being monitored with respect to oil production operations at the North Burbank Unit's tertiary oil recovery project. Within the AoR there are 62 active shallow groundwater monitoring wells. Please note that these freshwater zones, while containing some salinities lower than 10,000 mg/L, are not considered USDWs due to deliverability.

2.1.3 Regional Structural Geology

Approximately 1.1 billion years ago during the late Precambrian period, the Grenville Orogeny occurred as the result of a collision between the Yavapai-Mazatzal-Superior and the Grenville Precambrian provinces. Extensional forces northwest of the Greenville Orogeny's continental collision were probably in response to a massive hot spot within the North American craton. The Midcontinent's triple junction resides under Lake Superior with the failed rifts western arm and eastern arm each extending over 1000 miles. The western failed arm (**Figure 2-4**) runs from Lake Superior southwest through portions of Wisconsin, Minnesota, Iowa, Nebraska into southern Kansas. These failed rift arms left thick layers of igneous rocks with a major component along the rift being basalts. The Midcontinent Rifts system is the deepest and longest healed rift system discovered on the earth's crust. T Several Precambrian basement provinces with different ages, structures, and composition have been deformed by the rift (Van Schmus and Hinze, 1985), which is a prominent feature on gravity magnetic maps showing its geometry and extent (**Figure 2-5**). The Nemaha Uplift, a series of uplifted fault blocks has been attributed to isostatic uplift due to the thick basalts underneath the Midcontinent ridge. The timing and intrusion of the rhyolites and granites forming the Precambrian Hills of Osage County was also ongoing during the development of the Midcontinent Rift. A bedrock geologic map of Osage County is presented in **Figure 2-8**.

The southern Oklahoma Aulacogen (**Figure 2-10**) is another rift that failed to break up the North American continent. Starting in the early to middle Cambrian, rifting began in the region of the present-day Wichita Mountains and southwestern Arbuckle Mountains of southern Oklahoma. This rifting is represented by large volumes of Early Cambrian basalt and gabbro rock, the youngest is dated to 552±7 Ma (Bowring and Hoppe, 1982). Following the rifting phase, the aulacogen began to cool and subside forming the Anadarko Basin (Perry, 1989). The Ouachita orogeny (500-290 Ma) is a major tectonic event that extends from central Arkansas westward into southeastern Oklahoma (Sellars, 1967). The formation of the Ouachita Mountains in southern Arkansas and southeast Oklahoma are the result of this orogeny. The Ouachita Orogeny folded rocks ranging from Precambrian to Pennsylvanian in age and influenced basement rocks in Oklahoma. This mountain building process caused large stresses in the basement rocks in southern Arkansas and southeastern Oklahoma that could have influenced the basement rocks in northeastern Oklahoma as well (Khatiwada et al., 2013, Lillie et al., 1983, Sellars et al., 1967, Suneson et al., 2005).

Oklahoma's geologic provinces had already developed or were currently active by Pennsylvanian time (West, 2015). Along cross section A to A' (*Appendix A* **Figure A-1**) Osage County is bound to the east by the Ozark Uplift and to the west by the Nemaha Uplift. The Nemaha Uplift acts as the structural boundary between the Anadarko Shelf and the Cherokee Platform. Along cross section B to B' (*Appendix A* **Figure A-2**) the Arbuckle Uplift to the south of the gently dipping Cherokee Platform, with regional dip of the strata in Osage County to the west-southwest. These westward dipping formations feature structural deformation tectonic structures throughout the county (Bass, 1942), these features include localized domes, basins, folds, and en echelon normal faults. These faults trend north-northeast, perpendicular to the orientation of the maximum horizontal stress regime throughout Osage County (Thorman and Hibpshman, 1979). Smaller faults, perpendicular to this maximum horizontal stress direction occur with northwest orientations (Bass, 1942). Overall, Osage County has minor structural folds compared to other regions of Oklahoma, which neighbor the larger tectonic provinces.

The Pennsylvanian System was a period of change for the Midcontinent as it transitioned from a passive margin to an active margin. The transition to an active margin began during the Late Mississippian and Early Pennsylvanian. During the Early Pennsylvanian active tectonics were occurring to the south, southwest, and southeast of the Osage High. This active margin is a result of plate collision and southward subduction of the Laurentian plate as it collided with the Gondwana plate. The initial result of this collision, which began as early as the Ordovician, was the formation of the Appalachian Mountains. Other tectonic events that followed g the Appalachian Orogeny include the development of the geologic provinces throughout Oklahoma and Arkansas and those bounding the Cherokee platform. In the late Pennsylvanian, the development of multiple geologic provinces bordering this region, including the Ozark Orogeny to the east, the Ouachita Uplift to the southeast, and the Wichita Uplift to the southwest. Prior to this time there were three major geologic provinces: the Oklahoma Basin, the Ouachita trough, and the southern Oklahoma aulacogen.

Increased tectonic activity during the early and middle Pennsylvanian divided theses three provinces into a series of basins and uplifts, which produced the major geologic provinces throughout present day Oklahoma. The Wichita Uplift occurred during the early Pennsylvanian, resulting in the formation of the Wichita Mountains to the south of Osage County, as well as the formation of the neighboring Anadarko and Ardmore basins. Transitioning from the early Pennsylvanian to the middle Pennsylvanian, the Ouachita Orogeny occurred in Arkansas and Oklahoma, creating the Ouachita Mountains and neighboring Arkoma Basin located to the southeast of Osage County. The Arbuckle Orogeny followed the Ouachita Orogeny and occurred during the end of the Middle Pennsylvanian (Dott, 1927). The Arbuckle Uplift occurs directly south of Osage County. Although the Cherokee Platform is considered to be a stable margin throughout this complex tectonic history, it likely felt the collateral effects of varying sedimentation and subsidence rates related to these uplifts. This is reflected in the cyclic nature of the stratigraphy observed in the area.

At the present time, southwest to northeast trending fault zones that occur in the northeastern portion of Oklahoma (from west to east) are the Nemaha Fault Zone, The Labette Fault Zone and the Wilzetta Fault Zone (**Figure 2-11**). The Nemaha Fault zone is present in Grant, Kay, Garfield, Noble and Logan counties and occurs west of Osage County. The Labette Fault Zone is present in Osage County but occurs south and southeast of the proposed NBU CCS site. The Wilzetta Fault Zone is present within the east central portion of Oklahoma and occurs south southeast of Osage County. Although the NBU CCS site is bound by both the Nemaha and Labette Fault Zones, there are no faults in proximity to the NBU CCS project's location. Denison 1966, coined the Labette fault based on meta-rhyolites north and west of the fault, high gravity gradient parallel to the fault. Denison described the fault as a normal fault, but the dip of the fault plane is unknown, also there is not any evidence of any movement on the fault since Paleozoic time. Appendix A, **Figure A-20** illustrates the proposed location of the Labette fault as it dissects the northwestern flank of the Osage High. The Wild Creek 3-D confirms there is undiscernible offset along the fault trace under the 3-D. The Antelope 3-D, the NBU outline along with the proposed sequestration site are all illustrated on the map. The better explanation is a zone of weakness created/activated during the major batholitic assault of the Central Oklahoma Granite's intrusion into older igneous Precambrian rock.

The distribution of fault zones in association with the variations that occur with regard to the composition of the crystalline basement likely influences where seismically active regions within central Oklahoma exist. However, the region in northwestern Osage County where the NBU CCS site is to be located is buffered from and the surrounding fault zones and is therefore a more seismically stable region within this portion of the Cherokee Platform.

2.1.4 Regional Groundwater Flow in the Injection Zone

The proposed injection zone for the NBU CCS site is identified as the Cambrian - Ordovician age Arbuckle Formation. The direction of groundwater flow within the Arbuckle is to the west-southwest. A potentiometric surface map illustrating fluid flow is shown in **Figure 2-12**.

The structural dip rate for the top of the Arbuckle is less than 1 degree to the west southwest (**Figure A-5** in Appendix A). All formations within the AoR have a 0.5 to 1.5-degree structural dip rate to the west southwest.

Many of the studies for flow rates in deep saline aquifers come from the search for nuclear waste isolation sites. These studies show sluggish circulation to nearly static conditions in the deep subsurface (Bethke et al., 1988). Flow rates in the deep saline aquifers such as the Arbuckle were found generally to be on the order of inches per year. Site specific data on regional fluid flow in the injection zones will be collected via the injection wells and in-zone monitoring well once completed.

2.2 Local Geology of the NBU CCS Site

The proposed NBU CCS site is located on the western flank of the Osage High in western Osage County, Oklahoma**.** The proposed site is in Township 27 North Range 5 East, Sections 11 and 14, located approximately 30 miles northeast of the town of Ponca City, Oklahoma and 60 miles northwest of Tulsa, Oklahoma (**Figure 2-1**). Four Cross sections, Appendix B: **Figures B-1** through **B-4**, at eight wells per cross section, were created to document the stratigraphy of northeastern Kay County and northwestern

Osage County. Cross Sections **B-1** and **B-2** are a west to east structural and stratigraphic section, respective. Cross Section **B-3** is structural, and **B-4** is stratigraphic; both have a north to south azimuth. Structural sections document the structural fabric from lower Pennsylvanian through Cambrian. Arbuckle is over 1000' thick and is highlighted in blue. The Simpson likely contains seal facies with the Tyner member to be cored at multiple location in northwestern Osage County for confirmation. Above the Simpson and highlighted in brown and tan are the upper confining beds of the Woodford Shale and the Lower Mississippian tight argillaceous limestone. Above the lower Mississippian is the remaining Mississippian section. Above the Mississippian is the Lower Pennsylvanian clastic section of shales and Burbank sand Unit in yellow. Both structural cross sections illustrate the stratigraphic trapping that occurred along the northern and eastern margins of NBU. The Pink Lime and Red Fork Shales are the top sealing intervals for prolific NBU. The basal seal is the Savannah Shale, tan in color. The stratigraphic sections of **B-2** and **B-4** are both hung on the Woodford Shale. These stratigraphic illustrate most units do not vary in thickness except for the upper Mississippian and the Burbank Unit sand.

A detailed, site-specific topographic map showing the AoR, extent of the CO_2 plume, artificial penetrations, and project injection and monitoring well locations is provided in **Figure 2-3**. The pore space required within the preliminary AoR for the NBU CCS site is over 81 percent on surface lands owned by CapturePoint LLC. Though the proposed site is not positioned in any major or minor recognized aquifers by the state of Oklahoma, the site is positioned between two major shallow aquifers of Oklahoma. To the west is the Arkansas River alluvial aquifer and to the east is the Vamoosa-Ada Bedrock aquifer. Computational reservoir modeling results indicate that the AoR for the site encompasses approximately 11,325 acres and the resulting CO_2 plume is expected to occupy approximately 3,530 acres. Details of the modeling and simulation methods and results are detailed in Module B "*AoR and Corrective Action Plan*".

The local geology section contains detailed maps and cross sections that are focused on the AoR. **Table 2-3** contains the information on Maps and Cross Sections used in the local evaluation. All figures pertaining to the local geology are contained in **Appendix B** – "*Local Maps and Cross Sections"*. These maps have been generated using Petra.

Local structure and isopach maps for selected formations were developed from subsurface correlation of available well logs using Petra software. These maps provide structural and thickness information for units within the modeled area for this project. Below is a list of the maps developed for this application. These maps are contained within Appendix B.

- Figure B-5 - Basement Structure Map
- Figure B-6 - Arbuckle Structure Map
- Figure B-7 - Arbuckle Isopach Map
- Figure B-8 - Top Simpson Formation Structure
- Figure B-9 - Simpson Formation Isopach
- Figure B-10 - Woodford Structure Map
- Figure B-11 - Woodford Isopach Map
- Figure B-12 - Lower Mississippi Structure Map
- Figure B-13 - Lower Mississippi Isopach Map
- Figure B-14 - Mississippi Structure Map
- Figure B-15 - Savannah Shale Structure Map
- Figure B-16 - Savannah Shale Isopach Map
- Figure B-17 - Sand Percentage, Lower Cherokee Formation "Base Pine Lime- Top MS Fm Map
- Figure B-18 -Top Pink Lime
- Figure B-19 - Top Oswego

The following sections detail the geology and data sets used on a locally affected scale, specific to the area at and around the proposed NBU CCS site.

The general topographic relief within the AoR is at an elevation of between 1,050 and 1,150 feet above sea level. The area is mainly grasslands with minimal relief and few trees. The site is located on lands owned by Capture Point and within the North Burbank Unit, an active CO_2 enhanced oil recovery project. These privately owned tracts will serve as the location where surface facilities, injection and monitoring wells will be developed.

The Upper Primary confining zone is the Woodford Shale and the secondary confining unit is the Lower Mississippi Formation. Together these units have a combined thickness of approximately 80 feet**.** Additional confinement is provided by the Savannah Shale which overlies the Mississippian Formation. The 900 foot targeted injection interval is in the Arbuckle Formation that in total is approximately 1,100 feet thick. The interval thickness of the these formations are shown in the Type Log from the NBU 1542 well (**Figure 2-2**).

2.2.1 Data Sets

Table 2-3 contains a list of cross sections and maps that are included in Appendix B. A total of 149 wells were used to correlate formations and units for the geologic model at the NBU CCS site. **Table 2-4** contains the list of wells used in cross sections B-1 through B-4 in appendix B. Available geophysical well logs that were obtained and used in the construction of the geologic model include 13 porosity logs, 7 Delta-T logs, 6 Density logs, 11 Gamma Ray logs and 13 Resistivity logs. The limitation on this information is that many of the wells were not drilled into the lower portion of the Arbuckle Formation. A list of the wells with well logs and las files that are used are listed in **Table 2-5.**

Table 2-6 contains a tabulation of wells that are found within the AoR. Well information was compiled using multiple sources. These include GeoMap, S&P Global, Enverus (Drilling Info), Bureau of Indian Affairs (BIA), Operator records and the Oklahoma Corporation Commission (OCC). The data compilation effort involved online searches and well record downloads in combination with onsite record searches. During this well records search effort, it was discovered that there are no records available for 61 wells within the AoR. Information gathering efforts will continue in order to locate all available well data for this list of wells. A list of the wells where no publicly available information is available is presented in **Table 2-7**. Well logs were acquired from the Sonris Data base, IHS market database and other third party well log libraries.

There are 16 wells drilled through the Lower Mississippi and Woodford confining zones. A detailed evaluation of the construction of offset wells is discussed in Module B "*AoR and CA Plan*". Within the AoR there are no active subsurface cleanup sites, Class I injection wells or subsurface mines. Although there are no Tribal lands within the AoR, the Osage Nation maintains control of 100 percent of the mineral rights. With respect to cleanup sites there is an archived superfund site located near Shidler, Oklahoma. This site was identified because it once posed a potential risk to human health. Butler Resources Ltd is currently registered as an Archived superfund site by the EPA and does not require any clean up action or further investigation at this time. The vast majority of the surface rights in Osage County belong to private individuals with the exception of small holdings by the Tribe.

2.2.2 Local Stratigraphy

The injection and confinement systems that occur beneath the proposed NBU CCS site are composed of geologic formations that range in age from the Precambrian through the Pennsylvanian. The local stratigraphy is established on composite type logs (**Figure 2-2**) and used as a basis for correlations. The primary well is the (NBU 1542, API 35-113-44125), however all three wells are located in Township 27 North Range 5 West, Section 11. Two cross sections that illustrate the structural and stratigraphic nature of the geology within the AoR are presented in **Figures B-1** and **B-3** (Structural cross sections) and **B-2 and B-4** (Stratigraphic cross sections) in Appendix B.

Using this type log, the following local geologic formations were evaluated:

- Lower Mississippi Formation (Secondary Confining Zone)
- Woodford Formation (Primary Confining Zone)
- Arbuckle Formation (Injection Zone)

Isopach maps were developed for units above the injection zone that serve as confining zones. In ascending order these are F**igures B-11** (Woodford – primary confining zone), **B-13** (Lower Mississippi – secondary confining zone) and **B-16** (Savannah Shale – additional confining zone). Local structure maps for these three formations are also provided, **Figure B-10** (Woodford), **Figure B-12** (Lower Mississippi) and **Figure B-15** (Savannah Shale). The structure and isopach maps that are provided are located in Appendix B. The Woodford is present as a distinct shale is approximately 10-15' feet thick and occurs directly above the Simpson. Above the Woodford is a package of carbonate sediment comprised of argillaceous limes that makes up the Lower Mississippi Formation. The Lower Mississippi Formation ranges in thickness up to 70 feet within the AoR. The base of the Savannah Shale occurs approximately 250 above the Lower Mississippi Formation and averages approximately 40 feet thick. Additionally, there are shales within the Simpson Group that provide confinement and also likely internal confinement within the Arbuckle. The character and combined thickness of these three formations make up the upper confining units for this proposed injection site.

It is important to note that formation pressures above and below the Lower Mississippian argillaceous lime are very different regionally and within the AoR. Below the Lower Mississippi argillaceous lime, specifically within the Arbuckle Formation, the pressure is such that wells that inject into the mapped area take fluids on a vacuum. Bottom Hole Pressure taken in the Conklin 9-3 in 10/23/17 (9 T27N-R5E) registered a maximum pressure of 1963 #'s at 4493' for a gradient of .437psi/ft. Above the Savannah Shale, formation pressures are approximately 126 psi above the Arbuckle for a hydrostatic pressure gradient of 0.465 psi/ft.

General knowledge from Arbuckle injection profiles in eastern Kay, eastern Noble, Payne, Pawnee and western Osage, the Lower Arbuckle is the primary disposal interval for this region. For example, an injection profile on the Williams 7-D 22 ran in 1/20/2005 approximately 20 miles south of the proposed NBU sequestration site (22-T24N R6E) had 100% of the injection between the intervals of 4,159' and 4,380', an interval of 221'. The top Arbuckle was 3,301' TVD and top of Granite was 4,497'. Therefore, in this area of southern Osage no injection occurred within 117' of the top of the granite basement. Arbuckle injection within northern NBU from 1980 until 1996 had rates over 1.2 million bbls per month into multiple wells. These wells drilled in 1980 for the NBU polymer flood were all drilled within 200' of basement and completed open hole. In 2017, OCC required Arbuckle injection wells open to basement to be plugged back to 100' above basement to limit seismicity. Three basement penetrations in close proximity to the proposed NBU site all have approximately 70' of very low porosity rock on top of the Reagan Formation or Precambrian basement. This interval will be logged to confirm lateral extent and represents a possible secondary lower seal above basement. Type wells for the tight Basal Arbuckle member are Conklin 9-3, Sec.9 27N-5E, Graham Ranch 28-1, Sec. 28 27N- 5E, and the Riley #1-A, Sec. 12 25N- 5E.

The injection zone is the Arbuckle Formation which is comprised of a series of layered dolomites and limestones. Within the AoR the Arbuckle is approximately 1,100 feet thick. The Arbuckle was deposited during the Middle Cambrian and early Ordovician periods. The Arbuckle Formation occurs over a large regional area including most of Oklahoma and adjacent states (Ching and Friedman, 2000, Gatewood, 1978). The Arbuckle Formation is associated with shallow shelf carbonates that were deposited in a shallow sea which covered a large portion of the continental interior. The Arbuckle is part of the "Great American Carbonate Bank," which is comprised of intertidal to shallow subtidal carbonate cycles. The lithology of the Arbuckle is primarily dolomite with dolomitic shale, limestone, and sandstone units (Rottmann, 2018). The Arbuckle was deposited conformably over the Reagan Sandstone (where present) (Keroher and Kirby, 1948). The Reagan Sandstone likely represents reworked lag gravel deposits eroded from the Precambrian basement (Keroher and Kirby, 1948). In certain locations, and due to the paleotopography of the Precambrian basement, the Reagan Sandstone is not present. At these locations, the Arbuckle rests directly on top of crystalline basement.

The Arbuckle Formation is affected by extensive karstic features, and solution-collapse brecciation. Regionally, the Upper Arbuckle contains extensively karsted intervals. Locally in northeastern Oklahoma and southeastern Kansas, the lower one third of the Arbuckle was repeatedly exposed due to regressive events and had repeated subaerial exposure. These karst features are prominent factors that control and enhance the matrix porosity and permeability and result in a significant amount of potential storage volume for injected fluids.

2.2.3 Local Structure

The proposed site is in northwstern Osage County, Oklahoma and located on the western flanks of the Osage High within the Cherokee Platform. The Cherokee Platform is a low relief geologic province bordered by high relief structural features (**Figure 2-4**). Along an east to west transect, the platform is bordered by the Ozark Uplift on the east and the Nemaha Uplift on the west. The Arbuckle Uplift and Arkoma Basin are located to the south and the Bourbon Arch in Kansas is to the north. The Mississippian and Pennsylvanian structures seen in Osage County are gentle and were not influenced by the nearby Nemaha Uplift to the west. There are a couple of local Arbuckle structures within the area of the proposed CCS site. These have not been found to be productive. The general CPS explanation is that the primary migation pathway for the hydrocarbons in this area was facilitated along faults within the Nemah uplift. These faults juxatapostion with the Burbank sand essentially stole the hydrocarbon column from the low relief Arbuckle closures in this area of northwest Osage County. The regional and local geologic structure demonstrates that the strata are on a homoclinal dip at a dip rate of between 1 and 1.5 degrees. This minimal dip rate in combination with capillary trapping will contain the dense phase CO_2 plume after injection has ceased. The local geological structural fabric within the of the AoR is uncomplicated, and therefore does not have any uncertainties or alternative interpretations.

2.2.4 Faulting in the Area of Review

As evidenced by the structure and isopach maps prepared for the proposed site, there is no evidence of faulting or subsurface structures within the projected AoR. Based upon all mapping performed and literature researched, the confining and injection zones within the AoR are all laterally continuous and free of transecting, transmissive faults which could allow fluids to migrate into a freshwater zone.

A bedrock geologic map of the region is shown in **Figure 2-8,** which indicates shallow faults within Osage County. There are no known faults in the shallower producing horizons of the North Burbank Unit that would extend deeper to the Arbuckle Formation that would provide a potential pathway for upward fluid flow. This observation is supported by the fact that the Arbuckle Formation is at a lower pressure than the younger Burbank Sandstone (Red Fork), which is the productive formation at the North Burbank Unit. The Savannah lies stratigraphically between the Arbuckle and the Burbank. Also supportive of this isolation is that significant amounts of oil and natural gas have been produced from the shallower reservoirs which indicate that high quality seals exist both below and above the Burbank Sandstone. Recorded pressures within the Burbank Sandstone and from below in the Arbuckle Formation also indicate there is no communication between the two formations.

The operating history of the North Burbank Field also demonstrates that there are no faults penetrating the reservoir or deeper horizons. Fluids including water, carbon dioxide and polymers have been successfully injected into the field since 1950. Approximately 374 million barrels of water have been injected as wastewater into the Arbuckle since injection started in 1956. In fact, since 1975 an estimated 352 million barrels of saline water has been injected into the Arbuckle without any known induced seismicity event or any fluid interaction with existing or new faults or fractures. The absence of these faults is one of the reasons why the NBU was such a strong candidate for waterflooding and now CO_2 flooding operations as well as the capture and geologic storage of CO_2 into the Arbuckle Formation. Regionally the Arbuckle remains under pressured despite the billions of barrels of water disposed of into the Arbuckle Formation in Kansas and Oklahoma.

2.3 Description of the Confining and Injection Zones

Demonstration of confining isolation for a Class VI injection site includes an impermeable containment layer with the absence of vertically transmissive faults and fractures that could form breaches within that containment system. Therefore, the Confining Zone is defined as a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone(s) that acts as a barrier to vertical fluid movement. For the proposed site, this has been designated as the regionally extensive Woodford and Lower Mississippi formations. Approximately 250 feet above these formations is the Savannah Shale which will provide an additional measure of safety, along with shales in the Simpson Group and likely internal confinement within the Arbuckle itself.

Injection targets are identified as formations below a depth of 2,500 feet which defines the top supercritical window for the injected CO_2. Dolomites and limestones of the Arbuckle Formation are between 3,450 feet and 4,400 feet deep and contain the necessary characteristics to be an effective injection interval at this location. The injection zone is located at least 2,780 feet below the lowermost freshwater zone that for permitting purposes is being treated as a USDW (less than 10,000 mg/l total dissolves solids content). A schematic cross section illustrating the general configuration of the stratigraphy and well placement is provided in Section 1.0 **Figure 1-2**.

The geologic characteristics for the proposed site are summarized in **Table 2-8**, which is based upon offset analog and regional core data. Site specific data will be collected during the drilling of a stratigraphic test well.

2.3.1 Confining Zones

Demonstration of security for injection includes a geologic containment demonstration and the absence of vertically transmissive faults that could form breaches of the containment system. In accordance with the EPA 40 CFR §148.21(b) standard, the confining zone is a laterally extensive and sufficiently low in permeability and porosity layer, which restricts the vertical flow of CO_2 and or formation fluids. At the proposed injection site, there are two identified upper confining zones, a primary and a secondary. These are the Woodford Shale and Lower Mississippi Formation. The confining zones presented below both meet EPA standards and will restrict the vertical flow of fluids out from the designated injection zone. Depth and thickness of the injection zone have been based upon the offset log from the NBU 1542 well. There is no core data currently available for the confining zones in Osage County. Data was acquired using literature sources, offset log analysis, and interval core data from within the state.

NOTE: CapturePoint Solutions will collect additional site-specific data with downhole data acquisition during the drilling of a stratigraphic test well and during the drilling of the injection wells. Details on the data acquisition are contained in Module D "*D Pre-Operational Testing and Logging Plan*" in this permit application.

2.3.1.1 Primary Upper Confining Zone – Woodford Shale

The primary upper confining zone is defined as corresponding to the Woodford Shale, which is approximately 10 feet thick and occurs 75 feet above the Arbuckle injection zone. The unit between the Woodford and the Arbuckle is called the Simpson Group, which also contains shales that will aid in confinement.

The Woodford Shale is comprised of alternating shale and calcareous facies. The Woodford occurs approximately 3,365 feet to 3,375 feet below ground as shown on the structure map in **Figure B-10** in Appendix B. At the injection location, the Woodford Shale is approximately 10 feet thick with well data supporting the conclusion the area is structurally free of transecting faults. A localized isopach map of the Woodford Shale is presented in **Figure B-11** in Appendix B.

The Simpson Group is Ordovician in age and is comprised of alternating shale and calcareous facies. Shales of the Simpson are confining. The Simpson is approximately 65 ft thick with well data also indicating the area void of transecting faults. An Isopach of the Simpson is presented in **Figure B-9** in Appendix B.

2.3.1.2 Formation Characteristics of the Woodford Shale

Thorough investigation of the Woodford Shale and other confining units a will be supported by the sample and data acquisition collected from a stratigraphic test well.

The Woodford Shale is a tight petroliferous shale for much of the Anadarko and Arkoma basins. Woodford thickness varies from hundreds of feet in the Anadarko Basin to where it is absent on the Ozark uplift. In the vicinity of the NBU CCS site, the Woodford ranges in thickness from 10 to 15 feet. The compositional nature of the Woodford based on its organic content lends itself to being nearly impermeable to vertical fluid migration.

2.3.1.3 Mineralogy and Petrophysics of the Woodford Shale

Core data or images are not available for the Woodford Shale in the AoR; however, a general description was obtained from Alkhammali (2009) for the Woodford Shale.

"The Woodford Shale of the middle Devonian to early Mississippian age is underlain unconformably by Silurian Hunton group and is overlain by lower Mississippian Lime unit (Bebout et al., 1993; Henry and Hester, 1995 and Johnson and Cardott, 1992). The Woodford Shale, which is known as the major source rocks for hydrocarbon deposition in the Anadarko and Arkoma basins and also in the Cherokee Platform (Rascoe and Hyne, 1988; Wickstrom and Johnson, 2012), consists largely of fine-grained sediments with a high organic content (Ramirez-Caro, 2013). The thickness of the Woodford Shale just south of the proposed CCS site ranged between 50 and 100 ft on the shallow shelf region in northern Oklahoma, and between 200 and 900 ft thick in the southern Oklahoma Aulacogen (Johnson and Cardott, 1992). The Woodford Shale is an organic-rich siliceous shale with varied amounts of interbedded carbonate and chert beds in association with phosphatic nodules (Andrews, 2009).

During the period between Late Devonian and the Early Mississippian, euxinic sea transgression occurred from south to southeast (Kirkland et al., 1992), resulting in the deposition of black organic rich sediments that included the Woodford Shale.

During the late Mississippian to early Pennsylvanian, the Oklahoma region experienced epeirogenic uplift and erosion, and followed by periods of orogenesis (Johnson and Cardott, 1992). These events produced the present-day display of depositional and tectonic provinces.

Based on geochemical parameters, geotechnical responses and well logs, the Woodford Shale has been subdivided into three members, Lower, Middle, and Upper (Portas, 2009, Miceli, 2010, Slatt et al., 2013). The lower member contains interbedded black and gray siliceous fine-grained rocks whereas the middle member is made up of black to gray fissile shale. In many ways, the upper member is similar to the lower member. Both include cherty beds, with interbedded black to gray-siliceous shale, but the upper member is noted for presence of abundant included phosphate nodules (Ramirez-Caro, 2013). Most hydrocarbon production comes from the Middle member. According to Comer and Hinch (1987), there are differences in the organic carbon content. Chert contains less than 0.1 wt. percent, while black shale contains 35 wt. percent organic carbon. Mostly, the organic matter is oil-prone type II kerogen (Comer and Hinch, 1987). Kerogen Type II commonly contains the remains of plankton (McCarthy et al., 2011).

The Woodford Shale is characterized as having a good thermal maturity and has high silica concentrations. Vitrinite reflectance information indicates that the Woodford Shale in Oklahoma ranged between <0.5 percent Ro, which is a low value of oil generation and >0.2 percent Ro implying high oil generation to dry gas generation (Comer and Hinch, 1987).

The X-ray diffraction analyses of the < 2 µm-size fraction clays revealed that they consisted of discrete illite, the most dominant clay mineral, with smaller amounts of mixed-layer illite/smectite (about 90-95 percent of which was illite), chlorite and kaolinite.

X-ray diffraction patterns of < 2 µm-size fraction clays (oriented slides) illustrated discrete illite as a very sharp (well crystalline) and asymmetry on (001) peak at 9.99 Å. Moreover, a mixed layer illite/smectite was found in a few samples, glycolated peak a slight tail near 10.4 Å. On the reflection of heating condition showed two peaks at 9.98 Å and the other at 10.41 Å. The 9.98 Å reflection may reflect the presence of illite, and 10.48 Å reflection could be other type of mixed-layer clays of illite-smectite composition, but highly dominated by illite, possibly smectite with hydroxyl interlayer.

SEM diagrams provide a good view of morphology of clay minerals and their distinctive textures. All samples illustrated the presence of discrete illites. Based on scanning electron microscopy images, it was observed that illite showed different distinctive morphologic features and texture. In general, it illustrated common types of illite that are curled at the edges and platy shape that tend to be laminated, which is similar to the description of illite provided by Keller et al., (1986). The morphology of mixed-layer illite/smectite (I/S) was difficult to observe because there was a small amount of mixed-layer illite/smectite in the samples, compared to the proportion of illite. Kaolinite was also noted in the image of SA-8 sample. SEM micrograph of sample illustrated the presence of kaolinite as a shape pseudo-hexagonal plate with smooth plane (Alkhammali, 2009).

2.3.2 Secondary Confining Zone

The secondary confining zone is located within Mississippian age strata and consists predominantly of lithologies consisting of limestone, cherty limestone, chert, and sometimes shale. During the Mississippian period northeastern Oklahoma was covered by shallow seas with warm aerated climates. These favorable conditions resulted in the depositing of a 250- to 400-foot-thick carbonate sequence, with the Lower Mississippi Formation approximately 55 to 65 feet thick across the AoR. A localized isopach map of the Lower Mississippi is shown in **Figure B-11** in Appendix B.

The Mississippian lies approximately 200 feet above the Woodford Shale. The lower portion of the Mississippi Formation consists of a thick and dense argillaceous carbonate rock sequence which provides a thick, robust secondary seal above the primary confining zone and proposed injection zone. This formation extends from 3,297 feet to 3,365 feet in the subsurface. Significant vertical separation exists between the top of the secondary confining zone and the deepest freshwater zone that is being treated as a USDW, the Vanoss. There are no structural traps or faults though this formation within the AoR.

The Lower Mississippi Formation is a tight argillaceous limestone with porosities averaging 3 percent. The thickness of the Lower Mississippi at the site is approximately 60 feet. The Lower Mississippi is considered barren and free from the accumulation of hydrocarbons. The primary reason for this is that it lacks adequate porosity and permeability. As a result, there are limited to no core evaluations or other information that describes this unit in the subsurface.

2.3.2.1 Formation Characteristics of the Lower Mississippi

The Lower Mississippi Formation is a tight argillaceous limestone with porosities averaging 3 percent. The thickness of the Lower Mississippi at the site is approximately 60 feet. It is considered barren and free from the accumulation of hydrocarbons. The primary reason for this is that it lacks adequate porosity and permeability.

The depositional geology of the Mississippi Lime has been reported as a shelf limestone in the Kingfisher area (Harris, 1975), shallow shelf limestone in North Central Oklahoma (Curtis and Champlin, 1959), and shelf or outer shelf over much of Oklahoma (Heinzelman, 1957). According to Curtis and Champlin (1959), there are three different categories of Mississippian carbonates in Oklahoma. Chemically precipitated lime muds, which are common in the Kinderhook and Osagean Section, throughout the State and are carbonates composed of fine micro-to cryptocrystalline particles. These sediments were deposited in warm, quiet, saline, slightly alkaline waters of shallow depths. The depositional positions were either very shallow banks, or shoals, sheltered from winds and current free, or deeper areas, below local wave base, and current free. Fine mud that was deposited was not washed away. These deposits accumulated on a stable platform or a slowly subsiding basin into which little or no terrigenous sediments were being introduced. The controlling factors were the petrophysical requirements and the low energy for retaining the microcrystalline precipitate.

The second type of carbonate present throughout Oklahoma, according to Curtis and Champlin (1959), were mechanically accumulated concentrations of locally derived carbonate with chemically precipitated cement. These carbonates were composed of fossils and fossil fragments, oolites, disturbed fragments or particles of lime mud, or carbonate pellets. The environment was the same as the chemical precipitates but required a higher energy environment with agitated water to produce the fragments and oolites. This type of Mississippian carbonate formed either in a less sheltered, shallower environment above local wave base, or in a current washed area. Most of these types of accumulations had little or no fine-grained chemical or detrital material, and were cemented with clear crystalline sparry calcite, during diagenesis. These fragments: pellets, fossils, fossil fragments and oolites could have become incorporated in the low energy environment mud. These deposits accumulated on a stable shelf or a slowly subsiding basin, but had open water, near shore, with warm, shallow, agitated water. This type of Mississippian carbonate is found in the Osagean rocks of Northeastern Oklahoma and becomes more common in Meramecian and Chesterian Rocks (Curtis and Champlin, 1959).

The third type of carbonate present throughout the Mississippian Section, according to Curtis and Champlin (1959) is a coarsely crystalline or dolomitic limestone. These had been replaced or recrystallized during diagenesis. The authors did not speculate on the specific depositional environments. Harris (1975) studied the Mississippian carbonates in Northwestern Oklahoma and described the Osage-Meramec Section as a micritic shelf limestone containing large amounts of chert. The section contains biohermal build-ups that relate to favorable food supply, proper water temperature and depth, to produce extremely numerous fossil populations. The Chesterian Section contains oolites and indicates high energy shelf limestones. Southward these limestones grade into a shale-sand sequence (Harris, 1975). Heinzelmann (1957) stated that Mississippian rocks in Northeastern Oklahoma were shelf or outer shelf environment. It is noted in many of the readings (Harris, 1975 and Selk, 1948), that many authors define facies changes from north to south in the Meramec-Osage section of Oklahoma. Selk (1948) recognized these changes and interpreted them as facies belts with an east-northeast to west-southwest trend. These facies from north to south were "white lime", "siltstone", "siliceous", and "Mayes-Sycamore". These are denoted as a progressive decreasing in environmental energy, either wave action or current velocity. The study area lies within a siliceous facies and would be basinward from the "white lime" facies. Thornton (1958), Rhoads (1968), and Jordan and Rowland (1959) all noted the facies variation within the Meramec-Osage as investigated by Selk.

2.3.2.2 Mineralogy and Petrophysics of the Lower Mississippi Formation

At the NBU CCS site, the Lower Mississippi Formation consists predominantly of dense argillaceous limestone, cherty limestone, chert, and sometimes shale. The formation is characterized as light to dark brown siliceous and dolomitic and medium to fine crystalline limestone (Clare, 1963). The Lower Mississippi is also the formation host rock for the zinc and lead ores in the Tri-State mining district.

2.3.3 Lower Confining Zone

The CapturePoint proposed CCS site is located within the area of the Washington Volcanic Group (WVG) of basement rocks. The (WVG) underlies the northwestern section of Osage County and was deposited in a sequence of flows and tuffs. The WVG is predominately composed of rhyolite, meta-rhyolite, and andesite with isotropic age of 1,282 ± 15 Ma determined from nine samples.

The Reagan Sandstone is the Cambrian clastic unit covering the topographic low portions of northern Oklahoma on the Precambrian erosional surface (Reeves et al., 1999). Reagan deposition began when the sea level advanced and basal sandstones were progressively deposited to the north along with the overlying sandy, dolomitic Arbuckle (Dille, 1956). The Reagan Sandstone generally has high porosity and permeability that makes it an excellent reservoir in many parts of the south-central Midcontinent but is sporadic and very thin in Osage County (Reeves et al., 1999). It is unknown whether the Reagan is present at the NBU CCS site; if it is present and contains porosity, it will function as a dissipation interval. This will be confirmed when drilling a stratigraphic test well.

2.3.3.1 Formation Characteristics of the Precambrian Basement

Basement rocks of the Washington Volcanic Group (WVC) is s composed of three subgroups based on rock type: rhyolite, andesite, and meta-rhyolite. Rhyolite porphyries and their equivalent tuffs are by far the most common and widespread rock type. Andesite is restricted to an area in Craig and Ottawa Counties in Oklahoma and Labette and Cherokee Counties in Kansas and to a single well in Barry County, Missouri. The meta-rhyolites occupy a broad subsurface band essentially between normal rhyolite and other rock groups extending from western Pawnee County, Oklahoma, to Cherokee County in southeastern Kansas. Another small area of meta-rhyolite is found to the south around southern Sequoyah County, Oklahoma. Farquhar (1957) described andesitic volcanic rocks in Craig County, Oklahoma. Their reports suggest a more intermediate general character to volcanic rocks but the composition of the andesites is not typical of the rock group as a whole. The WVC Group is composed mostly of rhyolite porphyry, but andesite and meta-rhyolite are also included. The volcanic rocks underlie approximately 18,000 square miles. The thickness is not known but is undoubtedly substantial.

2.3.3.2 Mineralogy and Petrophysics of the Precambrian Basement

There is no core material available for Basement Rocks within the AoR; however, core is available from the Marland No. 1 Joynson well, located in Township 28 North Range 3 East, Section 18 in Kay County approximately 12 miles northwest of the site. The mineral and petrophysical properties of the basement rocks were described as follows:

METARHYOLITE PORPHYRY Groundmass, 79.0; microcline perthite, 18.5; quartz, 2.1; opaque minerals, 0.4; feldspar alterations, tr.; chlorite, tr.; apatite, tr.; epidote, tr.; biotite, tr. This is a meta-rhyolite porphyry in which former perthitic feldspar phenocrysts have been converted to microcline perthite. Areas of recrystallization vary. Perthites are present as faint relicts in the coarser reconstituted part. Relict spherulites also present along with apparent flow bands. Thin quartz veins present as well as linear coarsening. Quartz phenocrysts are euhedral. Small epidote crystals are in microcline. Chlorite and biotite (both secondary) are disseminated in groundmass. Groundmass and feldspars are surprisingly clear of disseminated hematite. Grain sizes 2+ mm maximum; microcrystalline average. Textures Granoblastic-relict perlitic-spherulitic and porphyritic. The rhyolite is considered the metamorphosed phase of the Washington Volcanic Group. The rock is a curious mixture of well-defined relict textures with strong reconstitution overprinted on the groundmass. The clearing of hematite from the groundmass is a sure sign of later thermal activity. The well is located about 11 miles due east of the granite in Ky-1 and this granite is interpreted as the agent for the metamorphism. (Denison, R.E., 1966).

A second well drilled by Spyglass Energy Group in 2012 drilled approximately 4,500’ of basement with a total depth of 8,067’. The Wha Zha Zhi, API 35-116-44568, is approximately 6.7 miles east of the NBU sequestration site in section 12-T27N R6E. Personal communication, Shane Matson, the test was looking for Helium in an igneous complex, well was completed as a dry hole. Additional information has been held confidential.

2.3.4 Injection Zone

The injection zone is defined as the geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive carbon dioxide through a well or

wells associated with a GS project. Ordovician-aged dolomites of the Arbuckle Formation contain the necessary characteristics to be an effective injection interval at the CapturePoint Solutions site. Although storage reservoirs within the Simpson Group were modeled, only the Arbuckle will be perforated. The injection zone has been designated as follows:
Injection Zone – Arbuckle Formation

2.3.4.1 Arbuckle Formation

The intended target formation for Carbon Sequestration at the NBU CSS site is the Arbuckle Formation. **Figure A-5** (from Derby 2012) illustrates the Great American Carbonate Bank that encircled the North American craton in early Ordovician time. The Arbuckle as regionally defined is found in the South-Central Plains states and was deposited in late Cambrian-middle Ordovician time. The Arbuckle carbonate section lies directly above the Reagan if present, otherwise with no Reagan, it sits directly on basement rocks. The Arbuckle is comprised mostly of dolomite and can be divided into members based on magnesium concentrations. It is the thickest sequence of lower Paleozoic strata throughout Oklahoma; however, it is noted that the Arbuckle thickness fluctuates throughout Osage County. In areas of basement highs, the Arbuckle can be absent; whereas, in other areas, such as western Osage County, it can have thicknesses of greater than 1,400 feet (Beckwith, 1928). Carbonate sediment was deposited in a shallow shelf setting. Equivalent lithostratigraphic units are the El Paso Group of southwestern Texas, the Ellenburger Group of central and north Texas, the Knox group of the eastern United States and the Beekmantown Group in the northeastern United States. In southern Oklahoma, stratigraphic units of the Arbuckle are the Fort Sill Limestone, Royer Dolomite, Signal Mountain Formation, Butterfly Dolomite, McKenie Hill Formation, Cool Creek Formation, Kindblade Formation, and West Spring Creek Formation (Ham, 1973). However, based on previous investigations, the Arbuckle Formation in northern Oklahoma is more comparable to the Arbuckle facies of the Ozarks, Appendix A, **Figure A-9**, adapted Fritz, 2012. The dolomite units in the Arbuckle are common reservoir rocks throughout Oklahoma for both oil and natural gas. The formation varies in color from white to brown and varies from dense to coarsely crystalline in texture (Beckwith, 1928). Appendix A **Figure A-16** illustrates the regional depositional setting on a broad and low relief platform that surrounded the south flank of the North American craton. Generally, the permeability is better developed in the subtidal facies. Sea level oscillations created numerous prograding carbonate sequences with major regional unconformities associated with eustatic drops in sea level and subsequent significant karsting occurring in the lower Arbuckle section and near the top of Arbuckle., Appendix A, **Figure A-17** Fritz, 2012, illustrates four paleo-topographic block models for different types for probable Arbuckle karsting. In the eastern Kay, eastern Noble, western Osage, Payne and Pawnee counties the lower Arbuckle is known for taking disposal fluids on a vacuum or near vacuum. Appendix A, **Figure A-18** (Fritz, 2012). Appendix A, **Figure A-19**, Adapted Denison ,1966, is a map of Precambrian structural features with 3-D seismic volumes in green that have been shot back to the mid 1990's. The Osage Tribe has specifically released the Antelope, Wild Creek and Grey Horse 3-Ds to Universities for study and publication. Excellent theses have been published from these 3-Ds on the Ordovician, Mississippian and Pennsylvanian stratigraphy for Osage as it relates to Northeast Oklahoma. For example, (Keeling, 2016) used the Wild Creek Survey in Osage County to identify where the major karsting events were occurring using negative amplitudes. His findings supported a major karsting event above the basement and localized karsting events within the middle Arbuckle. An additional thesis worth noting is (Jennings, 2014) Geomechanical Properties of the Mississippian Limestone. Jenning's data will be used with the proposed stratigraphic test well data for predicting and verifying Lower Mississippian seals.

Off of the NBU basement Platform to the east and southeast in Osage County the Precambrian igneous complex develops into pinnacle structures. In some cases, the lowermost Arbuckle beds, which were deposited on the shores of Precambrian islands, are rich in feldspar and quartz (Reeves et al., 1999). These units contain a large volume of granite fragments ranging from fine to coarse grains that were derived from the old Precambrian monadnocks (Reeves et al., 1999).

2.3.4.2 Formation Characteristics of the Arbuckle Formation

Milad, 2022 evaluated 988 wells with raster images and one cored well throughout Osage County, Oklahoma. Of the evaluated wells, 124 out of 988 wells were digitized, and some of them with broad log suites including GR, Resistivity, Bulk Density, Neutron Porosity, DT, and Sonic logs. Logged Arbuckle thickness ranges from 35 to 1,100 ft with an average of 303 ft. The 35 ft thickness of Arbuckle represents the minimum Arbuckle thickness found in Osage County. The entire Arbuckle in 41 out of 124 digitized wells have complete stratigraphic thickness of Arbuckle rocks with some depths into the Precambrian basement. The average porosity and thickness are 10 percent and 640 feet. The Arbuckle is affected by extensive karstic features, and solution-collapse brecciation developed, especially the lower Arbuckle and often near the upper part of Arbuckle during repeated subaerial exposure of a north-south trending marine system around the western flank of the Osage High, Appendix A, **Figure A-8,** (Liner 2015).

2.3.4.3 Mineralogy and Petrophysics of the Arbuckle Formation

According to Milad, et.al. (2018) the presence of karst features in Arbuckle Formation of Osage County may provide a significant amount of porosity and permeability. Also, average porosity and thickness for Arbuckle are 10 percent and 640 ft, respectively. In their study, the predominate lithology from both core and PE (photoelectric) log interpretation was crystalline dolomite. Karst features were clearly observed adding to the potential storage capacity of the Arbuckle reservoir. The average for total porosity calculated from available logs located in Osage County was 11.4 percent, and the arithmetic mean of total porosity from cores in the region was 7.5 percent. Subsequent data for mapping yielded porosities ranging from 3 to 29 percent with a mean of 10 percent. Permeabilities ranged from 0.0001 mD to 1,000 mD. Water saturations within the Arbuckle are highly variable both laterally and vertically. (Morgan and Murray, 2015), characterized small scale permeability on 4 cored, dominantly Upper Arbuckle wells with additional data from middle and Lower Arbuckle outcrops in the Slick Hills of southwestern Oklahoma and Arbuckle Mountain of south-central Oklahoma. Their findings based on these core and outcrop measurements were presumably where the Arbuckle takes high volume injection these intervals must include fractured or karsted sections that must have significant orders of higher magnitude permeabilities. For example, TetraTech modeled permeabilities in a 250’ Arbuckle interval at 40,000 BWPD required permeabilities to be near a Darcy per vertical foot.

Data from nearby trials, Wellington Field, Kansas:

Porosity: Core analysis from wells located in the Wellington Field trial 55 miles to the northwest showed the Arbuckle to be a triple-porosity system of interparticle, fracture, and vuggy pores. Typically, fracture porosity in carbonates is small in volume (1 to 2 percent) and very difficult to discriminate, as contrasted with vuggy porosity, whose evaluation shows distinctive differences between core and logs. The researchers at Wellington found zones with minimal vuggy porosity where there is good agreement between core and logged porosity. In sections with significant vuggy porosity, MRI-based effective porosity is usually greater than core porosity. They also found that the most reliable estimator of effective porosity that includes both interparticle and vuggy porosity is the MRI log. In vuggy zones, core porosity, matrix measurements are biased toward low values. In conclusion, effective porosity from the MRI log was used as the porosity deliverable to other evaluation modules. Porosity variations ranged from 1 to 12 percent (core), 3 to 18 percent calculated.

Permeability: Pore structure in the Arbuckle is very complex and there are many variations in pore size distribution (unimodal, bimodal and trimodal) versus depth in very short intervals. Due to this complexity and non-homogeneity in pore size distribution, for modeling purposes, the Arbuckle permeability was calculated based on pore size classification (micro, meso, and mega pores). Pore size classes were correlated to 1/(Swir*Phi) of the same class. Permeability was calculated based on correlations between pore size classes from core and 1/(Swir*phi) from log. Pore size classes from core data were calculated using K90 permeability, and 1/(swir*phi) was calculated using effective porosity and irreducible water saturation from the NMR log. FZI (flow zone indicator) and 1/(swir*phi) values were sorted from low to high. All FZI values less than 2 and 1/(swir*phi) values less than 48 were assigned for micro pore sizes, which correspond to permeability values less 0.5 milliDarcy (mD). FZI from 2 to 11 and 1/(swir*phi) from 48 to 106 were considered for meso pore sizes, which correspond to permeability from about 0.5 to 25 mD, and FZI from 11 to 150 and 1/(swir*phi) from 106 to 851 were considered for mega pore sizes, which correspond to permeability greater than 25 mD. Watney, 2012 and 2017 Final Report have excellent results and recommendations on the effectiveness of CO_2 storage in the Arbuckle Formation in southcentral Kansas. This KGS DOE funded study will be used in collaboration with stratigraphic test data taken in Osage County, (Holubnyak, 2016).

2.3.4.4 Expected Zone Capacity of the Arbuckle Formation

The expected storage capacity of the Arbuckle Formation for the proposed CCS project is approximately 90 million metric tonnes. This volume was determined from the overall thickness of the injection zone, average porosity and residual fluid saturation values, and the aerial extent of the plume based on modeled parameters. Although the available storage capacity is estimated to be 90 million metric tonnes, the estimated injected volume of the CO_2 over the life of the project (~20 years) is expected to be approximately 11 million metric tonnes.

2.4 Hydrogeology

The primary regulatory focus of the USEPA injection well program is protection of human health and the environment, including protection of potential underground sources of drinking water (USDWs). The Underground Source of Drinking Water (USDW) is defined by the EPA as an aquifer which supplies any public water system and contains fewer than 10,000 mg/l total dissolved solids (TDS). The following sections detail regional and local hydrogeology and hydrostratigraphy. [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

2.4.1 Regional Hydrogeology

According to information from the Oklahoma Water Resource Board (https://www.owrb.ok.gov/maps/data.php) the location of the proposed NBU CCS CO_2 sequestration site is not located below any defined freshwater aquifers (**Figure 2-13**). West of the proposed sequestration site is the North-Central Oklahoma aquifer system which is considered to be a major groundwater basin. To the east of the site is the Vamoosa-Ada major groundwater basin. Further information from the Oklahoma Water Resource Board indicates there are 123,742 groundwater wells that are located in Oklahoma. Four of these wells are located within the AoR of the proposed sequestration site. The classification of these wells includes one industrial water supply well, one irrigation well and three domestic water supply wells. Although there are no designated fresh groundwater aquifers within the AoR for the proposed sequestration site and yet there are 3 reported domestic water supply wells, it is suspected that water produced from these wells is of poor quality and is not used for fresh drinking water.

Currently there are 55,027 groundwater monitoring wells in Oklahoma according to the Oklahoma Water Resource Board (**Figure 2-14**). Of these wells, 67 are located within the AoR of the proposed sequestration site. These monitoring wells target the Oscar and Vanoss bedrock aquifers as part of tertiary oil recovery operations at the North Burbank oil field in Osage County.

With respect to defined hydrologic units (HUCs) in Osage and Kay counties, the proposed sequestration site is located at the boundary of the Kaw Lake HUC located to the west and Black Bear – Red Rock HUC to the east (**Figure 2-15**). This figure illustrates that the proposed injection site is located at the crest that separates these two hydrologic units.

In order to assess water supply for residents of the state, a comprehensive water plan in Oklahoma was developed. The Oklahoma Comprehensive Water Plan (OCWP) was originally developed in 1980, modified in 1995, then more recently updated in 2012. With the specific objective of establishing a reliable supply of water for State users throughout at least the next 50 years. The latest version represents the most ambitious and intensive water planning effort ever undertaken by the State. The *2012 OCWP Update* is guided by two ultimate goals:

1. Provide safe and dependable water supply for all Oklahomans while improving the economy and protecting the environment.
2. Provide information so that water providers, policy makers, and water users can make informed decisions concerning the use and management of Oklahoma's water resources.

This new strategy involved dividing the state into 82 surface water basins (**Figure 2-16**) for water supply availability analysis (see the OCWP *Physical Water Supply Availability Report*). Existing watershed boundaries were revised to include a United States Geological Survey (USGS) stream gage at or near the basin outlet (downstream boundary), where practical. The CapturePoint proposed NBU CCS site is located within the Upper Arkansas Planning Region in the Arkansas River Mainstem Water Plan Basin (Water Plan Basin Number 72). The largest cities in the planning region include Enid (2010 population 49,379), Stillwater (45,688), Ponca City (25,387), Blackwell (7,092), and Cushing (7,826). The greatest demand is from Municipal and Industrial and Thermoelectric water use. By 2060, this region is projected to have a total demand of 182,770 acre-feet per year (AFY), an increase of approximately 54,200 AFY (42 percent) from 2010.

The CapturePoint proposed CCS site is located within the Upper Arkansas Watershed Planning Region. This region includes seven basins (numbered 63 and 67-72) the CapturePoint CCS site is located in Basin 72. The Upper Arkansas region encompasses 7,452 square miles in northern Oklahoma, spanning from the northeast portion of Woods County to the northwest portion of Creek County. It also includes all or portions of Alfalfa, Grant, Kay, Osage, Garfield, Noble, Pawnee, Kingfisher, Logan, Payne, Tulsa, and Lincoln counties.

The Upper Arkansas region is located primarily in the Central Lowland physiography province. The terrain is dominated by broad, level-to-slightly rolling plains, with rougher, broken plains in the southern area of the region and transitioning to the rolling hills, ridges, and steep-sided valleys of the Flint Hills to the east. This region is a mix of cropland and rangeland, with mixed prairie grasses giving way to densely forested bottomland in the east. Incised stream valleys have down cut into underlying sedimentary rock units of Pennsylvanian through Permian age. Cattle ranching and petroleum and natural-gas extraction are the principal land uses in this rural area.

Due to the extreme variability of streamflow because of precipitation, weather events have a significant impact in this area. The climate is moist and sub-humid with the mean annual temperature of around 60°F. Annual average precipitation ranges from 24 inches in the northwest to 42 inches in the east. Rainfall peaks in the spring and fall, with May being the wettest month of the year. Annual evaporation ranges from 62 inches in the west to 55 inches in the east and often exceeds precipitation on an annual basis. Frequent droughts cause severe crop damage, but severe flooding can also occur as the result of heavy rainfall events. Thunderstorms accompanied by high winds, hail, and heavy rain increase the likelihood of flash flooding, emphasizing the necessity of watershed protection and flood prevention projects.

Freshwater resources in Osage County include water flowing in the Arkansas River and several smaller streams, water stored in several lakes, and groundwater contained in unconsolidated alluvial aquifers and bedrock aquifers. Per the 2012 Upper Arkansas Watershed Planning Region report, the Upper Arkansas Watershed Planning Region relies primarily on surface water supplies, and to a lesser extent, bedrock groundwater and alluvial aquifers, this is in contrast with other regions around the area and state which rely more heavily on bedrock aquifers. Where needed, the Vamoosa-Ada bedrock aquifer is the primary source of fresh groundwater in areas relying on bedrock aquifers. Fresh groundwater is underlain by saline groundwater in aquifers underlying the area. Total fresh surface-water withdrawals (use) and fresh groundwater withdrawals in the Osage County were estimated to have increased from 0.75 to 16.19 million gallons per day (surface water) and from 0.13 to 2.39 million gallons per day (groundwater), respectively, over the period from 1890 through 2010. It is anticipated that water users in the region will continue to rely on these sources to meet future demand. Groundwater storage depletions may lead to higher pumping costs, the need for deeper wells, and changes in well yields or water quality in same basins. To reduce the risk of adverse impacts on water supplies, it was recommended that surface water gaps and groundwater storage depletions be decreased where economically feasible. Additional conservation could reduce surface water gaps, alluvial groundwater storage depletions and bedrock groundwater storage depletions. Aquifer recharge and recovery could be considered to store variable surface water supplies, increased alluvial or bedrock groundwater storage, and reduce adverse effects of localized storage depletions in Basins 63 and 68. Surface water alternatives, such as groundwater supplies and/or developing small new reservoirs, could mitigate gaps without major impacts to groundwater storage.

The Upper Arkansas Watershed Planning Region Report Version 1.1 of 2012 identified 11 different aquifers within the Upper Arkansas Region. Two major bedrock aquifers, the Garber- Wellington and Vamoosa-Ada, and four major alluvial aquifers, Arkansas River, Cimarron River, Enid Isolated Terrace, and Salt Fork of the Arkansas River, underlie the Upper Arkansas Watershed Planning Region. In 2012, current water demand was 128,570 acre-feet/year or 7 percent of the Oklahoma state total. The largest demand sector was Municipal and Industrial, making up 37 percent of the regional demand. In 2012 water supply source was delivered by 69 percent Surface Waters, 24 percent Alluvial Groundwater, and 7 percent Bedrock Groundwater. Water usage for this region is projected to grow by 42 percent by 2060.

Surface Water

Surface water is used to meet about 69 percent of the region’s demand. The region is supplied by three major rivers: the Arkansas, Cimarron, and Salt Fork of the Arkansas. Historically, the region’s rivers and creeks have periods of low to no flow in any month of the year due to seasonal and long-term trends in precipitation. Large reservoirs have been built on several rivers and their tributaries to provide public water supply, flood control, power generation, and recreation. Large reservoirs in the Upper Arkansas Region include Keystone, Kaw, Sooner, Carl Blackwell, and Great Salt Plains. There are ten additional municipal lakes that have normal pools ranging from 1,795 to 19,733 acre-feet (AF).

Relative to other regions, surface water quality in the region is considered poor to fair. Multiple rivers, creeks, and lakes are impaired for Agricultural use (Crop Irrigation demand sector) and Public and Private Water Supply (Municipal and Industrial demand sector) due to high levels of total dissolved solids (TDS), chloride, sulfate and chlorophyll-a. These impairments are scheduled to be addressed through the Total Maximum Daily Loads (TMDL) process, but use of these supplies may be limited in the interim.

Alluvial Groundwater

Alluvial groundwater is used to meet 24 percent of the demand in the region. The majority of currently permitted withdrawals are from the Arkansas River and the Salt Fork of the Arkansas River aquifers. If alluvial groundwater continues to supply a similar portion of demand in the future, storage depletions are likely to occur throughout the year, although these projected depletions will be small relative to the amount of water in storage. The largest storage depletions are projected to occur in the summer. The availability of permits is not expected to constrain the use of alluvial groundwater supplies to meet local demand through 2060.

Groundwater

Groundwater is used to meet 7 percent of the demand in the region. Existing permitted wells and projected withdrawals are primarily from the Vamoosa-Ada aquifer, east of the proposed carbon capture site and North -Central Oklahoma minor aquifer. Outcropping to the east of the proposed CCS site, the Vamoosa-Ada has about 3.6 million AF of groundwater storage in the region. Beginning in 2020, aquifer storage depletions are likely to occur throughout the year in Basin 68 but will be largest in the summer months when there is less rain for aquifer recharge. By 2060, aquifer depletions will occur during the summer in Basin 72. These groundwater withdrawals are expected to be from the North-Central Oklahoma minor aquifer, which may be limited by low well yields. The availability of permits is not expected to constrain the use of groundwater supplies to meet local demand through 2060.

At the time of the State of Oklahoma report in 2012, Basin 72 accounted for about 48 percent of the current water demand in the Upper Arkansas Watershed Planning Region. About 62 percent of the demand is from the Thermoelectric demand sector. Self-Supplied Industrial (19 percent) is the second-largest demand sector. Surface water satisfies about 85 percent of the current demand in the basin. Groundwater satisfies about 15 percent of the current demand (13 percent alluvial and 2 percent bedrock). The peak summer month demand in Basin 72 is 1.2 times the winter demand, which is less pronounced than the overall statewide pattern.

Due to concern of the potential effects of early and oil-industry activities of surface disposal of produced-brine, in 1999, the United States Geological Society (USGS) in cooperation with the Osage Tribal Council and the United States Department of Energy (USDOE) and the Bureau of Indian Affairs (BoIA) completed a Surface-Water Characterization and Quality report for the Osage Reservation, Osage County, Oklahoma. By 1999, nearly 38,000 oil wells have been drilled in the Osage Reservation since drilling began in 1896. About 17,600 oil wells were drilled before 1940 (Bass et al., 1942) and 3,200 of these were dry and abandoned. In 1988 about 12,680 oil wells were actively operated and 4,200 of these were classified as pressure maintenance, salt-water disposal, or waterflood injection wells. The remaining oil wells (about 26,000) are temporarily or permanently plugged and abandoned. An early industry practice was to hold produced brine in surface pits. This was not allowed in the reservation after the late 1940s or early 1950s (Paul Yates, Bureau of Indian Affairs, Osage Agency, oral communication., 2000). Environmental problems with surface disposal of produced brine prompted a change to underground injection of the brine.

The report divided the Osage Reservation, Osage County, into three major drainage basins: the Caney River Basin is in the northeast, the Bird Creek Basin is in the southeast, and the Salt Creek Basin in the west. The proposed CCS site is located nearest to the Salt Creek Basin which flows into the Arkansas River. The report focused on concentrations of chloride found in surface and ground water within the Reservation. The report found that historical surface-water data indicate relatively large concentrations of chloride that occurred on the reservation at least locally in the 1950s and 1960s. A few surface-water samples had relatively large chloride concentrations in 1999 but these conditions do not appear to be regionally prevalent.

2.4.1.1 Arkansas River Alluvial Aquifer

The Arkansas River Alluvial Aquifer is the most important aquifer located southwest of the proposed CCS project site. Terrace deposits with surfaces ranging from 20 to 120 feet above the floodplain border the alluvium in segments on both sides of the Arkansas River. The deposits are composed mainly of silt, fine sand, and small amounts of coarse sand and gravel near the base. The terrace deposits yield small to moderate supplies of water. The alluvium is the most important aquifer along the Arkansas River. It is formed in segments 1 to 3 miles wide and 3 to 11 miles long. The total thickness averages 42 feet and the saturated thickness averages 25 feet.

Recharge occurs from precipitation. Natural discharge is from seepage into streams and by evapotranspiration. In large areas that are potentially favorable for development, groundwater wells will yield as much as 600 gallons per minute (gpm). The quality of the water is suitable for irrigation and for domestic, stock and limited industrial purposes without treatment. It is important to note that this aquifer and any recharge to this aquifer is not present within the AoR.

2.4.1.2 Cimarron River Alluvial Aquifer

The Cimarron River alluvial aquifer located southwest of the proposed CCS site, is a free-flowing river and is a major source of water as it flows across Oklahoma. Increased demand for water resources within the Cimarron River alluvial aquifer in north-central Oklahoma (primarily in Payne County) has led to increases in groundwater withdrawals for agriculture, public, irrigation, industrial and domestic supply purposes. The Quaternary-age deposits consist of alluvium and terrace deposits and dune sand. These deposits unconformably overlie the Permian-age geologic units. The alluvium deposits result from repeated cycles of river erosion and redeposition of detrital sediments (Reed et al., 1952). The terrace deposits are composed of interlayered lenses of clay, sand, and poorly sorted sand and gravel (Shelton and Noble, 1974). These deposits were laid down by the ancestral Cimarron River as it traveled southwesterly down the regional dip of the underlying Permian-age units (Reed et al., 1952). Thicknesses of the terrace deposits range from 0 to 120 feet. Variations of thickness occur as a result of erosional features in the underlying Permian-age beds and deposition and erosion of terrace deposits (Reed et al., 1952). The deposits consist primarily of sand, gravel, silt, and clay. The most extensive hydrologic boundary of the Cimarron River alluvial aquifer is the land surface. This boundary facilitates recharge to the aquifer. The base of the Cimarron River alluvial aquifer influences groundwater flow to the Cimarron River and affects inter-aquifer groundwater exchange. In some locations, lateral flow from other aquifers enters the Cimarron River alluvial aquifer along its boundaries. The Garber-Wellington aquifer contacts the Cimarron River alluvial aquifer along the southern boundary (Mashburn and Magers, 2011). For the Cimarron River alluvial aquifer lateral flow also enters the aquifer from the western boundary and exits the aquifer from the eastern boundary. The estimated groundwater withdrawal rates totaled 2,956 AF per year for the Cimarron River alluvial aquifer model extent for the period 2016-2018. (Pazis et al., 2018).

2.4.1.3 Enid Isolated Terrace Alluvial Aquifer

The Enid Isolated Terrace Aquifer is located in north-central Oklahoma in the western half of Garfield County with a small portion in Alfalfa County southwest of the CCS site. The aquifer consists of Quaternary-age alluvial and terrace deposits that are underlain by Permian-age clays, shales, and sandstones (Correll et al., 2014). The Enid Isolated Terrace aquifer extent generally follows surficial geology. The Quaternary-age deposits that comprise the Enid Isolated Terrace aquifer are divided into two geologic units: alluvium and terrace (Stanley et al., 2002; Stanley et al., 2008). Terraces in the area were deposited by the Cimarron River, which now occupies a valley at a lower elevation to the south because of its meandering nature. Fluvial processes during more recent times reworked the terrace deposits to form the alluvium deposits in and around stream beds. The alluvium deposits are described as unconsolidated clay, silt, sand, and gravel with a thickness of up to 80 feet (Stanley et al., 2002; Stanley et al., 2008). Some terrace deposits have been reworked into dune sand through eolian processes and consist of fine-grained to very fine- grained unconsolidated sand from older alluvium and terrace deposits (Stanley et al., 2002; Stanley et al., 2008). The terrace deposits are the oldest Quaternary-age deposits and are composed of silt, sand, and gravel with a maximum thickness of 75 feet along major streams (Bingham and Bergman, 1980). Permian-age units surround and unconformably underlie these Quaternary-age deposits.

Groundwater in the terrace deposits is unconfined, flowing generally from northwest to southeast. A lateral boundary is created where the alluvium and terrace deposits meet in the area with most of the Permian units contributing little to no water. Vertical hydrologic connectivity between the groundwater in the terrace deposits and the underlying Permian-age units has not been defined. Well log data indicate Permian-age units located beneath the aquifer are not transmissive enough to contribute substantial volumes of water to the Enid Isolated Terrace aquifer. The thickest terrace deposits are 80 feet thick and occur to the southwest of the proposed injection site near the City of Enid.

Saturated thickness of the Enid Isolated Terrace was estimated by subtracting the base elevation from the potentiometric surface elevation. The mean saturated thickness within the area was estimated to be ~15 feet. The area of greatest saturated thickness was to the north and northwest of the City of Enid in the vicinity of U.S. Highway 81 with a saturated thickness value of 65 feet.

Annual groundwater use data were reported by 64 permitted users of water from the area for the period of record, 1967–2013. Mean annual groundwater use for the period of record was 3,243 acre-feet (AF) per year with a maximum annual groundwater use of 4,882 AF in 2011 and a minimum annual groundwater use of 1,434 AF in 1996. Recharge for the Enid Isolated Terrace occurs from infiltration of precipitation.

2.4.1.4 Salt Fork of the Arkansas River Alluvial Aquifer

The Alluvium and Terrace Aquifer of the Salt Fork of the Arkansas River, located west of the proposed CCS site, is a freshwater aquifer used for agricultural, municipal, and domestic purposes. Surface water in the area flows over salt formations and is saline. The area consists of gently rolling prairie plains dissected and drained by the Salt Fork and its tributaries. The major tributaries include the Chikaskia and Medicine Lodge Rivers, Deer, Polecat, Bois d' Arc, Sand, Sandy, Pond, Crooked, and Driftwood Creeks. Water wells located close to the river or other saline surface water are sensitive to induced infiltration from pumping.

The alluvium and terrace deposits of the Salt Fork of the Arkansas River are of Quaternary age, and are comprised of gravel, silty sand, and clay. Dune sands are present in parts of the area. The deposits are quite broad in Alfalfa County, blanketing a large portion of the county and beyond into Kansas. In that county these sand deposits extend south from the Kansas border to a distance of 23 miles. From western Grant on to Kay and Noble Counties the deposits narrow and primarily follow the river where they range from one to five miles in width. The bedrock formations underlying the Quaternary alluvial and terrace deposits are primarily siltstones and shales of Permian age. The water table maps indicate that the alluvial and terrace deposits of the Salt Fork of the Arkansas River consist of two hydrologically separate groundwater basins. There is a groundwater divide on the eastern edge of the Great Salt Plains reservoir where the hills provide the eastern limits of the reservoir. This divide coincides closely with the Alfalfa - Grant County line. One groundwater basin is in Alfalfa County and the other in Grant, Kay and Noble Counties.

The total saturated thickness ranges from a few feet to 110 feet. Surface water quality is generally good in the tributaries to the Salt Fork of the Arkansas River. The Great Salt Plains Reservoir is saline and discharges from this reservoir are the major source of chloride in the river water. In Alfalfa County, groundwater is affected by saline discharges from the bedrock, especially in the vicinity of the Great Salt Plains Reservoir. In areas where the piezometric surface is above the top of the bedrock, saline water moves upward and mixes with otherwise fresh water of the overlying alluvial and terrace deposits. Groundwater discharges to streams in these areas of upward moving water, making the streams saline. Other areas of the County, upgradient of the discharges, have good quality water.

2.4.1.5 Chikaskia Alluvial Aquifer

The Chikaskia Alluvial Aquifer is designated as a minor aquifer by the Oklahoma Water Resources Board and is found west of the proposed CCS site. A minor groundwater basin is defined as a distinct underground body of water overlain by contiguous land and having substantially the same geological and hydrological characteristics and from which the groundwater wells yield less than 50 gallons per minute if in a structural basin and less than 150 gallons per minute if from an alluvial and terrace. The alluvial and terrace deposits associated with the lower reach of the Chikaskia River constitute a minor alluvial groundwater basin. This basin lies entirely within the confines of Kay County.

The Chikaskia River enters Oklahoma from Kansas in far northeastern Grant County. The Chikaskia flows primarily in a south-southeast direction crossing into Kay County a few miles south of the Kansas-Oklahoma border. It follows this general direction until its confluence with the Salt Fork of the Arkansas River, a total distance of about 32 miles. From this junction, approximately 11 miles east, the Salt Fork of the Arkansas joins the Arkansas River. Both fluvial and marine deposits comprise the sandstone, shale and limestone in this unit.

The Chikaskia depositional environment shifted back and forth between river, delta, and shallow sea. Fluvial sediments (sand, silt and clay) were eroded form low lying areas in northeastern Oklahoma and eastern Kansas and transported by westward flowing streams which deposited their sediments into a large inland sea whose shoreline was in proximity to the area. At other times, precipitation and deposition of marine (limestone) deposits occurred in the shallow sea environment. In Grant County, as a result of extended periods of evaporation of saline sea water, significant beds of rock salt and gypsum were precipitated which occur at depths ranging from 500 to 1,500 feet (Johnson, 1985).

This aquifer comprises approximately 33 square miles (21,500 acres) of Quaternary alluvium and terrace deposits that occur as channel and flood plain deposits and overlie the Permian Wellington Formation. These unconsolidated deposits consist of silt, clay, and fine sand with coarse sand and gravel at the base in places. Based on reported well yields and a review of drillers logs, this gravel is not always present or is thin along portions of this reach of river whereas northward from the city of Blackwell, coarse sand & gravel associated with the alluvium is more prevalent where higher yields have been reported (Bingham and Bergman, 1980). This aquifer occurs along the northern boundary and begins approximately 3 miles north-northwest of the city of Blackwell and terminates approximately 2 miles above the confluence of the Chikaskia, Salt Fork and Arkansas Rivers. The distance between these two points is approximately 13 miles. Along this reach of the Chikaskia, the alluvium forms a band on either side of the river reaching a maximum width of about 3 miles and averaging about 2 miles across. This basin resides only within Kay County.

For unconfined aquifers like the Chikaskia, the storage coefficient and specific yield are nearly equivalent. Specific yield for clay, silt, sand and gravel ranges from 1 percent for clay to 30 percent for gravel (Walton, 1970). Specific yield for other alluvial and terrace aquifers in Oklahoma has been estimated to range from 15-20 percent. Bingham and Bergman (1980) infer from their reporting of potential well yields that along this lower reach of the Chikaskia, the basal gravel is thin or sometimes absent and that the aquifer contains a higher proportion of fines than the upper reach of the Chikaskia. The specific yield of this unit is determined to be 15 percent. The alluvium in this unit may be as much as 60 feet thick (Bingham and Bergman, 1980), but review of well records indicates the average thickness to be 44 feet. From well records, the average depth to water in is determined to be 22 feet. The average saturated thickness of this unit is 22 feet corresponding to the difference between the average thickness (44 feet) and average depth to water (22 feet). Based on the limited information regarding the relative proportions of clay, silt, sand and in some cases gravel, the hydraulic conductivity (K) is estimated from Freeze and Cherry (1979). For these types of sediments, K can range from 1,000 feet/day for fine gravel and 7 to 10 feet/day for un-weathered clay. Hydraulic Conductivity is estimated at 100 feet/day with sand, silt, and clay being the majority sediment types comprising the unit. Transmissivity, a product of hydraulic conductivity and saturated thickness is 2,200 square feet per day. The recharge rate is estimated at 15 percent of the mean annual precipitation of the areas of Garfield, Grant and Kay counties or 4.5 inches per year. The estimate for the Chikaskia is correlated to Reed's (1952) recharge rate for the Cimarron Terrace Aquifer located west of the carbon capture area. Bingham and Bergman (1980) reported that recharge to other terrace and alluvium deposits within the Enid quadrangle may be about the same because the surface soils are sandy and capable of absorbing large amounts of water and because the lithologies of the aquifers are similar.

In north-central Oklahoma, chemical characteristics of the groundwater differ considerably within short distances. Groundwater in the Upper Arkansas Groundwater Basin can be characterized as a sodium-calcium-magnesium bicarbonate type with many variations in water type (Bingham and Bergman, 1980). In most places, the water is hard (121-180 mg/1) to very hard (> 180 mg/1 hardness). Reported concentrations of total dissolved solids (TDS) range from 429 to 6080 mg/1 (Bingham and Bergman, 1980). In Kay County, the groundwater underlying the area contained within Townships 26N to 29N, and Ranges 2WIM-2EIM typically have TDS greater than 1,000 mg/1. This area is mostly underlain by the Permian Wellington Formation as well as the alluvium and terrace deposits of the Chikaskia River (Bingham and Bergman, 1980). Thicker, bedded, evaporite deposits occur at depth in Grant County such as the Cimarron and Wellington evaporites (McMahan, 1977). The presence of these relatively minor amounts of gypsum and halite in the upper Permian are the likely source of the high TDS, sulfate and locally high chloride.

The quality of the groundwater in the Chikaskia is probably suitable for most beneficial uses except in localized areas. The Town of Tonkawa obtains its water supply from this unit and as described in the general discussion, dissolved solids, sulfate, and hardness are the most problematic aspects of their water supply. Because of the hardness and amount of dissolved solids in the groundwater, water softening units and some filtration may be required to reduce scale build-up on piping and to improve the palatability of the water.

2.4.1.6 Garber-Wellington Bedrock Aquifer

The Garber-Wellington Aquifer is a major sandstone aquifer in Central Oklahoma and is located in Logan and Cleveland counties. It is located south, southwest of the proposed CCS site. It is part of a larger unit called the Central Oklahoma Aquifer, which includes a geologic unit called the Oscar Formation in Lincoln and Pottawatomie counties. Also referred to as part of the Central Oklahoma Aquifer System, it is comprised primarily of rocks from the Lower Permian-age Garber Sandstone and Wellington Formations (Simpson, 1973). The total thickness of the combined formations is about 1,000 feet. Depth to water varies from less than 100 feet to 350 feet; saturated thickness ranges from 150 to 650 feet. Non-domestic wells completed in the aquifer can yield as much as 600 gallons per minute (gpm) but generally yield from 200 to 400 gpm.

Water from the aquifer is normally suitable for public water supply but in some areas the concentrations of nitrate, arsenic, chromium, uranium, and selenium may exceed drinking water standards. Elevated concentrations of nitrate occur in shallow water which can be a concern for domestic well users. Elevated concentrations of arsenic, chromium, and selenium occur in deep parts of the aquifer, which mostly affects public supply wells. The highest concentrations of arsenic tend to occur in the western portion of the aquifer, where it is overlain by the younger Hennessey Group.

The Garber-Wellington aquifer is an important source of domestic and public water supply. The aquifer is overlain in places by alluvial aquifers along the North Canadian and Canadian Rivers. Water is available from both aquifers. With the exception of Oklahoma City, all the major communities in central Oklahoma rely either solely or partly on groundwater from the Garber-Wellington (Oklahoma Water Resource Board, 2012).

The rocks that contain the Garber-Wellington aquifer lie in a north-northwest trending group of Permian age formations that include the Wellington Formation and the Garber Sandstone. The formations dip westward at 30 to 40 feet per mile (less than 0.5 degrees per mile). The result of this orientation is on the east side of Oklahoma County the unit is exposed on the surface but on the west side of the county the unit is nearly 400 below the Hennessey Shale. This geometry defines many important aspects of the aquifer, including well yields and water quality. The aquifer consists of about 900 feet of interbedded sandstone, shale, and siltstone and traces of carbonates. Sandstone comprises 35 to 75 percent of the aquifer and averages about 50 percent. Overlying the Garber Sandstone is the Hennessey Shale.

There are major sandstone channel fill deposits and associated levee and splay deposits off the main channels. These channels are associated with inter-channels filled with shale. Freshwater carbonates formed most likely as caliche in the arid environment of the Lower Permian (McBride, 1978). These caliche beds were reworked in pebble conglomerates in the base of the fluvial sediments. The sands are fairly uniform and very fine. These rock formations extend well beyond Central Oklahoma but contain almost no fresh water due to the fact that it is only in central Oklahoma that significant amounts of sand occur in the Garber Sandstone and the Wellington Formation.

Water-table conditions generally exist in the upper 200 feet in the outcrop area of the aquifer; semi-artesian or artesian conditions exist below a depth of 200 feet and beneath rocks of the Hennessey Group (predominantly shale) where the aquifer is fully saturated. Productive water sandstones have a measured porosity range from 25 to 35 percent and transmissivity from 5,000 to 8,000 gallons per day per foot (gpd/ft). In examining deep (> 600 feet) Garber-Wellington wells, in non-depleted areas one can expect to get 1.2 to 1.7 gallons per foot of aquifer exposed in the well bore. There are few impurities in this terrestrial clastic system. There are a few rare hematite deposits where iron appears to have concentrated along weathering zones, and even rarer dolomite deposits, which could have been caliche, deposited in the same environment.

2.4.1.7 Vamoosa-Ada Bedrock Aquifer

The Vamoosa-Ada aquifer, located east of the proposed CCS site is an important source of water that underlies about 2,320 square miles of parts of Osage, Pawnee, Payne, Creek, Lincoln, Okfuskee, and Seminole Counties. The Vamoosa-Ada aquifer is the most productive aquifer in Osage County. The aquifer underlies about one third of the Upper Arkansas Region in eastern portions of Basins 71 and 72 in the far southeastern portion of the Upper Arkansas Region (**Figure 2-16**). The aquifer consists principally of the Late Pennsylvanian age Vamoosa Formation and the overlying (and in hydrologic connection) Ada Group also of Pennsylvanian age. The western boundary of the confined Vamoosa-Ada aquifer is defined by the occurrence of 1,500 mg/L dissolved solids (D'Lugosz et al., 1986) is three times the secondary drinking-water standard (U.S. Environmental Protection Agency 40 CFR 143 Subpart A). The highest yields are in Creek County where some sandstone beds are coarse-grained. Rocks comprising the aquifer were deposited in a nearshore environment ranging from marine on the west to nonmarine on the east. Because of changes in depositional environments with time and from place to place, the aquifer is a complex sequence of fine- to very fine-grained sandstone, siltstone, conglomerates, and shale, with interbedded very thin limestones.

Several sub-environments can be differentiated on the basis of geometry, distribution, and lithology of the sandstone units (Terrell, 1972). The more significant sub-environments, hydrologically include: (1) stream channel and near channel, (2) distributary channel, (3) deltaic, and (4) delta fringe and shallow marine. Individual sandstone units are either thin bedded or lenticular. Although both types are fine grained and well sorted, thin-bedded units generally are finer grained and less well sorted. Thin-bedded sandstones are 1 to 5 feet thick and are laterally extensive. Maximum grain diameters are 0.167 to 0.30 millimeters (mm), median diameters are 0.084 to 0.170 mm, and mean diameters are 0.095 to 0.171 mm (Terrell, 1972). These sands probably were deposited in the delta-fringe-shallow-marine environment. Lenticular sandstones are 5 to 30 feet thick and are 10 to 600 feet wide. These units are characterized by an overall upward decrease in grain size. Maximum grain diameters are 0.170 to 0.405 mm, median diameters are 0.091 to 0.240 mm, and mean diameters are 0.101 to 0.225 mm (Terrell, 1972). The lenticular sandstones have well-defined upper, lower, and lateral contacts. These sandstones probably represent distributary, channel, or near-channel deposits. The aggregate thickness of water-bearing sandstones is greatest south of the Cimarron River, where it reaches a maximum of 550 feet in the vicinity of Seminole. North of the Cimarron River, the average aggregate thickness of the sandstones is about 100 feet, but locally it may be as much as 200 feet.

The water-yielding capabilities of the aquifer are generally controlled by lateral and vertical distribution of the sandstone beds and their physical characteristics which are in turn related to the environments of deposition. Studies by Terrell (1972) show that lenticular sandstones have a preferred direction of grain orientation. Measurements of these sandstones show that maximum horizontal permeability is parallel to the preferred direction of grain orientation and that horizontal permeability is 18 percent greater than vertical permeability. Thin bedded sandstones do not display this preferred direction of permeability. The flow of groundwater through the rocks is also controlled by variations in permeability related to changes in lithology, sandstone thickness, and faulting (D'Lugosz et al., 1986). Transmissivity values derived from seven aquifer tests made for this study ranged from 70 to 490 square feet per day; values decrease from south to north with decreasing sandstone thickness. Hydraulic-conductivity values range from 2 to 4 feet per day. Storage coefficients for the confined part of the aquifer, as determined from four aquifer tests made during 1944, have an average value of 0.0002. The average storage coefficient for the unconfined part of the aquifer is estimated at 0.12, based on an analysis of geophysical logs and grain-size data. The specific capacity of wells tested is generally less than 1 gallon per minute per foot of drawdown. An approximate hydrologic budget for the aquifer for 1975 gives values, in AF per year, of 93,000 for recharge, 233,000 for runoff, and 2,003,000 for evapotranspiration. The total of these values is almost equal to the average annual precipitation of 2,330,000 acre-ft per year. The estimated amount of water containing a maximum of 1,500 milligrams per liter of dissolved solids stored in the aquifer is estimated at 60 million AF. Of this amount, an estimated 36 million AF is available for use.

The quality of water in the Vamoosa-Ada aquifer generally is suitable for municipal, domestic, and stock use. Of 55 water samples analyzed in the laboratory, about 75 percent were of the sodium bicarbonate or sodium calcium bicarbonate type; the remainder were of the sodium sulfate, calcium sulfate, sodium chloride, or indeterminate types. Laboratory and on-site chemical-quality data indicate that mineralization of both ground and surface waters is greater than normal in some areas. Water samples from 7 wells and 12 stream sites had concentrations of bromide exceeding 1 milligram per liter; the only known source of bromide in the area is brine associated with petroleum production.

Most recharge to the Vamoosa-Ada aquifer is derived from precipitation falling directly on the outcrop area. Some recharge may occur where the aquifer is connected to the surface by sandstone beds in overlying rocks.

2.4.2 Local Hydrogeology, Oscar-Vanoss Aquitard

In Hydrologic Basin 72 of the Upper Arkansas Watershed Planning Region in Osage County, the area closest to the proposed project area is in an area defined by the Oklahoma Water Resource Board as an area that has no delineated aquifers. The primary water supply for the community of Web City which is located within the southeastern portion of the AoR is supplied by the Osage Rural Water District. Surface water satisfies about 85 percent of the current demand in this region while 13 percent is sourced from alluvial aquifers and 2 percent from bedrock aquifers. A map showing the top of the lowermost freshwater zone within the AoR is in **Figure 2-17**. The Arkansas Alluvial Aquifer is located to the southwest of the proposed injection site. The Vamoosa-Ada Aquifer is located approximately 25 miles east of the proposed site and is not present in the AoR. The Oscar-Vanoss aquitard does have shallow freshwater zones from 50’ to 200’ that occur within the AoR. The Oscar-Vanoss section is dominantly shales and low permeability limestones interfingered with thin, discrete, fine-grained sands. Monitoring of these zones is discussed in the “*Testing and Monitoring Plan*” in Module E.

The freshwater intervals within the Oscar and Vanoss have no continuity thus no deliverability because they reside within a Lower Permian Aquitard. The deliverability of these freshwater zones is extremely low and average 2 to 3 gallons per hour. Per the Code of Federal Regulations 40 CFR 144.3 a USDW is defined as “An aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer.” Given this definition, the freshwater zones within the Oscar and Vanoss formations within the AoR of this proposed project do not qualify as USDWs. Although these are not considered to be USDWs due to the low volume of water deliverability, the monitoring strategy proposed for this permit application will monitor them as such since some of their TDS values are below 10,000 mg/L

CapturePoint currently operates 67 fresh ground water monitoring wells within the AoR. Installation of the first monitoring well began in October of 2012 with the layout of the monitoring wells on a half mile grid. Two distinct Pennsylvanian-aged rock units are currently being monitored. These include sandstones in the Oscar and Vanoss formations. These two rock units are monitored each quarter.

- Oscar Formation
- Vanoss Formation

A west to east cross section B-B' (**Figure 2-18**) shows the Oscar zone as monitored by well MW-35, the Vanoss A zone is monitored in the MW-25 well and the Vanoss B zone is monitored in wells MW-24 and MW-23. A north to south cross section L-L' shows the Vanoss C zone as monitored in well MW-38 and the Vanoss B zone as monitored in the MW-22 well. The total depths of the monitoring wells are between 88 feet and 290 feet and average 189 feet.

CapturePoint LLC is required to collect and analyze samples for alkalinity, chlorides, and total dissolved solids (TDS). The lithology of each unit that is monitored varies. Monitoring well MW-6A is completed in a siltstone or very fine-grained sandstone unit of the Oscar Formation. The remaining 66 program monitoring wells are all completed within the older underlying Vanoss Formation (either Zones A, B, or C). The groundwater within these Vanoss wells has been shown through analysis of core samples to be sourced from bedding-plane partings within fractured limestone that is interbedded with shale. The yields from these Vanoss rock units are low to very low. Fluid volumes generally are not sufficient to supply a public drinking water system, and 35 wells have tested TDS concentrations that average over 10,000 ppm. Therefore, due to low production capacity and high TDS levels, the groundwater bearing units being monitored do not meet the definition of a USDW.

The top of the Vanoss A Zone is encountered at approximately 50 feet below the top of the Vanoss marker, and this zone is approximately 40 feet thick. The top of the Vanoss B Zone occurs approximately 100 feet below the top of the Vanoss marker, and this zone is ranges between 40 and 50 feet thick. The top of the Vanoss C Zone occurs approximately 180 feet below the top of the Vanoss marker, and this zone is approximately 30 feet thick. Mapping of these units has shown that the bedrock units near ground surface are dipping down to the west at a rate of 27 to 35 feet per mile.

The terrain in northwest Osage County is variable with rolling hills and valleys. Ground surface elevations of the monitoring wells range between 1,055 feet and 1,192 feet. The 75 groundwater monitoring wells are spread over an area of 18 square miles. The rolling and variable terrain in combination with a down-to-the-west structural dip of the bedrock provides meaningful evaluations of the physical and chemical measurements of the groundwater. Laboratory analytical results for groundwater samples taken from these monitoring wells require considerable correlation and analysis.

2.4.3 Determination of the Lowermost Base of USDW

The most accurate method for determining formation fluid properties is through the analysis of formation fluid samples. In the absence of formation fluid sample analyses, data from open-hole geophysical well logs can be used to calculate formation fluid salinity by determining the resistivity of the formation fluid (R_w) and converting that resistivity value to a salinity value. The two primary methods to derive formation fluid resistivity from geophysical logs are the "Spontaneous Potential Method" and the "Resistivity Method". The "Spontaneous Potential Method" derives the formation fluid resistivity from the resistivity of the mud filtrate, and the magnitude of the deflection of the spontaneous potential response (SP) of the formation (the electrical potential produced by the interaction of the formation water, the drilling fluid, and the shale content of the formations). The "Resistivity Method" determines formation fluid resistivity from the resistivity of the formation (R_t) and the formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987).

2.4.3.1 Spontaneous Potential Method

The spontaneous potential curve on an open-hole geophysical well log records the electrical potential (voltage) produced by the interaction of the connate formation water, conductive drilling fluid, and certain ion selective rocks (shales). Opposite shale beds, the spontaneous potential curve usually defines a straight line (called the shale baseline), while opposite permeable formations, the spontaneous potential curve shows excursions (deflections) away from the shale baseline. The deflection may be to the left (negative) or to the right (positive), depending primarily on the relative salinities of the formation water and the drilling mud filtrate. When formation salinities are greater than the drilling mud filtrate salinity, the deflection is to the left. For the reverse salinity contrast, the deflection is to the right. When salinities of the formation fluid and the drilling mud filtrate are similar, no spontaneous potential deflection opposite a permeable bed will occur.

The deflection of the spontaneous potential curve away from the shale baseline in a clean sand is related to the equivalent resistivities of the formation water (r_{we}) and the drilling mud filtrate (r_{mf}) by the following formula:

$$SP = -K\,Log\left(\frac{r_{mf}}{r_{we}}\right) \tag{1}$$

For NaCl solutions, K = 71 at 77°F and varies in direct proportion to temperature by the following relationship:

$$K = 61 + 0.133\,T° \tag{2}$$

From the above equations, by knowing the formation temperature, the resistivity of the mud filtrate, and the spontaneous potential deflection away from the shale baseline, the resistivity of the formation water can be determined (**Figure 2-19**). From the formation water resistivity and the formation temperature, the salinity of the formation water can be calculated (**Figure 2-20**).

2.4.3.2 Resistivity Method

The Resistivity Method determines formation fluid resistivity from the resistivity of the formation (R_t) and the formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987). The resistivity of a formation (R_t in ohm-meters) is a function of: 1) resistivity of the formation water, 2) amount and type of fluid present, and 3) the pore structure geometry. The rock matrix generally has zero conductivity (infinitely high resistivity) with the exception of some clay minerals, and therefore is not generally a factor in the resistivity log response.

Induction geophysical logging determines resistivity or R_t by inducing electrical current into the formation and measuring conductivity (reciprocal of resistivity). The induction logging device investigates deeply into a formation and is focused to minimize the influences of borehole effects, surrounding formations, and invaded zone (Schlumberger, 1987). Therefore, the induction log measures the true resistivity of the formation (Schlumberger, 1987). The conductivity measured on the induction log is the most accurate resistivity measurement for resistivity under 2 ohm-meters. Electrical conduction in sedimentary rocks almost always results from the transport of ions in the pore-filled formation water and is affected by the amount and type of fluid present and pore structure geometry (Schlumberger, 1988).

In general, high-porosity sediments with open, well-connected pores have lower resistivity, and low-porosity, sediments with sinuous and constricted pore systems have higher resistivity. It has been established experimentally that the resistivity of a clean, water-bearing formation (*i.e.,* one containing no appreciable clay or hydrocarbons) is proportional to the resistivity of the saline formation water (Schlumberger, 1988). The constant of proportionality for this relationship is called the formation resistivity factor (F), where:

$$F = \frac{R_t}{R_w} \tag{3}$$

For a given porosity, the formation resistivity factor (F) remains nearly constant for all values of R_w below 1.0 ohm-meter. For fresher, more resistive waters, the value of F may decrease as R_w increases (Schlumberger, 1987). It has been found that for a given formation water, the greater the porosity of a formation, the lower the resistivity of the formation (R_t) and the lower the formation factor. Therefore, the formation factor is inversely related to the formation porosity. In 1942, G.E Archie proposed the following relationship (commonly known as Archie's Law) between the formation factor and porosity based on experimental data:

$$F = \frac{a}{\phi^m} \tag{4}$$

Where:

ϕ = porosity

a = an empirical constant

m = a cementation factor or exponent.

In sandstones, the cementation factor is assumed to be 2, but can vary from 1.2 to 2.2 (Stolper, 1994). In the shallower sandstones, as sorting, cementation, and compaction decrease, the cementation factor can also decrease (Stolper, 1994).

$$F = \frac{0.81}{\phi^m} \tag{5}$$

Combining the equations for the Humble relationship and the definition of the formation factor, the resistivity of the formation water (r_{we}) is related to the formation resistivity (r_t) by the following:

$$R_t = \frac{R_{we}\ x\ 0.81}{\phi^m} \tag{6}$$

2.4.3.3 Methodology Used in the Site Evaluation

To determine the formation water resistivity in a particular zone, the resistivity of the drilling mud filtrate (obtained from the log header) at the depth of the zone must first be determined. Resistivities of saline solutions vary as a function of NaCl concentration and temperature. The relationship between temperature, NaCl concentration, and resistivity are typically shown in the form of a nomograph for computational ease (**Figure 2-19**). From this figure the resistivity of the drilling mud filtrate can be corrected to the temperature of the zone of interest. A shale baseline is next established on the spontaneous potential curve and the deflection away from the shale baseline measured. A chart containing the graphic solution of the spontaneous potential Equation (1) (**Figure 2-20**) gives the solution for the ratio between the resistivity of the mud filtrate and the formation water (R_{mf}/R_{we}) based on the measured spontaneous potential curve deflection. The resistivity of the formation water at formation temperature can be determined from the R_{mf}/R_{we} ratio and converted to the equivalent NaCl concentration from **Figure 2-19**. Once the base of the lowermost USDW is established, a formation resistivity (R_t) cut off on the deep induction log can be established. This formation resistivity cut-off is used to establish the base of the lowermost USDW at the proposed injection site.

By manipulating **Figures 2-19** and **2-20**, a formation water resistivity of 0.35 ohm-m corresponds to a salinity of 10,000 mg/l TDS. At a temperature of approximately 90 °F, a formation water resistivity value of 0.45 ohm-m corresponds to a salinity of 10,000 mg/l TDS. Deeper intervals with higher temperatures will have a higher resistivity cut off for analysis.

From this water resistivity value and an estimate of formation porosity, a formation resistivity (R_t) cut-off can be calculated. For the site, the USDW is projected to be relatively shallow, thus a formation water resistivity of 0.35 ohm-m is used. Using an assumed formation porosity of 34 percent (shallow unconsolidated sands) and solving for the total formation resistivity. From Equation (6), a formation resistivity (R_t) cut-off can be calculated if the approximate formation porosity is known. Therefore, solving Equation (6) gives the following result:

$$R_t = \frac{0.35\, ohm - m\ x\ 0.81}{0.34^2} = 2.45 ohm - m$$

Therefore, it is conservatively calculated that the sands with a formation resistivity of greater than 2.0 ohm-m were considered to be USDWs. This site-specific calculation agrees with the USGS and EPA which indicates that the USDW should fall between:

- Ground surface to 1,000 feet: 3 ohms or greater is considered USDW
- 1,000 feet to 2,000 feet: 2 ½ ohms or greater is considered USDW
- 2,000 feet and deeper: 2 ohms or greater is considered USDW

This methodology was employed by reviewing shallow well logs across the site. To be conservative in the current analysis, the base of the freshwater zone considered the lowermost USDW across the evaluated logs was placed at the deep resistivity 2-ohms cutoff.

2.4.3.4 Base of the Lowermost Base of USDW

In Oklahoma, the term “treatable” water is used instead of underground source of drinking water. Treatable water as explained under OAC Rule 165:10-1-2.

As defined subsurface water in its natural state, useful or potentially useful for drinking water for human consumption, domestic livestock, irrigation, industrial, municipal, and recreational purposes, and which will support aquatic life, and contains less than 10,000 mg/liter total dissolved solids or less than 5,000 ppm chlorides. Treatable water includes, but is not limited to, fresh water. **Figure 2-17** shows the depth to the base of the lowermost freshwater zone.

Radius of Endangerment:

Under the UIC Program, UIC Regulatory Agencies recognize two alternatives when reviewing the radius of endangerment. UIC Agencies are allowed to use a fixed radius, or calculate the radius based upon reservoir conditions. Most states use a fixed radius usually of one quarter mile with some states using a radius of up to 1 (one) mile. Oklahoma uses a calculated radius of endangerment. This calculation is done using a derivation of the Theis equation as specified in 40 CFR sec. 1466. This calculated value is then compared to the pressure differential calculated to the base of the treatable water.

The equation is: $\Delta P = (162.6) * Qu/kh \log (kt/70.4 * \Phi * ucr2)$

- ΔP = the pressure in the formation as created by the injection operation at a specified distance (r) from the well bore.
- 162.6 = constant
- Q = injection rate
- u = fluid viscosity (note: 1 cps. Is a constant)
- k = permeability in millidarcies (md)
- h = net pay thickness
- Log (kt/70.4ucr2)
- The logarithmic value of the calculation is taken.
- k = permeability in millidarcies (md)
- t = 10 years
- Φ = porosity
- u = fluid viscosity = 1 cps.
- c = total compressibility of the fluid, the value 7.5 x 10-6 is used (constant)
- r = radius from the well bore

In order to calculate the radius of endangerment, reservoir values must be known. This information becomes essential when problem wells are found within a one quarter mile radius of the subject well. The UIC Department cannot approve an application if there are wells within a one quarter mile radius of the subject well unless reasonable reservoir information is available to demonstrate that the injection well will not impact those wells. The key information is porosity (Φ), permeability as it relates to water (k), and reservoir pressure.

The most important value is reservoir pressure. If the reservoir pressure is too high, then a maximum of one quarter mile is automatically assumed as the radius of endangerment. In order to know if the reservoir pressure is going to be a critical issue, two factors must be known. The first is the fluid level in the well or the reservoir pressure of the subject injection zone and the second is the base of the treatable water (the fluid level or bottom hole pressure is used to calculate the current reservoir pressure).

If the level in the well bore is high enough to reach the base of the treatable water, then the radius of endangerment calculation is automatically one quarter mile.

In the following example an injection rate of 500 bbls/day is used. The injection zone is 25 feet thick, porosity is 18 percent, and the permeability is 67 mD. The fluid level was measured to be 1,000 feet. P = 359.7 psi with an assumed radius of 10 feet.

The pressure is then converted to a hydrostatic column of fluid in the well bore. Using a fluid with a specific gravity of 1.074, the value of 0.465 psi/ft is used. Converting 359.7 psi to a water column, the hydrostatic column is then calculated as 359.7 psi /.465 psi/ft = 773.5 ft.

To obtain the height of the fluid column in the well that would occur due to the injection operation, the following calculation is required:

- Fluid level is 1,000 ft.
- Mid-point of perforations = 2,500 ft.
- Fluid column in well prior to injection is 2,500-1,000 =1,500 ft. Fluid column that would be generated after injection is 1,500 + 773.5 = 2,273.5 ft., the fluid in the well measured from the mid-point of the perforations.

- To establish the ground level base line, the base line is drawn at the 2,500-foot mark.
- To establish Base of treatable water or (USDW) base line, the baseline is drawn at a depth 500 feet below the 2,500-foot mark.
- This means that there are 2,000 feet between the BTW and the mid-point of the perforations prior to there being any fluid in the hole at the level of treatable water.
- Once the ground level and BTW base lines are established, the next step is to move out a distance of 10 feet (r) from the subject well and plot the value 2,273.5 feet. This value is measured from the mid-point of the perforations or the zero (0) point on the graph.
- Note that a distance of 10 feet (r) from the well bore and the fluid column is 273.5 feet above the base of treatable water. This means that a distance of 10 feet from the well bore any problem well within this radius is within the radius of endangerment.
- In order to avoid doing numerous calculations to determine what radius (r) is a safe distance from the well bore and outside the radius of endangerment, the data is graphically represented to determine the radius of endangerment.
- In order to graphically represent the radius of endangerment, ΔP is calculated at r=100 ft. and r= 1,320 ft. With three (3) points on the graph, a line can be drawn, and the radius can be determined.
- The radius is estimated by determining the point at which the hydrostatic column is found to be below the BTW
- In this example, the radius is found to be 200 feet from the well bore.
- Porosity information can be obtained from well logs.
- Once these values are known, then the radius of endangerment can be calculated.
- In most cases, the more accurate the information is the greater the advantage for the applicant. The less accurate the information requires the Pollution Abatement Department to use more conservative values.

2.4.4 Local Water Usage

Osage County has a population of approximately 45,839 people (US Census Bureau 2022). Surface water satisfies about 85 percent of the current demand for the area. The largest city in Osage County is Skiatook. The city’s water is supplied from the man-made Skiatook Lake's watershed. The watershed is 354 square miles and is fed by Hominy Creek. The lake itself is relatively large with a conservation pool of 310,086-acre feet. The Oklahoma Water Resource Board produced a “Upper Arkansas Watershed

Planning Region Report" in 2012. This report supplies valuable facts and information regarding the 13 watersheds throughout Oklahoma. Groundwater satisfies about 15 percent of the current demand (13 percent alluvial and 2 percent bedrock). The peak summer month demand in the area is 1.2 times the winter demand, which is less pronounced than the overall statewide pattern.

Surface water is used to meet about 69 percent of the region's demand. The region is supplied by three major rivers: the Arkansas, Cimarron, and Salt Fork of the Arkansas. Historically, the region's rivers and creeks have periods of low to no flow in any month of the year due to seasonal and long-term trends in precipitation. Large reservoirs have been built on several rivers and their tributaries to provide public water supply, flood control, power generation, and recreation. Large reservoirs in the Upper Arkansas Region include: the Keystone, Kaw, Sooner, Carl Blackwell, and Great Salt Plains. There are 10 additional municipal lakes that have normal pools ranging from 1,795 AF to 19,733 AF.

Alluvial groundwater is used to meet 24 percent of the demand in the region. The majority of currently permitted withdrawals are from the Arkansas River and the Salt Fork of the Arkansas River aquifers. If alluvial groundwater continues to supply a similar portion of demand in the future, storage depletions are likely to occur throughout the year, although these projected depletions will be small relative to the amount of water in storage. The largest storage depletions are projected to occur in the summer.

Bedrock groundwater is used to meet 7 percent of the demand in the region. Currently permitted and projected withdrawals are primarily from the Vamoosa-Ada aquifer and North -Central Oklahoma minor aquifer. The Vamoosa-Ada has about 3.6 million AF of groundwater storage in the region.

In 2015, 128,570 AF/year or 7 percent of the states average were withdrawn from water sources in the Upper Arkansas Regional watershed. About 69 percent (88,713 AF/year) was withdrawn from surface water, and 24 percent (30,856 AF/year) was withdrawn from groundwater and 7 percent (9,000 AF/year) bedrock aquifers. Withdrawals for municipal and industrial accounted for 37 percent (47,570 AF/year) of the total water withdrawn. Major users of water are Thermal Electric and 29 percent and Crop Irrigation 15 percent. Total water useage is expected to increase 41 percent from 2010 to 2060.

The proposed CCS site is located approximately 2 miles east of the KAW Reservoir and 3 miles west of the Shidler Reservoir. The site is located within the Shidler Reservoir Watershed which is in turn located within the Upper Arkansas Watershed Planning Region.

From https://dc.library.okstate.edu/digital/collection/OKMaps/id/10771/

From chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://www.owrb.ok.gov/ocwp/pdf/2012Update/OCWP_UpperArkansas_Region_Report.pdf

2.4.5 Water Wells and Data Sets

Water well data was gathered from the online database of the Oklahoma Water Resources Board (OWRB), specifically the online GIS website:

https://owrb.maps.arcgis.com/apps/webappviewer/index.html?id=ed61209c40ec4f53bc51d2ffd18aa39b.

A public records request was submitted to the Oklahoma Department of Environmental Quality and the Oklahoma Water Resource Board in the late Spring of 2023. From the submitted requests the web address to the OWRB website was provided. Water well information for the NBU CCS site was compiled from the provided website. A total of 4 registered groundwater wells occur within the AoR. These wells extend from depths of 100 feet to 2,178 feet. Out of the 4 active water wells, no wells are used as water supply to rigs, 1 well is used for irrigation, 0 are used for commercial/municipal public supply, 3 are used for domestic/livestock purposes. CapturePoint owns and operates 75 groundwater monitoring wells located in the North Burbank Oil Field Unit. Of these wells, 62 are located within the AoR.

2.4.6 Injection Depth Waiver

The CapturePoint Solutions NBU sequestration site has their injection zones deeper than the base of lowermost USDW by more than 2,500 feet. Therefore, this section is not applicable.

2.5 Seismicity

An earthquake is a motion or trembling that occurs when there is a sudden breaking or shifting of rock material beneath the earth's surface. This breaking or shifting produces elastic waves which travel at the speed of sound in rock. These waves may be felt or produce damage far away from the epicenter-the point on the earth's surface above where the breaking or shifting occurred. When the stress from an event exceeds the rock strength of the formations, it causes a break in the rock along either new or pre-existing planes. The size of an earthquake can be expressed by either intensity or magnitude. Magnitude is based on an instrumental recording that is related to energy released by an earthquake, while intensity describes the felt effects of an earthquake:

> **Intensity** - effect of the ground motion on man, structures, and on natural features. The measure currently in use (since 1931) is known as the Modified Mercalli Intensity Scale (MMI). Before 1931, the quite similar Rossi-Forel Intensity Scale was used. Intensity observations are employed to construct isoseismal maps wherein the areas of equal shaking are contoured.
>
> **Magnitude** - instrumental measure of an earthquake. It is the response of a specified instrument (seismograph) with narrowly defined dynamic response. With the magnitude scale, earthquakes can be measured at a distance. Seismic stations should all achieve similar determinations from the same event since adjustments are made for distance and instrumental constants. The magnitude scale was devised by Dr. Charles F. Richter. There are now several iterations of the magnitude scale, depending on the type of seismic wave observed, epicentral distance, and several other factors. The original Richter Scale is divided into 10 levels of magnitude where the strength between each level is 10 times greater than the previous level.

Instrumental seismology is equally as important as the historic record, for instrumentation permits measurement and location of seismic events much smaller than those which may be felt. Thus, a catalog of seismic events may contain events that are instrumentally recorded but not felt by man. Also, since seismic ground motion attenuates with distance and the entire country is not adequately covered by seismographs, many small events are felt but not recorded or escape all detection.

2.5.1 Seismicity in the Region

Seismic activity in Oklahoma and the surrounding region is quite active. Data compiled from the USGS Earthquake catalogue (https://earthquake.usgs.gov/earthquakes/search/) in September of 2023 includes seismic events that occurred between 1981 and 2023 are contained in **Table 2-9**. A subset of this information for the period between 2000 and 2023 and that have a magnitude of 2.5 or greater are displayed in **Figure 2-21**. A magnitude 1.4 on August 14, 2020, near the southern edge of the AoR was detected and reported by the USGS. The USGS does not purport to record every earthquake of such a small magnitude, but rather gives a magnitude threshold (m_l) of ~2.4 and a moment magnitude (M_{we}) threshold of 2.7 for catalog completeness since 1980. The catalog contains no seismic events meeting these thresholds within the AoR. This calm contrasts with the extraordinary rates of seismicity in areas immediately to the west and south, namely, central and northcentral Oklahoma and southcentral Kansas, and as nearby as southwestern Osage County since 2010. As a result, the AoR in Osage County, Oklahoma, is seismically quiescent, devoid of both natural and human-induced earthquakes (**Figure 2-22**).

The lack of induced seismicity in the AoR cannot be ascribed to the Arbuckle, since drilling indicates subregional karsted intervals in the Arbuckle that would provide ample permeability and storage capacity. In fact, 3D seismic reflection volume attributes not only suggest large-relief karst features near the top of the Arbuckle (Aboaba and Liner, 2021) but also delineate a pervasive fracture network with trend-modes near azimuths of N5E and S60E, orientations conventionally described as 005 degrees and 120 degrees (Baruch, Elebiju, and Perez, 2009). While the former is sub-orthogonal to maximum horizontal compression and thus likely clamped shut with respect to fluid flow and frictional faulting, the latter is well aligned for shear slip in the modern stress field and therefore likely to be quite hydraulically conductive. The fracture density observed in the upper portion of the Arbuckle decreases downward into the formation and decreases further in the underlying Reagan Sandstone (where present) however, the combined ~N–S and ESE–WNW fracture systems appear to create a polygonal network in the upper Arbuckle, and the coherence of the highly energetic seismic reflections suggest that these structural lows may be an altered fracture network infilled with porous cherts (Baruch, Elebiju, and Perez, 2009).

The subpopulation of seismogenically well-aligned fractures in the upper Arbuckle does not appear to transect the underlying basement. Numerous coherent intra-basement reflectors do exist, but many observations suggest that they may be related to local magmatism and extension (Hinze et al., 1997). First, the top of the reflector is a positive impedance contrast with depth, while the base is a negative contrast: The reflector is a high-velocity and/or high-density lens. Second, the overall shape — a synform in E-W cross section — resembles with the ~N-trending sags associated with combined normal faulting and thermal subsidence of the Midcontinent Rift (Behrendt et al., 1990). Third, stacked, highly coherent reflective layers between the intra-basement reflectors and sub-horizontal Paleozoic section are thought to represent thermally metamorphosed extrusive and/or sedimentary fill (McBride et al., 2003). Fourth, truncated, subsidiary reflectors are interpreted as growth faults and/or conjugate faults soling into a local master detachment, and fifth, SE-striking reflectors are cross-cut by west-dipping reflectors, suggesting an intrusive relation (Baruch, Elebiju, and Perez, 2009).

In addition to the interpreted igneous origin of the intra-basement reflectors, the fracture-trend mode near 120 degrees that is observed in the Arbuckle is entirely absent in potential field trends of basement rocks. Instead, Baruch, Elebiju, and Perez (2009) observe orientations clustered near ~010 degrees and 145 degrees in tilt derivatives. While the former is sub-parallel to the 005-degree-trending fractures in the Arbuckle, that orientation is likely clamped (both seismogenically and hydraulically) in the modern stress field.

Osage County hosts an anomalous basement complex known as the Osage High (Baruch, Elebiju, and Perez, 2009). Four petrographically related basement rocks surround the Osage High: the Washington Volcanics, Osage Microgranite, Central Oklahoma Granite Group, and the Spavinaw Granite Group. The proposed site, and nearly all of the AoR, overlies meta-rhyolitic rock (Denison, 1981). Statewide, induced seismicity is most common in the Central Oklahoma Granite Group, followed by the Spavinaw microgranite, while areas underlain by extrusive volcanics are almost entirely quiescent, and metavolcanic basement shows only sparse activity. One possibility for this difference is that pore space in coarse-grained intrusive rocks mostly comprises fractures and faults, while pore space in extrusive rocks is more distributed (Freeze and Cherry, 1979). Therefore, injected fluids are dispersed in volcanic basement but channeled along faults in crystalline rock. Alternatively, the extrusive suites may deform more ductilely than intrusive rocks.

Substantial increases in seismicity across northcentral Oklahoma in the last decade have been generally attributed to human activity. Several energy companies targeted the Cherokee Platform during the last oil and gas boom. However, these new production wells yielded sometimes as much as 90 percent (or more) formation saltwater, along with hydrocarbons, which was commonly disposed of into deeper zones within the Arbuckle. Wastewater injection into the Arbuckle, which directly overlies crystalline basement, has been proposed to hydraulically or elastically perturb the stresses on basement faults, causing them to slip. An Oklahoma seismicity map shows Osage County as an anomalously "quiet" region. Seismicity in counties surrounding Osage County experienced hundreds of earthquakes during the past couple of years, yet the area of Osage experienced less than a dozen earthquakes in the decades-long history of the Oklahoma seismic network. This is surprising since the fundamental geologic settings and possible anthropogenic triggers are essentially the same for these seismically active and quiet areas. Crain, et.al., 2017, present a possible geologic explanation for the anomalously quiescent Osage County. They modeled gravity and magnetics data to show that there are dense bodies beneath the Osage County area and use vitrinite reflectance data from the sedimentary strata to constrain the relative age of a possible intrusion event, which might have produced the dense bodies. They proposed that the intrusion of dense bodies could have caused significant basement alteration thereby reducing the seismogenic potential for basement faults to host larger, detectable earthquakes such as is observed in other regions of Oklahoma. (Crain, et.al., 2017). A regional correlation between fluid injection rates and recent seismicity in Oklahoma has been previously observed, but subsurface geologic features appear to impact seismic hazard at the local scale.

Areas underlain by extrusive igneous rock or thick (more than 3 or 4 km) sedimentary cover experience less seismicity. Large intrusions that are minimally fractured appear to impede seismicity, perhaps due to very low rock permeability and/or a lack of optimally oriented faults. Numerous earthquakes are observed along the edges of these features. While seismicity from 2009 to 2016 shows a broad, regional correlation with fluid injection activity, it also shows a local correspondence with lithology. Seismicity occurs mainly within crystalline basement comprising fractured intrusive or metamorphic rocks and rarely in sedimentary or extrusive rocks. While seismicity appears to generally be favored within intrusive rocks, there is also a notable drop in seismicity in some areas where larger (>30 km wide) intrusions with mafic phases are inferred. This effect is especially dramatic in the vicinity of the Cleveland anomaly, where minimal fracturing and faulting is inferred.

The dramatic 21st-century uptick in earthquake rates in neighboring areas is primarily the result of injection of produced wastewater from oil and gas operations (Ellsworth, 2013) and is associated particularly with high-rate disposal (Weingarten et al., 2015). Oil wells in the Mississippi Lime play may produce 10 or more barrels of naturally occurring brine for every barrel of hydrocarbon. To ensure that produced brines cannot be introduced into surface flow or groundwater aquifers, they are reinjected below the production horizons. The widespread Arbuckle Formation underlies hydrocarbon deposits and contains ample pore space to permanently store the wastewater. Moreover, pore fluid pressure in the Arbuckle is naturally below hydrostatic (Walsh and Zoback, 2015). Therefore, many reinjection operations involve merely completing a boring into the Arbuckle and disposing of the produced brines under a gravity feed with no added wellhead pressure.

This newly introduced fluid, however, does increase the pore fluid pressure in the Arbuckle and, more importantly, in the immediately underlying crystalline basement rock. In fact, all the seismic events in southwestern Osage County are spatially and temporally associated with saltwater disposal near the associated faults of the Nemaha Uplift.

The crystalline basement in Oklahoma was extensively faulted during Proterozoic Midcontinent Rift extension and tectonic inversion, Cambrian extension, and shortening in multiple directions during the Paleozoic Ouachita-Marathon / Ancestral Rockies orogenic events (Thomas, 2014). Since the most recent tectonic reorganizations affecting the central United States – including the Cretaceous opening of the Gulf of Mexico and the Oligocene shift from compression to transtension along North America's western margin – these faults have equilibrated with the crustal stress field at its naturally sub-hydrostatic pore fluid pressure. In this state, known as frictional failure equilibrium (Zoback, 2010), elastic strain due to continuous tectonic loading is accumulated in the crust and increases shear traction "τ" on faults until τ overcomes the frictional resistance to slip, following Mohr-Coulomb failure criteria (Hubbert and Rubey, 1959):

Frictional Failure Equilibrium: $$\mu\left(S_N - P_p\right) + C - \tau = 0$$

$$\rightarrow \tau = \mu(S_N - P_{Crit})$$

where

P_{crit} = the critical pore fluid pressure at the onset of frictional instability

S_N= the magnitude of the normal traction on the fault

τ = the magnitude of the shear traction on the fault

μ = the coefficient of friction on the fault

C = cohesion, which is assumed to be 0 megapascal (MPa)

Frictional resistance is the product of the coefficient of friction μ and effective normal stress, which is the magnitude of the normal traction S_N minus the present pore fluid pressure P_p. Frictional failure occurs if P_p increases to critical pore pressure P_{crit}. An air hockey table provides a tangible example of this phenomenon: With no added air pressure, the puck is frictionally stuck, yet turning on the air jets decreases effective normal stress and thus frictional resistance, allowing slip. In this analogy, cohesion *C* would manifest as a slightly sticky puck. We will neglect cohesion because induced earthquakes generally reactivate existing faults (McNamara et al., 2015), which are thought to have little cohesive strength (Zoback, 2010).

In a region equilibrated to ambient pre-injection pore pressure P_0, one can readily define the pressure perturbation required to make a given fault frictionally unstable:

$$\Delta P \equiv P_{crit} - P_0 = S_N - \tau/\mu - P_0$$

where

P_{crit} = the critical pore fluid pressure at the onset of frictional instability

P_0= the initial pore fluid pressure, prior to injection or extraction

S_N= the magnitude of the normal traction on the fault

τ = the magnitude of the shear traction on the fault

μ = the coefficient of friction on the fault

ΔP = the pore pressure increases to the onset of frictional instability

On a Mohr diagram, ΔP is the horizontal distance from the failure envelope.

From the tenet that continental crust is in a state of frictional failure equilibrium, it follows that an optimally oriented fault is critically stressed, with normal traction S_{Nopt} and shear traction τ_{opt}, at the ambient pore pressure:

$$\tau_{opt} = \mu(S_{Nopt} - P_0)$$

where

P_0 = the initial pore fluid pressure, prior to injection or extraction

S_{Nopt}= the magnitude of the normal traction on the optimally oriented fault

τ_{opt} = the magnitude of the shear traction on the optimally oriented fault

μ = the coefficient of friction on the fault

For this optimal fault, ΔP is 0; this plane plots where the failure envelope is tangential to the Mohr circle.

Because the Arbuckle is porous, fractured, and rests directly above basement rock, saltwater disposal increases pore fluid pressure not only within the sedimentary unit but also within fractures in the underlying crystalline rocks. This increased pressure triggers slip on near-critically stressed basement faults, mainly those for which ΔP is 2 MPa (~290 psi) or less (Walsh and Zoback, 2016).

2.5.2 Seismic Risk of the Site

A preliminary seismic risk evaluation is conducted for the project area. The proposed CCS site is located in Osage County, in an area of no known faulting. Overall seismic risk is rated very low based on:

- Low frequency of natural earthquake events near the CCS area
- Low intensity of natural earthquakes felt in the CCS area, with maximum ground motion on the surface being less than or equal to an intensity range of MMI=IV
- Low population density in near the CCS site limit exposures and impacts
- Lack of injection-induced seismicity in Class I or Class II wells in the area
- There are no known faults in the AoR

Typical geologic structures characteristic of this province is gently westerly dipping and thickening sedimentary strata.

The seismic activity in this part of Oklahoma is anomalously quiet. Underground tectonic forces that are continually applied to brittle rocks tend to deform or bend the rocks slightly. In this scenario, stress in brittle rock builds up during the "interseismic" period until the stress over time is greater than the strength of the rocks. When this occurs, the rock formations will rupture seismically and deform instantaneously. These instantaneous movements produce seismic waves that travel through the earth and along the surface of the earth and are responsible for the trembling and shaking known as an earthquake.

Based upon the low seismic risk evaluation for the site, a plan specific to earthquakes should not be required. However, the NBU CCS site will have an Emergency and Remedial Response Plan for facility related incidents and acts of nature. Acts of nature can include wildfires, tornados, floods, and earthquakes. The Emergency and Remedial Response Plan is submitted in Module E.

As a general policy the company provides site specific Emergency Response Plans for each company site. The site-specific Emergency response plan will include:

1. Shut down procedures
2. Procedure for reporting an emergency including hierarchy of authority
3. Procedures for emergency evacuation including type of evacuation and exit route assignments
4. Procedures to account for employees after evacuation
5. Procedures to be followed by employees who remain for facility operations prior to their evacuation
6. Name and job title for every employee who may be contacted by employees who need additional information about the plan or an explanation of their duties under the plan.

Evaluations have been performed to determine the possible effects of natural events on (1) the integrity of well construction materials; and (2) the integrity of both the Injection and Confining Zones beneath Osage NBU CCS site. A review of "The National Earthquake Information Center" (http://earthquake.usgs.gov/contactus/golden/neic.php) indicates that Osage County site area has a low potential for seismic activity.

2.5.3 Seismic Risk Model

A model earthquake is used to evaluate the potential effects, if any, of natural earthquakes on structures associated with the carbon capture project. In general, a source mechanism is required when designing a "model" earthquake. In these cases, it is usual to have a "known" active fault system with a measured strain or stress field. In the area of Osage County, the risk level is low.

This section discusses the methodology for estimating rates of natural earthquakes in the AoR. The lack of recorded earthquakes poses a challenge when estimating the frequency of potentially damaging earthquakes over geologic time. However, the Gutenberg-Richter (GR) relationship between earthquake magnitude M and frequency can provide a rough estimate of frequency:

$$\log_{10}(\#Earthquakes_{magnitude \geq M}) = a - bM$$

<u>where</u>

a = a constant reflecting the overall earthquake productivity; and

b = a positive constant reflecting the magnitude dependence of earthquake productivity.

M = earthquake magnitude

Globally, *b* hovers near 1.0, while the value of *a* depends on the number of earthquakes in a specified geographic area and over a specified duration.

The USGS creates a grid of estimated annual *a* values by pixelating the central and eastern United States into 0.1 x 0.1-degree latitude/longitude cells (~7 x 5 miles). With *b* fixed at 1.0, a GR distribution is fit to the average annual seismicity rates from the historical and instrumental seismicity catalog. Only earthquakes at or above the magnitude threshold are considered, allowing uniform treatment of well-instrumented and poorly monitored areas as well as populous and rural regions. Additionally, areas and years during which earthquakes may be related to human activities are excluded from this count. Thus, the *a*-grid represents the average number of naturally occurring events at M0 and greater in a year in each 0.1 x 0.1-degree block; because *b* is fixed at 1.0, *a*/10 M1, *a*/1000 M3, etc., earthquakes are expected annually in a cell. To make these extrapolations more reliable, the USGS also smooths the 0.1 x 0.1-degree *a*-grid. This smoothing raises *a* in the AoR from 0.00 (since there are no earthquakes above the completeness threshold) to roughly 0.03.

This *a*-value implies ~three M0 and greater earthquakes per 100 years in a 0.1 x 0.1-degree box, i.e., a recurrence interval of ~33 years for one M0. The AoR spans 0.3 x 0.5 degrees, from longitude -96.8 to -96.5 and latitude 36.5 to 37.0, or 15 cells in the *a*-grid. Therefore, ~one-half M0 and larger natural earthquakes are expected annually, or one every ~2 years. One natural M1 is expected every 20 years, a single M3 every 2,000 years, and a potentially damaging M5 every 20,000 years. Although these recurrences are calculated without considering the increase in earthquake rates in central and northern Oklahoma and southern Kansas potentially related to human activities, it is critical to note that current brine injection of ~16,000 (BWPD) and historical rates of 40,000 barrels of water per day (BWPD) within the AoR has not resulted in any documented seismicity since the middle 1980s. As a result, any increased hazard for ground motion is likely caused by the USGS's method of smoothing used to construct the *a*-grids or from shaking in the AoR due to earthquakes in adjacent, currently seismogenic regions of northcentral Oklahoma and southcentral Kansas.

Abundant potentially induced earthquakes have illuminated seismogenic fault patterns in great detail and allowed high-resolution mapping of crustal stress in seismically active areas that border the quiescent AoR. A strike-slip faulting regime with horizontal maximal compression (σ_{Hmax}) oriented ~N85E dominates from central Oklahoma to southern Kansas (Walsh and Zoback, 2016; Levandowski et al., 2018; Qin et al., 2019; Lund-Snee and Zoback, 2020) and mainly reactivates conjugate faults striking (055-075) or (105–125). A secondary extensional component increases in prominence from northward, with some normal faulting observed in northwestern Oklahoma and southern Kansas (Levandowski et al., 2018; Qin et al., 2019; Lund-Snee and Zoback, 2020). Although stress-field constraints within the AoR are lacking, this general consistency of stress patterns over hundreds of miles suggests that extrapolation ~30 miles into the AoR is defensible. The single stress indicator within the AoR (World Stress Map, 2016 – their WSM42790) is a set of drilling-induced fractures with σ_{Hmax} N91E, which is assumed to be consistent with the regional pattern.

The orientations of the principal stresses, their relative magnitudes, and uncertainties can be quantified by inversions of earthquake focal mechanisms for the normalized crustal stress tensor. Such inversions are well established and stem from the axiom that co-seismic slip parallels the shear traction resolved on the fault plane (Angelier, 1979). The latter depends linearly on the orientation of the fault and on the 3D stress tensor. Assuming that earthquakes in a small region are all responding to a similar 3D stress field, this linear system quickly becomes overdetermined with multiple slip observations from faults of different orientations. Inverting this linear system solves for the 3D stress tensor that minimizes the angular misfit between the slip vectors and shear traction on the respective fault planes.

The normalized stress tensor can be fully described in terms of the directions and relative magnitudes of the principal stresses (i.e., ϕ). Simpson (1997) combined ϕ with the style of faulting (normal/strike-slip/reverse, as defined by principal axis plunges (Zoback, 1992) to describe the style of deformation as a quantity Aϕ.

$$A\Phi = (n + 0.5) + (-1)^n(\phi - 0.5),$$

where

ϕ = the stress ratio defined above

n indicates the style of faulting: *n* = 0 for normal faulting, 1 for strike-slip, and 2 for thrust

Consequently, Aϕ defines a continuum from radial extension (Aϕ = 0) to radial contraction (Aϕ = 3), passing through: uniaxial extension/pure normal faulting (Aϕ =0.5); oblique extension (Aϕ =1.0); horizontal shear/strike-slip (Aϕ =1.5); oblique contraction (Aϕ =2.0), and uniaxial contraction/pure thrust, (Aϕ =2.5).

Values of Aϕ range from ~1.5 in central Oklahoma to ~0.9 in southern Kansas. Levandowski et al. (2018), Lund-Snee and Zoback (2020), and Qin et al. (2019) found similar patterns, although Aϕ varies among the models by ±0.2 because the authors grouped focal mechanisms into different geographic bins for inversions. The present analysis selects and inverts focal mechanisms derived from waveform-based regional moment tensors (Herrmann et al., 2022) for earthquakes within ~93 miles of the AoR (n = 447). Details of the inversion algorithm are given by Levandowski et al. (2018); uncertainties are appraised by jackknife-resampling the focal mechanisms — discarding sqrt(n) — and adding ±15-degree perturbations to the slip vectors in each of 1,001 iterative inversions (Vavryčuk, 2014). These inversions yield best-fit σ_{Hmax} N84E±1 and Aϕ = 1.39±0.02: a strike-slip regime with a very minor extensional component and roughly east-west maximal compression.

To model fault slip potential (FSP), this estimate of the normalized crustal stress tensor is used with Equations 2.6.2.1–2.6.2.3 to compute the full stress tensor, from which the shear and normal tractions and then ΔP can be calculated for any fault orientation. With a ΔP at 5 km depth as a function of strike and dip for 125,613 fault planes samples the focal sphere evenly. The parameter values for this deterministic model are 2,550 kg/m^3 overburden density, 1.2 MPa (~174 psi) pre-20th-century underpressure, and coefficient of friction 0.71; the stress tensor is defined by Aϕ=1.4 and σ_{Hmax} N84E. For reference, solid black lines show the 2 MPa (~290 psi) contour, which corresponds to an additional 1.25 MPa (~181 psi) pressure increase due to injection superimposed on the regional 0.75 MPa (~109 psi) increase. At 5 km (3.1 miles) depth, faults striking in the ranges [049–062 | 105–118 | 229–242 | 285–298] and dipping more than 77 degrees are predicted to become unstable with this pressure increase.

Probabilistic FSP models are conducted to appraise uncertainty with respect to inputs. For 1,000 Monte Carlo trials, the input parameters are resampled from appropriate distributions. The 1,000 stress tensors are taken from the 1,000 inversions presented in Section 2.6.3. Sedimentary rock (overburden) density is sampled from a uniform distribution 2350–2650 kg/m^3. Friction is sampled from a distribution with mean 0.71 and standard deviation 0.05, based on Laboratory measurements of friction in Westerly Granite at appropriate temperature and pressure (Blanpied et al., 1994). Initial underpressure is taken from a uniform distribution 1.2±0.3 MPa (~0.75±0.19 psi), although the FSP is insensitive, to any practical extent, to this parameter.

These 1,000 outcomes are used to define confidence bounds for the maximum pore pressure increase under which a given fault is expected to remain stable. For instance, **Figure 2-23** shows the perturbations at which the faults remain frictionally stable in 95 percent of the simulations (conversely, the level at which they destabilize in 5 percent of the models).

FSP models are only actionable given a specific fault orientation and depth, and no faults are currently mapped in the immediate vicinity of the injection site. Over the course of the project, as local geologic structure becomes better defined by mapping, well logs, gravity and/or magnetics analyses, or 3D seismic, any inferred faults would be examined in the context of FSP. For instance, if 3D seismic suggests a fault oriented [095,85S] at 5 km depth, **Figure 2-23** indicates that a total pressure increase of 10.5 MPa (~1,523 psi) would be required to have a 5 percent chance of destabilizing the fault.

Vertical separation between the injection point and basement faults is known to be important for reducing induced seismicity risk. In the context of FSP, however, fault depth matters because the depth bgs (regardless of the depth of the injection point) controls the total weight of overburden and thus confining pressure at the fault. As a result, the depth of potentially seismogenic faults is the second most important control — following orientation with respect to the local stress field — on the tolerable pressure increase, and ΔP scales roughly linearly with depth. As an endmember, consider that a fault was imaged at the top of basement, 1.3 km depth, beneath the site. The range of fault orientations destabilized by a 2 MPa pressure increase in at least 5 percent of the simulations (**Figure 2-24**) expands compared to models at 5 km (~0.8 mile) depth. The [095,85S] used as an example in the previous paragraph now lies quite near the 2 MPa (~290 psi) 95% confidence contour.

Thus, if basement faults at the site are imaged or inferred over the course of the project, their FSP responses should be examined as a function not only of orientation but also depth to determine the probability that a given pressure increase may trigger instability.

2.5.4 Induced Seismicity

Seismicity related to fluid injection normally results from activity involving high injection pressure, injection rates and large volumes, such as those associated with high-pressure water flood projects for enhanced oil recovery, or disposal of wastewater. This seismicity is caused by increased pore pressure, which reduces frictional resistance and allows the rock to fail. Fluid withdrawal has caused land subsidence and earthquakes due to dewatering and differential compaction of the sediments. Earthquakes of magnitude greater than 4.0 have been detected south and west of the proposed injection site but not within 30 miles of the site. Osage County in general and specifically the area around the Osage High are particularly "quiet" seismic zones.

Since 2010, parts of Oklahoma have experienced marked increases in the number of small- to moderate-sized earthquakes. In three areas that encompass the vast majority of the recent seismicity, it is shown that the increases in seismicity follow 5-to-10-fold increases in the rates of saltwater disposal. Adjacent areas where there has been relatively little saltwater disposal have had comparatively few recent earthquakes. In the areas of seismic activity, the saltwater disposal principally comes from "produced" water, a brine that is coproduced with oil and then injected into deeper sedimentary formations. These formations appear to be in hydraulic communication with potentially active faults in crystalline basement, where nearly all the earthquakes are occurring. (Walsh and Zobak, 2015). It is important to note there have been 70 years of active Arbuckle water disposal activities related to operations at the North Burbank Unit into the Arbuckle. These 357 million barrels of Arbuckle injection have not caused any known induced seismic events. The basement rocks and lack of faults within the region surrounding the AoR are thought to contribute to the seismic stability of the area.

The increased rate of occurrence in previously inactive seismic areas has been correlated with the increased use of injection wells located near faults. Fluid injection induced earthquakes are most likely caused by the increased pore pressure from injection operations which have reduced effective stress of faults leading to failure. This mechanism has been used to explain the best-known cases of injection-induced seismicity which was first studied in the Rocky Mountain Arsenal near Denver. New case studies have increased with the use of wastewater injection wells associated with hydraulic fracturing. In many sites, smaller seismic occurrences have shown to be precursors to larger events. More data has become available since the Rocky Mountain study in the 1960's, leading to a better understanding of factors and processes associated with induced seismicity.

One of the most notable regional cases of induced seismicity associated with injection wells occurred in Youngstown, Ohio. In 2011, 12 low-magnitude seismic events occurred along a previously unknown fault line (Ohio Department of Natural Resources, 2012). These events occurred less than a mile from Class II injection well Northstar I. Previously, the area was seismically inactive, with earthquakes beginning a few months after the injection of wastewater. The injectable pressure at Northstar I was increased twice over six months and may have reduced the effective stress on a fault. After the well was shut down by the Ohio Department of Natural Resources, the seismic activity declined. As a result of this case, seismic monitoring prior to injection and after injection has become common in Class II sites.

A case study in the Dallas-Fort Worth area tied small seismic events to a Class II injection well. Eleven hypocenters have been observed at a focal depth of 4.4 km and 0.5 km from a deep saltwater disposal (SWD) well. Injection at this well began eight weeks prior to the first recorded seismic event. A northeast trending fault is located approximately at the same location of the DFW focus. As a result of fluid injection into the disposal well, the stress upon the fault had been reduced and thus reactivated the fault. All of the seismic events associated with the DFW focus were small magnitude events (less than 3.3) and occurred very shortly after initial injection.

In Oklahoma, one of the largest earthquakes in the state's history may have been a result of wastewater injection at a Class II disposal site. In 2011, Prague, Oklahoma was the location of a 5.7 magnitude earthquake that was followed by thousands of smaller aftershocks. Wastewater had been pumped continuously into an old oil well for 17 years. As the pore spaces filled, the wellhead pressure was increased to continually inject the wastewater. This reduced the effective stress upon the Wilzetta fault located 650 meters from the well. The fluid was injected into the same sedimentary strata at which 83 percent of the aftershocks originated. In this case, the seismic event occurred years after the initial injection phase. Since the area was considered low risk seismically, there is no data on smaller earthquakes that may have proceeded the event in 2011.

In Texas there are at least two known examples of previously seismically inactive areas becoming seismically active after major injection programs began. One site is located in the Central Basin Platform, near Kermit, and the other is in the Midland Basin near Snyder. In both cases, large scale, high pressure, oil field related waterflooding projects were under way, and earthquakes with a magnitude of over 4.0 on the Richter scale were recorded. Historically, induced earthquakes in Texas have not exceeded 4.6 magnitudes. Factors for an induced earthquake are limited to the distance a well is located from a fault, the stress state of the fault, and a sufficient quantity of fluids from the injection well at a high enough pressure and enough time to cause movement along the fault (Ohio Department of Natural resources, 2012).

A hydraulic conduit from the injection zone to a fault may also induce earthquakes (Ellsworth, 2013). The largest injection-induced events are associated with faulting that is deeper than the injection interval, suggesting that the increased pressure into the basement increases the potential for inducing earthquakes (Ellsworth, 2013). In all cases, faults have been reactivated at or in close proximity of Class II injection sites. In some cases, previously unknown faults have been discovered. No induced earthquakes have been known or are postulated to have been caused by Class I injection operations.

2.5.4.1 Induced Seismicity Analysis and Injection Site

A working model for the project is available from Class I injection well sites located in Oklahoma. The Oklahoma Environmental Quality Land Protection Division has established regulations for underground injection control. "To increase ground water protection, a federal Underground Injection Control (UIC) program was established under the provisions of the Safe Drinking Water Act of 1974. Since then, state, and federal regulatory agencies have modified existing programs or developed new strategies to protect ground water by establishing even more effective regulations to control permitting, construction, operation, monitoring and closure of injection wells."

The UIC Program in the Land Protection Division reviews permits for, and performs inspections of, injection wells used for the disposal of liquids in underground geologic formations, except for those wells that, by state statute, are regulated by the OCC. Permits issued by LPD are for a 10-year period. If a facility submits a renewal application before the permit expiration date, the injection well may continue operations under the terms of the expired permit until the new permit is issued. Delegation of the federal program to the State of Oklahoma can be found in 40 CFR 147, Subpart LL. Federal regulations for the

UIC program can be found in 40 CFR 144-148. DEQ's UIC rules can be found in Oklahoma Administrative Code (OAC) 252:652.

The UIC program divides injection wells into five classifications. The classifications, and the agency with jurisdiction over them, are as follows:

CLASS I wells are used for injection of liquid hazardous and non-hazardous wastes beneath the lowermost underground sources of drinking water. DEQ has jurisdiction over these wells. Oklahoma currently has five Class I non-hazardous injection wells and no Class I hazardous waste injection wells.

CLASS II wells are used for injection of fluids associated with the production of oil and natural gas. The three types of Class II wells are enhanced recovery wells, disposal wells and hydrocarbon storage wells. OCC has jurisdiction over all Class II wells.

CLASS III wells inject fluids to dissolve and extract minerals such as uranium, salt, copper, and sulfur. Currently, there are no Class III injection wells in Oklahoma.

CLASS IV wells were used for injection of hazardous or radioactive wastes into or above an underground source of drinking water. In 1984, EPA banned the use of Class IV injection wells for disposal of hazardous or radioactive waste. Now, these wells may only be operated as a part of an EPA or state authorized clean-up action.

CLASS V wells are those not included in Classes I – IV and are generally used for injection of non-hazardous fluids into or above an underground source of drinking water. DEQ has jurisdiction over the majority of these wells; however, OCC has jurisdiction over Class V wells used in the remediation of groundwater associated with underground or above ground storage tanks regulated by OCC.

Determining whether seismic activity is induced, or triggered by human activity has gained particular interest in Oklahoma. In the past 10-15 years, north central Oklahoma has experienced a significant increase in earthquakes. This increase (**Figure 2-25**) shows the earthquake densities in Oklahoma on a yearly basis from 2000 to 2023.

Over the past 10-15 years, the Cherokee Platform in north central Oklahoma was targeted by many oil and gas companies for horizontal shale oil drilling. Many of these production wells, including those horizontial wells from the Mississippi Limestone formation, yielded significant volumes of saltwater along with the hydrocarbons, and the produced saltwater was commonly disposed of into deeper formations such as those in the Arbuckle. Injection of this produced saltwater into the Arbuckle, which directly overlies crystalline basement rock in areas outside the NBU, has been proposed to perturb the stresses on basement faults, causing them to slip and contributing to at least some increased density of earthquakes. The majority of the observed earthquakes (from 2000 to 2023) were traced to the crystalline basement.

However, Osage County has a much different experience to report: An Oklahoma seismicity map shows Osage County as an anomalously "quiet" region. Seismicity in counties surrounding Osage County experienced hundreds of earthquakes during the past couple of years, yet the area of Osage experienced less than a dozen earthquakes in the decades-long history of the Oklahoma seismic network (Crain 2017). In a recent study focused on the injection of produced saltwater in Osage County into the Arbuckle Formation, the study agreed that Osage County is a seismically quiet location with a high density of active disposal wells (Barbour, 2019). The study also demonstrates that the Arbuckle thicker on the western edge of Osage County where the NBU unit boundary is located, and is thinner both to the east and to the west of the western edge of Osage County,(Barbour, 2019) indicating that western Osage County (and the NBU area) has a lower seismic risk than the surrounding area related to injection into the Arbuckle. In some instances of induced seismic activity in Oklahoma over the past 15 years, the water was injected into a saline aquifer formation immediately above or very near the basement rock. However, as a recent study noted, the details of how the Arbuckle contacts with the Precambrian basement rock tends to vary spatially (Barbour, 2019).

While it has been theorized, and shown, that increased injectivity into a formation increased pore pressure on the formation. This increased pore pressure inturn causes the reactivation of faults is the origin of new faults. Documented instances of induced seismicity have not been reported within the NBU boundary. It is shown by pressure testing of the Arbucke reservoir at the NBU that the Arbuckle is still approximately 200 underpressure even after decades of water disposal into the formation. Controlled high injection rates of water into the Arbuckle reservoir has been ongoing at NBU since 1956 without any documented instances of induced seismicity. This history of over 66 years of injection into the reservoir demonstrates the low seismic risk associated with reservoir operations. Since 2014, the State of Oklahoma's Coordinating Council on Seismic Activity (CCSA) has organized state resources and other activities related to increased seismic activity in the State, and provides collaboration among interested stakeholders including industry, regulators, academia, nongovernmental organizations, and environmental-focused associations. The CCSA shares data, studies, developments, and proposed actions related to earthquakes in Oklahoma.

The State of Oklahoma maintains one of the nation's most robust seismic monitoring systems, and that system (along with actions taken by regulators and industry participants) has resulted in a dramatic decrease in the incidence of significant earthquakes in Oklahoma. This trend of induced seismic activity demonstrates that actions taken in recent years have significantly reduced the risk of earthquakes caused by injection of produced water into the Arbuckle Formation – none of which involves the NBU unit boundary geographic area, and none of which involves the reservoir which is approximately 1,400 shallower as compared to the Arbuckle Formation. Since 1980, the nearest earthquake greater than a magnitude 2.0 near the NBU CCS site was south of White Eagle, Oklahoma, approximately 25 miles away. The nearest large earthquake was in Pawnee, Oklahoma in 2016, which is nearly 35 miles away from the NBU. CapturePoint is not aware of any reported loss of CO_2 or water to the surface in the NBU associated with any seismic activity. A concern about induced seismicity is that it could lead to fractures in the seal, providing a pathway for CO_2 leakage to the surface. However, the subject wells injecting produced wastewater into the Arbuckle Formation are injecting fluids at approximately 3,500 feet deep, which is about 500 feet lower than the reservoir in the NBU that contains the injected CO_2. Moreover, there have been no reports of loss of injectant (wastewater or CO_2) to the surface associated with any seismic activity.

Therefore, there is no direct evidence to suggest that natural seismic activity poses a significant risk for loss of CO_2 to the surface from the NBU CCS site. If induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, then other reservoir fluid monitoring methods (such as reservoir pressure, well pressure and pattern monitoring) would lead to further investigation.

The United States Environmental Protection Agency (USEPA) Findings: The USEPA issued in a report regarding the Monitoring, Reporting and Verification (MRV) Plan for North Burbank Unit dated 12/16/2020, **Section 3.3, Leakage through Natural and Induced Seismic Activity**, the USEPA cites "the MRV plan states that while there has been a significant increase in earthquakes over the past 15 years in this part of Oklahoma, there is no direct evidence to suggest that natural seismic activity poses a significant risk for loss of CO_2 to the surface from the NBU. **Section 4.3** of the MRV plan provides information regarding induced seismicity from produced water injection into the Arbuckle Formation in areas of the state where the Arbuckle contacts the crystalline basement. The MRV plan cites a study that concludes that the majority of observed earthquakes in Oklahoma (from 2009 to 2016) were traced to fluid injection in the Arbuckle near the crystalline basement. CapturePoint also makes the case that injection of CO_2 resulting in the production of fluids, like that in a CO_2-EOR operation, where the objective is to maintain a constant reservoir pressure, is much different from a disposal operation where produced water is constantly injected without any other fluid production, and where pressure in the disposal zone can increase. The MRV plan states that this trend in reducing earthquakes resulting from induced seismic activity demonstrates that actions taken in recent years have significantly reduced the risk of earthquakes caused by injection of produced water into the Arbuckle Formation – none of which involves the geographic area containing the NBU, and none of which involves the reservoir which is approximately 1,400 feet shallower as compared to the Arbuckle Formation. Thus, the MRV plan provides an acceptable characterization of the likelihood of leakage from natural and induced seismic activity.

They found there is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the NBU.

CapturePoint Solutions employs conservative assumptions to the causative mechanisms of induced seismicity and the geomechanical conditions within the NBU area of interest to conservatively constrain parameters. The potential for induced seismicity at the proposed injection site can be evaluated using the very conservative zero-cohesion Mohr-Coulomb failure criterion, recommended by the U.S. Geological Survey. This method is based on the following equation:

$$P_{crit} = \frac{S_v(3\alpha - 1)}{2} \quad (1)$$

where:

P_{crit} = the critical injection zone fluid pressure required to initiate slippage along faults and fractures

S_v = the total overburden stress (which represents the maximum principal stress)

α = the ratio of the minimum principal stress (Need orientation for Mid-Continent) to the maximum principal stress (overburden stress)

Inherent in Equation (1) are a number of conservative assumptions, guaranteed to produce a worst-case lower bound to the critical fluid pressure for inducing seismicity. These are:

1) It neglects the cohesive strength of the sediments

2) It assumes that a fault or fracture is oriented at the worst possible angle

3) It assumes a worst-case value of 0.6 for the coefficient of friction of the rock

For present purposes, Equation (1) can be expressed in a more convenient form by introducing the so-called matrix stress ratio (K_i) (Matthews and Kelly, 1967; Eaton, 1969), which is defined as the ratio of the minimum to the maximum "effective" principal stresses. Effective principal stress is equal to actual principal stress minus fluid pore pressure (p_o). Thus:

$$K_i = \frac{\alpha S_v - p_o}{S_v - p_o} \quad (2)$$

Substituting Equation (2) into Equation (1) yields:

$$\Delta P_{crit} = \left(\frac{3K_i - 1}{2}\right)\left(S_v - p_o\right) \quad (3)$$

where ΔP_{crit} is the critical injection zone pressure build-up required to induce seismicity, with:

$$P_{crit} = p_o + \Delta P_{crit} \quad (4)$$

Equation (3) will be used to evaluate induced seismicity at the NBU CCS site.

Initial plots at the injection depths evaluated 40 pressures for a pressure gradient in the across the intervals. The analysis determined an initial pore pressure (p_o) of 0.455 pounds per square inch (psi) per foot of depth. Eaton (1969) provides a plot of the effective overburden stress (S_v) as a function of depth. This plot indicates S_v values exceed 0.90 psi/ft for the injection interval reservoirs. Matthews and Kelly (1967) provide a plot of the matrix stress ratio (K_i) for tectonically relaxed reservoir sediments. CapturePoint Solutions wells will be completed within the Arbuckle Formation at depths greater than 3,450 feet (approximate). Therefore, the P_{crit} for the upper most injection interval is calculated as the most conservative depth to determine critical pressure to induce seismicity.

2.5.4.2 Estimated Fracture Gradient of the Injection Zones

The fracture gradient for injection interval can be estimated using Eaton's Method (Eaton, 1969).

$$FG = \frac{\left(P_{ob} - P_r\right)e}{\left(1 - e\right)} + P_r$$

Where:

FG	=	Fracture Gradient
P_{ob}	=	Overburden Gradient – depth dependent
P_r	=	Reservoir Pressure Gradient (original)
e	=	Poisson’s Ratio – depth dependent

The nomographs are solved for all injection intervals at the NBU CCS site using the top of the formations in the offset NBU 1542 Well. An example calculation is included for the Arbuckle Formation:

$$FG = \frac{(0.9042 - 0.455) * 0.3983}{(1 - 0.3983)} + 0.455$$

$$= \quad 0.75 \text{ psi/ft}$$

Using the calculated fracture gradient of 0.75 psi/ft, the fracture pressure for the top of the Arbuckle injection zone is estimated to equal 2,582 psi at 3,443 feet.

Fracture Gradient Determination

When pore fluid pressure exceeds the minimum confining stress S_3, the rock can be hydraulically fractured (Zoback, 2010). In a dominantly strike-slip regime such as northern Oklahoma, S_v is the intermediate stress.:

$$S_2 = S_v = \rho g z$$

Rearranging to isolate S_1:

$$S_1 = \frac{\left(\rho g z - S_3\right)}{\phi} + S_3$$

And finally,

$$S_3 = \frac{\left(\frac{\rho g z}{\phi} - P_0 + \gamma P_0\right)}{\left(\frac{1}{\phi} - 1 + \gamma\right)}$$

Where:

S_3 = the magnitude of the minimally compressive stress

S_2 = the magnitude of the intermediate stress

S_1 = the magnitude of the maximally compressive stress

S_v = the magnitude of the vertical stress

g = gravitational acceleration

ρ = the density of overburden rock

z = depth

ϕ = the stress ratio defined previously

P_0 = the initial pore fluid pressure, prior to injection or extraction

This quantity is necessarily computed for all 1,000 stress inversions as part of the full stress tensor and also depends on the model of initial underpressure. In the preferred constant-underpressure case,

$$S_3(z) = 15.73\, z - 0.75$$

with *z* in km. For a constant initial gradient of 8.5 MPa/km,

$$S_3(z) = 14.93\, z$$

An alternative approach to estimate the fracture gradient follows Eaton (1969) and requires knowledge of the rock's Poisson's ratio ν:

$$Fracture\ Gradient = \frac{(\rho g - {}^{\partial P_0}/_{\partial z})\nu}{1-\nu} + {}^{\partial P_0}/_{\partial z}$$

Where

S_3 = the magnitude of the minimally compressive stress

g = gravitational acceleration

ρ = the density of overburden rock

z = depth

P_0 = the initial pore fluid pressure, prior to injection or extraction

ν = Poisson's ratio of the rock

Bustamante (2019) gives Poisson's ratios of the Woodford Shale as functions of lithofacies, with dolomitic mudstone/shale — which we suggest as a proxy for both the Woodford confining layer and the dolomitic Arbuckle — clustered near 0.28 (0.255–0.305).

In the constant-gradient pre-industrial pressure scenario,

(25-8.5) 0.28 / (1- 0.28) + 8.5 MPa/km = **14.8 MPa/km or 0.65 psi** (14.2 – 15.8) for the listed range of ν

In the constant-underpressure scenario,

(25-9.8) 0.28 / (1- 0.28) + 9.8 MPa/km = **15.7 MPa/km or 0.69 psi** (15.0 – 16.5) for the listed range of ν.

Thus, four estimates of the minimum-stress (or fracture) gradient have been derived using two methods applied to two initial pore pressure models. The median estimate is ~15.3 MPa/km or 0.67 psi, and uncertainties are ~0.5 MPa/km. Site-specific pore pressure gradient and Poisson's ratio data will reduce the uncertainty of these models.

2.6 Geomechanics

Preliminary geomechanical data is obtained from regional literature sources and Department of Energy Partnership Projects. Preliminary petrophysical data is also obtained from regional literature sources and Department of Energy Partnership Projects and log analysis of wells located within 10 miles of the project area. Open hole log data was used to perform a petrophysical evaluation using Techlog Wellbore Software Platform software. The majority of the wells only contained SP, Resistivity and Compressional Sonic data; therefore, the interpretation was focused on estimation of lithology, Vshale, Porosity, Permeability, and capillary pressures. Due to the lack of density and shear logs, only analogue data was used for rock mechanical properties estimate.

To achieve the correct characterization of the overlying containment zones and through the injection zones, an enhanced log suite is needed as well as a detailed geomechanical testing program to be performed in conjunction with the installation of one or more of the Class VI injection wells and or/ associated monitoring wells. A testing procedure for obtaining *in situ* geomechanical data across the Injection Zone and the Confining Zone and laboratory analyses of recovered whole and rotary core samples is detailed in Module D "*Pre-Operational Testing and Logging Plan*."

The Arbuckle is the principal reservoir used for wastewater disposal in Oklahoma: Arbuckle injection ramped significantly from 1980 until 2000 during NBU's enhanced recovery from polymer period. NBU's injection in those years averaged over 800,000 bbl. per month of Arbuckle injection. In 1996, saltwater disposal peaked at an estimated 40,000 barrels of water per day. Field injection data supports over 357 million bbl. of water have been injected into the Arbuckle at NBU. Increased seismicity in Oklahoma due to wastewater disposal has focused attention on pore pressure within the Arbuckle reservoir. In Osage County — a seismically quiet part of the state — continuous measurements of fluid pressure reveal that pressure in the reservoir is increasing by at least 5 kilopascals (kPa) annually and sometimes at a much higher rate (Barbour and Pollitz, 2019). It is assumed that the source of this increase is saltwater disposal.

Fluid pressures in the Arbuckle have been sporadically reported for several decades, allowing estimation of pre-industrial pressure (P_0). In Osage County, 10 drill-stem tests from 1956 to 1974 show an average underpressure of 1.07 MPa (~155 psi), with 90 percent confidence interval (CI) 0.89–1.36 MPa (Hussey and Halihan, 2018; Barbour and Pollitz, 2019). Pre-1985 drill-stem tests between depths of ~1,500 feet and ~3,300 feet in the Arbuckle just east of Osage in Kay County, Oklahoma, reveal a gradient of ~13.7 MPa/mile (~1,987 psi/mile). This gradient corresponds to an underpressure at the top of basement (~2,950 feet below ground surface, bgs) of ~1.2 MPa (~174 psi) in Kay County or 1.7 MPa (~247 psi) in northwestern Osage County (~4,265 feet bgs). Thus, three estimates of pre-injection underpressure at the top of basement are 1.07 MPa (~247 psi), 1.2 MPa (~174 psi), and 1.7 MPa (~247 psi) sub-hydrostatic.

Continuous monitoring from 2010 to mid-2016 (Nolte, 2017) of the Arbuckle in southern Kansas documents an increase from 0.63 MPa (~91 psi) underpressure to 0.46 MPa (~67 psi) underpressure: Specifically, at a depth of 5,049 feet bgs, pressure in June 2016 measured 14.6MPa (~2,118 psi) compared to the 15.1 MPa (~2,190 psi) freshwater hydrostatic pressure.

In April 2017, USGS instrumented an inactive wastewater disposal well in central Osage County to measure pore pressure in the Arbuckle at ~3,084 feet bgs. Initially, fluid pressure measured 0.46 MPa (~67 psi) below hydrostatic, the same value as reported one year earlier in southern Kansas (Nolte, 2017). In the following 1.5 years, the fluid level rose by 4.6 feet and pressure increased by 14 kPa, or 0.014 MPa (~2 psi), in the well. Pressure peaked at ~0.445 MPa (~64.5 psi) sub-hydrostatic in late 2019 before leveling off near 0.450 MPa (~65 psi) sub-hydrostatic through the end of reporting in November 2020 (Barbour et al., 2021).

The differences between these most recent pore pressure data from the earlier estimates of 1.07, 1.2, and 1.7 MPa sub-hydrostatic suggests that 0.62-1.25 MPa (~90 psi to ~181 psi) pore pressure increase has already occurred. For discussion, intermediate values of ~0.75 MPa (~109 psi) increase and a modern underpressure of 0.45 MPa (~65 psi) will be used subsequently. It is not known, however, whether a model in which underpressure is constant with depth *z* (in km), such as

$$P_0(z) = 9.8\,z - 1.2 \text{ MPa}$$

or one in which the pressure gradient is constant, such as

$$P_0(z) = 8.5\,z \text{ MPa}$$

Where

P_0 = the initial pore fluid pressure, prior to injection or extraction

z = hypocentral depth in km

is more appropriate for P_0 in the Arbuckle. Site-specific data gathered during this project will refine these values, especially the modern underpressure. Recalling that P_0 refers to the long-term (e.g., 1950s) pore pressure, and ΔP is the difference between the instantaneous pressure and P_0. Therefore, when considering fault slip potential modeling or other applications, it is important to remember that around 1 MPa (~145 psi) of pressure increase has already occurred, so the operative values of ΔP should be adjusted accordingly.

Full Stress Tensor Calculation

To calculate shear and normal tractions — and hence ΔP — the magnitudes of the three principal stresses must be known. Following Levandowski et al. (2018a), these magnitudes can be computed as functions of P_0, μ, hypocentral depth, overburden density, faulting environment, and the stress ratio (see below).

The equation below implies the relationship between the magnitudes of the maximally compressive stress S_1 and minimally compressive stress S_3 (Zoback, 2010):

$$\frac{(S_1 - P_0)}{(S_3 - P_0)} = [\sqrt{\mu^2 = 1} + \mu]^2 \equiv \gamma$$

Where

P_0 = the initial pore fluid pressure, prior to injection or extraction

S_1 = the magnitude of the maximally compressive stress

S_3 = the magnitude of the minimally compressive stress

μ = the coefficient of friction on the fault

The vertical normal stress at depth z depends on the average density of overburden ρ:

$$S_v = \rho g z$$

Where

ρ = the density of overburden rock

S_v= the magnitude of the vertical stress

g = gravitational acceleration

z = depth

In normal, strike-slip, and thrust faulting environments, S_V can be substituted for S_1, S_2, and S_3, respectively.

To build a three-equation system that can be simultaneously solved for the magnitudes of the three principal stresses are combined with the stress ratio ϕ (Angelier, 1990):

$$\phi = \frac{(S_2 - S_3)}{(S_1 - S_3)} \qquad \text{Equation 2.6.2.3}$$

Where

S_1 = the magnitude of the maximally compressive stress

S_2 = the magnitude of the intermediate stress

S_3 = the magnitude of the minimally compressive stress

ϕ = the stress ratio, as defined by this equation

Inversions of earthquake focal mechanisms can provide both ϕ and the orientations of the principal stresses. Multiplying the unit vectors of the three principal stresses by their respective magnitudes gives the full stress tensor σ. For a fault of interest with a normal vector *n*, the traction vector *t* produced by σ is σ*n*. The magnitude of the normal component gives S_N:

$$S_N = \boldsymbol{t} \cdot \boldsymbol{n}$$

Where

S_N = the magnitude of the normal traction

t = the traction vector

n = the unit normal vector to the fault

The shear traction vector τ is given as the cross product of *n* with the normal vector to the plane that contains *t* and *n*.

$$\boldsymbol{\tau} = \boldsymbol{n} \times (\boldsymbol{t} \times \boldsymbol{n})$$

Where

τ = the shear traction vector

t = the traction vector

n = the unit normal vector to the fault

The shear traction magnitude τ is simply the magnitude of $\boldsymbol{\tau}$. Finally, combining these equations solve for ΔP for the fault in question.

2.6.1 Shale Ductility

In Earth Science, ductility refers to the capacity of a rock to deform to large strains without macroscopic fracturing. Unconsolidated sediments are mechanically weaker than lithified rock, but their ductility provides certain advantages for carbon storage. For sealing units (confining zones), stress in unconsolidated sediments is typically accommodated by creep behavior promoted by high clay contents that induce self-sealing behavior. This has major implications on the suitability of confining zone units because ductile deformation of clay/mudstone prevents potential leakage pathways to the surface. These include natural pathways such as faults, and man-made pathways such as well boreholes.

1. Ductile deformation is typically characterized by diffuse deformation (i.e., lacking a discrete fault plane) and is accompanied on a stress-strain plot by a steady state sliding at failure, compared to the sharp stress drop observed in experiments during brittle failure.

The ductility of a shale top seal is a function of compaction state. Uncompacted, low-density shales are extremely ductile and can thus accommodate substantial amounts of strain without undergoing brittle failure and loss of top seal integrity. Highly compacted, dense shales are extremely brittle and may undergo brittle failure and loss of top seal integrity with very small amounts of strain.

Figure 2-26 shows the relationship between ductility and density for 68 shales. The ductility of the shales was measured in the laboratory at confining pressures of 1, 200, and 500 kg/cm^2 (i.e., 14, 2,845, and 7,112 psi). All samples were deformed in compression.

The ductility of a shale top-seal can be predictive of its long-term integrity. More ductile material withstands larger strain without fracturing and thus remains impermeable. Shale ductility at a given temperature and pressure depends on compaction state—dewatering embrittles muds as diagenesis lithifies them to shale—and on composition, such as total organic matter content (TOC) and quartz, carbonate, chert, and shale abundance.

The compositional dependencies lead to important fluctuations in ductility within a given unit that reflect the depositional environment, especially within a sequence-stratigraphic framework. In the Woodford Shale in northern Oklahoma, transgressive systems tracts typically correspond to ductile high-TOC clay/mudstone compared to brittle quartz- and carbonate-rich lithologies associated with highstand systems tracts (Infante, 2015). The former display upward-increasing gamma ray values and vice-versa (Slatt and Abousleiman, 2011) in borehole gamma-ray logs, though high gamma-ray values alone do not necessarily indicate ductility (Verma et al., 2012). Rather than relying solely on gamma rays, Becerra et al. (2018) constructed detailed bedding-scale (i.e., ~10 cm) lithologic logs of the alternating "soft" / "hard" lithologies of the Woodford, which are more precisely characterized as comparatively rich / poor in shale, TOC, Mo, U, Ti, Zr, K, and Al by laboratory methods (XRD, XRF, thin-section petrography, SEM). Laboratory Unconfined Compressive Strength (UCS) tests revealed that the "soft" shales' ductility reflects substantial plastic deformation before failure, while the brittle "hard" beds did not support plastic strain before failure, and — although the UCS values range only from 135 MPa (shale) (~19580 psi) to 155 MPa (chert) (~22481 psi) — their Young's moduli span 9 to ~27 GPa, respectively. This dichotomous behavior also manifests in outcrop: Two bedding-perpendicular conjugate fracture sets are abundant in the brittle beds but irregular or absent in the soft materials (Galvis-Portilla et al., 2016).

Because the bimodal ductility of the Woodford strata is conserved from microscopic- to borehole- to outcrop-scale, site-specific data from a stratigraphic test well at the proposed injection site will be diagnostic of the sub-regional ductility profile. For example, stress-strain data from UCS tests on cored material can be used to quantify brittleness — as the ratio of reversible elastic strain to total strain at failure (Hucka and Das, 1974). Additional measurable proxies for ductility and threshold values for embrittlement that have been determined specifically for the bimodal Woodford strata include quartz content >85 percent, Si/Al ratio >0.2, "mineralogical brittleness" ratio {quartz+carbonate}: {quartz+carbonate+clays} > 0.85 (after Jarvie et al., 2007), TOC <6 percent, and hardness >700 LH (Becerra et al., 2018). Site-specific samples will be analyzed according to these and similar criteria to assess prospects for long-term top-seal integrity.

Density Constraints

The ductility can be inferred from the density of the material. Denser shales, such as those greater than 2.1 g/cm^3, are more brittle and can withstand less strain before fracturing. Less-dense shales, such as those less than 2.1 g/cm^3, are more ductile and can withstand larger strains before fracturing.

Pressure Constraints

Additionally, ductility of a material increases with increasing confining pressure. The ductility of a shale top seal decreases with progressive burial, compaction, and diagenesis within a sedimentary basin. The mechanical properties are not constant but change with the progressive burial as the top seal is converted from a mud to a rock. The ductility of a shale top seal also increases in response to increasing confining pressure. Thus, a shale with constant mechanical properties will have a lower ductility at shallow depths than at greater depth. Since a shale top seal does not have constant mechanical properties with progressive burial, compaction decreases ductility at the same time as confining pressure increases ductility.

Depth Constraints

Density and shale ductility vs. brittleness are functions of depth. Laboratory data are plotted on a shale compaction curve showing density vs. depth. Ductile shales do not fracture; brittle shales do. A low-density shale at a depth of 500 m (1,640 ft) is more ductile than a highly compacted shale at a depth of 5,000 m (16,404 ft) in the center of the basin. In other words, identical traps, one from a deep graben and one from an adjacent marginal platform, will present different seal risk.

Time Constraints

Ductility changes not only with depth of burial but also with time and progressive subsidence. A shale top seal now buried at 4,000 meters and having a density of 2.6 g/cm^3 was once buried at a shallower depth and had a lower density. This now-brittle seal was once ductile.

Predicting Paleoductility

To predict paleoductility, we must know both the density and the confining pressure at the time of deformation. A database of top seal mechanical properties over a range of pertinent confining pressures is a basic tool for seal analysis. Ductility-time plots can be constructed from shale compaction curves and burial history curves. Burial history curves give the depth of burial of a top seal at a specific time. Shale compaction curves let us infer the shale density at a specific depth of burial and time.

Figure 2-27 is a ductility-time plot for an Upper Jurassic top seal in the Central Graben in the North Sea. The plot shows the paleodensity and inferred paleoductility during progressive burial of shales at the 141- and 151-million-year (m/y.) sequence boundaries. Prior to approximately 100 Ma, the Late Jurassic shale top seal had a density of three and was ductile. Strain prior to 100 Ma would not contribute to seal risk. Any deformation occurring after 100 Ma could have caused fracturing, given sufficiently high strains.

2.6.2 Stresses

Qin et.al., (2019), studied an area that included the proposed CCS site and predominately counties west and south of the area. Their study included an improved stress map that determined a gradual transition from oblique normal faulting in western Oklahoma to strike-slip faulting in central and eastern Oklahoma. The stress amplitude ratio shows a strong correlation with pore pressure from hydrogeologic models, suggesting that pore pressure exhibits a measurable influence on stress patterns. The results indicate that most active faults have near vertical planes (planarity >0.8 and dip >70◦), and there is a strong correlation between fault length and maximum magnitude on each fault. The fault trends show prominent conjugate sets that strike 55–75 degrees and 105–125 degrees. A comparison with mapped sedimentary faults and basement fractures reveals common tectonic control. Based on 3-D Mohr circles, they find that 78 percent of the faults are critically stressed (understress ≤0.2), while several seismogenic faults are misoriented with high understress (>0.4).

2.6.3 Pore Pressures

The Arbuckle Formation is the principal reservoir used for wastewater disposal in Oklahoma far beyond any other reservoir. An estimated 374 million barrels of water have been disposed of into the rocks of the Arbuckle Formation in the Burbank Field alone. Increased seismicity in Oklahoma due to wastewater disposal has heightened the look at pore pressure within the Arbuckle reservoir.

In April of 2017, the U.S. Geological Survey (USGS) instrumented an inactive wastewater disposal well in central Osage County to measure pore pressure in the Arbuckle and a broadband seismometer buried at the wellhead to measure seismic waves. Tubing (73 mm i.d.) extends from the surface to the open-hole interval (920 to 960 m) inside steel casing. The annulus between the tubing and casing is sealed at the top of the open-hole interval, which lies immediately below the upper contact between the Arbuckle and the Hominy Sandstone and Woodford Shale units. The overall increase in pressure in the Arbuckle can be compared to independent evidence from drill-stem tests (DSTs), which provide a means to directly measure pore pressure gradients at a given location. At the Mervine Field in neighboring Kay County, Oklahoma, DSTs collected prior to 1985 (Davis, 1985) show a sub-hydrostatic pore pressure gradient of 8.48 kPa/m and an equivalent Arbuckle under pressure of ~1.86 MPa. In Osage County, DSTs collected between 1956 and 1974 (S. Hussey, written communication, May 24, 2018) show reservoir under pressures of ~0.84 to 1.32 MPa on average. Considering the elapsed time between the predisposal DSTs and our continuous measurements, the relative pressure increase implied by the Osage DSTs is similar in scale to the KGS observations. Complete records of injection volume from Osage County notwithstanding, it is likely that the overall increase in reservoir pressure is a result of decades of wastewater disposal across the county and beyond.

A vertical pressure profile in the project area will be determined during installation of the Class VI injection wells and the stratigraphic test well. A testing procedure for obtaining formation pressures is detailed in Module D "*Pre-Operational Testing and logging Plan*".

2.7 Geochemistry

A review of available regional geochemistry data (e.g., Department of Energy regional partnership publications, regional analogs, and USGS water quality samples database) was conducted to make an initial assessment of CO_2 compatibility with mineralogy of the injection zones. Based on this review, no compatibility issues are predicted in the reservoir formations. This initial assessment will be confirmed with site-specific data from rock samples collected from a stratigraphic test or injection well to fully characterize the geochemistry of the injection and confining zones. More information about the data collection program can be found in Module D, "*Pre-Operational Testing and Logging Plan*."

The data collection program contained in Plan *"Pre-Operational Testing and Logging Plan"* (submitted in Module D) will be designed and implemented to fully characterize mineralogy in the injection and confining zones. Based on select investigations performed for the Department of Energy Regional Partnerships and regional analogues, no compatibility issues are predicted in the reservoir formation.

Porous intervals below the base of the Vanoss which is being treated as the lowermost USDW and down to the base of the Arbuckle all contain saline brines. Historic analysis of fluid samples dating back to 2016 from the 34-40 Well (API #3511341950) all show TDS values between 85,000 and 140,000 ppm for the Arbuckle. Open hole log analysis techniques can be used to define the vertical distribution in concentration of the formation brines.

2.7.1 Methodology for Salinity Determination

The methodology is very similar to the USDW determination. The general theory in determining water quality in clean water-bearing zones flows from the formation water resistivity (R_w), which can be calculated by using the Archie equation (Schlumberger, 1988). The underlying assumption in the Archie equation is that the zone or permeable bed in which water resistivity is to be determined is 100 percent water saturated and must not contain any clay or shale (*i.e.*, clean sand). It is further assumed that the bed is sufficiently thick so that the deep investigation resistivity open hole geophysical logging tool is not affected by shoulder beds or is affected by mud filtrate invasion.

The general form of the water saturation equation is:

$$Swn_W^n = \frac{R_w}{(\phi^m \ x \ R_t)}$$

where

S_w = water saturation of the uninvaded formation

n = saturation exponent, which varies from 1.8 to 4.0 but normally is 2.0

Rw = formation water resistivity at formation temperature

Φ = porosity

m = cementation exponent, which varies from 1.7 to 3.0 but normally is 2.0

R_t = true resistivity of the formation, corrected for invasion, borehole, thin bed, and other environmental effects

In shaly rocks, the Archie law over-estimates the water saturation. Many models have been developed that consider the shale volume ("Vshale") in the formation matrix to account for the excess in conductivity. As an example, the Simandoux equation (1963) is among the most used ones and reduces mathematically to the Archie equation when the formation is clean (*i.e.*, Vsh=0).

In the case of a fully saturated formation, the resistivity (R_t in ohm-meters) is a function of: 1) resistivity of the formation water, 2) amount and type of fluid present, and 3) the pore structure geometry. The rock matrix generally has zero conductivity (*i.e.*, has infinitely high resistivity) and therefore is not generally a factor in the resistivity log response. Induction geophysical logging determines resistivity or Rt by inducing electrical current into the formation and measuring conductivity (reciprocal of resistivity). The induction logging device investigates deeply into a formation and is focused to minimize the influences of borehole effects, surrounding formations, and invaded zone (Schlumberger, 1987).

Therefore, the induction log is considered to measure the true resistivity of the formation (Schlumberger, 1987). The conductivity measured on the induction log is the most accurate resistivity measurement for resistivities under 2 ohm-meters.

Electrical conduction in sedimentary rocks almost always results from the transport of ions in the pore-filled formation water and is affected by the amount and type of fluid present and pore structure geometry (Schlumberger, 1988). In general, high-porosity sediments with open, well-connected pores have lower resistivity and low-porosity sediments with sinuous and constricted pore systems have higher resistivity.

It has been established experimentally that the resistivity of a clean, water-bearing formation (*i.e.*, one containing no appreciable clay or hydrocarbons) is proportional to the resistivity of the saline formation water (Schlumberger, 1988). The constant of proportionality for this relationship is called the formation resistivity factor (F), where:

$$F = \frac{R_t}{R_w}$$

For a given porosity, the formation resistivity factor (F) remains nearly constant for all values of R_w below 1.0 ohm-meter. For fresher, more resistive waters, the value of F may decrease as R_w increases (Schlumberger, 1987). It has been found that for a given formation water, the greater the porosity of a formation, the lower the resistivity of the formation (R_t) and the lower the formation factor. Therefore, the formation factor is inversely related to the formation porosity. In 1942, G.E Archie proposed the following relationship (commonly known as Archie's Law) between the formation factor and porosity based on experimental data:

$$F = \frac{a}{\phi^m}$$

where

ϕ = porosity

a = an empirical constant

m = a cementation factor or exponent.

In sandstones, the cementation factor is assumed to be 2, but can vary from 1.2 to 2.2. In the nearer surface sandstones, as sorting, cementation, and compaction decrease, the cementation factor can also decrease. Experience over the years has shown that the following form of Archie's Law generally holds for sands in the Gulf Coast and is known as the Humble Relationship (Schlumberger, 1987):

$$F = \frac{0.81}{\phi^2}$$

By combining the two equations:

$$\frac{R_t}{R_w} = \frac{0.81}{\phi^2}$$

Resistivities of saline solutions vary as a function of NaCl concentration and temperature. The relationship between temperature, NaCl concentration, and resistivity are typically shown in the form of a nomograph for computational ease (**Figure 2-19**).

2.7.2 Formation Brine Properties

No wells have been drilled within Osage County for this Class VI permit application as of initial submittal. Formation fluid samples will be collected from the injection interval and analyzed according to the *"Pre-Operational Testing and Logging Plan*," which is submitted in Module D. This plan details the additional geological data to be acquired during the drilling and testing of a stratigraphic well and the injection wells. It is thought that there is some dilution of formation brine in the Arbuckle as a result of water disposal related oil recovery operations at the North Burbank Unit. Injection of produced water into the Arbuckle started in 1970's and peaked in 1984. Injection volumes during this period averaged 850,000 barrels per month. Currently there are approximately 16,000 barrels per day that are being injected into the Arbuckle. Average values are listed below.

Salinity: 85,000 to 140,000 ppm

Specific Gravity: 1.06 to 1.11

PH: 5.4 to 6.2

Temperature: > 105 (upper) to 135 (lower) F

2.7.2.1 Temperature

Obtaining reliable temperature data from existing regional data, and not directly from a stratigraphic test, well is challenging. In USGS Open file Report 2019-1143, the authors, Lauri A. Burke, Ofori N. Pearson, and Scott A. Kinney, recognized that while bottom hole temperature measurements are useful for the characterization of a subsurface thermal regime, they are not without problem. Geographically, variability exists and areas with similar characteristics can be grouped together for ease of gradient calculation. Due to both the nature of the borehole radius and fluid invasion (mud filtrate) the temperature measured at the borehole and attenuates over time (Poulsen et al., 2012). These temperatures are affected by the time duration between the end of circulation and the time the logging tool reaches the drilled bottom of the well. As such, they are likely to represent cooler than actual temperatures, as the mud column has not had sufficient time to reach temperature equilibrium.

Cheung, 1978, realized that heat generated from depths greater than 600 miles beneath the earth's surface has not reached upper portions of the crust by heat conduction alone. Igneous intrusion and volcanism are means or upward mass transfer of heat. These processes are responsible for many of the geothermal anomalies seen at the earth's surface. There are several factors related to the geothermal gradient, (Cheung, 1978).

- Climate
- Thermal conductivities
- Abnormal pore pressure
- Migrating fluids
- Tectonics
- Distribution of radioactive isotopes

Therefore, the use of correction tools, such as thermal gradient maps are useful in helping to determine true bottomhole temperatures. The geothermal gradient is defined as the increase in temperature with depth. Most workers have applied an equation-based correction to raw bottomhole temperatures to account for nonequilibrium conditions before calculating geothermal gradient or heat flow. The corrected gradients have then generally been smoothed before contouring to generate the maps, (Ruppel, et.al. 2005).

Cheung, (1975) utilized equilibrated temperatures including temperature logs, temperatures from shut-in gas well pressure tests, and from air-drilled wells in his study area of Oklahoma. A correction factor used to correct the bottom-hole temperatures was obtained by comparing the differences between bottom-hole temperatures and equilibrated temperatures as a function of depth. Because surface ground temperatures are often different from mean annual temperature, a near surface temperature, determined by extrapolation of reliable temperature at depth, Chung, (1975) used a control point for constructing a linear gradient where subsurface temperatures are available for a single depth. Cheung, (1975) created two maps. One shows the geothermal gradients of normally pressured formations in Oklahoma. The other shows the temperature gradients within the abnormally pressured Lower Pennsylvanian Upper Mississippian rocks in the deep part of the Anadarko and Ardmore basins. Temperature gradients change abruptly as pore pressure becomes abnormal. Cheung, (1975) determined that the gradient maps correlate well with major tectonic-structural features. The low gradients of Anadarko and Ardmore basins reflect their thick sedimentary rock section, and presence of abnormally pressured formations at depth that result in restriction of upward heat flow. The high gradients of Arkoma basin suggest that the origin of the basin may be associated with a continental margin or rift zone. For areas outside the Arkoma basin, geothermal gradients appear to be related primarily to basement configuration and fluid migration. Several geothermal-gradient anomalies correlate well with oil and gas accumulations; the best correlations involve gradients within the abnormally pressured formation. Correlations with geophysical features further suggest the geothermal gradients of Oklahoma are generally related to basement relief. Using the geothermal gradient map by Cheung, a geothermal gradient of 1.4 deg. / 100ft. with a mean surface temperature of 74 degrees, the estimated subsurface temperature for the injection interval at a depth of 4,000' each interval can be calculated to be 102.5 degrees. Bottomhole temperatures for the Arbuckle range from 105 (upper Arbuckle) to 135 degrees (lower Arbuckle). This estimated temperature can be compared to the measured temperature from the 34-40 well used to measure the formation brine properties.

Based on a review of available data, the bottom-hole temperature (BHT) at the Class VI site is estimated at 120 degrees F (4,600 feet). This initial assessment will be confirmed with site-specific data obtained from a stratigraphic test or injection well.

Estimating formation temperature from existing regional data is challenging. While bottomhole temperature measurements are useful for the characterization of a subsurface thermal regime, they are not without problem. The temperature measured at the bottom of the borehole will be affected by both drilling fluid invasion and the borehole radius (Poulsen et al., 2012). Additionally, temperature is affected by the time between the end of circulation and the time the logging tool reaches the drilled bottom of the well. As such, measured temperature is likely to represent cooler than actual temperature, as the mud column often has not had sufficient time to reach temperature equilibrium with the formation. Geographic variability also exists, and areas with similar characteristics can be grouped together for ease of a temperature gradient calculation.

In the AoR, Cheung's (1975) map suggests a gradient of approximately14 degrees F/1,000 feet. For a mean annual surface temperature of 74 degrees F, this slope predicts a temperature of 123 degrees F at 3,500 feet below ground. This estimate is in reasonable agreement with the estimated 101.67 degrees F bottomhole temperature at 3,500 feet, especially considering the transient cooling effect of drilling fluid and mud.

2.7.2.2 Salinity

Figure 2-28 is a regional map that shows the distribution of salinity values for the Arbuckle. Note that in the vicinity of the proposed project site the salinity values range between 100,000 and 200,000 TDS.

Recent analysis of formation fluids from the Arbuckle southeast of the injection site is 93,000 TDS. This value stands out as indicating that within this area the formation brines within the Arbuckle have been somewhat diluted in response to water disposal operations. Fluid samples will be collected from a stratigraphic test-well to better evaluate the local total dissolved solids. It is important to note that the location of the stratigraphic test well is west southwest of the site and therefore should yield higher TDS values.

2.7.2.3 Viscosity

Viscosity is the tendency of a fluid to resist flow. The approximate formation brine viscosity at reservoir conditions is determined using a Microsoft EXCEL spreadsheet correlation as a function of pressure, temperature, and NaCl content developed by Douglas M Boone in 1993. At the assumed formation conditions, the injection interval water (brine) viscosities are expected to be approximately:

1) 0.5173 centipoise in the Arbuckle Injection Zone (temperature = 101.67° F at a reference depth of 3,500 feet).

2.7.2.4 Additional Properties

Additional information pertaining to Arbuckle properties will be collected from a stratigraphic test well that is to be drilled in the fourth quarter of 2023.

2.7.3 Compatibility of the CO_2 with Subsurface Fluids and Minerals

While no direct evaluation of CO_2-brine interactions within the proposed CCS site has taken place, 55 miles to the northwest, in Sumner County, Kansas, a successful small scale CO_2 sequestration test in the Wellington Field was performed. Initially the injection of CO_2 was planned for both the Mississippian and Arbuckle formations; injection into the Arbuckle was not performed due to permitting reasons. Between January 9th and June 16th, 2016, approximately 20,000 metric tons of CO_2 was injected in the upper part of the Mississippian reservoir. A total of 1,101 truckloads, 19,803 metric tonnes, average of 120 tonnes per day were delivered over the course of injection. Post injection of CO_2 injection, the KGS 2-32 well was converted to water injector and monitored. CO_2 -EOR progression in the field was monitored weekly with fluid level, temperature, and production recording, and formation fluid composition sampling.

As a result of CO_2 injection, the observed incremental average oil production increase was ~68 percent with only ~18 percent of injected CO_2 produced back. Simple but robust monitoring technologies proved to be very efficient in detection and locating of CO_2. High CO_2 reservoir retentions with low yields within actively producing field could help to estimate real-world risks of CO_2 geological storage for future projects. Wellington Field CO_2-EOR was executed in a controlled environment with high efficiency.

In the absence of major structural features such as faults, a key interaction of concern between the CO_2 and the rock of the confining interval, is the potential for the CO_2 to exceed the capillary entry pressure. If the CO_2 breaches the cap rock the plume could potentially leave the reservoir, migrating upwards into layers above the USDW (Gaus, 2010). However, the nature of shale (due in part to the small pore size) imparts a high capillary entry pressure, and also high viscous drag. These properties prevent the upward migration of CO_2 into the caprock. The acidification of the brine may allow the buoyant CO_2 plume to modify the initial pore structure of the cap rock. The impact and degree of these modifications depends on the kinetics of the reaction for a specific site and the degree of heterogeneity of the cap rock (Espinoza & Santamarina, 2017).

Interactions between CO_2 and the rocks in the subsurface may be categorized as those during the period of injection or immediately following injection, and interactions that occur over the long term of CO_2 storage. While the interactions occurring during injection and in the early phase of CO_2 capture can be directly studied and evaluated, the interactions that happen over geologic time can be evaluated through modeling and other forms of prediction. Although direct data for the proposed site location does not exist, the sampling program has been designed to include fundamental testing to evaluate key geochemical parameters in Module D "*Pre-Operational Testing and Logging Plan*".

The main drivers of CO_2-rock interactions are the dissolution of the CO_2 in the brine, acid induced reactions, reactions caused by changes in the brine concentration, clay desiccation, CO_2 and rock interactions, and the potential for other reactions caused by gasses present other than CO_2. Evaluation of the impact of CO_2 on injection and seal interval rocks and cements and the identification of potential additional reaction pathways can be evaluated for a specific site location and specific CO_2 stream to be injected. Evaluation of the interactions along operational interfaces (i.e., the wellbore, cements, host rock and cap rock) also need to be evaluated for both CO_2 and the acidified brine (Gaus, 2010). The sampling program has been designed to include these tests on both injection interval and caprock (See *"D.1 – Pre-Operational Testing and Logging*", which is submitted in Module D).

2.8 Economic Geology of the Area

The proposed site is located on the northern end of the Burbank oil field's North Burbank Unit CO_2 tertiary flood. The Burbank Field has produced oil and gas from the Pennsylvanian age Burbank (Red Fork) sands. The area has been actively explored since 1920. The Arbuckle in nortwestern Osage County has not been hydrocarbon productive.

2.9 Site Suitability Summary

The Osage County, North Burbank Unit CCS site is located within the broad platform that dips less than 2 degrees to the west. Locally, this platform or shelf is basement supported from the large igneous intrusions to the southeast that created and formed the Osage High. The Arbuckle Formation has been identified by numerous researchers as one of the best potential saline aquifer sequestration zones in Oklahoma. Regionally, the Platform area encompasses much of northeastern Oklahoma. Charpentier, 1995, described the Cherokee Platform as an area that extends from southeastern Kansas and part of southwestern Missouri to northeastern Oklahoma and is 235 miles long (north-south) by 210 miles wide (east-west) having an area of 26,500 square miles. The platform is bound on the western edge by the Nemaha Ride (Uplift) and to the east by the Ozark Uplift. Hydrocarbon exploration in Osage County has been prolific since the early 1900's. However, production from the Arbuckle in western Osage County has not been as prolific as the Upper Mississippian strata and shallower Pennsylvanian formations. The NBU CCS site is located within the northern confines of a Lower Pennsylvanian Tertiary recovery project located in the North Burbank Unit CO_2 flood in a formation 508 feet shallower than the Arbuckle. Shallow well density in the AoR is limited to 16 deep penetrations. The proposed injection interval is the dolomitic and limestone rich Arbuckle Formation. This proposed CCS site is located along the western flank of the Cherokee Platform located between the Nemaha Ridge to the west and Ozark Uplift to the east.

The Arbuckle Formation saline rocks are found at depths of 3,420 feet to 4,520 feet at the proposed CCS site. The gross carbon storage interval is approximately 1,100 feet with porous and permeable rocks. The

Arbuckle in northeastern Oklahoma was deposited during late Cambrian-middle Ordovician time when the interior of the United States was covered by a shallow sea. The formation is comprised primarily of dolomites and consists of multiple members or units based on magnesium concentrations. The Arbuckle thickens to the southwest of the proposed CCS site, regional dip is to the west-southwest. An in-zone monitoring well will be constructed east of the injection site to monitor changes in pressure and the CO_2 plumes' reaction to the possible regional "up-dip" flow path. The karsted interval of the Arbuckle is proposed to have the greatest CO_2 storage capacity. These karsted intervals will have enhanced porosity and permeability values due to their overall alteration of the dolomite section. The Arbuckle contains only saline zones. A stratigraphic test wells will provide detailed information as to the porosity and permeability of the injection and confining zones. The proposed site has multiple confining units to be confirmed with stratigraphic tests at the proposed sequestration site. The primary confining zone is the Woodford Shale, and the basal confining zone is the weathered igneous Precambrian basement. The Reagan Sandstone may be present at the site between the Arbuckle and the basement. The upper secondary confining zone is the Lower Mississippi, an argillaceous limestone sequence. The regional permeability data for the confining zones illustrate permeabilities of less than 1mD. As stated above, this regional data set will be further enhanced from cores taken from a stratigraphic test well.

Subregionally, the Tyner Shale of the Simpson Group at an average thickness of 60' feet and the Lower and Middle Mississippian tight limes exceeding 100'of thickness will be cored for confirmation of the confining attributes.

Together these two confining zones would serve as robust impermeable sealing units for the NBU CCS injection project.

CO_2 has not been injected in the Arbuckle Formation in Oklahoma for the tertiary recovery of oil. The Arbuckle is generally under a strong water drive and therefore this water drive significantly reduces tertiary oil recovery. At the NBU CCS site, the regional dip is extremely shallow and therefore subsurface fluid flow in the Arbuckle is limited. However, the Ellenburger Formation, time equivalent to the Arbuckle and with similar compositional lithologies and saline water characteristics has been tertiary flooded in multiple West Texas fields. Approximately 2 billion bbl of Tertiary oil has been recovered from West Texas Paleozoic carbonates from similar reservoir characteristics. Locally, CO_2 sequestration has been demonstrated to work in the Mississippian limestone northwest of the proposed site without compatibility problems. Therefore, there is a very low probability of the injected CO_2 reacting detrimentally with the injection or confining zones. This hypothesis will be confirmed from the testing on the injection and confining intervals from the stratigraphic test well to be drilled prior to the construction phase of the project.

The preliminary CO_2 plume modeling demonstrates limited movement of the plume after injection has ceased due to the low formational dip rate in the area. The limited Arbuckle wildcatting to the target injection horizon within the AoR has produced only dry holes. There are 16 Arbuckle penetrations that have been drilled within the AoR, most drilled between the 1960's to mid-1980's. These wells have been evaluated to determine if reentry is required for additional well bore isolation and or replugging, this information is contained in the Corrective Action section of the "*AoR and CA Plan*" in Module B.

The site's proximity to the regional data sets from company owned oil and gas operations in the area and the evaluation of the available information indicate that 1) there are no USDWs within the AoR 2) there are multiple confining units that will restrict the vertical migration of fluids out of the injection zone 3) the geologic setting is such that the risk of induced seismicity due to injection operations is extremely low and 4) the injection zone is sufficient to store the anticipated volumes of injected CO2. The regional petrophysical data used in the preliminary reservoir modeling analysis supports the rate and storage capacity numbers obtained. The modeling estimates will be confirmed as conservative as additional petrophysical data is acquired.

The site will be surveyed for archeological or cultural sites and threatened or endangered species prior to the construction phase of the project. There are no mines or subsurface cleanup sites within or near the AoR. CPS will have full access to the injection site during all phases of the project. Although the site is located in Osage County, Oklahoma – and considered to be within the tribal lands of the Osage Nation, the site actually located on private land owned by CapturePoint and the Osage Nation's interest only pertains to the mineral rights, not the surface ownership. The site is also located in proximity to existing CO_2 pipeline infrastructure and is near industrial CO_2 emitters.

In summary, the site's general location, including the characteristics of the confining and injection zones, contribute to a carbon capture site with excellent reservoir management potential. Faulting is not present within the NBU CCS site area. Furthermore, the site's location in combination with the nature of the properties of the crystalline basement serve to explain the seismically quiet nature of the region surrounding the NBU CCS site.

3.0 AoR and Corrective Action

The fully completed AoR and Corrective Action Plan Report has been submitted via the GSDT. All Tabs that require input data within the module have also been completed and submitted via the GSDT.

The report covers in detail the computational modeling approach to the delineation of the Area of Review (AoR), the Corrective Action Plan relating to existing well penetrations within the AoR and the Reevaluation Schedule for AoR delineation once operations commence. A thorough review of the geology and the hydrogeology was also supplied as an appendix to the main report, along with a comprehensive bibliography of references utilized during the AoR modelling execution and reporting phase.

The AoR and Corrective Action Plan Report satisfies rule requirements 40 CFR 146.82(a)(13), 146.84(b) and 146.84(c).

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

4.0 Financial Responsibility

CapturePoint Solutions LLC (CPS) is providing financial responsibility pursuant to 40 CFR 146.85. CPS expects to be utilizing any one of or a combination of (1) Surety Bonds, (2) Trust Account or (3) Insurance to cover the costs of potential corrective action, emergency and remedial response, injection well plugging, post-injection site care, or site closure. The required information has been submitted via the GSDT. All Tabs that require input data within the module have also been completed and submitted via the GSDT.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

5.0 Injection Well Construction

Pursuant to 40 CFR 146.82(a)(9), (11), and (12) and 40 CFR 146.86 injection wells will be constructed in a manner that utilizes CO_2 resistant materials and permits the use of downhole tools and gauges and be designed to accommodate workover equipment. Wells will be constructed using a 120 ft conductor pipe, 600 ft of surface casing set below the Vanoss, which is being treated as the lowest USDW, intermediate casing set to a depth of ~3,000 ft or below the active Burbank CO_2 tertiary project. The intermediate casing and cement will effectively confine the active North Burbank Unit (NBU) CO_2 tertiary operation from other reservoirs. A production/long string casing will be run and cemented approximately 100' into the top of the Arbuckle reservoir at approximately 3,550'. The production/long casing string and cement will effectively confine the top of the Arbuckle, the two confining zones, and the saline monitoring zone with both CO_2 resistive cement and a casing string. The lower Arbuckle interval will then be completed open hole. At each phase of construction casing will be cemented to the surface.

The Arbuckle zone has been used for water disposal in wells in the NBU since the 1950s or approximately 70 years. Approximately 300 million barrels of net produced water have been effectively injected or disposed of and confined in the Arbuckle reservoir within the NBU. All the disposal wells within the unit have been completed very similarly to what is being recommended with a string of casing cemented in place approximately 100' into the Arbuckle reservoir. The injection/disposal wells are then completed open hole in the Arbuckle reservoir. The long term and high volume of water injection/disposal supports this type of completion technique to effectively and successfully confine the CO_2 in the Arbuckle reservoir at NBU.

The production/long string portion of the offset in-zone monitoring well will be fitted with tubing and a packer. Tail pipe tubing will be run below the packer and into the Arbuckle open hole interval. Piezo ultrasonic pressure transducers or equivalent will be run and set in the open hole portion of the tubing. The transducers will continuously monitor Arbuckle reservoir temperature and pressure. Data will be connected to the surface automation via TEC control line.

5.1 Introduction

The construction details for two injection wells (wells NBU CCS 1 and NBU CCS 2) are described in this attachment. All injection wells will be drilled to a total depth of approximately 4,450 feet and will be open hole completed within their targeted injection zone. These wells will be completed in accordance with 40 CFR 146.86. The drilling and completion of these wells will be sufficient to permit the use of appropriate testing devices and workover tools. Materials used in the construction of these wells will be CO_2 resistant and of sufficient structural strength to meet construction requirements.

5.2 Construction Procedures [40 CFR 146.82(a)(12)]

The drilling and completion of injection and monitoring wells will be completed in such a manner to meet 40 CFR 146.82 (A)(12) and 146.86(b) and to prevent the movement of formation and injection fluids into or between USDWs. During drilling, fluid levels, mud losses/gains will be monitored, and the appropriate mud weights used to control the movement of formation fluid, detailed information regarding fluid movement and well control events are addressed in Table 3 of the Emergency Identification and Response Action section in the Emergency and Remedial Response Plan.

The well completion design calls for the surface casing to be set at approximately 600', well below the Vanoss, which is considered the lowermost USDW for permitting purposes. Surface casing will be cemented to surface to prevent the movement of fluids into or between freshwater zones. Cement integrity will be verified by running a Cement Bond Log.

An intermediate string of casing will be run and cemented in place just below the active Burbank CO_2 tertiary project at approximately 3,050'. The Burbank zones may require significantly higher mud weights in the 12 ppg range and must be covered up prior to drilling into the lower pressure reservoirs below the Burbank zone. A DVD type tool will be run in the casing at a depth of approximately 1,700' to ensure higher weight CO_2 resistant cement is effectively placed across the Burbank zone and that lower weight CO_2 resistant cement is circulated to surface. A cement bond log will be run to confirm cement integrity.

The production/long string casing for each well will be set to a depth of approximately 3,550' through the saline monitoring, both confining layers and approximately 100 feet into the Arbuckle injection zone. CO_2 resistant cement will be circulated to the surface. Cement integrity will be verified by running a Cement Bond Log.

Materials meeting ASTM standards were selected for well construction at this site and were chosen specifically because of their resistance to the effects occurred during exposure to a CO_2 stream and related fluids. Detailed information regarding construction materials is located in section 6.4 of the Testing and Monitoring Plan.

5.3 Casing and Cementing

Well construction materials meet existing industry standards and were selected using ASTM standards and due to their strength and structural characteristics for this case-specific application and to satisfy 40 CFR 146.86(b)(iv). The selected construction materials are designed to withstand downhole conditions such as corrosion, thermal fluctuations, pressures and exposure to formation fluids and the injection stream. Any indication of impacts to structural strength of materials used in the well construction during injection operations will be monitored through implementation of corrosion monitoring at the surface. Details are contained in section 6.4 in the "*Testing and Monitoring Plan"* which has been submitted in Module E – Project Plan Submissions.

Table 5.1 provides casing depths and open hole diameters. **Table 5.2** provides the casing specifications. **Table 5.3** provides the proposed surface, intermediate and production/long string cement programs. **Tables 5.4** and **5.5** provide the tubing and packer specifications. **Figure 5.1** provides a well schematic for the proposed Arbuckle Injection well completions.

The following casing and cementing program will be applied to two injection wells. Conductor pipe will be the first string of casing set. The pipe is auger drilled from surface into the ground to a depth of approximately 120'. Each joint will be welded together as it is run into the ground. The conductor pipe provides the initial stable structural foundation for a well to be drilled.

The 16” surface casing will be set at approximately 600’ and will be cemented with both a lead and a tail cement. From a casing depth of 0-500’, the casing will be cemented with a lead cement of 415 sacks of ECONOCEM™ plus additives or equivalent. From 500-600’, the casing string will be cemented with a tail of 135 sacks of HALCEM™ cement with additives or equivalent. To ensure that cement is circulated to surface, the volume of cement used includes 100% excess. Additionally, excess cement will also be on location to ensure cement is topped off at surface.

The 9-5/8” intermediate casing string will be set at a depth of approximately 3,050’ or just below the active tertiary Burbank CO_2 project. The Burbank reservoir is a higher pressured reservoir and typically requires higher mud weights to drill through and set casing across prior to drilling the lower pressured Arbuckle reservoir. The intermediate casing string will be cemented in two separate stages. A DVD tool will be run in the casing at a depth of approximately 1,700’. The first stage will cement the interval from approximately 3,050’- 1,700’ and consist of approximately 1,020 sacks of SBM CEM SHALECEMTM plus additives or equivalent. The first stage cement will immediately be followed by a first stage bottom plug. Cement pump rates must be reduced to 2-3 bbl/min 150 to 200 feet prior to the plug reaching the DVD tool @1,700. After bumping plug against the casing collar, release the casing pressure to check that float valves are holding. Once verified, remove the top cap, and drop the free fall DVD opening plug into the casing. Calculate the time needed for free fall opening plug to reach the stage tool opening seat in the DVD tool. After the free fall opening plug lands, apply casing pressure to open the tool. Opening pressures are labeled on the tool and packing crate.

After opening the tool, circulate the hole two bottoms up volumes to ensure the hole is clean. Be sure to note, cement circulated to surface from Stage 1.

Begin pumping Stage 2 cementing from 1,700’ to surface consisting of 730 sacks of Neochem™ plus additives or equivalent. Release the DVD closing plug immediately behind the Stage 2 cement and displace with the calculated displacement volume. When the closing plug is within 10 bbls of the stage tool, adjust the pump rate to 3 – 5 bbl/min prior to landing the plug. When the closing plug lands, increase casing pressure to the pre-calculated pressure. Hold pressure for a minimum of 2 minutes, then release casing pressure, and observe flow back. If flow back persists after casing is bled off, this is an indication that the tool is still open, re-apply pressure with an additional 250 psi over previous calculated pressure and hold for two more minutes. Release pressure. RIH w/bit and drill pipe. Drill through DVD plugs and test casing. Drill to approximately 3,569’. POOH.

The production/long string casing will be set at a depth of approximately 3,569’for both the planned injection wells. The production/long string casing will be cemented with a lead and a tail cement. The lead cement, from a depth of 0 – 2,850’, will consist of 225 sacks Neochem™ plus additives or equivalent followed by 130 sacks of SBM CEM SHALECEM™ plus additives or equivalent from 2,850’- 3,569’.

The cement blends and additives have been used in the oil and gas sector and have proven to be an effective cement blend in tertiary CO_2 projects for many decades. NeoCem™ cement is a low-Portland cement system that delivers high-performance compressive strength, elasticity, and shear bond at a lower density than conventional cement systems. The NeoCem™ cement system is the first low-Portland oilfield cement system capable of improving the integrity of the hydraulic annular seal as well as the set-sheath elasticity. The benefits of the NeoCem™ system is to help manage equivalent circulating densities with a lower-density system while retaining key performance parameters and to achieve barrier properties that help withstand the downhole dynamic demands from continual pressure and temperature changes throughout the life of a well. Poz or Pozzolan Ash replaces the cement and is CO_2 resistant. Pheno Seal Medium is an additive that helps with loss circulation and is made up primarily of formica. The lower portion of the long string casing from 2,850 – 3,569’ will require CO_2 resistant cement. Halliburton’s version of this slurry is named SBM CEM SHALECEM™ Sys w/0.25% HR-7 additive. The cement is made up of 50/50 Class

H/Poz and/or Neo Cem TM discussed above plus a Latex 3000™ additive. The Latex 3000™ cement additive is a liquid additive designed to lower equivalent circulating density (ECD) and impart excellent fluid-loss control, high-temperature suspension properties and reinforces acid resistance to cement slurries and is used in both primary casing cementing operations and remedial squeeze work. These two cement blends have been successfully used for many decades in tertiary CO2 floods across Oklahoma, West Texas, New Mexico, Mississippi, and Louisiana. The additive 0.25% HR-7 is a retarder and is made up of sodium lignosulfonate. Small amounts of HR-7 retarder can extend a slurry's temperature range and yield a smoother, more uniform slurry. In addition, HR-7 can provide extended pumping times, early cement-strength development, more predictable thickening times and improve slurry displacement rates at steady pressure. The long string cement volume is calculated including 35% excess cement in the open hole interval to ensure that cement is circulated to surface

Cement bond, variable density and temperature logs will be run for the surface, intermediate and the production/long string casing. Details on the logging program are contained in the "*Pre-Operational Logging and Testing Plan*" submitted in Module D - Pre-Operational Testing. Expected downhole temperatures at 3,569 feet, are not considered detrimental to the cement. The cement will increase in hardness over time and reach a value close to its maximum compressive strength soon after setting. In addition, a pressure fall-off test will be conducted to ensure that the well is completed as designed and that there is no opportunity for fluid migration into USDWs because of injection. Prior to running the tubing in the hole, each string will be visually inspected and drifted to ensure that no defects are present. The connections will be cleaned, and the manufacturer's recommended thread compound will be applied to the pin of each connection before make-up. Each connection of the injection tubing will be externally pressure tested to ensure no leaks exist upon makeup.

Injection packers will also be visually inspected to ensure no defects are present. A pressure test of the annulus will be conducted during installation of the packer to confirm proper setting and absence of leaks. The annular fluid designed for these wells is 9.0 lb/gal (1.08 Sp. Gr.) sodium chloride brine with inhibitors or equivalent. An annulus monitoring and pressurization system will always maintain the annulus at least 100 psi pressure greater than the injection tubing pressure. **Figure 5.2** is an example of the proposed wellhead and Christmas tree for an injection well and will be used on both injection wells. The wellhead is a general term used to describe the component at the surface of an oil and gas well that provides the structural and pressure containing interface for production equipment. The primary purpose of a wellhead is to provide the suspension point and pressure seals for the casing strings. The Christmas tree is installed on top of the wellhead and is a set of valves, spools, and fittings used to control the well fluids during production. All flow-wetted parts of both the wellhead and Christmas tree will be made of CO_2 resistant material.

5.4 Well Construction Details

Tables 5.1 through **5.5** provide the casing and cement programs for the injection wells. Injection wells will be constructed to meet the requirements of 40 CFR 146.86. This includes strategies to prevent the movement of fluids into or between freshwater zones, be constructed to permit the use of downhole tools and workover equipment. Wells will also be constructed using materials meeting ASTM standards and where necessary be constructed using CO_2 resistant materials. During construction the surface, intermediate and production/long string casing will be cemented to surface. This will be followed by running a cement bond log to verify integrity. The last step in well construction will be to perform mechanical integrity tests on each constructed injection well. Construction rules and details are shown in **Table 5.6**.

Details pertaining to equipment used in monitoring injection operations of the well(s) is described in the QASP as an attachment to the "*Testing and Monitoring Plan*". Emergency events and shut-off procedures are described in the "*Emergency and Remedial Response Plan*". Both of these plans are contained in Module E – Project Plan Submissions.

Table 5.1. Casing Depths and Open Hole Diameters

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Conductor	0 – 120	26	Auger/Cement
Surface	0 – 600	20	Set below USDW
Intermediate	0 – 3,050	14 3/4	Base of Burbank
Long String	0 – 3,569	8 5/8	Casing set 100 ft into Arbuckle
Open Hole	3,569 – 4,430	6 1/8	Arbuckle

Table 5.2. Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lbs/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity (BTU/ft.hr deg F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	0 -120	26	24	Sch 20	N/A	Welded	31	N/A	N/A
Surface	0 – 600	20	16	75	J-55	STC	31	2,630	1,020
Intermediate	0 – 3,050	14 3/4	9 5/8	40	J-55	LTC	31	3,950	2,570
Long String	0 – 3,569	8 5/8	7	26	J-55	LTC	31	4,980	4,320
Open Hole	3,569 – 4,430	6 1/8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 5.3. Proposed Surface, Intermediate and Production/Long String Cement Programs

Casing	Openhole Diameter (inches)	Cement Stage	Type Cement	Depth (feet)	Density (ppg)	Excess (%)	Capacity (ft^3/ft)	Yield (ft^3)	Sacks	Volume (bbl)
Surface	20	Lead	ECONOCEM plus additives	0-500	12.7	100	0.7854	1.912	410.8	74
Surface	20	Tail	HALCEM plus additives	500-600	15.6	100	0.7854	1.179	133.2	24

Casing	Openhole Diameter (inches)	Cement Stage	Type Cement	Depth (feet)	Density (ppg)	Excess (%)	Capacity (ft^3/ft)	Yield (ft^3)	Sacks	Volume (bbl)
Surface		Tail Shoe Jt	HALCEM plus additives	555-600	15.6	0	1.2476	1.179	47.6	9
Intermediate	14.75	Stage 1	SBM CEM SHALECEM plus additives	1,700-3,050	14.5	35	0.6813	1.261	984.7	175
Intermediate		Stage 1 Shoe Jt	SBM CEM SHALECEM plus additives	2,960-3,050	14.5	35	0.6813	1.261	30.4	6
Intermediate	14.75	Stage 2	Neochem	600-1,700	11.8	35	0.6813	2.018	502	90
Intermediate	15.124	Stage 2	Neochem	0-600	11.8	0	0.7423	2.018	221	40
Production	8.835	Lead in Csg	Neochem	0-2,850	11.8	0	0.1585	2.018	223.8	40
Production	8.835	Tail in Csg	SBM CEM SHALECEM plus additives	2,850-3,050	14.5	0	0.1585	1.261	25.1	5
Production	8.835	Tail in OH	SBM CEM SHALECEM plus additives	3,050-3,569	14.5	35	0.1385	1.261	77	14
Production		Tail-Shoe Jt	SBM CEM SHALECEM plus additives	3,479-3,579	14.5	0	0.2148	1.261	15.3	4

Table 5.4. Tubing Specifications

Name	Packer Setting Depth	OD (inches)	ID (inches)	Weight (lbs/ft)	Grade (API)	Internal Coating	Design Coupling	Burst Strength (psi)	Collapse Strength (psi)	Joint Yield Strength lbs/ft
4 ½" Tubing	75 feet above injection zone	4.5	3.958	12.75	J-55	Internal Coated with CO_2 Resistant Material	Premium Connection	5,800	5,720	198,000

Table 5.5. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet)	Length (feet)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
7" x 4 1/2" 13Cr AHR packer	Within 75 feet of top of perf	4.7	23-29	6	3.875

Tensile Rating (kbls)	Burst Rating (psi)	Collapse Rating (psi)	Pressure Rating (psi)	Temperature Rating (Deg F)
80	8,430	7,500	5,000	40-325

Table 5.6. Summary of Construction Details

CFR Rule	Details
40 CFR 146.86(a) 1-3	Well construction will prevent the movement of fluids between or into USDWs, permit the use of downhole tools and work over equipment, and permit continuous monitoring of the annulus between the casing and injection tubing
40 CFR 146.86(b) 1-3	Casing and cement used in the construction of the well will meet structural requirements, be constructed with materials meeting ASTM standards, and details of construction and depths for wells are shown in **Figures 5.1** through **5.3**.
40 CFR 146.86(b) 4 and 5	Surface and long string casing will be cemented to surface and verified with a cement bond log. Cement used for the long string casing will be CO_2 resistant, tubing and packer materials will meet ASTM standards. Characteristics of the CO_2 stream are detailed in the Testing and Monitoring Plan, and injection operation parameters are located in the Well Operations section in Project Information Tracking

5.5 Well Construction Diagrams

A well construction diagram for the injection interval and wellhead schematic is shown in the following page(s).

Figure 5.1 Injection Well Diagram for Arbuckle Injection Wells

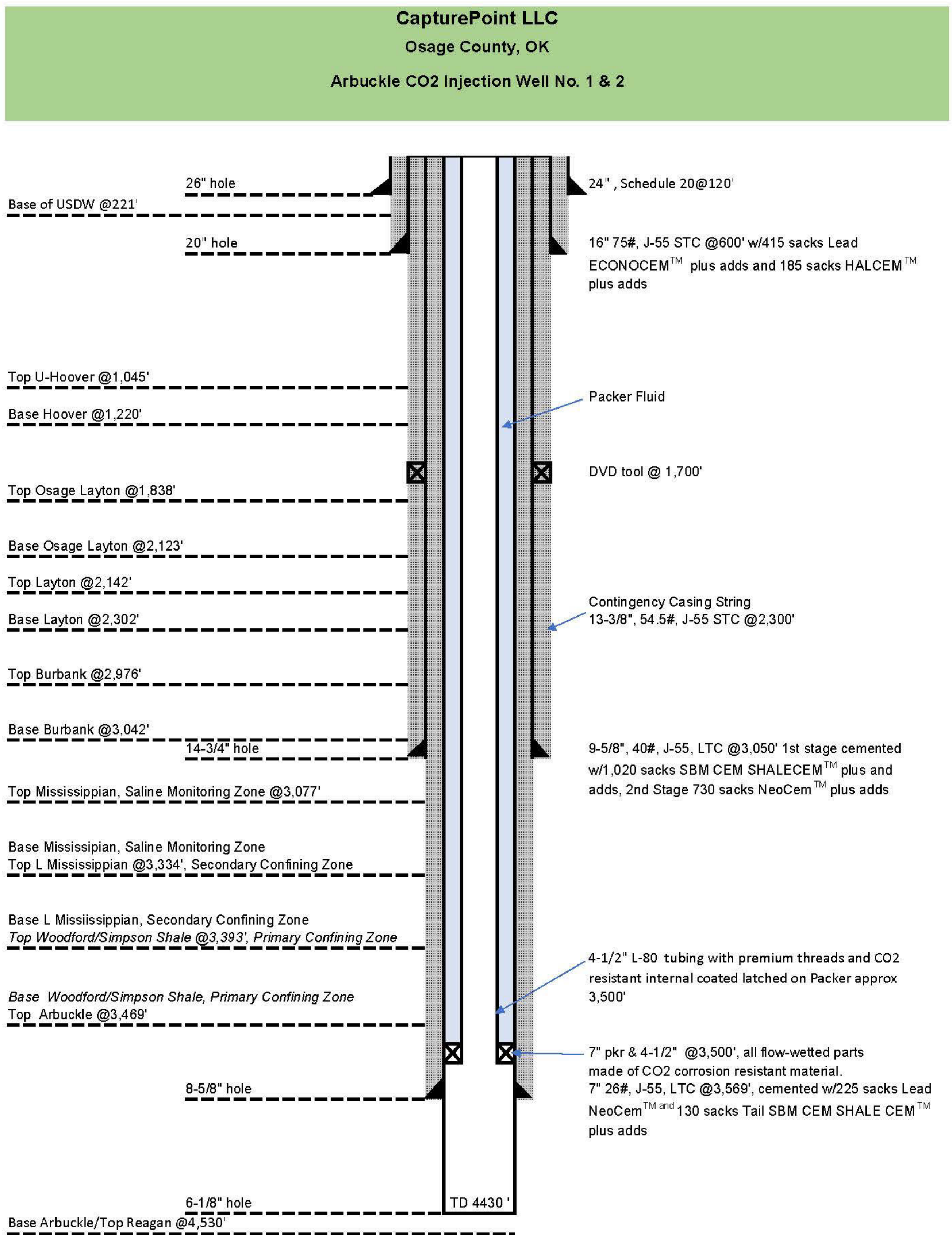
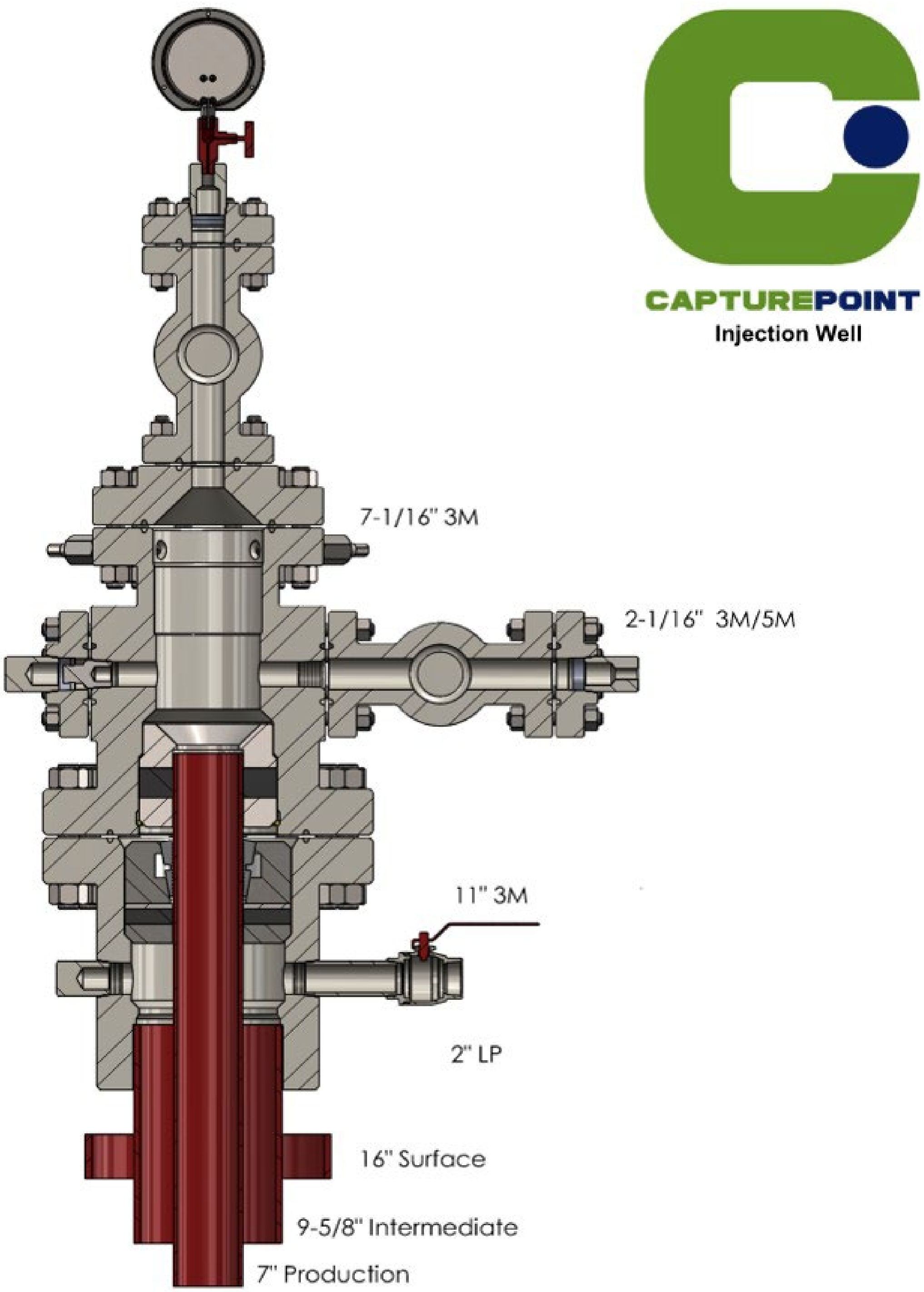


Figure 5.2. Wellhead and Christmas Tree Schematic



6.0 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

In each well, reservoir formation properties and individual well perforations will be determined by open hole log analysis and utilizing offset core and open hole logging data. The injection intervals selected are expected to have favorable reservoir characteristics that should not limit proposed injection targets. However, upon initial completion, it is expected to perform a low volume weak acetic acid matrix stimulation to clean the perforation tunnels, ensure all perforations are open and to remove any damage near well bore caused during the drilling and completion of the well. Per 40 CFR 146.91(d)(2), we are notifying the director of the intent to perform this type of stimulation to the well.

40 CFR 146 82(a)(9) requires the stimulation program, a description of the stimulation's fluids and a determination that stimulation will not interfere with containment. It is proposed to perform a weak acetic acid matrix stimulation to clean the perforation tunnels, ensure all perforations are open and to remove any damage near wellbore caused during the drilling and completion of the well. A low volume, weak acid matrix acidizing stimulation procedure is planned to accomplish this goal. Matrix acidizing refers to one of the two stimulation processes in which acid is injected into the well penetrating the rock pores at pressures below fracture pressure. As an additional safety factor, we will pump at a maximum treating pressure of 80 percent of the calculated fracture pressure. Following the matrix acid stimulation procedure an injection survey will be used to ensure that the stimulation did not interfere with containment.

Stimulation Fluids

80 percent Acetic Acid

Additives

Not applicable at this time

Diverters

Not applicable at this time

Stimulation Procedures

In order to meet the requirements of 40 CFR 146 82(a)(9) please find the procedure to perform a weak and low volume acetic acid stimulation procedure on each interval perforated within a well.

- Acetic acid will be used based upon 10 gallons per 1 foot of perforation. For 300 feet of perforations assumed in this procedure 3,000 gallons of acetic acid will be used.

- The fracture pressure of each zone will be determined by core analysis and/or Step Rate Testing. The fracture pressure will not be exceeded.

- Coiled tubing will be used to spot the acetic acid across the perforation intervals.

- An injection survey will be run to verify containment within injection interval.

- The well has been perforated based upon openhole log evaluation and prior to rigging up coiled tubing to perform procedure. Assume a 300-foot perforated interval for volumes and rates. This will be adjusted based upon actual perforations.

Coiled tubing perforation cleanup matrix acidizing procedure

1. MIRU 2-3/8” coiled tubing. Spot acetic acid tanks. Hook up choke and blow down line.
2. RIH slowly through tree to make sure BHA clears. Begin rolling over pumps at approximately 0.25 BPM while maintaining shut in wellhead pressure on the choke.
3. Once 30 feet below wellhead, pick up speed to 100 feet per minute while continuing to circulate 0.25 BPM.
4. Stop 10 feet below perforated interval. Bring pump rate up to 2 barrels per minute and switch to pre-mixed acetic acid blend. Pump 3,000 gallons of acetic acid blend then switch to fresh water.
5. With 3 barrels before acetic acid blend reaches top perf, start POOH at 8.5 feet per minute. Pump acid blend across perforations at 10gal/ft. After the 3,000 gallons have been displaced through coiled tubing, start pulling out of hole at 100 feet per minute.
6. Once on surface, shut in well. Begin rigging down coiled tubing unit.
7. Displace 3.0 volumes of 9-5/8” 47 #/ft, L-80 casing perforated volumes or 3.0 X 0.0732 barrels/feet X 300 feet = 65 barrels treated fresh water. Pump at a rate of 2 BPM at a maximum pressure of 80 percent of the calculated frac pressure.
8. Leave well shut–in overnight.
9. MIRU wireline unit. Run injection profile log including temperature surveys to evaluate containment of injection fluids. Rig down wireline
10. Report results and supply all profile logs to appropriate regulatory authorities.

7.0 Pre-Operational Logging and Testing

A stratigraphic test well will be drilled into the targeted injection zone. This well will be drilled, cored, logged and tested to obtain the necessary information as it pertains to both the confining zone and for the injection zone per the noted rules detailed in **Table 4**.

There are to be five intervals that are to be cored. These include the Upper Mississippi, Lower Mississippi and Woodford, Upper Arbuckle, Middle Arbuckle and the Lower Arbuckle. Collected core will be analyzed and used to determine porosity, permeability, saturation and thickness. Fluid samples that are to be collected will be used to assess compatibility with the injected CO_2 and will comprise salinity, specific conductance and temperature. The compilation of geophysical log suites that are to be generated will be used to determine porosity, permeability and lithology for the zones of interest. Well tests that are to be performed will include a step-rate test for determining injection zone fracture pressure, operational injection pressure and a pump/injectivity test to determine operational injection rates and volumes for each of the three injection zones.

Prior to injection mechanical integrity tests (MITs) will be performed on each well to verify that mechanical integrity is sound and that there is no risk of endangerment to safety, USDWs or the environment.

Table 7.1. Summary of Data Components and Applicable Rules

Data Component	Rule Reference
Well logs	40 CFR 146.86(a)(2) 40 CFR 146.87 40 CFR 146.87(e)(1)
Cores	40 CFR 146.87(b) 40 CFR 146.82(a)
Fluids	
Well MIT	40 CFR 146.89(a)(1) 40 CFR 146.87(a)(4) 40 CFR 146.87(e)(1)
Formation characteristics	40 CFR 146.82(a)(8) 40 CFR 146.87(b) 40 CFR 146.87(c) 40 CFR 146.87(d)(1)

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

8.0 Well Operation

Injection wells will be equipped with continuous pressure, temperature and rate monitoring equipment as well as physically monitored on a daily basis. As a consequence, the operation of wellhead and site valves will not be operated on any regular basis. Only in the event of a compression or supply issue, or scheduled testing will the wells be shut-in from injection. On shut-in condition, valves should be closed in order from downstream to upstream and reversed on restart of injection. In all cases caution should be taken to avoid the condition of trapped gas between valves at the surface.

The NBU CCS site is a proposed gas storage project that is targeting the Arbuckle Formation for CO_2 injection. CO_2 will be injected into the Arbuckle using two wells. Injection into the targeted storage zone will occur at pressures that are not to exceed 90 percent of the determined fracture pressure. The injection rate for the Arbuckle is expected to be ~14.7 mmcf per day. Additional Well Operation information is detailed in Section 2.5 in the "*AoR and Corrective Action Plan*" submitted in Module B.

8.1 Operational Procedures [40 CFR 146.82(a)(10)]

Operational procedures for the NBU CCS site are to be determined based on formation properties such as fracture pressure and injectivity. A site characterization well will be drilled and provide the necessary information to provide for a more comprehensive update to the preliminary AoR model and injection simulation for the targeted injection zones. Calculations, assumptions and input parameters for the preliminary AoR modeling and simulation are described in the "*AoR and Corrective Action Plan*" submitted in **Module B**. Additional formation data will be collected with each injection well that is drilled at the site. Together the collected data and modeling and simulation will be used to determine Operational Procedures. These protocols are described in the "*Pre-Operational Testing Plan*" submitted in **Module D**. As part of the "*Pre-Operations Testing Plan*" submitted in **Module D** pursuant to 40 CFR 146.82(a)(8) and 146.87 a step rate test will be run in each well to confirm the fracture gradient and be used to determine injection pressure for the various layers.

Additionally, an injectivity test will be performed for each well to determine amenable volumes that can be injected. Together these formation tests will be used to refine the geologic model and to establish injection rates and volumes. During the operation phase of this sequestration project injection data regarding rates, volumes and temperatures will be continuously monitored per the "*Testing and Monitoring Plan*" submitted in **Module E**. This will include operating data for the targeted injection zones, average and maximum daily rates and volumes of the injected CO_2 stream and average and maximum daily injection pressures per 40 CFR 146.82. Injection data will be provided to the UIC Program Director in semi-annual reports.

The proposed key operating parameters were calculated based on the formula below. Further details are provided in Section 4 of "*AOR and Corrective Action Plan*" submitted in **Module B**.

Generalized Pressure Equations:

- Max Downhole Injection Pressure = $TVD_{fm} * F_g * 90\%$
- Max Injection Pressure (Surface) = Max Downhole Injection Pressure * $TVD_{fm} * H_p * SG_{CO2\ average}$

Where

TVD_{fm} = Injection zone true vertical depth

F_g = Fracture pressure gradient

H_p = Hydrostatic pressure gradient

$SG_{CO2\ average}$ = Average Injecting CO_2 Specific Gravity

Well tests for each injection well will occur once per year unless injection monitoring information indicate more frequent testing. Well workovers will also occur pending the results of continuous monitoring. Though not planned, it is likely that disruptions to the CO_2 supply will occur. These instances may occur as source providers may shut down for scheduled maintenance or because of other operational issues.

Near wellbore damage from salt and/or compressor oil deposition could degrade injectivity over time. In addition, reservoir back pressure could increase as the plume radius increases hence reducing injectivity. Although it should be minimal in these formations.

Table 8.1. Proposed Arbuckle operational procedures.

Operating Information	NBU CCS 1	NBU CCS 2
Location – North American Datum 1927		
Longitude	-96.7251	-96.7251
Latitude	36.8292	36.8228

Operating Information	NBU CCS 1	NBU CCS 2
Model coordinates (feet) X Y	 2373139.0 668347.1	 2373154.6 666010.5
No. of perforated intervals	1	1
Perforated interval (TVDSS, feet) Z top Z bottom	 -2,524 -3,042	 -2,419.51 -3,186.02
Wellbore diameter (inches)	4	4
Injection duration (years)	20	20
Maximum injection pressure at the top of perforated interval (psi)	2,523.22	1,517.62
Injection rate (mmscfd)	14.37	14.37
Injection rate in metric tons per day	821.92	821.92

TVDSS = true vertical depth relative to mean sea level; psi = pounds per square inch; mmscfd = million standard cubic feet per day.

The plan for the proposed NBU CCS Site includes targeting the Arbuckle Formation as the intended injection zone. For the injection zone we used the allowable reservoir pressure with a safety factor of 90% to arrive at the maximum injection pressure which is then used in the AoR model to arrive at the daily injection volumes.

As part of the "*Pre-Operations Testing and Logging Plan*" submitted in **Module D** pursuant to 40 CFR 146.82(a)(8) and 146.87 a step rate test will be run to confirm the fracture gradient and be used to determine injection pressure for the various layers. Additionally, an injectivity test will be performed in the Arbuckle to determine amenable volumes that can be injected. Together these formation tests will be used to refine the geologic model and to establish injection rates and volumes.

8.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

Sources of CO_2 for the NBU CCS site are described in Section 1. In summary sources will include industrial plants including fertilizer, ammonia and natural gas processing plants. CO_2 purity will be determined at the source of each industrial provider. CO_2 specifications for this gas storage project are noted in the "*Testing and Monitoring Plan*" submitted in **Module E**.

Characteristics of the CO_2 stream are described in the "*AoR and Corrective Action Plan*" submitted in **Module B**. Below are some excerpts from that section that describe the corrosive nature and likely behavior of CO_2 in the subsurface.

It is known that CO_2 and water will form Carbonic Acid (H_2CO_3) which in turn has the capability to dissolve calcium species in the formation. This can alter formation permeability and porosity depending on the native mineralogy. At the injection wellbore this can be an issue for well casing; however, the dry dense phase CO_2 will continuously dry the area around the wellbore inhibiting any corrosion by absorbing the formation water and moving deeper into the formation.

The injected CO_2 at the NBU CCS site is expected to be soluble in water, which can provide a significant CO_2 trapping mechanism. This feature affects the reservoir by causing the higher density brine to sink within the formation thereby trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration.

Materials exposed to the CO_2 injection stream will be monitored throughout the injection phase of the project; methods of monitoring are also addressed in the "*Testing and Monitoring Plan*" submitted in **Module E**. All materials with exposure to the injection stream were selected based on their resistance to corrosion when exposed to CO_2 and CO_2-related fluids.

9.0 Testing and Monitoring

The Testing and Monitoring Plan Report has been submitted via the GSDT. All tabs that require input data within the module have also been completed and submitted via the GSDT.

The report covers in detail the overall strategy and approach for testing and monitoring, carbon dioxide stream analysis, continuous recording of operational parameters, corrosion monitoring, above confining zone monitoring, external mechanical integrity testing, pressure fall off testing, carbon dioxide plume and pressure front tracking, environmental monitoring at the surface, sampling/analytical procedures. A Class IV well Quality Assurance and Surveillance Plan (QASP) was submitted as an appendix along with additional information relation to project management, data generation and acquisition, assessment and oversight and data validation and usability.

The Testing and Monitoring Plan Report satisfies rule requirements 40 CFR 146.82(a)(15) and 146.90.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

10.0 Injection Well Plugging

An Injection Well Plugging Plan has been developed and electronically submitted to the GSDT pursuant to 40 CFR 146.82(a)(16) and 146.92(b). The plan describes the materials that are to be used and includes a plugging schematic representative for all injection wells.

The Injection and Well Plugging Plan has been submitted via the GSDT. All Tabs that require input data within the module have also been completed and submitted via the GSDT.

The report covers in detail the planned tests and measurements to determine the bottom hole reservoir pressure, Planned External Mechanical Integrity Test, Information on Plugs, methods used for volume calculations, notifications, permits and inspections required, plugging procedures and contingency procedures/measures. The Injection and Well Plugging Plan satisfies rule requirements 40 CFR 146.82(a)(16) and 146.92(b).

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

11.0 Post-Injection Site Care (PISC) and Site Closure

The Post Injection Site Care and Site Closure Plan (PISC) Plan has been submitted via the GSDT. All Tabs that require input data within the module have also been completed and submitted via the GSDT.

The report covers in detail the pre and post injection pressure differential, post-injection monitoring plan, alternative post-injection site care timeframe, non-endangerment demonstration criteria, site closure plan and QASP.

An Alternative PISC timeframe has been proposed as part of the GSDT submission. CapturePoint Solutions, LLC has indicated an alternative PISC timeframe of 50 years.

The Post Injection Site Care and Site Closure Plan satisfies rule requirements 40 CFR 146.82(a)(17) and 146.93(a) and the Alternative PISC submission satisfies rule requirements 40 CFR 146.82(a)(18) and 146.93(c).

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

12.0 Emergency and Remedial Response

The Emergency and Remedial Response Plan has been submitted via the GSDT. All Tabs that require input data within the module have also been completed and submitted via the GSDT.

The report covers in detail the local resources and infrastructure, potential risk scenarios, response personnel and equipment, emergency communications plan, a plan review and staff training and exercise procedures. The Emergency and Remedial Response Plan Report satisfies rule requirements 40 CFR146.82(a)(19) and 146.94(a).

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

13.0 Injection Depth Waiver and Aquifer Exemption Expansion

An injection depth waiver is not required for this permit application.

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Depth Waiver supplemental report ***[40 CFR 146.82(d) and 146.95(a)]*** ☒ Aquifer exemption expansion request and data ***[40 CFR 146.4(d) and 144.7(d)]***

14.0 Other Information

CapturePoint Solutions, LLC utilized the EJScreen: Environmental Justice Screening and Mapping Tool (Version 2.0) (https://ejscreen.epa.gov/mapper/) to identify issues with respect to the proposed CCS Site. At this time, no instances of the listed indexes in the tool were identified to be impacted or exacerbated by the proposed GS project. The nearest denoted index issues are identified to be located approximately 20 miles northeast of the proposed site location and these all relate to Ponca city. Results from the EJScreen tool are shown in **Table 14.1**.

Table 14.1 Environmental Justice Screening and Mapping Tool Results

Environmental Justice Index	Percentile (%)
Particulate Matter	44
Ozone	45
Diesel Particulate matter	6
Air Toxics Cancer Risk	3
Air Toxics Respiratory HI	31
Toxic Releases to Air	41
Traffic Proximity	5

Environmental Justice Index	Percentile (%)
Lead Paint	68
Superfund Proximity	16
RMP Facility Proximity	6
Hazardous Waste Proximity	5
Underground Storage Tanks	0
Wastewater Discharge	65

CapturePoint Solutions LLC is currently evaluating the following permits including the Resource Conservation and Recovery Act (RCRA), Underground Injection Control (UIC), National Pollutant Discharge Elimination System (NPDES) and Prevention and Significant Deterioration (PSD)

The evaluation of these permits and their applicability to this proposed CCS site is ongoing and will be addressed as permitting requirements are identified. This application for a Class VI permit (OS-0001) is in regard to the UIC requirement. A preliminary compilation of additional permits that are to be sought for this GS project are included in **Table 14.2**.

Table 14.2 Preliminary List of Permits to be Sought for the proposed CCS Project

<table>
<tr><th>Permit</th><th>Regulatory Agency</th><th>Application Status</th></tr>
<tr><td colspan="3">Federal Permits</td></tr>
<tr><td>Underground Injection Control (UIC) Class VI</td><td>EPA Region 6</td><td>Submitted September 2023</td></tr>
<tr><td>Hazardous Waste Management Program under Resource Conservation and Recovery Act (RCRA)</td><td rowspan="3"></td><td rowspan="2">Filing under RCRA and SDWA will occur after the Class VI permit to construct is provided. CPS will submit and provide notices prior to drilling activities</td></tr>
<tr><td>UIC Program under Safe Drinking Water Act (SDWA)</td></tr>
<tr><td>National Pollutant Discharge Elimination System (NPDES) Program under Clean Water Act (CWA)</td><td></td></tr>
</table>

Permit	Regulatory Agency	Application Status
Prevention of Significant Deterioration (PSD) under the Clean Air Act	EPA	N/A
Nonattainment Program under the Clean Air Act		If required filing will occur after the Class VI permit to construct is provided. CPS will submit and provide notices prior to drilling activities and construction.
National Emission Standards for Hazardous Pollutants (NESHAPS) under the Clean Air Act		N/A
State Historical Preservation Office (SHPO)	Corps of Engineers	Necessary permits will be identified based on project parameters and impacts per SHPO determination
State Permits - Oklahoma		
Injection Wells	Oklahoma Corporation Commission	Filing will occur after the Class VI permit to construct is provided. CPS will submit and provide notices prior to drilling activities and construction.
Water Supply Wells		
Monitoring Wells		
Pipeline Construction and Operation		
Permit	**Regulatory Agency**	**Application Status**
State Permits – Oklahoma		
Environmental	Department of Wildlife and Fisheries	Will be submitted after CPS receives the Class VI permit to construct
Environmental	Department of Agriculture and Forestry	
Road Construction	OK Dept of Transportation and Development	

Permit	Regulatory Agency	Application Status
Power Line Construction	OK Dept of Transportation and Development	
Local Permits – Osage Nation		
Well Construction	Bureau of Indian Affairs (BIA)	Will be submitted after CPS receives the Class VI permit to construct
Local Permits – Osage County		
Communication Tower	Osage County	Will be submitted after CPS receives the Class VI permit to construct
**To be determined upon further project development		

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