CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Facility Information

Facility Name:	Pelican Renewables, LLC
Well Names:	Rindge Tract CCS Well #1 Rindge Tract CCS Well #2
Facility Contact:	John Zuckerman, Pelican Renewables – Managing Member 2200 W. Forest Lake Rd, Acampo, California, 95220 917-868-4346/john.zuckerman@pelicanrenewables.com
Well Locations:	Rindge Tract Island, San Joaquin County, California 38.021507, -121.428926 (Well #1) 38.014567, -121.415405 (Well #2)

Project Background and Contact Information

The effects of climate change are becoming increasingly apparent. These include increased wildfires, record-breaking heat waves, and disruptive changes in weather cycles. The State of California has pledged zero net emissions by 2045 (California Assembly Bill 1279, 2022). Climate mitigation efforts are advancing, but California will also need to capture, remove and permanently sequester tens of millions of tons of carbon dioxide from the atmosphere and large sources in order to achieve this goal. (California Air Resources Board, Scoping Plan of 2022). Pelican Renewables, LLC and its affiliates (Pelican) is a Stockton, California-owned entity with a vested interest in improving the life of all San Joaquin Delta residents and preserving the Delta. The Pelican Carbon Sequestration Project is being developed to reduce the atmospheric content of greenhouse gases, provide new jobs, and create new economic opportunities and revenue for local causes.

The Pelican Carbon Sequestration Project consists of a corn-based ethanol production plant, a carbon dioxide capture and processing facility, transportation infrastructure, and two Class VI carbon dioxide deep injection wells. This Class VI Permit Application is for Rindge Tract CCS Wells #1 and #2. The data gathering, analysis, and presentation have been performed for a two-injection well project.

Figure 1-1 shows an overview of the Pelican Carbon Capture and Sequestration project. The ethanol plant and carbon dioxide capture and processing facility will be located in the Port of Stockton. The Class VI injection wells will be located on Rindge Tract Island in the San Joaquin Delta. The transportation infrastructure will be developed along the San Joaquin River, which will connect the facilities at the Port of Stockton with the injection wells on Rindge Tract Island.

Figure 1-2 shows the facilities at the Port of Stockton. The Pelican Renewables (PR) ethanol plant produces CO_2 as part of its process. Currently, the CO_2 vents to atmosphere (80-90%) or is captured at the ethanol plant and then converted to a food-grade liquid or dry-ice product (10-20%) by an adjacent facility operated by Airgas. The PR project is designed to capture the full CO_2 stream from the ethanol plant and process the CO_2 for storage and transport to Rindge Tract Island for permanent sequestration.

Figure 1-3 illustrates the overall process for handling the CO_2 from source to injection well. The CO_2 will be transferred to a barge for transport to the Rindge Tract Island offloading facility (about every 3 days at design rates). A pump will move CO_2 from site storage through a transfer line to the dock, at which multiple load points will be utilized to load a barge transport.

The barge transport will have CO_2 stored in multiple tube systems (stacked up to 5 high and in rows). A manifold will be present that connects the tube systems together, equipped with valves to open or isolate as required. After loading, the barge transport will travel down river and upon arrival at Rindge Tract Island, unloading operations will commence to transfer the CO_2 for injection. A pump will offload the barge to an injection line and boost the pressure for sequestration. The location of the pump used for unloading will be located on the barge side of the levee so suction piping to the pump can be short distances and can be kept at a low elevation. The discharge piping from the pump will be routed over the levee.

The pump will boost the pressure of the CO_2 from the Barge Transport to injection pressure (1,400 psig design) at a nominal rate of 100 million standard cubic feet per day (MMscfd). Two Class VI injection wells will be permitted for the PR project. Both are located on the interior of Rindge Tract Island and are connected with transfer piping. The CO_2 flow rate and pressure will be measured on both ends of the transfer line before it reaches the wells and as it is injected into the reservoir. This provides a mass balance check on the transfer line and ensures the integrity of the system.

The two-well system is designed to efficiently use the pore space of the injection zone, provide for operational flexibility, and to allow for maximum deployment of devices to monitor the pressure front and the extent of the plume as injection proceeds. This permit is for both injection wells, Rindge Tract CCS #1 and #2, and the Area of Review (AOR) modeling and delineation, Testing and Monitoring Plan, and Operational Plans were all prepared for a two-well system.

Both wells are designed for a 20-year injection period. CCS #1 is designed to be injection-rate controlled with an approximate flow rate of 1.25 million metric tons per year (Mt/yr). Initial injection pressures would peak at about 4200 pounds per square inch (psi) and drop to about 3700 psi toward the end of the 20-year injection period. CCS #2 is also an injection-rate controlled with an approximate flow rate of 0.75 million metric tons per year (Mt/yr). The injection pressure is a little under 3600 psi. The total amount sequestered over the 20-year period is a little under 40 million metric tons. After about 120 years, about 10 million metric tons end up sequestered in solution (dissolved in aqueous brine), about 25 million metric tons are structurally sequestered, and about 5 million metric tons are sequestered by capillary trapping.

The targeted injection zone is the Mokelumne River Formation (MRF), a Cretaceous, sandy, river deltaic sediment that ranges from 200 to 2300 feet thick and is about 5,500 feet below ground surface at Rindge Tract. The pore water in the MRF is mildly saline with a salinity of about 12,500 parts per million. Neither an injection depth waiver nor an aquifer exemption is being requested in this permit application. The MRF is underlain by the H&T shale, which is the lower confining unit. The primary upper confining unit is the Capay Shale and low permeability layers of the Meganos Gorge Fill, with secondary confinement from low permeability layers in the Domengine and Nortonville formations. The details of the subsurface geology are discussed in detail in the following Section of the permit application (Site Characterization Narrative).

The lowermost underground source of drinking water (USDW) is the Markley Formation, which is about 1,000 feet to 2,700 feet above the top of the MRF in the vicinity of Rindge Tract. The salinity of pore water in the Markley formation is highly variable, ranging from 2,000 to 16,000 ppm, and averaging about 3,000 ppm. Because of its depth, the Markley Formation is not currently, and is not expected to be a source of drinking or irrigation water.

Water wells near Rindge Tract and Stockton are much shallower; either in the Modesto formation (unconfined) or Turlock Lake/Laguna formation (unconfined to locally semi-confined or confined). The base of freshwater is around 900 feet below ground surface. Saltwater intrusion from the west is an issue with these aquifers and differentiating between the potential impacts of saltwater intrusion and brine migration from the injection zone will be an important component of the Testing and Monitoring Plan.

The land on Rindge Tract Island is privately owned. No designated federal, state, territorial, or tribal lands are located within the Pelican Class VI project area. Pelican has access agreements with all owners of property within the Area of Review. Consultations with local and tribal organizations will be conducted as needed. State and local agencies with jurisdiction over one or more parts of the project or that may be affected by the project are listed in **Table 1-1**. A list of local tribal organizations is provided in **Table 1-2**.

Pelican Renewables is preparing plans for the injection and transportation of the supercritical CO_2 to the proposed injection site. Permission to construct will require permits from federal, state and local agencies (**Table 1-1**). The permit applications to be prepared for these agencies will address all National Endangered Species Act and National Historic Preservation Act concerns. Pelican does not anticipate the use, transport or storage of any hazardous substances; therefore, permitting under the Resource Conservation and Recovery Act (RCRA) will not be required.

The proposed Pelican Class VI project will require federal permits under Sections 404 and 401 of the Clean Water Act (33 USC §1344), and Sections 10 and 408 of the Rivers and Harbors Act (33 USC §43), including a National Pollutant Discharge Elimination System Permit. As part of the permit application process, Pelican will draft a full Biological Assessment (BA). During the BA development, Pelican will access the US Fish and Wildlife Service (USFWS) "Information for Planning and Consultation" database online. A Section 7 consultation with the USFWS and National Oceanic and Atmospheric Administration (NOAA) Fisheries will be conducted. The Section 7 consultation will enable Pelican to receive technical assistance from USFWS and NOAA Fisheries regarding the project's potential effects on species of concern and their critical habitats. Federal permitting will also require compliance with Section 106 of the National Historic Preservation Act (16 USC §470).

Pelican Renewables will be required to obtain state and local permits that will include additional analyses of project effects on special status plant, fish and wildlife species. The permit may also be subject to consultation with the State Historic Preservation Officer. The list of California state and local agencies requiring permits for the project includes, but is not limited to, the agencies listed in **Table 1-1.**

Table 1-1. State and Local Agencies

AGENCY	FIRST NAME	LAST NAME	TITLE	PHONE NUMBER	EMAIL	STREET ADDRESS	CITY	STATE	ZIP
CalGem Northern District Sacramento Office	Miguel	Cabrera	District Deputy	916-322-1110	CalGEMNorthern@conservation.ca.gov	715 P Street MS 1804	Sacramento	CA	95814
California Council of Land Trusts	Bridget	Fithian	Chair	916-497-0272	mail@calandtrust.org	1017 L Street #664	Sacramento	CA	95814
California Cultural Resources Division, California Department of Parks and Recreation	Leslie	Hartzell	Ph.D., Division Chief	916-653-6995	not listed	715 P Street Suite 13	Sacramento	CA	94296
California Environmental Protection Agency - Air Resources Board	Rajinder	Sahota	Cap and Trade	916-323-8503	Rsahota@arb.ca.gov	PO Box 2815	Sacramento	CA	95812
California Fish and Wildlife - Ecosystem Conservation Division	Josh	Grover	Deputy Director		Joshua.Grover@wildlife.ca.gov	1234 East Shaw Avenue	Fresno	CA	93726
California Natural Resources Agency	Wade	Crowfoot	Secretary for Natural Resources	916-653-5656	secretary@resources.ca.gov	715P Street, 20th Floor	Sacramento	CA	95814
California Public Utilities Commission	Alice	Reynolds	President	415-703-2431	CDcompliance@cpuc.ca.gov	505 Van Ness Avenue	San Francisco	CA	94102
California State Water Resources Control Board - Regional Board: 5S/Central Valley	Mark	Bradford	Board Chief	916-464-3291	not listed	11020 Sun Center Drive, #200	Rancho Cordova	CA	95670
California Threatened and Endangered Species, California Department of Fish and Wildlife, Habitat Conservation Planning Branch	Jeff	Drongesen	Branch Chief		HCPB@wildlife.ca.gov	1010 Riverside Parkway	West Sacramento	CA	95695
Center on Race, Poverty, and the Environment	Caroline	Farrell	Executive Director	661-720-9140	cfarrell@crpe-ej.org	1012 Jefferson Street	Delano	CA	93215
City of Stockton - Planning, Land Use, Zoning	not listed			209-937-8893	planning@stocktonca.gov	425 North El Dorado St	Stockton	CA	95202
Delta Stewardship Council	Virginia	Madueno	Chair	916-445-5511	hello@deltacouncil.ca.gov	715 P Street 15-300	Sacramento	CA	95814
Office of the State Fire Marshal	Jim	Hosler	Assistant Deputy Director	916-263-6300	not listed	715 P Street	Sacramento	CA	95814
Port of Stockton - Regulatory & Public Affairs	Jeffrey	Wingfield	Deputy Port Director	209-946-0246	jwingfield@stocktonport.com	2201 West Washington Street	Stockton	CA	95203
Port of Stockton - Real Estate and Port Development	Rhonda	Nelson	Director of Real Estate and Port Development	209-946-0246	rnelson@stocktonport.com	2201 West Washington Street	Stockton	CA	95203
Sacramento-San Joaquin Delta Conservancy	Campbell	Ingram	Executive Officer	916-375-2084	cingram@deltaconservancy.ca.gov	1450 Halyard Drive Suite 6	West Sacramento	CA	95691
San Joaquin Valley Air Pollution Control District	Nick	Peirce	Manager, Permitting	209-557-6400	nick.peirce@valleyair.org	4800 Enterprise Way	Modesto	CA	95356
State Historical Resources Commission and Office of Preservation California State Parks	Julianne	Plianco	State Historic Preservation Officer	916-445-7000	info@calshpo@parks.ca.gov	1725 23rd Street Suite 100	Sacramento	CA	95816
State Historical Resources Commission and Office Preservation California State Parks	Adam	Sriro	Commission Char	916-445-7000	info@calshpo@parks.ca.gov	1726 23rd Street Suite 100	Sacramento	CA	95816
US Army Corp of Engineers, Sacramento Civil Works, Regulatory District, and Military District	not listed			916-557-5100	spk-pao@usace.army.mil	1325 J Street	Sacramento	CA	95814
Bureau of Reclamation, Bay-Delta Office, Reclamation Mid-Pacific Region	David	Mooney	Area Manager	916-414-2400		801 I Street, Suite 140	Sacramento	CA	95814
California Natural Resources Agency, Central Valley Flood Protection Board	Andrea	Buckley	Environmental Services and Land Management Branch Chief	916-574-0332	Andrea.Buckley@cvflood.ca.gov	3310 El Camino Avenue, Suite 170	Sacramento	CA	95821
California State Lands Commission, Environmental Science, Planning, and Management Division	Nicole	Dobroski	Chief	916-574-0742	Nicole.Dobroski@slc.ca.gov	100 Howe Avenue, Suite 100 South	Sacramento	CA	95825

***Note**: not listed information was not located through online sources*

Table 1-2. T, Local Tribal Contacts

AGENCY	FIRST NAME	LAST NAME	TITLE	PHONE NUMBER	EMAIL	STREET ADDRESS	CITY	STATE	ZIP
Lytton Rancheria	Marjorie	Mejia	Chairperson	707-575-5917	margiemejia@aol.com	437 Aviation Blvd.	Santa Rosa	CA	95403
Buena Vista Rancheria of Me-Wuk Indians	Rhonda	Morningstar Pope	Chairperson	916-491-0011	rhonda@buenavistatribe.com	1418 20th Street, Suite 200	Sacramento	CA	95811
California Valley Miwok Tribe (federally recognized)	Silvia	Burley	Chairperson	209-931-4567	office@cvmt.net	14807 Avenida Central	La Grange	CA	95329
North Valley Yokuts Tribe	Katherine	Erolinda Perez	Chairperson	209-887-2415	canutes@verizon.net	PO Box 717	Linden	CA	95236
California Tribal TANF Partnership	Lisa	Martin	Regional Manager	209-474-6890	lmartin@cttp.net	2291 W March Lane, Suite D-210	Stockton	CA	95207
Central California Regional Office - Bureau of Indian Affairs	Harley	Long	Superintendent	279-444-0323	harley.long@bia.gov	650 Capitol Mall, Suite 8-500	Sacramento	CA	95814
Environmental Quality - Central California Regional Office - Bureau of Indian Affairs	Eddie	Dominguez	Environmental Quality Services Officer	279-444-0323	eddie.dominguez@bia.gov	650 Capitol Mall, Suite 8-500	Sacramento	CA	95814

State and local permits will require environmental analysis under the California Environmental Quality Act (CEQA). This work will include assessment of all species of concern including special status species under the California Endangered Species Act (CESA). The species of importance to be evaluated will be developed by consulting the California Natural Diversity Database (https://wildlife.ca.gov/Data/CNDDB).

Pelican Renewables LLC will obtain all of the necessary permits to support the development of this project in conformance with Federal, State, Local Government, and Tribal requirements.

References

California Assembly Bill 1279, (2022). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB1279, retrieved February 8, 2023.

California Air Resources Board, (2022). Scoping Plan of 2022. https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents#:~:text=The%202022%20Scoping%20Plan%20for,directed%20by%20Assembly%20Bill%201279,

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)]***

Site Characterization

Pelican Renewables, LLC and their affiliates (Pelican) are developing a carbon dioxide (CO_2) sequestration facility on Rindge Tract Island, located within the Sacramento Delta in San Joaquin County, California. The Class VI Wells will be named Rindge Tract CCS Well #1 and #2. This section discusses the available data that describe the natural environment in the vicinity of Rindge Tract CCS Wells #1 and #2.

An overview of the planned Class VI injection facility (encompassing both Wells #1 and #2) is shown in **Figure 2-1**, and is located at Section 21, Township 02N, Range 05E. The Class VI well injection facility site is located immediately west of the northern limits of Stockton, CA, and is approximately six miles northwest of the planned CO_2 source, Pelican Renewables, Inc. Ethanol Plant, located in the Port of Stockton.

The proposed facility is located on the shallow eastern flank of the Sacramento Basin, a Cretaceous marine basin that is part of the Great Valley province of California. The Sacramento Basin was identified by the California Energy Commission-led and United States Department of Energy-supported West Coast Regional Carbon Sequestration Partnership (WestCARB) as having favorable conditions for CO_2 sequestration, including the presence of multiple sequences of thick sandstone packages with overlying marine shale sequences (Downey and Clinkenbeard, 2010). Extensive gas field development in Cenozoic and Cretaceous sandstone reservoirs has generated abundant data for stratigraphic and structural characterization of the section (USGS, 2020).

The target CO_2 injection zone is the Upper Cretaceous Mokelumne River Formation, with primary upper confinement by the Capay Shale and low-permeability sediments of the Meganos Gorge fill and secondary confinement by shales in the overlying Domengine Formation and Nortonville Shale. The Capay Shale and Nortonville Shale formations are regionally extensive Eocene marine shales with low porosity and permeability. The target interval and injection site were chosen based on the quality and thickness of both injection and confining units, and limited faults or other geologic structures in the defined Area of Review (AOR), supported by the availability of characterization information from wireline, core data, and 3D seismic data.

Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

The proposed sequestration area is located near the southern end of the Sacramento Basin, an asymmetric, northwest-trending basin that is part of the Central Valley of California. The regional setting is shown in **Figure 2-2**. The basin is approximately 60 miles wide and 200 miles long, bounded by the Sierra Nevada Mountains to the East, the Klamath Mountains to the North, the Coast Ranges to the West, and the Stockton Arch to the South. Rindge Tract Island is the proposed location of the Class VI well and is the geographic location that will contain the defined AOR. Rindge Tract Island is within the Sacramento River Delta, bordered on the south by the San Joaquin River, on the west and north by White Slough, and on the east by Fourteen Mile Slough. **Figures 2-3a** and **2-3b** show cross sections through the proposed storage complex at Rindge Tract Island and the delineated AOR.

Tectonic History and Summary of Stratigraphy

The Sacramento Basin is a relict forearc basin initially formed in the Late Jurassic-Early Cretaceous Period. The evolution of the basin is shown in **Figure 2-4**, and a generalized regional stratigraphic column is shown in **Figure 2-5.** In the Late Jurassic, subduction of the Farallon Plate under the North American plate initiated, creating a basin between an active, Andean-style arc to the east, and the Franciscan accretionary prism to the west. Active volcanism on the eastern side continued through the Early Cretaceous, with the axis of volcanism migrating to the east. Starting in the Late Cretaceous during the Laramide Orogeny, the axis of volcanism migrated far to the east as the angle of slab subduction decreased. Starting in the Paleogene, the western limb of the basin was uplifted and eroded. Migration of the Mendocino Triple Junction and development of the San Andreas Fault Zone during the Miocene led to deformation that continues to present day (Ingersoll and Dickinson, 1981).

Regional relative sea level changes that occurred in the Late Cretaceous do not correlate in time with global eustatic sea level, suggesting the deposition and erosion of basin sediments was driven by tectonic events. The sequestration area is located at the southern end of the basin and on the eastern side of the structural and depositional axis of the basin. Cenozoic deformation on the western side of the basin has shortened basin width significantly, possibly by as much as half (Ingersoll and Dickinson, 1981), but there is little evidence of compression in the sequestration area. This forearc basin is preserved with very little deformation because the associated convergent margin was supplanted by a transform system (i.e., the San Andreas Fault Zone) (Orme and Graham, 2018).

The basement of the Sacramento Basin is ophiolitic ocean crust, a remnant trapped between the Sierra Nevada Arc and the Franciscan accretionary prism. Upper Jurassic and Lower Cretaceous sediments are uplifted and exposed within the northwest limb of the basin, but are thin to absent within the sequestration area and at the proposed Class VI wellsite (Moxon, 1990). Mineral provenance studies of exposed Lower Cretaceous sedimentary and metasedimentary sections show sediment sources were the Klamath Mountains and the Sierra foothill terranes (Surpless, 2015). The Jurassic and Cretaceous formations are the lowermost formations in the Great Valley Sequence.

At the start of the Late Cretaceous, the eastern side of the Sacramento Basin was a gently dipping shelf margin, while the west was a deep trough. The sequestration area was located in a deep marine setting. The Dobbins Shale, Forbes Formation, and Kione Formation were deposited as part of a progradational sequence during that time. The Dobbins Shale is composed of pelagic to hemi-pelagic sediments on the basin floor with slope deposits to the east. Mud-rich submarine fans comprise the middle and upper member of the Forbes Formation in the distal basin, with deposition of mud-rich turbidites on the shelf slope (Imperato et al., 1990). The deltaic Kione Formation overlies the Forbes Formation, but does not extend into the sequestration area (Imperato et al., 1990; Nilsen, 1990). This sequence is overlain by the Sacramento Shale, a 50 to 350-foot-thick marine shale deposited during a regional relative sea level high. The Sacramento Shale sits at the base of the Upper Campanian (Upper Cretaceous) sequence.

In Late Campanian to Maastrichtian time, a series of submarine fans developed, depositing the Lathrop, Winters, Tracy, and Blewett formations. Of these, only the Lathrop Formation and the

Winters Formation are present in the sequestration area. The fan deposits prograded from the north and northeast. The Lathrop, Winters, Delta, and Starkey formations were deposited synchronously, representing a linked system consisting of distal, mud-dominated fans (Lathrop Formation), sand-dominated basin floor fans (Winters Formation), muddy slope deposits (Delta Shale) and a deltaic sand and shale system (Starkey Formation). The Starkey Formation contains two basin-wide shale units that are chronostratigraphic markers of relative sea-level highs (Moore et al., 1990). In the vicinity of the sequestration area, the Lathrop, Winters, and Starkey Formations are stacked vertically. Only the uppermost Starkey Sand is present, and there is a lateral facies change to slope and basin plain shale deposits to the west. The Starkey Formation is truncated by angular unconformities to the north, east, and west of the Stockton area (Downey and Clinkenbeard, 2010).

The Starkey Formation is overlain by the H&T Shale, a shallow marine or slope shale that was deposited during a relative sea-level high. The H&T Shale is the base of the Upper Maastrichtian depositional sequence. The H&T Shale is thick and laterally extensive near Stockton, and pinches out to the northeast near Lodi and to the west where it is truncated by a regional unconformity. The H&T Shale also thins north of Stockton and pinches out south of Sacramento (Downey and Clinkenbeard, 2010).

The Upper Maastrichtian Mokelumne River Formation is the proposed injection zone for the Class VI well. It is part of a fluvial-deltaic system that prograded westward across the basin, depositing a minimum of 2,250 feet of sands and shales. The lowest unit in the Mokelumne River Formation is interpreted as a distributary mouth bar and channel sands and consists of very fine to medium grained sandstones. The subsequent units are series of interbedded sands and shales deposited in distributary channels, natural levees, and crevasse splay sands. Lignite seams are present in the interbedded sands and shales and within shale units. Shale units within the Mokelumne River Formation were deposited in distributary bays, and coastal marshes. (Johnson, 1990). On wireline logs within the sequestration area, all lithologies except shale appear to be present. Rapid sedimentation and oblique extension at the end of the Late Cretaceous led to the formation of the Midland and Kirby Fault Zones, which are north-south trending, down to the west growth faults that continued moving until the Oligocene Epoch, shown on **Figure 2-2**. Fault movement funneled sediments to a depositional center on the downthrown block to the west of the sequestration area (Krug et al. 1992). The regional extent of the Mokelumne River Formation is shown on **Figure 2-6**.

During the Paleogene, the western side of the Sacramento Basin underwent up to seven cycles of uplift and erosion followed by renewed subsidence, a rise in relative sea level, and a period of deposition (Sullivan and Sullivan, 2007). During the second cycle of erosion, the Meganos Gorge incised deeply into the Mokelumne River Formation within the sequestration area, in some areas eroding the unit out (Almgren, 1984). The extent of the Meganos Gorge is shown in **Figure 2-6.** Renewed subsidence and sea level rise resulted in filling of the Meganos Gorge with up to 2000 feet of marine sand and shales, known as the Meganos Formation (Almgren, 1984; Boyd, 1984). Sand deposits within the Meganos Gorge are concentrated along the central axis and near the head and outlet of the gorge (Almgren, 1984; Boyd, 1984). Wireline logs in the sequestration area, located on the southeast side of the gorge, indicate gorge fill is shale. Compaction of the original thickness of gorge fill shale is estimated at 40% (Edmondson, 1984). Differential compaction between gorge fill shale and the surrounding Mokelumne River Formation Sandstone caused thickness variations in subsequently deposited Eocene sediments.

The Meganos Formation and Mokelumne River Formation are overlain unconformably by the Capay Formation, a Lower Eocene basin-wide shallow marine or slope deposited shale. The Capay Formation is identified as the primary upper confining unit. The Capay thins and pinches out to the north and east towards Lodi (Downey and Clinkenbeard, 2010). To the north and west of the Class VI well location, at Rio Vista and Kings Island Gas Fields, there are sandstones interbedded with shales in the Capay Formation. Based on review of well logs within the sequestration area, the Capay consists of primarily shale with minor thin sand interbeds that are not continuous across the sequestration area (**Figure 2-27**).

The Capay Formation is overlain by the Domengine Formation, deposited during the Middle Eocene in an estuarine and fluvial setting along a north-south trending shoreline. The upper and lower (referred to locally as the River Island Sand) members of the Domengine Formation are unconformity-bounded packages following a succession of thick, medium to coarse-grained, massive to cross-bedded sandstones with interbedded siltstone, shale, and coal. The upper member of the Domengine Formation typically has a shale-rich section at the base, with stacked, thickening-upward interbedded shale, siltstone, and rare sandstone (Sullivan and Sullivan, 2012). Within the sequestration area, shale units within the Domengine are present in all well logs examined, and are part of the identified complex of upper confining units.

The Domengine Formation is overlain by the Nortonville Formation, a regionally extensive neritic mudstone deposited during a relative sea level high in the Middle Eocene (Almgren, 1984). The Nortonville Shale is the uppermost member of the identified complex of confining units (secondary confining unit), and is described as interbedded shales, mudstones, and lithic sandstones (Sullivan and Sullivan, 2012).

Deposition of the Nortonville Formation was followed by another episode of uplift and erosion, with the formation of Markley Canyon 15 miles to the northwest of the sequestration area. Within the sequestration area, the Nortonville Formation remained present in all well logs examined. Markley Canyon was subsequently filled during the Late Eocene by the Markley Formation, a deltaic to shallow marine sandstone unit. The Markley Formation is identified as the lowermost source of underground source of drinking water (USDW) in the sequestration area, based on estimated total dissolved solids concentrations of less than 10,000 ppm (described in Hydrogeology and Hydrology sub-section). The Markley is overlain by the Sydney Flats Shale just east of the Midland Fault, and Miocene-Pliocene alluvial fan and eolian sediments farther east near the sequestration area.

During the Late Oligocene-Early Miocene, the Mendocino Triple Junction migrated to the north of the basin, changing the plate boundary from a convergent to a transform margin, docking the Salinian Block to the west and causing uplift of the Franciscan Complex (Dickinson and Snyder, 1979).

During the Miocene to Pliocene, depositional environments transitioned from marine to intertidal, flood basin, and terrestrial deposits (alluvial fan, eolian). This transition also led to the deposition of freshwater-bearing formations between the Miocene and Holocene. This includes the Mehrten

Formation (Miocene to Pliocene), Laguna Formation (Plio-Pleistocene), Modesto/Riverbank Formations (Pliocene), and other alluvial and stream deposits (Holocene). Additional detail is provided in the Hydrologic and Hydrogeologic Information sub-section.

The Holocene environment of deposition for the sequestration area cycled between a tidal-wetland, with development of peat deposits during interglacial period sea-level highs and a supra-tidal plain, with fluvial and eolian deposition derived from the Sierra Nevada Mountains. Current surface sediments within the AOR are mostly peat, with some exposure of eolian sands and alluvial fans of the Modesto Formation (Atwater, 1982). Reclamation and agricultural development of the sequestration area has contributed to ground level subsidence through oxidation of organic matter comprising peat deposits. Ground elevation within the AOR is near mean sea level. The Island that contains the AOR currently consists of primarily agricultural land and it is leveed to protect it from flooding; therefore, the facilities and CCS operations would be protected from flooding events.

Summary of Sequestration Area Stratigraphy

Figures 2-3a and **2-3b** show cross sections through the proposed sequestration area at Rindge Tract Island and the delineated AOR. **Figure 2-5** summarizes the generalized regional stratigraphy from the land surface to the basement. This column includes the following stratigraphic units of interest within the proposed sequestration area (from top to bottom): the Markley Formation (lowermost Underground Source of Drinking Water (USDW)), Nortonville Shale (secondary confining zone), Domengine Formation (secondary confining zone within low permeability layers), Capay Shale/Meganos Gorge Fill (primary upper confining zone), Mokelumne River Formation (proposed sequestration zone), H&T Shale (lower confining zone), other deeper zones that could potentially be used for sequestration, and the remaining formations down to basement at greater than 12,000 feet msl. These stratigraphic units were described in context of the tectonostratigraphic history of the Sacramento Basin in the preceding section. **Figure 2-5** includes ages, locally-used lithostratigraphic nomenclature, lithologies, and depositional information. The lithostratigraphic nomenclature of the Sacramento Basin is complex; for consistency, the names used in this section are based on formations identified from well reports local to the area. **Table 2-1** summarizes the elevations and thicknesses of the injection and upper confining zones beneath the AOR.

Structure

The sequestration area is located on the east flank of the Sacramento Basin. Stratigraphic units dip southwest, and angles increase with stratigraphic age as basin fill causes subsidence. The sequestration area is located away from major structural features of the Southern Sacramento Valley, as shown on **Figure 2-2**.

In the sequestration area, the base of the Mokelumne River Formation strikes northwest to southeast, and dips approximately 160 feet/mile to the southwest. The erosional contact between the Mokelumne River Formation and the overlying Meganos Gorge and Capay Formations is variable in both dip angle and dip direction (see **Figure A3-2** of **Section 3 – Area of Review and Corrective Action Plan**); however, the base of the Mokelumne and underlying units dip southwest overall, since the sequestration area is on the southeast margin of the Meganos Gorge.

The closest major structural feature to the sequestration area is the faulted antiform that forms the oil and gas accumulation trend of the MacDonald Island and Robert Island Gas fields to the southwest. The oil and gas traps are fault-bound on three sides (California Department of Conservation, 1982).

The sequestration area is approximately eight miles north of the Stockton Arch fault zone. The Stockton Arch likely formed as a remnant structure of the Great Valley forearc basin (Imperato, 1992). The Stockton Arch serves as the structural high that separates the Sacramento and San Joaquin Basins. The Stockton Arch faults originated as Cretaceous normal faults subsequently reactivated as reverse faults, and are considered aseismic.

Regional Structure and Stress

Late Cenozoic folds and faults in the Sacramento Valley appear to have formed in an east-west compressive stress regime. The axial traces of many folds are parallel to the trends of adjacent faults, and the folding appears to be related to drag on those faults. The amount of lateral displacement on faults in the valley is difficult to determine. The late Cenozoic kinematic pattern and inferred east-west compressive stress regime in the Sacramento Valley appear to be anomalous with respect to contemporary tectonism in adjacent regions (Harwood and Helley, 1987).

In the California Coast Ranges to the west and in the northern Basin and Range Province to the east, north-trending faults generally show normal and right-lateral displacements; east-trending faults show reverse and left-lateral movement; and northwest- and northeast-trending faults show dominantly right-lateral and left-lateral displacement, respectively (Zoback and Zoback, 1980; Hill, 1982). It is inferred that the maximum horizontal compressive stress was oriented approximately north-south and the least horizontal compressive stress (maximum extension) was oriented approximately east-west (Zoback and Zoback, 1980; Hill, 1982). Hill (1982) related the contemporary stress patterns to movement between the North American and Pacific plates and visualized the western part of the North American plate as a continuous broad zone of deformation following the model first proposed by Atwater (1970).

East-west compressive deformation in the Sacramento Valley suggests that the late Cenozoic stress field was not homogeneous between the continental margin and the northern Basin and Range province. Instead, the Sacramento Valley apparently acted as an independent block where relatively small-scale compressive strain was periodically released in response to large-scale right lateral transform tectonism in the San Andreas fault zone to the west and major east-west crustal extension in the northern Basin and Range Province to the east. Furthermore, the well-dated deformation patterns in the Sacramento Valley indicate that the compressive strain was not released randomly but, rather, that the late Cenozoic structural features formed in a sequential pattern that is progressively younger to the north. Northward progression of the compressive deformation implies a northward-migrating stress regime or a migrating energy source sufficient to initiate deformation in a regional compressive stress field. The interaction of lithospheric plates along the continental margin appears to provide a reasonable mechanism for generating the sequential compressive strain release observed in the valley.

Kinematic patterns of late Cenozoic structural features in the Sacramento Valley differ significantly from those in the Coast Ranges to the west and the northern Basin and Range Province to the east. For at least the past 2.5 million years, deformation in the valley has occurred in a regional stress field in which the maximum horizontal component of compressive stress was oriented approximately east-west and the minimum component of compressive stress (maximum extension) was oriented approximately north-south (Harwood and Helley, 1987). Within this stress regime, strain has been released primarily by reverse movement on north- and northwest-trending high angle faults and associated folding in the sedimentary rocks of the valley fill. During the late Cenozoic, the Sacramento Valley appears to have acted as an independent block on which relatively small-scale compressive deformation was imposed by eastward-directed subduction that was followed by large-scale transform tectonism along the continental margin and major east-west crustal extension in the Basin and Range.

The well-dated and diverse deformation patterns in the Sacramento Valley indicate that late Cenozoic tectonism evolved through the region in response to major crustal movements outside the valley's physiographic boundaries. East-west compressive tectonism may have been imposed on the valley by eastward subduction of the Juan de Fuca plate, and consequent tectonic wedging of the Franciscan Complex coupled with a major component of westward stress due to east-west extension in the Basin and Range Province.

Tectonic forces aside, until drilling and injection begin, we assume that the sum of stresses (radial, shear, normal) are zero. Once the well is installed, fall-off tests and down-hole strain monitors will allow a more detailed analysis of the stress field within the Mokelumne River Formation (injection zone). In-situ formation stress test data are not available for the upper confining zone (Capay Shale/Meganos Formation). Once the stratigraphic test well is drilled, Pelican will analyze the stress field within the injection and confining zones via in-situ formation stress tests per ASTM Method D 4645-08. Pelican will also demonstrate that the in-situ stress field data are appropriate and consistent with proposed injection pressures and fault stability analyses.

Project Data Sources and Pre-Processing Steps

The principal site characterization data sources include published geological reports; a WestCARB evaluation of the Sacramento Basin; Division of Oil, Gas, and Geothermal Resources (DOGGR) volume reports on petroleum fields in the region (California Department of Conservation, 1982); and geophysical well logs for the proposed sequestration area from the CalGEM Well Statewide Tracking and Reporting System Database. Existing 2D and 3D seismic data in the sequestration area were used to characterize the subsurface geology in the anticipated Area of Review (AOR). Various pre-processing steps were necessary in order to analyze these data in an appropriate and consistent spatial framework. The details of these pre-processing steps are described in **Attachment 1** (Seismic Report) and **Attachment 2** (Petrophysics Report and Products). The purpose of this section is to briefly summarize those pre-processing steps.

The first section of the Seismic Report (**Attachment 1**) discusses the data availability and quality. The second section discusses the conversion from the time domain into the depth domain. A 25 square mile subsection of the Conestrama 3D seismic survey was acquired from PacSeis, Inc. The licensed data is proprietary to PacSeis, Inc. and subject to confidentiality terms of the license to Pelican Renewables.

The first section of the Petrophysics Report and Products (**Attachment 2**) discusses the primary data sources. The second section discusses pre-processing steps to get data into a common spatial framework. The third section discusses data normalization and digital analysis of analog geophysical logs. Legacy wells in the sequestration area and its surroundings were identified from the CalGEM Well Statewide Tracking and Reporting System Database.

In addition to the regional primary data sources and pre-processing steps, additional data from the Citizen Green #1 well were used (**Attachment 3**). The Citizen Green #1 well was drilled in 2011 as part of a California Energy Commission Project to characterize the CO_2 sequestration potential of the Southern Sacramento Basin. The core data from this well are the only core data that are publicly available in the vicinity of the AOR for the units within the proposed storage complex. The Citizen Green #1 well is located approximately three miles north of the AOR. As part of the drilling program, an extensive series of geophysical well logs, core samples, and sidewall core samples were collected. These data are summarized as follows:

- Whole core of the Nortonville and Mokelumne River formations.
- Sidewall cores of the Nortonville, Domengine, Capay, Mokelumne River, H&T Shale, and Starkey formations.
- Petrophysical logs including gamma ray, spontaneous potential, resistivity, density, neutron porosity, combinable magnetic resonance (CMR), spectral gamma ray, elemental captive spectrometry, formation micro imager, and sonic scanner
- Drill cuttings and grab samples

Subsequent analyses included:

- Thin sections taken from sidewall cores
- XRD of cores, cuttings, and grab samples
- Helium porosimetry, air permeability, and saturation determinations for 15 sidewall core samples in the Mokelumne River, H&T Shale, and Starkey formations and brine permeability for a subset of 14 of these cores
- Helium pycnometry (HeP) of four sidewall cores in the Mokelumne River and Starkey formations, and mercury intrusion capillary pressure (MICP) measurements of five samples in the Domengine, Mokelumne River, and Starkey formations

Only a subset of this data is publicly available, including the basic triple-combo well log suite and, through the U.S. Department of Energy, Energy Data eXchange (EDX) database, thin section photographs, XRD data, porosity and permeability analyses, and HeP and MCIP data. Additional detail on the availability of data to inform site characterization is discussed in Injection and Confining Zone Details.

The Citizen Green #1 well location is shown on **Figure 2-7** and falls within the extent of licensed 3D seismic data. Citizen Green #1 penetrated into the Winters Formation, with core and sidewall core collected from the Capay Formation, Mokelumne Formation, H and T Formation, Starkey Formation, and Winters Formation. Given the proximity to this project's AOR and lack of site-specific information within the AOR itself, the extensive log suite and rock analyses from Citizen Green #1 are used as an analog for the injection and confining zone units in the project area. Data for Citizen Green #1 are available from CalGEM and from entries in the National Energy Technology Laboratory EdX system (**Attachment 3**). A stratigraphic test well will be drilled within the AOR before the Class VI authorization to construct or convert is issued. As discussed in Section 3 (Area of Review and Corrective Action Plan), the AOR-specific site characterization data collected via the stratigraphic test well and deep monitoring wells will be utilized to inform the model and re-evaluate the AOR prior to commencing injection.

Hydrogeology Summary

The proposed project is located within the Eastern San Joaquin Sub-basin (Sub-basin Number 5-22.01) of the larger San Joaquin Valley Groundwater Basin. The San Joaquin Valley Groundwater Basin formed in a broad structural trough that extends approximately 270 miles trending northwest to southeast in the northern portion of the Central Valley of California. The proposed project is located on the eastern edge of the Sub-basin on Rindge Tract Island, which is part of the Sacramento-San Joaquin River Delta.

A complete hydrogeologic review is provided in a sub-section below. The list below provides a high-level summary of the findings presented in that sub-section:

- **Topography**: Generally flat throughout Rindge Tract Island with elevations near mean sea level,
- **Freshwater:** Located at or near the surface from 10 feet to approximately 900 feet below the ground surface at Rindge Tract Island,
- **Freshwater Formations:** Alluvium, Modesto/Riverbank formations, Laguna Formation, and Mehrten Formation,
- **Groundwater Flow:** Generally, from west to east due to significant groundwater pumping near Stockton, California,
- **Groundwater Wells**: 23 groundwater wells were located within one mile of Rindge Tract Island, with the deepest well reaching approximately 300 feet below ground surface,
- **Underground Source of Drinking Water (USDW):** Lowermost USDW is the Markley Formation, which was identified through petrophysical log calculations (**Attachment 2**).

Maps and Cross Sections of the AOR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Figures 2-3a and **2-3b** are cross sections from the static geologic model that highlight the geologic units within the proposed storage complex at Rindge Tract Island and the delineated AOR. **Figure 2-8** presents the conceptual site model of the Area of Review (AOR) and includes the sequestration area stratigraphy and other significant geologic features. Numerical modeling was conducted to characterize the storage capacity and the extent of the AOR as presented in **Figure 2-9**. The numerical modeling of the AOR is presented in **Section 3**: AOR Evaluation and Corrective Action Plan.

Structural maps were created from interpreted key 3-D seismic horizons confirmed with well ties. Sonic and density logs from the Big Valley Eberhart 1 well were used to convert the seismic data from time to depth. Depths below sea level are referred to as true vertical depth at subsea (TVDSS).

The depth to the top (structure) of the basement is shown on **Figure 2-10. Figure 2-11** provides the H&T Shale structure map. The H&T Shale is thick and continuous throughout the section. Overlying the H&T is the Mokelumne River Formation, which is the target sequestration formation. The Mokelumne is continuous up-dip to the east within the proposed injection area. **Figure 2-12** presents the Mokelumne River Formation structure map and **Figure 2-13** presents the Mokelumne isopach map.

As seen by thinning and deepening of the Mokelumne on **Figures 2-3a**, **2-3b**, **2-12**, and **2-13**, the Mokelumne has been eroded by the Meganos Gorge to the west. In the deepest section of the Gorge, it appears that the Meganos Gorge has completely eroded the Mokelumne River Formation; however, well logs indicate that the Mokelumne River Formation is present in the proposed sequestration area and provides abundant storage capacity. **Figure 2-14** highlights the area of the Meganos Gorge. The Capay Shale, the primary upper confining unit for the sequestration area, is continuous throughout the AOR. The surface of the Meganos Gorge and the overlying Capay are difficult to differentiate within the seismic sections; therefore, the Capay and Meganos Gorge Formation top structure and thicknesses are combined in **Figures 2-15** and **2-16**. The depths to the top of the overlying Domengine Formation and Nortonville Shale are shown on **Figures 2-17** and **2-19**, respectively. The thickness of the Domengine Formation is presented in **Figure 2-18**. The Nortonville Shale is a secondary confining unit that is laterally continuous across the AOR, as shown in **Figure 2-20.** As described in a previous section the upper Domengine Formation also contains shale interbeds across the sequestration area. Both the Domengine and the Nortonville are thick and continuous across the sequestration area (**Figures 2-18** and **2-20**). **Figures 2-33** and **2-38a-c** highlight the relative vertical positions of the USDWs to the proposed injection wells and injection zone (Mokelumne River Formation). Detailed explanations of these figures are provided in the section "Hydrologic and Hydrogeologic Information."

Faults mapped within the AOR include basement faults, listric gravitational faults within the Meganos Gorge, and syn-depositional faults in formations above the objective section. The fault distributions are shown in **Figure 2-21**. Cross sectional maps provided in **Figures 2-22**, **2-23**, and **2-24** depict the faulting and provide example seismic profiles. The Meganos Gorge Formation consists of sands and shales that have experience differential compaction and gravitational faults (slump faults) as noted within the sections (**Figures 2-22**, **2-23**, and **2-24**. Examples of the listric faults associated with the gorge are shown in **Figures 2-25** and **2-26**. Within the AOR, there are no major structural closures formed by faults or domes.

Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Faults over the Rindge Tract Island (AOR) were interpreted using the Conestrama 3D seismic Volume. Three distinct sets of faults were identified and are illustrated in **Figure 2-22** (cross sectional profile A-A'): 1) shallow syn-depositional faults, 2) slump and gravitational faults of the Meganos Gorge and 3) deep basement faults. The volume provided extensive coverage of the proposed AOR (**Figure 2-21**).

The Meganos Gorge cut approximately 2,000 feet into the Mokelumne River Formation (MRF). Slumps were generated in the gorge by mass sediments moving downslope. The eastern side of the gorge is mapped by the fault depicted in blue in **Figures 2-22**, **2-23**, and **2-24** (cross-sectional profiles A-A', B-B', C-C', respectively). The western side of the Meganos Gorge is mapped by the fault depicted in maroon (**Figure 2-24** C-C'). Slump surfaces that occurred after the infill of the Meganos and the Capay were reactivated by gravitational forces. Within the gorge, syn-depositional faulting is documented by the rollover antiform observed in **Figure 2-24** C-C'. Should the MRF reservoir be juxtaposed to Meganos infill sand, the stratigraphic nature of the sands and the sealing capacity of the shales would not threaten the vertical migration of CO_2 into reservoirs above the Capay Formation.

Listric slump faults are present within the Meganos Formation. During its initial incision, the Meganos Gorge cut approximately 2,000 feet into the Mokelumne River Formation (MRF) injection zone to the north and west of the AOR. Mass sediments moving downslope created slumps, which reactivated by gravitational forces to create slump faults. The listric curved plane of slump failure defines the edges of the Meganos Formation, where it is in contact with the MRF. The 2-D cross-sections show that these listric slump faults are wholly contained within the Meganos Gorge and do not transect the MRF zone of interest, which lies to the east of the gorge. The interpretation of the 3D seismic volume additionally confirms that the Meganos Gorge slump faults are contained within the Meganos Gorge and are not transecting the MRF. The Meganos Gorge is comprised of approximately 95% silty shale and shaley siltstone (Dickas and Payne, 1967). During the formation and later filling of the gorge, the slopes along the edges failed, forming slump faults that dip toward the center of the channel. Subsequent deposition within the channel and the eventual deposition of the overlying Capay Shale form a thick, continuous seal. The slump faults are dip-sealing, as evidenced by the presence of hydrocarbons both within the region and RTI, as noted in the 3D seismic volume.

The lowest seismic sequence deposited on top of the basement has variable thickness (**Figure 2-25**). The sequence thickness variation is related to tectonic processes during deposition. The strong reflector that tops the sequence, and the lack of fault discontinuity into the above sequence, indicates a prolonged period of exposure and erosion. One basement fault was apparently reactivated during the Upper Cretaceous; the fault strikes east-west and is depicted in yellow in **Figures 2-22**, **2-25** and **2-26**. This fault does not cut the MRF, as it was eroded in the area by the Meganos Gorge. The fault cut into the lowermost Meganos infill sequence. Over 1500’ of the Meganos and Capay sequence is undisturbed and considered an excellent seal.

Pelican additionally assessed the risk of induced seismicity and the potential for fault propagation within the project area, particularly associated with the Meganos Gorge slump and gravitation faults, under planned operational conditions. This assessment is included as **Attachment 4** to this narrative.

Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

The injection complex within the AOR consists of a lower confining zone (H&T Shale), an injection zone (Mokelumne River Formation), and an upper confining zone (Capay Shale/Meganos Gorge sedimentary fill). The depositional history and tectonostratigraphic framework of these units at a basin-wide scale is discussed in the sub-section entitled “Regional Geology, Hydrogeology, and Local Structural Geology.” The purpose of this section is to discuss the details of the injection complex in the vicinity of the Class VI injection location. **Table 2-1** summarizes the elevations and thicknesses of the injection and upper confining zones beneath the AOR.

Table 2-1. Elevations and Thicknesses of Stratigraphic Units Beneath the AOR

Formation	Sequestration Complex Component	Elevation of Top of Unit (range in feet below mean sea level)	Elevation of Top of Unit (range in meters below mean sea level)	Thickness Range (Feet)	Thickness Range (Meters)	Lithology
Nortonville Shale	Secondary Confining Zone	3700-4235	1128-1291	58-490	18-149	Shale
Domengine Formation	Secondary Confining and Pressure Dissipation Zone	3850-4516	1173-1376	497-1229	151-375	Sandstone and shale
Capay Shale/Meganos Gorge Fill	Upper Confining Zone	4593-5577	1400-1700	66-1444	20-440	Shale
Mokelumne River Formation	Injection Zone	4987-6824	1520-2080	197-2034	60-620	Sandstone, shale, minor coal

Note: Top elevations and thickness ranges listed are for the extent shown in Figures **2-12** through **2-20**.

The Lower Confining Zone

The lower confining zone is the H&T Shale. In the vicinity of the AOR, the depth to the top of the unit ranges from approximately 6700 to 7200 feet below mean sea level (MSL) (**Figure 2-11**). The only well within the AOR that fully penetrates the H&T Shale is Big Valley Eberhart 1. Big Valley Eberhart #1 is located on the extreme eastern edge of the island. The well log for Big Valley Eberhart #1 shows a gradational contact with the base of the Mokelumne River Formation (**Figure 2-27**). The top of the H&T Shale is at 6690 feet below MSL at this location and the thickness is approximately 100 feet. The variability in the top of the H&T Shale across the AOR is informed, in part, by interpolation from other wells that penetrate the H&T Shale within or near the AOR (**Figure 2-7**). The variability in the top of the H&T Shale is also informed by interpretation of 3-D and 2-D seismic reflection profiles (**Figure 2-7**).

The mineralogy, petrology, and material properties were informed by core and sidewall core taken from the Citizen Green #1 well. Data are provided in **Attachment 3**. The Citizen Green #1 well is the closest location to the AOR for which mineralogic and petrologic data have been collected for the units of interest within the proposed storage complex. X-ray diffraction (XRD) data were not analyzed for shales within the H&T Shale interval; as such, the mineralogic composition of the shale is unknown. However, XRD data were analyzed for one sand stringer within the H&T Shale interval at an approximate depth of 6297'. Quartz, andesine (plagioclase feldspar), and potassium feldspars dominate the mineralogical composition of this sample.

Four sidewall core samples were described as shale in the depth interval from 6,899 feet to 6,993 feet that is within the H&T Shale at this location. The intrinsic permeability in brine of one sample (#16) was estimated to be <0.001 mD. The intrinsic permeability in air was estimated to be 0.006 mD (#16) and <5 mD (#14). The porosity was estimated to be 1.8% (#16) and 22.4% (#14). The grain densities were estimated to be 2.73 g/cm3 (#16) and 2.68 g/cm3 (#14). No relative permeabilities were measured.

Key uncertainties in understanding the character of the lower confining zone result from the lack of site-specific data within the AOR. The uncertainties will be reduced by initially treating the Class VI well as a stratigraphic test well with complete core sampling, sidewall core sampling, and geophysical logging. This stratigraphic test well would be drilled before the Class VI authorization to construct or convert is issued. The stratigraphic test well will extend into the H&T Shale in order to sufficiently characterize this unit as a lower confining zone. The key parameters governing the seal quality in the H&T Shale are the density, porosity, intrinsic permeability and anisotropy ratio, relative permeability, and capillary pressure. At least three samples from the H&T Shale at a minimum of 10-foot intervals will be submitted for analytic determination of these key parameters. Mineralogic and petrologic characterization of these samples will also be completed to ensure the compatibility of the lower confining zone with the carbon dioxide stream.

The Injection Zone

The selected injection zone for the Class VI well is the Mokelumne River Formation (MRF). Within the AOR, the depth to the top of the unit ranges from approximately 5100 to 6800 feet below MSL (**Figure 2-12; Table 2-1**). Within the AOR, the thickness of the MRF ranges from approximately 200 feet to 1700 feet (**Figure 2-13; Table 2-1**). The variability in thickness depends on the depth of erosion by Paleocene or Eocene unconformities that comprise the upper surface. Six penetrations of the Mokelumne River Formation on Rindge Tract Island and within or near the defined AOR were selected for further analysis. The geophysical logs for these wells are shown on **Figure 2-27**.

Core and sidewall core data from Citizen Green Well #1 indicate textural changes within the injection zone (**Attachment 3**). These changes are likely to influence the permeability distribution within the injection zone. The vertical scale of permeability variation appears to be on the order of 100 feet. We can infer from seismic data (**Attachment 1**) that similar variations exist within the injection zone beneath the delineated AOR (**Figure 2-27**). The geophysical logs for the six penetrations of the Mokelumne River Formation show indicators of textural variability on the same scale. The stratigraphic stacking patterns for Big Valley Eberhart 1 is very similar to type log sections for the Mokelumne River Formation presented by Johnson (1990), with a basal coarsening upward sand unit, interbedded sands and shale, and massive sands at the top of the formation. The shale interbeds will impact CO_2 migration within the injection zone but do not appear laterally continuous enough to serve as a primary confining unit.

The mineralogy, petrology, and material properties were informed by core and sidewall core taken from the Citizen Green #1 well (**Attachment 3**). The Citizen Green #1 well is the closest location for which mineralogic and petrologic data have been collected (approximately three miles north of the delineated AOR at Rindge Tract Island). X-ray diffraction (XRD) data for four samples within the Mokelumne sands show that the mineralogic composition is dominated by feldspars and quartz (**Table 2-6**). Additional details on the mineralogy of the Mokelumne are discussed in the Geochemistry sub-section. 16 sidewall core samples from the Mokelumne were described as sands or silty sands in the depth interval from 5350 feet to 6800 feet. Within this depth interval, one sample was described as a clay-siltstone layer (approximately 20 feet thick).

Porosity, intrinsic permeability, and grain densities were measured in six samples from the lower Mokelumne River Formation. The intrinsic permeability in brine was estimated to range from 0.57 to 86.3 mD. The intrinsic permeability in air was estimated to range from 4.8 to 367.1 mD. The porosity was estimated to range from 27.7 to 33.0%. The grain densities were estimated to range from 2.65 to 2.70 g/cm3. No relative permeabilities were measured.

Injectivity tests are not available for the Mokelumne River Formation in the project area and are included in the Pre-Operational Logging and Testing Plan in **Section 6** of this application. There are multiple lines of evidence supporting that the Mokelumne River Formation has sufficient injectivity for CO_2 injection: (1) The Mokelumne River Formation is already used for gas storage injection at the MacDonald Island Gas Storage Field; (2) Sidewall core and petrophysical well log analysis indicates that the Mokelumne River Formation has sufficient porosity and permeability to store CO_2 and dissipate pressures; and (3) The mercury capillary entry pressure (MICP) for two sidewall cores Citizen Green #1 are .45 and .49 psia (**Attachment 3**).

Key uncertainties in understanding the character of the injection zone result from the lack of directly measured site-specific data within or near the AOR. The uncertainties will be reduced by initially treating the Class VI well as a stratigraphic test well with complete core sampling, sidewall core sampling, geophysical logging, and injectivity testing. The key parameters governing the injectability and storage capacity in the Mokelumne are the density, porosity, intrinsic permeability and anisotropy ratio, relative permeability, and capillary pressure. Mineralogic and petrologic characterization of these samples will also be completed to ensure the compatibility of the injection zone with the carbon dioxide stream. This stratigraphic test well would be drilled before the Class VI authorization to construct or convert is issued. Following test well construction and data collection, characterization data for the Mokelumne will be input into DOE-NETL's CO2 Storage prospeCtive Resource Estimation Excel aNalysis (CO2-SCREEN) or a similar tool to quantitatively interpret reservoir quality.

The Upper Confining Zone

The top of the injection zone is vertically separated from the lowermost USDW by at least 1000 feet and up to approximately 2600 feet of strata. The primary upper confining zone is low permeability strata of the Meganos Gorge Fill and Capay Shale that directly overly the injection zone. The secondary upper confining zone contains low permeability shale intervals within the lower and upper members of the Domengine Formation and the Nortonville Formation. Within the AOR, the depth to the top of the primary confining zone ranges from approximately 4900 to 5600 feet below mean sea level (MSL) (**Figure 2-15; Table 2-1**). Within the AOR, the thickness of the primary upper confining zone ranges from approximately 150 feet to 1400 feet (**Figure 2-16; Table 2-1**). The six penetrations selected for further analysis all contain instances of the primary upper confining zone, indicating that this unit is continuous across the AOR (**Figure 2-27**). This is consistent with interpretations from the seismic reflection data (**Attachment 1**). There is minimal textural variability within the Capay Shale across these penetrations (**Figure 2-27**). The Capay-Meganos sequence is a sufficient primary confining zone due to its thickness, extensivity, lack of faults and fractures, and minimal textural variability in the shales within and near the AOR. The secondary confining zones have been identified as an additional protection for USDWs due to the variability in vertical separation between the injection zone and lowermost USDW within and near the AOR.

Within the AOR, the depth to the top of the Domengine Formation ranges from approximately 4300 to 4500 feet below MSL (**Figure 2-17; Table 2-1**) and ranges from approximately 600 to 1100 feet thick (**Figure 2-18; Table 2-1**). The upper portion of the Domengine Formation contains shale units that will provide secondary confinement. Within the AOR, the depth to the top of the Nortonville Shale (secondary confining zone) ranges from approximately 3900 to 4200 feet below MSL (**Figure 2-19; Table 2-1**), and the thickness ranges from approximately 100 to 500 feet (**Figure 2-20; Table 2-1**). The top structure map of the Nortonville Shale also delineates the base of the lowermost USDW unit (Markley Formation) (**Figure 2-19**). The six penetrations selected for further analysis all contain instances of these secondary confining units. The well logs indicate that the upper portion of the Domengine consists primarily of shale with sandstone interbeds in the vicinity of the AOR that this part of the Domengine is continuous across the AOR. These logs also indicate that the Nortonville Shale is continuous across the AOR (**Figure 2-27**). This is consistent with interpretations from the seismic reflection data (**Attachment 1**).

XRD, porosity, permeability, and MICP data were not analyzed for the upper confining zone units at the Citizen Green #1 well. Six core samples were taken within the Capay Shale, but not analyzed. Of the six sidewall core samples collected from the Capay, three were described as shale, one was missing, and two were described as sand or silty sand. At the Citizen Green #1 Well, the depth interval described as Capay ranges from 5108 feet to 5202 feet (**Attachment 3**). Six core samples were taken within the Domengine and five were taken within the Nortonville, but not analyzed. Of the core samples collected from the Domengine, five were described as unconsolidated sand and one sample was missing. At the Citizen Green #1 Well, the depth interval described as Domengine sandstone ranges from 4350 feet to 5100 feet (**Attachment 3**). Of the core samples collected from the Nortonville, three were missing, one was described as shale, and one was described as shale and sand. At the Citizen Green #1 Well, the depth interval described as shale ranges from 3995 feet to 4200 feet (**Attachment 3**).

Key uncertainties in understanding the character of the upper confining zone result from the lack of directly measured site-specific data within or near the delineated AOR. The uncertainties will be reduced by initially treating the Class VI well as a stratigraphic test well with complete core sampling, sidewall core sampling, and geophysical logging of the primary and secondary confining zones (i.e., all units beneath the base of the lowermost USDW (Markley Formation)). The key parameters governing the suitability of this zone as a seal are the density, porosity, intrinsic permeability and anisotropy ratio, relative permeability, and capillary pressure. Mineralogic and petrologic characterization of these samples will also be completed to ensure the compatibility of the upper confining zone with the carbon dioxide stream. This stratigraphic test well would be drilled before the Class VI authorization to construct or convert is issued. To confirm that the Capay Shale supports confinement across the AOR, Pelican will additionally drill three of the above confining zone monitoring well holes into the Capay Shale to confirm its confinement potential across the AOR. This extended drilling will be deep enough to support sufficient characterization of the Capay Shale, but will not fully penetrate the zone as to not negatively impact the integrity of the confining zone. This will take place at the locations for GMW-1D, GMW-2D, and GMW-3D, which will ultimately monitor the lowermost transmissive sands within the Domengine Formation as defined in the Testing and Monitoring Plan (Section 8). These test holes will be plugged back to the intended monitored zone within the Domengine Formation before the monitoring wells are constructed.

Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Geophysical well log data collected from 30 oil and gas wells in the general vicinity of the proposed injection site were evaluated to determine reservoir and confining unit characteristics for the Nortonville Shale and underlying units including Domengine Formation, Capay Shale, Meganos Gorge, Mokelumne River Formation (MRF), and the H&T Shale. Geologic units above the Nortonville Shale were not included. The distribution of the 30 wells is shown on **Figure 2-7**. Core data from Citizen Green #1 well were used to calibrate log responses for all other wells. A comparison of core and well log data for Citizen Green #1 is provided in **Attachment 3**. A detailed description of the petrophysical analysis methods and the tabulated results are provided in **Attachment 2**.

Eleven of the 30 wells contained full suites of logs including Resistivity, Spontaneous Potential (SP), Gamma Ray (GR), Density/Neutron and in some cases Sonic Delta-T. There were nine wells that contained resistivity, SP, and DT only. The remaining wells contained only resistivity and SP data. Petrophysical analyses described in the referenced report were used to calculate the estimated formation porosity, permeability, Volume of Clay (VCL), and salinities for wells in the project area. A Petrophysical Zone Averages Report spreadsheet includes tabulation of the unit top and bottom elevations, the gross thickness, net thickness, net to gross (NTG), average porosity, average VCL and average VCL thickness for Nortonville to TD, Domengine Formation and the Mokelumne River Formation (MRF). This information was initially provided to the Pelican modeling team to develop the parameters for the numerical models.

In addition to the petrophysical data analysis, well logs were assembled to create geologic cross sections centered near the sequestration site and extending from 1.5 to 3 miles from northwest to southeast and from west to east. The petrophysical data analysis and geologic cross sections reveal the following formation characteristics:

Nortonville Shale: The well logs indicate a low permeability, laterally continuous formation with average gross thickness of approximately 254 feet. Porosities range from 0.06 to 0.53 with a gross average of 0.35. The NTG for Nortonville is 0 indicating the volume of reservoir rock in this formation is minimal. The average VCL is 0.54. Average air permeability (K_{air}) is 1.3 milliDarcy (mD). There is no deflection from the SP and no separation between the deep and shallow resistivity curves. These observations together suggest very low permeability in the Nortonville and likely would not see any fluid migration upward from zones below. Nortonville Shale characteristics indicate this formation may serve as an additional confining unit for the sequestration project.

Domengine Formation: The well logs show the formation has favorable reservoir permeability, and is laterally continuous with average gross thickness of approximately 857 feet. The formation thickness is approximately 800 feet above the injection site, thickening to the northwest to approximately 1,100 feet at the 3-mile radius and thinning to approximately 600 feet to the east. The formation consists of thick blocky sands with intermittent thin interbedded shale, and most notably an approximately 100 to 200 feet thick low permeability section in upper portion of the formation. Wells further to the west of the proposed injection site exhibit thicker sand packages, thinning as you go east. The eastern wells exhibit good, developed sands in the bottom half of the Domengine and poorer quality toward the upper half of the zone. Porosities range from 0.06 to 0.53 with a gross average of 0.35. The average NTG for Domegine is 0.51 and the maximum NTG is 0.923 indicating predominance of reservoir rock in this formation. The average VCL is 0.27. Average K_{air} is 93 mD. The is well developed SP deflection as well as more separation between the deep and shallow resistivities in the western wells compared to the eastern wells. Although this suggests better permeability to the west, the eastern wells still indicate favorable permeability, albeit in thinner packages. The low permeability section in the upper portion of the formation may serve as additional confining unit for sequestration in this area.

Capay Shale: The well logs indicate a low permeability, laterally continuous formation with relatively uniform thickness ranging from approximately 330 feet thickness west and northwest of the sequestration area/injection site to approximately 100 feet in the east. Overall, the average gross thickness is approximately 200 feet. Porosities range from 0.09 to 0.48 with a gross average porosity of 0.28. The NTG for Capay is 0.016 indicating the volume of reservoir rock in this formation is minimal. The average VCL is 0.49. Average air permeability is 2.5 mD. There is negligible SP deflection and both resistivities stack indicating very low permeability and likely a barrier to flow. The Capay thickens near the proposed injection site (see Dow Services Allied and RTP #1-21) then thins to the southeast with the top of the unit shallower than the northwest wells, possibly due to the presence of a fault. The low permeability Capay formation should serve effectively as primary confining unit overlying the MRF sequestration zone.

Meganos Gorge: The well logs indicate a low permeability formation present west of the sequestration area seen in Spaletta #1 well that cuts approximately 700 feet into the MRF and thickens to the west and northwest. The Meganos zone is present in the northwest wells then is not present in the southeast (east of Cities Services Allied well) suggesting a fault. Where Meganos is present, it has the characteristic of a low flow zone like the Capay. The Meganos tends to have larger gross thickness than the Capay, ranging from 600-1000 ft thick. Meganos porosities range from 0.12 to 0.48 with a gross average porosity of 0.28. The NTG for Meganos is 0.13. The average VCL is 0.42. Average air permeability is 4.6 mD. There is negligible SP deflection and both resistivities stack indicating very low permeability and likely a barrier to flow. The low permeability Meganos with the Capay should serve effectively as the primary confining unit overlying and adjacent to the MRF sequestration zone.

MRF: The well logs indicate this formation consists of thick sands with intermittent thin interbedded shale providing favorable reservoir permeability and is laterally continuous with average gross thickness of approximately 645 feet. Well logs in the vicinity of the proposed injection site indicate significant offset in the MRF from the Dow Services Allied well at approximately 6300 feet and RTP #1-21 well top at approximately 5370 feet indicating a fault or slump in this area. Porosities range from 0.11 to 0.39 with a gross average porosity of 0.28. The average NTG for MRF is 0.51 and the maximum NTG is 0.7 indicating predominance of reservoir rock in this formation. The average VCL is 0.25. Average air permeability is 127 mD. The MRF wells have well developed SP deflection as well as more separation between the deep and shallow resistivities in the western wells compared to the eastern wells. Although this suggests better overall permeability to the west, the eastern wells still indicate favorable permeability.

H&T Shale: The well logs indicate a low permeability, laterally continuous formation with average gross thickness is approximately 73 feet. Porosities range from 0.09 to 0.38 with a gross average porosity of 0.23. The NTG for H&T Shale is 0.012 indicating the volume of reservoir rock in this formation is minimal. The average VCL is 0.31. Average air permeability is 0.19 mD. There is negligible SP deflection and both resistivities stack indicating very low permeability indicating a barrier to flow. The low permeability H&T Shale formation should serve effectively as underlying confining unit for the MRF sequestration zone.

Reservoir salinities were calculated for MRF and to identify any units that may have salinities less than the 10,000 parts per million (10 kppm) which is the threshold used to identify an underground source of drinking water (USDW) aquifer. The calculated salinities for Domengine and MRF remain above 10,000 parts per million (ppm).See **Table 2-5** for calculated salinities from legacy wells within and near the AOR, as well as **Attachment 2** for a discussion of the petrophysical calculations to evaluate salinities.. There are some wells that have calculated intervals that all are at the top of the MRF that calculated less than 10,000 ppm but these are high resistive zones that are potentially charged and not considered wet and are likely shale stringers. The Domengine have clear wet sands that calculate salinities in similar ranges to the MRF. The units above the Nortonville Shale show “clean, wet sands” with salinities less than the 10,000 ppm USDW threshold, ranging from 2,000 ppm to 6,000 ppm. SCS understands there have been no water quality samples taken in the MRF with the Area of Review. In addition, SCS conducted an online database review and found no available fluid geochemistry data for the MRF within the AOR and extending out to the edge of the Rindge Tract Island. Two (2) wells located inside the AOR have well logs suitable for salinity calculations; of these 2 wells, Eberhardt 15-34 (API: 407720498), is the only well that penetrates the MRF. Based on the log derived salinity calculations, the salinities for the sand intervals within the MRF range from approximately 11,000 to 22,000 parts per million (ppm) as shown on **Figure 2-38b**. Based on the limited amount of well log data and water quality samples within the AOR, the log calculations are the best tool to estimate the salinity of the MRF at this time. The proposed stratigraphic test well will collect water quality samples of the MRF to confirm that salinity of the formation water is below 10,000 ppm within the sand intervals utilized for injection.

<u>Data Gaps and Recommendations</u>:

Geomechanical data were not available in the information provided for this review. The lack of directly measured site-specific data at Rindge Tract will be reduced by initially treating the Class VI well(s) as a stratigraphic test well(s) with complete core sampling, sidewall core sampling, and geophysical logging of the primary and secondary confining zones (i.e., all units beneath the base of the Markley Formation (USDW). In addition, geochemical data will be collected to confirm the lowermost USDW and its salinity, as well as the salinity of the proposed injection zone (MRF) and sand units between the injection zone and lowermost USDW.

Since there was no indication that lab testing has been performed to calculate rock ductility, rock strength, stress, brittleness or other geomechanical parameters, rock cores should be collected from the Class VI test well(s) for geomechanical laboratory analysis. In addition, combination of advanced sonic logs measuring both shear and compressional sonic travel time in the same well(s) can be used for data calibration and application for off-set wells.

Test results regarding Faults and Fractures were not available. Class VI test well(s) should include resistivity imaging tool/s for fracture identification, bedding information (NTG), as well as fault and fracture identification. Imaging tools will also be able to provide rock strength information through the identification of breakouts.

Pore pressure data were not obtained from the available well log data. The acquisition of formation pressures will provide pore pressure and in-situ permeability data. Collecting fluid samples for direct salinity measurements can be used to verify USDW; as mentioned, this information will be collected when the stratigraphic test well is drilled. Gathering segregated downhole water samples would provide the resistivity of formation water (Rw), salinity and Total Dissolved Solids (TDS) values required by CalGEM. Vertical Interference Testing (VIT), from Modular Dynamic Tester (MDT), can also be used to measure vertical communication between sand and shale units.

The permeability estimation model for this project relied on limited rotary sidewall core data taken from the Citizen Green #1 including the Nortonville shale interval and the MRF formation. The uncertainty around permeability warrants collecting additional cores (rotary or whole core). The core should be collected in all zones to obtain a spectrum of porosities and apparent clay contents. Measurement of air and liquid permeability as well as x-ray diffraction (XRD) measurements for clay content would be beneficial to develop a single permeability transform or to identify units that require a separate transform. Acquisition of magnetic resonance information to compare to core would be helpful to quantify total porosity as well as independently validate the permeability transform. The use of spectroscopy logging tools can be used to validate of clay volume calculations and to compare to core XRD measurements. Dielectric logs are another option for calibration of clay volume and has been utilized in the Central Valley for heavy oil and fresh water environments.

Seismic History [40 CFR 146.82(a)(3)(v)]

The initial evaluation of Rindge Tract for carbon sequestration included assessing the potential for earthquakes at or near the injection zone, and the integrity of the target injection formation seal (the Capay Shale and Meganos Gorge Fill) during seismic events. The geologic characterization includes a detailed evaluation of the Capay and Meganos Gorge, as well as a secondary seal, the Nortonville Shale.

SCS obtained fault and seismicity data from the following sources:

- Northern California Seismic Network (2020)
- USGS and California Geological Society, Quaternary Fault and Fold Database (2022)
- Characterizing the Earthquake Ground Shaking Hazard in the Sacramento-San Joaquin Delta, California (Wong et al, 2009)
- Late Cenozoic Tectonism of the Sacramento Valley, California (Harwood and Helley, 1987)
- USGS Seismic Hazard Map (2018)
- Characterization of Potential Seismic Sources in the Sacramento-San Joaquin Delta, California (Unruh et al, 2009)

According to the USGS National Quaternary Fault and Fold Database, the closest mapped Quaternary fault to the proposed injection site on Rindge Tract is the South Midland Fault, which is located approximately seven miles west of the island. However, upon review of data obtained from previous natural gas exploration, the Rindge Tract AOR is located approximately 1.5 miles northeast of the McDonald Island gas field, which consists of a structural trap formed by a fault-bound anticlinal feature.

The Quaternary South Midland fault was formed during the development of the Rio Vista Basin, part of the ancestral Great Valley forearc basin, and was initially active as a normal fault during the Cretaceous (Harwood and Helley, 1987). The fault was reactivated during the late Cenozoic as a reverse-oblique fault that strikes north-northeast, dips steeply to the west with a right-lateral strike-slip component. Many hundreds of feet of undifferentiated Miocene sediments obscure the South Midland fault trace; therefore, the fault location as depicted on **Figure 2-28**, is inferred.

In 2009, Unruh et al. (2009) published a detailed study of the South Midland fault that included the analysis of gas exploration and production boring data, historical geologic maps, topographic maps, and aerial photographs. Aerial photographs and topographic maps reveal geomorphologic features that indicate movement, such as uplifts and depressions, and stream offsets. Geologic maps and boring logs show the relative locations of geologic units and indicate unit displacement. According to the study, the South Midland fault experienced displacement as recently as the middle to late Holocene. The National Quaternary Fault Database (USGS, 2022) reports no seismic activity originating at the South Midland fault within recorded history.

SCS reviewed geologic data for the McDonald Island gas field, southwest of Rindge Tract. The McDonald Island gas field consists of a northeast-southwest trending fault bound anticlinal feature that forms a structural trap for natural gas. It is unclear whether the faulting is due to brittle or ductile deformation. SCS found no evidence of seismicity associated with the McDonald Island faults.

SCS examined the USGS Seismic Hazard Map and historical seismicity records to determine the potential for earthquake shaking within the Rindge Tract AOR. The USGS Seismic Hazard Map includes the entirety of California as an area of elevated risk, much of which is due to the Northern California transverse tectonic regime and the blind thrust faults prevalent in Southern California. Using data from the Northern California Seismic Network (1967-2020), SCS plotted earthquake activity proximal to the AOR (**Figure 2-28**). Events shown on **Figure 2-28** lie outside the AOR, and based on the calculated magnitude do not pose a significant risk to the target injection zone or stratigraphic seals. Table 2-2 below details these events and their location, magnitude, depth, and distance from the AOR.

Table 2-2. Recent Seismic Events in the Vicinity of the AOR

EventID	Date	Latitude	Longitude	Depth (Miles)	Magnitude	Magnitude Type	Number of Stations	Distance from AoR (miles)	Source
21224932	5/8/2002	38.22383	-121.8375	17.43	3.6	Mw	156	25.05	NCSN
21247683	9/29/2002	37.8745	-121.611	4.31	3.42	ML	79	13.17	NCSN
51199149	3/27/2008	37.93083	-121.803	14.11	3.14	ML	103	20.19	NCSN
71280691	9/13/2009	37.85483	-121.772	13.80	3.21	Mw	135	20.92	NCSN
71670931	10/26/2011	37.85383	-121.8915	8.73	3	ML	133	26.68	NCSN
72795746	4/30/2017	37.82516	-121.806	15.20	3.78	Mw	264	23.59	NCSN
73034206	6/22/2018	37.99117	-121.7205	10.40	3.24	Mw	205	14.82	NCSN
73225421	7/16/2019	37.81867	-121.75684	12.38	4.31	Mw	143	21.67	NCSN
73225436	7/16/2019	37.81867	-121.76033	11.71	3.2	ML	110	21.82	NCSN

Notes: Data obtained from the Northern California Seismic Network (NCSN) earthquake catalog
AOR: Area of review - distance from estimated earthquake epicenter to the boundary of the AOR

Wong et al (2009) performed a Probabilistic Seismic Hazard Analysis (PSHA) for the Sacramento-San Joaquin Delta area using information on the geology, known faults and seismic history of the region. The PSHA calculates the probability of peak ground acceleration (PGA) and the projected frequency of the PGA. According to the USGS, PGA is "a measure of the maximum force experienced by a small mass located at the surface of the ground during an earthquake." The results of the PSHA predict PGA of between 0.16 and 0.20% g for a 2% probability within 250 years. The calculations returned a repeat period of approximately 500 years for the area including Rindge Tract. SCS used the USGS Unified Hazard Seismic Tool (Tool) to calculate the PGA at Rindge Tract at 2% within 250 years. The Tool uses a shear wave velocity of 750 m/sec, the uppermost of the Class C fault velocity range/lowermost of the Class B velocity range. The calculated peak Unified Hazard Response Spectrum was 0.3403g, and the annual frequency of an event of greater than 0.2g was $1.7e^{-3}$, or a repeat time of approximately 585 years. Pelican also conducted a risk assessment for induced seismicity as a result of project operations, which is discussed in detail in **Attachment 4** of this narrative.

Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

The following sections present the results of a hydrologic and hydrogeologic study for the proposed Pelican CCS Project. The study reviewed online databases, well records, and historical literature relative to groundwater in the Eastern San Joaquin Sub-basin of the

San Joaquin River Hydrologic Region. The more refined Study Area extended approximately one mile beyond the boundary of Rindge Tract Island.

Methods

Sources, including geologic maps, well completion reports, well logs, and historical reports, were reviewed to complete this analysis. A list of these sources is displayed in **Table 2-3**.

Table 2-3. Hydrogeologic Data Sources

Data Type	Source or Author	Website or Record Name
Online Databases		
Groundwater Elevation	California Department of Water Resources	http://www.water.ca.gov/waterdatalibrary/
Water Well Completion Reports	California Department of Water Resources	https://dwr.maps.arcgis.com/apps/webappviewer
Groundwater Ambient Monitoring and Assessment Program (GAMA) (water quality, well locations and monitoring data)	California State Water Resources Control Board	https://www.waterboards.ca.gov/water_issues/programs/gama/online_tools.html
Groundwater Elevation/Water Quality	Eastern San Joaquin Sub-basin Data Management System	https://opti.woodardcurran.com/esj/main.php
Groundwater – Produced Water Geochemical Data	USGS: Produced Waters Database v. 2.3	https://tableau.usgs.gov/views/USGSPWDBv3_0/USGSPWDBv3_0Dashboard?%3Aembed=y&%3AisGuestRedirectFromVizportal=y
Literature Review		
Groundwater Basin Information	California Department of Water Resources	California's Groundwater Bulletin 118 Groundwater Basin Number: 5-22.01
Freshwater Formation descriptions	Eastern San Joaquin Groundwater Authority	Eastern San Joaquin Subbasin - Groundwater Sustainability Plan, June 2022 http://www.esjgroundwater.org/Documents/GSP
Groundwater data, elevations, maps, etc	San Joaquin County Flood Control and Water Conservation District	San Joaquin County Flood Control and Water Conservation District Annual Groundwater Report for 2021
	California Natural Resources Agency datasets	CNRA_dataset
Hydrogeology Research	David R. O'Leary & John A. Izbicki & Loren F. Metzger	Sources of high-chloride water and managed aquifer recharge in an alluvial aquifer in California, USA
Reservoir Characteristics	California Geologic Energy Management Division	CALIFORNIA OIL & GAS FIELDS, Volume III – Northern California 1982
Well Records		
Oil & Gas Well Records and Reservoir Characteristics	California Geologic Energy Management Division	https://www.conservation.ca.gov/calgem/Pages/WellFinder.aspx
Maps		
Geologic Map	Wagner, Jennings, Bedrossian, and Bortugno, 1981	Geologic Map of Sacramento Quadrangle

Groundwater Basin Overview

The Pelican CCS Study Area is located within the Eastern San Joaquin Groundwater Sub-basin Number 5-22.01 (Sub-basin) of the San Joaquin River Hydrologic Region, as designated by the California Department of Water Resources (DWR) in Bulletin 118. The San Joaquin River Hydrologic Region formed in a broad structural trough that extends approximately 270 miles and trends northwest to southeast in the southern portion of the Central Valley of California. The Mokelumne River bounds the Sub-basin on the north and northwest, the San Joaquin River on the west, the Stanislaus River on the south, and consolidated bedrock on the east. The Study Area, which extends approximately one mile beyond the Rindge Tract Island boundary, is located in the eastern half of the Sub-basin. (**Figure 2-29)**.

Topography

The Sub-basin ground surface elevations range from approximately 1,000 feet above mean sea level (MSL) in the Sierra Nevada Mountains on the eastern side to near sea-level on the western side. The topography slopes from east to west as shown in **Figure 2-30**.

Surface water drains west toward the San Joaquin River, which flows north along the western side of the Sub-basin. The Mokelumne and Stanislaus Rivers are major tributaries to the San Joaquin River that flow westerly and define the Sub-basin's northern and southern boundaries. (**Figure 2-30)**.

Water Bearing Freshwater Formations

The lithology of the Sub-basin is comprised of unconsolidated to semi-consolidated sedimentary deposits. Water-bearing units include the unconsolidated surficial alluvium and intertidal deposits of the Modesto/Riverbank Formations, and other unnamed Flood Basin deposits near the San Joaquin River delta (Recent to Late Pleistocene), underlain by the Laguna Formation (Plio-Pleistocene) and Mehrten Formation (Miocene to Pliocene). The Mehrten Formation is considered to be the oldest and deepest fresh water-bearing unit, since underlying Formations were deposited in a marine environment and contain more saline pore water relative to younger units (DWR, 2020).

Regional freshwater-bearing formations in the Sub-basin are described in the 2022 Groundwater Sustainability Plan, prepared by the Eastern San Joaquin Groundwater Authority. A summary of these descriptions is provided on **Figure 2-31**.

Surficial units in the Study Area include the Modesto Formation alluvium deposits on its eastern portion, and intertidal deposits at the surface on its western portion (**Figure 2-32**). The alluvium and Modesto/Riverbank formation deposits are undifferentiated units of Recent to Late Pleistocene in age. According to Bulletin 118 (DWR, 2020), these units range in thickness from a "thin veneer" on the east side of the basin to over 150 feet near the center of the Sub-basin. Groundwater is unconfined within these units.

Freshwater

Base of Freshwater

The vertical extent of fresh, non-saline groundwater in the Sub-basin is illustrated on **Figures 2-33** and **2-34**. Freshwater is defined by the USGS as containing less than 1,000 parts per million (ppm) total dissolved solids (TDS)[1]. While water-bearing formations exist in deeper units, high salinity and the drilling depth required to install wells make accessing these aquifers economically infeasible. The base of freshwater in the Sub-basin ranges from approximately 600 to 1,400 feet below ground surface (bgs) (**Figure 2-35)**; the base of freshwater in the Study Area is approximately 900 feet bgs. As depicted on **Figure 2-35**, the Valley Springs Formation is the deepest unit within the Sub-basin to contain freshwater and the Mehrten Formation is the deepest unit within the Study Area containing freshwater.

Groundwater Elevations

Current groundwater elevation conditions have been characterized using May 2022 data from the California Natural Resources Agency's network of groundwater monitoring wells within the Sub-basin. The groundwater elevations show a depression in the center of the Sub-basin near the east side of the City of Stockton caused by groundwater pumping in this area (**Figure 2-36**).

Regional Groundwater Flow

As seen in **Figure 2-36**, groundwater pumping has lowered water table elevations and potentiometric pressures have induced groundwater flow east towards the City of Stockton. The lateral gradient along the western side of the Sub-basin near the Study Area ranges from approximately seven feet/mile during the seasonal high to six feet/mile during the seasonal low. Prior to development of groundwater resources in the area, groundwater is likely to have flowed west following the land surface topography and the flow direction of surface water in the Sub-basin.

Local Water Well Review

Review of available online databases including the DWR's water well completion records indicates that there are 23 water wells located inside or within one mile of Rindge Tract Island. Of the 23 well records, 13 included well completion reports. The deepest water well in the Study Area was drilled to 295 feet bgs (well record #334901). **Table 2-4** (below) displays wells with known drilling depth. Ten were drilled to maximum depths of less than 200 feet bgs. Reported static water levels ranged from eight to 20 feet bgs. The water well completion records identify the depth of completion for these shallow water wells, but the records do not specify the formation. For the purposes of this assessment, wells completed less than 300 feet bgs are described as "shallow".

[1] https://www.usgs.gov/special-topics/water-science-school/science/saline-water-and-salinity?qt-science_center_objects=0#qt-science_center_objects

Based on the Geologic Surface Map and the geologic unit characteristics in the Study Area, these wells are likely completed in the Modesto/Riverbank Formation. **Figure 2-37** displays the location and total depth of the available water well records in the Study Area.

Table 2-4. Well Completion Records with Completion Depths

WCR Number	Legacy Log Number	Township	Range	Section	Baseline Meridian	Total Completed Depth	Top of Perforated Interval	Bottom of Perforated Interval
WCR2004-002067	927054	02N	05E	21	Mount Diablo	85	50	70
WCR2021-009839	-	02N	05E	18	Mount Diablo	63	43	63
WCR1986-004210	187198	02N	05E	5	Mount Diablo	142	-	-
WCR0288639	61314	02N	05E	5	Mount Diablo	120	100	120
WCR1988-004091	250491	02N	05E	27	Mount Diablo	85	-	-
WCR0300272	83715	02N	05E	27	Mount Diablo	54	44	54
WCR2002-008121	808983	02N	05E	27	Mount Diablo	100	60	80
WCR2002-008122	808983a	02N	05E	27	Mount Diablo	85	62	82
WCR0317062	77044	02N	05E	27	Mount Diablo	63	48	63
WCR1981-003194	77044	02N	05E	27	Mount Diablo	82	-	-
WCR1989-011025	334901	02N	04E	12	Mount Diablo	295	-	-
" – " indicates no data available								

Underground Sources of Drinking Water

Figure 2-33 is a cross-section drawn to scale that highlights the vertical separation between the proposed injection wells and zones and USDWs at Rindge Tract. Specifically, this section highlights the freshwater USDWs, deeper non-freshwater USDWs, the lowermost USDW (Markley Formation), and all zones within the proposed sequestration complex (i.e., Nortonville Shale (secondary upper confining zone); Domengine Formation (secondary upper confining zone); Capay Shale/Meganos Formation (primary upper confining zone); and Mokelumne River Formation (injection zone). More detail on the USDWs is provided in the following sections.

Freshwater

Freshwater in the Study Area is found in the Holocene alluvium and the Late Pliocene and Pliocene Modesto and Riverbank Formations. As indicated by the water well search, there are 23 water wells located within one mile of the Rindge Tract Study Area with the deepest reaching 295 feet bgs. Fourteen of the 23 water wells in the Study Area were listed as Domestic Water Supply wells, and the remaining nine wells did not list the well type. Based on the well completion records and the review of data sources listed in **Table 2-3**, freshwater that currently has a beneficial use is found within the upper several hundred feet in the Study Area. Fresh water is defined as having a Total Dissolved Solids (TDS) of less than 1,000 milligrams per liter (mg/L).

Brackish Water

While high salinity adversely affects water quality in formations deeper than the Modesto and Riverbank Formations, according to the 40 CFR 144.3 definition some may qualify as a potential USDW. According to 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.*

Using these criteria as a template for reviewing the USDW in the Study Area, this analysis focused on defining the lowermost formation with groundwater TDS below 10,000 mg/L, and water-bearing formations containing a sufficient quantity of groundwater to supply a public water system.

Readily available groundwater quality information was reviewed to determine the base of the potential USDW. The data indicate there are no public or private water wells that penetrate deeper than the Modesto/Riverbank Formations. To determine which formations may qualify as a USDW within the Study Area, SCS employed the following methods:

- Evaluated available water quality data for formations deeper than the Modesto/Riverbank Formations,
- Reviewed historic literature in nearby state designated oilfields, and
- Performed salinity calculations using petrophysical logs.

Literature Review

Well files acquired from the CalGEM online well records database were reviewed to identify publicly-available water quality data within the Study Area; however, no water quality records or analytical data were identified. Water quality data obtained from CalGEM's CALIFORNIA OIL & GAS FIELDS, Volume III – Northern California 1982 publication were reviewed and compiled. This resource lists state designated oilfields in California including subsurface producing Formations and, if available, rock property and reservoir fluid data. The literature review yielded little data to support which formation could serve as the lowermost potential USDW as defined by 40 CFR 144.3.

Salinity Calculations

Salinity calculations utilizing petrophysical logs was the next approach to determining the lowermost USDW. Multiple salinities were calculated based on different methods including the Spontaneous Potential (SP) method and the Humble Salinity calculation. The Humble equation is a four-step process: (1) converting measured density to formation porosity, (2) calculation of apparent water resistivity using the Humble equation, (3) correcting apparent water resistivity to a standard temperature, and (4) converting temperature corrected apparent water resistivity to salinity. The SP calculation method utilizes the measured SP baselined to 0 mV and is very sensitive to the recorded drilling mud salinity (Rmf). Please refer to **Attachment 2** for additional details on how the salinity calculations were performed and the complete petrophysical results.

To determine the depth to the lowermost USDW, 10,000 parts per million (ppm) constant line was overlain on the calculated salinity curves (see **Figures 2-38a-c** for examples). Note that TDS is a measure of dissolved solids in a volume of water and recorded in units of mg/l; this unit is interchangeable with parts per million (ppm) (1 ppm is equivalent to 1 mg/liter). The interpretation of the petrophysical calculations shows a clear trend of increasing salinity with depth (Refer to Salinity Log Plots in **Attachment 2**). This transition depth of greater than 10,000 ppm salinity was then compared to the corresponding geologic formation. As shown in **Table 2-5** below, all of the wells analyzed indicate the Domengine has greater than 10,000 ppm salinity, while units above the Domengine calculated salinities are less than 10,000 ppm. According to the 40 CFR 144.3 definition, the Markley is the lowermost USDW in the Study Area.

The base of the Markley/Top of the Nortonville Shale has been mapped for the purposes of displaying the base of the lowermost USDW (**Figure 2-19**). **Figures 2-38a**, **2-38b**, and **2-38c** additionally highlight the relative positions of the USDWs to the proposed injection wells and zones in the vicinity of Rindge Tract. As discussed in prior sections, one of the Class VI wells will be initially constructed as a stratigraphic test well with complete core sampling, sidewall core sampling, and geophysical logging of the primary and secondary confining zones (i.e., all units beneath the base of the lowermost USDW (Markley Formation)). In addition, pre-operational water quality testing will be conducted to confirm the lowermost USDW. This stratigraphic test well would be drilled before the Class VI authorization to construct or convert is issued.

Table 2-5. Calculated Salinities

Well Name	API	Salinity (ppm)	Depth to 10,000 ppm or > Salinity (feet md)	Top Markley (feet md)	Top Nortonville Shale (feet md)	Top Domengine (feet md)	Domengine Sand Base (feet md)	Formation with Salinity > 10,000 ppm	Average Markley Salinity (ppm)
Allied Properties No 1	4077004690000	11,002	4,461	4,057	4,152	4,455	5,186	Domengine	3,221
Allied Properties No 1 sec 22	4077004760000	12,012	5,038	4,244	4,412	4,678	5,433	Domengine	2,044
Big Valley Everhardt No 1	4077203510000	10,876	4,581	4,034	4,121	4,325	4,907	Domengine	5,197
Cortopassi	4077004750000	10,428	4,812	4,057	4,242	4,456	5,043	Domengine	1,305
Eberhardt 15-34	**4077204980000**	**10,445**	**4,782**	**3,993**	**4,096**	**4,382**	**5,117**	**Domengine**	**3,516**
McCulloch Stefani No 1	4077005160000	10,414	4,440	3,781	3,879	4,107	4,927	Domengine	2,873
Pacific States No 1	407700470000	10,927	4,409	4,012	4,166	4,411	5,106	Domengine	2,949
Rindge Tract No 1	**4077004710000**	**10,191**	**4,473**	**4,090**	**4,203**	**4,465**	**5,341**	**Domengine**	**6,007**
Rocha et al unit No 1	4077203350000	11,382	5,067	3,814	3,915	4,151	5,243	Domengine	3,765
RTP 1-21	4077207250000	10,042	4,763	4,110	4,159	4,408	5,198	Domengine	4,036
SFEC - Luckey 7-1	4077205220000	10,412	4,654	3,875	3,981	4,277	5,375	Domengine	1,615
Shell Al Prop 1-8	4077004680000	11,960	4,295	3,902	4,011	4,290	5,421	Domengine	6,789

Stockton Port District No 1	4077203210000	11,476	4,500	4,134	4,217	4,496	5,221	Domengine	3,834
Victor Leo et Al #1	40770467000	10,427	4,535	3,789	3,886	4,135	5,040	Domengine	3,298
Zuckerman 1-19	4077204760000	10,049	4,635	3,939	3,990	4,364	5,343	Domengine	3,044
Zuckerman No A-1	4077203160000	20,836	4,934	4,041	4,130	4,484	5,483	Domengine	15,675
Citizen Green 1	4077206880000	14,629	4,356	4,190	4,280	4,340	?	Domengine	9,882

Note: Bold wells are those inside the AOR. Rindge Tract No. 1 does not penetrate the MRF.

Geochemistry [40 CFR 146.82(a)(6)]

In the context of Class VI injection, CO_2 sequestration involves the compression of gaseous CO_2 into a supercritical fluid and injection into deep subsurface geologic units. Supercritical CO_2 is not miscible with formation fluids, but can dissolve into them up to a solubility limit dependent on temperature, pressure, and composition of the fluid. When this dissolution happens, carbonic acid (H_2CO_3) is formed, which creates a weak acidic solution. The weak acidic solution will interact with the formation solid phase assemblage. The interaction between formation fluids, carbonic acid, and formation assemblage can precipitate dissolved constituents and alter the injection zone. There is less potential for acidified formation fluids to interact with the confining zone because it is physically separated from the formation fluid in most areas by supercritical CO_2. Understanding both the solid-phase and aqueous phase geochemistry of the injection complex is important for identifying potential reactions that could occur as a result of CO_2 injection.

To evaluate the potential interactions between the formation fluids and the injection zone solid phase assemblage, data are required for the formation fluid composition, pH, temperature, pressure; and the minerals in the solid-phase assemblage. No primary data have been collected for this evaluation (i.e., no test well within the AOR). All data are pre-existing data from wells in the vicinity of the project area.

SCS reviewed publicly available XRD data from the Citizen Green #1 well (**Attachment 3**). As discussed in the sub-section "Injection and Confining Zone Details", XRD data were not collected for the shales within the lower or upper confining zones. XRD data are available for four samples from the Mokelumne River Formation sands (injection zone) and one sample from a shale baffle in the Mokelumne River Formation. A summary of these data is included in **Table 2-6** below. All sand samples were dominated by feldspars and quartz. The shale baffle sample was dominated by potassium feldspar, quartz, and kaolinite. The solid-phase assemblages for the injection zone are dominated by silicate minerals; the samples contained no carbonates or sulfates. Samples will be collected from the lower and upper confining zone units and the injection zone for XRD analysis when the test well is drilled.

SCS reviewed brine composition data from the USGS Produced Water Database for wells drilled in the southern Sacramento Basin in the vicinity of the project area. This database provides well location information, depths, geologic formations, and analytical data for brines encountered during the drilling process. Data were evaluated for 27 wells (**Figure 2-39**). There are no available nearby data in the produced waters database for brine in the Mokelumne River Formation (injection zone). 13 of the 27 samples have formations listed as unknown, and all other samples are from units located stratigraphically above or below the injection zone. The available data are summarized in **Table 2-7**. pH values indicate these produced waters are near neutral.

Table 2-6. XRD Data for the Mokelumne River Formation: Citizen Green #1

Pelican Renewables

Depth	**Wireline Depth (ft)**	**6598**	**NA**	**6466**	**6400**	**5249**	**5247**
	True Vertical Depth (ft)	**5970.1**	**NA**	**5843.1**	**5780.1**	**4725.2**	**4723.5**
Flow Properties	Porosity (Helium %)	31.3	NA	31.3	33	NA	NA
	Permeability (gas, mD)	135.5	NA	71.9	367.1	NA	NA
Mineral Composition (%)	Quartz	33.924835	34.2	36.325405	40.30969	17	27.8
	K-Feldspar	21.998177	24.1	12.587689	17.08427	32.7	16.2
	Albite	0	0	0.22734216	0	6.5	34
	Labradorite	0	0	36.58359	29.232862	0	0
	Andesine	34.47543	31	0	3.6258943	0	0
	Kaolinite	3.6258416	2.9	2.6778169	5.230892	34.9	3.6
	Chlorite	5.4110084	2	5.3593655	3.9868908	0	17
	Pyrite	0.213066	0.5	0.69619757	0	0	0
	Horneblende	0.230967	1.1	0.5695263	0.17200066	0	0
	Sepiolite	0	NA	0	0	0	0
	Detrital Mica	0.12067264	4.2	4.9730654	0.35749906	8.4	0
	Montmorillonite	0	NA	0	0	trace	1.1

Notes:
NA = Data not available or not recorded.
Blue = Sample was collected from a shale baffle within the Mokelumne River Formation

Table 2-7. Produced Waters Data in the Vicinity of the Project
Pelican Renewables
(Results in mg/L, unless otherwise noted)

Well Name	Well API	Date	Depth Upper	Depth Lower	Formation	Geochemical Parameters																										
						pH (Std. Units)	TDS	Charge Balance	Boron	Barium	Bromide	Calcium	Chloride	Caesium	Fluoride	Iron (Total)	Iodide	Potassium	Lithium	Magnesium	Manganese	Sodium	Rubidium	Sulfate	Silicon	Strontium	Bicarbonate Alkalinity	DIC	DOC	Acetate	H2S	NH3
Walnut Grove Unit A-2	0406700 0290000	1982-06-08	2890	3036	Unknown	7.05	9750	0.1	45	5.6	17.68	200	5380	--	0.47	0.18	17	54.10	0.39	123.5	0.33	3000	0.12	1.167	22	5.7	434	85.61	7.5	--	0.1	8
Patterson Unit #2	0407700 2150000	1982-06-03	3060	3513	Unknown	7.58	7800	-0.7	3	8.5	23.57	230	6490	0.03	0.26	0.1	21	36.5	0.2	114	0.15	3650	0.06	0.38	23	8.2	259	42.49	8.16	4	0.9	11
Capital D-2	0406700 2280000	1982-06-08	3526	3549	Markley-nortonville	7.05	9100	4.1	35	5.7	16.63	163	4300	0.02	0.27	4.1	18	64.8	0.37	80	0.11	2650	0.07	0.2101	36	4.8	567	102.5	27.86	20	0.3	14
Jensen #2	0406720 1750000	1982-06-07	--	3600	Markley-nortonville	7.91	7150	-1	36	7.8	19.32	165	4460	0.02	0.23	--	18	86.7	0.38	77.7	--	2450	0.09	0.8028	36	5.7	555	81.1	26.84	44	--	9.6
Tyler Island #6	0406720 1360000	1982-06-07	3608	3713	Nortonville	7.04	5850	2.4	32	6.2	17.92	168.5	3720	--	0.14	17.2	16.5	95.4	0.17	65	0.51	2160	0.1	0.306	16	4.4	530	79.62	155.8	190	0.1	6.8
Tyler Island #8	0406720 1570000	1982-06-07	3610	3722	Nortonville	8.12	6500	4.1	30	8.2	21.38	215	4060	0.02	0.25	--	20	134.7	0.52	49.7	0.12	2450	0.11	16.4	20	4.2	440	53.87	8.77	86	--	12
Tyler Island #10	0406720 1770000	1982-06-07	3668	3743	Nortonville	7.19	7150	-35.6	45	8.9	20.6	156	4540	0.07	0.28	4.60	18	64.5	0.4	84.3	0.12	1020	0.09	0.529	32	5.9	609	112.20	15.32	10	--	11
Wineman Zone Unit (WZU) #13	0409520 5360000	1982-06-02	4756	4778	Unknown	7.7	442	9.8	3	0.4	11.66	29.2	2610	--	1.4	--	7	20.1	0.14	9.1	--	2000	0.045	0.5100	29	0.75	808	149.3	16.72	11	0.10	11
Winters Community #1	0411300 0940000	1982-06-01	5000	5010	Unknown	7.22	13600	-2.6	39	3.9	28.1	120.1	7460	--	1.2	14.2	28	25.6	0.32	48.4	0.48	4350	0.03	1.2920	20	5.1	322	62.45	11.76	11	0.8	24
Langhart Spreckels #8	0406720 1500000	1982-06-07	4000	5218	Unknown	7.46	18800	1.2	102	4.5	29.34	120	9530	--	0.69	0.10	28	35.9	0.085	92.8	0.16	6000	0.09	0.37	36	8.4	730	127.5	11.48	13	--	18
Perry Anderson #19 (RVGU 223) Upper Zone	0409520 0660000	1982-06-03	5547	5582	Unknown	7.28	7480	1.3	110	5.7	27.8	158	8650	0.05	4.6	0.13	33	52	0.51	32.4	0.19	5500	0.13	29.87	57	8.8	705	67.82	212.5	396	--	21
Sacramento River Unit 2-2	0406720 0630000	1982-06-08	5503	5770	Unknown	8.09	14300	0.5	14	2.9	25.74	66	7130	--	0.64	0.13	22	28.7	0.015	71.2	0.07	4450	0.08	0.2739	31	4.8	1146	173.5	44.92	17	0.2	13
Rio Vista State 12 (RVGU 220)	0409520 0420000	1982-06-03	5824	5925	Martinez	7.57	9230	-0.7	24	4	26.68	113	7590	0.03	0.49	0.65	25	32.6	0.26	33.5	--	4650	0.06	5.95	32	6.6	482	85.25	84.21	482	0.7	22

Suisun Community #17	04095003080000	1982-06-04	3460	6068	Unknown	7.66	18800	1.2	29	13.7	58.64	130	9200	0.06	0.38	0.1	41	36.5	1.31	75.6	0.05	5800	0.09	0.6566	39	8.7	627	95.87	46.88	38.00	0.2	28.0
Perry Anderson #19 (RVGU 223) Middle Zone	04095200660000	1982-06-03	6070	6172	Unknown	6.85	4220	11.2	19	1.5	9.84	41.6	2420	0.04	0.28	29.2	12	14.1	0.14	8.1	0.34	1900	0.035	8.43	14	3.1	934	46.71	388.6	755	0.2	21
Union Unit 2 #1	04113200800000	1982-06-01	6333	6394	Starkey	7.53	24700	1.3	92	2.600	25.27	100	7020	--	1.8	--	25.0	29.1	0.42	49.2	0.09	4450.0	0.08	0.902	30	6.9	481	79.12	31	42	0.5	16
McCormick #6	04095203070000	1982-06-03	5971	6560	Martinez	7.57	9880	3.5	58	4.600	31.12	126	7770	0.07	2.4	0.2	27.0	55	0.48	27.1	0.05	5200.0	0.28	40.6	39	13.8	1531	73.45	507	1030	0.3	22
Perry Anderson #19 Lower Zone	04095004090000	1982-06-04	5910	6800	Anderson, Martinez	7.02	16900	-0.3	72	4.600	35.03	121	8430	0.06	1.1	2.9	29.0	43.6	0.44	25.8	0.14	5250.0	0.15	52.48	50	11.7	1507	61.22	533	1190	0.1	21
Bunker Gas zone unit #801	04095204080000	1982-06-02	6834	6838	Unknown	7.5	20200	-2.9	41	6.900	49.37	246	11300	0.03	1.3	0.13	25.0	74.5	0.3	54.8	0.32	6500.0	0.15	9.02	36	12	386	68.56	41	24	--	19
Rio Vista State 11	04067200070000	1982-06-03	6500	7550	Martinez	7.08	13000	-1.2	180	8.800	36.9	252	11400	0.05	0.66	1	29.0	56.7	0.49	51.7	0.10	6800.0	0.11	20.59	39	21	482	74.66	113	229	0.5	27
Feykert #2	04095200690000	1982-06-04	7572	7730	Unknown	7.3	11000	-0.7	153	3.200	19.84	87	5320	--	4.4	--	21.5	70.4	1.35	16.4	0.10	3250.0	0.21	55.16	66	13.2	730	67.68	213	420	--	35
Brown - Amerada Sorenson #1	04113200790000	1982-06-01	7866	7890	Unknown	7.33	12700	3.2	188	2.400	19.3	76	6360	--	2.6	22.2	23.0	37.3	0.59	17.8	0.54	4300.0	0.12	84.62	33	5.9	1070	119.6	216	333	0.3	22
Sonol Securites #3	04077201710000	1982-06-09	9700	9730	Winters	6.81	19500	6.3	340	4.300	13.57	165	9290	0.06	1.7	10.9	25.5	94.8	1.69	40.5	0.51	6600.0	0.31	169.9	66	28.7	1152	99.63	294	580	0.8	67
Yamada L-W #1	04077202890000	1982-06-09	9830	10070	Winters	6.92	18800	5.1	188	2.800	31.27	86	8580	0.12	2.1	0.13	26.0	90.9	2.16	17.7	--	6000.0	0.3	40.36	76	17.8	2321	110.9	696	1360	0.4	64
Serpa #4	04095204390000	1982-04-27	10356	10412	Unknown	8.7	7416	18.3	94	1.600	17.88	13	3750	0.03	2	--	25.0	73.1	1.46	5.16	--	3500.0	0.13	53.01	16	2.4	2500	124.6	711	1400	0.3	30
Peterson #4	04095000070000	1982-06-02	9130	10419	Unknown	7.22	15900	-22.5	130	9.500	36.28	279	12400	0.11	1.2	0.22	39.0	76.5	0.62	60	0.33	4600.0	0.2	9.66	40	19.6	579	61.72	120	233	--	34
Peterson Estate #3-27	04095203360000	1982-06-08	8752	11140	Unknown	6.82	13000	1.9	59	12.500	55.32	322	11700	0.12	7.1	6.8	31.0	83.2	0.94	34.8	0.55	7400.0	0.3	14.21	66	17.9	1266	--	--	--	--	34
CAS No.						--	--	--	7440-42-8	7440-39-3	7726-95-6	7440-70-2	16887-00-6	7440-46-2	7782-41-4	7439-89-6	7553-56-2	7440-09-7	7439-93-2	7439-95-4	7439-96-5	7440-23-5	7440-17-7	14808-79-8	7440-21-3	7440-24-6	--	--	--	71-50-1	7783-06-4	7664-41-7

Abbreviations:
mg/L = milligrams per liter
CAS No. = Chemical Abstracts Service Number
-- = No Data

Notes: Blondes, M. S., Gans, K. D., Engle, M. A., Kharaka, Y. K., Reidy, M. E., Saraswathula, V., Thordsen, J. J., Rowan, E. L., & Morrissey, E. A. (2019). U.S. Geological Survey National Produced Waters Geochemical Database v2.3 [Data set]. U.S. Geological Survey. https://doi.org/10.5066/F7J964W8
Data derived from the Yousif Kharaka dataset

A smaller subset of the produced water data for 12 nearby wells was evaluated via geochemical modeling. The geochemical modeling was completed using PHREEQC version 3 (Parkhurst and Appelo, 2013), using an ion-association model created by Lawrence Livermore National Laboratory (LLNL). These models determined saturation indices of various minerals based on chemical compositions of the produced waters, as well as the simulated effect of increasing pCO_2 on the saturation indices of the various minerals from $10^{-3.5}$ to 1 atmosphere (atm). **Tables 2-8** through **2-19** summarize the saturation indices as a function of pCO_2 for the 12 produced water samples in the vicinity of the AOR. The saturation indices for all of the solid phases were at least two orders of magnitude less than one. The injection of supercritical CO_2 is not expected to induce formation plugging for the produced waters modeled by the precipitation of silicate, sulfate, or carbonate solid phases. The saturation indices decrease (i.e., become more negative) as the pCO_2 increases and the pH lowers.

As none of these produced water samples are within the AOR and were not collected from the Mokelumne River Formation (injection zone), formation fluids will be sampled from the Mokelumne for chemical analysis when the test well is drilled. These waters will be examined via geochemical modeling for any changes related to increasing pCO_2.

Table 2-8. Saturation Indices for Solid Phases in Brines near the AOR

Jensen #2					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.283	5.441	4.788	4.237	3.977
Mineral	**Saturation Index**				
Quartz	-2.13	-2.13	-2.13	-2.13	-2.13
Tridymite	-2.31	-2.31	-2.31	-2.31	-2.31
Chalcedony	-2.39	-2.39	-2.39	-2.39	-2.39
Cristobalite(alpha)	-2.65	-2.65	-2.65	-2.65	-2.65
Coesite	-2.91	-2.91	-2.91	-2.91	-2.91
Cristobalite(beta)	-3.06	-3.06	-3.06	-3.06	-3.06
SiO2(am)	-3.31	-3.31	-3.31	-3.31	-3.31
C	-4.35	-4.29	-4.04	-3.67	-3.46
Witherite	-3.24	-3.92	-4.23	-4.33	-4.36
Boric_acid	-5.49	-5.49	-5.49	-5.49	-5.49
Barite	-5.62	-5.59	-5.58	-5.59	-5.59
S	-6.92	-6.62	-6.42	-6.26	-6.19
N2(g)	-5.53	-5.8	-5.99	-6.15	-6.22
Calcite	-5.87	-6.56	-6.86	-6.97	-6.99
Aragonite	-6.02	-6.7	-7.01	-7.11	-7.14
Magnesite	-6.27	-6.96	-7.26	-7.37	-7.39
Monohydrocalcite	-6.78	-7.46	-7.77	-7.88	-7.9
Nahcolite	-9.12	-8.96	-8.61	-8.16	-7.92
H2(g)	-6.69	-7.16	-7.53	-7.85	-7.99

Table 2-9. Saturation Indices for Solid Phases in Brines near the AOR

Patterson Unit #2					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.054	5.338	4.76	4.235	3.98
Mineral	Saturation Index				
Quartz	-2.38	-2.38	-2.38	-2.38	-2.38
Tridymite	-2.55	-2.55	-2.55	-2.55	-2.55
Chalcedony	-2.63	-2.63	-2.63	-2.63	-2.63
Cristobalite(alpha)	-2.89	-2.89	-2.89	-2.89	-2.89
Coesite	-3.14	-3.14	-3.14	-3.14	-3.14
Cristobalite(beta)	-3.29	-3.29	-3.29	-3.29	-3.29
C	-4.51	-4.32	-3.98	-3.58	-3.37
SiO2(am)	-3.54	-3.54	-3.54	-3.54	-3.54
Witherite	-3.71	-4.14	-4.3	-4.35	-4.36
Barite	-6	-5.95	-5.94	-5.93	-5.93
N2(g)	-5.64	-5.85	-6.01	-6.16	-6.24
S	-7.01	-6.75	-6.57	-6.41	-6.34
Boric_acid	-6.6	-6.6	-6.6	-6.6	-6.6
Calcite	-6.17	-6.6	-6.76	-6.81	-6.82
Aragonite	-6.31	-6.74	-6.9	-6.95	-6.97
Magnesite	-6.52	-6.95	-7.11	-7.16	-7.17
Monohydrocalcite	-7.09	-7.52	-7.68	-7.73	-7.74
Nahcolite	-9.22	-8.94	-8.51	-8.04	-7.8
H2(g)	-6.63	-7.03	-7.36	-7.66	-7.81

Table 2-10. Saturation Indices for Solid Phases in Brines near the AOR

Rio Vista State 11					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.391	5.568	4.907	-4.351	4.09
Mineral	Saturation Index				
Quartz	-2.54	-2.54	-2.54	-2.54	-2.54
Tridymite	-2.7	-2.7	-2.7	-2.7	-2.7
Chalcedony	-2.77	-2.77	-2.77	-2.77	-2.77
Cristobalite(alpha)	-3	-3	-3	-3	-3
Coesite	-3.24	-3.24	-3.24	-3.24	-3.24
Cristobalite(beta)	-3.34	-3.34	-3.34	-3.34	-3.34
SiO2(am)	-3.54	-3.54	-3.54	-3.54	-3.54
C	-4.86	-4.75	-4.5	-4.13	-3.93
N2(g)	-3.75	-4	-4.18	-4.33	-4.41
Barite	-4.54	-4.47	-4.45	-4.44	-4.45
Witherite	-3.4	-4.05	-4.37	-4.49	-4.51
S	-5.91	-5.53	-5.3	-5.13	-5.06
Boric_acid	-5.1	-5.1	-5.1	-5.1	-5.1
Calcite	-5.25	-5.9	-6.22	-6.34	-6.36
Aragonite	-5.4	-6.04	-6.37	-6.48	-6.51
H2S(g)	-6.08	-6.15	-6.3	-6.44	-6.52
H2(g)	-5.54	-5.98	-6.36	-6.67	-6.82
Magnesite	-5.73	-6.38	-6.7	-6.82	-6.84
Anhydrite	-7.14	-7.08	-7.05	-7.05	-7.05
Gypsum	-7.4	-7.33	-7.31	-7.3	-7.31
Monohydrocalcite	-6.31	-6.95	-7.28	-7.39	-7.41
Bassanite	-7.79	-7.72	-7.7	-7.69	-7.7
CaSO4:0.5H2O(beta)	-7.91	-7.84	-7.82	-7.81	-7.82
Nahcolite	-9.06	-8.88	-8.54	-8.1	-7.86
Rhodochrosite	-6.87	-7.51	-7.84	-7.95	-7.98

Table 2-11. Saturation Indices for Solid Phases in Brines near the AOR

Tyler Island #10					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.182	5.396	4.781	4.244	3.986
Mineral	Saturation Index				
Quartz	-2.25	-2.25	-2.25	-2.25	-2.25
Tridymite	-2.42	-2.42	-2.42	-2.42	-2.42
Chalcedony	-2.5	-2.5	-2.5	-2.5	-2.5
Cristobalite(alpha)	-2.76	-2.76	-2.76	-2.76	-2.76
Coesite	-3.01	-3.01	-3.01	-3.01	-3.01
Cristobalite(beta)	-3.16	-3.16	-3.16	-3.16	-3.16
SiO2(am)	-3.4	-3.4	-3.4	-3.4	-3.4
C	-4.42	-4.31	-4.01	-3.63	-3.42
Witherite	-3.44	-4.01	-4.24	-4.32	-4.34
Boric_acid	-5.43	-5.43	-5.43	-5.43	-5.43
Barite	-5.83	-5.78	-5.76	-5.76	-5.77
N2(g)	-5.5	-5.74	-5.92	-6.07	-6.15
S	-6.97	-6.68	-6.49	-6.33	-6.26
Calcite	-6.06	-6.64	-6.87	-6.95	-6.96
Aragonite	-6.21	-6.78	-7.01	-7.09	-7.11
Magnesite	-6.37	-6.94	-7.17	-7.25	-7.27
H2(g)	-6.54	-6.98	-7.33	-7.64	-7.79
Monohydrocalcite	-6.99	-7.56	-7.79	-7.87	-7.89

Table 2-12. Saturation Indices for Solid Phases in Brines near the AOR

Tyler Island #6					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.135	5.38	4.783	4.251	3.995
Mineral	Saturation Index				
Quartz	-2.59	-2.59	-2.59	-2.59	-2.59
Tridymite	-2.77	-2.77	-2.77	-2.77	-2.77
Chalcedony	-2.85	-2.85	-2.85	-2.85	-2.85
Cristobalite(alpha)	-3.1	-3.1	-3.1	-3.1	-3.1
Coesite	-3.35	-3.35	-3.35	-3.35	-3.35
Cristobalite(beta)	-3.49	-3.49	-3.49	-3.49	-3.49
C	-4.58	-4.43	-4.11	-3.72	-3.51
SiO2(am)	-3.73	-3.73	-3.73	-3.73	-3.73
Witherite	-3.73	-4.24	-4.44	-4.5	-4.52
Boric_acid	-5.61	-5.61	-5.61	-5.61	-5.61
Barite	-6.24	-6.2	-6.19	-6.19	-6.19
N2(g)	-5.78	-6.01	-6.19	-6.34	-6.42
S	-7.27	-7	-6.81	-6.65	-6.58
Calcite	-6.1	-6.61	-6.81	-6.88	-6.89
Aragonite	-6.25	-6.76	-6.95	-7.02	-7.04
Magnesite	-6.53	-7.04	-7.23	-7.3	-7.31
Rhodochrosite	-6.77	-7.28	-7.48	-7.54	-7.56
H2(g)	-6.48	-6.9	-7.25	-7.55	-7.69
Monohydrocalcite	-7.04	-7.55	-7.74	-7.81	-7.83

Table 2-13. Saturation Indices for Solid Phases in Brines near the AOR

Tyler Island #8					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.377	5.501	4.816	4.253	3.99
Mineral	**Saturation Index**				
Quartz	-2.44	-2.44	-2.44	-2.44	-2.44
Tridymite	-2.61	-2.61	-2.61	-2.61	-2.61
Chalcedony	-2.69	-2.69	-2.69	-2.69	-2.69
Cristobalite(alpha)	-2.95	-2.95	-2.95	-2.95	-2.95
Coesite	-3.2	-3.2	-3.2	-3.2	-3.2
Cristobalite(beta)	-3.35	-3.35	-3.35	-3.35	-3.35
SiO2(am)	-3.6	-3.6	-3.6	-3.6	-3.6
C	-4.63	-4.6	-4.37	-4.01	-3.81
Barite	-4.28	-4.27	-4.27	-4.27	-4.28
Witherite	-3.07	-3.82	-4.19	-4.32	-4.35
S	-6.11	-5.8	-5.59	-5.43	-5.36
N2(g)	-4.75	-5.04	-5.24	-5.4	-5.48
Boric_acid	-5.6	-5.6	-5.6	-5.6	-5.6
Calcite	-5.54	-6.3	-6.67	-6.8	-6.83
Aragonite	-5.69	-6.44	-6.81	-6.94	-6.97
Magnesite	-6.23	-6.98	-7.35	-7.48	-7.51
Gypsum	-7.53	-7.53	-7.52	-7.53	-7.54
Anhydrite	-7.54	-7.54	-7.54	-7.54	-7.55
H2S(g)	-7.13	-7.3	-7.48	-7.64	-7.72
Monohydrocalcite	-6.46	-7.22	-7.59	-7.72	-7.75
Nahcolite	-9.07	-8.94	-8.63	-8.19	-7.96

Table 2-14. Saturation Indices for Solid Phases in Brines near the AOR

Capital D-2					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.126	5.368	4.77	4.238	3.981
Mineral	Saturation Index				
Quartz	-2.18	-2.18	-2.18	-2.18	-2.18
Tridymite	-2.36	-2.36	-2.36	-2.36	-2.36
Chalcedony	-2.44	-2.44	-2.44	-2.44	-2.44
Cristobalite(alpha)	-2.69	-2.69	-2.69	-2.69	-2.69
Coesite	-2.95	-2.95	-2.95	-2.95	-2.95
Cristobalite(beta)	-3.09	-3.09	-3.09	-3.09	-3.09
C	-4.27	-4.14	-3.83	-3.44	-3.23
SiO2(am)	-3.34	-3.34	-3.34	-3.34	-3.34
Witherite	-3.73	-4.25	-4.44	-4.51	-4.53
Boric_acid	-5.53	-5.53	-5.53	-5.53	-5.53
N2(g)	-5.64	-5.85	-6.01	-6.16	-6.23
Barite	-6.53	-6.44	-6.4	-6.38	-6.38
S	-7.16	-6.85	-6.65	-6.48	-6.41
Calcite	-6.17	-6.68	-6.88	-6.95	-6.96
Aragonite	-6.31	-6.83	-7.03	-7.09	-7.11
Magnesite	-6.52	-7.04	-7.24	-7.3	-7.32
H2(g)	-6.51	-6.94	-7.29	-7.59	-7.74
Monohydrocalcite	-7.09	-7.6	-7.8	-7.87	-7.88
Nahcolite	-9.29	-9.04	-8.64	-8.17	-7.93
NH3(g)	-9.29	-9.04	-8.64	-8.17	-7.93

Table 2-15. Saturation Indices for Solid Phases in Brines near the AOR

Sacramento River Unit 2-2					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.786	5.827	4.988	4.339	4.057
Mineral	Saturation Index				
Quartz	-2.43	-2.43	-2.43	-2.43	-2.43
Tridymite	-2.6	-2.6	-2.6	-2.6	-2.6
Chalcedony	-2.68	-2.68	-2.68	-2.68	-2.68
Cristobalite(alpha)	-2.92	-2.92	-2.92	-2.92	-2.92
Coesite	-3.17	-3.17	-3.17	-3.17	-3.17
Cristobalite(beta)	-3.3	-3.29	-3.29	-3.29	-3.29
C	-3.75	-3.83	-3.8	-3.55	-3.37
SiO2(am)	-3.52	-3.52	-3.52	-3.52	-3.52
Witherite	-2.88	-3.8	-4.48	-4.78	-4.85
N2(g)	-5.18	-5.45	-5.68	-5.85	-5.93
S	-7.66	-7.05	-6.72	-6.51	-6.42
Barite	-7.17	-6.86	-6.76	-6.72	-6.71
Magnesite	-5.05	-5.96	-6.64	-6.94	-7.01
Calcite	-5.15	-6.07	-6.75	-7.05	-7.11
H2(g)	-5.67	-6.21	-6.7	-7.07	-7.23
Aragonite	-5.29	-6.21	-6.89	-7.19	-7.26
Nahcolite	-8.6	-8.56	-8.4	-8.04	-7.83

Table 2-16. Saturation Indices for Solid Phases in Brines near the AOR

Langhart Spreckels #8					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.43	5.554	4.864	4.297	4.034
Mineral	**Saturation Index**				
Quartz	-2.37	-2.37	-2.37	-2.37	-2.37
Tridymite	-2.54	-2.54	-2.54	-2.54	-2.54
Chalcedony	-2.61	-2.61	-2.61	-2.61	-2.61
Cristobalite(alpha)	-2.86	-2.86	-2.86	-2.86	-2.86
Coesite	-3.11	-3.11	-3.11	-3.11	-3.11
Cristobalite(beta)	-3.23	-3.23	-3.23	-3.23	-3.23
C	-4.07	-4.09	-3.89	-3.55	-3.35
SiO2(am)	-3.46	-3.46	-3.46	-3.46	-3.46
Witherite	-3.41	-4.16	-4.54	-4.68	-4.71
Boric_acid	-5.2	-5.2	-5.2	-5.2	-5.2
N2(g)	-5.12	-5.34	-5.51	-5.66	-5.73
S	-7.23	-6.76	-6.5	-6.31	-6.23
Barite	-6.79	-6.55	-6.46	-6.42	-6.42
Calcite	-5.61	-6.36	-6.74	-6.88	-6.91
Magnesite	-5.65	-6.4	-6.78	-6.92	-6.95
Aragonite	-5.75	-6.5	-6.89	-7.02	-7.05
H2(g)	-5.83	-6.34	-6.74	-7.07	-7.22
Nahcolite	-8.83	-8.7	-8.39	-7.96	-7.72
Monohydrocalcite	-6.58	-7.33	-7.71	-7.85	-7.88
H2S(g)	-7.53	-7.57	-7.71	-7.85	-7.92
Rhodochrosite	-6.66	-7.41	-7.79	-7.92	-7.95

Table 2-17. Saturation Indices for Solid Phases in Brines near the AOR

Walnut Grove Unit A-2					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.038	5.327	4.752	4.228	3.973
Mineral	**Saturation Index**				
Quartz	-2.36	-2.36	-2.36	-2.36	-2.36
Tridymite	-2.54	-2.54	-2.54	-2.54	-2.54
Chalcedony	-2.62	-2.62	-2.62	-2.62	-2.62
Cristobalite(alpha)	-2.88	-2.88	-2.88	-2.88	-2.88
Coesite	-3.13	-3.13	-3.13	-3.13	-3.13
Cristobalite(beta)	-3.28	-3.28	-3.28	-3.28	-3.28
SiO2(am)	-3.54	-3.54	-3.54	-3.54	-3.54
C	-4.73	-4.53	-4.19	-3.78	-3.57
Witherite	-3.89	-4.31	-4.46	-4.51	-4.53
Boric_acid	-5.4	-5.4	-5.4	-5.4	-5.4
Barite	-5.59	-5.58	-5.57	-5.58	-5.59
S	-6.8	-6.56	-6.38	-6.23	-6.16
N2(g)	-5.61	-5.83	-6	-6.15	-6.22
Calcite	-6.27	-6.69	-6.85	-6.9	-6.91
Aragonite	-6.42	-6.84	-6.99	-7.04	-7.06
Magnesite	-6.55	-6.97	-7.12	-7.17	-7.19
Monohydrocalcite	-7.18	-7.6	-7.76	-7.81	-7.82
Rhodochrosite	-7.19	-7.61	-7.76	-7.81	-7.83
Nahcolite	-9.29	-9	-8.58	-8.1	-7.86

Table 2-18. Saturation Indices for Solid Phases in Brines near the AOR

Sonol Securities #3					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.58	5.732	4.993	4.401	4.132
Mineral	**Saturation Index**				
Quartz	-2.41	-2.41	-2.41	-2.41	-2.41
Tridymite	-2.57	-2.57	-2.57	-2.57	-2.57
Chalcedony	-2.63	-2.63	-2.63	-2.63	-2.63
Cristobalite(alpha)	-2.85	-2.85	-2.85	-2.85	-2.85
Coesite	-3.09	-3.09	-3.09	-3.09	-3.09
Cristobalite(beta)	-3.18	-3.18	-3.18	-3.18	-3.18
SiO2(am)	-3.37	-3.37	-3.37	-3.37	-3.37
N2(g)	-2.82	-3.03	-3.2	-3.34	-3.41
Barite	-3.97	-3.91	-3.89	-3.88	-3.88
C	-4.92	-4.77	-4.58	-4.24	-4.04
S	-5.26	-4.78	-4.49	-4.3	-4.21
Witherite	-3.44	-4.13	-4.61	-4.8	-4.84
Boric_acid	-4.89	-4.89	-4.89	-4.89	-4.89
H2S(g)	-5.22	-5.16	-5.28	-5.41	-5.48
Anhydrite	-6.29	-6.23	-6.2	-6.19	-6.2
Calcite	-5	-5.7	-6.18	-6.36	-6.41
Gypsum	-6.62	-6.56	-6.53	-6.52	-6.53
Aragonite	-5.15	-5.84	-6.32	-6.51	-6.55
H2(g)	-5.23	-5.66	-6.06	-6.4	-6.55
Magnesite	-5.34	-6.03	-6.51	-6.7	-6.74
Bassanite	-6.93	-6.87	-6.84	-6.84	-6.84
CaSO4:0.5H2O(beta)	-7.05	-6.98	-6.96	-6.95	-6.96
Rhodochrosite	-5.75	-6.44	-6.92	-7.11	-7.15
Monohydrocalcite	-9.01	-8.85	-8.59	-8.18	-7.95
Nahcolite	-9.01	-8.85	-8.59	-8.18	-7.95

Table 2-19. Saturation Indices for Solid Phases in Brines near the AOR

Yamada L-W #1					
PCO2	-3.5	-2.5	-1.5	-0.5	0
pH	6.922	6.045	6.29	4.486	4.194
Mineral	Saturation Index				
Cristobalite(alpha)	-2	-2	-2.86	-2.86	-2
Quartz	-2.43	-2.43	-2.43	-2.43	-2.43
Tridymite	-2.6	-2.59	-2.59	-2.59	-2.59
Chalcedony	-2.65	-2.65	-2.65	-2.65	-2.65
Cristobalite(beta)	-3.1	-3.1	-3.18	-3.18	-3.1
Coesite	-3.11	-3.1	-3.1	-3.1	-3.1
SiO2(am)	-3.36	-3.36	-3.36	-3.36	-3.36
N2(g)	-2.98	-3.13	-3.31	-3.46	-3.53
C	-4.36	-4.28	-4.26	-4.05	-3.88
S	-6.15	-5.4	-4.97	-4.71	-4.61
Barite	-5.42	-5.05	-4.88	-4.81	-4.8
Witherite	-3.03	-3.78	-4.53	-4.9	-4.99
Boric_acid	-5.22	-5.22	-5.22	-5.22	-5.22
H2S(g)	-5.59	-5.3	-5.36	-5.49	-5.56
H2(g)	-4.64	-5.1	-5.59	-5.98	-6.15
Calcite	-4.55	-5.3	-6.05	-6.42	-6.51
Aragonite	-4.69	-5.45	-6.19	-6.57	-6.65
Magnesite	-4.9	-5.65	-6.39	-6.77	-6.86
Anhydrite	-7.68	-7.3	-7.13	-7.07	-7.06
Gypsum	-8.08	-7.71	-7.54	-7.47	-7.46
Monohydrocalcite	-5.7	-6.45	-7.19	7.57	-7.66
Bassanite	-8.32	-7.95	-7.78	-7.72	-7.7
CaSO4:0.5H2O(beta)	-8.4	-8	-7.89	-7.82	-7.8

Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)

The PR Project has focused has focused its Operational Plan, Testing and Monitoring Plan and Post-Injection Site Care Plan on deep geologic and hydrogeologic resources. The objectives of these plans are to continue to refine site characterization data that will update the multiphase transport model that delineates the Area of Review, detect any excursions between predicted plume and pressure front extents, and control the injection such that CO_2 is confined to the injection zone. These objectives all support the protection of underground sources of drinking water that are used for irrigation and drinking water near the PR project. These multiple layers of protection will provide early warning of any issues before surface air and/or soil gas could ever be affected. Pelican Renewables, LLC does not propose any shallow (i.e., at or near surface) environmental monitoring and views the monitoring programs described above to be protective of human health and the environment.

Site Suitability [40 CFR 146.83]

40 CFR 146.83 requires Owners and Operators of Class VI injection wells demonstrate to the Director that the wells are sited within a geologic area appropriate for the intended use. The first specific requirement is to demonstrate that there is sufficient extent, thickness, porosity, and permeability to sequester the carbon dioxide (CO_2) permanently and that the site has an adequate storage capacity for the design volumes. The second criterion within the regulation is to demonstrate the integrity of the confining zone, faults within the project area, and the potential for pressure build-up that could compromise the confining zone.

The information informing the suitability of the site include:

- Core descriptions and tests on materials from the Citizen Green #1 Well,
- Well deviation surveys,
- Geophysical logging data from wells in the area,
- Two- and three-dimensional seismic data, and
- Numerical modeling of multiphase flow.

The sequestration area in the vicinity of the proposed Class VI injection well has a simple geologic structure. Detailed geologic mapping and geophysical (seismic) surveys have established that over a regional scale, the thickness and porosity of the Mokelumne River Formation (MRF) are sufficient to store large amounts of CO_2. In particular, there is sufficient pore-space beneath Rindge Tract Island to accommodate approximately 40 million metric tons of supercritical CO_2 at typical storage efficiencies, and retain the plume extent and the critical pressure front beneath the footprint of the island.

The injection zone has the temperature and pore pressure to maintain the CO_2 in a supercritical state:

- Using the proposed injection depth of 6,400 feet and a formation water gradient of 0.44 pounds per square inch (psi) per foot the formation pressure was calculated at 2,816 psi. The reported reservoir shut-in pressure in the Mokelumne River Formation at 6,301 feet average depth at the Roberts Island Gas Field wells measured 2,750 psi (formation water gradient of 0.437 psi/ft), and 2,350 psi at 5,220 feet at the MacDonald Island Gas Field (formation water gradient of 0.450 psi/ft.), both of which are normally pressured. Consequently, the Mokelumne River Formation is normally pressured at the proposed injection location and depth.
- Subsurface temperatures have been measured in petroleum wells in the vicinity of the sequestration area. The temperature gradient is 11 to 14 °F per 1,000 feet in the depth range of 0-7,000 feet, this depth range includes the injection and upper and lower confining units. The heat flow ranges from 30 to 34 milliwatts per square meter (mW/m^2) according to the Geothermal Map of North America (Blackwell and Richards, 2004). The subsurface temperatures in the proposed sequestration zones are suitable for injection and storage of CO_2

Trapping mechanisms include structural trapping, capillary trapping, and solution trapping. The porosity and intrinsic permeability are suitable for storage. For a 20-year injection rate of about 1.25 million metric tons per year, the pressure front for both Well #1 and Well #2 is attenuated after about 25 years, and the extent of the plume becomes stable after about 100 years.

Candidate injection zones are bounded by multiple continuous, laterally-extensive low-permeability confining zone shale units overlying and underlying the storage zone. The potential injection sands are well below the lowermost Underground Source of Drinking Water (USDW) and are separated from the lowermost USDW by multiple alternating sand-shale intervals. The potential injections sands are also vertically separated from existing freshwater supply and irrigation wells by sufficient distance and geologic structure to prevent endangerment.

40 CFR 146.83 sets the minimum requirements for siting a Class VI injection well. This Site Characterization Narrative and **Section 3**, the Area of Review and Corrective Action Plan demonstrate that:

- The injection zone is of sufficient extent and has properties sufficient to sequester more than 40 million metric tons of supercritical CO_2,
- The confining zone will contain the supercritical CO_2 at proposed injection pressures with an appropriate safety factor that will not propagate fractures in the confining zone (see **Section 7**, Well Operating Plan), and
- The separation and presence of confining layers will prevent USDWs from becoming endangered.

AOR and Corrective Action

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)]***

Financial Responsibility

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]***

Injection Well Construction

This application is for two new Class VI wells. Schematics showing the surface and subsurface well construction details are provided pursuant to 40 CFR 146.82(a)(11) and are supplemented with annotations on the graphic.]

Pre-Operational Logging and Testing

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]***

Well Operation

Text, tables, and figures are provided to fulfill the operating data requirements for the permit application, listed at 40 CFR 146.82(a)(7) and (10) and with 40 CFR 146.88.

Testing and Monitoring

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]***

Injection Well Plugging

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)]***

Post-Injection Site Care (PISC) and Site Closure

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)]***

Emergency and Remedial Response

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)]***

Injection Depth Waiver and Aquifer Exemption Expansion

No Injection Depth Waiver or Aquifer Exemption Expansions are requested by this Permit Application.

Other Information

An Environmental Justice Report was included and uploaded to the GSDT as Other Information.

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Figures

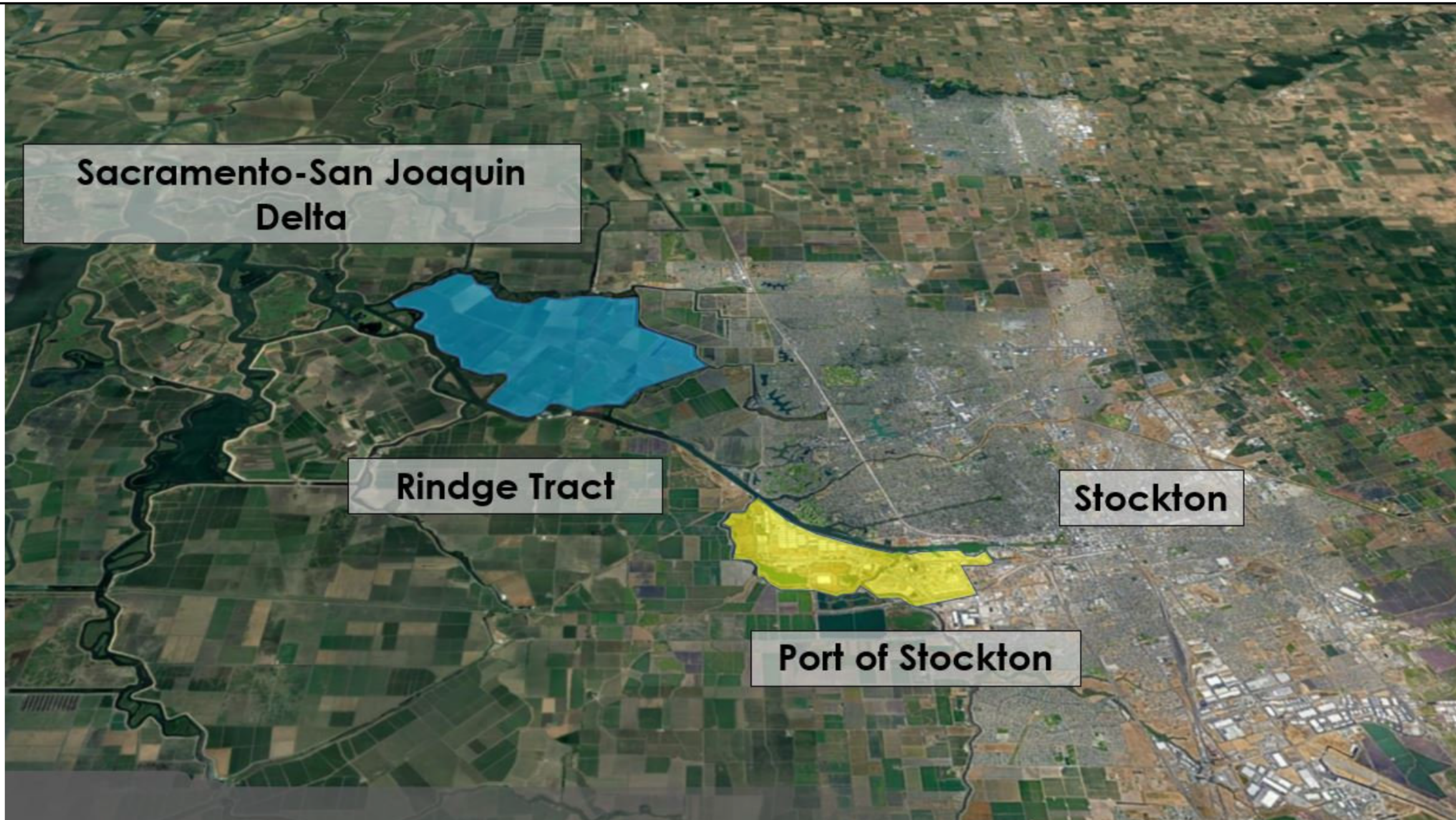

FIGURE 1-1
OVERVIEW OF PELICAN RENEWABLES, LLC
CARBON SEQUESTRATION PROJECT
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS
Wichita, KS | November 2022

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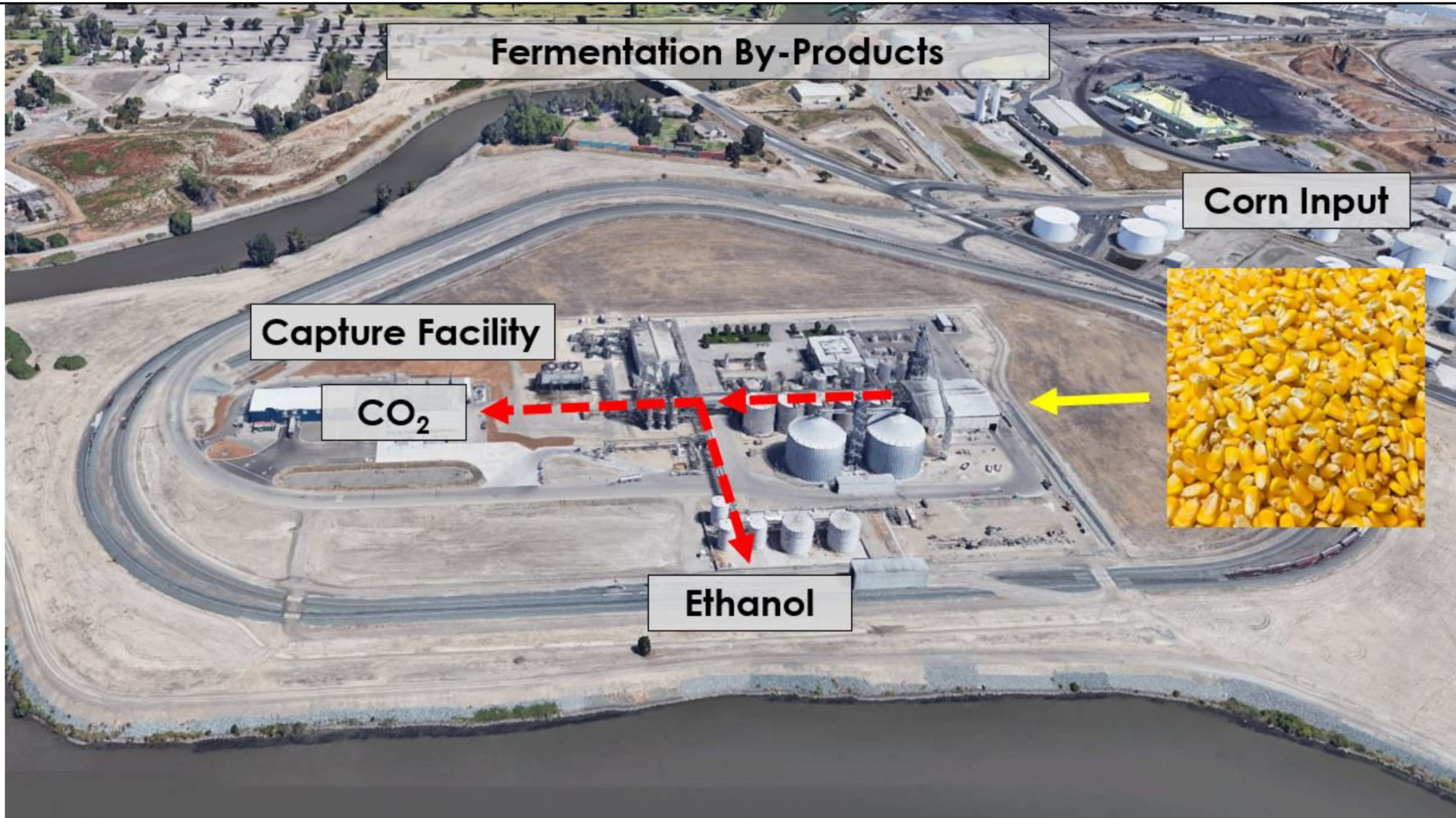
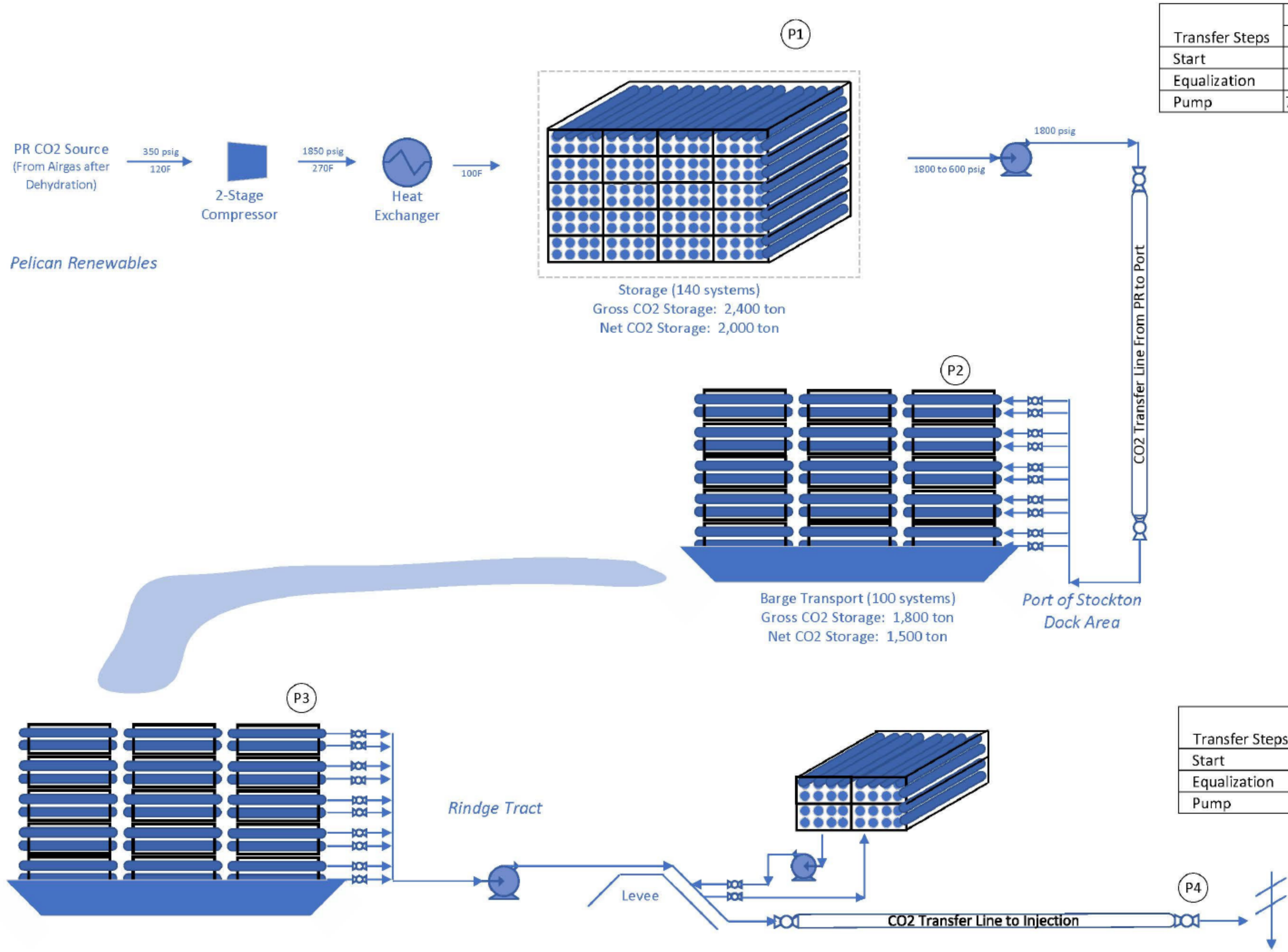


FIGURE 1-2
ETHANOL PLANT AND CARBON DIOXIDE CAPTURE FACILITY
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS
Wichita, KS | November 2022

N



Transfer Steps	P1 psig	P2 psig
Start	1800	600
Equalization	785	785
Pump	785 to 600	1800

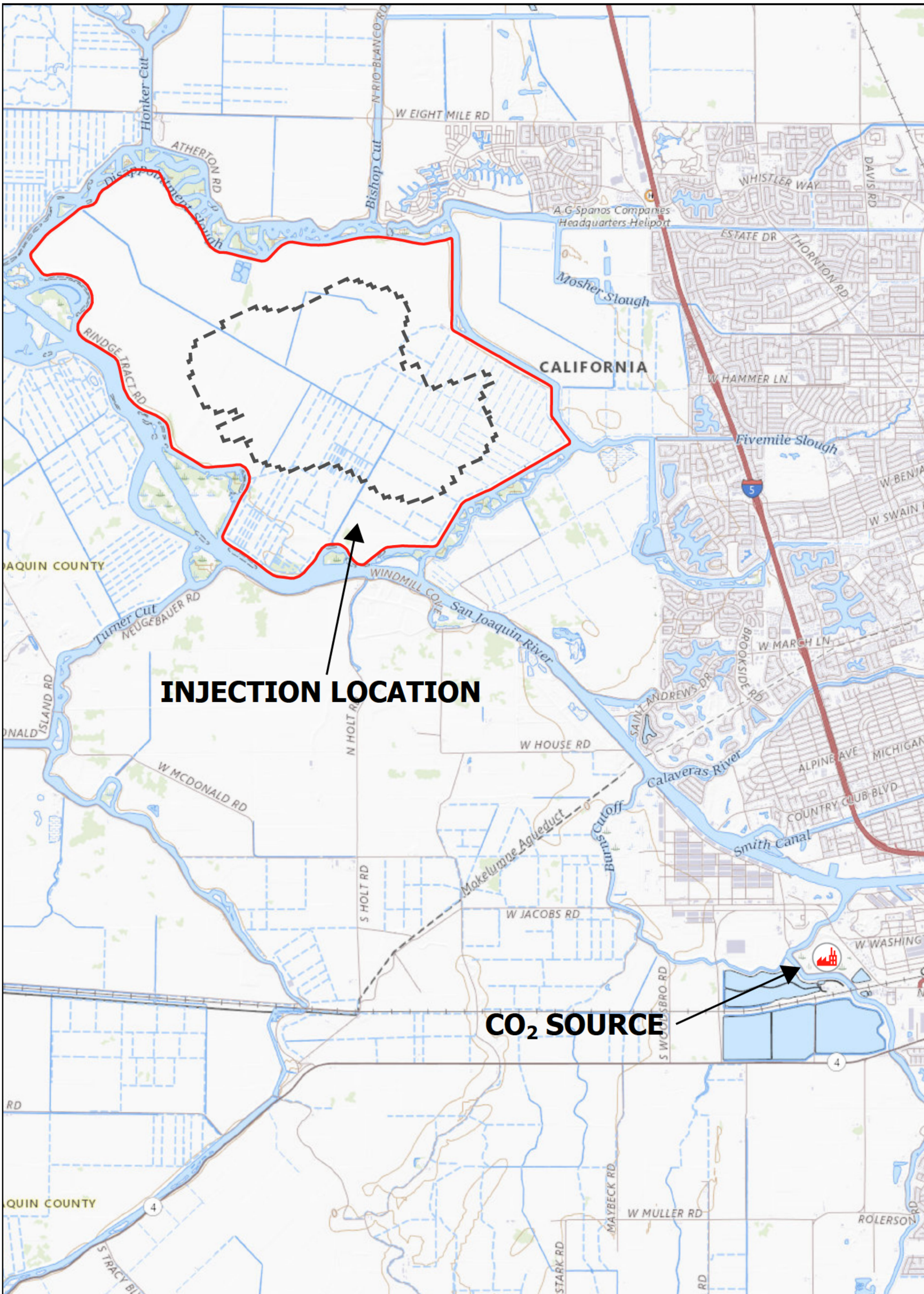
Transfer Steps	P3 psig	P4 psig
Start	1800	600
Equalization	850	850
Pump	850 to 600	1400

FIGURE 1-3

GENERAL PROCESS DIAGRAM - HP CO_2 TRANSPORT
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS	January 2023



Legend

Pelican Renewables Ethanol Plant

Delineated Area of Review

Rindge Tract Island

FIGURE 2-1

LOCATION MAP

PELICAN RENEWABLES INC.

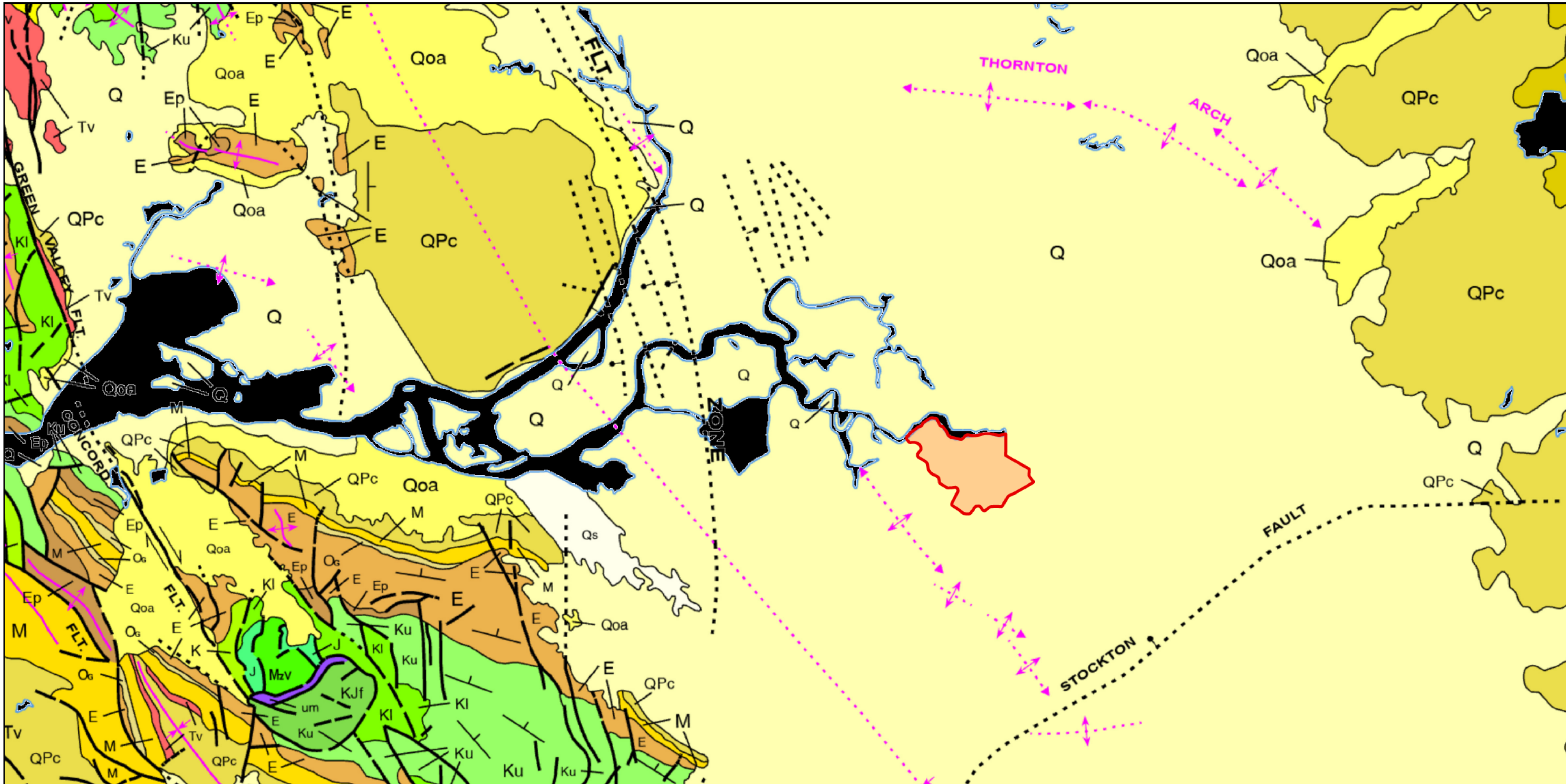
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS | April 2024

0 6,000 Feet

N



Legend

Rindge Tract Island

Fold Types

- anticline, concealed
- anticline, concealed, double plunge
- anticline, concealed, south plunge

Fault Type

- fault, concealed
- normal fault, concealed

Geologic Formations

- Eocene
- Paleocene, undifferentiated
- Franciscan Complex Melange
- Franciscan Complex
- Upper Cretaceous
- Tertiary Volcanic
- Paleozoic
- Holocene
- Quaternary Alluvium
- Plio-Pleistocene
- Mesozoic Plutonic
- Water

FIGURE 2-2

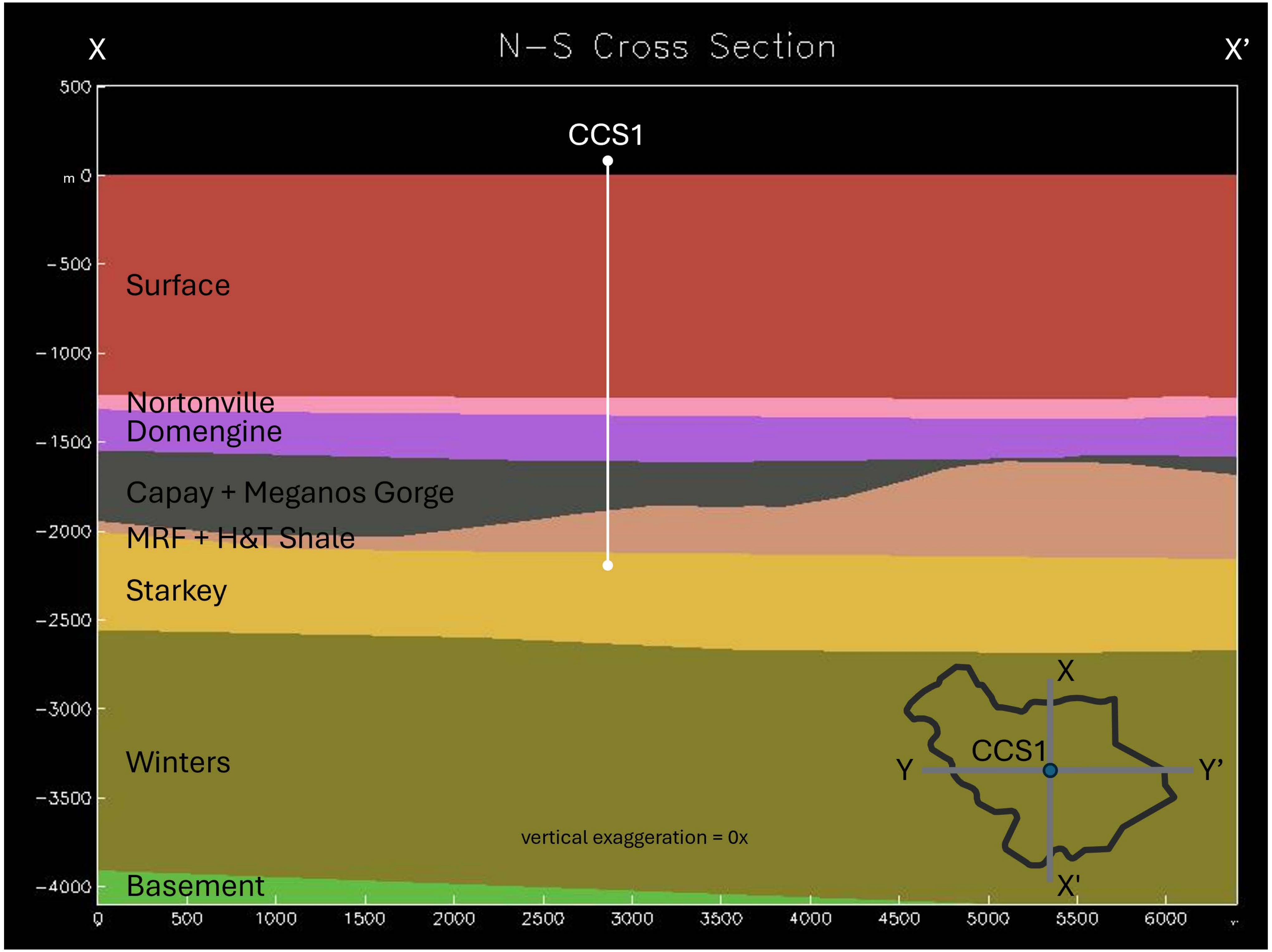
REGIONAL GEOLOGIC MAP
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS | November 2022

0 27,000 54,000 Feet

N



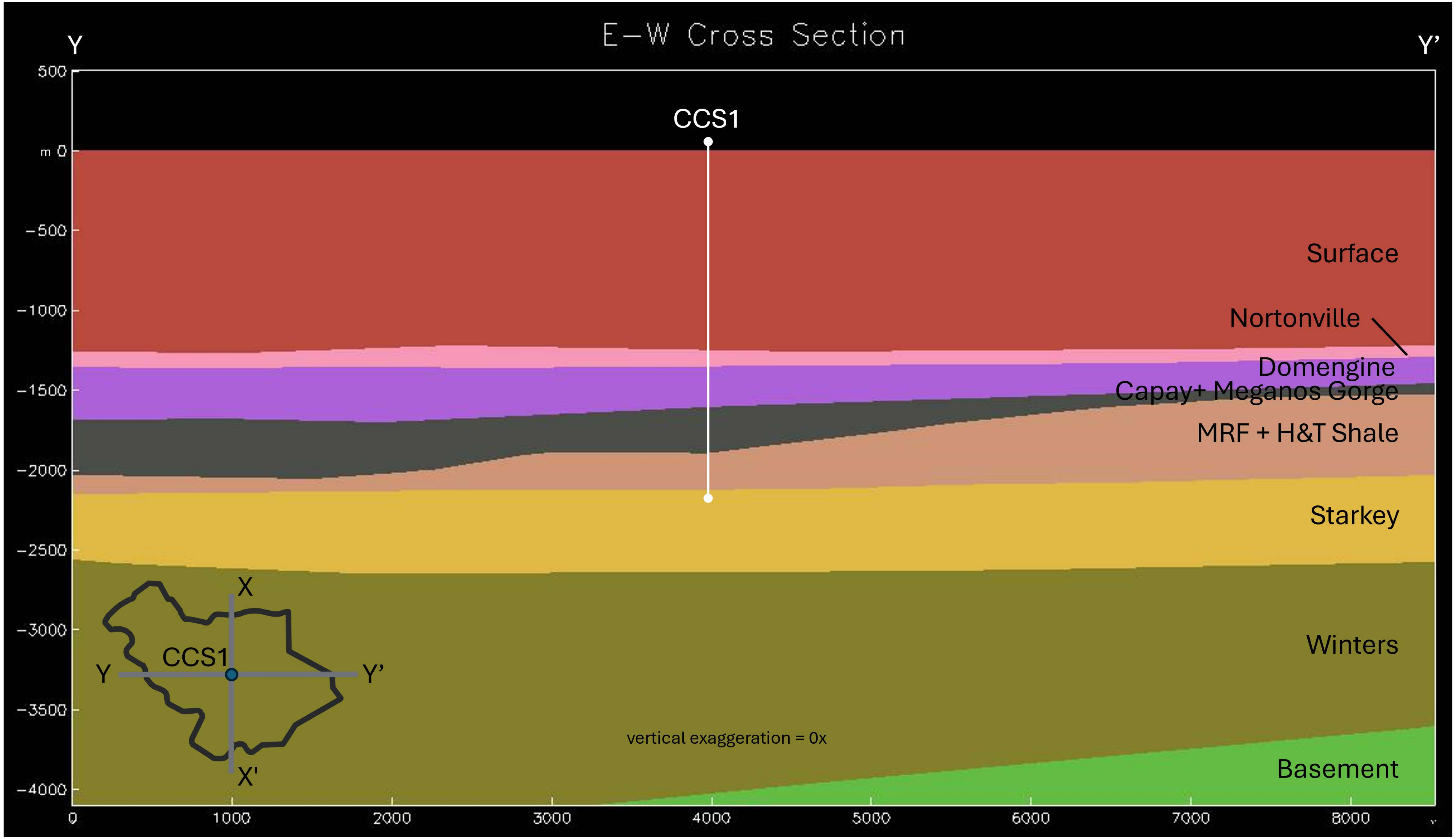
Notes:
- Data presented is scaled in meters.
- The H&T Shale is grouped with the Mokelumne River Formation (MRF). For details on reasoning, please refer to the Static Geologic Model description in Section 3 – Area of Review and Corrective Action Plan.

Source:
Lawrence Livermore National Laboratory, 2024. Personal communication from Briana Schmidt to Kacey Garber.

FIGURE 2-3A
NORTH-SOUTH CROSS SECTION
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS	April 2024



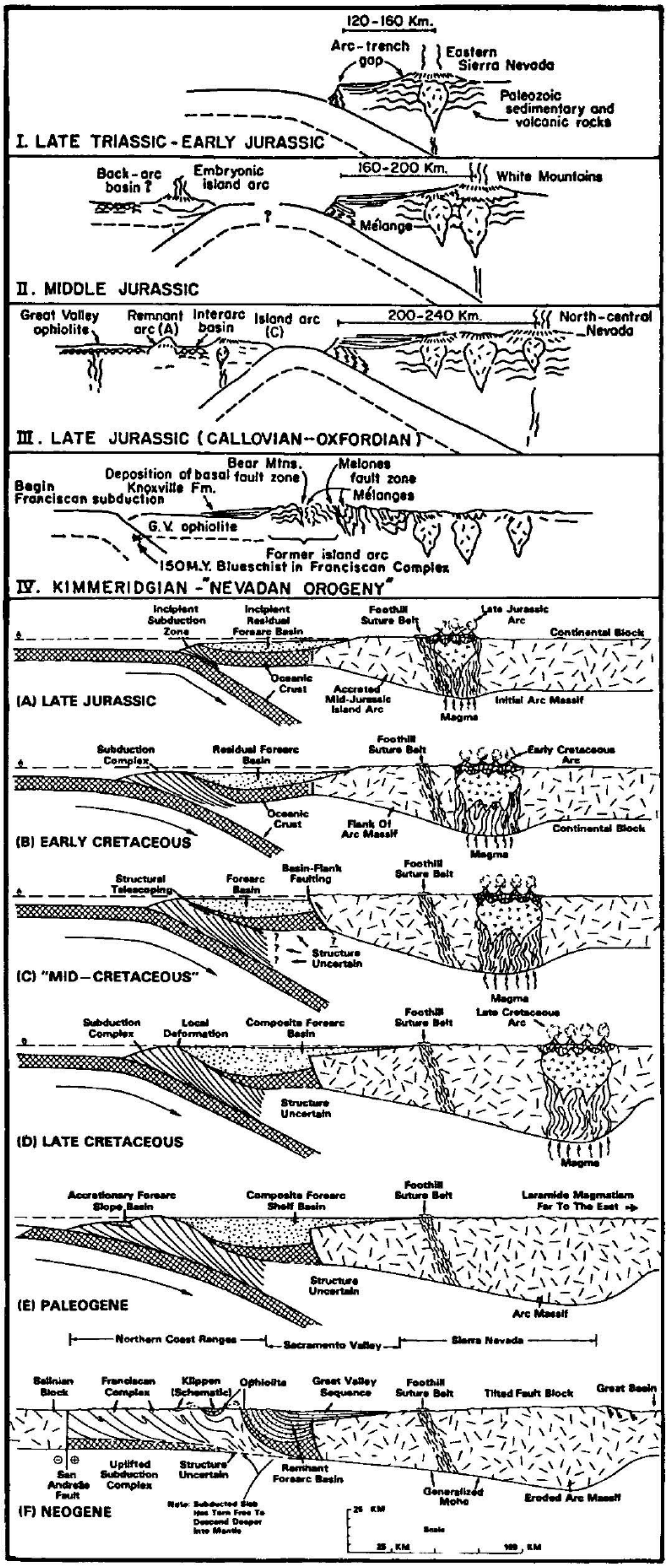
Notes:
- Data presented is scaled in meters.
- The H&T Shale is grouped with the Mokelumne River Formation (MRF). For details on reasoning, please refer to the Static Geologic Model description in Section 3 – Area of Review and Corrective Action Plan.

Source:
Lawrence Livermore National Laboratory, 2024. Personal communication from Briana Schmidt to Kacey Garber.

FIGURE 2-3**B**
EAST-WEST CROSS SECTION
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS	April 2024



Note:

- Schematic cross sections of northern California during Mesozoic and Cenozoic from formation of Coast Range ophiolite behind east-facing intraoceanic arc (III) to termination of Great Valley fore arc by conversion to transform margin (F). A-F are true-scale drawings, whereas I-IV are more schematic.
- Figure adapted from Ingersoll and Dickinson (1981).

FIGURE 2-4

TECTONIC HISTORY OF SACRAMENTO BASIN
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS | November 2022

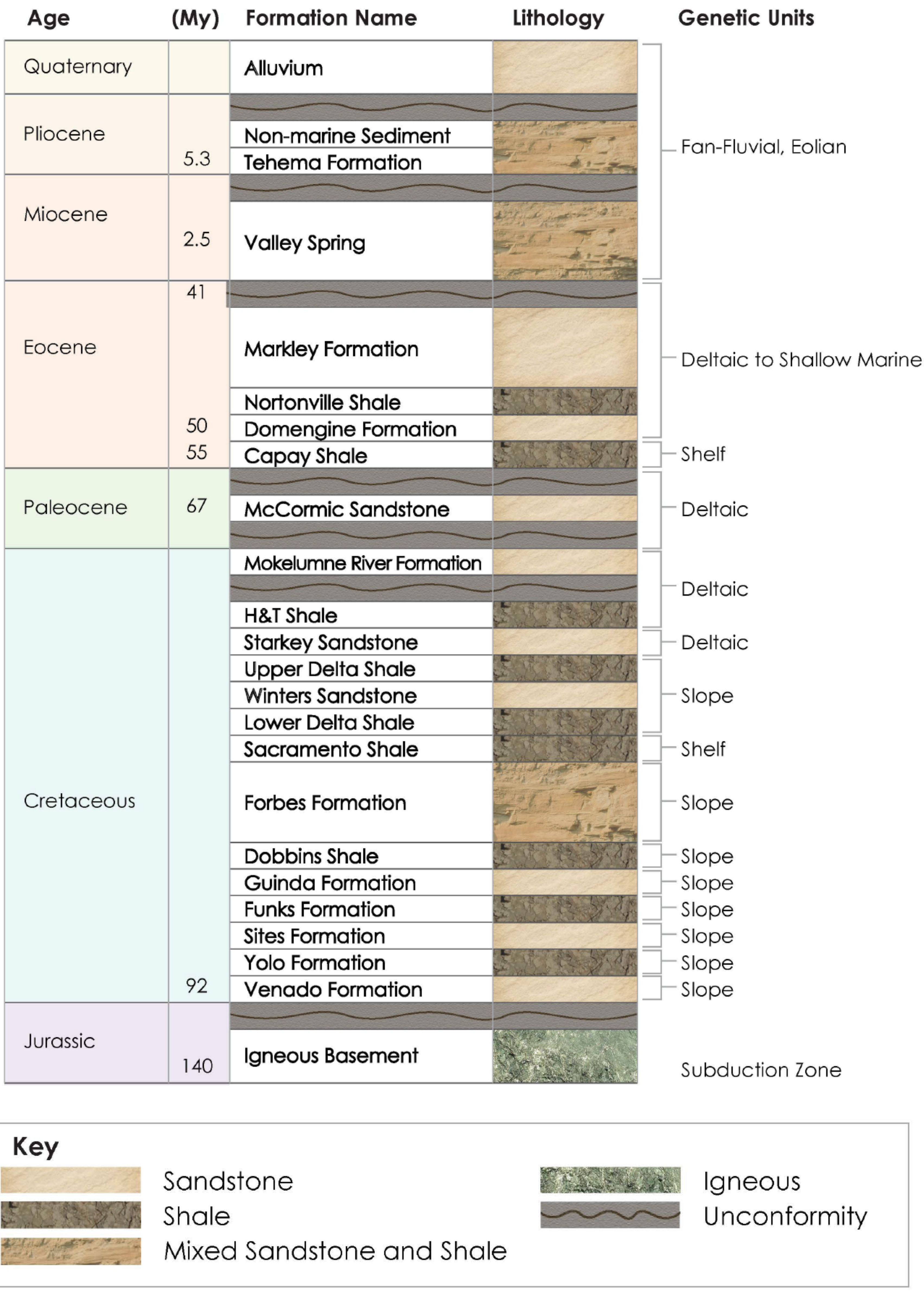
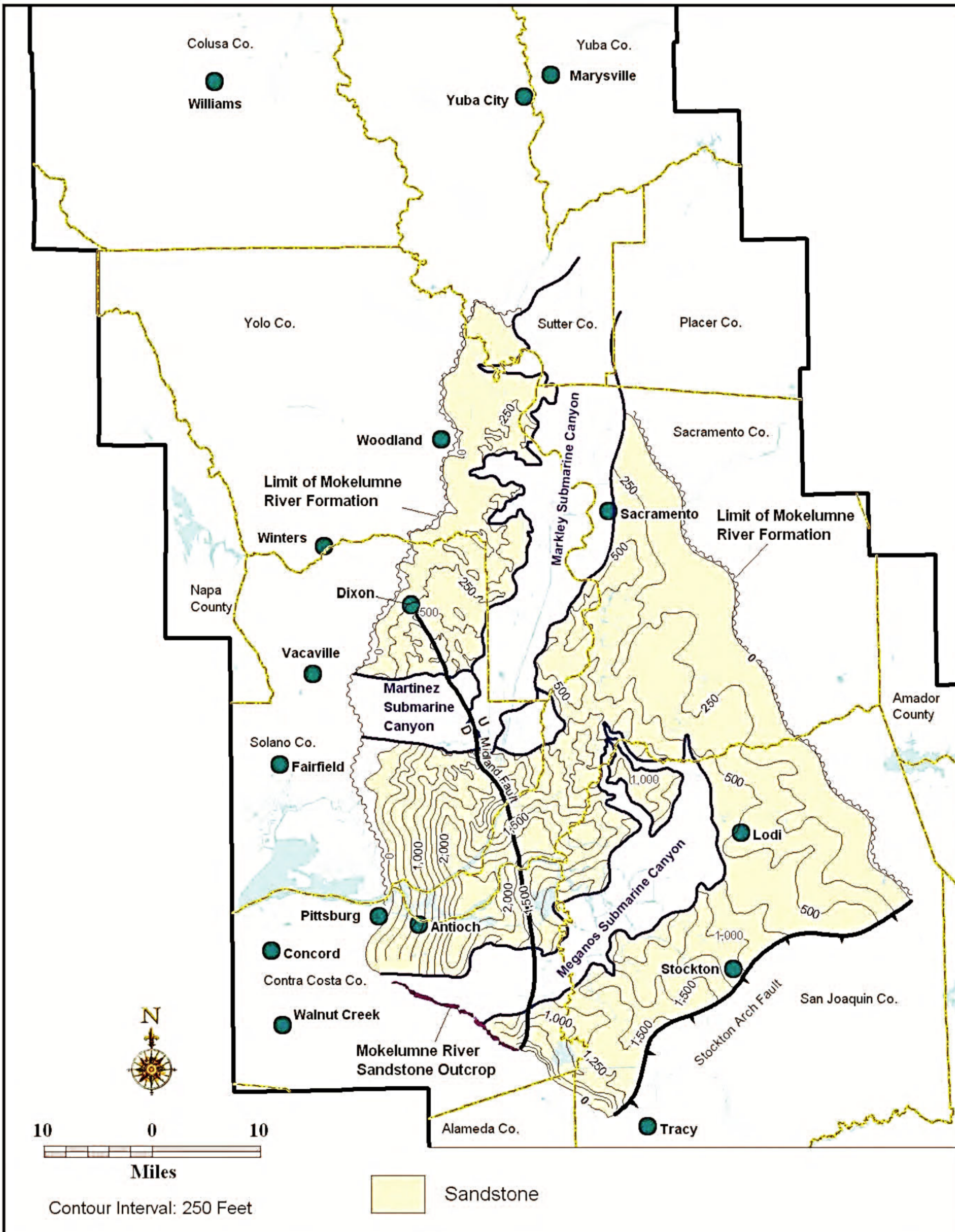


FIGURE 2-5
GENERALIZED REGIONAL
STRATIGRAPHIC COLUMN
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

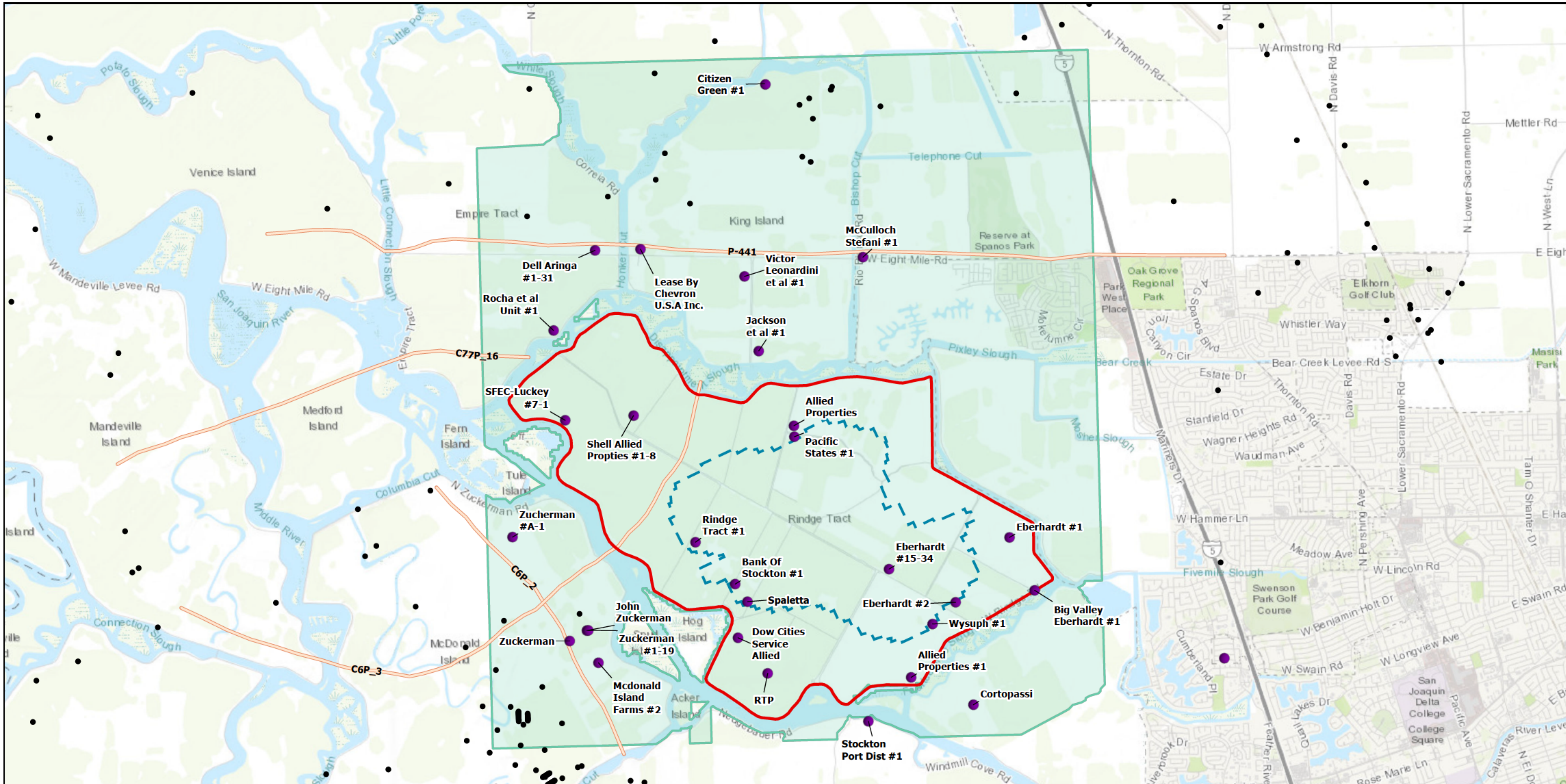
Wichita, KS | January 2023



Source:
California Geological Survey

FIGURE 2-6
REGIONAL EXTENT OF MOKELUMNE FORMATION
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS
Wichita, KS | November 2022



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island
- Select PacSeis 2D Data
- Conestrama 3D Data

FIGURE 2-7
DATA AVAILABILITY
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | April 2024

0 5,000 10,000 Feet
N

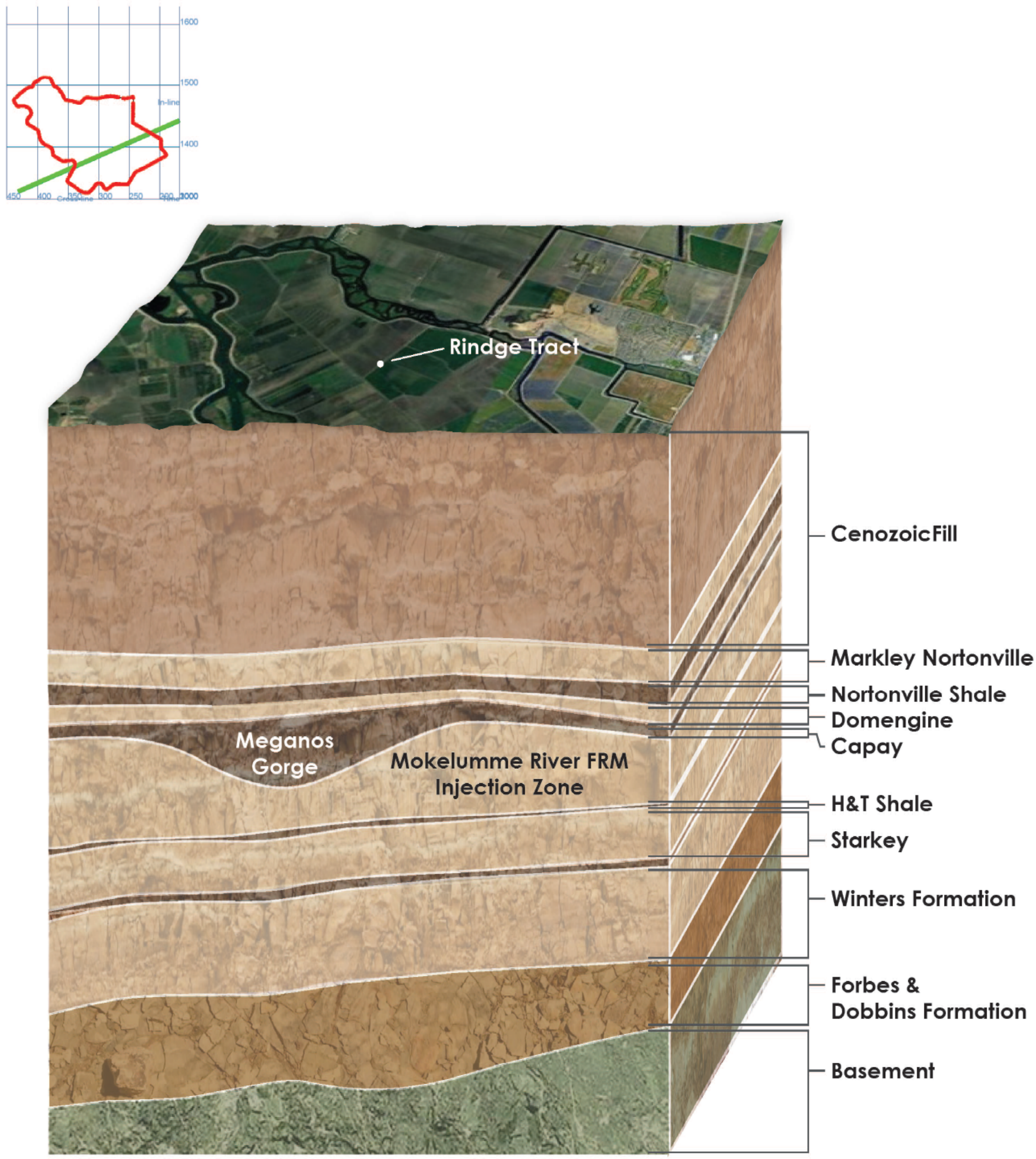
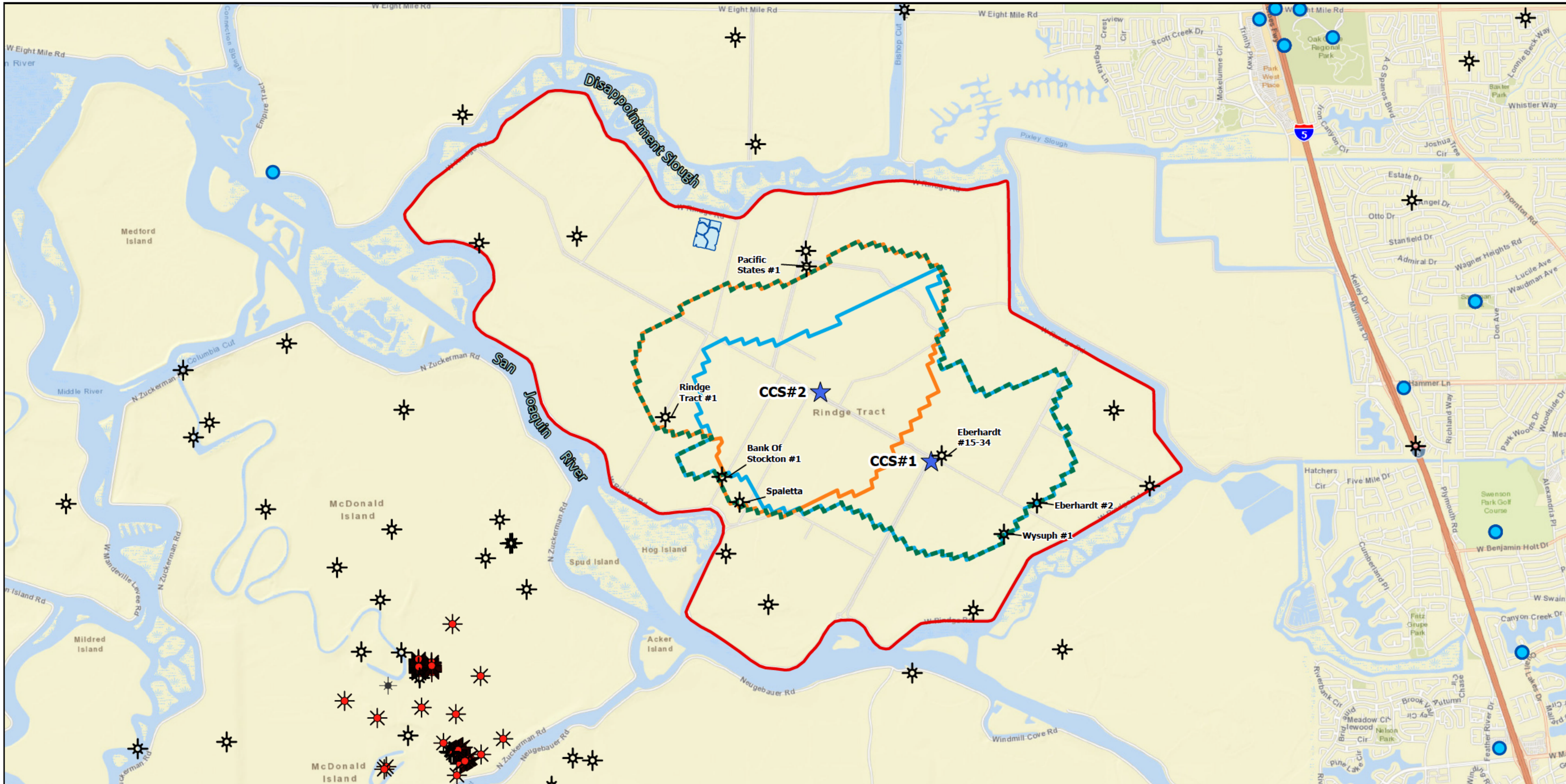


FIGURE 2-8
AOR CONCEPTUAL SITE MODEL
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS | November 2022

N



Legend

- Injection Well
- Delineated Area of Review
- Pressure Front
- Maximum Predicted Extent of Super Critical CO_2
- Rindge Tract Island

Artificial Penetrations' Status

- Active
- Idle
- Plugged

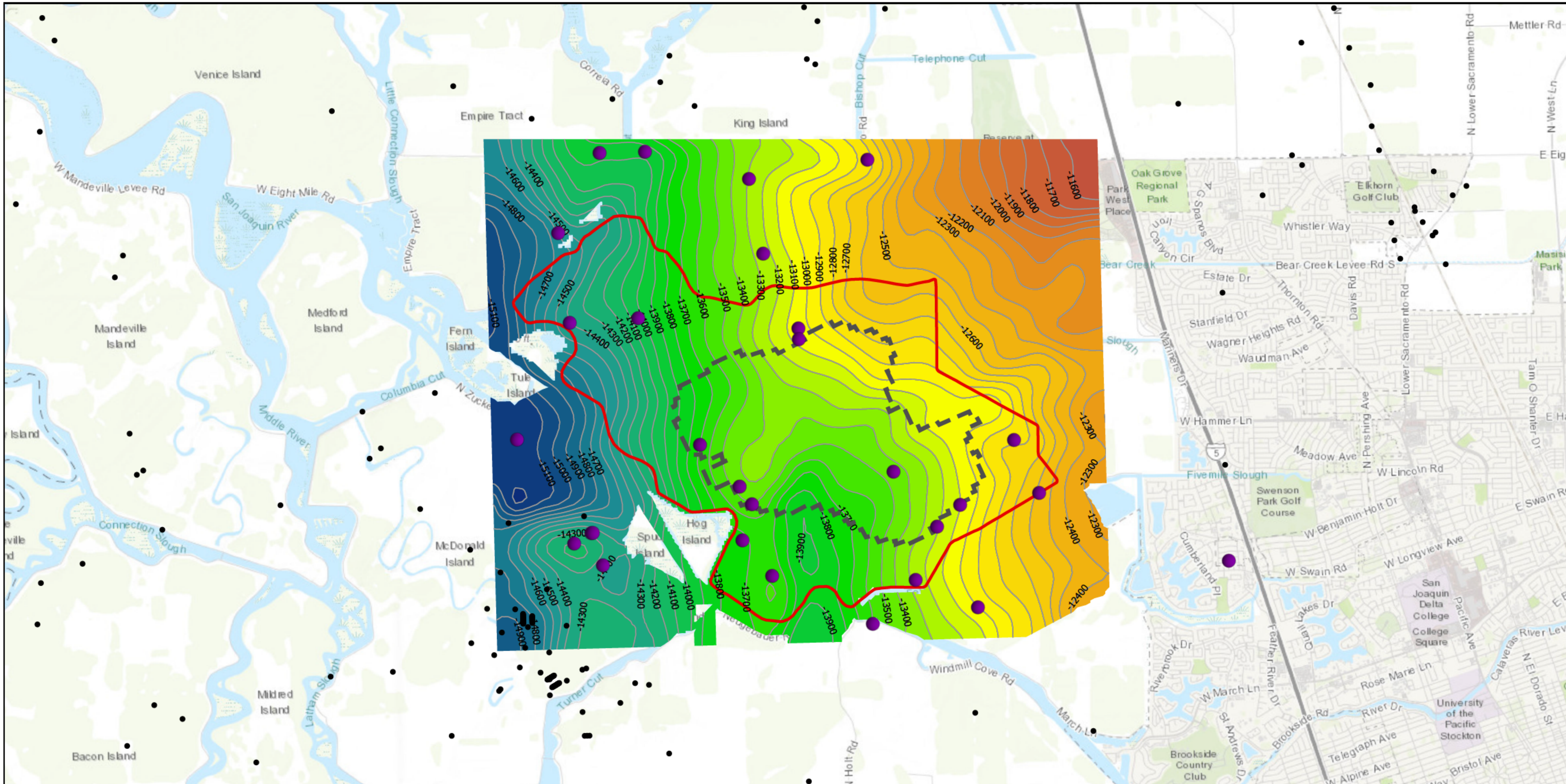
- Groundwater Well Location
- Ephemeral Reservoir

Note:
The maximum pressure front is shown at 25 years after the start of injection (the year of maximum delta pressure). The critical pressure is 145 psi.

FIGURE 2-9
DELINEATED AREA OF REVIEW
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | April 2024

0 3,500 7,000 Feet
N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Depth to top, TVDSS*

-11600' -15200'

100' Contour Intervals

FIGURE 2-10

BASEMENT STRUCTURE MAP

PELICAN RENEWABLES, INC.

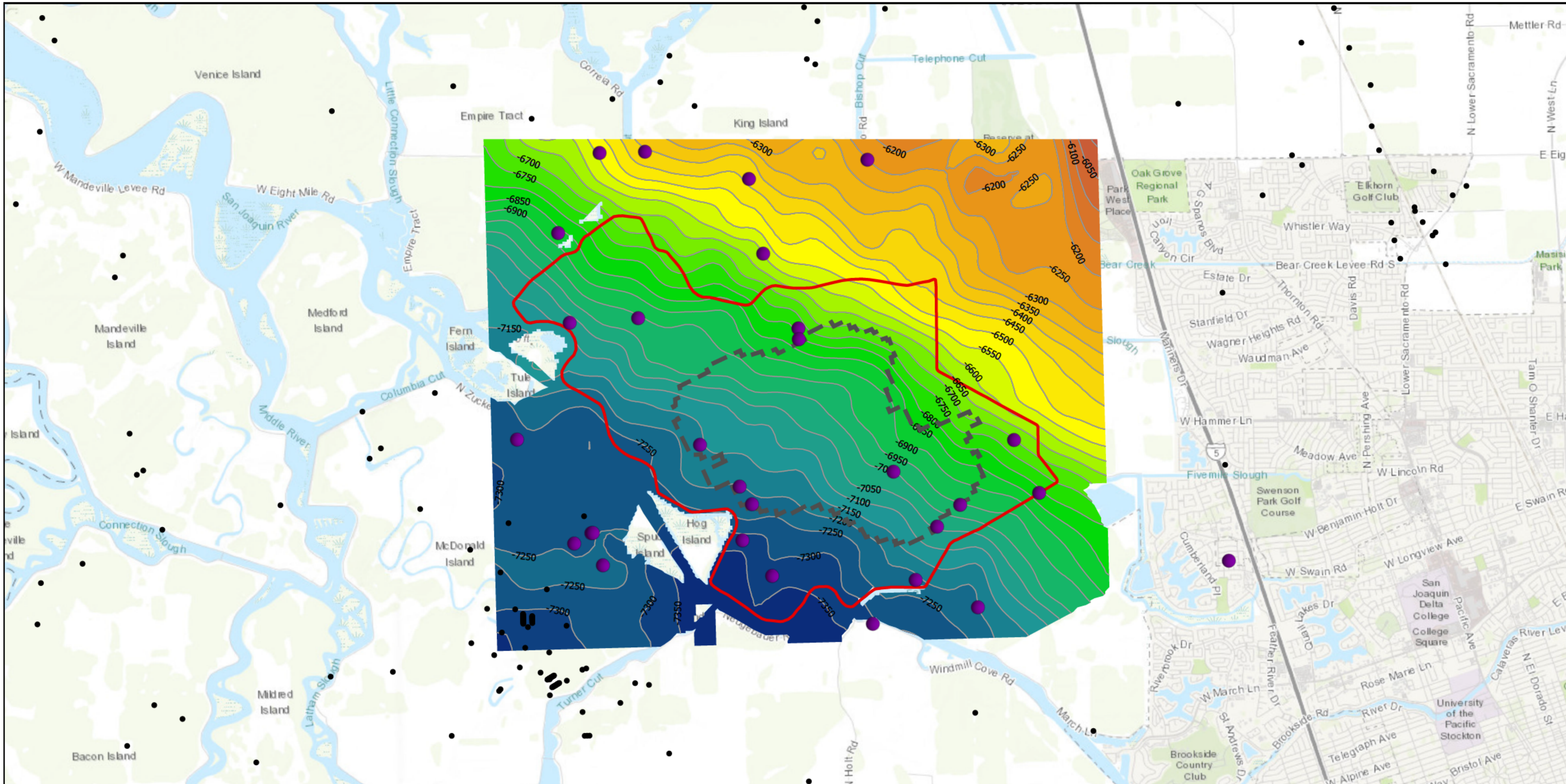
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 5,000 10,000 Feet

N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Depth to top, TVDSS*

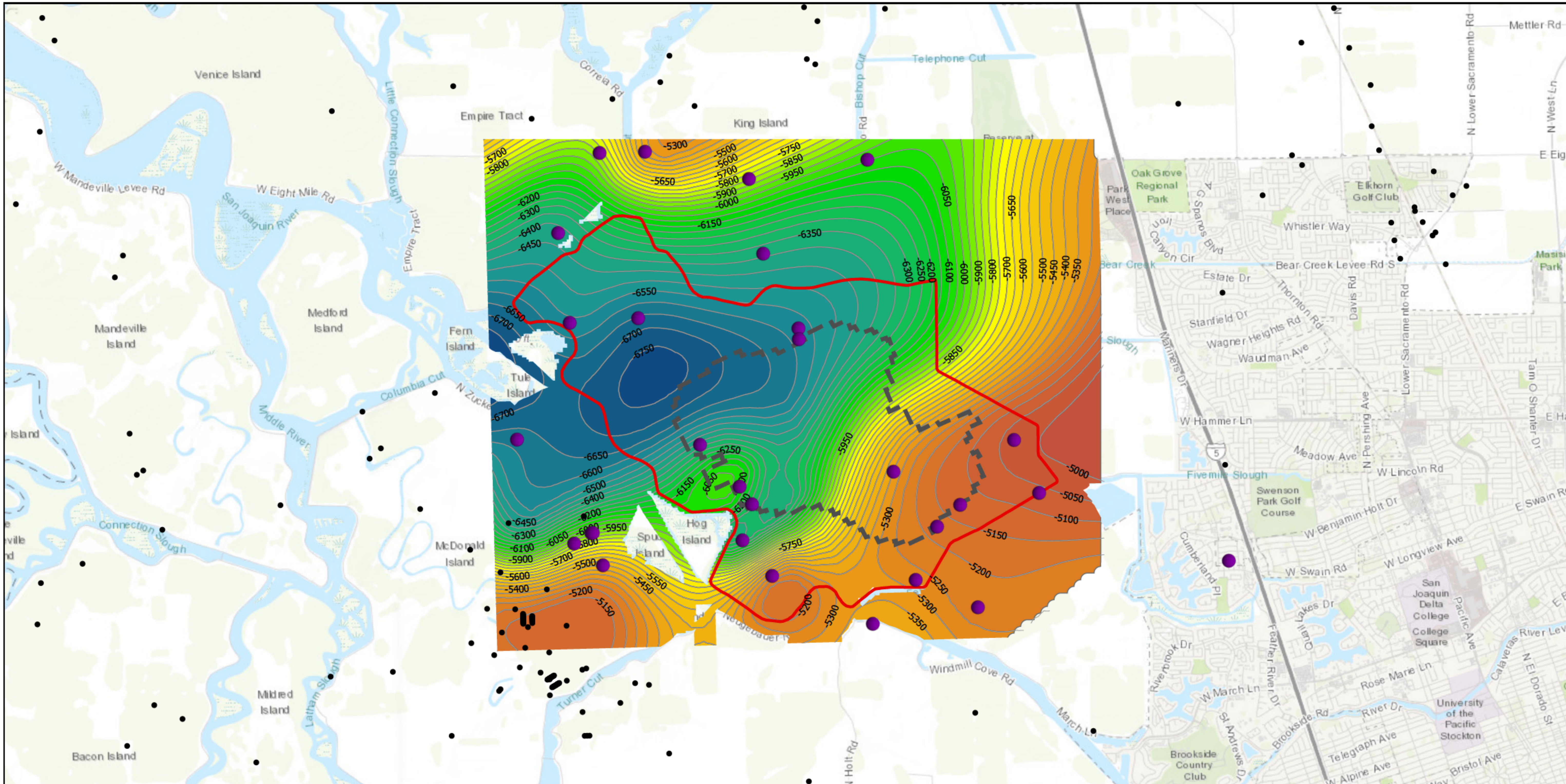
-6000' -7350'

50' Contour Intervals

FIGURE 2-11
H&T SHALE STRUCTURE MAP
PELICAN RENEWABLES, INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | April 2024

0 5,000 10,000 Feet
N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Depth to top, TVDSS*

-4950' to -6800'

50' Contour Intervals

Note:
- TVDSS* = True Vertical Depth Sub Sea.

FIGURE 2-12

MOKELUMNE RIVER FORMATION STRUCTURE MAP

PELICAN RENEWABLES, INC.

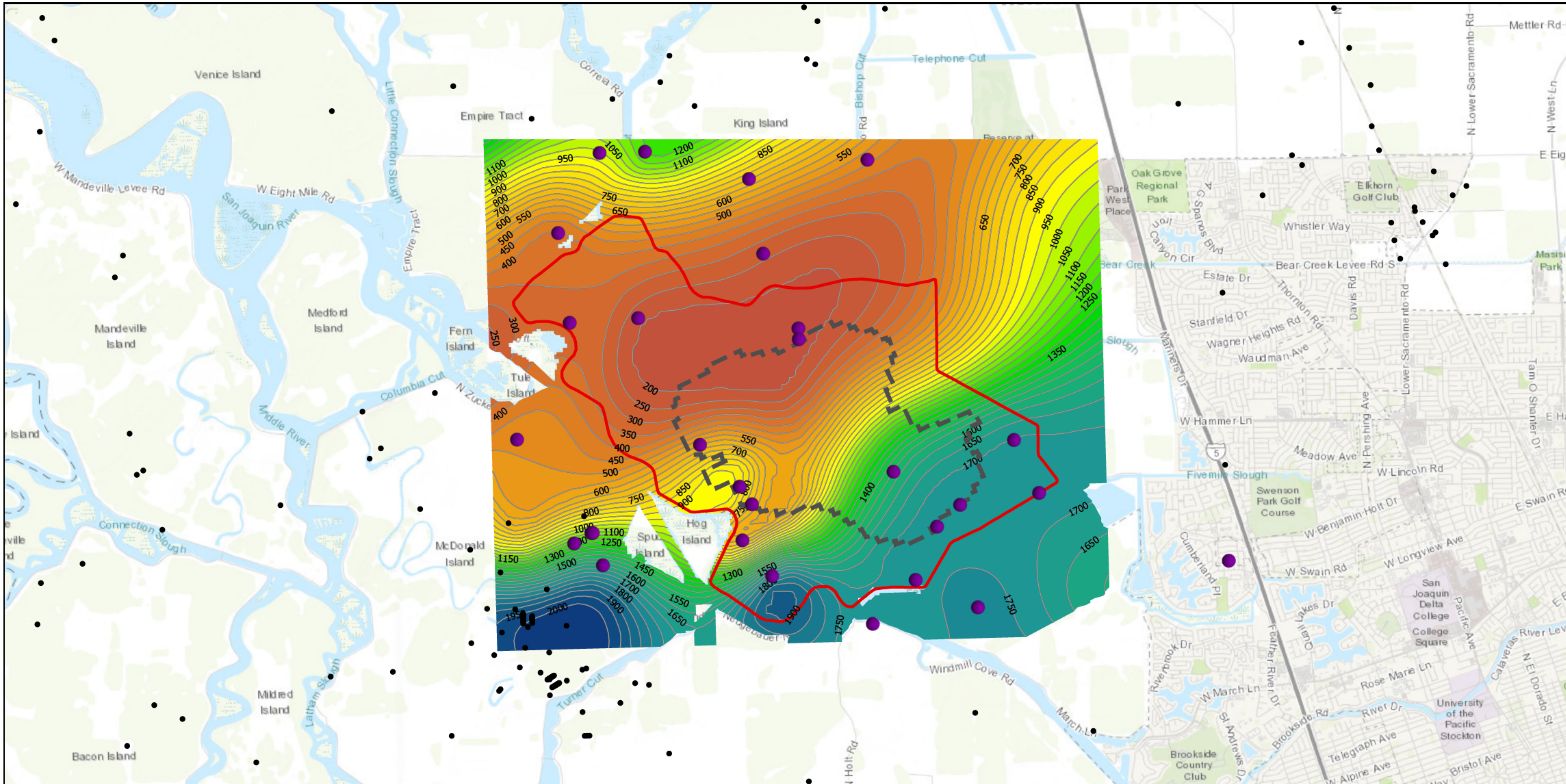
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 5,000 10,000 Feet

N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Thickness, TVDSS*

150' 2050'

50' Contour Intervals

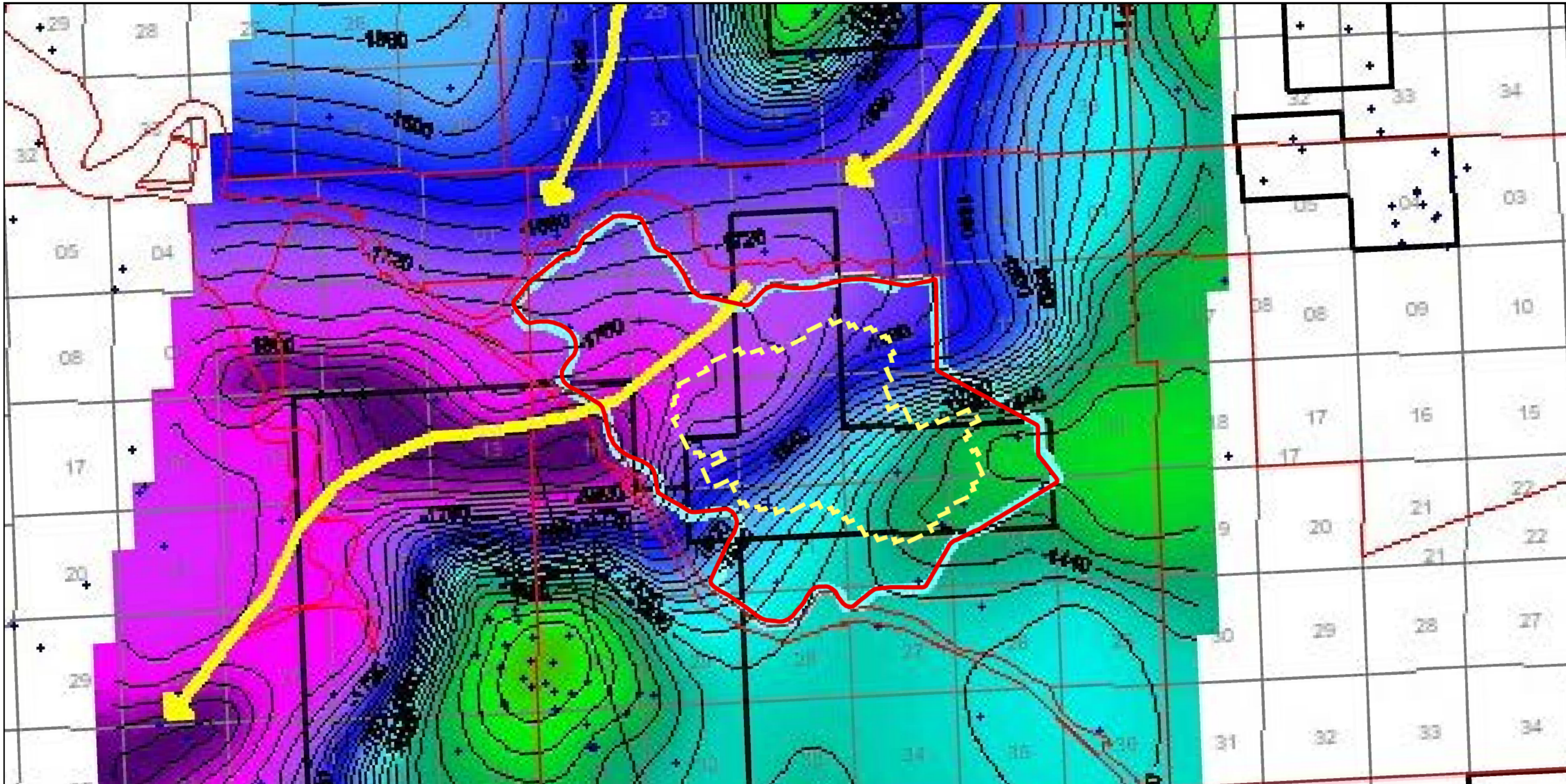
Note:
- Depth grid converted using time-depth relationship from Big Valley Eberhart 1.
- TVDSS* = True Vertical Depth Sub Sea.

FIGURE 2-13
MOKELUMNE RIVER FORMATION ISOPACH MAP
PELICAN RENEWABLES, INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | April 2024

0 5,000 10,000 Feet

N



Legend

Delineated Area of Review

Rindge Tract Island

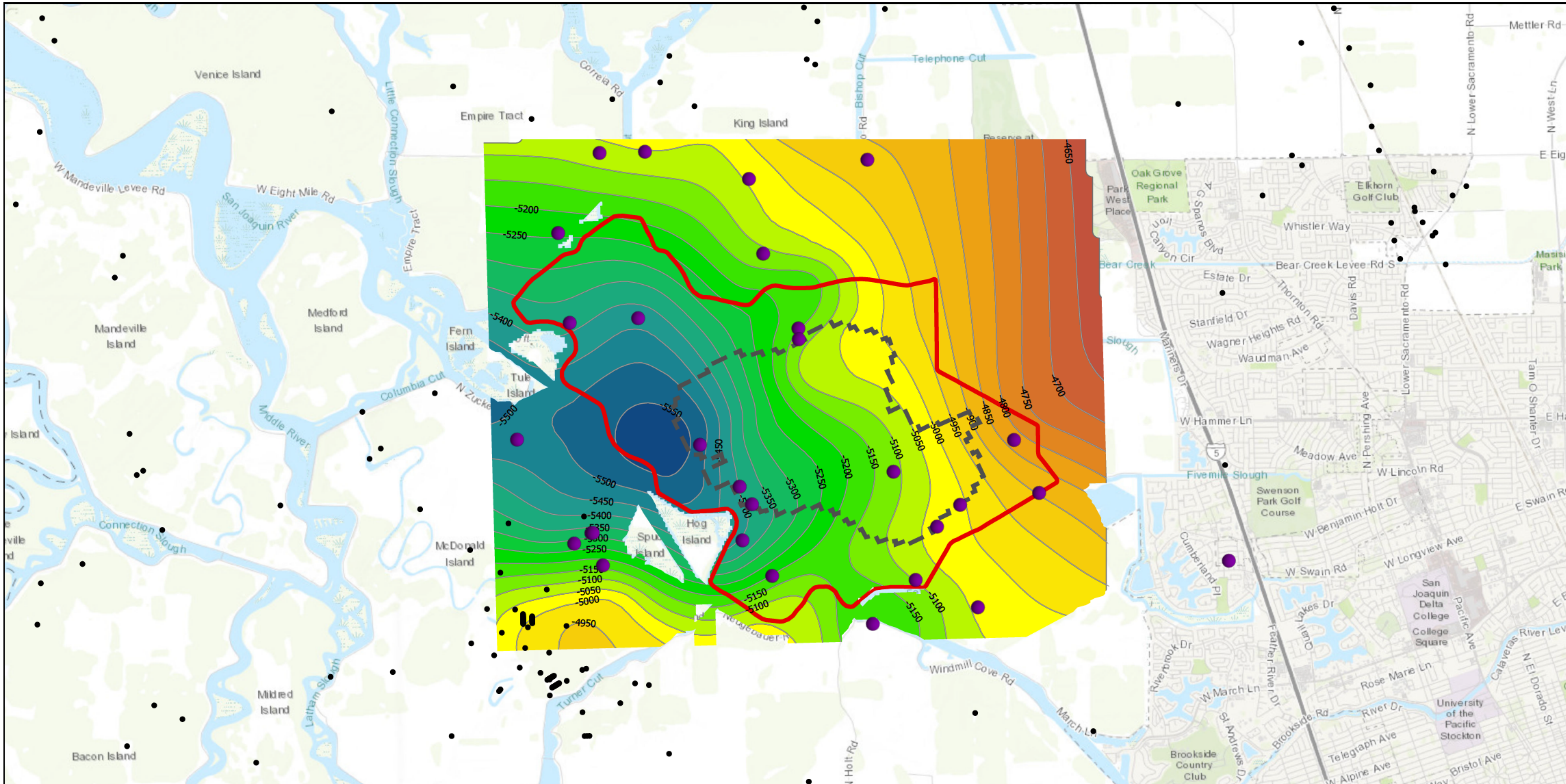
Source:
Oil & Gas Field Redevelopment Group, LLC. (n.d.) Final Report. Figure 7. Digitized Selected Time Intervals Imported into GeoGraphix p.12.

FIGURE 2-14
MEGANOS GORGE BOUNDAY
PELICAN RENEWABLES, INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | January 2023

0 5,000 10,000 Feet

N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Depth to top, TVDSS*

-4650' -5550'

50' Contour Intervals

Note:
- TVDSS* = True Vertical Depth Sub Sea.

FIGURE 2-15

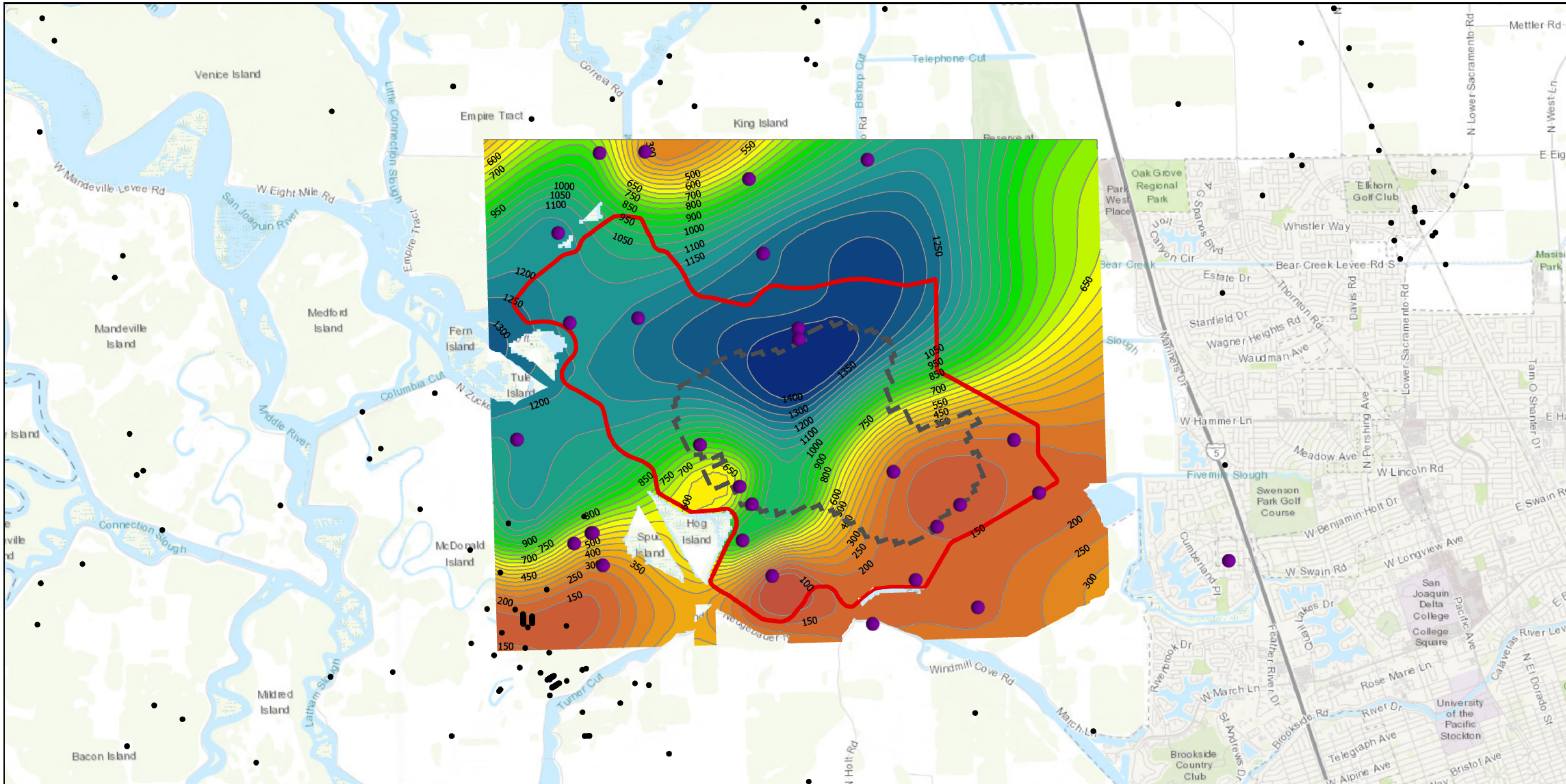
CAPAY & MEGANOS GORGE STRUCTURE MAP
PELICAN RENEWABLES, INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 5,000 10,000 Feet

N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Thickness, TVDSS*

150' – 2050'

50' Contour Intervals

Note:
- Depth grid converted using time-depth relationship from Big Valley Eberhart 1.
- TVDSS* = True Vertical Depth Sub Sea.

FIGURE 2-16

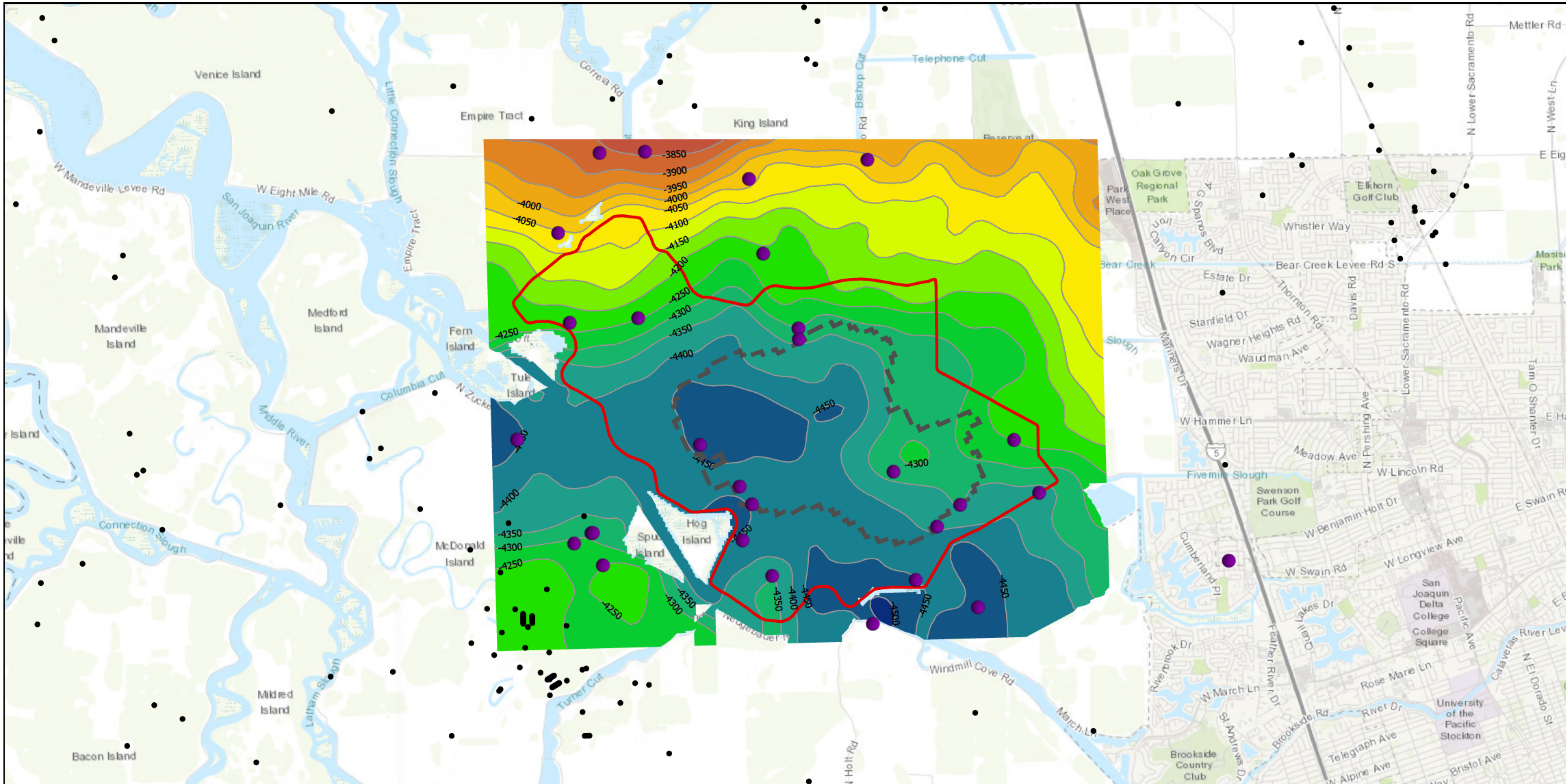
CAPAY SHALE & MEGANOS GORGE ISOPACH MAP PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 5,000 10,000 Feet

N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Depth to top, TVDSS*

-3850' -4500'

50' Contour Intervals

FIGURE 2-17

DOMENGINE FORMATION STRUCTURE MAP

PELICAN RENEWABLES, INC.

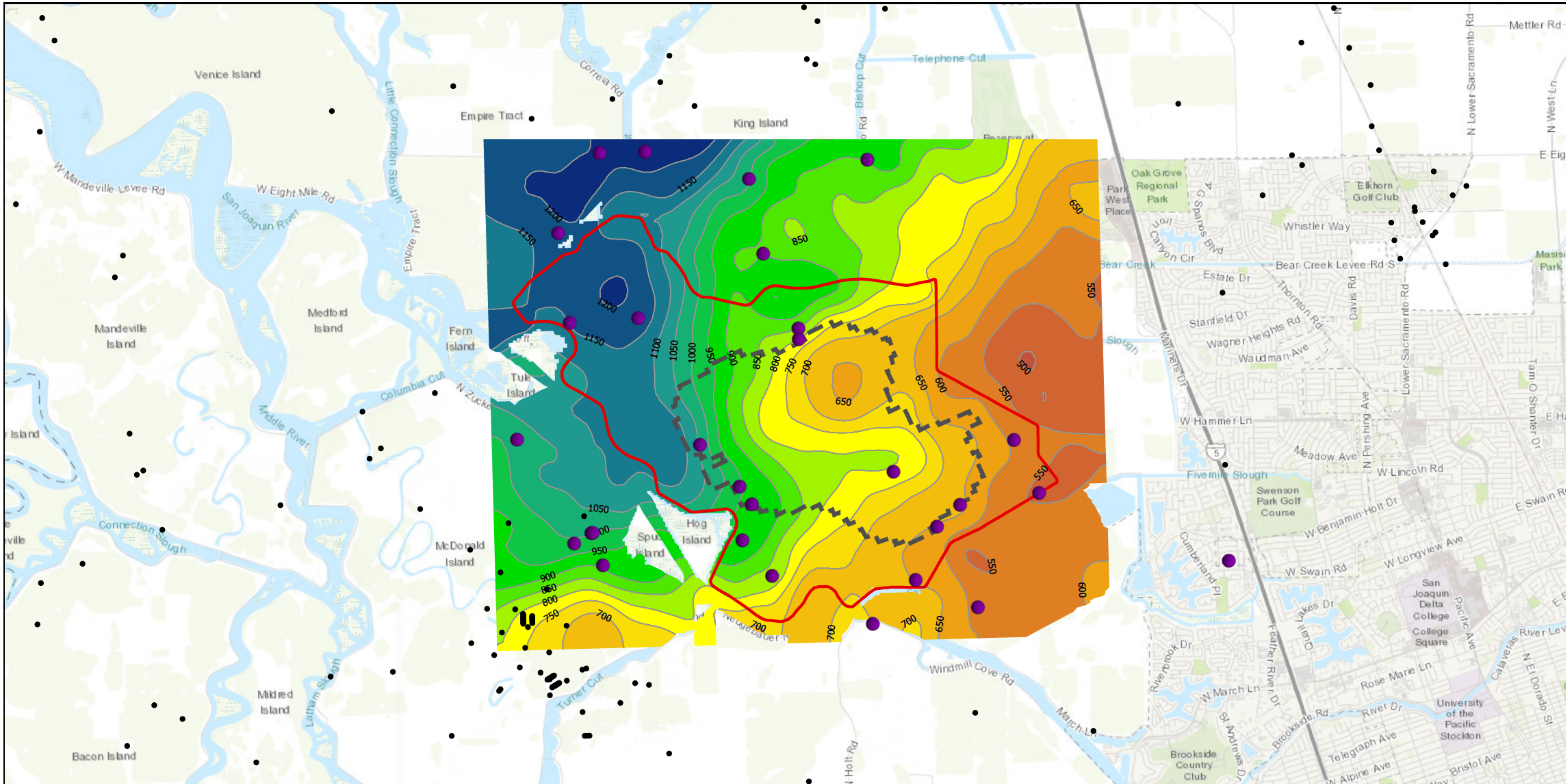
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 5,000 10,000 Feet

N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Thickness, TVDSS*

500' — 1200'

50' Contour Intervals

Note:
- Depth grid converted using time-depth relationship from Big Valley Eberhart 1.
- TVDSS* = True Vertical Depth Sub Sea.

FIGURE 2-18

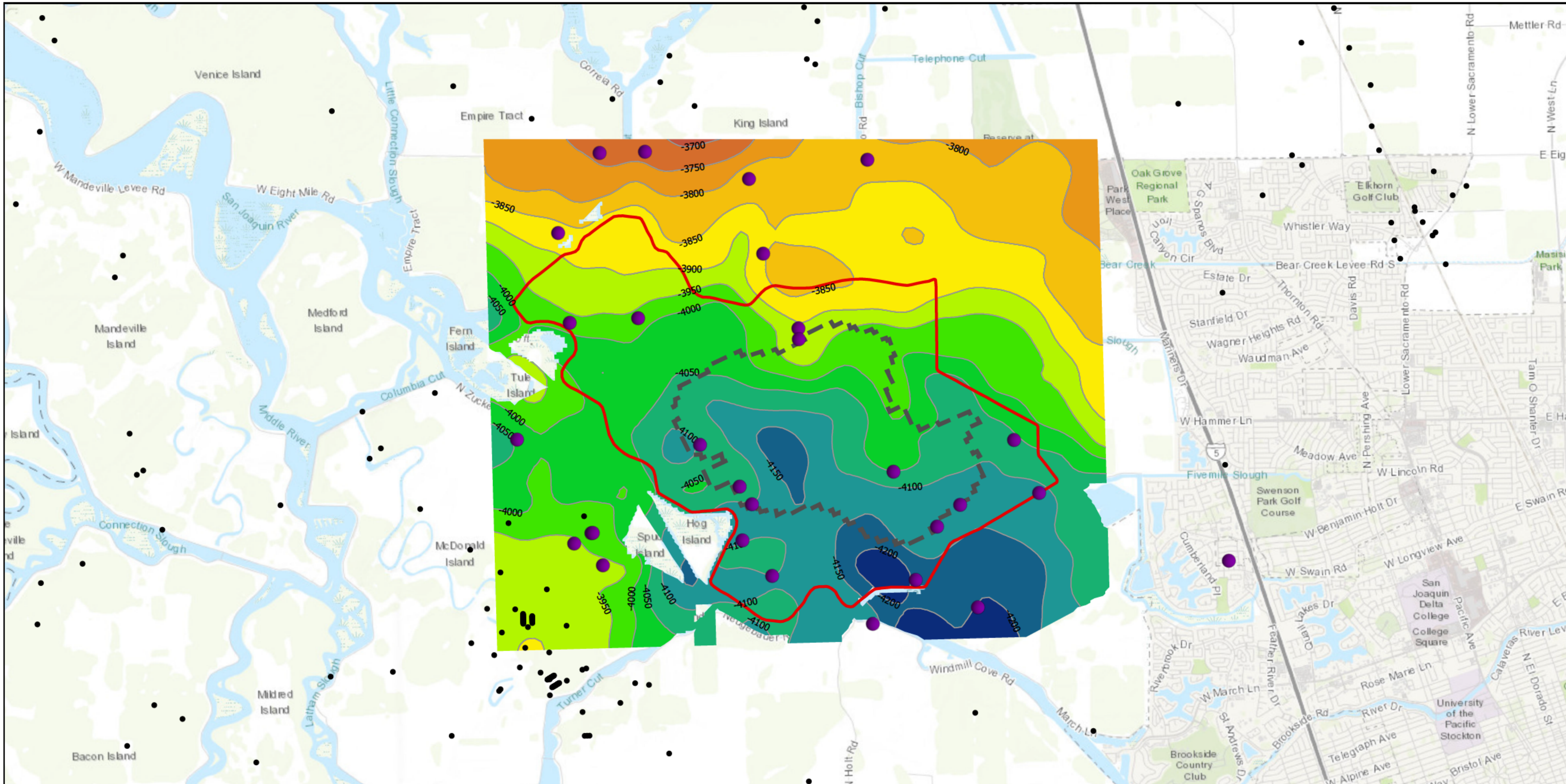
DOMINGINE FORMATION ISOPACH MAP
PELICAN RENEWABLES, INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 5,000 10,000 Feet

N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Depth to top, TVDSS*

-3700' — -4200'

50' Contour Intervals

FIGURE 2-19

NORTONVILLE SHALE STRUCTURE MAP

PELICAN RENEWABLES, INC.

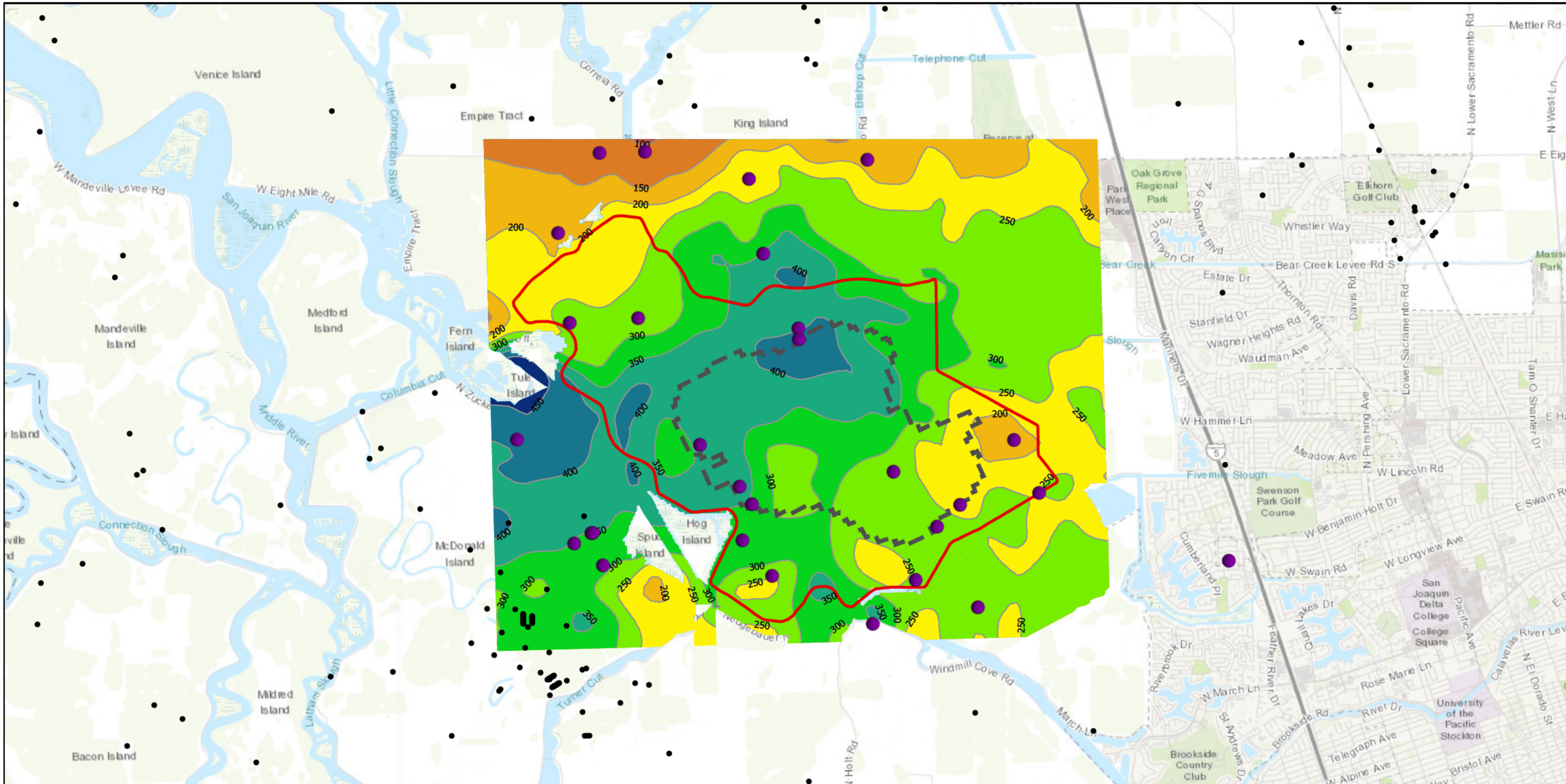
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 5,000 10,000 Feet

N



Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Rindge Tract Island

Thickness, TVDSS*

50' — 450'

50' Contour Intervals

Note:
- Depth grid converted using time-depth relationship from Big Valley Eberhart 1.
- TVDSS* = True Vertical Depth Sub Sea.

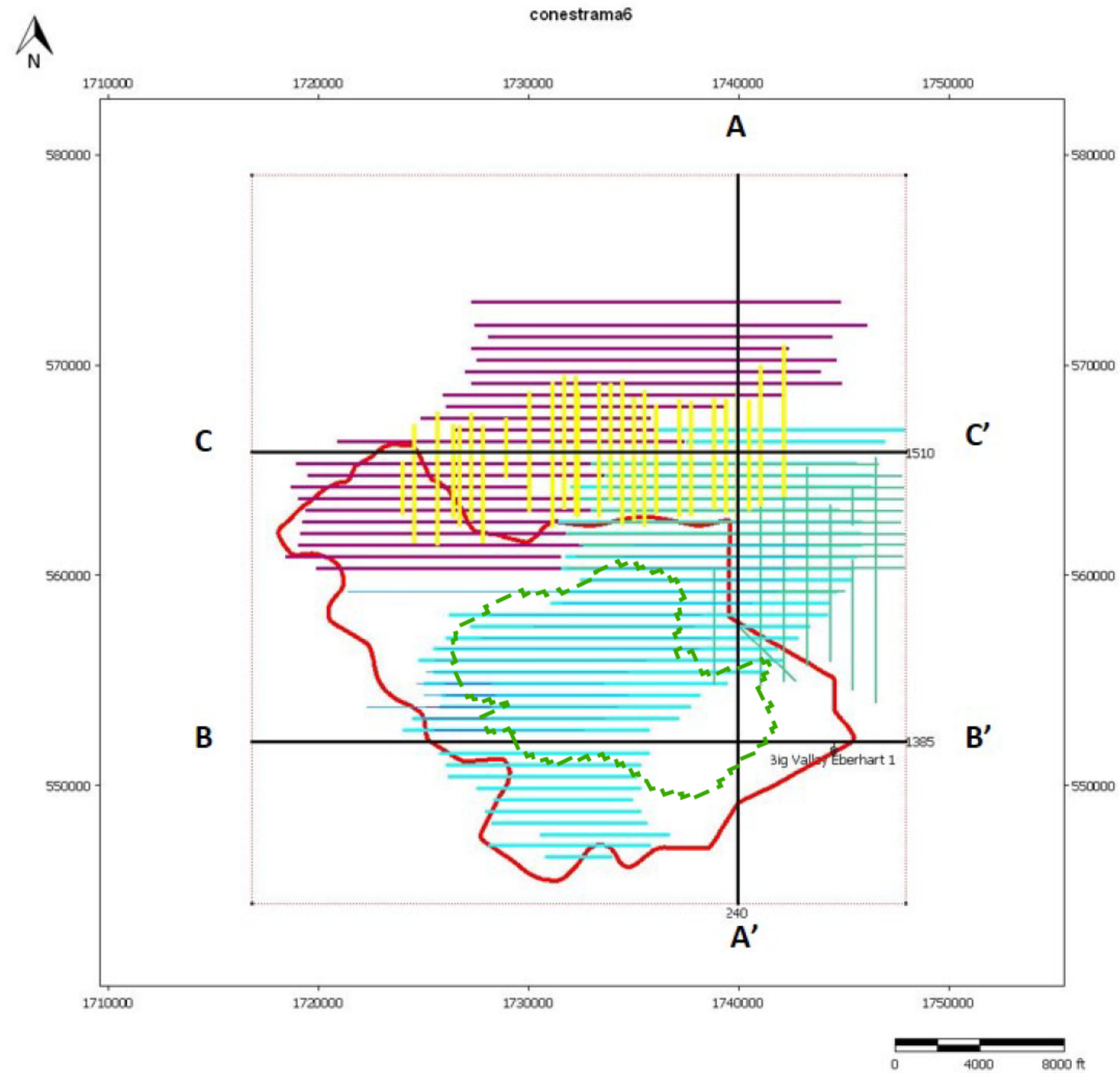
FIGURE 2-20
NORTONVILLE ISOPACH MAP
PELICAN RENEWABLES, INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 5,000 10,000 Feet

N

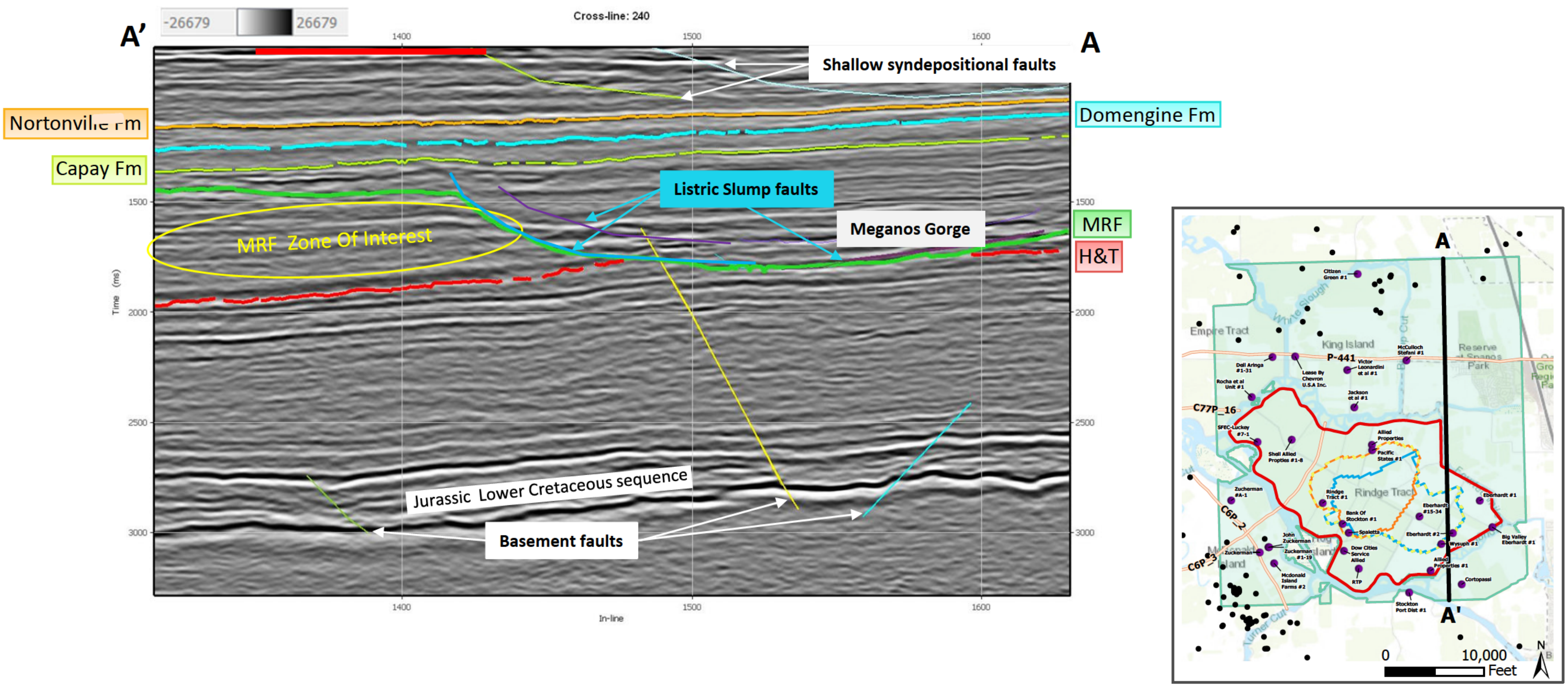


Legend

- Listric faults dipping West
- Listric faults dipping East
- Listric faults dipping North
- Basement fault dipping North
- Delineated Area of Review

FIGURE 2-21
FAULT DISTRIBUTION MAP
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | April 2024



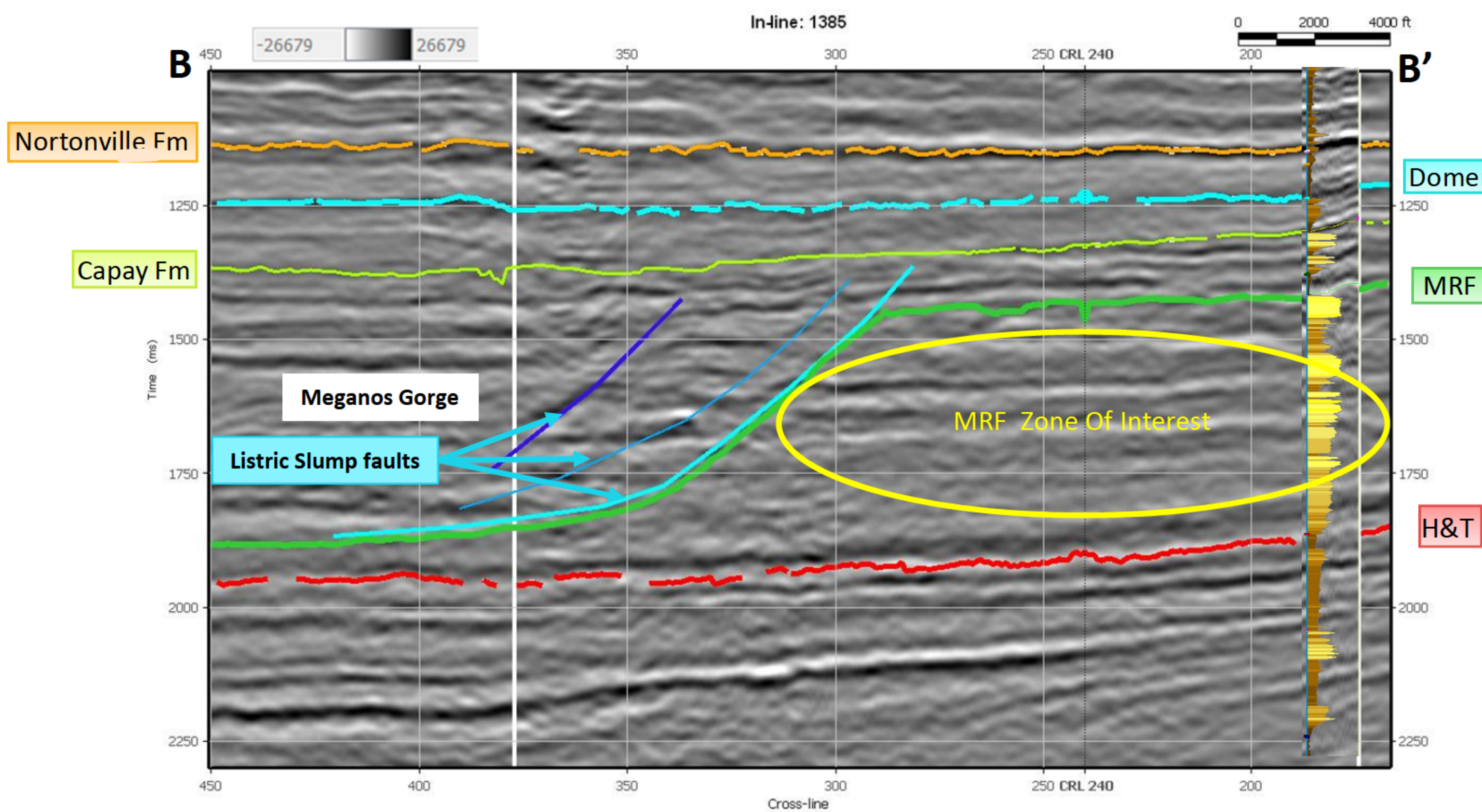
Legend

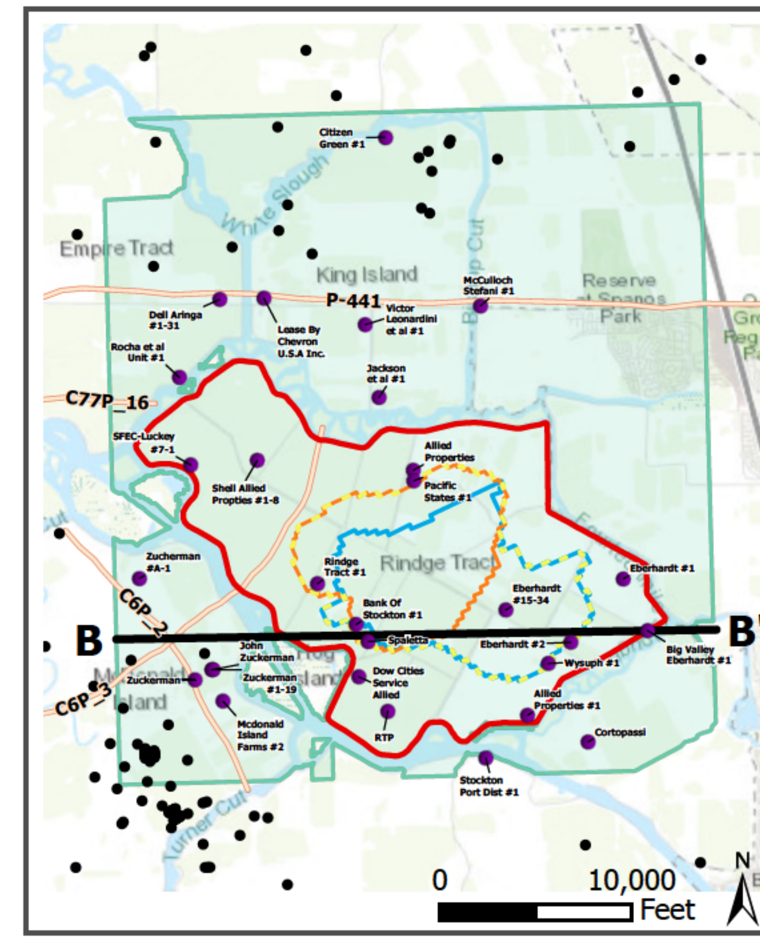
- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Maximum Predicted Extent of Super Critical CO_2
- Pressure Front
- Cross Section A-A'
- Select PacSeis 2D Data
- Conestrama 3D Data
- Rindge Tract Island

FIGURE 2-22
CROSS-SECTION A-A'
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS	April 2024



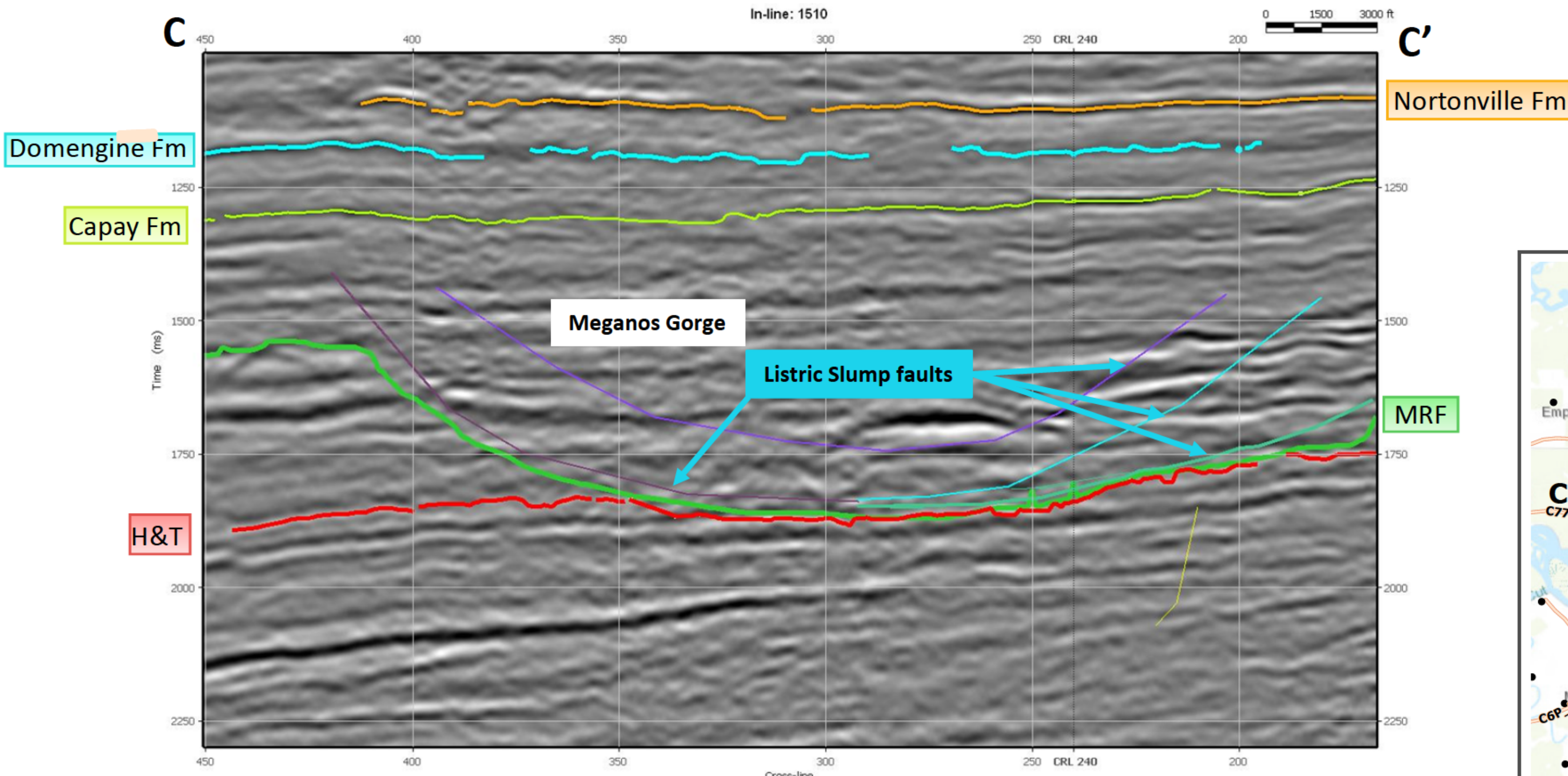


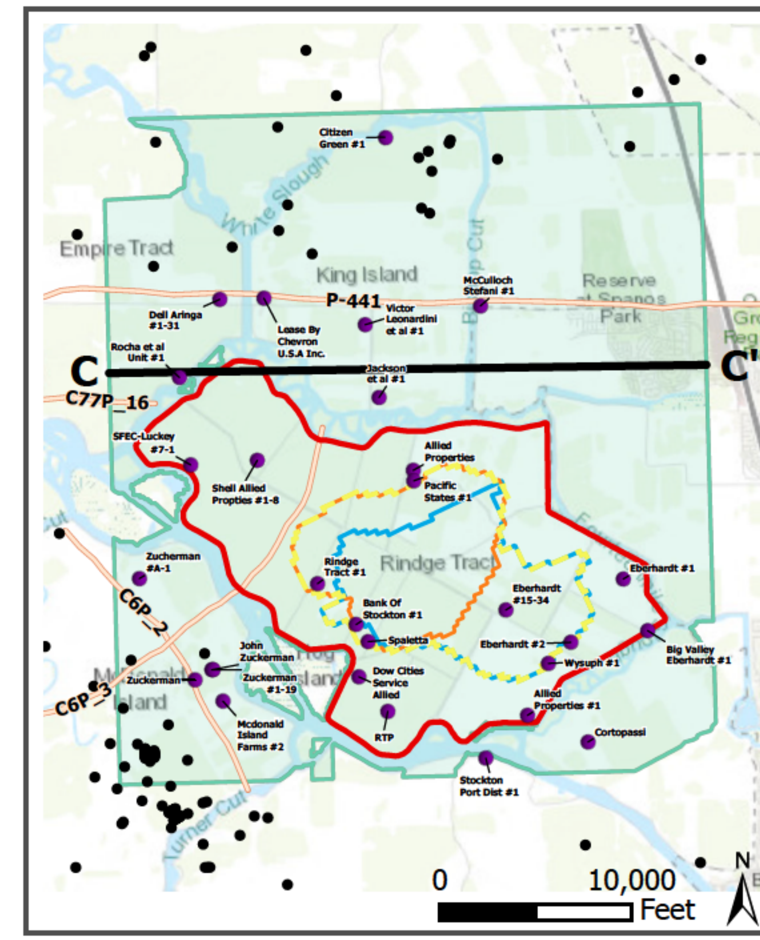
Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Maximum Predicted Extent of Super Critical CO_2
- Pressure Front
- Cross Section B-B'
- Select PacSeis 2D Data
- Conestrama 3D Data
- Rindge Tract Island

FIGURE 2-23
CROSS-SECTION B-B'
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | April 2024





Legend

- Well Control Used in Interpretation
- Oil & Gas Wells
- Delineated Area of Review
- Maximum Predicted Extent of Super Critical CO_2
- Pressure Front
- Cross Section C-C'
- Select PacSeis 2D Data
- Conestrama 3D Data
- Rindge Tract Island

FIGURE 2-24

CROSS-SECTION C-C'

PELICAN RENEWABLES INC.

SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS	April 2024

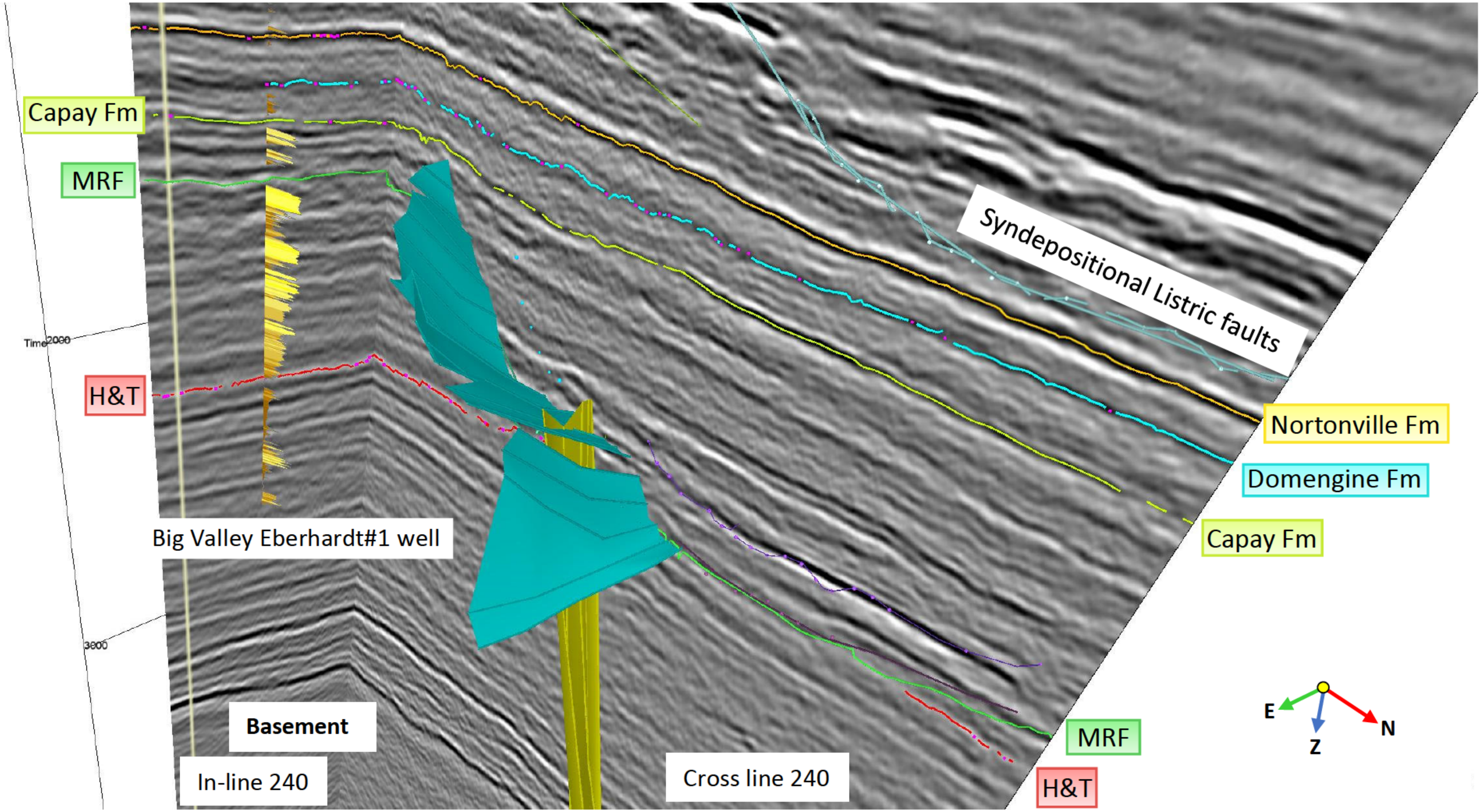


FIGURE 2-25
3-D FAULT VISUALIZATION
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | January 2023

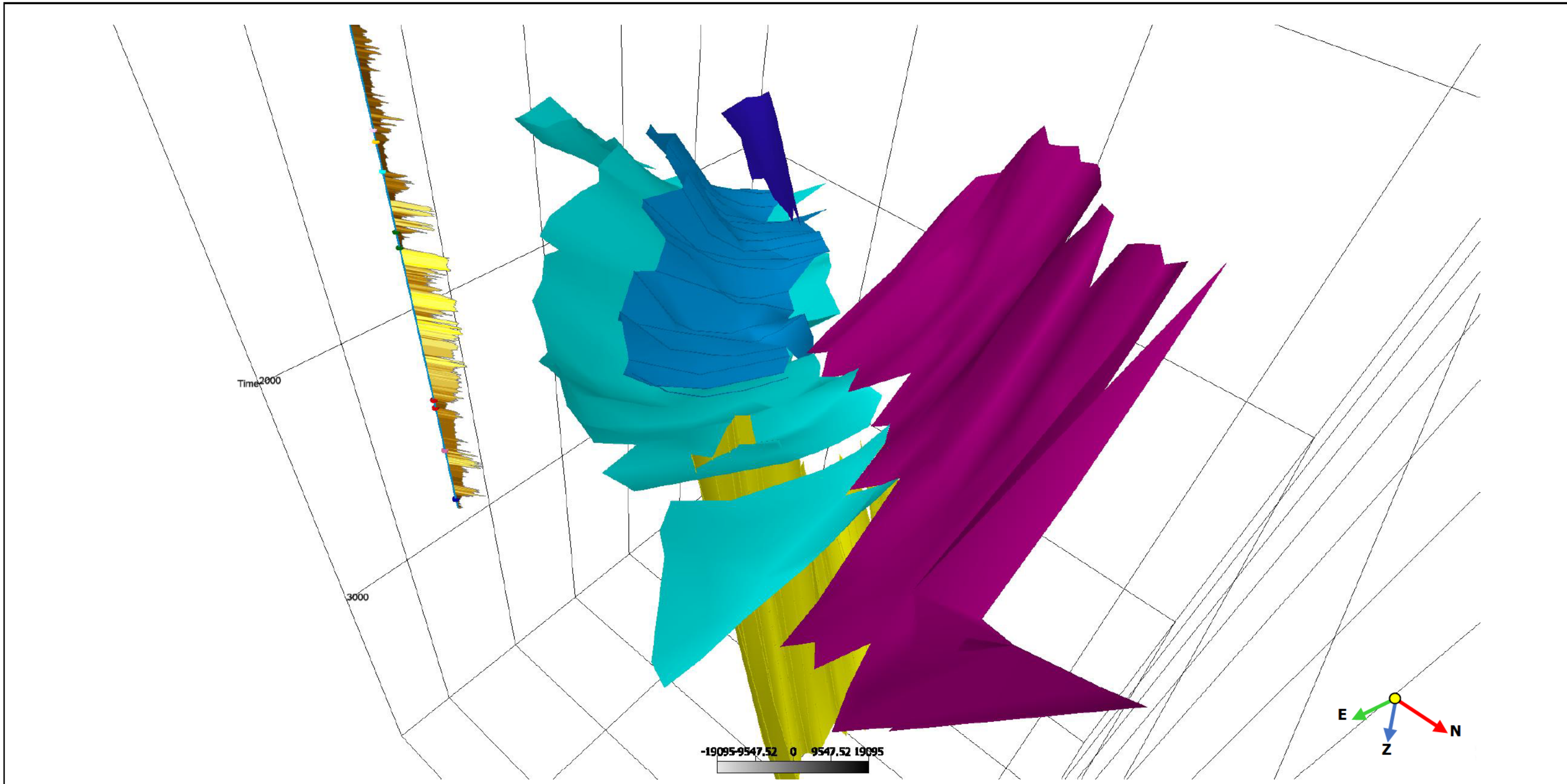


FIGURE 2-26
LISTRIC FAULTS ASSOCIATED WITH
THE GENERATION OF THE MEGANOS GORGE
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS	January 2023

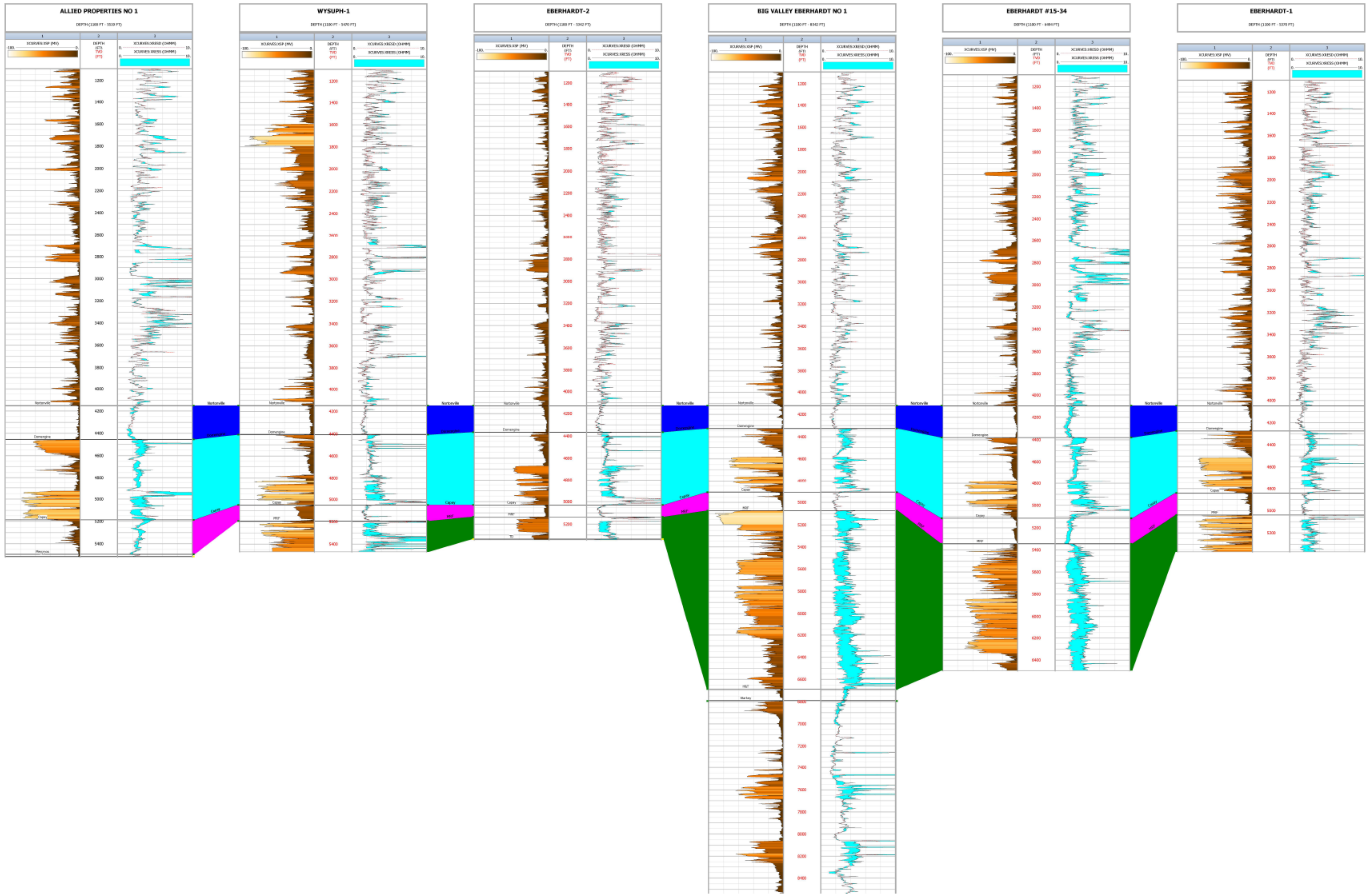
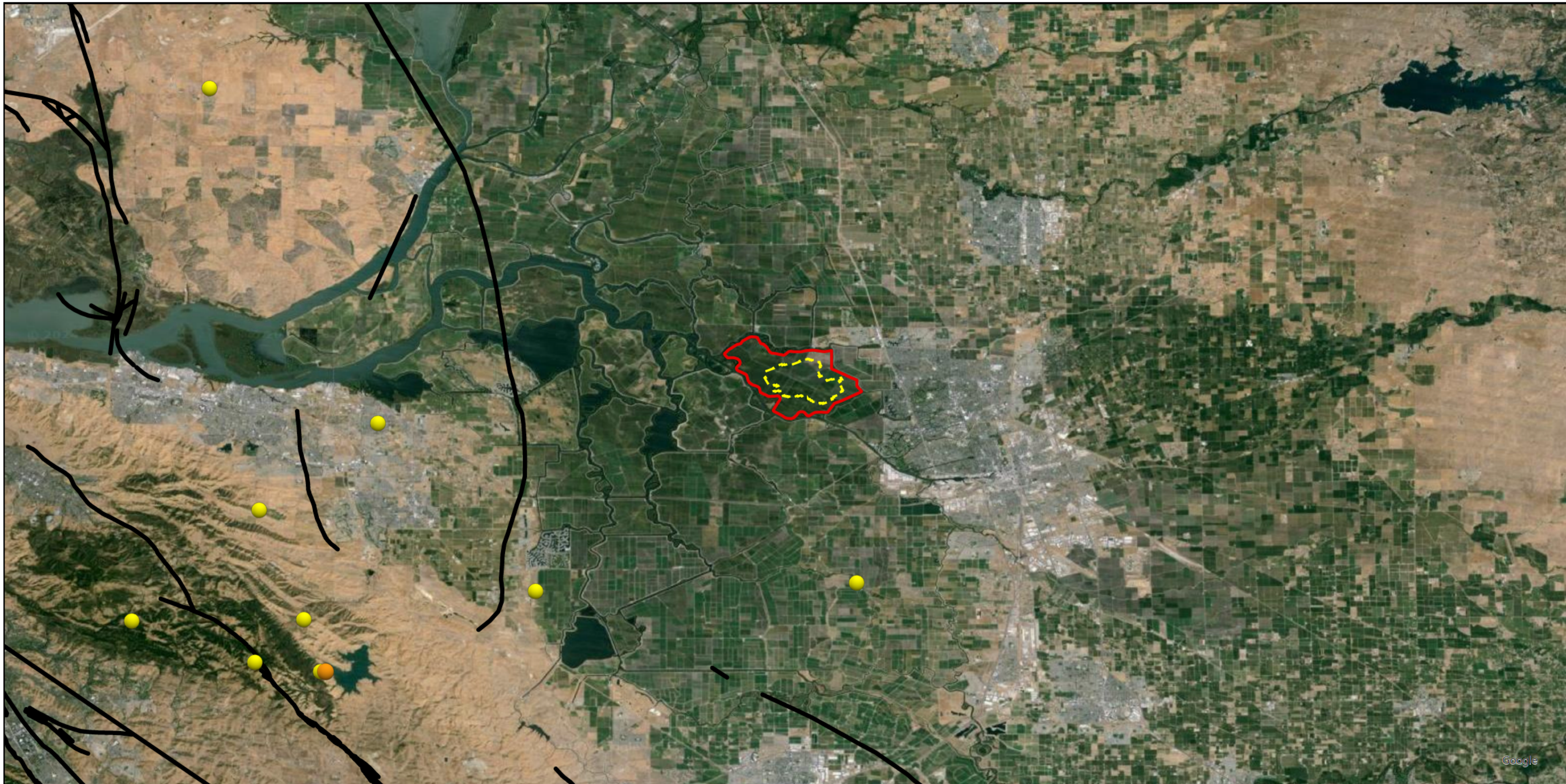


FIGURE 2-27
WELL LOGS FOR RINDGE TRACT ISLAND WELLS
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS	November 2022



Legend

- <4.0 Magnitude
- ≥4.0 Magnitude
- Quaternary Faults
- Delineated Area of Review
- Rindge Tract Island

Sources:
1. Northern California Seismic System, Northern California Earthquake Catalog.
2. United States Geological Survey, Interactive Fault Map.

FIGURE 2-28
QUATERNARY FAULTS AND SEISMICITY NEAR RINDGE TRACT (1967-2020)
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | April 2024

0 25,000 50,000 Feet
N

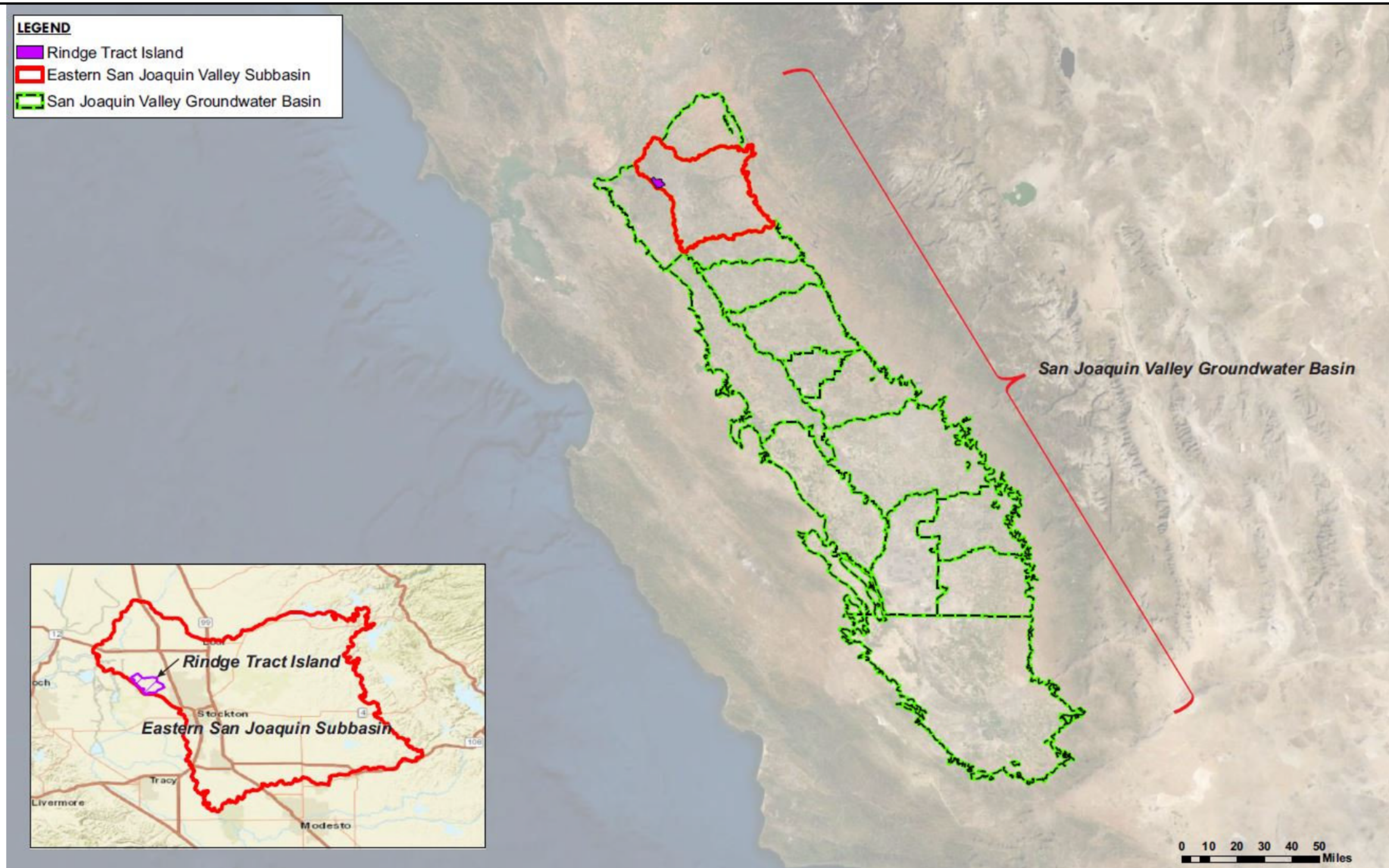


FIGURE 2-29
GROUNDWATER BASIN VICINITY MAP
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS	November 2022

N

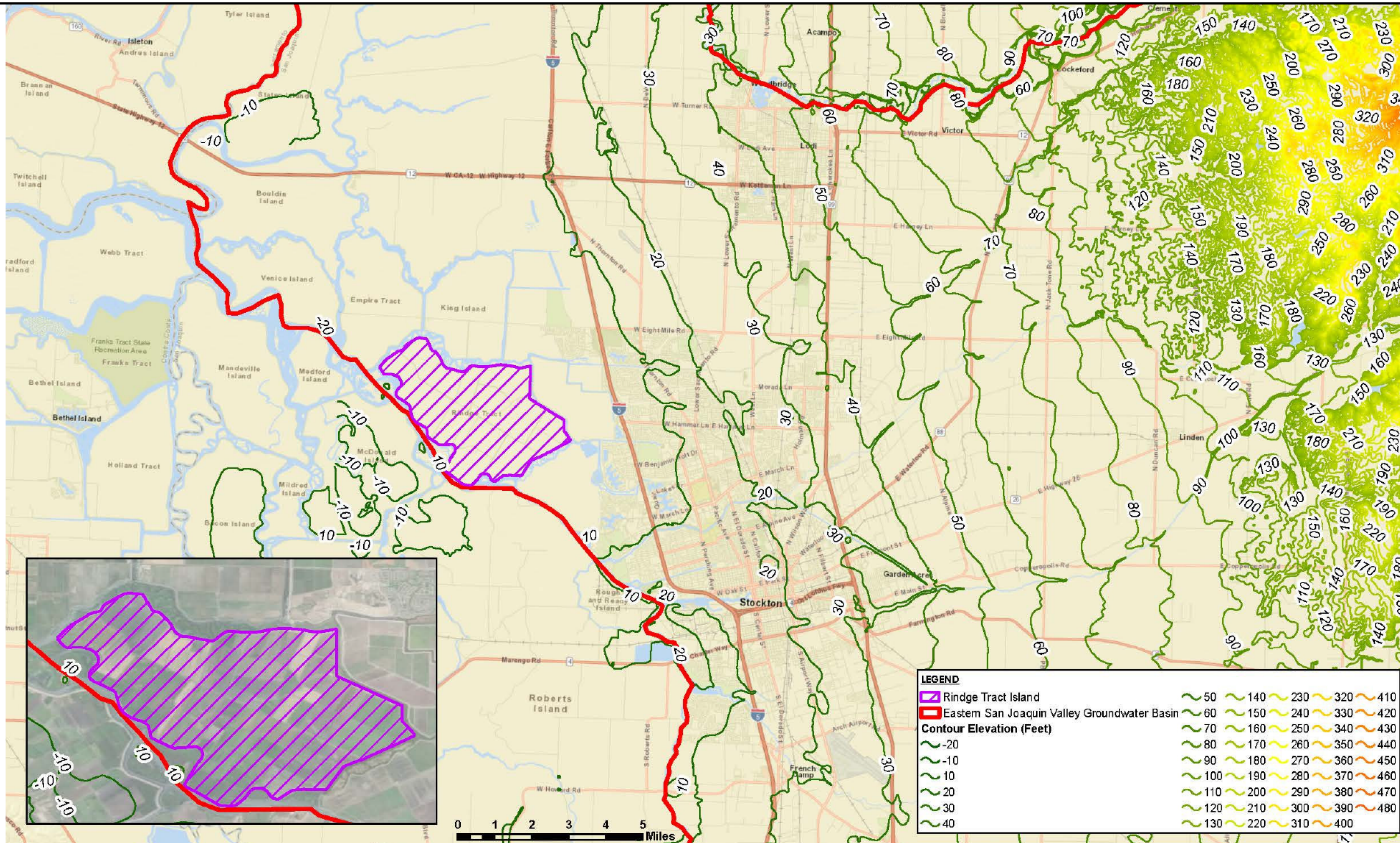
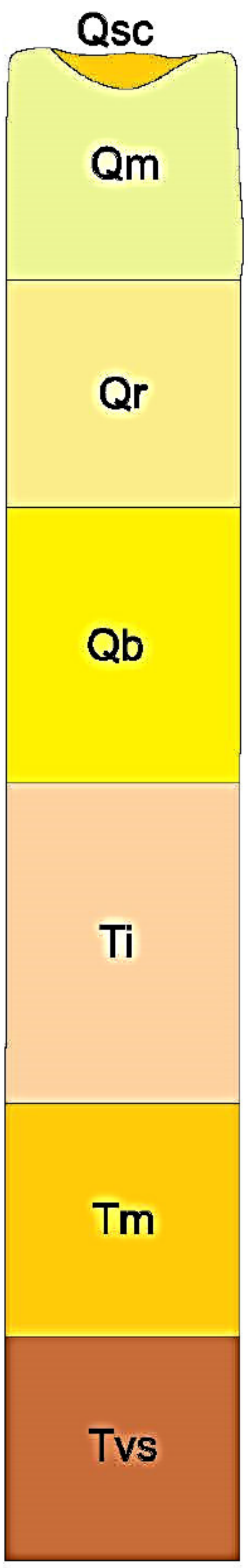


FIGURE 2-30
TOPOGRAPHIC MAP
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS
Wichita, KS | November 2022



Series	Formation	Approximate Thickness	Characteristics	Water-Bearing Properties
Holocene	Stream Channel Deposits	50	Unconsolidated gravel, coarse to medium sand	High permeability, not saturated except by the San Joaquin River.
Late Pliocene	Modesto	65 - 130	Continental fan & interfan deposits; lenticular gravel, sand, silt, and clay.	Mod. permeability, unconfined aquifer.
Pliocene	Riverbank	150 - 250	Continental fan & interfan deposits; lenticular gravel, sand, silt, and clay. Reddish clay-rich duripan caps the unit.	Mod. permeability, unconfined aquifer.
Recent to Plio-Pleistocene	Flood Basin Deposits	0 - 1,000	Continental basinal equivalent of Laguna, Tulare & younger formations. Clay, silt & sand.	Low permeability, unconfined to confined aquifer.
Plio-Pleistocene	Laguna	0 - 1,000	Continental, semi to unconsolidated silt, sand & gravel, poorly sorted.	Mod. permeability, unconfined to semi-confined aquifer.
Mio-Pliocene	Mehrten	0 - 600	Continental andesitic derivatives of silt, sand & gravel & their indurated equivalents; tuff, breccia, agglomerate.	Mod. permeability, to high where "Black Sands" occur. Confined to unconfined. Saline west of Stockton.
Miocene	Valley Springs	0 - 500	Continental rhyolitic ash, clay, sand & gravel and their indurated equivalent.	Low permeability. Saline in Stockton area. Not considered significant in groundwater studies.

FIGURE 2-31

REGIONAL WATER BEARING FORMATIONS
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS | November 2022

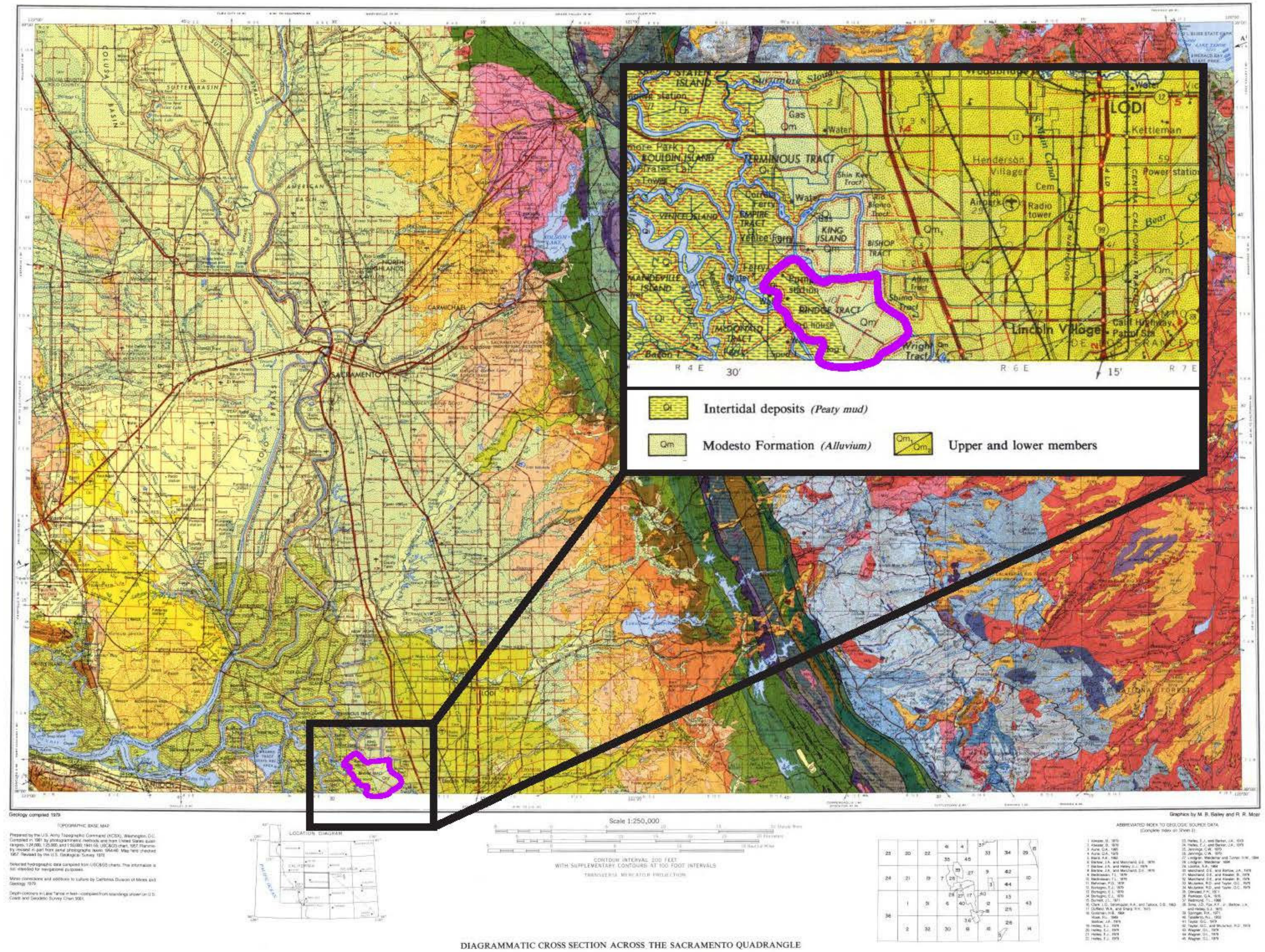


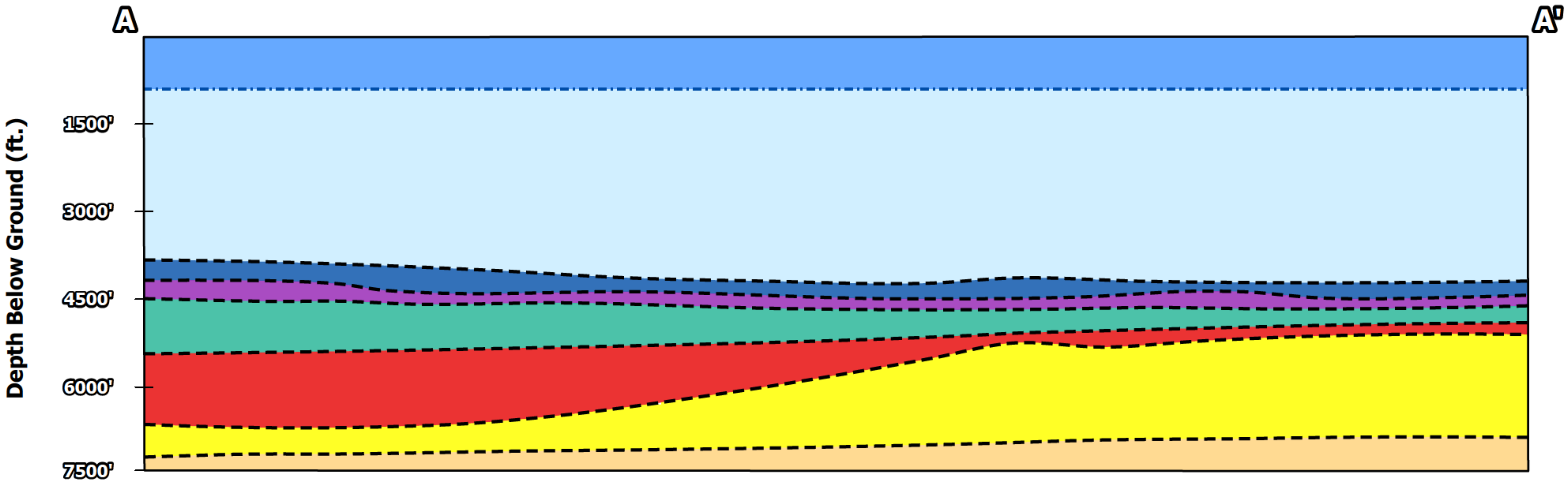
Figure Adapted From:
California Division of Mines and Geology.
Geologic Map of the Sacramento Quadrangle, California.
1981. 1:250,000; Compilation by Wager, D.L., Jennings, C. W., et al.

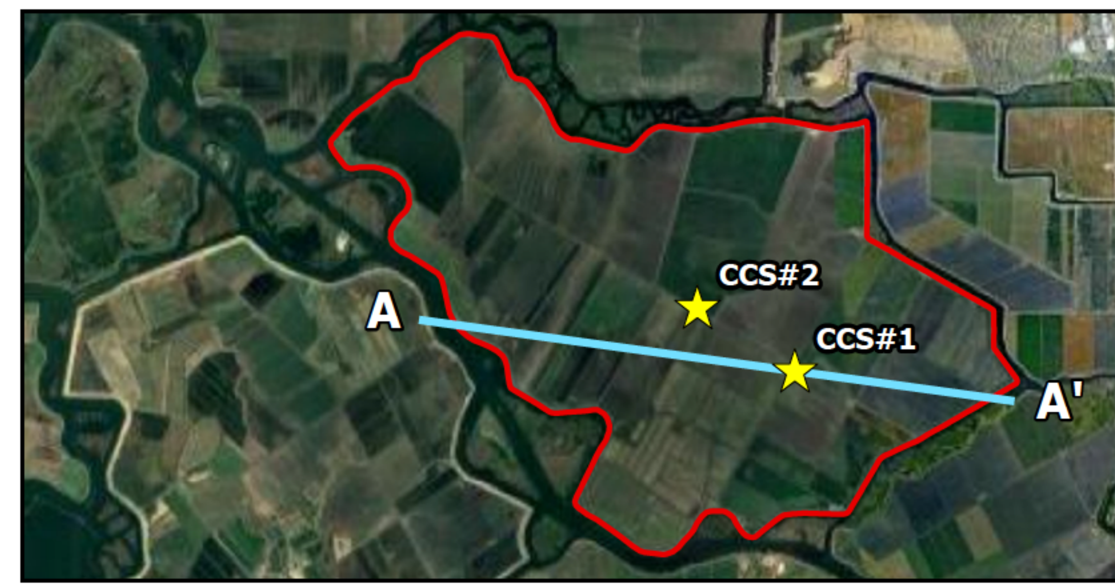
FIGURE 2-32
HOLOCENE GEOLOGIC MAP
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS	November 2022

N





Legend

- Freshwater USDWs
- Eocene - Holocene USDWs
- Markley Fm. (Lowermost USDW)
- Nortonville Shale
- Domingine Fm.
- Capay/Meganos Fms.
- Mokelumne River Fm. (Injection Zone)
- H&T Shale & Deeper Units
- Approximate Base of Freshwater (900 feet)
- Approximate Contacts between Geologic Units

FIGURE 2-33
CROSS SECTION OF USDWS AND CO_2 STORAGE COMPLEX
BENEATH RINDGE TRACT
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | March 2023

0 2,500 5,000 Feet
N

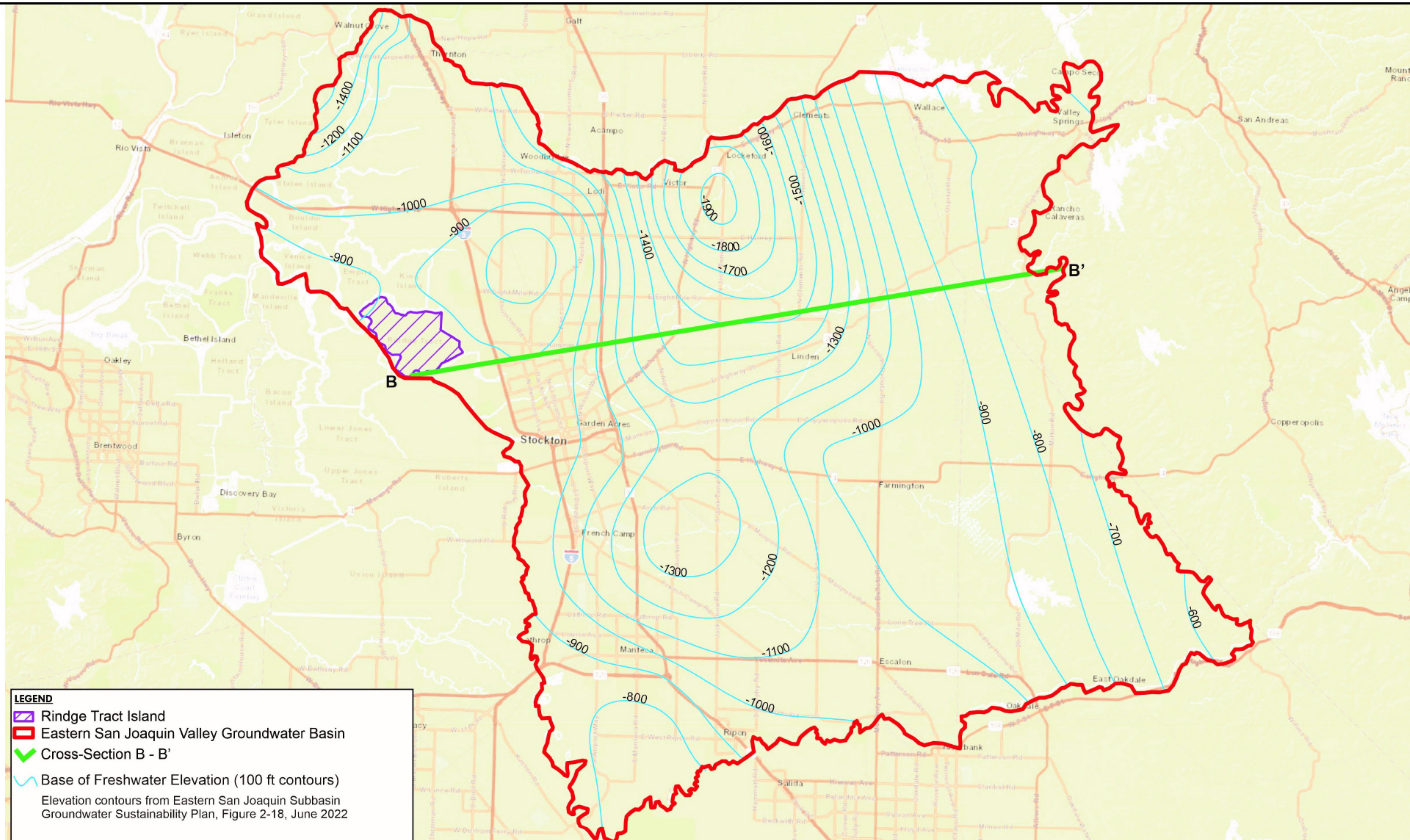


FIGURE 2-34

BASE OF FRESH WATER ELEVATION CONTOURS
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS | November 2022

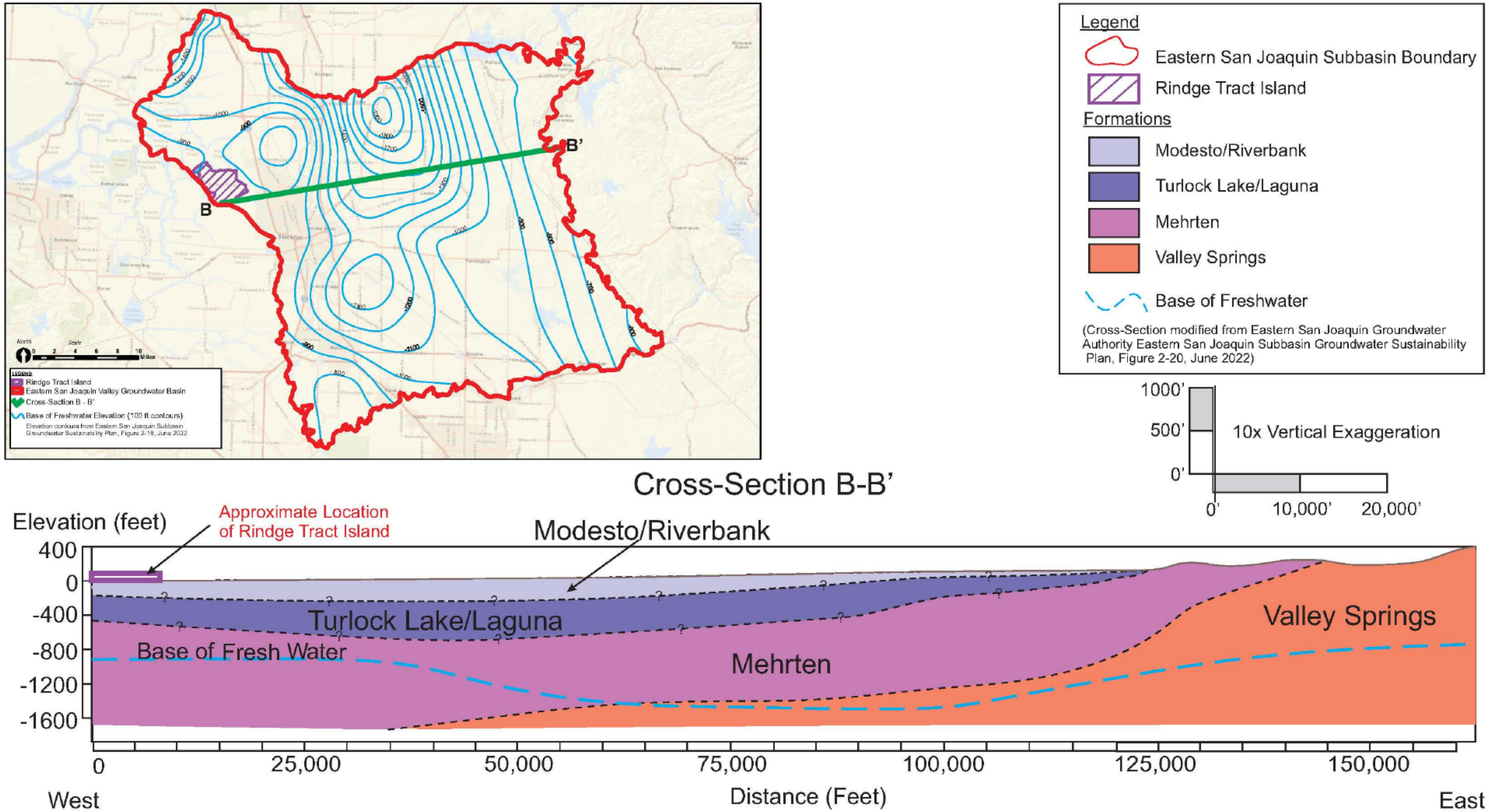
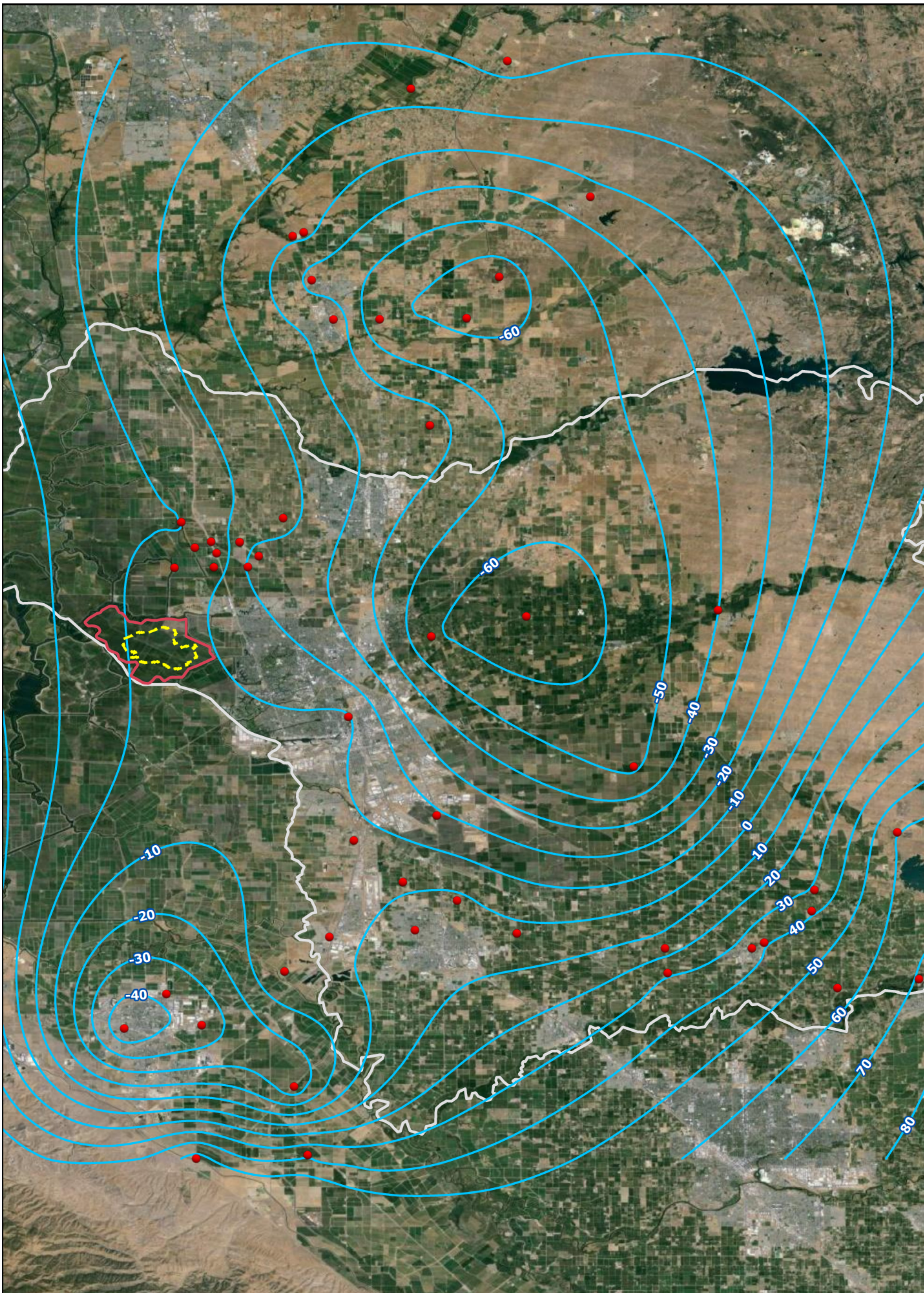


FIGURE 2-35
BASE OF FRESH WATER CROSS SECTION B-B'
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS
Wichita, KS | November 2022



Legend

- Groundwater Well
- May 2022 Groundwater Contours (10')
- Eastern San Joaquin Groundwater Subbasin
- Delineated Area of Review
- Rindge Tract Island

FIGURE 2-36

GROUNDWATER ELEVATION MAP
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 25,000 Feet

N

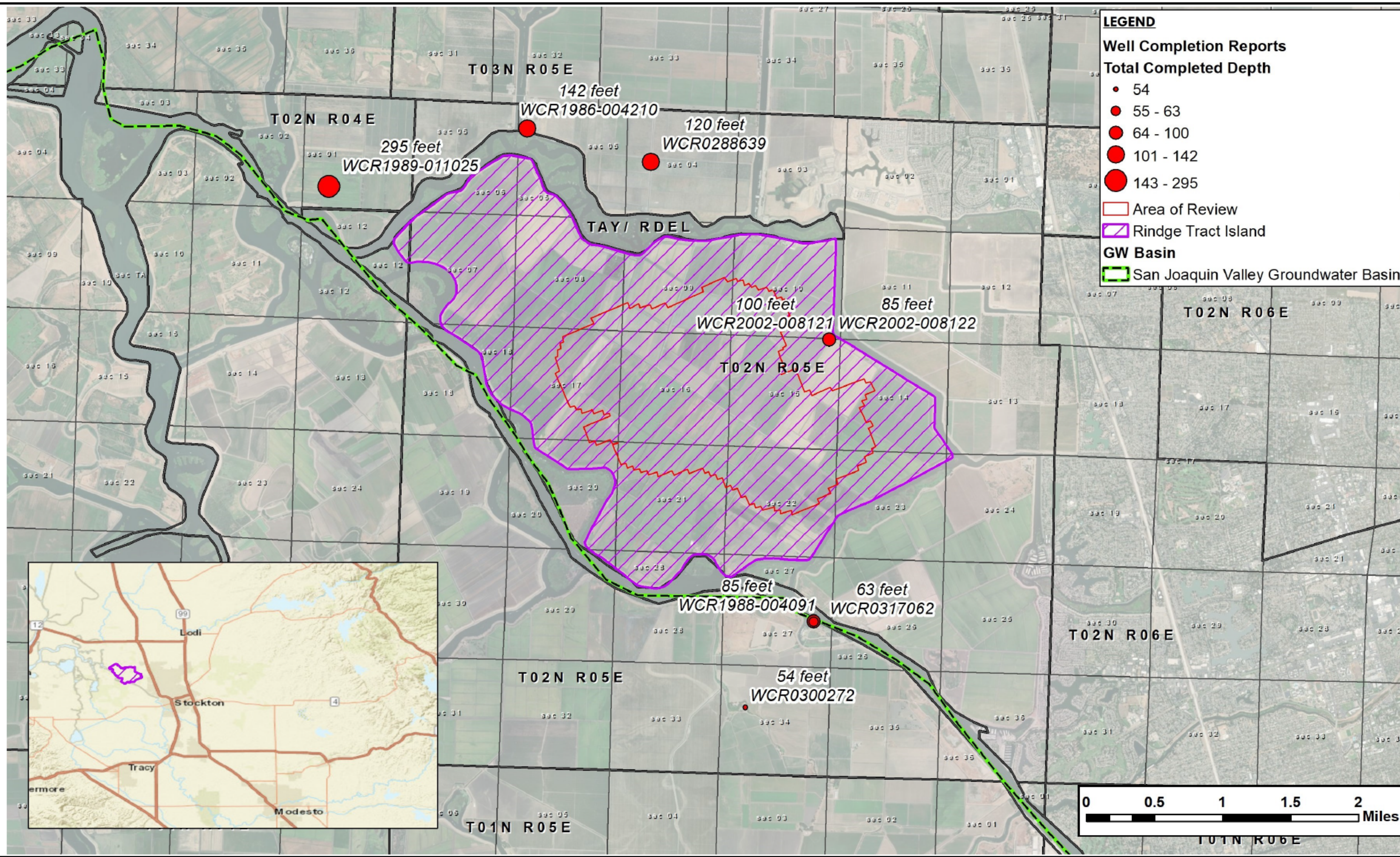
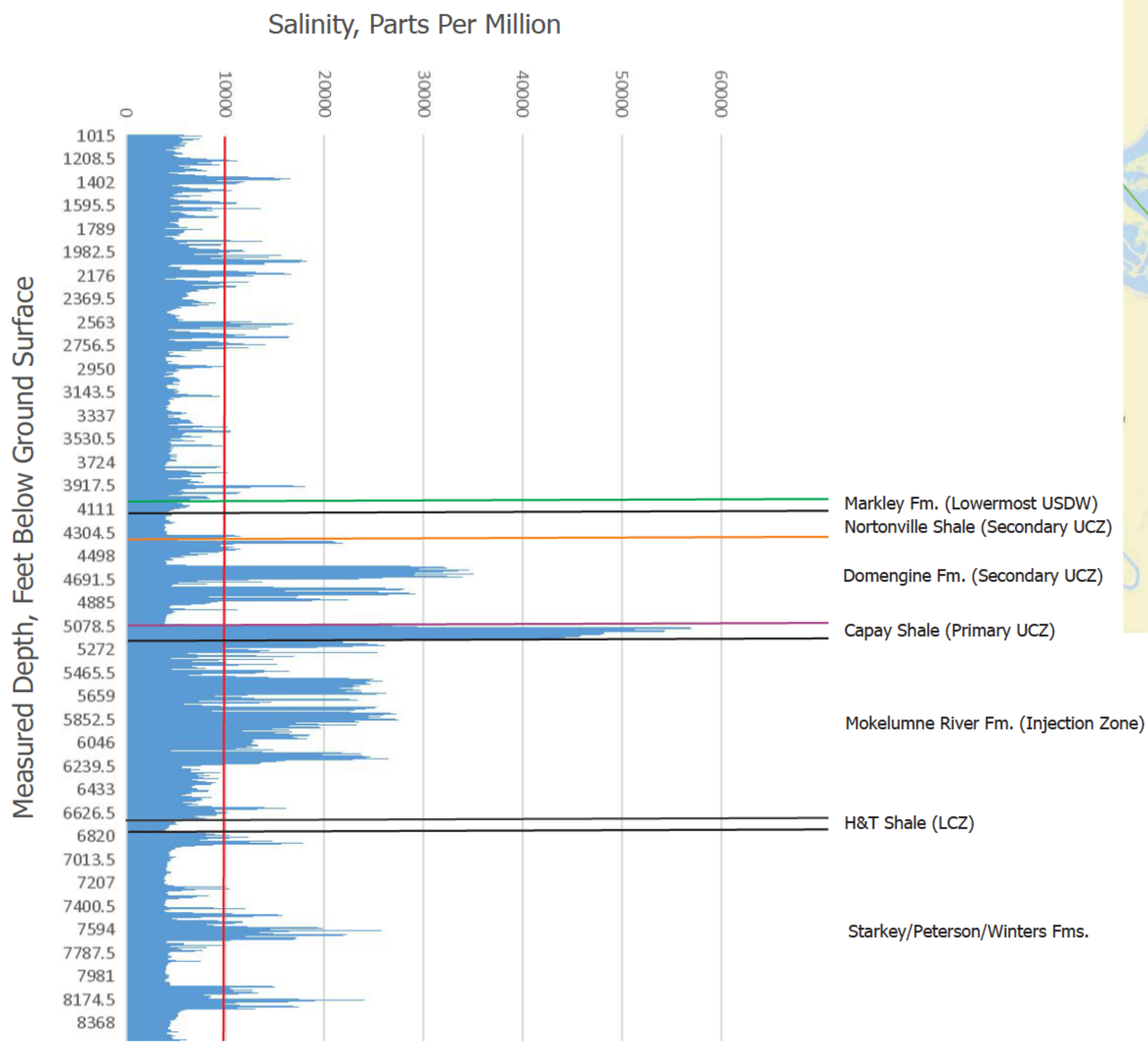


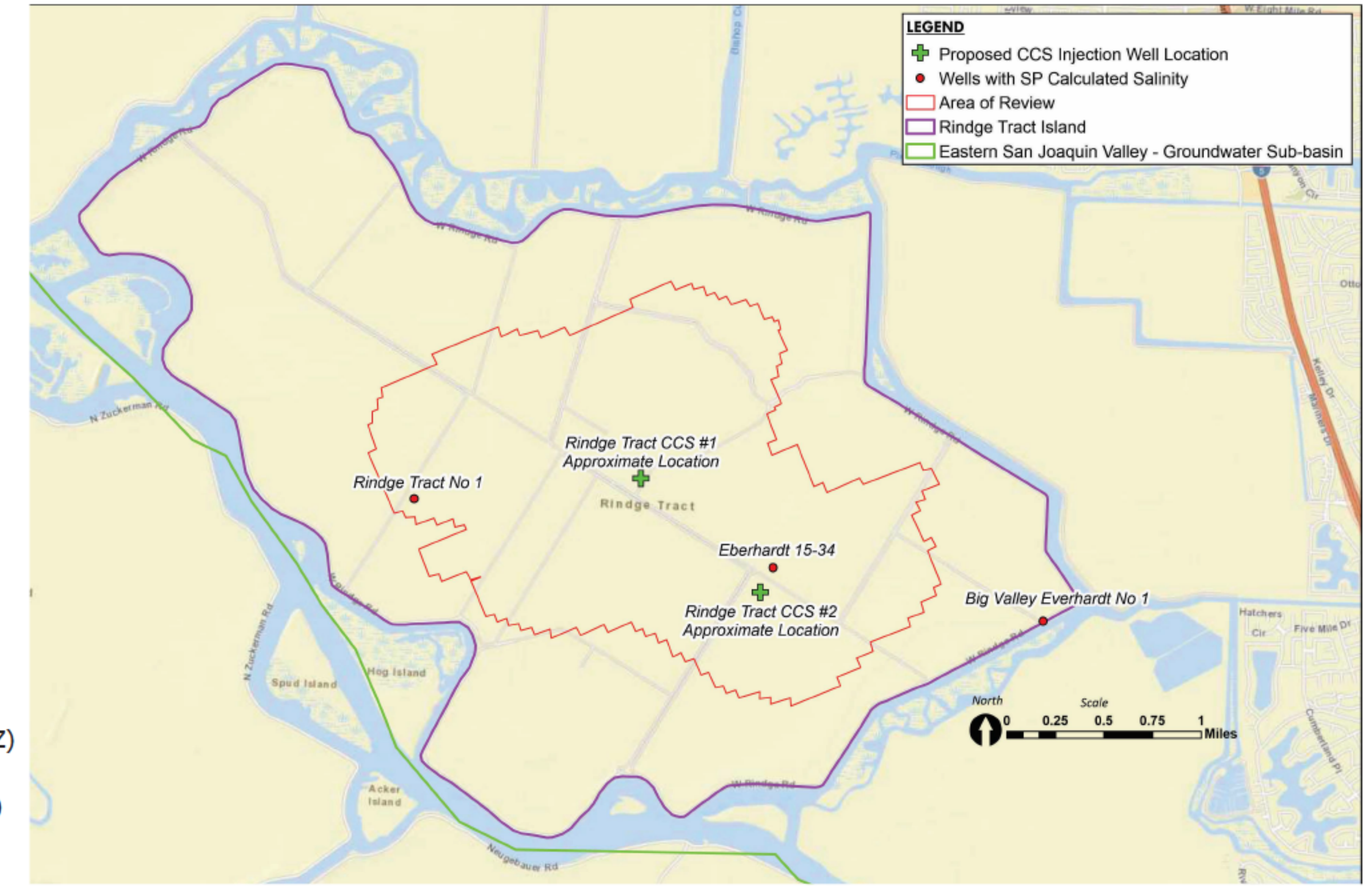
FIGURE 2-37

WATER WELL DEPTH AND LOCATION
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CA

SCS ENGINEERS

Wichita, KS | April 2024





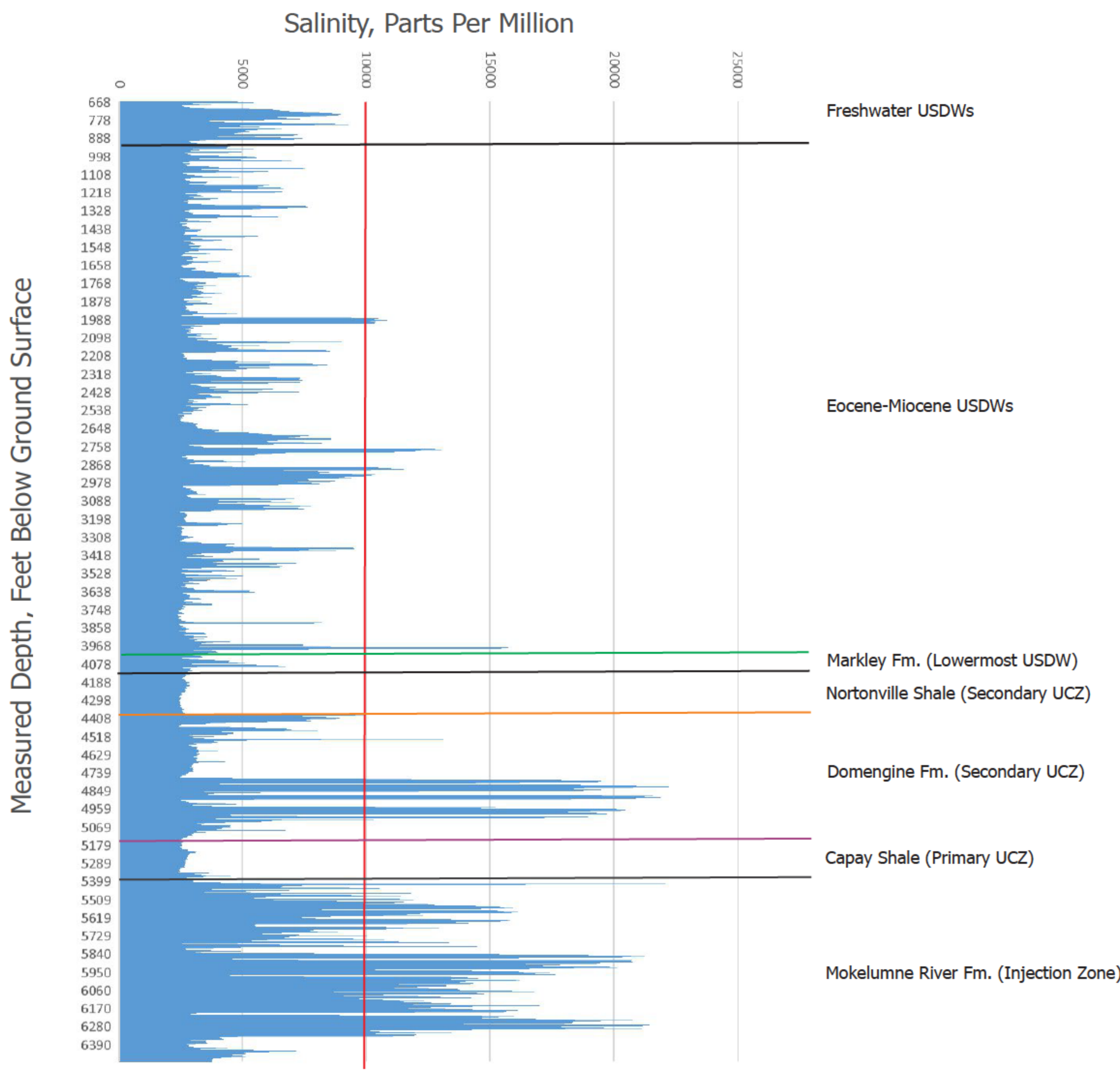
Notes:
- Salinity Calculations Performed by The Rock Data Solutions.
- Logging was not completed above 1015 feet.
- Freshwater is located approximately 900 feet below ground surface.
- USDW = underground source of drinking water
- UCZ = upper confining zone
- LCZ = lower confining zone

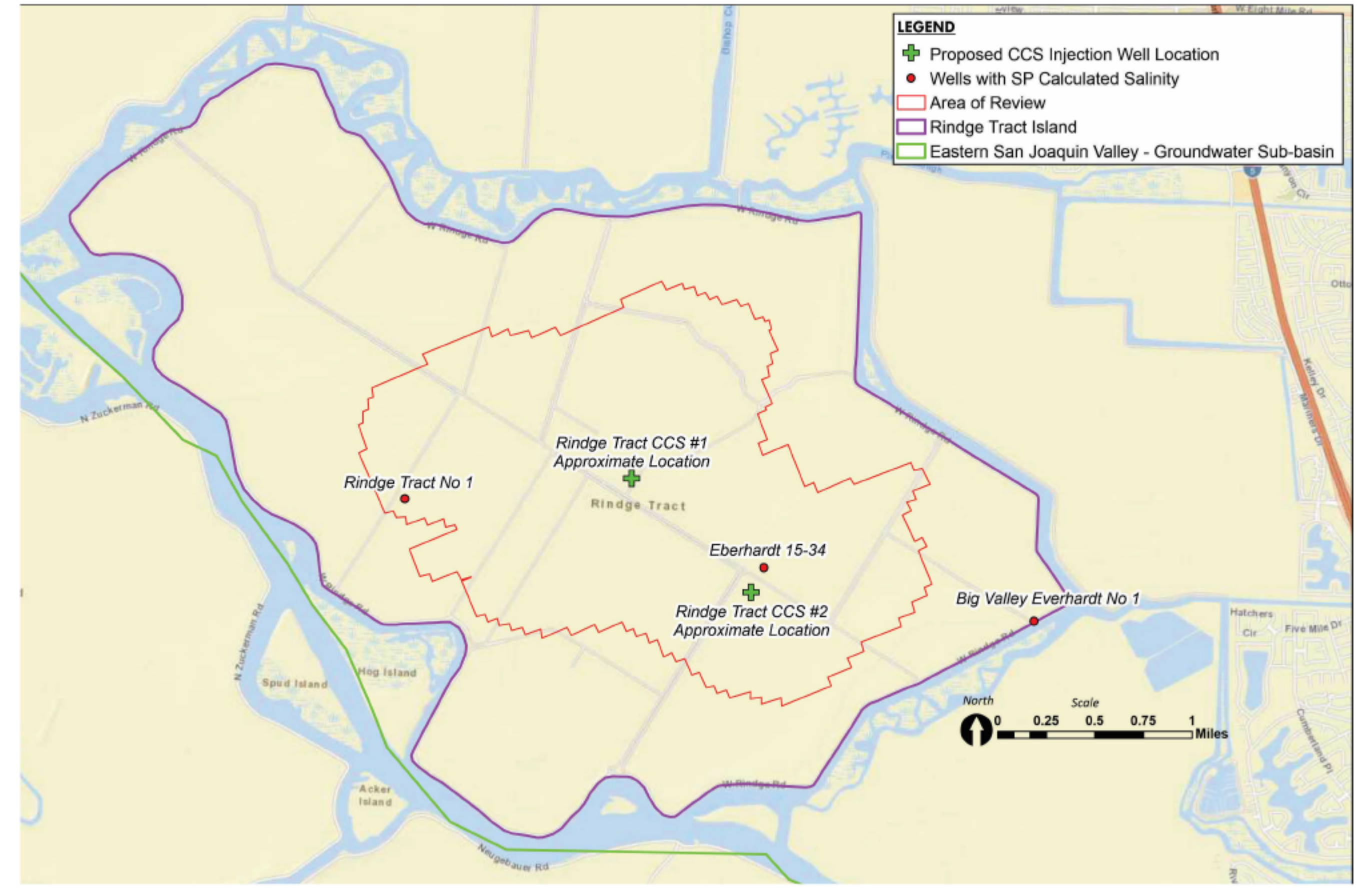
FIGURE 2-38A

CALCULATED SALINITY AND A FUNCTION OF DEPTH –
BIG VALLEY EBERHART No 1
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | March 2023



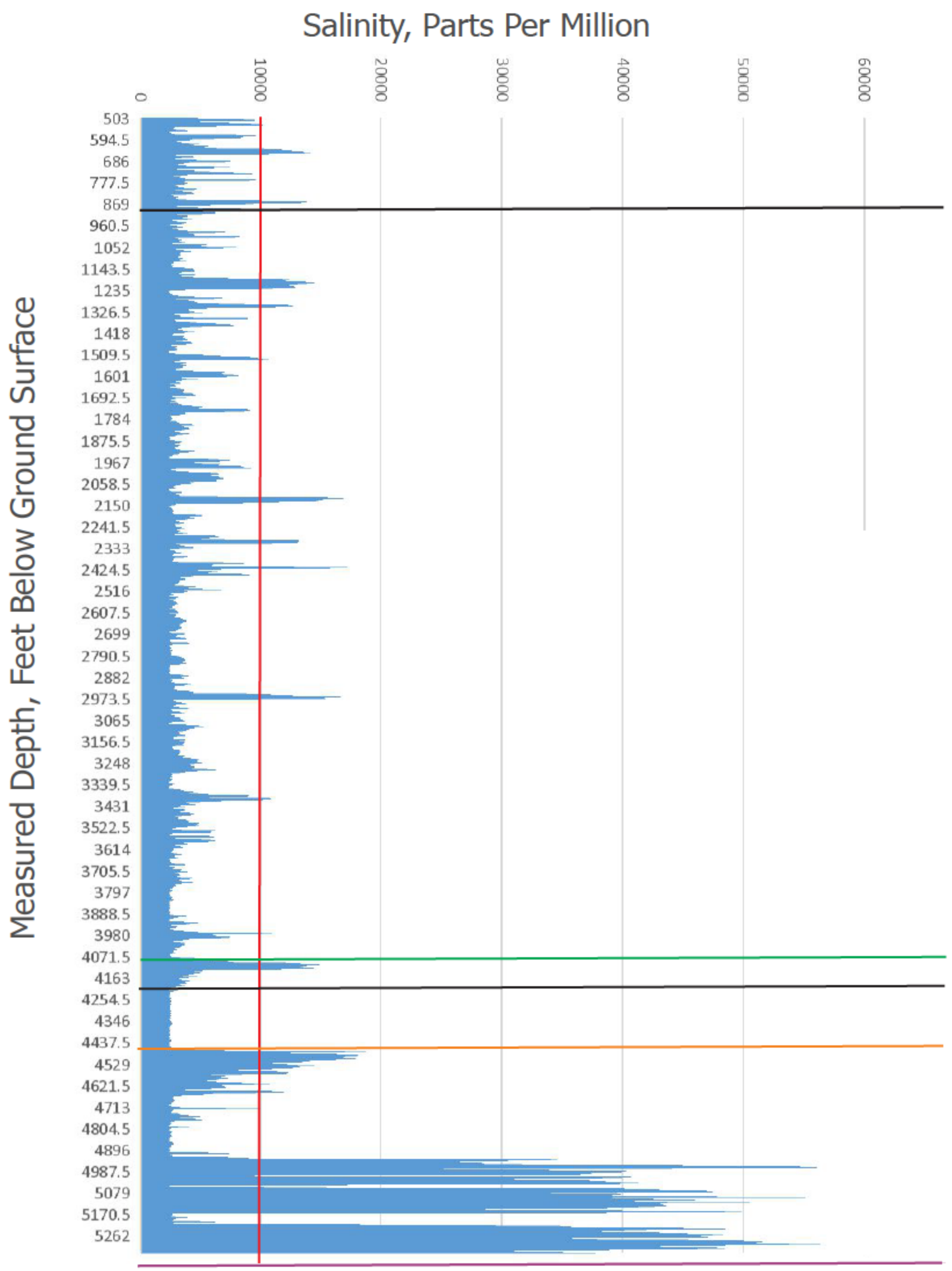


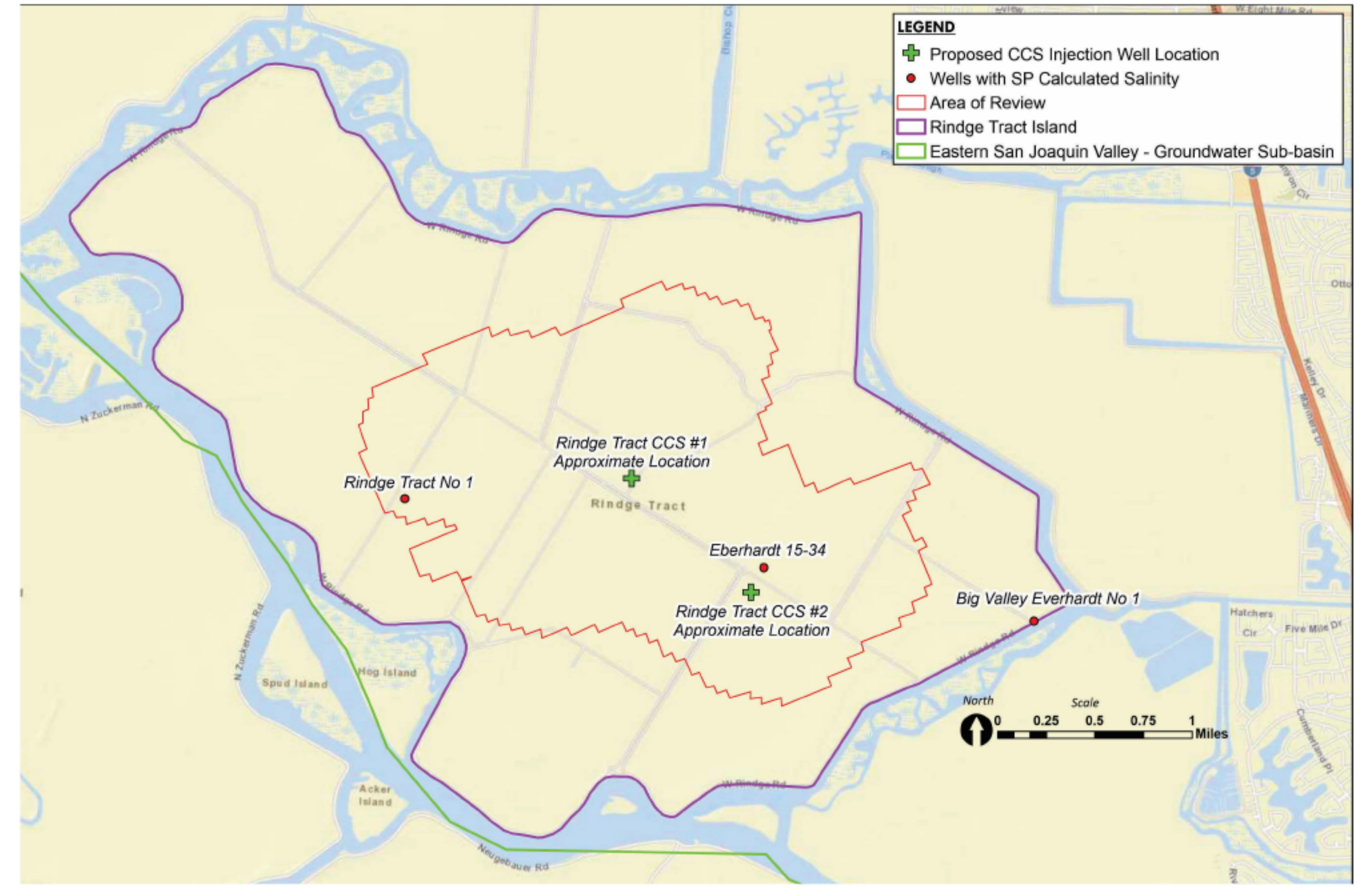
Notes:
- Salinity Calculations Performed by The Rock Data Solutions.
- USDW = underground source of drinking water
- UCZ = upper confining zone
- LCZ = lower confining zone

FIGURE 2-38B
CALCULATED SALINITY AND A FUNCTION OF DEPTH – EBERHART 15-34
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS	March 2023





Notes:
- Salinity Calculations Performed by The Rock Data Solutions.
- USDW = underground source of drinking water
- UCZ = upper confining zone
- LCZ = lower confining zone

FIGURE 2-38C

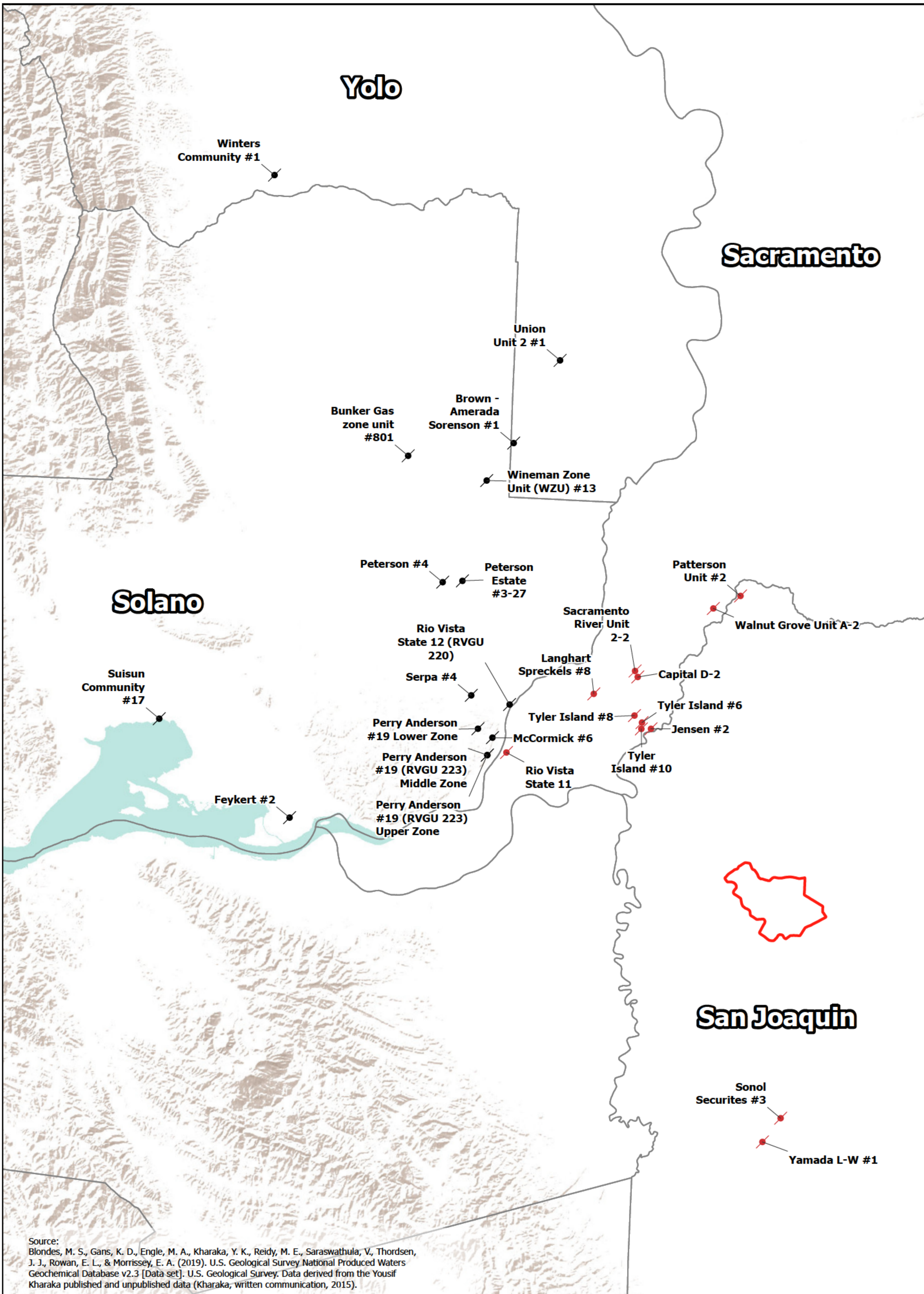
CALCULATED SALINITY AND A FUNCTION OF DEPTH – RINDGE TRACT No 1

PELICAN RENEWABLES INC.

SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS	March 2023



Legend

- Wells with Produced Water Data Utilized for Geochemical Modeling
- Wells with Produced Water Data Not Utilized for Geochemical Modeling
- County Boundaries
- Rindge Tract Island

FIGURE 2-29
DISTRIBUTION OF AVAILABLE GEOCHEMICAL DATA FOR PRODUCED WATERS IN THE VICINITY OF THE PROJECT
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | April 2024

0 25,000 Feet

N

Attachment 1

Redacted; claimed as PBI

Attachment 2

PROJECT WORKFLOW

Initial Data Provided

All data were provided by SCS Engineers through a secure online Microsoft Teams account. Data included:

- LAS Files (30 wells)
- Well history data including TIF images of accessible well logs from CalGem website (38 wells)
- Well tops spreadsheet
- Geochemistry data of nearby wells (not Project wells) by formation
- Deviation surveys of directionally drilled wells
- Available core data
    - Citizen Green 1
        - Mercury Injection Capillary Pressure (MICP)
        - Rotary Side Wall Porosity, Perm (K), Saturation measurements (PKS)
        - X-Ray Diffraction (XRD)

Wells Provided

There were a total of thirty wells provided for this project (**Table WF-1**). Of those wells, eleven contained full suites of logs including resistivity, Spontaneous Potential (SP), Gamma Ray (GR), density/neutron and in some cases (*) Sonic Delta-T (DT) (**Table WF-2**). There were nine wells that contained resistivity, SP, and DT only (**Table WF-3**). The remaining wells contained only resistivity and SP data.

Table WF-1 - Pelican Renewables Project (30 wells)

API #	Well Name	Surf Lat	Surf Long
04077000970000	MCDONALD ISLAND FARMS 2	38.00269699	-121.4648361
04077000990000	MCDONALD ISLAND 1	38.00875854	-121.4813309
04077004670000	VICTOR LEONARDI ET AL 1	38.05619049	-121.437973
04077004680000	SHELL ALLIED PROPERTIES 1-8	38.03705215	-121.4579163
04077004690000	ALLIED PROPERTIES NO 1	38.03525543	-121.4297104
04077004700000	PACIFIC STATES NO 1	38.033741	-121.4296722
04077004710000	RINDGE TRACT NO 1	38.01926422	-121.4473877
04077004750000	CORTOPASSI 1	37.99596786	-121.3989334
04077004760000	ALLIED PROPERTIES NO 1 SEC 22	37.99993134	-121.4098129
04077005160000	MCCULLOCH STEFANI NO 1	38.05858994	-121.4170532
04077202620000	DOW CITIES SERVICE ALLIED	38.00585175	-121.4401932
04077203160000	ZUCHERMAN NO A-1	38.02040863	-121.479599
04077203210000	STOCKTON PORT DIST NO 1	37.99391174	-121.4174805

04077203350000	ROCHA ET AL UNIT NO 1	38.04909897	-121.4717636
04077203510000	BIG VALLEY EBERHARDT NO 1	38.0117569	-121.3878098
04077203560000	LEASE BY CHEVRON U.S.A. INC 1	38.06022263	-121.4562225
04077204740000	SPALETTA 1	38.01086044	-121.4384079
04077204760000	ZUCKERMAN 1-19	38.00722885	-121.4665222
04077204860000	DELL ARINGA 1-31	38.06016159	-121.4642258
04077204980000	EBERHARDT 15-34	38.01506042	-121.4133911
04077205220000	SFEC LUCKEY 7-1	38.03656006	-121.4699783
04077205750000	ZUCKERMAN 1 ST1	38.01919174	-121.392067
04077206260000	EBERHARDT 1	38.01919174	-121.392067
04077206270000	BANK OF STOCKTON	38.01334763	-121.4405289
04077206280000	WYSUPH 1	38.00730515	-121.4058838
04077206300000	JACKSON ET AL 1	38.04909897	-121.4665222
04077206450000	EBERHARDT 2	38.01028442	-121.4017487
04077206770000	JOHN ZUCKERMAN 1	38.00720978	-121.466774
04077206880000	CITIZEN GREEN 1	38.08288574	-121.4337082
04077207250000	RTP 1-21	38.00082779	-121.4350662

Table WF-2 - Wells with full suite of logs (*) includes sonic

API #	Well Name	Surf Lat	Surf Long
04077202620000	DOW CITIES SERVICE ALLIED	38.00585175	-121.4401932
04077203160000	***ZUCHERMAN NO A-1****	38.02040863	-121.479599
04077203350000	***ROCHA ET AL UNIT NO 1****	38.04909897	-121.4717636
04077203560000	***LEASE BY CHEVRON U.S.A. INC 1****	38.06022263	-121.4562225
04077204860000	***DELL ARINGA 1-31****	38.06016159	-121.4642258
04077206260000	EBERHARDT 1	38.01919174	-121.392067
04077206270000	BANK OF STOCKTON	38.01334763	-121.4405289
04077206280000	WYSUPH 1	38.00730515	-121.4058838
04077206300000	JACKSON ET AL 1	38.04909897	-121.4665222
04077206450000	EBERHARDT 2	38.01028442	-121.4017487
04077206880000	***CITIZEN GREEN 1****	38.08288574	-121.4337082

Table WF-3 - Wells with resistivity and sonic only

API #	Well Name	Surf Lat	Surf Long
04077004680000	SHELL ALLIED PROPERTIES 1-8	38.03705215	-121.4579163
04077203510000	BIG VALLEY EBERHARDT NO 1	38.0117569	-121.3878098
04077204740000	SPALETTA 1	38.01086044	-121.4384079
04077204760000	ZUCKERMAN 1-19	38.00722885	-121.4665222
04077204980000	EBERHARDT 15-34	38.01506042	-121.4133911
04077205220000	SFEC LUCKEY 7-1	38.03656006	-121.4699783
04077205750000	ZUCKERMAN 1 ST1	38.01919174	-121.392067
04077206770000	JOHN ZUCKERMAN 1	38.00720978	-121.466774
04077207250000	RTP 1-21	38.00082779	-121.4350662

QC Data Provided

All digital well log data were loaded into Interactive Petrophysics (IP) software where the 30 wells were initialized, and raw data were loaded to a common data set. All data were displayed and subjected to quality review to identify adverse logging conditions such as significant wellbore washouts that may affect the readings of some logging tools. Generally, wells with caliper did not appear to have significant washouts and the data from wells with washouts were not seriously compromised.

Two wells required some digitization. Key well, Citizen Green 1, only had the sonic data available when data were transferred to the Microsoft Team site. A full triple combo file was located but the TIF image contained page breaks. However, once the file was loaded to the digitization software, Neuralog, the page breaks were removed, and the log curves were successfully digitized. One additional well, MacDonald Island 1, required log digitization for SP and Deep and Shallow Resistivities.

Header Information

All thirty well headers were entered into the IP header files. Vital mud information including mud resistivity (Rm), mud filtrate resistivity (Rmf) and mud cake resistivity (Rmc) plus the respective measured temperatures was used to calculate salinities and saturation parameters. The bottom hole temperature was used to create a continuous temperature curve from total depth (TD) to surface and the resulting temperature curve was used for salinity calculations and saturation parameters. Finally, surface Latitude and Longitude values were carefully entered to accurately define surface locations of offset wells (**Figure WF-1**).

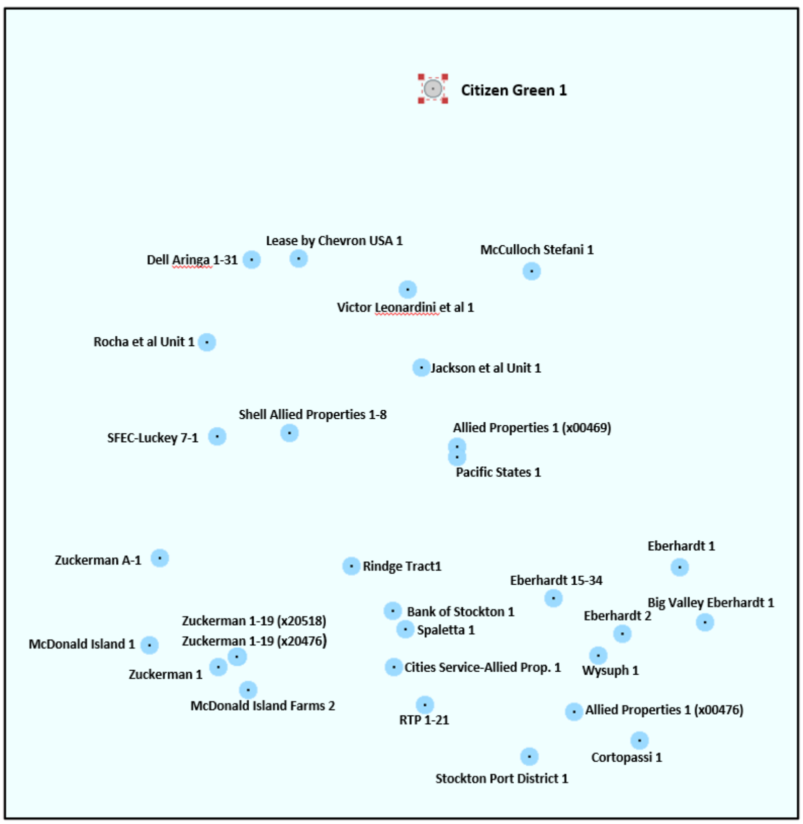


Figure WF-1. **-** *Areal well distribution of Pelican Renewables Project.*

Deviation Surveys

Deviation surveys were loaded to IP followed by calculations for True Vertical Depth (TVD below datum) and then True Vertical Depth Sub Sea (TVDSS) based off the Kelly Bushing Height (KB) elevation from logs and/or well history files. The original directional survey files from the directional drilling companies were not available, so it was assumed that the Geodatum used was WGS 84 (default in IP). All calculations used in IP were calculated using Minimum Curvature method because the deviation calculation method of original directional surveys was not known. Any well without an official directional survey was assumed to be straight. In this case we assumed a top depth of zero with direction and azimuth of 0, and a bottom depth of well TD with direction and azimuth of 0. Then the TVD and TVDSS were calculated using KB height as depth reference.

Temperature Gradient Calculations

None of the 30 project wells had continuous temperature measurements, so a bottom hole temperature value entered on each of the log well headers was used initially as the ground truth. A consistent mean surface temperature value of 77 degrees Fahrenheit (degF) was used due to the variability of surface temperatures when wells are logged (winter times colder, summer times hotter). The source of the maximum temperature used in header entries is assumed to be from a maximum reading thermometer, but it could also be internal tool temperatures. Anomalous readings could also be attributed to wells in a different thermal gradient environment. Crossplots were used to reveal general trends (i.e., changes or anomalies) in the bottom hole maximum temperatures (**Figure WF-2**).

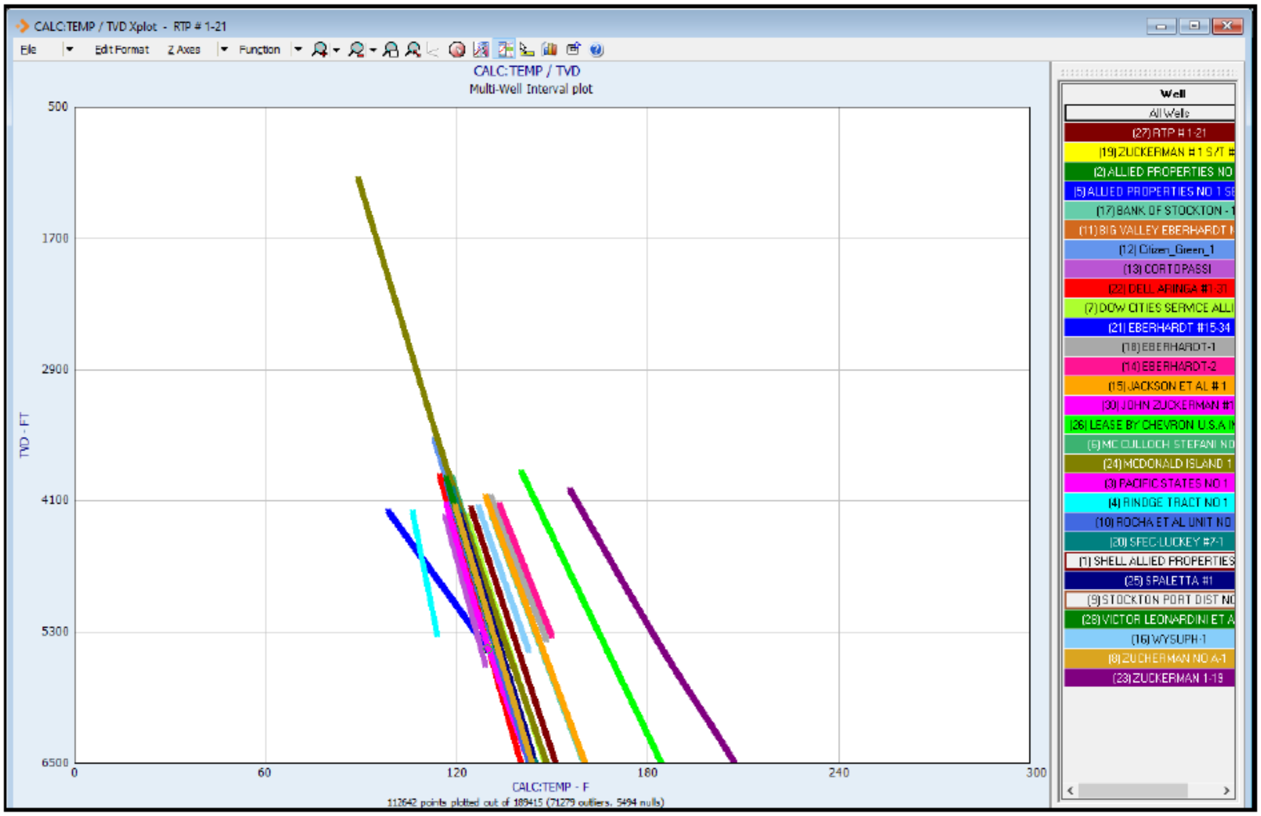


***Figure WF-2** - Temperature vs TVD, all wells Pelican Renewables Project*

This figure shows well outliers on either side of the general cluster of wells and wells, albeit shifted from the cluster, that have consistent slope with the cluster. One reason for the same slope could be attributed to an incorrect bottom hole temperature being recorded at the time of logging. Future recommendations for data collection would be to run continuous temperatures either in the open hole or cased hole environment.

After removing outliers, remaining data were used for regression analysis to determine a reasonable temperature gradient, *Temp = 76 + 0.011*TVD* (**Figure WF-3**).

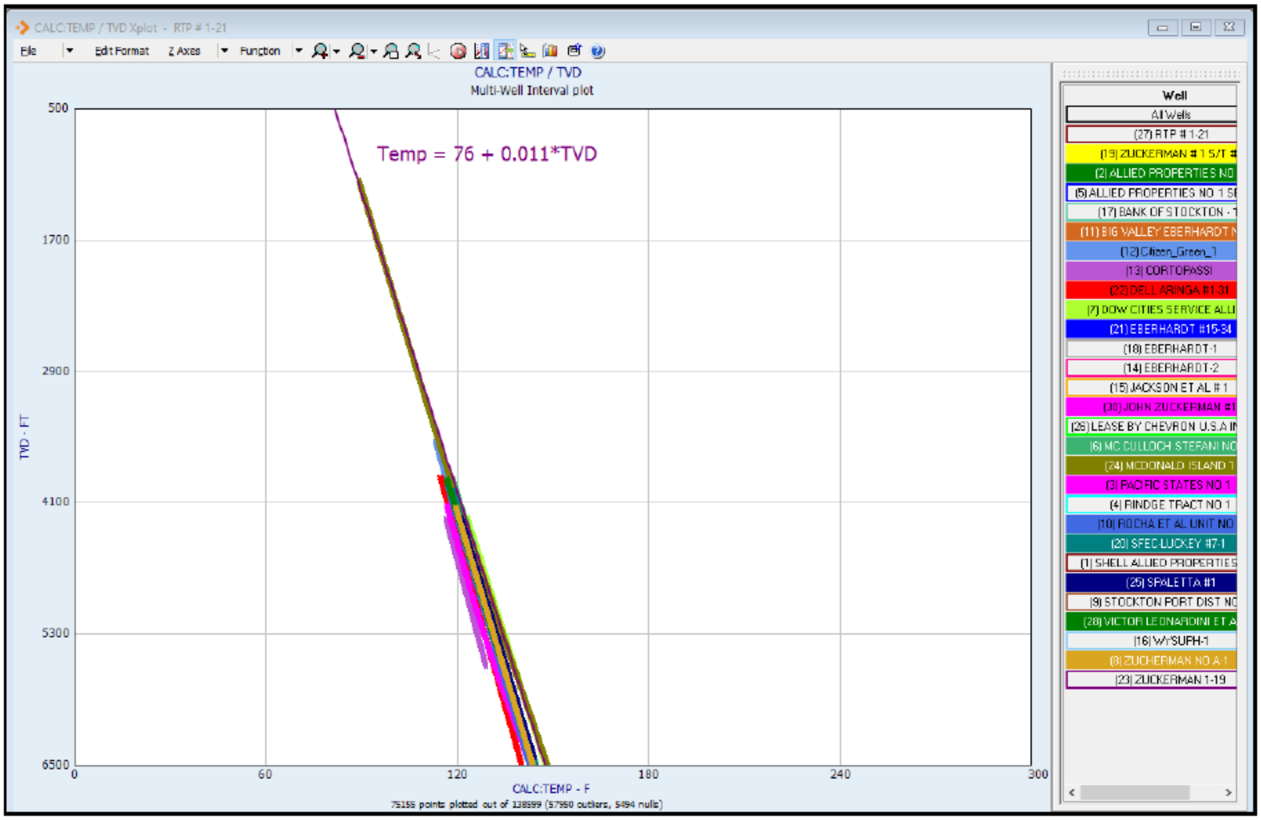


Figure WF-3 *- Cluster of wells used to define temperature gradient for Pelican Renewables Project*

SP Normalization

It was noted that this set of wells have a good SP signature that defines the shales and sands which could be used as an input for clay volume estimation (VCL). An automated program was used to baseline shift all SPs to a shale baseline value of 0. Within the same program a VCL calculated from SP was compared later with VCL calculated from gamma ray (GR) and the density/neutron cross plot.

Common Well Tops

Stratigraphic marker tops were provided by the project geologist and were loaded into the IP project. Common tops were:

- Nortonville
- Domengine
- Capay
- Meganos

- Mokelumne River Formation (MRF)
- H&T Shale
- Starkey
- Winters
- Total Depth (TD)

It is important to note that not all tops are present in all wells.

Data Normalization

It was important to inspect the well log data for obvious data "busts" when compared to other wells over the same geological interval. It is important to only normalize data with obvious shifts, and not to normalize out a geological event. This condition is evident in the distribution of the bulk density histogram of the Zuckerman No. A-1 (**Figure WF-4**). Even though its histogram is shifted compared to the "bell curve" of the other wells, it was not normalized because its distribution was only across the Starkey and Winters Sands which were not present in the other wells. But it does have the same shape as part of the Jackson Et Al #1 since it also penetrates those similar intervals.

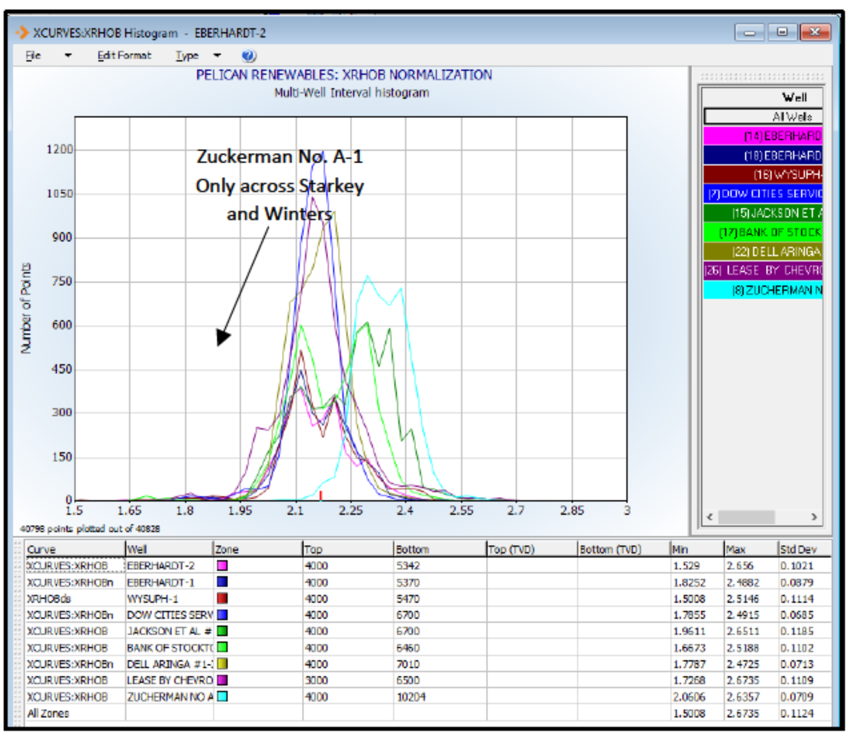


***Figure WF-4** - Bulk density distribution of Pelican Renewables Project*

Similar steps were taken for normalization of gamma ray and neutron porosity (**Figure WF-5**).

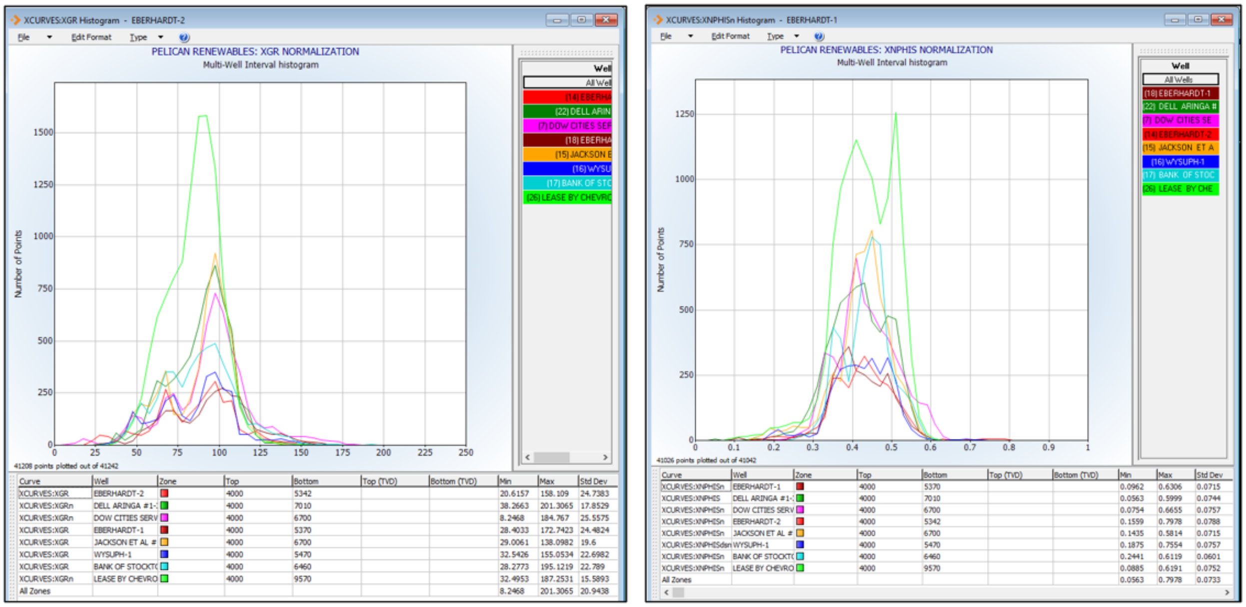


Figure WF-5 - *Histograms of Gamma Ray and Neutron Porosity (Sandstone) for Pelican Renewables Project*

<u>Porosity Calculations</u>

After data normalization, porosities were computed for Neutron Porosity (Limestone Matrix), Density Porosity from Bulk Density, and Sonic Porosity.

All raw neutron porosities received from original digital files were assumed to be on a sandstone matrix. A conversion was necessary because the input into the saturation module expects the neutron curve to be on a limestone matrix. The conversion was handled in IP's Basic Log Function module where the input is the Neutron on sandstone matrix (raw or normalized), selection of the vendor (i.e., Schlumberger or Halliburton), and the neutron tool type. This conversion was performed on all wells having neutron curve data.

The density porosity, or total porosity (PhiT), was calculated using the bulk density (raw or normalized), the matrix density value, and the fluid density value. A matrix density of 2.65 g/cm3 (sandstone) was used and a fluid density for fresh fluid of 1.0 g/cm3 was used on all wells.

The sonic porosity was computed using sonic transit time, Delta-T (DT). There are two sonic porosities that can be calculated (Wyllie, Hunt-Raymer). The first, Wyllie time-average equation requires input of a DT matrix. A value of 55.5 µsec/ft (standard for sandstones) was used. It also requires a DT value of the wellbore fluid. A value of 189 µsec/ft was used which is standard for fresh water-based muds. The last input parameter needed for Wyllie is a compaction factor. Different pore pressure regimes (over pressured, under pressured) tend to vary from a value of 1 to 1.3. At the time of working on this project the correct compaction factor for these wells was not known. So, a porosity comparison exercise workflow is needed. Because different types of porosity tools measure porosity differently, we need a porosity that will most closely compare to the calculated sonic porosity. One general comparison is to calculate a cross plot porosity of the density and neutron (PhiNDxp) and use it for comparison to a calculated sonic porosity. We then can vary compaction factors to find the best fit to the cross-plot porosity. The standard equation for the density-neutron cross plot porosity is:

$$\emptyset_{xplt} = \sqrt{\frac{\emptyset_n^2+\emptyset_d^2}{2}}$$

This exercise was done on the Citizen Green 1 well and results in a favorable overlay in the shallower zones using a compaction factor of **1.3** until reaching the Mokelumne River Formation (MRF) zone through the Starkey and Winters Formations where there is a consistent divergence away from the cross-plot porosity (**Figure WF-6**). This suggests that there is a change in pore pressure requiring use of a different compaction factor. The other area of overlay divergence is in gas zones (**Figure WF-7**). A compaction factor of **1.1** seems to be a reasonable value to use in the deeper zones from the MRF down through Starkey and Winters Formations. Sonic porosity was also calculated using the Hunt-Raymer method which only employs a DT-Matrix (55.5 µsec/ft for sandstone) and DT-fluid (189 µsec/ft for fresh fluid).

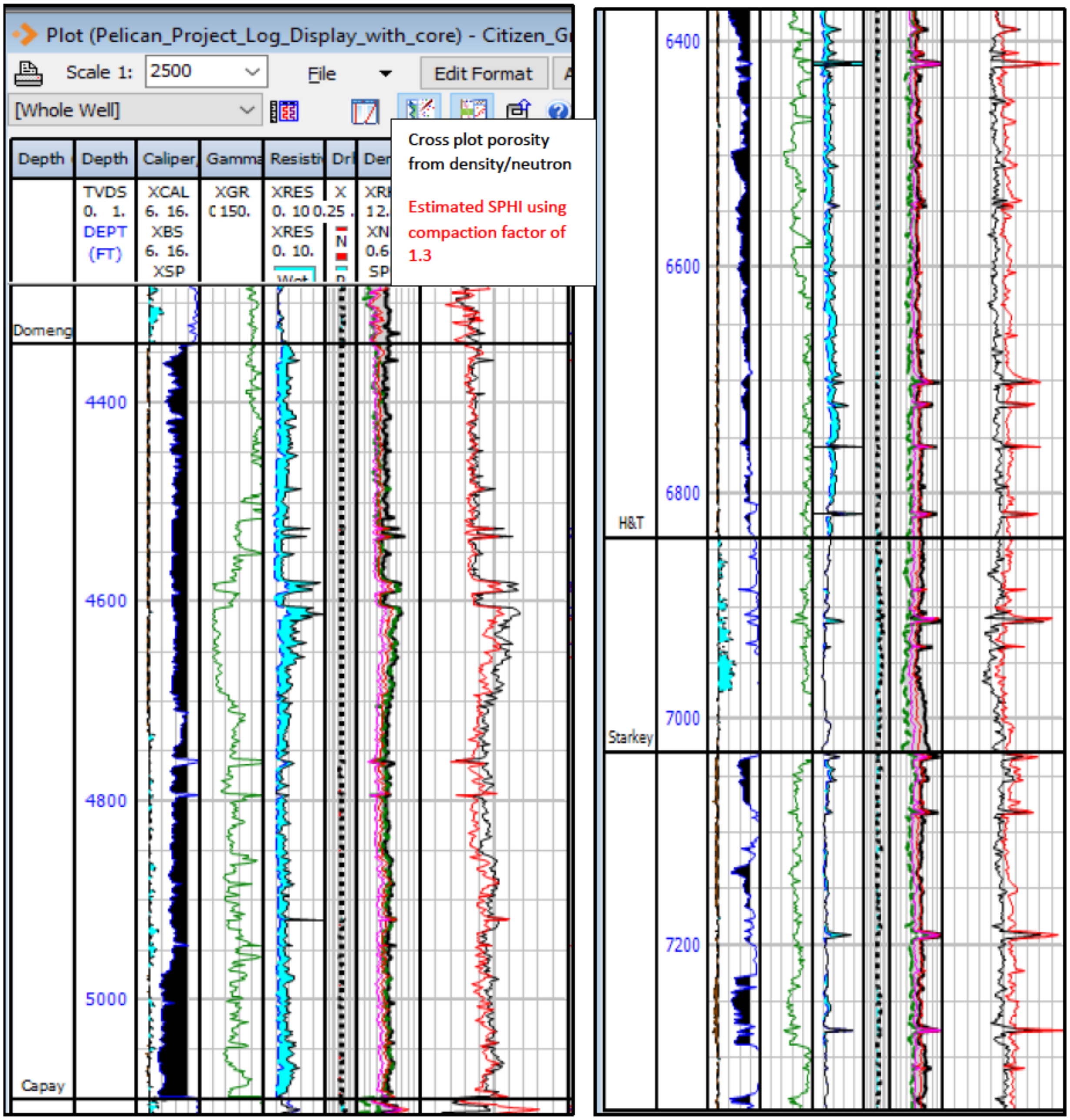


Figure WF-6 - *Consitent overlay of SPHI and crossplot porosity (Left); shift in overlay midway through MRF and Starkey (Right). May require different compaction factor through this zone.*

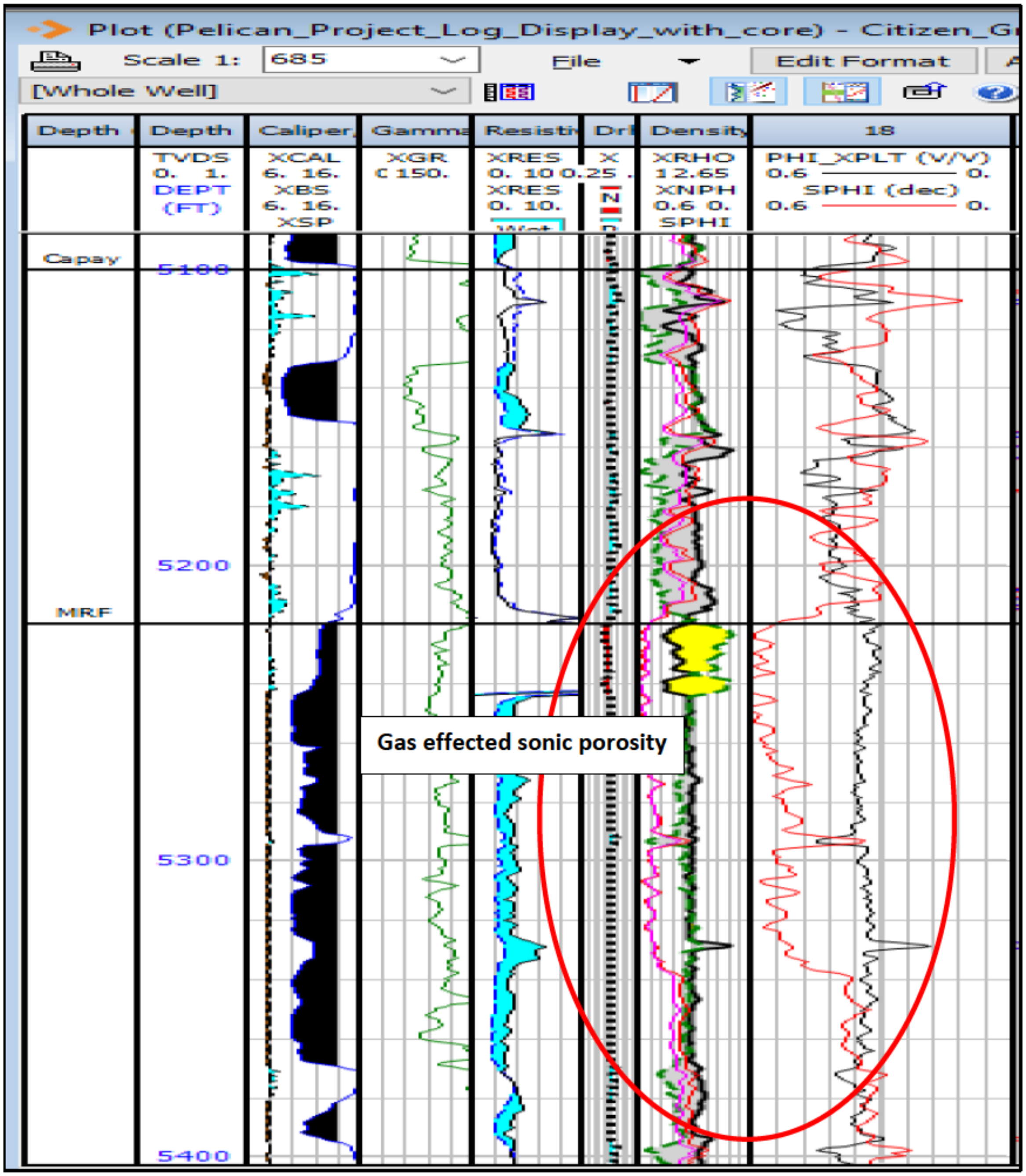


Figure WF-7 *- Large shift in sonic porosity compared to cross-plot porosity due to apparent gas effect.*

VCL Estimations

The next step was to estimate VCL for each well. Each well had at least an SP except for John Zuckerman # 1 (04077206770000). However, John Zuckerman #1 had a DT and GR, so the VCL was calculated using those inputs. In the case where wells only had an SP, the SP was used to calculate the VCL. In the case where an SP, GR, and Density/Neutron were available, all three were used to calculate a VCL. The SP and Density/Neutron were more dependable, and the GR least dependable because of spikes seen on the high side that were not necessarily being seen by the SP and Density/Neutron. The VCL window was initiated with GR, SP and Density/Neutron inputs then clean and clay endpoints were established for each input. Sometimes shifts in the log data (geological changes) are seen and zoning was necessary to apply different VCL endpoints (**Figure WF-8**). After applying different endpoints over multiple intervals, a VCL was produced for each clay indicator. A volume of clay average (VCLav) was also calculated and used in the saturation model.

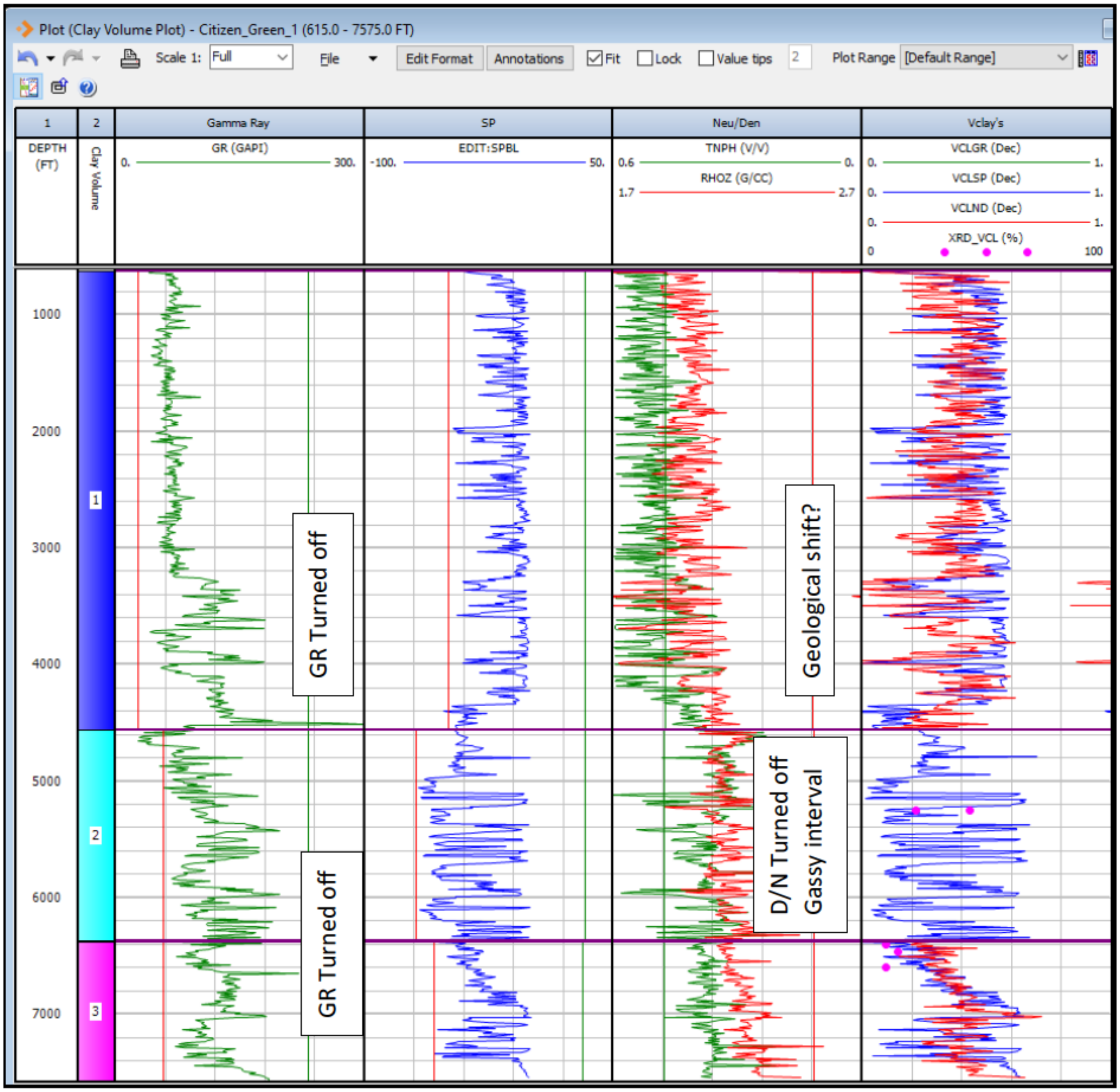


Figure WF-8 - *VCL calculation window with 3 inputs (GR, SP, Density/Neutron). GR is turned off, zones created because different constraints needed to account for geological changes.*

There were 5 XRD data points provided in the Citizen Green 1 well over the MRF zone, presumably from rotary sidewall core points. The mineral components all added up to 100% for each core point. The clay percentage was loaded into the well for each core depth and overlayed with the calculated VCLav curve. The three points lower in the MRF zone had better overall comparison than the upper two points, but those three points consistently read cleaner than the calculated VCLav. Future data collection that could help with the VCL estimation would be additional XRD data points in additional zones (clean and shaley), Nuclear Magnetic Resonance (NMR) for looking at clay bound porosity, and a specialized neutron-induced capture gamma ray spectroscopy tool that can resolve continuous elemental contributions in the reservoir. NMR and spectroscopy data would be very useful to collect in future wells to ensure that VCL calculations are realistic going forward considering VCL is used to estimate effective porosity, and potentially, effective permeability.

Salinity and Rw Calculations

Even though salinity was not an initial deliverable requested at the beginning of this project, standard salinity calculations were made, and their associated formation water resistivity (Rw) calculated for input into the saturation calculations.

Multiple salinities were calculated using different methods. The first, and historically most common, is from the SP. The standard input is a baseline shifted SP to a 0-mV line, calculated temperature, and a measured mud filtrate resistivity (Rmf) value. This method can have inherent flaws in the calculations because the SP can be affected by many borehole effects (high salinity of drill fluid, oil-based muds, washouts, loss of fluid, etc.). Likewise, the temperature impacts the Rw derived from SP so having a well-defined temperature gradient is necessary. The Rmf is a measurement performed at the wellsite and there can be metering issues or inability to get enough mud filtrate fluid to accurately measure. So, determination of salinity from SP is not used as often if porosity and resistivities are available to use instead. For completeness, all wells with an SP were assigned an estimated Rw and Salinity.

Salinity and Rw were also calculated using the Humble Salinity calculation using a total porosity curve (calculated from bulk density), neutron porosity (sandstone matrix), deep resistivity, temperature, and VCL. Since the Rw and salinities should only be used in “clean, wet sands”, a VCL cutoff of 0.20 was used as a discriminator for reservoir cleanliness.

The steps that go into the Humble Salinity calculations:

- If VCL<0.20, calculate…otherwise, no calculations are performed
- Calculate total porosity from formation bulk density (Rhob) with a 2.65 sandstone matrix and 1.0 fluid density
- Calculate neutron limestone porosity from neutron sandstone
- If total porosity is greater than neutron sandstone (gas crossover), then total porosity uses the calculated neutron limestone curve as total porosity…otherwise it uses the calculated total porosity from Rhob
- Calculate Humble apparent Rw (Rwah) using cementation value of 2.15 and tortuosity value of 0.62
    - Can also calculate Archies apparent Rw (Rwaa) using cementation value of 2.0 and tortuosity value of 1.0
- Temperature correct Rw values using Arp’s Empirical formula:

  - Rwahc = Rwah*(T1+6.77)/(T2+6.77) where T2 is the average mean surface temperature of 77 degF and T1 is the continuous downhole temperature calculation. This is the Humble temperature corrected apparent Rw (Rwahc)
- Salinities are then calculated from temperature corrected Rw curves
  - Salinity from Humble, SAL_h= 10^((3.562-(Math.Log(Rwahc-0.123, 10)))/0.955) where the value 10 is the log base

An underground source of drinking water (USDW) is an aquifer or a part of an aquifer that is currently used as a drinking water source. A 10 kppm constant line (SAL_10KPPM) was created to overlay the salinity calculations to identify in the well the base of the USDW (**Figure WF-9**).

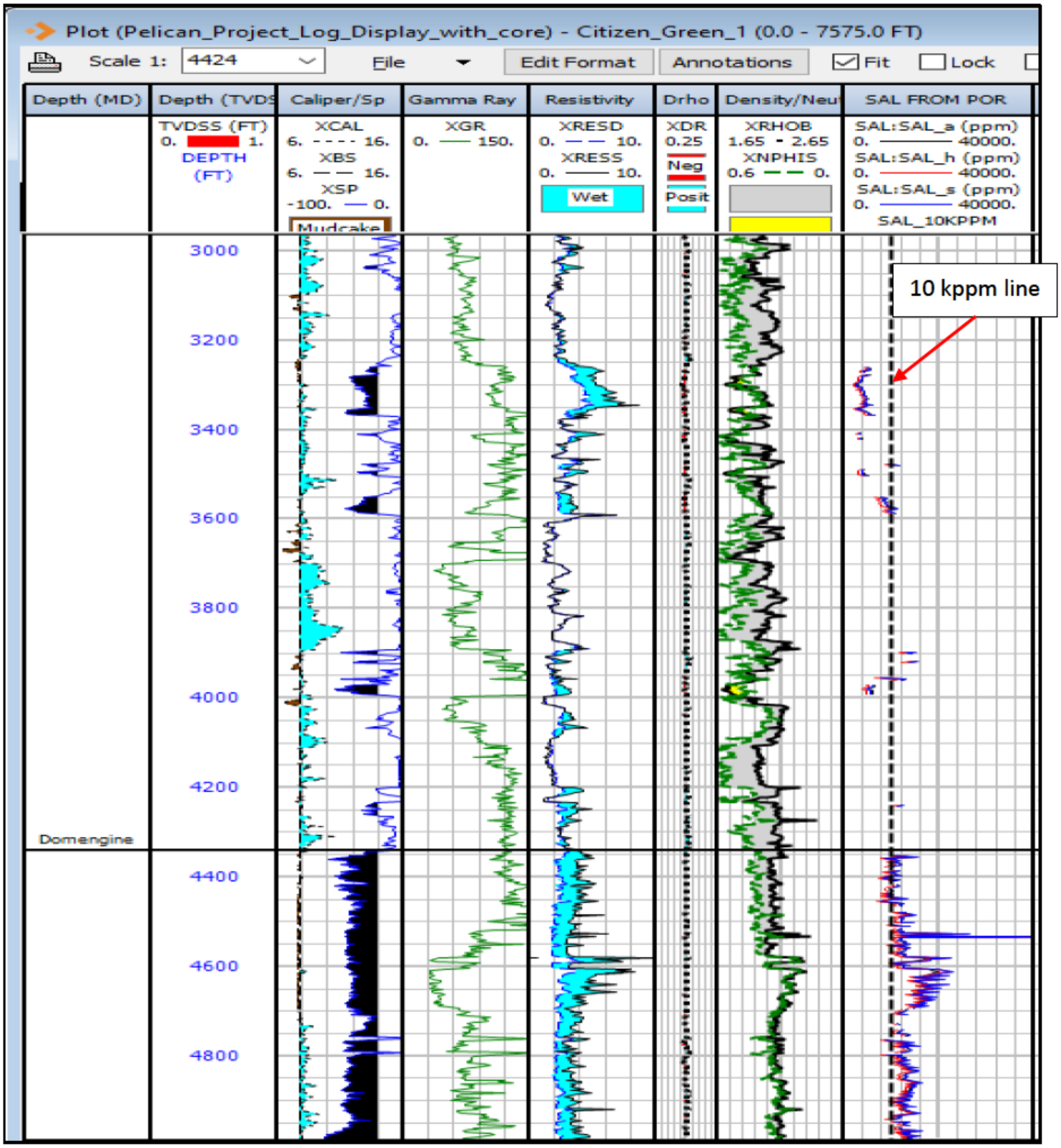


***Figure WF-9** - Log plot display showing the calculated salinities compared to the 10 kppm USDW line.*

Saturation Model

At this point the required saturation input parameters are calculated or already provided in the original data. The required inputs are Neutron Limestone (NLIM), Bulk Density (RHOB), Deep Resistivity, VCL, and Temperature. Because of the limited amount of Special Core Analysis (SCAL) data available, the Archie Saturation Equation was chosen to keep the saturation model as simplistic as possible. The bulk density value of wet clay was assumed to be 2.2 g/cm3, dry clay value of 2.78 g/cm3. Corrected Rw calculated from salinity calculations was used as a continuous input for Rw. Since the Rwahc calculated from porosity is only calculated when VCL<= 0.20, the Rw calculated from SP was used when Rwahc was not present and when in apparent gas zones. If more complex saturations equations are necessary in the future, additional SCAL core work would be necessary for the saturation model. Cation Exchange Capacity (CEC) analysis, derived from CoCw analysis, or NMR readings on core, would be able to use these data for clay corrections. Assumed electrical properties for this project was a=1, m=2, n=2. Most sands appear to be wet showing deep resistivities of about two Ohm-m, and about two Ohm-m of separation with the shallow resistivity indicating reasonable permeability. There appears to be potential hydrocarbon bearing sands (not in all wells) just below the MRF geological pick where there is significant gas cross-over between the bulk density and neutron with an apparent water leg at the base of the cross-over (**Figure WF-10**). Even though rotary side wall cores were taken in Citizen Green 1, no cores were taken to verify presence of hydrocarbons although a 60 foot (5246-5306') whole core was taken in the apparent water leg interval immediately below the gas cross-over sand. Citizen Green 1 (0407720688) was drilled in 2011. The top 6 feet of the MRF Sand (5612-22') was completed on 03/16/2012 and still had gas production as of August 2022. King Island 1-28 (same API number) was drilled in 2005. The equivalent sand below the MRF pick seen in **Figure 10** was completed in the King Island 1-28 and had 220 units of gas on the mud log. Well history file shows it was perforated but does not indicate producibility.

An Archie model was also used for wells with porosity derived from sonic. For this case, the sonic porosity was derived using the Wyllie time average equation in IP. The sonic porosity calculation used varied compaction factors based on zones (1.1 for Nortonville – MRF, 1.3 MRF – TD).

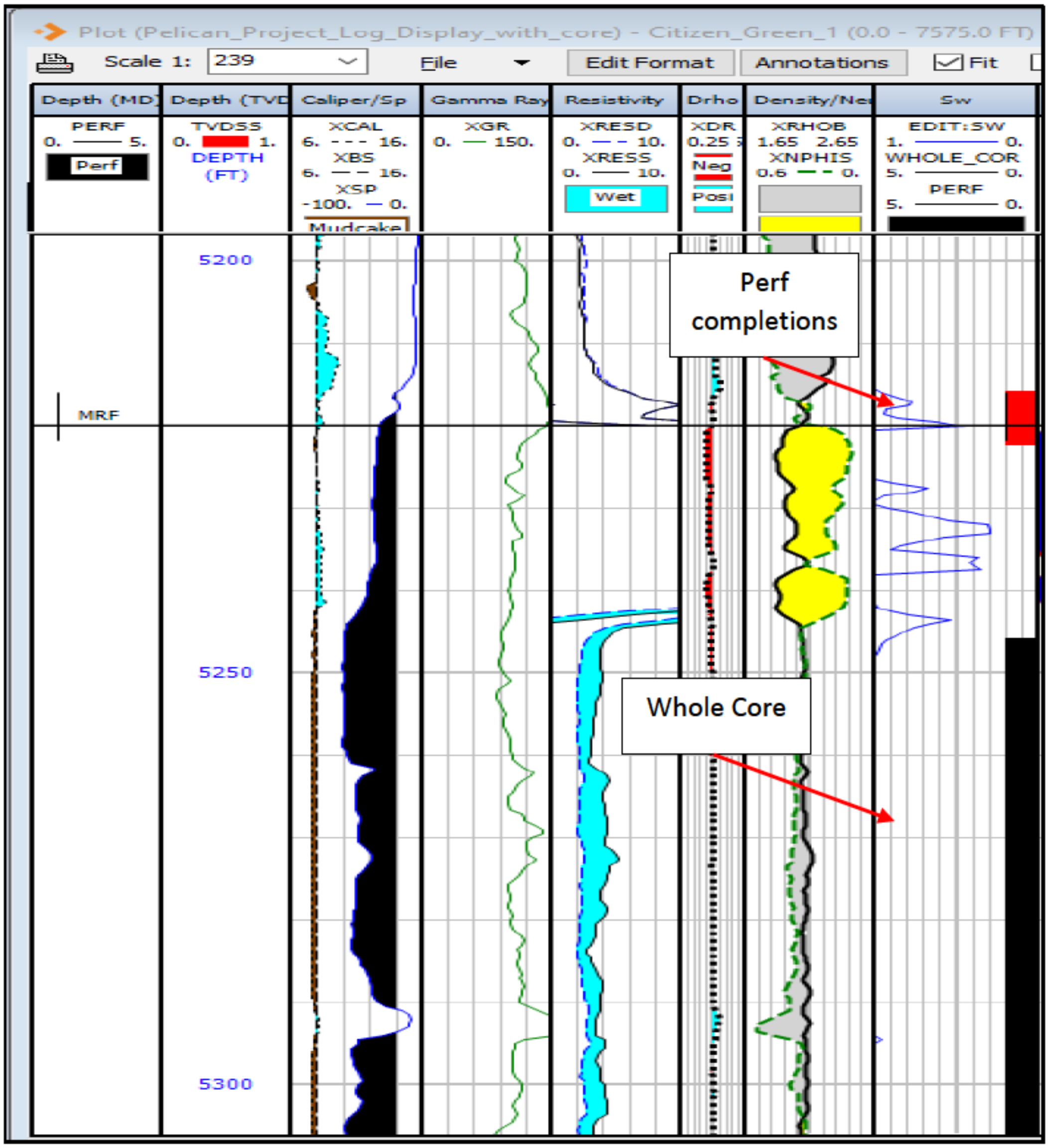


***Figure WF-10** - Potential gas hydrocarbon bearing sand below the MRF geological horizon with an apparent water leg at the base of the sand.*

<u>Permeability Estimation Model</u>

The permeability estimation model for this project relied on limited rotary sidewall core data taken from the Citizen Green 1. Although two 60-foot whole cores were collected from this well, any Porosity, Perm (K), Saturation measurements (PKS) for these sections were not available for our review. The upper whole core was collected above the Domengine (4189-4249'), presumably in the Nortonville shale interval. The second whole core was collected in the MRF formation. Rotary sidewall sample in-fill points for the whole core were cut across all major horizons (50 samples taken), although not all recovered. The table of core data were from the MRF, H&T Shale, and

Starkey Formations. From a total porosity standpoint of the open hole log data, the core porosity and log porosity had a favorable overlay with each other aside from a couple data points that may be from a depth discrepancy in the H&T zone (**Figure WF-11**).

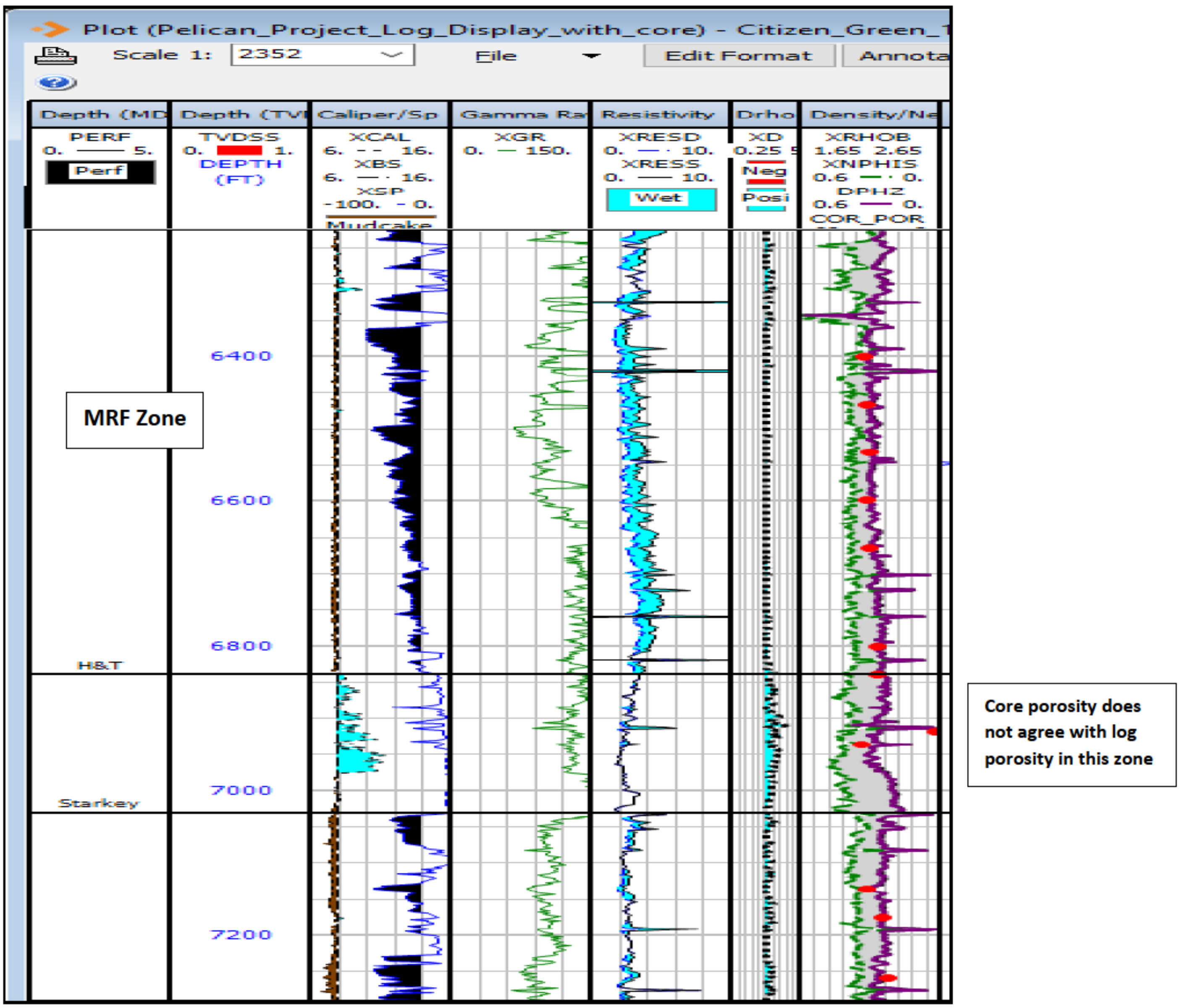


Figure WF-11 *- Core porosity comparison to log derived porosity. Poor overlay in H&T zone possibly depth related.*

The core permeability and porosity were loaded into IP and a cross-plot created to see if there was a good trend to create a transform. What was noted was that the lowest porosity was about 22%

although there was one at 1.8% (presumably a tight streak "bone"). However, the tight streak did not line up with the log porosity and skewed the trend. So, a series of lower porosities and corresponding perms were created to give a broader porosity and permeability spectrum (**Figure WF-12**). Once this was complete, a third order polynomial trend was run and an equation for that trend exported having a 97% regression coefficient. Note that this porosity and permeability trend is based on total porosity and not effective porosity. Estimating effective permeability from liquid permeability data was not performed but may be included in future work. Utilization of magnetic resonance data is a useful tool to better quantify effective porosity and back to a permeability downhole. A CMR tool was run on the Citizen Green 1 well, but its data were not available for review.

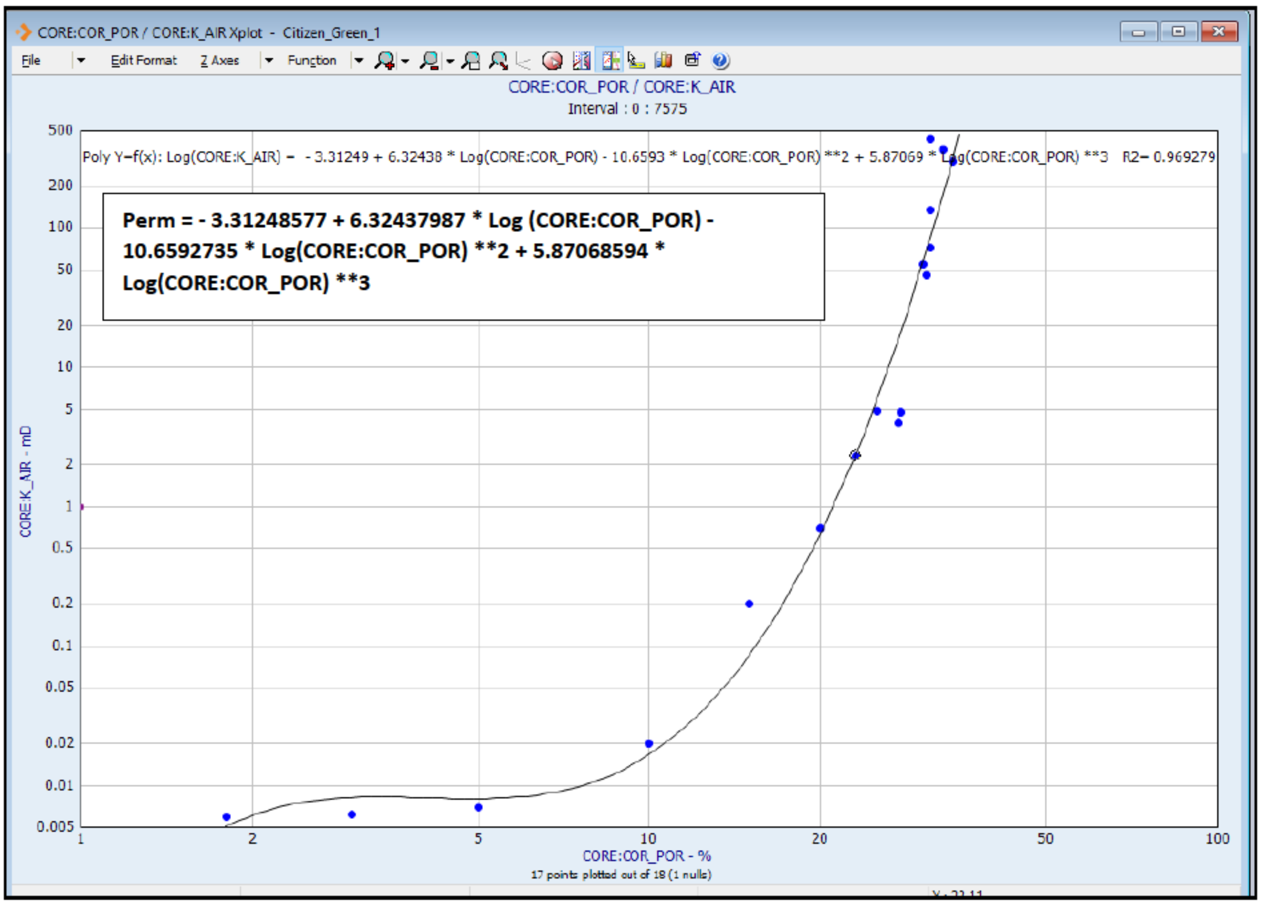


Figure WF-12 *- Core porosity and permeability cross-plot relationship. Porosities below 20% were created to expand spectrum of data to build the trend.*

This trend was applied to all wells with a porosity curve. For wells with only a sonic derived porosity, the sonic porosity would read higher than PhiT in the more clay rich zones and in turn, the permeability would be higher. To mitigate this issue, the Wyllie sonic porosity was adjusted based on the calculated VCLav to mimic the total porosity in a well with both total density porosity and sonic porosity. The relationship with the best fit was in Citizen Green 1, using the equation **SPhi_WYL_corr= PhiT*(1-0.5*VCLav)**. A cross-plot comparison resulted in a regression coefficient of 77% (***Figure WF-13***). This regression coefficient was applied to wells with only a sonic porosity and then permeability was calculated in each well.

This permeability regression data was confined to the MRF, H&T Shale and Starkey interval since these intervals had core data to establish the transformation. Core data were not available across the Domengine, but the established transformation was applied to this interval even though the Domengine is known to have higher permeability than the MRF zones. To establish a more accurate permeability estimation in the Domengine, it is recommended in future data wells to acquire whole or rotary sidewall samples in the Domengine as well as magnetic resonance logs whose estimated permeability can be correlated to core permeability measurements.

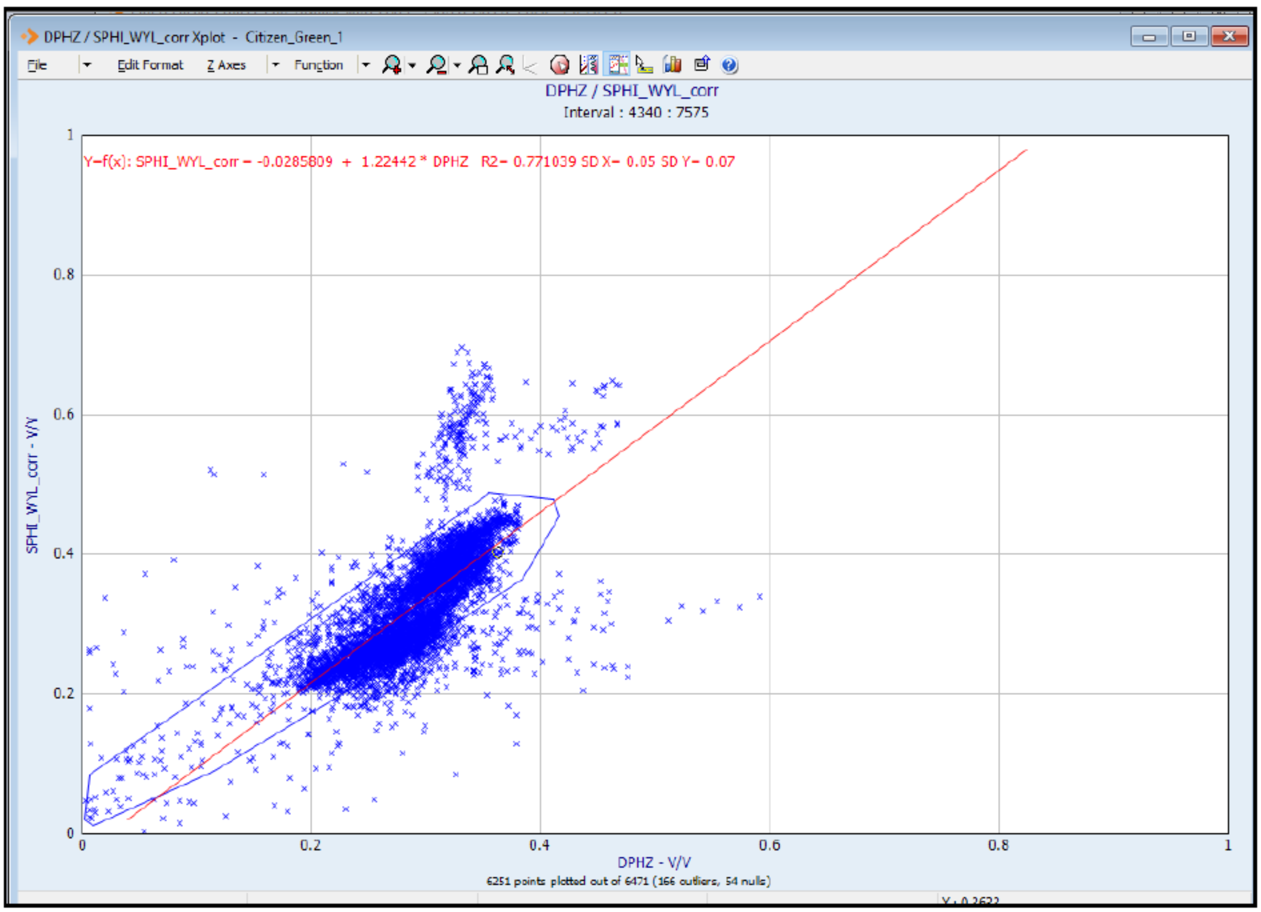


***Figure WF-13** - Relationship of sonic porosity (SPhi_WYL_corr) to total porosity (DPHZ).*

Permeability was calculated for wells with only sonic porosity as its only source of porosity using the corrected sonic porosity as PhiT for the input.

Net to Gross

The final deliverable was to establish cutoffs for Net to Gross (NTG) and summations for all wells in the project. Citizen Green 1 well was chosen to establish the cutoffs. We used two curves, the PhiT and VCL, knowing that both go hand in hand with defining reservoir quality. The initial parameters used were PhiT>= 0.20 and VCL<=0.25. To identify the most appropriate cutoff value, a sensitivity analysis was performed on a range of PhiT and VCL values that included plotting the distribution of each. Subsequently the P90 case for each parameter was applied to the rest of the project wells. The PhiT values ranged from 0 to 1 at increments of 0.02. The VCL parameter ranged from 0 to 0.60 at 0.02 increments. The distributions are shown in **Figures WF-14 and WF-15.**

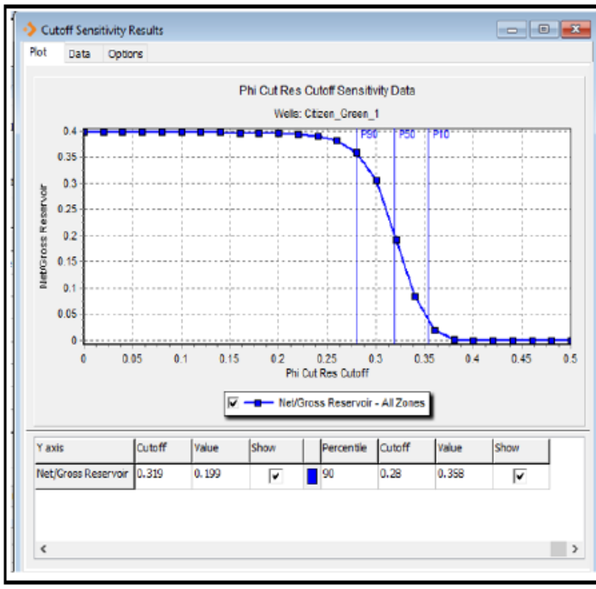


***Figure WF-14** - Sensitivity of PhiT on NTG.*

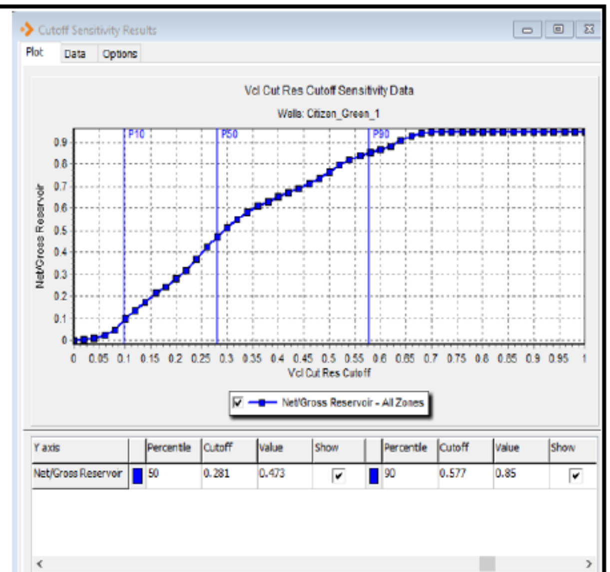


***Figure WF-15** - Sensitivity of VCL on NTG*

The P90 case of PhiT corresponds to a value of 0.28. On the other hand, because there's such a wide range of calculated VCL, the P90 included more interval outside the reservoir but fit within the porosity cutoff. To be more conservative we used the P50 case for the VCL cutoff which corresponded to a value of 0.28. A spreadsheet was created over the Nortonville through TD interval with details corresponding to NTG, average Porosity Height (PhiH) and Volume of Clay Height (VCLH) for each well meeting the cutoff criteria. For wells with only resistivity and SP, a similar sheet was created using a VCL cutoff of <= 0.28. Based off the resulting Reservoir Flag (ResFlag) being a 1 (On) or 0 (off), a lithology flag SAND and CLAY were created. If ResFlag was a 1, SAND was set to 1 otherwise it was set to 0. If ResFlag was 0, CLAY was set to 1 otherwise it was set to 0.

Thoughts, Conclusions, Go Forward

Sacramento Valley wells generally have limited well data. The wells provided for this project had a suitable distribution of data, with about a third of the wells having a full suite of data across the zone of interest, a third having resistivity and sonic data and another third having only SP and resistivity. Overall, the well data quality was good with washouts at a minimum. Wells with washouts still contained usable data. The data were consistent well to well with only minimal shifts needed for normalization.

Some ideas come to mind when considering going forward if decision is to continue future work. One of the biggest variables for saturation, effective porosity, and permeability is the porosity. How effectively are we calculating total and effective porosity? Running NMR in future wells would help narrow the uncertainty. Comparing NMR total porosity to the total porosity calculated from the bulk density would indicate whether your matrix density is correct (2.65 for this project) or if the matrix density is varying. An NMR would also help verify whether the saturation model input assumptions are correct. The NMR measures the complete spectrum of porosity bins, so free fluid porosity (effective) and clay bound porosity can be effectively derived.

The NMR tool is also useful to estimate permeability. Although it should be tied to core data, at a minimum it would reveal changes in permeability compared to calculated values. Again, because the NMR tool breaks out total and effective porosity, both total and effective permeability can be quantified.

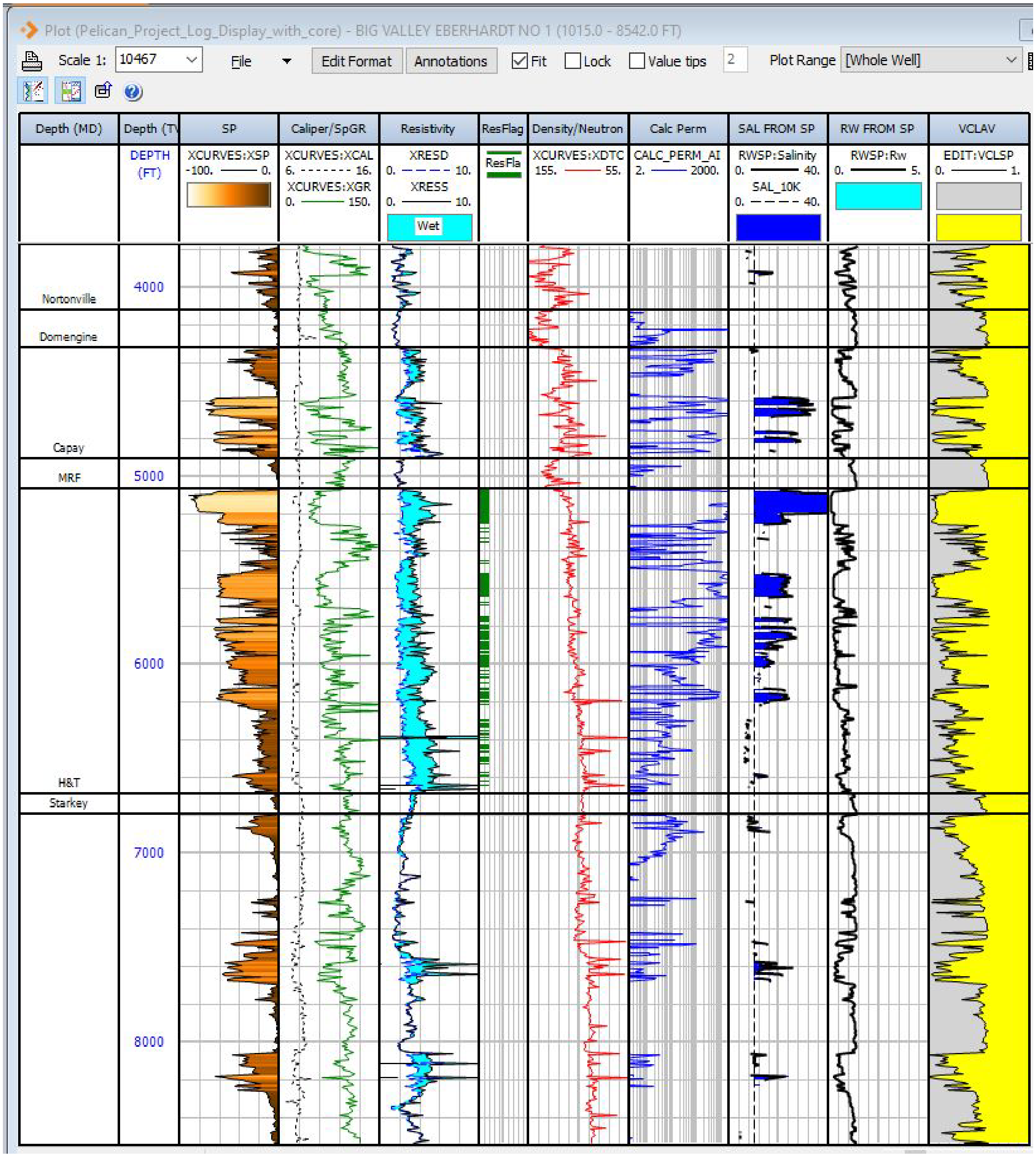
An accurate VCL calculation is necessary to quantify NTG and calculating effective porosity. In cases where wells had both a baseline shifted SP and Density/Neutron porosity, the VCL overlay between the two complemented each other. GR did not seem to have that same complement possibly due to higher streaks present in the reservoir that the SP and Density/Neutron did not see. In most cases, the SP and Density/Neutron were more reliable than the GR unless the GR was the only input available (1 well). The limited number of available XRD data samples, although not laying on top of the predicted VCL curve, showed “clean” when compared to the VCL curve, and “more clay rich” when the predicted VCL curve was higher.

Two ideas come to mind for future work. First would be to collect more XRD samples. XRD can be done from drill cuttings, so you do not need a physical cored sample. The samples are collected over a larger interval, providing more data points because drill cuttings are caught over the entire area of interest through mud logging. The second idea is to acquire additional cores, but this comes at a higher cost. One logging option is to run a neutron-gamma elemental spectroscopy tool that can narrow the uncertainty of the VCL calculation. Collecting XRD data in the same well is recommended for better calibration, but not a necessity. Another logging option is to run a dielectric log. Dielectric logs have been utilized in the Central Valley usually in heavy oil, freshwater environments, but has some benefits for calculating VCL.

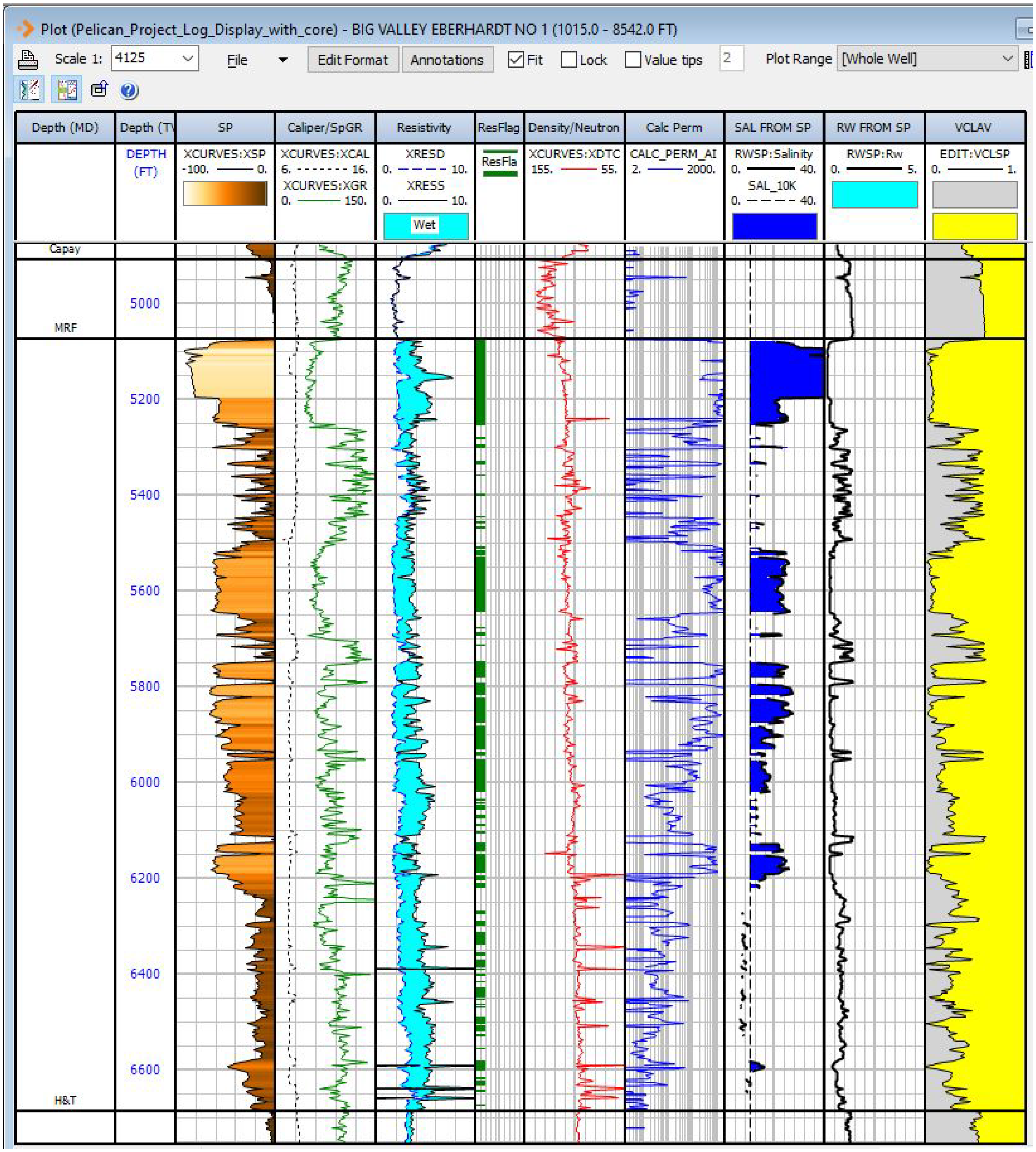
Regarding NTG, the question is always, “are we capturing everything”? Are there layers that are not revealed with the limited resolution of the tools? Running electrical imaging tools can serve a dual purpose providing beneficial information for this project. The first benefit is the ability to detect and quantify faulting in the field. The other benefit, because of imaging tools resolution (12 samples/ft) the amount of sand (reservoir) layers and NTG footages can be accurately quantified. The tools are combinable and would not require additional runs in the wellbore unless wellbore stability dictates it.

A last suggestion for future data acquisition is formation sampling/testing. Both Rw and salinity are typically “unknowns”, so gathering segregated downhole water samples would provide the Rw, salinity and Total Dissolved Solids (TDS) values required by CalGem. Salinity and TDS would provide information helpful to verify the base of the USDW. Formation testing could help in a variety of other ways. Performing standard drawdown and buildup pressures would provide information regarding the current pore pressure of the field. The drawdown and buildup plots also provide good independent calculation of liquid permeability. Although noted as “mobility”, it is essentially a downhole permeability (liquid permeability). Lastly, vertical interference testing (VIT) can be utilized to verify transmissibility of the shales. It’s been utilized in CO_2 tertiary projects to make sure that injected CO_2 will stay in zone.

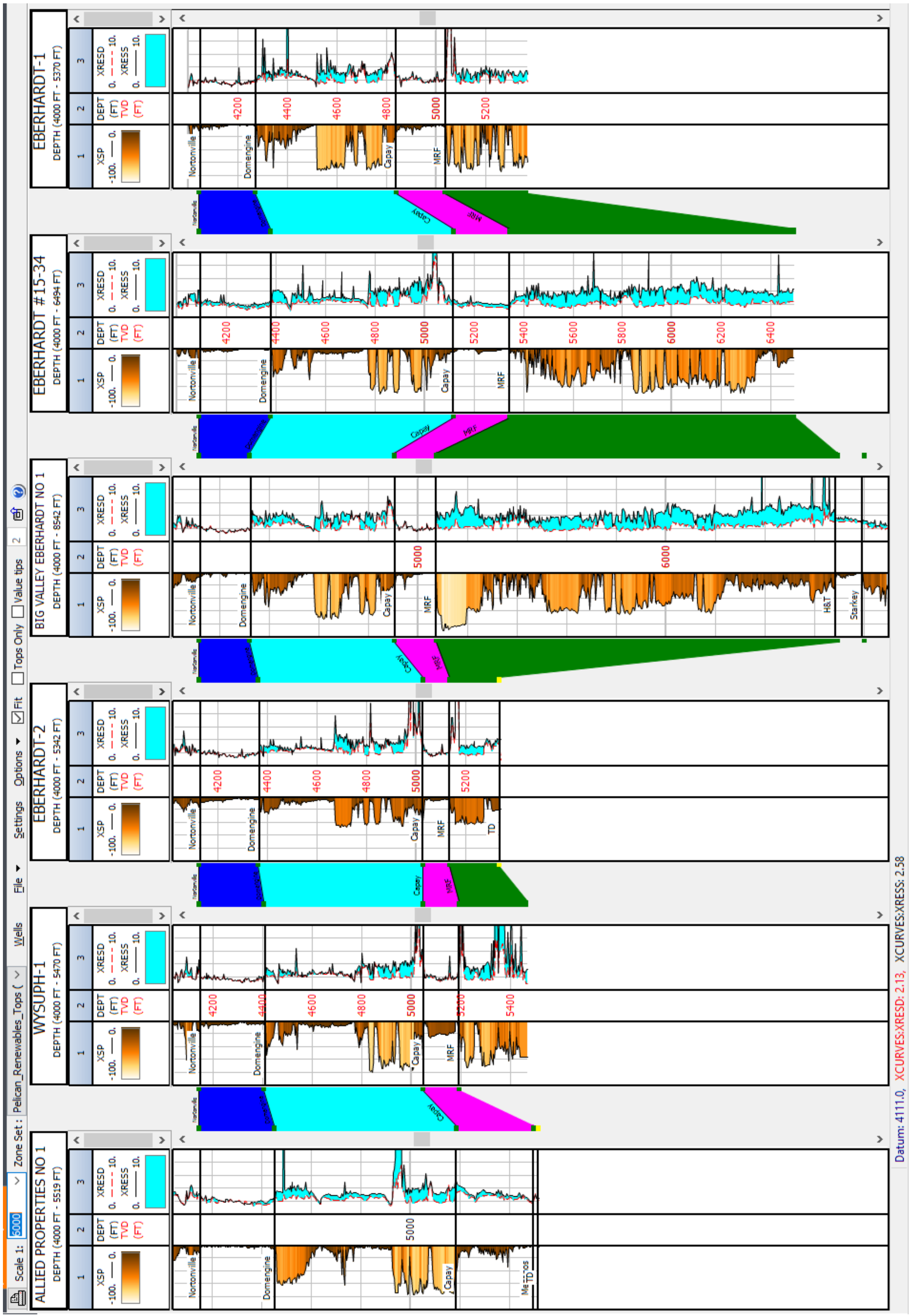
APPENDICES



Appendix WF-A - *Big Valley Eberhardt #1 Log Display Capay thru Starkey*



Appendix WF-B *- Big Valley Eberhardt #1 Log Display Mokelumne River Formation.*



Appendix WF-C - *(Southwest-Northeast) Cross-Section of 6 Pelican Renewables wells flattened on the Nortonville marker.*

Acronym	Description	Units of Measure
BVW	Bulk Volume Water	Dec
CEC	Cation Exchange Capacity	meq/100g
CLAY	Clay Lithology Flag	FLAG
CoCw	Conductivity oil, Conductivity water (core service)	
DPHI, DPHZ	Density Porosity	Dec
DT	Delta-T, interval transit time	USEC/FT
GR	Gamma Ray	GAPI
IP	Interactive Petrophysics (software)	
Kair	Permeability to air	mD
KB	Kelly Bushing height	FT
MICP	Mercury Injection Capillary Pressure	
NLIM	Neutron Limestone Matrix	Dec
NMR	Nuclear Magnetic Resonance	
NPHS	Neutron Sandstone Matrix	Dec
NTG	Net To Gross	Dec
PhiE	Effective Porosity	Dec
PhiH	Average porosity * feet reservoir	FT
PhiNDxp	Neutron/Density Cross-plot Porosity	Dec
PhiT	Total Porosity	Dec
PKS	Porosity, Perm (K), Saturation (core service)	
ResFlag	Reservoir Flag, using cutoff parameters	FLAG
ResH	ResFlag Height, from cutoff parameters	FT
ResVclH	Average VCL*Height, from cutoffs parameters	FT
RHOB, RHOZ	Bulk Density	G/CM3
Rm	Resistivity of mud	OHM-M
Rmc	Resistivity of mud cake	OHM-M
Rmf	Resistivity of mud filtrate	OHM-M
Rw	Resistivity of formation water	OHM-M
Rwaa	Apparent water resistivity Archie	OHM-M
Rwaac	Apparent water resistivity Archie Temperature Corrected	OHM-M
Rwah	Apparent water resistivity Humble	OHM-M
Rwahc	Apparent water resistivity Humble Temperature Corrected	OHM-M
SAL_10KPPM	Constant 10kppm line	KPPM
SAL_a	Salinity, Archie	PPM
SAL_h	Salinity, Humble	PPM
Salinity	Salinity, From SP	KPPM
SAND	Sand Lithology Flag	FLAG
SCAL	Special Core Analysis (core service)	

SP	Spontaneous Potential	mV
SPhi	Sonic Porosity	Dec
SW	Water Saturation	Dec
TD	Total Depth	FT
TEMP	Temperature	degF
TVD	True Vertical Depth, below datum	FT
TVDSS	True Vertical Depth Sub Sea	(-) FT
USDW	Underground Source Drinking Water	
VIT	Vertical Interference Testing (log service)	
VCL	Volume of Clay	Dec
VCLav	Average Volume of Clay	Dec
VCLH	Average clay volume * feet reservoir, from cutoff parameters	FT
VLCGR	Volume of Clay from GR	Dec
VLCND	Volume of Clay from Neutron/Density	Dec
VLCSP	Volume of Clay from SP	Dec
XCAL	Caliper	IN
XDTC	Compressional Delta-T	USEC/FT
XGR	Gamma Ray	GAPI
XNPHIL	Neutron Limestone Matrix	Dec
XNPHIS	Neutron Sandstone Matrix	Dec
XPHIE	Effective Porosity	Dec
XPHIT	Total Porosity	Dec
XRD	X-Ray Diffraction (core service)	
XRESD	Deep Resistivity	OHM-M
XRESM	Medium Resistivity	OHM-M
XRESS	Shallow Resistivity	OHM-M
XRHOB	Bulk Density	G/CM3
XSP	Baseline Shifted SP to 0 mV	mV

Appendix WF-D - *Curve and tool acronym index with Units of Measure (UoM) where applicable*

Attachment 3

			From PEX (SP) - Burton					From PEX (SP) - Beyer						
Side wall core #	Depth from logging tool	Formation	Formation top (Measured)	Formation bottom (Measured)	thickness (Measured)	Notes - Burton	Sample Comments - Burton	Formation or *Unit* Top (Measured)	Formation or *Unit* Bottom (Measured)	Formation or *Unit* Thickness (Measured)	Formation or *Unit* Top (Vertical)	Formation or *Unit* Bottom (Vertical)	Formation or *Unit* Thickness (Vertical)	Notes - Beyer
50	4090.0	Nortonville Formation	4000	4350	350	moved up 60 ft to shalier zone	missing	3995	4343	348	3620	3920	300	sample not recovered
49	4140.1	Nortonville					missing							sample not recovered
48	4225.0	Nortonville				moved down 15 to avoid sand stringer	missing							sample not recovered
		Nortonville shale						*3995*	*4200*	*205*	*3620*	*3798*	*178*	*Unit depths and thicknesses*
47	4295.1	Nortonville shale & sand					unconsolidated sand (stuck in tool)	*4200*	*4343*	*143*	*3798*	*3920*	*122*	*Unit depths and thicknesses*
46	4475.0	Domengine sand	4350	5100	750	Actual top at 4350, but want to start lower because of whole core and unconsolidation	unconsolidated sand (stuck in tool)	4343	5098	755	3920	4596	676	
45	4600.0	Domengine ss					unconsolidated sand (stuck in tool)							
44	4725.0	Domengine ss					removed by Shala							
43	4850.0	Domengine ss					missing							
42	4975.0	Domengine ss					unconsolidated sand							
41	5070.1	Domengine ss					unconsolidated sand							
40	5108.0	Capay shale	5100	5210	110	moved up 10 ft to avoid sand stringer	unconsolidated shale	5098	5215	117	4596	4693	97	
39	5117.0	Capay shale				moved up 10 ft to avoid sand stringer	1 very small piece-shale (counted as missing by							
38	5140.0	Sand in Capay					unconsolidated sand							
37	5165.0	Capay shale	5150	5210	60		unconsolidated shale							
36	5183.0	Capay shale					missing							sample not recovered
35	5202.0	Capay shale					unconsolidated silty sand							
34	5350.0	Mokelumne ss	5210	6850	1640	total thickness; sidewalls in selected sand layers and below 6100 because of whole core and unconsolidation above 6100	unconsolidated silty sand	5215	6840	1625	4693	6200	1507	
33	5770.0	Mokelumne ss	5700	5910	210	sand layer within Moke	unconsolidated sand							
32	5840.0	Mokelumne ss					unconsolidated silty sand							
31	6023.0	Mokelumne ss	5995	6080	85	sand layer within Moke	unconsolidated sand							
30	6052.0	Mokelumne ss					unconsolidated sand							
29	6090.0	Mokelumne (shaley)	6080	6100	20	clay-siltstone layer	removed by Shala							
28	6166.0	Mokelumne ss	6100	6760	660		unconsolidated sand							
27	6232.0	Mokelumne ss					unconsolidated sand							
26	6268.0	Mokelumne ss				moved up 30 ft to avoid silt zone	hard core, but not well							
25	6334.0	Mokelumne ss					unconsolidated sand							
24	6400.0	Mokelumne ss					hard core-silty sand							
23	6466.0	Mokelumne ss					hard core-silty sand							
22	6532.0	Mokelumne ss					hard core-silty sand							
21	6598.0	Mokelumne ss					hard core-silty sand							
20	6664.0	Mokelumne ss					hard core-silty sand							
19	6800.0	Mokelumne ss	6760	6880	120	not convincingly shale (gradational contact from 6750 to 6830)	hard core-silty sand							gradual transition from Moke to H&T
18	6840.0	H&T shale					hard core-sandy shale	6840	7032	192	6200	6383	183	gradual transition from Moke to H&T
17	6899.0	H&T shale	6880	7030	150	definitely shale	removed by Shala							
16	6918.0	H&T shale					hard core-shaly, marly?							

15	6936.0	H&T shale					hard core-sand							
14	6955.0	H&T shale					1 piece partial-shale							
13	6974.0	H&T shale				sand stringer	missing							sample not recovered
12	6993.0	H&T shale				moved down 10 ft to better shale	hard core pieces-shale							
11	7011.0	H&T shale					hard core pieces-sand							
10	7067.0	H&T sand	7030	7290	260		hard core-sand	7032	7290	258	6383	6630	247	
9	7104.0	H&T sand or shale				shale stringer or still in H&T shale?	hard core-sand							
8	7136.0	H&T sand				moved up 5 to better sand	hard core-sand							
7	7174.0	H&T sand or shale					hard core-sand with shale							
6	7230.9	H&T sand				Moved down 20 ft to better sand	removed by Shala							
5	7258.0	H&T sand					hard core-sand							
4	7309.0	Starkey shale	7290	7560	270	moved up 20 ft to better shale	hard core-shale	7290	*7560*	*270*	6630	*6887*	*257*	*Bottom of log; thickness logged*
3	7347.0	Starkey shale					removed by Shala							
2	7385.9	Starkey shale					2 large pieces and 1 small hard core-shale							
1	7424.0	Starkey shale					hard core-shale							
	7462.6	Starkey shale					not taken because previous logging tool sticking at this depth (replaced by sample further up)							no sample
TD		in Starkey shale						7570			6920			
Whole cores														
4210-4249 ft MD 19 ft recovered														
5246-5306 ft MD 57.5 ft recovered														

Petroleum Services

Sidewall Core Analysis

Lawrence Berkeley Natl. Laboratory

Citizen Green #1 Well

King Island Field
San Joaquin County, California

FINAL REPORT

November 12, 2012

CL File: 57111-212369LA

Performed by:
Core Laboratories, Inc.
3437 Landco Drive
Bakersfield, California 93308
(661) 325-5657

Petroleum Services Division
3437 Landco Dr.
Bakersfield, California 93308
Tel: 661-325-5657
Fax: 661-325-5808
www.corelab.com

November 12, 2012

Jonathan Ajo-Franklin
Lawrence Berkeley Natl. Laboratory
#1 Cyclotron Road, MS 90-1116
Berkeley, CA 94720

Subject: Sidewall Core Analysis
File No.: 57111-212369LA

Dear Mr. Ajo-Franklin:

Enclosed are final data for 15 rotary sidewall samples submitted to our laboratory from well Citizen Green #1, King Island Field, San Joaquin County, CA.

Air porosity, permeability, and saturation (PKS) determinations, along with white and ultraviolet light photographs, were performed on each of 15 samples. Brine permeability at 3400 psi was performed on the 14 suitable samples. Thin Section slides from endtrims of each sample where prepared. Per request, sample remainders were returned to Lawrence Berkeley National Laboratory. Core analysis procedures are documented on the following pages for reference.

Thank you for this opportunity to be of service to Lawrence Berkeley Natl. Laboratory. Please do not hesitate to contact us at (661-325-5657) if you have any questions regarding these results or if we can be of any additional service.

Sincerely,
Core Laboratories

Larry Kunkel
Area Manager

Distribution: 1 original report, 1 CD copy: Addressee

Petroleum Services Division
3437 Landco Dr.
Bakersfield, California 93308
Tel: 661-325-5657
Fax: 661-325-5808
www.corelab.com

Basic Test Procedures [1]

Core Analysis

- Remove visible drilling mud contamination from sidewall sample.
- Expose a fresh sample surface and photograph (if requested) under white and ultraviolet (UV) lighting.
- Retain endtrim for future analysis.
- Record lithological description.
- Package samples, if required, using nickel foil and end screens.
- Seat sleeve at depth - 100psi (750psi maximum).
- Remove water by Dean Stark extraction using toluene. Summation of fluids method used for samples <0.5" long or irregular shaped.
- Record stablized produced water volume.
- Leach remaining oil and salts by Soxhlet extraction using an 80/20 mixture of methlyene chloride/methanol.
- Dry at 235 °F to stable weight (minimum of 24 hours).
- Cool to ambient temperature in dessicator to prevent moisture accumulation.
- Record stable dry weight.
- Determine grain volume and grain density by helium expansion (Boyle's Law).
- Determine helium (Boyle's Law) pore volume at 250psi confining pressure.
- Determine steady-state permeability to air at 250psi confining pressure. Emperical method used for samples <0.5" long or irregular shaped.

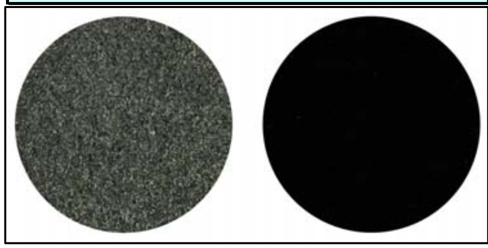
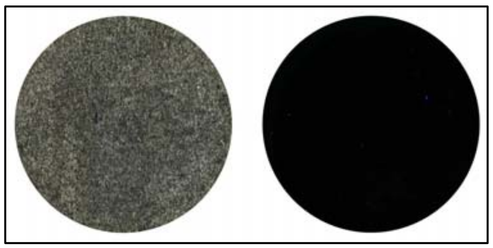
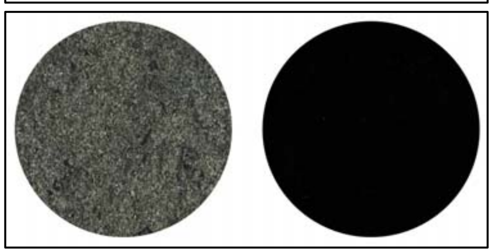
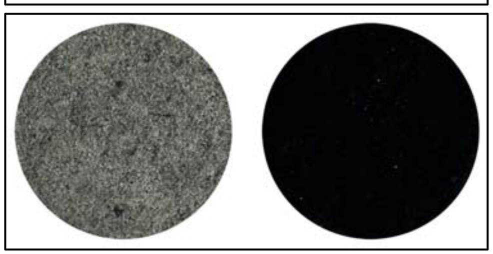
(1) See Core Analysis Procedures page for specific methods used.

Company: Lawrence Berkely Natl. Lab.
Well: Citizen Green #1
Field: King Island

Location: Sec. 28-3N-5E
Elevation:
Drlg Fluid:

File No.: 57111-212369LA
API No.: 04-077-20688
Date : 8/10/2012

Rotary Sidewall Core Analysis Results

Core Images (White Light | UV Light)	Sample Number	Depth	Rec	Perm. Kair	Porosity	Fluid Saturation				Grain Den	Sample Wt.	Method
						Oil	Water	O/W	Total			
		ft	in	md	%	%	%	Ratio	%	g/cc	g	
	24	6400.0	1.5	367.1	33.0	0.0	90.1	0.00	90.1	2.68	23.0	4
	Sst gy vf-fgr slty no stn no flor											
	23	6466.0	1.6	71.9	31.3	0.0	92.0	0.00	92.0	2.68	24.2	4
	Sst gy vf-fgr vslty carb scly smica no stn no flor											
	22	6532.0	1.5	54.8	30.3	0.0	91.2	0.00	91.2	2.70	24.6	4
	Sst gy vf-fgr vslty carb smica no stn no flor											
	21	6598.0	1.7	135.5	31.3	0.0	95.0	0.00	95.0	2.67	23.9	4
	Sst gy vf-fgr slty carb smica no stn no flor											

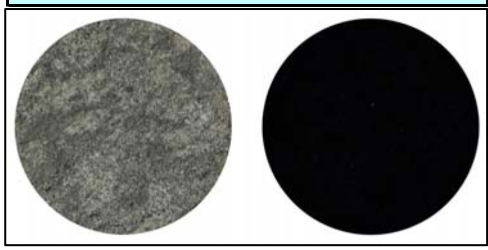
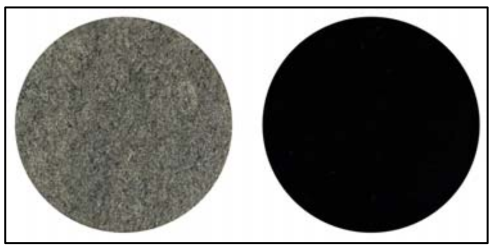
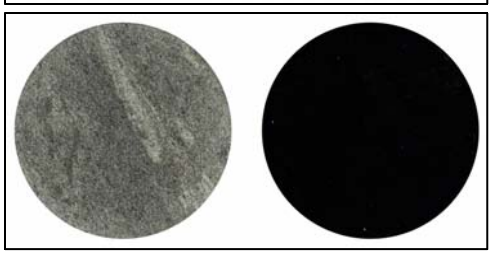
F/ Indicates Visible Fracture(s) Present

Company: Lawrence Berkely Natl. Lab.
Well: Citizen Green #1
Field: King Island

Location: Sec. 28-3N-5E
Elevation:
Drlg Fluid:

File No.: 57111-212369LA
API No.: 04-077-20688
Date : 8/10/2012

Rotary Sidewall Core Analysis Results

Core Images (White Light | UV Light)	Sample Number	Depth ft	Rec in	Perm. Kair md	Porosity %	Fluid Saturation Oil %	Water %	O/W Ratio	Total %	Grain Den g/cc	Sample Wt. g	Method
	20	6664.0	1.4	46.4	30.8	0.0	90.1	0.00	90.1	2.66	22.4	4
	Sst gy vfgr vslty carb scly mica no stn no flor											
	19	6800.0	1.3	4.8	27.7	0.0	96.0	0.00	96.0	2.65	20.0	4
	Sst gy vfgr vslty carb scly smica no stn no flor											
	18	6840.0	1.7	4.0	27.4	0.0	95.2	0.00	95.2	2.65	22.7	4
	Sst gy vfgr vslty cly carb smica no stn no flor											
	16	6918.0	1.7	0.006	1.8	0.0	92.5	0.00	92.5	2.73	30.9	4
	Sst gy vfgr slty vcalc no stn no flor											

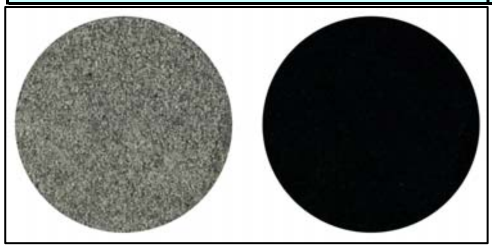
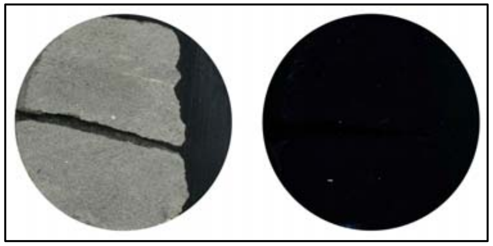
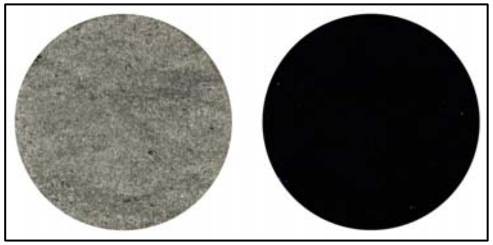
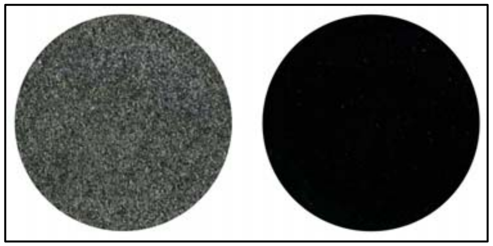
F/ Indicates Visible Fracture(s) Present

Company: Lawrence Berkely Natl. Lab.
Well: Citizen Green #1
Field: King Island

Location: Sec. 28-3N-5E
Elevation:
Drlg Fluid:

File No.: 57111-212369LA
API No.: 04-077-20688
Date : 8/10/2012

Rotary Sidewall Core Analysis Results

Core Images (White Light | UV Light)	Sample Number	Depth (ft)	Rec (in)	Perm. Kair (md)	Porosity (%)	Fluid Saturation: Oil (%)	Water (%)	O/W (Ratio)	Total (%)	Grain Den (g/cc)	Sample Wt. (g)	Method
	15	6936.0	1.4	299.850	34.2	0.0	94.2	0.00	94.2	2.66	23.0	4
	Sst gy vfgr slty mica no stn no flor											
	14	6955.0	0.4	<5.0	22.4	0.0	98.3	0.00	98.3	2.68	5.9	4
	Mdst gy vslty no stn no flor											
	9	7104.0	1.6 F/	114.3	27.6	0.0	86.6	0.00	86.6	2.67	25.8	1
	Sst gy vfgr vslty carb cly mica no stn no flor											
	8	7136.0	1.6	432.6	31.3	0.0	91.9	0.00	91.9	2.69	23.9	4
	Sst gy vf-fgr slty-sslty smica no stn no flor											

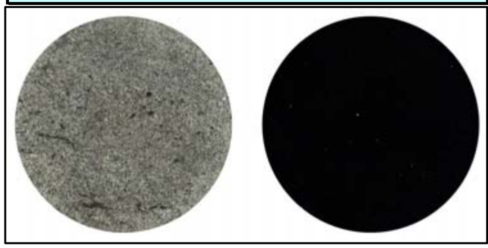
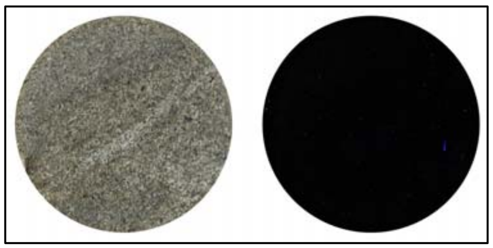
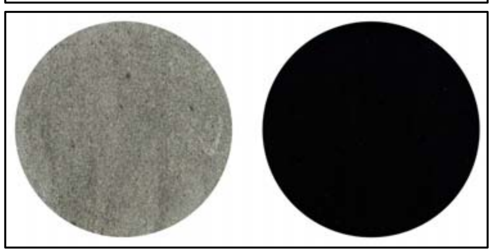
F/ Indicates Visible Fracture(s) Present

Company: Lawrence Berkely Natl. Lab.
Well: Citizen Green #1
Field: King Island

Location: Sec. 28-3N-5E
Elevation:
Drlg Fluid:

File No.: 57111-212369LA
API No.: 04-077-20688
Date : 8/10/2012

Rotary Sidewall Core Analysis Results

Core Images	Sample Number	Depth	Rec	Perm.	Porosity	Fluid Saturation				Grain	Sample	Method
White Light | UV Light				Kair		Oil	Water	O/W	Total	Den	Wt.	
		ft	in	md	%	%	%	Ratio	%	g/cc	g	
	7	7174.0	1.7	4.9	25.2	0.0	95.8	0.00	95.8	2.80	26.2	4
	Sst gy vfgr vslty-slty carb scly mica no stn no flor											
	5	7258.0	1.7	2.3	23.1	0.0	99.0	0.00	99.0	2.70	25.7	4
	Sst gy vf-fgr vslty scly no stn no flor											
	4	7309.0	1.5 F/	11.1	23.0	0.0	99.5	0.00	99.5	2.66	21.7	1
	Sst gy vfgr vslty cly no stn no flor											

* - Air Perm. For sample 6936ft corrected due to data entry error

F/ Indicates Visible Fracture(s) Present

Company: Lawrence Berkely Natl. Lab.
Well: Citizen Green #1
Field: King Island

Location : Sec. 28-3N-5E
Elevation :
Drlng Fluid :

CL File No. : 57111-212369LA
API No. : 04-077-20688
Date : 8/10/2012

Humidity Controlled Core Analysis Results

Sample Number	Depth ft	Perm. Kair md	Routine POR %	Humid POR %	Routine So %	Humid So %	Routine Sw %	Humid Sw %	Routine GD g/cc	Humid GD g/cc	Wt Ratio Hum/Dry Ratio	Clay Factor %
24	6400.0	367.1	33.0	32.1	0.0	0.0	0.0	89.8	2.68	2.66	1.005	5.1
23	6466.0	71.9	31.3	29.7	0.0	0.0	0.0	91.6	2.68	2.64	1.009	8.6
22	6532.0	54.8	30.3	29.3	0.0	0.0	0.0	90.8	2.70	2.68	1.006	5.6
21	6598.0	135.5	31.3	30.8	0.0	0.0	0.0	94.9	2.67	2.66	1.003	2.9
20	6664.0	46.4	30.8	30.0	0.0	0.0	0.0	89.9	2.66	2.64	1.005	4.6
19	6800.0	4.8	27.7	26.2	0.0	0.0	0.0	95.8	2.65	2.61	1.008	8.0
18	6840.0	4.0	27.4	25.7	0.0	0.0	0.0	94.9	2.65	2.61	1.009	9.0
16	6918.0	0.006	1.8	1.2	0.0	0.0	0.0	88.6	2.73	2.72	1.002	2.3
15	6936.0	299.9	34.2	33.5	0.0	0.0	0.0	94.1	2.66	2.64	1.004	4.1
14	6955.0	<5.0	22.4	18.5	0.0	0.0	0.0	98.0	2.68	2.60	1.019	18.9
9	7104.0 F/	114.3	27.6	23.8	0.0	0.0	0.0	84.5	2.67	2.59	1.019	19.2
8	7136.0	432.6	31.3	30.6	0.0	0.0	0.0	91.7	2.69	2.67	1.004	3.9
7	7174.0	4.9	25.2	23.2	0.0	0.0	0.0	95.4	2.80	2.76	1.009	9.4
5	7258.0	2.3	23.1	21.6	0.0	0.0	0.0	98.9	2.70	2.67	1.007	7.3
4	7309.0 F/	11.1	23.0	19.4	0.0	0.0	0.0	99.5	2.66	2.59	1.017	17.4

* - Air Perm. For sample 6936ft corrected due to data entry error

Company: Lawrence Berkely Natl. Lab.
Well: Citizen Green #1
Field: King Island

File No.: 57111-212369LA
API No.: 04-077-20688
Date : 8/10/2012
Core Type: Rotary SW Core

Core Analysis Procedures and Conditions

	Procedure (1)	Procedure (2)	Procedure (3)	Procedure (4)
Sampling Method	Percussion	Percussion	Percussion	Rotary
Drill Coolant	N/A	N/A	N/A	N/A
Jacket Material	Nickel	None	N/A	None
Saturation Method	Dean Stark (Toluene)	Dean Stark (Toluene)	Retort	Dean Stark (Toluene)
Porosity Method				
Grain Volume	Boyle's Law (Helium)	Boyle's Law (Helium)	Bulk Vol-Pore Vol	Boyle's Law (Helium)
Pore Volume	Boyle's Law (Helium)	Bulk Vol-Grain Vol	Summation Of Fluids	Bulk Vol-Grain Vol
Bulk Volume	Pore Vol + Grain Vol	Mercury Displacement	Mercury Displacement	Mercury Displacement
Permeability Method	Air	Empirical	Empirical	Air

Common Conditions

Sleeved Sample Seating Pressure: N/A

Confining Pressure Pore Vol & Permeability: 400 psig

Samples Dried At 235 Degrees Fahrenheit

Additional Extraction by Soxhlet with Methylene Chloride/Methanol

Oil Density used in Calculation: 0.97g/cc

SUMMARY OF LIQUID PERMEABILITY MEASUREMENTS

Net Confining Stress: 3400 psi   Temperature: 75°F
Fluid: Simulated Formation Brine

PETROLEUM SERVICES

Lawrence Berkeley Natl. Laboratory   Core Lab File No: 212369LA

Well: Citizen Green #1
Field: King Island
Location: San Joaquin County

Sample ID	Depth Interval, feet	Sample Orientation	Sample Length, cm	Sample Area, cm^2	Specific Permeability to Brine, mD
24	6400.0	H	2.590	4.247	2.72
23	6466.0	H	2.670	4.255	2.87
22	6532.0	H	2.650	4.287	23.1
21	6598.0	H	2.640	4.250	86.3
20	6664.0	H	2.510	4.203	23.6
19	6800.0	H	2.170	4.226	0.570
18	6840.0	H	2.480	4.181	0.670
16	6918.0	H	2.720	4.213	<0.001
15	6936.0	H	2.580	4.302	139
9	7104.0	H	2.750	4.314	0.00297
8	7136.0	H	2.660	4.218	123
7	7174.0	H	2.670	4.195	0.0973
5	7258.0	H	2.690	4.145	0.0353
4	7309.0	H	2.270	4.201	<0.001

Simulated Formation Brine requested by client: 18,700 ppm with 80% NaCl and 20% KCl

Brine Saturation Procedure

- Place dried samples in saturator cell.
- Vacuum samples overnight.
- Saturate samples with brine at 2000 psi for several hours
- Unload saturator, weigh samples and store under brine
- Load in hydrostatic coreholder at net confining stress.
- Flow through saturate sample with several pore volumes of brine at 400 psi back pressure.
- Begin brine permeability test.

Brine Permeability Procedure

- Kw was measured at three flow rates with the exception of the very low permeability samples.
- For low Kw samples, a constant pressure was applied and time and volume were used to calculate flow rate.
- Flow rate, differential pressure and test temperature were measured at each rate.
- Brine permeability was calculated using sample length & area, brine viscosity, flow rate and differential pressure.

Citizen Green #1 Solid phase chemistry Reservoir Sand Samples WC Whole Core

Quant XRD + Standard Petrophysics Compiled by J. Ajo-Franklin & M. Voltolini 4/27/2013

				Flow Properties		Quant XRD Weight %																						
	Wireline Depth (ft)	TVD (ft)	Formation	Porosity (Helium %)	Permeability (gas mD)	Quartz (%)	(error)	K-Feldspar (%)	K-Feldspar (error)	Albite (%)	Albite (error)	Labradorite (%)	Labrodorite (error)	Andesine (%)	Andesine (error)	Kaolinite (%)	Kaolinite (error)	Chlorite (%)	Chlorite (error)	Pyrite (%)	Pyrite (error)	Horneblende) %	Amphibole (error)	Sepiloite (%)	Sepiolite (error)	Detrital Mica (%)	Detrital Mica (error)	Montmorillonite
8	7136	6492.3	Top Starkey Sand	31.4	432.6	42.825294	1.093	8.66532	0.856536	0	0	0	0	39.57602	1.4783	1.3892618	0.352977	4.6722794	0.459155	0.45348	0.139263	(trace?)	0	0	0	2.418344	0.58034664	0
9	7104	6460.9	Top Starkey Sand	27.6	114.3	39.88028	0.429723	6.516561	0.17615	0	0	0	0	27.354673	0.60929	5.663464	0.44129	8.506132	0.51125	1.2477217	0.147536	0	0	1.3393781	0.19645663	9.491793	0.598864	0
15	6936	6296.8	stringer)	34.2	299.9	44.121063	0.405019	16.600073	0.337001	0	0	0	0	30.431965	0.436227	4.2134457	0.34288	4.4872065	0.40515	0	0	0	0	0	0	0.14624651	0.4589355	0
21	6598	5970.1	Mokelumne River Fm.	31.3	135.5	33.924835	1.08852	21.998177	1.10104	0	0	0	0	34.47543	1.52196	3.6258416	0.448284	5.4110084	0.62217	0.213066	0.15257	0.230967	0.306775	0	0	0.12067264	0.57176816	0
22			Mokelumne River Fm			34.2		24.1		0		0		31		2.9		2		0.5		1.1				4.2		
23	6466	5843.1	Mokelumne River Fm.	31.3	71.9	36.325405	1.79403	12.587689	2.6742	0.22734216	0.48343	36.58359	6.70537	0	0	2.6778169	0.347	5.3593655	0.449744	0.69619757	0.16844	0.5695263	0.21495785	0	0	4.9730654	0.6601443	0
24	6400	5780.1	Mokelumne River Fm.	33	367.1	40.30969	0.5161	17.08427	0.61682	0	0	29.232862	0.649562	3.6258943	0.822466	5.230892	0.481134	3.9868908	0.57289	0	0	0.17200066	0.52136195	0	0	0.35749906	0.65387833	0
WC (shale baffle)	5249	4725.2	Mokelumne River Fm.	NA	NA	17	-	32.7	-	6.5	-	0	-	0	-	34.9	-	0	0	0	-	0	-	0	-	8.4	-	trace
WC (top reservoir sand)	5247	4723.5	Mokelumne River Fm.	NA	NA	27.8	-	16.2	-	34	-	0	-	0	-	3.6	-	17	0	0	-	0	-	0	-	0	-	1.1

README.kingIslandPCsat

J. Ajo-Franklin, June 22nd, 2022 : Contact info, ja62@rice.edu, (510)-735-4350

This submission includes information on helium pycnometry & MICP measurements conducted on sidewall sub-samples from the Citizen Green #1 well drilled on King Island, CA (API 07720688) as part of the WESTCARB partnership basin characterization effort. Cores were acquired with a rotary sidewall tool at a range of depths. See the sidewallCore submission for additional formation data.

https://edx.netl.doe.gov/dataset/citizen-green-1-well-sidewall-core-permeability-studies

Samples are from the Starkey and Mokelumne River formation as well as one Domengine sample from Black Diamond Mine Regional Park. The location of the cores are shown in citGreen_compositeSidewal_lIllus_v1.jpg. Samples WestCarb8 and WestCarb9 are located in the 1st Starkey Sand while samples WestCarb23 and WestCarb24 are in the middle of the Mokelumne River formation. The Domengine sample is from BDMRP as mentioned previously.

All measurements were conducted at Lawrence Berkeley National Laboratory (LBNL) & Stanford University (courtesy of Ronny Pini).

Files included:

README.kingIslandPCsat :	This file
Cal1.txt :	Calibration file for pycnometer
Cal2.txt :	Calibration file for pycnometer
Cal3.txt :	Calibration file for pycnometer
Cal4.txt :	Calibration file for pycnometer
Cal5.txt :	Calibration file for pycnometer
citGreen_compositeSidewal_lIllus_v1.jpg :	Plot of sidewall locations from CG #1 well
DOMERP.XLS	MICP data for Domengine Sample
Log File.docx	Notes on pycnometer and MICP data
WECA8RP.XLS	MICP data for Starkey Sample, Sidewall #8
WECA9RP.XLS	MICP data for Starkey Sample, Sidewall #9
WECA23RP.XLS	MICP data for Mokelumne River Sample, Sidewall #23
WECA24RP.XLS	MICP data for Mokelumne River Sample, Sidewall #24
WestCarb8_300R.txt	Helium pycnometer data for Sidewall #8
WestCarb8_500R.txt	Helium pycnometer data for Sidewall #8
WestCarb9_500R.txt	Helium pycnometer data for Sidewall #9
WestCarb23_500R.txt	Helium pycnometer data for Sidewall #23
WestCarb24_500R.txt	Helium pycnometer data for Sidewall #24

Sample ID:	weca23rp		
Operator:			
Submitter:	Ronny		
File:	C:\DOCUME~1\EVERYO~1\MYDOCU~1\RONNY\WECA23RP.SMP		
LP Analysis Time:	3/26/2013 3:09:17PM	Sample Weight:	0.3120 g
HP Analysis Time:	3/26/2013 4:18:03PM	Correction Type:	Blank
Report Time:	3/26/2013 4:18:03PM	Show Neg. Int:	No

Summary Report

Penetrometer parameters

Penetrometer: #13-0376 (13) 3 Bulb, 0.412 Stem, Solid

Pen. Constant:	11.007	µL/pF	Pen. Weight:	61.5470	g
Stem Volume:	0.4120	mL	Max. Head Pressure:	4.6800	psia
Pen. Volume:	3.6621	mL	Assembly Weight:	108.7390	g

Hg Parameters

Adv. Contact Angle:	140.000	degrees	Rec. Contact Angle:	140.000	degrees
Hg Surface Tension:	485.000	dynes/cm	Hg Density:	13.5386	g/mL

User Parameters

Param 1:	N/A	Param 2:	N/A	Param 3:	N/A

Low Pressure:

Evacuation Pressure:	50	µmHg
Evacuation Time:	5	mins
Mercury Filling Pressure:	0.21	psia
Equilibration Time:	20	secs

High Pressure:

Equilibration Time:	20	secs

Blank Correction Sample:
C:\DOCUME~1\EVERYO~1\MYDOCU~1\RONNY\CALP1RP3.SMP
(From Pressure 0.10 to 60000.00 psia)
Intrusion Data Summary

Total Intrusion Volume =	0.2397	mL/g
Total Pore Area =	5.901	m²/g
Median Pore Radius (Volume) =	57312	A
Median Pore Radius (Area) =	55	A
Average Pore Radius (2V/A) =	813	A
Bulk Density at 0.21 psia =	1.5646	g/mL
Apparent (skeletal) Density =	2.5039	g/mL
Porosity =	37.5113	%
Stem Volume Used =	18	% ****

Pore Structure Summary

Threshold Pressure:	0.45	psia (Calculated)
Characteristic length =	2384835	A
Conductivity formation factor =	0.033	
Permeability constant =	0.00442	
Permeability =	32944.5414	mdarcy
BET Surface Area =	230.0000	m²/g
Pore shape exponent =	1.00	
Tortuosity factor =	2.052	
Tortuosity =	8.8139	
Percolation Fractal dimension =	2.957	

Backbone Fractal dimension =	2.732	

Mayer Stowe Summary

Interstitial porosity =	47.6300	%
Breakthrough pressure ratio =	3.8014	

Material Compressibility

Linear Coefficient =	-2.7098e-03	1/psia
Quadratic Coefficient =	5.4330e-05	1/psia^2

Sample ID:	weca24rp				
Operator:					
Submitter:	Ronny				
File:	C:\DOCUME~1\EVERYO~1\MYDOCU~1\RONNY\WECA24RP.SMP				
LP Analysis Time:	3/27/2013 4:56:08PM	Sample Weight:	0.3120 g		
HP Analysis Time:	3/27/2013 6:38:53PM	Correction Type:	Blank		
Report Time:	3/27/2013 6:38:53PM	Show Neg. Int:	No		

Summary Report
Penetrometer parameters

Penetrometer:	#13-0376 (13) 3 Bulb, 0.412 Stem, Solid				
Pen. Constant:	11.007	µL/pF	Pen. Weight:	61.6860	g
Stem Volume:	0.4120	mL	Max. Head Pressure:	4.6800	psia
Pen. Volume:	3.6621	mL	Assembly Weight:	109.0800	g

Hg Parameters

Adv. Contact Angle:	140.000	degrees	Rec. Contact Angle:	140.000	degrees
Hg Surface Tension:	485.000	dynes/cm	Hg Density:	13.5379	g/mL

User Parameters

Param 1:	N/A	Param 2: N/A	Param 3: N/A

Low Pressure:

Evacuation Pressure:	50	μmHg
Evacuation Time:	5	mins
Mercury Filling Pressure:	0.21	psia
Equilibration Time:	20	secs

High Pressure:

Equilibration Time:	20	secs

Blank Correction Sample:
C:\DOCUME~1\EVERYO~1\MYDOCU~1\RONNY\CALP1RP3.SMP
(From Pressure 0.10 to 60000.00 psia)
Intrusion Data Summary

Total Intrusion Volume =	0.2037	mL/g
Total Pore Area =	7.690	m^2/g
Median Pore Radius (Volume) =	47693	A
Median Pore Radius (Area) =	57	A
Average Pore Radius (2V/A) =	530	A
Bulk Density at 0.21 psia =	1.6928	g/mL
Apparent (skeletal) Density =	2.5837	g/mL
Porosity =	34.4818	%
Stem Volume Used =	15	% ****

Pore Structure Summary

Threshold Pressure:	0.49	psia (Calculated)
Characteristic length =	2186853	A
Conductivity formation factor =	0.025	
Permeability constant =	0.00442	
Permeability =	20916.0376	mdarcy

BET Surface Area =	230.0000	m^2/g
Pore shape exponent =	1.00	
Tortuosity factor =	2.079	
Tortuosity =	7.3470	
Percolation Fractal dimension =	2.893	
Backbone Fractal dimension =	2.698	

Mayer Stowe Summary

Interstitial porosity =	47.6300	%
Breakthrough pressure ratio =	3.8014	

Material Compressibility

Linear Coefficient =	7.2463e-05	1/psia
Quadratic Coefficient =	-3.0043e-04	$1/psia^2$

Attachment 4

Fault Stability and Risk of Induced Seismicity

Fault stability and induced seismicity risk were evaluated using the Stanford Center for Induced and Triggered Seismicity (SCITS) Fault Slip Potential (FSP 2.0) software, a probabilistic screening tool that uses Coulomb-Mohr failure criterion to calculate the conditions under which failure (slip) will occur on fault planes due to pressure perturbations from injection.

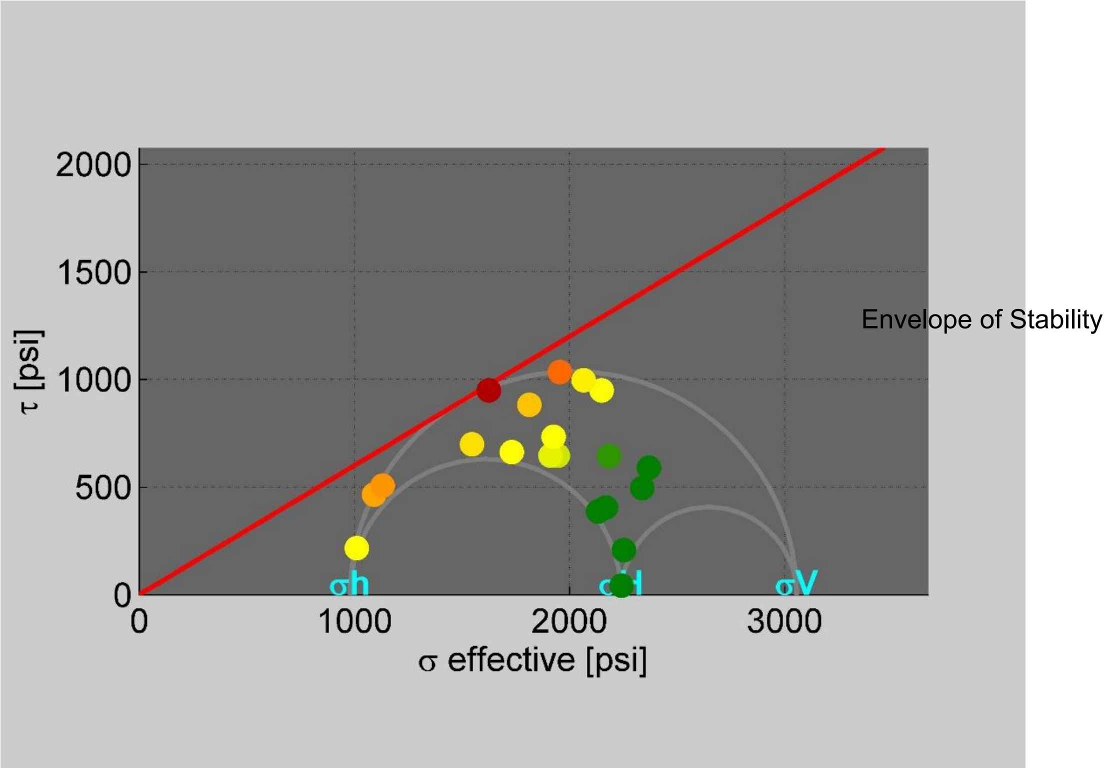
In 1979, Jaeger and Cook described Mohr–Coulomb failure criterion ($|\tau|$) using principal stresses to evaluate the conditions under which a material will fail, such that:

$$|\tau| = \tau_0 + \sigma \tan \varphi$$

Where:

$|\tau|$ is the Mohr-Coulomb failure criterion
τ_0 is the apparent internal cohesion
σ is the principal stress
φ is the angle of internal friction

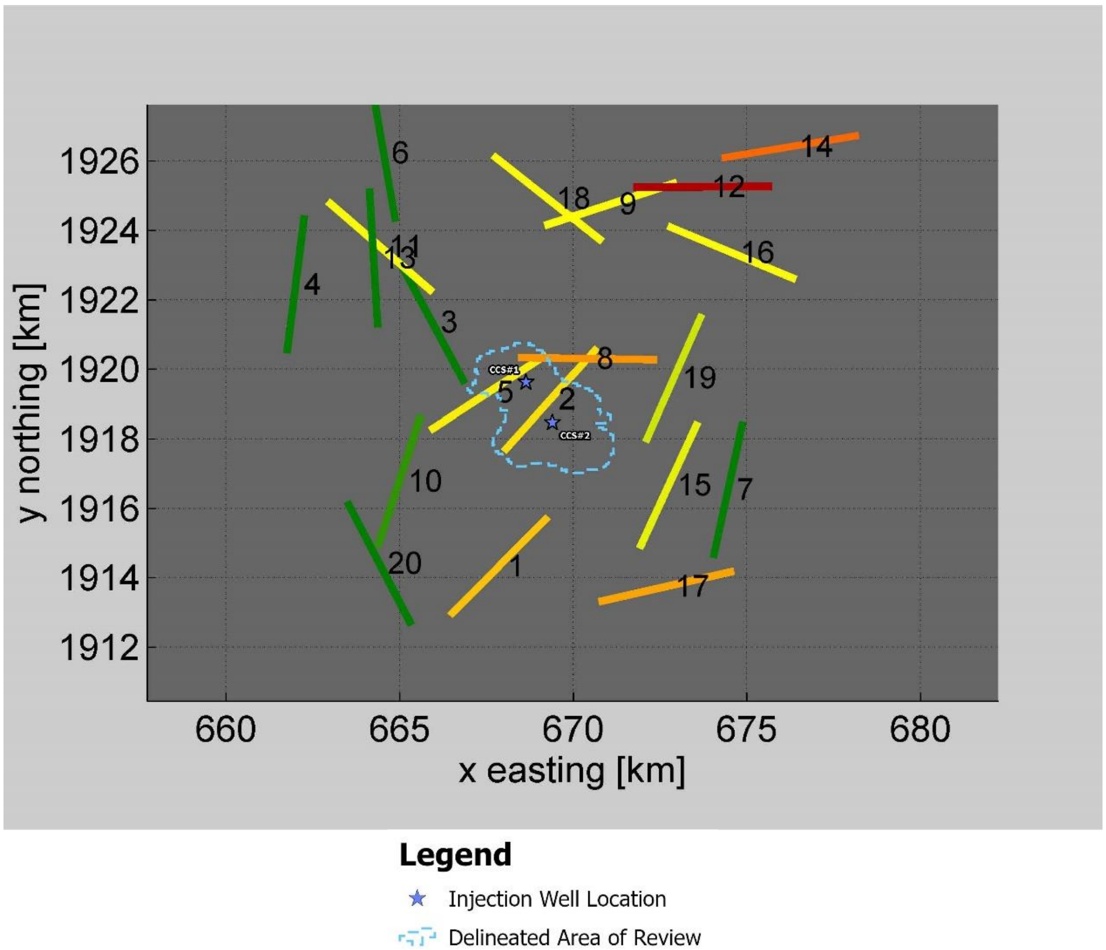
FSP 2.0 (Walsh et al., 2017) uses MatLab computational software to incorporate site-specific parameters, including in-situ vertical and horizontal stress, hydrologic conditions, injection volume and pressure to evaluate the threshold pressure at which a fault will slip, depending on the location and orientation of the fault. The results are plotted on a Mohr diagram, which identifies the envelope of stability as shown here:



Mohr diagram of calculated Coulomb-Mohr stress criterion for generated faults.

Note: Each of the colored dots represents a fault and the probability of failure at the plotted critical stress. The dots are coded from green (very low-to-no risk of slip) to dark red (highest risk of slip).

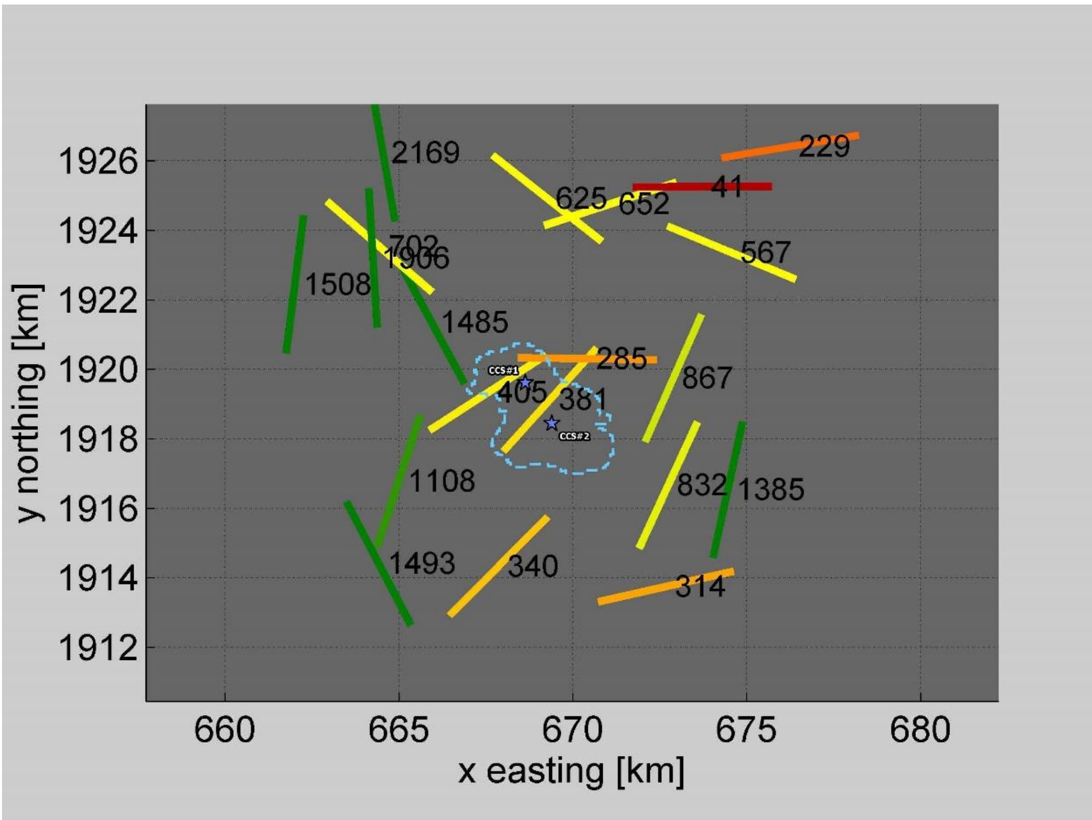
FSP 2.0 was used to evaluate the potential for induced seismicity due to pressure perturbations from carbon dioxide injection at proposed injection wells CCS#1 and CCS#2. The pressure changes used in FSP 2.0 were based upon the injection volumes, pressure, and period of injection. Maximum horizontal stress orientation was approximated from the conterminous US maximum horizontal stress orientation map (Zoback et al., 1991; Lundstern and Zoback, 2020). Additional FSP input included geomechanical and hydrological parameter values from the static and dynamic models demonstrated in this application. To evaluate slip potential on faults of varying orientations at varying distances from the injection wells, FSP 2.0 enables users to generate random faults. Twenty faults were generated at varying strike and dips and the estimated pore pressure change due to injection calculated. The results, as shown in the Mohr diagram, provide the distance and orientation of faults at which slip is likely to occur during injection.



Injection well locations (CCS #1 and CCC #2) and randomly generated faults.

Note: Faults are colored coded from most likely to slip (dark red) to least likely (green)

Pressure changes through time based were based on the proposed 20-year injection period. The calculated maximum pressure change (41psi) occurred on Fault #12 in 2045, the last year of injection.



Legend

Injection Well Location

Delineated Area of Review

Coulomb-Mohr pressure change to slip in psi within the AoR.

The FSP 2.0 screening was based on the most conservative estimate of potential slip and provides a “worst case” scenario for induced seismicity on the randomly generated faults. The number and distribution of faults are hypothetical. No faults were identified within the 3D seismic volume at the critical distance, orientation, or potential pressure changes that would exceed the Coulomb-Mohr criterion. During microseismicity monitoring (described in the Testing and Monitoring Plan), small events of Magnitude 1.0 may suggest faulting not previously identified. The results of this screening will enable Pelican to observe and evaluate pressure changes of any faults similar in orientation and distance to those generated by FSP 2.0 with higher slip potential.

FSP 2.0 Input

Stress Data		
Vertical gradient	0.75	psi/ft
A-Phi Parameter	0.60709	
Maximum Horizontal Stress Direction	80	Degrees (azimuth)
Initial Reservoir Pressure Gradient	0.28	psi/ft
Reference Depth	6500	ft
Hydrology Data		
Unit Thickness	500	ft
Porosity	30	%
Permeability	250	mD
Injection Wells		
CCS#1	3424.7	metric tons/day
CCS#2	2054.8	metric tons/day
Injection Period	20	years
Additional Parameters		
Density of Super Critical CO^{2}*	772.3382	kg/m^3
Dynamic Viscosity of Super Critical CO^{2*}	6.82E-05	Pascal-seconds
Compressibility	3.60E-08	Pascal^{-1}
Rock Compressibility	1.08E-09	Pascal^{-1}

Notes:

psi/ft: pounds per square inch per foot

A-phi parameter is FSP 2.0 default

Hydrology data approximated

mD: millidarcies

kg/m^3: kilogram per cubic meter

** calculated at 310 bars and 76 degrees C*

References:

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