OMB No. 2040-0042 Approval Expires 11/30/2014

EPA

United States Environmental Protection Agency

Underground Injection Control
Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number

	T/A	C
U		

Read Attached Instructions Before Starting

For Official Use Only

Application approved mo day year	Date received mo day year	Permit Number	Well ID	FINDS Number

II. Owner Name and Address			III. Operator Name and Address		
Owner Name: Panoche Energy Center, LLC			Owner Name: Panoche Energy Center, LLC		
Street Address: 43883 West Panoche Road		Phone Number: (559) 659-2270	Street Address: 43883 West Panoche Road		Phone Number: (559) 659-2270
City: Firebaugh	State: CA	ZIP CODE: 93622	City: Firebaugh	State: CA	ZIP CODE: 93622

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
[x] Yes [ ] No	[x] Private [ ] Federal [ ] Other	[x] Owner [ ] Operator	4911

VIII. Well Status *(Mark "x")*

[x] A. Operating	Date Started mo day year: 03/03/2009	[ ] B. Modification/Conversion	[ ] C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

[x] A. Individual	[ ] B. Area	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
		4	2	Lat Long Sec. XI below is center of project. See attached table for individual wells.

X. Class and Type of Well *(see reverse)*

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
Class I	I		

XI. Location of Well(s) or Approximate Center of Field or Project

Latitude			Longitude			Township and Range							
Deg	Min	Sec	Deg	Min	Sec	Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
36	39	2.8	120	35	4.2	05	15S	13E	SW				

XII. Indian Lands (Mark 'x')

[ ] Yes
[x] No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*	B. Phone No. *(Area Code and No.)*
Melvin D Murphy	(817) 707-9219
C. Signature	D. Date Signed
	03/05/2019

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

UIC PERMIT APPLICATION TABLE:
NAME AND LOCATION OF INDIVIDUAL CLASS 1 INJECTION WELLS

Well Status	Well Name	Surface Location
Currently Operating Well	IW1	36° 39' 2.321" N, 120° 35' 1.777" W
Currently Operating Well	IW2	36° 39' 2.164" N, 120° 35' 5.637" W
Currently Operating Well	IW3	36° 39' 2.264" N, 20° 35' 0.170" W
Currently Operating Well	IW4	36° 39' 3.372" N, 120° 35' 9.076" W
Proposed Well	IW5	36° 39' 0.201" N, 120° 35' 1.069" W
Proposed Well	IW5	36° 39' 0.248" N, 120° 35' 8.834" W

www.haleyaldrich.com

2019 UPDATE AND RE-SUBMITTAL OF PEC'S 2017 UIC PERMIT RENEWAL APPLICATION PANOCHE ENERGY CENTER FIREBAUGH, CALIFORNIA

by
Haley & Aldrich, Inc.
Oakland, California

for
Panoche Energy Center, LLC
Firebaugh, California

File No. 132869-004
March 2019

HALEY & ALDRICH, INC.
1956 Webster Street
Suite 300
Oakland, CA 94612
510.879.4544

1 March 2019
File No. 132869-004

United States Environmental Protection Agency – Region 9
Regional Groundwater Division
Groundwater Office (Mail Code WTR-9)
75 Hawthorne Street
San Francisco, California 94105-3901

Attention: George Robin

Subject: 2019 Update and Re-submittal of PEC's 2017 UIC Permit Renewal Application
Panoche Energy Center
Firebaugh, California

Dear Mr. Robin:

On behalf of Panoche Energy Center, LLC (PEC), Haley & Aldrich, Inc. (Haley & Aldrich) has submitted this revised application for renewal of the PEC Underground Injection Control (UIC) permit in accordance with the requirements of the U.S. Environmental Protection Agency (USEPA) UIC Program Class I Non-Hazardous Waste Injection Wells Permit application document 7520-6. PEC has been permitted by the USEPA's UIC Program under Permit Number CA10600001, beginning in April 2008. With the goal to continue to operate these injection wells at PEC, a permit renewal application was submitted to USEPA on 20 October 2017 (No. R9UIC-CA1-FY17-2R). After minor revision, USEPA provided administrative approval on 20 February 2018. In a letter dated 18 May 2018, USEPA requested additional information for their technical review of the permit renewal application. On 12 July 2018 PEC provided a summary response to USEPA that included follow-up questions. USEPA replied to the letter on 7 September 2018, and PEC has now prepared the attached re-submittal of the permit application to provide all requested information to USEPA.

Please contact us at your earliest convenience if you have any questions or comments regarding these attachments and procedures.

Sincerely yours,
HALEY & ALDRICH, INC.

Charles Payne, PG
Project Geologist

Murray Einarson, PG, CHG, CEG
Principal Hydrogeologist

Enclosures

c: Panoche Energy Center, LLC; Attn: Melvin D. Murphy, Robin G. Shropshire

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Table of Contents

Page

List of Figures

1. Executive Summary

1.1 INTRODUCTION

On behalf of Panoche Energy Center, LLC (PEC), Haley & Aldrich, Inc. (Haley & Aldrich) has submitted this revised application for renewal of the PEC Underground Injection Control (UIC) permit in accordance with the requirements of the U.S. Environmental Protection Agency (USEPA) UIC Program Class I Non-Hazardous Waste Injection Wells Permit application document 7520-6. The PEC is a simple-cycle power generation plant that consists of four natural gas-fired combustion turbine generators. PEC currently disposes of the cooling water blowdown and other nonhazardous wastewaters associated with plant operations via four Class I deep injection wells. These injection wells were authorized under USEPA UIC program Permit CA10600001 in 2008 for construction of up to six injection wells (IW1, IW2, IW3, IW4, IW5, and IW6). IW1 & IW2 were installed at the PEC site in 2009. IW3 & IW4 were installed in 2009 and deepened in 2011 and 2012. IW3 was fracture stimulated in May of 2012. In 2014, additional perforations were added to IW4 during well repair and IW3 was also re-perforated in 2014.

With the goal to continue to operate these injection wells at PEC, a permit renewal application was submitted to USEPA on 20 October 2017 (No. R9UIC-CA1-FY17-2R). After minor revision, USEPA provided administrative approval on 20 February 2018. In a letter dated 18 May 2018, USEPA requested additional information for their technical review of the permit renewal application. On 12 July 2018, PEC provided a summary response to USEPA that included follow-up questions. USEPA replied to the letter on 7 September 2018, and PEC has now prepared the attached this re-submittal of the permit application to provide all requested information to USEPA.

1.1.1 Organization of this Submittal

In addition to this executive summary and the signed UIC Permit Application Form, this renewal application includes the required Attachments listed below. Each attachment includes relevant tables figures, and exhibits (historical reports that EPA requested be included with this submittal). The exhibits are listed in the table of contents for each Attachment, and are provided on a CD for convenience.

- Attachment A: Area of Review Methods
- Attachment B: Maps of Wells and Area of Review
- Attachment C: Corrective Action Plan and Well Data
- Attachment D: Maps and Cross Sections of USDWs
- Attachment F: Maps and Cross Sections of Geologic Structure of Area
- Attachment H: Operating Data
- Attachment I: Formation Testing Program
- Attachment J: Stimulation
- Attachment K: Injection Procedures
- Attachment L: Construction Procedures
- Attachment M: Construction Details

- Attachment O: Plans for Well Failures
- Attachment P: Current Monitoring Program
- Attachment Q: Plugging and Abandonment Plan
- Attachment R: Necessary Resources
- Attachment S: Aquifer Exemptions
- Attachment T: EPA Permits Held by Facility
- Attachment U: Description of Business

1.1.2 Site Location

The PEC site is located at 43883 West Panoche Road, in an unincorporated area of western Fresno County, just east of the Panoche Hills and approximately 16 miles south-southwest of the city of Firebaugh, California (Figure 1). The site is approximately 50 miles west of the City of Fresno and approximately 2 miles east of Interstate 5. The site is in the southwest quarter of Section 5, Township 15 South, Range 13 East on the United States Geological Survey Quadrangle map (Figure 2). The assessor's parcel number of the parcel containing the site is 027-060-78S. Figure 3 shows the plant outline and location of the four injection wells (IW1's wellhead is located at 36° 39' 02.27" N, 120° 35' 00.17" W, IW2's wellhead is located at 36° 39' 02.27" N, 120° 35' 00.17" W, IW3's wellhead is located at 36° 39' 02.27" N, 120° 35' 00.17" W and IW4's wellhead is located at 36° 39' 03.372" N, 120° 35' 09.076" W).

1.1.3 Facility and Operations

The PEC facility is a simple-cycle peak power generation plant consisting of four General Electric LMS100 natural gas-fired combustion turbine generators (CTGs) and associated equipment. The total net generating capacity is approximately 400 megawatts (MW) with each CTG capable of generating approximately 100 MW. The plant is owned and operated by PEC (also referred to as the Applicant). PEC is designed as a peaking facility to meet electric generation load during periods of high demand. Auxiliary equipment includes: a mechanical draft cooling tower, circulating water pumps, water treatment equipment, natural gas compressors, generator step-up and auxiliary transformers, the enhanced wastewater treatment system and water storage tanks (Figure 3).

Wastewater generated at the facility is disposed of using four Class I nonhazardous injection wells (IW1, IW2, IW3, and IW4). Two additional wells are available in PEC's current UIC Permit but, have not been drilled. As specified in the current UIC Permit, PEC's wells are authorized to receive cooling tower blowdown water, reverse osmosis system reject water, evaporative cooler blowdown water, combustion turbine intercooler condensate, and oil/water separator discharge water (see Attachment K).

Process water for the cooling towers and other non-potable water supplied to the PEC from two groundwater wells is disposed of on-site using a deep-well injection system (Figure 3). The production water wells (PEC-1 and PEC-2) were installed in 2008 to supply service and fire water for the PEC. Wells PEC-1 and PEC-2 (Figure 3) are completed in a confined aquifer from approximately 1,000 to 1,350 feet below ground surface (bgs) and from 960 to 1,360 feet below ground surface (bgs), respectively (see Attachment D for details).

1.2 AREA OF REVIEW

The Area of Review (AOR) is the radius around the injection well in which impacts from injection could potentially occur. It is based on parameters of the target injection zones and the location of the underground sources of drinking water (USDWs).

As discussed in Attachment A, because the Panoche Formation target injection zone is naturally over-pressurized, and the intermittent nature of wastewater injection at the PEC facility, conventional calculation methodologies of the Zone of Endangered Influence (ZEI) would not apply. The ZEI at PEC was determined utilizing an alternative method that evaluates the pressure increase necessary to move fluid upward in a wellbore that existed prior to the start of injection operations at PEC. Thus, for the purpose of this permit renewal application (and all subsequent submittals), PEC proposes using the entry pressure based on the minimum gel strength limit of 41.96 pounds per square inch as limit as the AOR review limit for this project.

In addition, this review considers the locations and plug and abandonment status of the wells within the AOR that have penetrated the target injection zones (Table A-1, Figure A-1, and Table C-1), which all have documented abandonment records filed with the California Department of Oil, Gas, and Geothermal Resources (DOGGR). Using reasonable site-specific data and assumptions, calculations indicate that these wells will not provide a conduit for fluid migration and will not result in impacts to USDWs. As such, a corrective action program to locate and seal wells is not proposed (See Attachment C).

1.3 UNDERGROUND SOURCES OF DRINKING WATER

Freshwater aquifers, including information on the original estimate for the depth to base of fresh water (i.e., less than 10,000 milligrams per liter of total dissolved solids [TDS]), were described in URS's UIC Well Completion Reports all submitted to USEPA in 2009 (see Attachment D for details) and included a description of the freshwater aquifer units (e.g., name, age, depth, thickness, lithology, and average TDS). Based on additional analysis performed for this submittal (see Attachment D for details), PEC believes that the base of the lowermost USDW extends to the base of the sandy interval at the stratigraphic contact between the Kreyenhagen Shale and the overlying Tumey Formation at a depth of 3,430 feet below kelly bushing in IW1 (see dip and strike geologic cross section in Attachment F). Below this depth, the Kreyenhagen Shale indicates low overall deep resistivity character and a general lack of "clean" sand. All aquifers below the top of the Kreyenhagen are not considered USDWs (See Attachment D for details).

1.4 GEOLOGY OF INJECTION AND CONFINING ZONES

Attachment F provides a geological evaluation of the subsurface stratigraphy in the vicinity of the PEC site, and the selection of target injection zones. The geological evaluation indicates that both the target injection zones and overlying confining intervals can be correlated and mapped within a large outcrop area west of the site (Figure F-1). The geological relationships between the target zones and the other geologic units of the area (Panoche Hill out crop and the Cheney Field type section) can be seen on Figure F-2. Two plans were presented for possible well completion in the 2008 permit application: Plan A and B. Under Plan A (not the current configuration), the injection zone would be in the Eocene to upper Cretaceous age Domengine, Laguna Seca, and Moreno Formations below the Kreyenhagen Shale Formation (confining zone). Under Plan B (the current well field configuration), the injection zone is the

Late Cretaceous age, upper three sandstone-dominated intervals of the Panoche Formation below the Marca and Tierra Loma Shale members of the Moreno Formation (confining zone). IW1 and IW2 were installed at the PEC site in 2009 as Plan B completions. IW3 and IW4 were installed in 2009 as plan A completions but were deepened in 2011 and 2012 and converted to plan B completions. All the wells at PEC are now injecting into the top of the Panoche Formation.

1.5 DRILLING, STIMULATION AND TESTING PROGRAMS

Attachments I, J, L, and M provide details on the permitted, currently drilled and operating wells (IW1, IW2, IW3, and IW4) and the proposed drilling and testing of two addition wells (IW5 and IW6), if required, at the PEC site. Installation and testing of these wells all followed specific guidelines for Class I nonhazardous wells as required by Control UIC Permit CA10600001. Both types of Mechanical Integrity Tests (MITs) are required after drilling and well installation. An internal MIT is required in each well once every five years. During the initial Internal MIT, the annulus is pressurized to ensure that there is no leakage between the annulus and the injection zone or overlying geologic formation. An External MIT consists of temperature logging and radioactive tracer (RAT) surveys. MITs are submitted to USEPA within 60 days of completing the work. Additionally, procedures to acid stimulate the wells for periodic clean-out of the wells have been presented in Attachment J.

1.6 INJECTION MONITORING AND REPORTING

Attachment P outlines the ongoing monitoring program for injection operations at the PEC site. The monitoring program consists of continuous readings of injection pressure, annular pressure, flow rate, and volume, as well as quarterly sampling and analysis of wastewater injectate. Continuous pressure monitoring of in the annulus and tubing provide the capability of detecting any leaks within the tubing or at the packer.

Measurements and analytical data are submitted to USEPA on a quarterly basis and maintained at the site for inspection. Injection fluids are monitored for a suite of organic and inorganic constituents as well as physical parameters (Attachment P). A hazardous waste determination has been made on the injection fluid during the current permitted operation (See Attachment H) and will be made any time there is a change in the waste stream or treatment process that could impact water quality. Injection pressure transducers, casing-tubing annulus pressure transducers, injection rate meters, and temperature meters were all installed in early 2009. These systems are also discussed in more detail in Attachment P.

1.6.1 Quarterly Monitoring Reports

Each quarterly monitoring report prepared and submitted to USEPA will contain a summary of the well performance, volumes of wastewater injected, and the results of chemical testing of a sample of the injection fluid. A sample of waste water is collected by PEC personnel in the middle of each quarter and submitted to a California Certified Laboratory for chemical analysis. These reports are due at the end of the month following the end of each quarter (see Monthly Schedule in Appendix B of the current UIC permit).

1.6.2 Annual Monitoring Reports

USEPA requires that the Fourth Quarter monitoring report of each year contain additional information about the reservoir that the wells are injecting into. This is part of a supplemental evaluation called a

Zone of Endangering Influence evaluation. This information is combined with the Fourth Quarter monitoring report as an Annual Monitoring Report and submitted to USEPA by the end of January each year.

1.6.3 Annual Mechanical Integrity Tests and Fall-Off Tests

Currently two types of MITs are required for each well at the PEC site. An internal MIT is required in each well once every five years. During an Internal MIT, the annulus of the well is pressurized to ensure that there is no leakage between the annulus and the injection zone or overlying geologic formation.

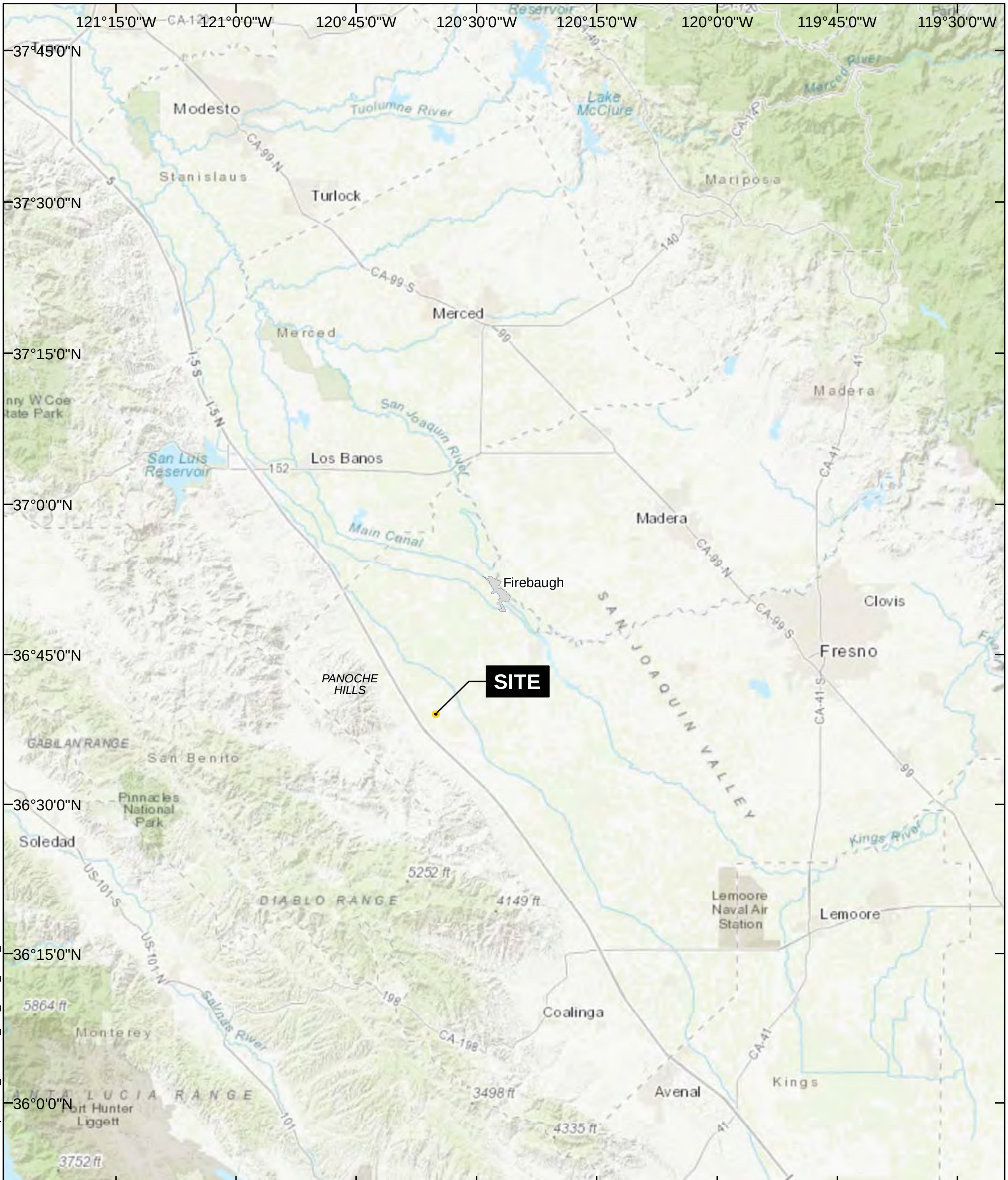
External MITs, consisting of dual temperature logging and RAT surveys at each well, are required annually in all operating injection wells in accordance with the requirements of PEC's UIC Permit. The external MITs consist of a baseline temperature log and temperature decay log combined with a RAT survey at each well as required to comply with annual well integrity testing requirements per Section C paragraph 2(b)(ii) of the Permit. The purpose of these external MITs is to demonstrate that the fluid injected into the well is confined to the permitted injection zone and does not cause significant flow within or between USDWs. Work plans are submitted to USEPA prior to performing the work and a report documenting the MITs is submitted to USEPA within 60 days of completing the work.

Pressure fall-off tests (FOTs) are required annually by USEPA to document changes in the formation properties in each well's injection interval. Performing FOTs requires that the injection wells be offline for up to several days. During a FOT, wastewater is injected into a well and then injection stops. Injection into other wells must be curtailed while testing is performed in a well. The rate that pressure in the formation equilibrates is recorded and the data analyzed. Because all the wells at PEC are injecting into a common interval (the upper three sandstone units of the Panoche Formation) one well (IW2) has been used for FOT analysis of PEC's well field (Attachment P).

1.7 WELL PLUGGING AND ABANDONMENT

Once an injection well is no longer necessary or not performing as required (and cannot be repaired), the well will be abandoned in accordance with DOGGR and USEPA abandonment procedures. Attachment Q provides a plugging and abandonment program for the injection wells, including the exact depths of the plugs and abandonment procedures.

FIGURES



N

0 10 20

SCALE IN MILES

MAP SOURCE: ESRI
SITE COORDINATES: 36°39'3"N, 120°35'4"W

HALEY ALDRICH

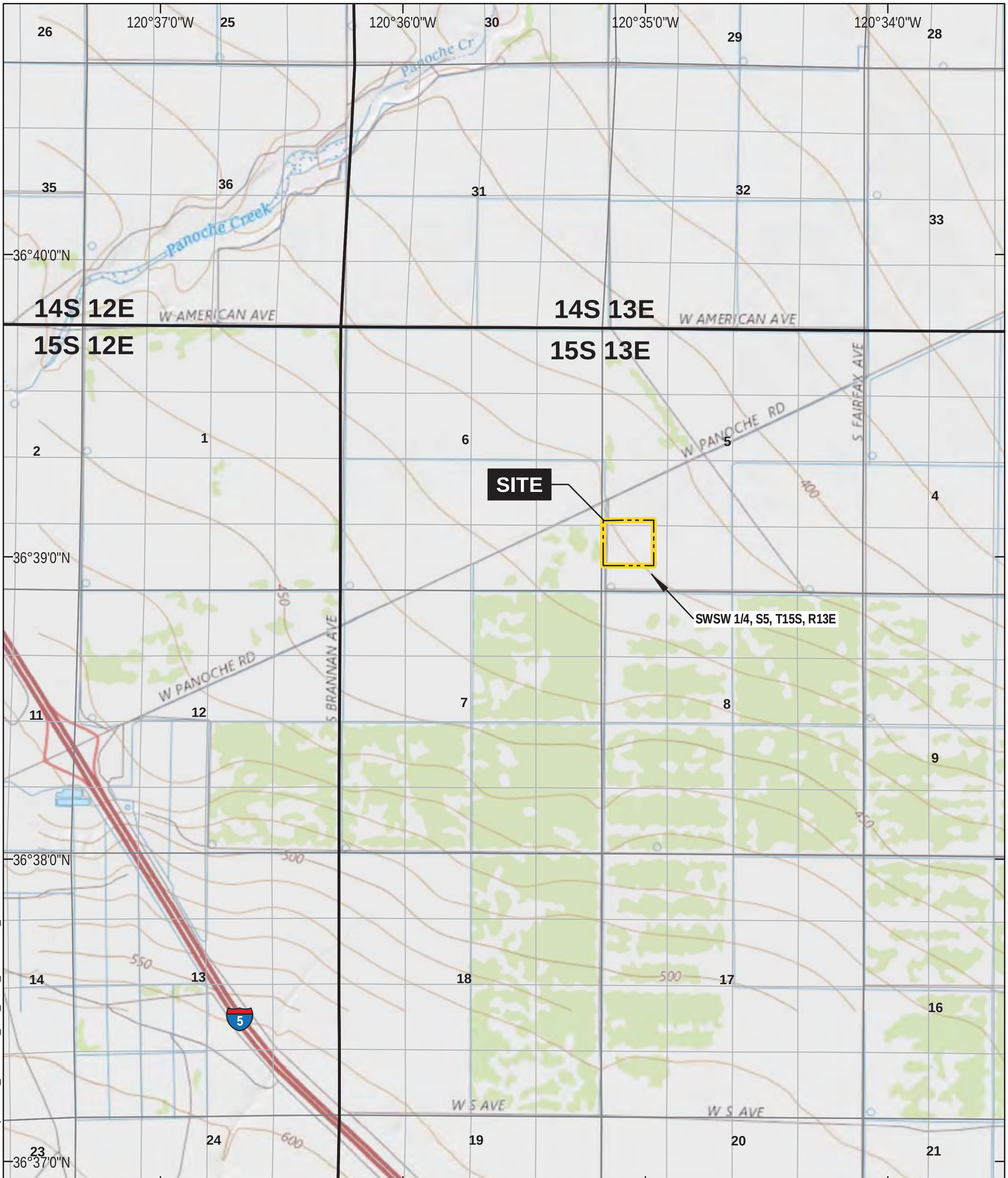
PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

SITE VICINITY

APPROXIMATE SCALE: 1 IN = 20 MI
OCTOBER 2017

FIGURE 1

GIS FILE PATH: G:\39073_Panoche_Compliance\GIS\Maps\2017_08\39073_007_0001_SITE_VICINITY.mxd — USER: ibruce — LAST SAVED: 10/17/2017 5:12:17 PM



N

0 0.5 1

SCALE IN MILES

MAP SOURCE: ESRI
SITE COORDINATES: 36°39'5"N, 120°35'7"W

HALEY ALDRICH

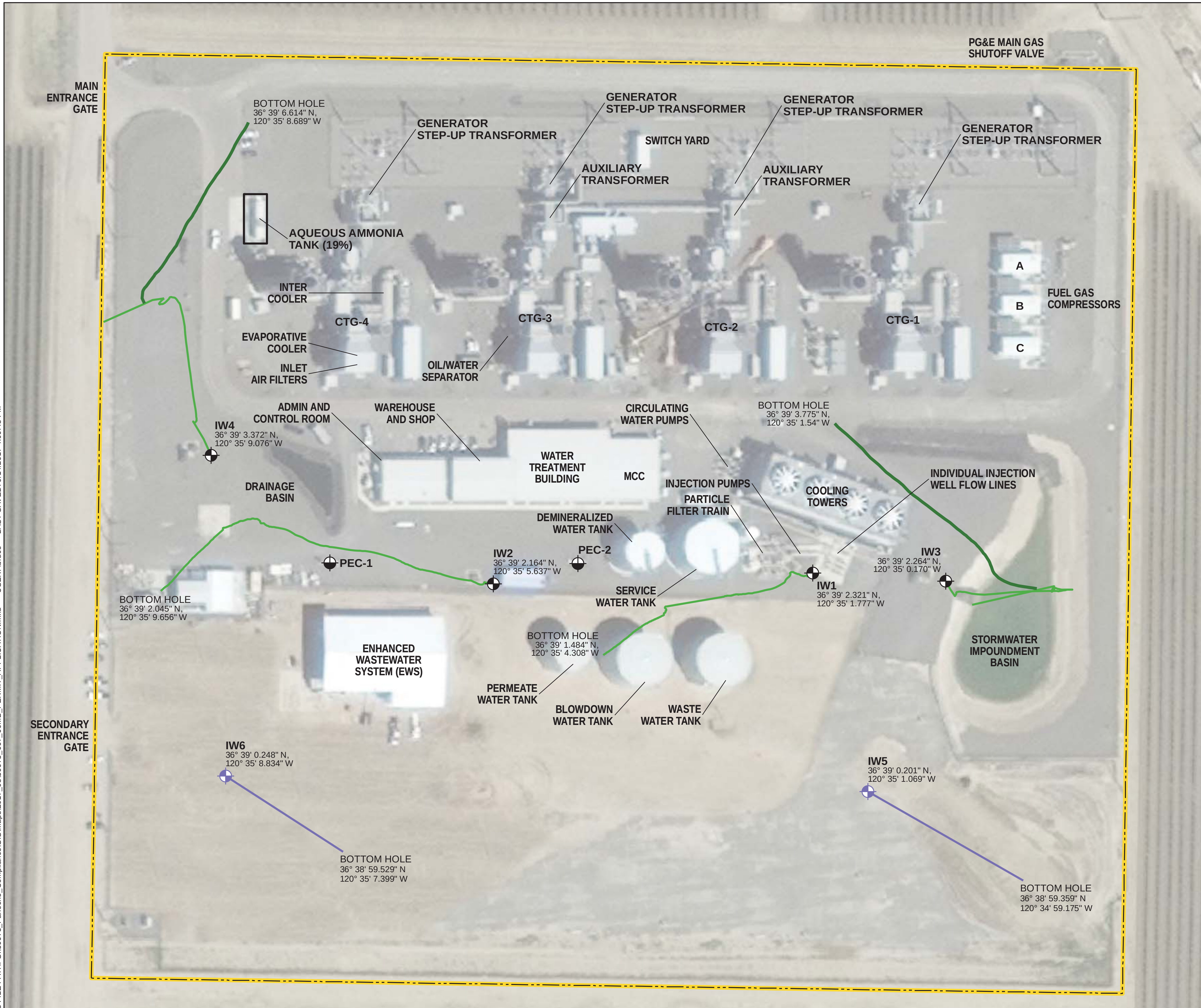
PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

PROJECT LOCUS

APPROXIMATE SCALE: 1 IN = 1 MI
SEPTEMBER 2017

FIGURE 2

GIS FILE PATH: G:\39073_Panoche_Compliance\GIS\Maps\2017_08\39073_007_0002_PROJECT_LOCUS.mxd — USER: ibruce — LAST SAVED: 9/1/2017 12:05:00 PM



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LEGEND

- INJECTION WELL
- SUPPLY WELL
- PROPOSED WELL LOCATION
- ORIGINAL WELL PATH
- DEEPENED WELL PATH
- PROPOSED WELL PATH
- SITE BOUNDARY

NOTES

1. ALL LOCATIONS AND DIMENSIONS ARE APPROXIMATE.
2. AERIAL DATA SOURCE: TERRASERVER, MULTISPECTRAL, 1-METER RESOLUTION, 18 APRIL 2016, MODIFIED TO REFLECT EXISTING CONDITIONS

N

0 100 200
SCALE IN FEET

HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

SITE LAYOUT WITH
WELL LOCATIONS

SEPTEMBER 2017

FIGURE 3

ATTACHMENT A

Area of Review Methods

Table of Contents

List of Tables

List of Figures

List of Exhibits

A-4 Haley & Aldrich. 2018. 2017 External Mechanical Integrity Testing and Pressure Fall-off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

A-5 Haley & Aldrich. 2018. Fourth Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. January.

A-6 URS. 2009. Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California. March.

A-7 URS. 2009. Well Completion Report – UIC Well IW2, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California, March.

ATTACHMENT A – AREA OF REVIEW METHODS

PERMIT APPLICATION REQUIREMENTS

As stated in the U.S. Environmental Protection Agency (USEPA) Underground Injection Control (UIC) Permit Application Form 7520-06 (Rev. 12-08) instructions, the applicant shall "give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation). The area of review shall be a fixed radius of 1/4 mile from the wellbore unless the use of an equation is approved in advance by the Director."

INTRODUCTION

The method for determining Area of Review (AOR) around an injection well or injection project area is defined in 40 Code of Federal Regulations (CFR) 146.3 as "the area surrounding an injection well described according to the criteria set forth in §146.6…" Regulation 146.6 states that the "Area of Review for each injection well or each field, project or area… shall be determined…" using the zone of endangering influence (ZEI) calculation in 146.6(a) or a fixed radius according to 146.6(b). In the regulations, the ZEI for a single injection well cluster is the radius encompassing the lateral distance in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into an underground source of drinking water (USDW).

Panoche Formation Information

The Panoche Formation, which receives wastewater injected by Panoche Energy Center, LLC (PEC), is encountered at a depth of approximately 7,100 feet below kelly bushing (KB) at PEC. On a rotary drilling rig, the KB imparts rotation to the drill string from the rig floor, which is located above the superstructure or base of the drilling rig. Well depth measurements are commonly referenced to the KB in feet below the elevation of the KB. The original KBs for each PEC injection well were established from the respective drilling rig during original well installation in 2009 or sidetrack installation in 2011/2012. As such, KB is ground level elevation plus 13 feet for both injection wells IW1 and IW2, and 17 feet above ground level for IW3 and IW4 (Haley & Aldrich, 2018a).

The Panoche Formation was initially observed to be over-pressurized in its native state preceding any injection occurring at PEC. This observation is based on a review of static surface shut-in pressures reported after well development via swabbing and backflowing, which was conducted during the IW1 and IW2 well completions in January of 2009 prior to the collection of reservoir fluid samples. The initial pressure ranged from 25 to 35 pounds per square inch (psi), respectively based on field activity reports (URS, 2009a; URS, 2009b). Additionally, although a fluid level of 67 feet below ground level (80 feet KB) was reported prior to the step rate testing (SRT) at IW2 on 10 February 2009, review of daily reports indicates that the well was killed with the addition of 9.4 pounds per gallon fluid on 28 January 2009, and no further well activity was reported prior to the SRT URS, 2009b). This positive surface wellhead pressure indicates that the reservoir is "over pressured" or artisan and would naturally flow at the surface.

The on-site water supply well, PEC-2, is screened to the lower fresh water aquifer, which is below the Corcoran Clay, and the hydrostatic head observed in PEC-2 (approximately 429 ft below ground surface (URS, 2009b) or calculated as -186 psi using the ground surface as the datum) can be used to represent the hydrostatic head in the lowermost regional aquifer. The representative pressure head in the Panoche Formation is 216 psi higher than the representative pressure head in the USDW under natural conditions (URS, 2009a; URS, 2009b). Therefore, prior to PEC's wastewater injection operations in 2009, there was the potential for migration of Panoche Formation water to the lowermost regional aquifer through any pre-existing conduits that were not properly constructed or sealed (e.g., abandoned oil wells or borings).

SELECTING THE AREA OF REVIEW

Because the injection reservoir is over-pressured, standard ZEI calculations do not provide valid results and indicate that the ZEI is essentially infinite in extent. As such, the ZEI at PEC was determined utilizing an alternative method that evaluates the pressure increase necessary to move fluid upward in a wellbore that existed prior to the start of injection operations at PEC. This method is based on the assumption that the pre-existing Oil and Gas wells (Figure A-1) were drilled using rotary drilling methods, which was the drilling method used for all of the wells considered within a 3-mile radius of PEC based on available drilling records. During rotary drilling operations, drilling mud is utilized to clean, stabilize, and control pressure in the wellbore. Based on drilling records, water-based mud was utilized to drill the offset wellbores surrounding the PEC site. Water based mud uses clay additives (typically bentonite) commonly referred to as "gel" to impart the desired physical qualities needed for the mud. Gel strength is indicative of the thixotropic properties of a drilling fluid due to the presence of electrically charged molecules and clay particles that aggregate into a firm matrix when drilling fluid circulation is stopped (Baker Hughes, 2006). Gel refers to the fact that the fluid, while being pumped, appears thin and free flowing but when static the fluid builds a gel structure that suspends drill cuttings in the fluid column. As such, this gel structure essentially sets up into a rigid or semi-rigid structure if allowed to stand at rest and resists flow. To re-initiate flow, a significant adequate force must be applied to "break the gel" and re-establish mud circulation. Generally, gel strength will increase with time, temperature, and an increase in solids content (Baker Hughes, 2006).

In addition to hole cleaning and stabilization, the density or weight of the mud column provides a counter-balance to formation pressures encountered and must be maintained in order to keep control of the well and prevent a blowout. The assumption that a column of drilling mud remaining in an uncased well provides a hydrostatic pressure opposing fluid entry from penetrated strata is generally accepted (Collins and Kortum, 1989). In addition, the gel qualities of the mud impart a gel strength factor, which is the shear stress of the mud after the mud has been static. As such, research (Barker, 1981; Johnson and Knape, 1986; Collins and Kortum, 1989) confirms that the gel strength of the mud contributes to the hydrostatic force imparted by the mud column that resists flow or entry of fluid into the wellbore.

For the PEC AOR determination, gel strength calculations were performed for all penetrations within a 3-mile radius of the PEC facility to determine the lowermost value of gel strength that exist in an offset wellbore that would need to be exceeded to cause fluid to flow in the wellbore. In general, the entry pressure necessary to displace the mud in the wellbore varies directly with the gel strength and well depth and inversely with the borehole diameter. The gel strength provides a shear force at the wall of the hole that must be overcome for fluid flow to be initiated.

The formula utilized is that presented by Johnston and Knape (1986) as follows:

P = (0.00333)(GS)(h) / D

Where:

GS = gel strength (pounds per 100 square feet [lbs/100 ft^2)

H = height of mud column (feet)

D = borehole diameter (inches)

P = pressure required to overcome gel strength of mud (psi)

Based on literature review, the values of GS vary. Barker (1981), as reported in Johnston and Knape (1986), observed in limited data gel strengths ranging from 25 to 120 lbs/100 ft^2. Johnston and Knape (1986) concluded “that in the absence of mud gel strength data for abandoned wells, minimum gel strength of 25 lbs/100 ft^2 can be conservatively assumed.” Collins and Kortum (1989) reported based on experiments that “data indicate that in most circumstances the gel character of the mud contributes as much to the minimum fluid entry pressure as does the hydrostatic head of the mud. In fact, in many cases the gel might contribute more to the sealing pressure than hydrostatic head by a factor of three or more.” Johnston and Knape (1986) and Collins and Kortum (1989) also reported the following observations regarding gel strength from their research and experiments:

- Mud will not be displaced until the gel structure is broken;
- Mud gel strength increases with time;
- Mud gel strength increases with temperature;
- Irregularities in the hole diameter cause increases in gel strength; and
- Mud filter cake will retard or prevent inter-formational flow.

For this AOR evaluation, a very conservative value of 25 lbs/100 ft^2 was utilized for GS in the calculations. As noted above, much higher values of GS are probable based on the age, depth, and geometry of the boreholes evaluated. The results of the calculation are presented in Table A-1, which is cross referenced to Figure A-1. The results indicate that when using a very conservative gel strength value of 25 lbs/100 ft^2, the minimum gel strength value of the mud column occurs at AOR location #5 and is 41.96 psi. Therefore, at this location it would require a 41.96 psi of pressure buildup in the reservoir due to injection activities at PEC to overcome the gel strength of the mud column and initiate flow in the wellbore. As a result, 41.96 psi has been determined to be the extent of the AOR to be evaluated for corrective action at PEC. The ranges in conservatively calculated gel strength values used for the determination are indicated in Table A-1.

It should be noted that based on water sampling results at IW1 and IW2 prior to PEC’s wastewater injection, the concentration of total dissolved solids (TDS) in the Panoche Formation water ranged from approximately 35,000 to 112,000 milligrams per liter (mg/L), up to two orders of magnitude higher than the TDS concentrations (between 700 and 1,160 mg/L) observed in the on-site water supply wells, PEC-1 and PEC-2 (URS, 2009b) completed in the lowermost regional aquifer. The difference in the TDS concentrations observed in the Panoche Formation and the overlying USDW aquifer indicates the presence of effective geological barriers to groundwater flow/migration (such as several shale-dominated formations, including the Kreyenhagen and Moreno Formations; see Attachment D for details) between them (URS, 2009b). The effectiveness of the geological barriers between the Panoche Formation and the USDW is also confirmed through pressure fall-off tests (FOTs). Since 2009, several

FOTs have been conducted to assess the integrity of injection well IW2 and the formation near the injection well (Haley & Aldrich, 2018a). The FOT results throughout many years consistently indicate that applying an injecting pressure of between approximately 1,800 and 2,000 psi over several years does not create any preferential pathway that may help relieve injection pressure. These FOTs also show that the reservoir pressure is increasing in a predictable and expected manner indicating that the reservoir pressure is not leaking off into overlying strata. In addition, the temperature logging results from the annual mechanical integrity tests conducted at PEC do not reveal any anomalous temperature trends that would indicate the presence of inter-formational fluid flow that might suggest that the potential upper confining zone is not serving as a reliable separation between fluids in the injection zone and the lowermost USDW.

The final permit application for the PEC wells and a subsequent annual update in 2011 were based on a net pressure increase model where the pressure increase above the background water pressure in the Panoche Formation would be attributed to PEC's injection operations (URS, 2009b; AMEC, 2012a; Haley & Aldrich, 2018b). As described in the *Fourth Quarter 2011 Monitoring Report* (AMEC, 2012a), the USEPA acknowledged that conventional methodologies of the ZEI calculation would not apply to the site due to naturally over-pressured conditions in the Panoche Formation. An alternative method of calculation was developed and accepted by the USEPA, which involves using a mathematical model (equivalent to the Theis calculation method) to simulate the pressure distribution in the Panoche Formation due to pressurized wastewater injection; the area of net pressure influence was depicted through contouring the area that shows at least 25 psi of pressure increase above the background pressure (25 psi). However, based on the information presented above, this arbitrary threshold appears to be overly conservative and a differential pressure of 41.96 psi has been selected as the extent of the AOR. For the purpose of this permit renewal application (and all subsequent submittals), PEC proposes using the entry pressure based on the minimum gel strength limit of 41.96 psi as a replacement for the 25 psi limit as the AOR review limit for this project.

WASTEWATER INJECTION VOLUMES AND IMPACT OF THE ENHANCED WASTEWATER SYSTEM

In 2015 and 2016, PEC built an enhanced wastewater system (EWS) to enhance the reuse of water (Haley & Aldrich, 2016). With the new EWS, cooling tower blowdown and reverse osmosis reject from the water treatment plant, which was formerly directly disposed of down the injection wells, is now treated and then returned to the cooling tower for reuse (see Attachment K for details). Construction of the EWS commenced in August 2015, and the EWS began operating as designed by the end of June 2016 (Haley & Aldrich, 2016). Operation of the EWS reduces the rate of wastewater injection by more than 70 percent (generally between 73 and 75 percent) during periods of peak power generation at the plant. A more thorough review of the EWS performance using the operation data between August 2016 and November 2018 shows that an overall efficiency between 62 and 67 percent has been achieved. This overall efficiency includes the EWS system downtime due to maintenance and trouble shooting and the time when the system was not running at its optimal conditions.

The annual injection volumes between 2009 and 2018 are shown in Figure A-2. Because of the EWS operation, the annual wastewater injection volumes between 2016 and 2018 have decreased significantly. The anticipated annual wastewater volumes to be injected between 2019 and 2029 will also be significantly less than the annual injection volume which occurred between 2014 and 2015. The projected annual injection volumes over the next decade may result in a gradual dissipation of increased formation pressure due to the higher annual volumes injected before the use of the EWS.

In fact, the effects of gradual pressure dissipation have been observed through the recent trend of the shut-in pressures at the injection wells. Table A-2 shows the relationship between the minimum shut-in pressure for the month of June from 2012 to 2018 and the total injection volume within 12 months before the end of June for the corresponding years. Significantly higher annual injection volumes between July 2013 and June 2016 result in significantly higher shut-in pressures for the well field; however, the use of EWS between July 2016 and June 2018 results in a lower annual injection volume and also reduces the shut-in pressure in the well field. Because an annual injection volume like those between July 2013 and June 2016 is not expected to occur in the future due to the use of the EWS, the future pressure level in the injection zone is expected to be lower than the levels observed between June 2014 and June 2016.

To facilitate the AOR and ZEI evaluation for this permit application, the groundwater flow model used for the most recent AOR and ZEI evaluation (Haley & Aldrich, 2018b) was used to estimate the net pressure increase trend and the spatial extent of injectate for the permit application period. The evaluation procedure and results are presented below.

ESTIMATED FUTURE WASTEWATER INJECTION VOLUMES AND RATES

To assess the effects of future wastewater injection on the trend of pressure buildup in the Panoche Formation, annual total injection volumes between January 2019 and December 2029 are projected by considering the future California energy demand. Based on the draft report issued by the California Energy Commission (CEC, 2016), the future energy demand annual growth rate in California may be as high as 1.45 percent. Since the amount of wastewater generation is approximately linearly proportional to the amount of electricity generation, the projected annual wastewater injection amounts for the period between 2019 and 2029 were estimated using the growth rate of 1.45 percent and using the projected annual injection volume for 2018 as the baseline. The annual volume for 2018 was established using the actual wastewater injection volume data from 2018. Note that the use of the 2018 annual volume as the baseline for future injection would represent a conservative representation of wastewater reduction under sub-optimal conditions because the EWS underwent major maintenance and troubleshooting during the summer of 2018.

Note that the annual growth rate of 1.45 percent used to project future wastewater injection volume is likely to be a very conservative assumption. In September 2018, California Senate Bill 100 was passed, which sets to implement a zero-carbon electricity grid by 2045. By 2025, the electricity system powered by non-renewable energy resources should decrease to 50 percent in California. Therefore, the demand for electricity generated by the Panoche facility is expected to decrease over time since the facility uses natural gas, a non-renewable source, for power generation.

Based on this projection method, the estimated annual injection rate in 2029 is approximately 32 milligal (MGal) and the projected total injection volume between January 2019 and December 2029 is 328 MGal, which is slightly lower than the total injection volume from the beginning of PEC operations (2009) to December 2018 (355 MGal). The projected annual injection volumes between 2019 and 2029 are shown in Figure A-3.

After the future annual total injection volumes were projected, they were allocated by month using the percentages provided in Table A-3. The percentages shown are based on the average of monthly injection percentages of the corresponding annual injection amounts between 2014 and 2018.

The monthly injection amount was further allocated to injection wells IW1, IW2, IW3, and IW4 based on the fractions of the total injected amount received by individual wells between July 2016 and June 2017 (IW1 = 23.5 percent, IW2 = 36.5 percent, IW3 = 13 percent, and IW4 = 27 percent). The estimated monthly injection volumes for the four injection wells between January 2018 and December 2027, together with the historical monthly injection data, were input into the groundwater flow model used for the 2017 annual AOR (Haley & Aldrich, 2018b) to simulate the potential pressure buildup trend and spatial extent of injectate due to wastewater injection at PEC over the next 11 years.

The proposed injection wells of IW5 and IW6 were not considered in the ZEI calculation because the simulated net pressure increase contour of 41.96 psi resulting from the current well field are far away from the site and are not sensitive to the locations of the injection wells on the plant property and how the total injection volumes or rates are distributed among the injection wells. The total injection rates or annual injection volumes of the well field are the primary factors that dictate the extent of the net pressure increase contour of 41.96 psi. Therefore, there is no need to simulate IW5 and IW6 explicitly.

MODELING APPROACH

The modeling procedure and parameters used were the same as those used for the 2017 annual AOR and ZEI evaluation (Haley & Aldrich, 2018b) except that the initial background formation pressure and the pressure for the model constant boundary cells were revised to be based on an average formation pressure of approximately 30 psi using data reported in the IW1 and IW2 completion reports (URS, 2009a; URS, 2009b). In the previous AOR modeling, the initial background formation pressure and the pressure for the model constant boundary cells were set at 260 psi, which was based on the plant surface pressure gauge readings for IW2 during the initial startup of wastewater injection. Because the pressure observed during the startup period might have been affected by the IW2 step rate test (URS, 2009a), which was performed approximately 4 weeks prior to the startup, and because the plant surface gauge was not located right at the well head, the shut-in pressure reported in the IW2 completion report is thus considered to be more representative of the initial formation pressure conditions.

The model parameters, model assumptions, and model structure are provided below.

<u>Modeling programs, basic model assumptions, model domains, and boundary conditions</u>:

- The MODFLOW software is used for pressure calculation (equivalent to the Theis calculation method) and the MODPATH program is used for tracing the footprint of the injected wastewater;
- An isotropic, confined, low permeability aquifer is assumed;
- The horizontal extent of the model is 8 miles by 8 miles, and the site is in the middle of the model;
- The reservoir thickness of the Panoche Formation that is permeable for water flow is conservatively assumed to be 245 feet (the thicknesses obtained from the flow profiling during the annual mechanical integrity testing activities are generally higher than 400 feet); note that simulated net pressure increase contour of 41.96 psi is not sensitive to this parameter;
- The horizontal discretization of the model domain consists of coarse cells (990 feet by 990 feet) far away from the site, refined cells at the site (10 feet by 10 feet), and transitional cells of various sizes that bridge the coarse cells and refined cells;

- There is only one model layer, which represents the Panoche Formation; and
- The constant head boundary conditions are set at the perimeter of the model; the value of 30 psi (69.3 feet of water) is used for the head boundary cells and the initial background pressure throughout the model domain. The change from the value of 260 psi in the previous model to the value of 30 psi does not result in a noticeable difference in the modeling results of simulated net pressure increase distributions in the model domain because the extent of net pressure increase primarily depends on the value of transmissivity and is not sensitive to the assumed background pressure value.

Model flow and transport parameters:

- A constant transmissivity value of 12 feet^2 per day (equivalent to 1,020 milidarcy-feet) is used. This value was estimated based on the FOT results (AMEC, 2012a); note this value corresponds to the lowest value found among all FOTs (Haley & Aldrich, 2018a). Note that the distribution of the net pressure increase is sensitive to this parameter and the use of a low transmissivity value would result in more pressure buildup in the formation; therefore, the transmissivity value used for the model is conservative;
- A constant storage coefficient of 0.00024 is used; the value was based on the IW1 pressure data in response to IW2 injection during the period of July 2010 (AMEC, 2012a); and
- The porosity of the Panoche Formation is assumed to be 0.2 (AMEC, 2012a), this is based on the IW1, IW2, and IW3 log/core analysis for porosity of the Panoche Formation; the porosity values were found to range from 13.1 to 27.7 percent (AMEC, 2012b).

RESULTS

The estimated spatial extent of injectate at the end of 2029 is shown in Figure A-4. The simulated net-pressure increase in the Panoche Formation at the end of 2018 and 2029 are shown in Figure A-1. The spatial extent of the 41.96 psi pressure contour at the end of 2029 is smaller than that at the end of 2018, indicating that the wastewater injection at the end of 2029 will not result in more pressure buildup. This result is consistent with the expectation that the injection intensity during the next 11 years will be lower than the injection intensity between 2013 and 2016 because of the EWS operations.

Because the Panoche Formation is not expected to become more pressurized under the anticipated future wastewater injection operations, the estimated pressure conditions at the end of 2018 can be used as the basis to define the scope of AOR for this permit application if required. The net 41.96 psi radial contours at the end of 2018 are located approximately 2.3 miles from the PEC facility (Figure A-1).

As discussed above, the representative background pressure head in the Panoche Formation is 216 psi higher than the representative head in the USDW under the natural conditions. A net 41.96 psi increase in the Panoche Formation would result in approximately only 20 percent higher in pressure difference between the Panoche Formation and the overlying USDW aquifer under the natural conditions. For this permit application, the simulated net 41.96 psi radial contour for 2018 has been selected to establish the AOR boundary if required. This is more conservative (i.e., provides an additional factor of safety) than the USEPA-mandated ¼-mile radius.

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TABLES

TABLE A-1
OIL AND GAS WELLS WITHIN 3 MILES OF PEC'S INJECTION WELL FIELD
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

AOR No.	API No.	Operator Name	Operator Well ID	Spud Date	Total Measured Depth (ft. KB)	Surface Casing Detail	Longstring Casing Detail	Mud Weight and Source	Hole Geometry for Gel Strength Calculation	Calculated Gel Strength Using (25 lbs/100ft^2) *	Plugged Interval Details (Ft. KB)	Panoche Top (ft. KB)	KB Elevation (ft)	Dryhole	Status	Year Plugged
1	1900190	Exxon Corporation	Cheney Ranch #1	11/19/1939	9,284 Orig. 7,215 sidetrack	13 3/8" 54# to 529 ft with 320 sx cement (17 1/2" hole) .	8 5/8" to 6,676' (12.25" hole) with 350 sx.. Shot and recovered from 908'. 6 5/8" liner 6,658 to 7,215'.	79 lb/ft^3 = 10.6 ppg (log)	N/A	Plugged between Lowermost USDW and Injection Zone	<u>Orig. Hole:</u> 7,775 to 7,662 (30 sx); 7,326 to 7,191 (39 sx); 6,720 to 6,691 (70 sx) with junk at 6,720 to 6,723. <u>ST Hole:</u> 6,720 to 6,480 (23 sx); 5037 (CBP + 9 sx); 4016 (CBP + 20 sx); 908 (14 sx); 549 to 503 (35 sx); 503 to 26 (dirt); 26 to 5 (8 sx).	7,310	392	No	P	1952
2	1900191	Exxon Corporation	Cheney Ranch #2	11/23/1940	7,354 (Plugged back to 7,280)	11 3/4" 54# to 538 ft with 315 sx cement (15 1/2" hole)	7", 26 & 28#, to 7,200 ft with 300 sx. Shot off and recovered from 457 (10.625" hole)	73 lb/ft^3 = 9.8 ppg (log)	N/A	Plugged between Lowermost USDW and Injection Zone	7,354 to 7280 (50 sx); 7,082 to 6,802 (50 sx); 5,680 to 5,635' (8 sx); 3,100' to 2,960' (25 sx); 2,000' to 1,944' (10 sx); 457' to 421' (20sx); 421' to 27' (dirt); 27' to 7' (12 sx)	7,288	392	No	P	1964
3	1900192	Jergins Oil Co.	Cheney Ranch #3	4/6/1942	7,702	13-3/8" to 1,320' with 1000 sx (17 1/2" hole)	None	77 lb/ft^3 = 10.3 ppg (log)	12.25" from 1,230 to 5,944'. 8.5" from 5,944 to 7,702'.	7,190' to 1,340'= 5,850 49.3 psi	1,340 to 1,248 (100 sx); 25 to surface	7,190	404	Yes	P	1942
4	1900193	L. M. Lockhart	England #1-31	11/27/1950	10,357 (Plugged back to 10,169	14" to 609 ft 47.5# with 700 sx cement (20" hole)	5 .5" 20# to 10,038 ft with 300 sx, shot and recovered 782 ft (10.625" hole to 7,425'; 9.875" hole to 9,995'; 7.625" hole to TD)	84 lb/ft^3 = 11.23 ppg (log)	5.5" 17 & 20# from 794 (base plug in annulus) to IZ (7,077')	Annulus behind Longstring = 7,077 to 794' = 6,283' so 102.1psi	10,357' to 10,169' (50 sx); 10,167' to 9,880' (50 sx); 1,045' to 987' (6 sx); Wood Plug driven from 782' to 794'; 794' to 744' (26 sx); 629' to 552' (33 sx); 15' to surf (14 sx)	7,077	419	No	P	1964
5	1906032	L. M. Lockhart	Souza #1-36	7/13/1951	10,635	14" 47.5# to 376 ft with 650 sx cement (20" hole) (stuck running surface casing)	None	88 lb/ft^3 = 11.76 ppg (log)	20" hole to 666'; 10.625" to 8315'; 9.875" to 9,578'; 7.625" to 10,635'	6,555' to 1,200' = 5480' so 41.96 psi	1,200' to 1,146' (40 sx), 396' to 350' (40sx); 10' to surface	6,555 (1st Sand at 6,750)	432	Yes	P	1951
6	1906039	Atlantic Richfield Company	Roberts #1	12/22/1963	8,772	10 3/4", 40.5# to 506 ft with 300 sx cement (15" hole)	None	81 lb/ft^3 = 10.83 ppg (log)	Surface Casing + 9 7/8" (506' to 1,413') + 8 3/4" (1,430' to 8,772')	7650' to 1845' = 5,805' so 55.23 psi	1,845' to 1,692' (75 sx) , 550' to 485' (50 sx), 29' to 19'	7,650	384	Yes	P	1964
7	1906071	Marathon Oil Company	Russell Giffen #1	9/23/1955	7,671	13 3/8" , 54#, to 702.5 with 575 sx cement (17 1/2" hole)	None	81 lb/ft^3 = 10.83 ppg (log)	N/A	Plugged between Lowermost USDW and Injection Zone	**3,330 to 3,188 (90 sx)**; 858 to 608 (150 sx); 37 to 16 (8 sx)	5,730	480	Yes	P	1955
8	1920687	Cencal Drilling Inc.	Silver Creek #77X	5/26/1972	7,250	9 5/8" 54# to 753 with 564 sx cement (13 3/4" hole)	5.5" 15.5 & 17# to 7250' with 240 sx.	9.9 ppg emplaced during P&A	N/A	Plugged between Lowermost USDW and Injection Zone	**7,224 to 7,003 (35 sx)**; 1,807 to 1,571 (35 sx); 55 to 5' (23 sx)	7,298	377	No	P	1992
9	1920710	E. A. Bender, Operator	Silver Creek #72X	8/31/1972	7,827	9", 45#, to 1,700 with 790 sx. (12 1/4" hole)	None	77 lb/ft^3 = 10.3 ppg (record)	Surface + 7 7/8"(1,700' to 7,827')	7,310' to 1,911' = 5,399' so 57.08 psi	1,911 to 1,325 (125 sx) ; 25 to Surface	7,310	389	Yes	P	1973
10	1920712	Cencal Drilling Inc.	Silver Creek #14X	10/11/1972	7,394 Plugged back to 7,265	9" 45# to 1,707' with 650 sx to Surf. (12 1/4" hole)	5.5" 15.5 & 17# to 7,392' with 210 sks in 7 7/8" hole. TOC shown @ 6181'	Applied during P&A - 72 lb/ft^3 = 9.63 ppg (10.1 ppg in annulus per log)	Longstring ID Max = 4.95"	Between Plugs in Casing - 6,970 to 1,600 = 5,370' so 90 psi	**7,260 to 6,970 (56 sx)**; 1,600 to 1,300 (30 ft^3); 30 to 5	7,300	384	No	P	1994
11	1920726	Cencal Drilling Inc.	Silver Creek #27X	12/7/1972	7,460 Plugged back to 7,286	9" 45# to 1,710' with 650 sx to Surf. (12 1/4" hole)	4.5" 9.5 & 10.5# to 7,332' with 270 sx in 7 7/8" hole.	Applied during P&A - 72 lb/ft^3 = 9.63 ppg (10.03 ppg in annulus per log)	Longstring ID Max = 4.09"	Between Plugs in Casing - 6,686' to 1,600' = 5,086' so 103.5 psi	7,332' to 7,290' (53 ft^3); 7,290' to 7,286' (35 sx); 7,280' to 6,686' (53 ft^3); 1,601' to 1,510' (35 ft^3); 30' to 5' (12 sx)	7,286	388	No	P	1994
12	1920758	E. A. Bender, Operator	Silver Creek #54X	3/27/1973	10,887' (plugged back to 6,923') and redrilled to 7,183 for Test	9 5/8" 36# to 1,752' with 905 sx (13 .75" hole)	None	76 lb/ft^3 = 10.2 ppg (log)	8 .75" hole PBTD @ 6,958'; 7.875 hole to 7,183'	Between Plugs in Openhole - 6,953' to 1,807' = 5,146' so 48.96 psi	7,260' to 7,183' (210 sx); 7,180 to 6,953' (70 sx) ; 1,807 to 1,654 (80 sx)	7,140	421	Yes	P	1973
13	1920776	E. A. Bender, Operator	Silver Creek #32X	9/19/1973	7,531	9 5/8" 40# to 750' with 550 sx (13 3/4" hole)	None	74 lb/ft^3 = 9.89 ppg (record)	8.75" from 750' to 6,951'; and 7.875" to 7,531'	Between Plugs in Openhole - 6,956' to 1,744' = 5,212' so 52.1 psi	**7,296' to 6,956' (100 sx)**; 1,744' to 1,530' (100 sx); 791' to 633' (60 sx)	7,260	395	Yes	P	1973
14	1920804	E. A. Bender, Operator	Silver Creek #18	3/23/1974	8,698	9 5/8" 47# to 768' with 500 sx (13 3/4" hole)	None	75 lb/ft^3 = 10.03 ppg (record)	8.5" hole from 768' to 8,698'	7,440' to 1,700' = 6040' so 56.2 psi	1,700' to 1,437' (100 sx) ; 817' to 678' (50 sx); 35' to 8'	7,440	391	Yes	P	1974
15	1920830	Cencal Drilling Inc.	Silver Creek #22X	11/8/1974	7,502	8 5/8" 24# to 780 with 525 sx (12 1/4" hole)	None	75 lb/ft3 = 10.03 ppg (log)	7.875" hole from 780' to 7500'.	7,355' to 1,350' = 6,005' so 63.5 psi	1,350 to 1,255' (50 sx); 840 to 704' (50 sx), 46 to surface	7,355	382	Yes	P	1974

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FRESNO COUNTY, CALIFORNIA

AOR No.	API No.	Operator Name	Operator Well ID	Spud Date	Total Measured Depth (ft. KB)	Surface Casing Detail	Longstring Casing Detail	Mud Weight and Source	Hole Geometry for Gel Strength Calculation	Calculated Gel Strength Using (25 lbs/100ft^2) *	Plugged Interval Details (Ft. KB)	Panoche Top (ft. KB)	KB Elevation (ft)	Dryhole	Status	Year Plugged
16	1921446	Cencal Drilling Inc.	Cheney Ranch #15X	7/12/1981	7,300	9 5/8" 47# to 768' with 500 sx (13 3/4" hole)	4.5" 11.6# to 7,300 with 400 sx in 7 7/8" hole.	Applied during P&A 68 lb/ft^3 = 9.1 ppg (10.03 ppg in annulus per log)	Longstring ID Max = 4.00"	6,920' to 1,595' =5,325' so 110.8 psi	**7,300 to 6,920' (36 ft^3)**, 1,595 to 1,385' (16 sx), 30 to 5 (5 sx)	7,302	386	No	P	1994
17	1921924	American Hunter Exploration Ltd.	Souza #1	11/4/1983	10,217	9 5/8" 36# to 1,709' with 796 ft^3 unspecified cement (12 1/4" hole)	5.5" 20# to 10,213 ft with 2,287 ft^3 cement in 8.75" hole	10.8 ppg emplaced during P&A	Longstring ID Max = 4.778"	6,155' to 1,400' = 4,755' so 82.85 psi	**6,330' to 6,155'** (6 bbls); 1,400 to 1,200 (15 bbls), 90 to 5' (2 bbls)	6,290	452	Yes	P	1984
18	1922412	American Hunter Exploration Ltd.	Souza #2	12/14/1985	6,587	9 5/8" 36# to 700' with 287 sx cement (12 1/4" hole)	N/A	9.2 ppg (log)	8.75" from 702' to 6,587'	6,587' to 1,327' = 5,260' so 50.0 psi	1,327 to 1,177' (78 sx); 1,130 to 1,080' (18 sx), 742 to 642 (49 sx), surface (40 sx)	6,252	434	Yes	P	1985
19	1923117	Nahama & Weagant Energy Co.	Cheney Ranch #81X-30	5/24/1989	7,400	8 5/8" 23# to 767' with 248 sx cement (12 1/4" hole)	N/A	75 lb/ft^3 = 10.03 ppg (log)	7.875" from 767' to 7,400'	7,400' to 1,512' = 5,888' so 62.25 psi	1,512 to 1,269' (88 sx), 808 to 652' (45 sx); 44 to 19 (5 sx)	7,315	386	Yes	P	1989
20	1924225	R&R Resources, LLC	Blue Agave #1	9/28/2002	7,612 (1st); 7,753 (2nd)	9 5/8" 36# to 820' with 260 sx cement (12 1/4" hole)	N/A	10.9 ppg (log)	File doesn't indicate OH size. Assume 8.75" hole (max bit size in 9 5/8", 36# Casing).	7,753' to 1,465' = 6,288' so 59.83 psi	6,012 to 5,741 (70 sx) Original hole; 1,465 to 1,160 (130 sx); 894 to 382' (73 bbls);	7,218	397	Yes	P	2002 and 2015

Notes:
* Gel Strength of Mud Column calculated using 25 lbs/100 ft^2 per Johnston, O. and Knape, B. (1986), Pressure Effect of the Static Mud Column in Abandoned Wells. Texas Water Commission, September 1986.
ft = feet
ft^3 = cubic feet
lbs/100 ft^2 = pounds per 100 square feet
lbs/ft^3 = pounds per cubic feet
# = pound
AOR = Area of Review
bbls = barrels
KB = Depth Relative to Kelly bushing
N/A = not applicable
OH = openhole
P = Plugged
P&A = Plug and Abbandon
ppg = parts per gallon
psi = pounds per square inch
sx = sacks
USDW = underground source of drinking water

TABLE A-2
RELATIONSHIP BETWEEN SHUT-IN PRESSURE AND INJECTION VOLUME
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Year	Injection Volume (Million Gallons)	EWS?	Minimum Shut-In Pressure in June (psi)				
			IW1	IW2	IW3	IW4	Median Value
July 2011 - June 2012	21.9	No	438	420	355	427	424
July 2012 - June 2013	31.8	No	455	449	381	320	415
July 2013 - June 2014	64.1	No	643	833	918	738	785
July 2014 - June 2015	78.6	No	790	815	858	810	813
July 2015 - June 2016	66.2	No	632	617	807	712	672
July 2016 - June 2017	13.9	Yes	506	545	538	556	542
July 2017 - June 2018	20.0	Yes	556	529	539	532	535

Notes:

EWS = enhanced wastewater system

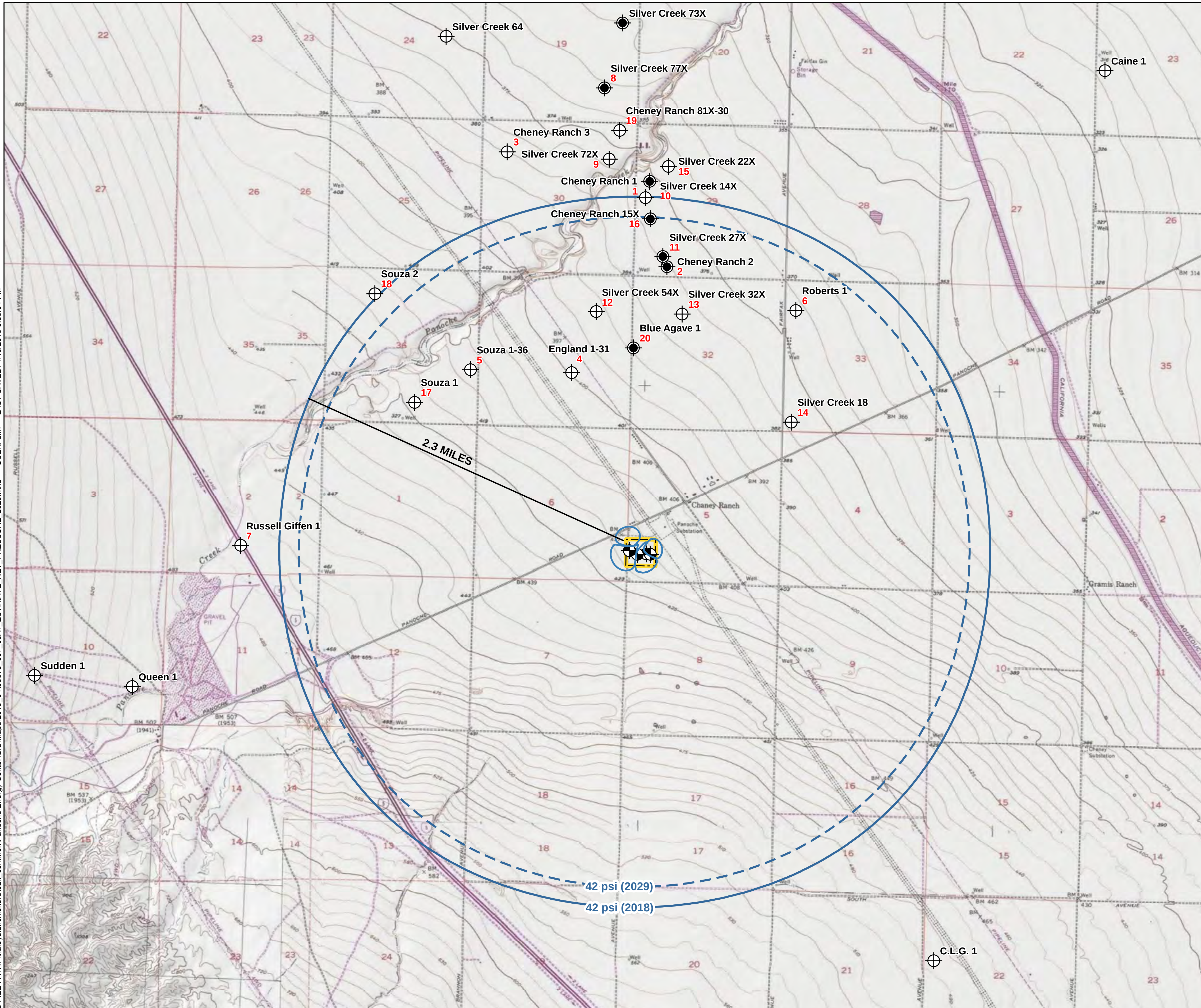
psi = pounds per square inch

TABLE A-3
MONTHLY INJECTION AS A PERCENTAGE OF ANNUAL INJECTION
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Month	% of Annual Total
January	4.7%
February	4.5%
March	6.0%
April	6.4%
May	7.7%
June	9.8%
July	16.0%
August	14.8%
September	9.8%
October	8.7%
November	6.8%
December	4.8%
Annual Total	**100%**

Notes:
% = percent

FIGURES



LEGEND

INJECTION WELLHEAD

OIL AND GAS WELLS

PLUGGED, DRY HOLE

PLUGGED AND ABANDONED

NET PRESSURE HEAD CONTOUR (2018)

NET PRESSURE HEAD CONTOUR (2029)

SIMULATED EXTENT OF INJECTATE (2029)

SITE BOUNDARY

20 WELL NUMBER ON TABLE A-1

NOTES

1. ALL LOCATIONS AND DIMENSIONS ARE APPROXIMATE.

2. PRESSURE INCREASE CONTOURS CALCULATED BASED ON THE FOLLOWING PARAMETERS:
NET PERMEABLE THICKNESS = 245 FEET
TRANSMISSIVITY = 12 FT^2/D
STORAGE COEFFICIENT = 0.00024
EFFECTIVE POROSITY = 0.2

3. SIMULATION RESULTS OF 2016 PRESSURE HEAD CONTOURS WERE FROM THE FOURTH QUARTER 2016 MONITORING REPORT, CLASS 1 NONHAZARDOUS WASTE INJECTION WELLS, UIC PERMIT CA 10600001, PANOCHE ENERGY CENTER, LLC, WEST PANOCHE ROAD, FIREBAUGH, CALIFORNIA.

4. SIMULATION RESULTS OF 2029 PRESSURE HEAD CONTOURS SHOW THE NET PRESSURE INCREASE FROM THE BEGINNING OF THE INJECTION INTO THE PANOCHE FORMATION IN 2009 TO THE END OF 2029.

5. OIL AND GAS DATA PROVIDED BY THE CALIFORNIA DEPARTMENT OF CONSERVATION, DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES (DOGGR) USING THE DOGGR WELL FINDER (https://maps.conservation.ca.gov/doggr/wellfinder).

6. BASE DATA SOURCE: USGS, 1:24,000 QUADRANGLE (ESRI)

N

0 3,500 7,000
SCALE IN FEET

HALEY ALDRICH

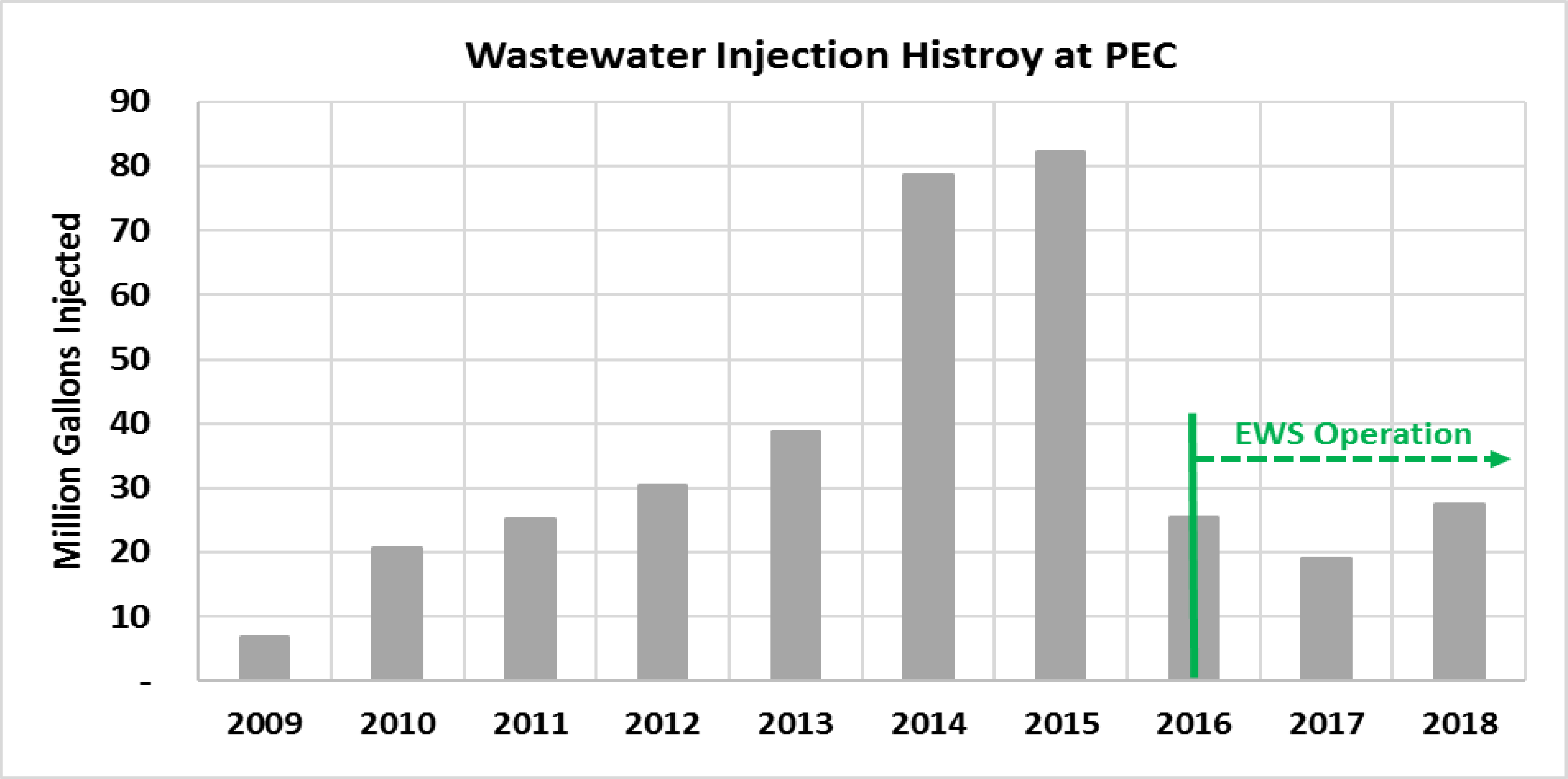
PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

ESTIMATED NET PRESSURE INCREASE WITHIN THE PANOCHE INJECTION ZONE IN 2029

JANUARY 2019

FIGURE A-1

GIS FILE PATH: \\haleyaldrich\share\oak_common\Panoche Energy Center\GIS\Maps\2019_01\39073_007_00A1_ESTIMATE_NET_PRESSURE_2029.mxd — USER: dfm — LAST SAVED: 1/10/2019 3:30:04 PM



NOTES:
1. THE OPERATION OF THE ENHANCED WASTEWATER SYSTEM (EWS) BEGINS AT THE END OF JUNE 2016.
2. THE ANNUAL INJECTION VOLMUNES ARE BASED ON THE PLANT OPERATION DATA.

HALEY ALDRICH

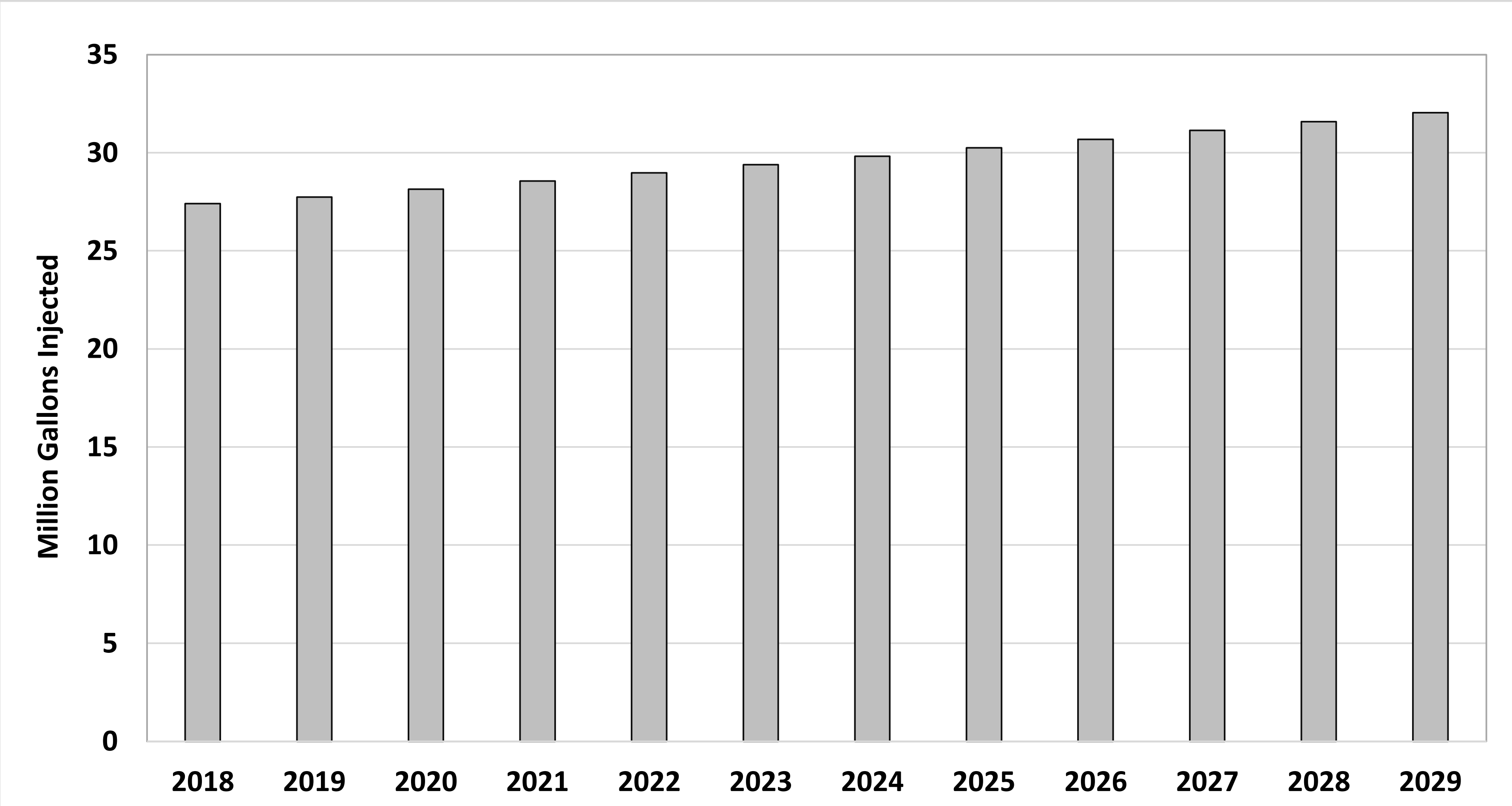
PANOCHE ENERGY CENTER
43833 WEST PAHNOCHE ROAD
FIREBAUGH, CALIFORNIA

WASTEWATER INJECTION ANNUAL VOLUMES (2009 - 2018)

JANUARY 2019

FIGURE A-2

C:\Users\jchu\Dropbox\NOD Response\~NOD RESPONSES FINAL DOCUMENTS\ATT. A - AOR\[Figure A-1.xlsx]Figure E



NOTE:
1. THE ANNUAL WASTEWATER VOLUME INJECTED FOR 2018 IS BASED ON THE PLANT OPERATIONS DATA.

HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PAHNOCHE ROAD
FIREBAUGH, CALIFORNIA

PROJECTED WASTEWATER INJECTION ANNUAL VOLUMES (2019 - 2029)

FEBRUARY 2019

FIGURE A-3

LEGEND

- INJECTION WELLHEAD
- ORIGINAL WELL PATH
- DEEPENED WELL PATH
- SIMULATED EXTENT OF INJECTATE (2029)
- SITE BOUNDARY

NOTES

1. ALL LOCATIONS AND DIMENSIONS ARE APPROXIMATE.
2. EXTENT OF INJECTATE SIMULATED BASED ON THE GROUNDWATER FLOW MODELING AND PARTICLE TRACKING RESULTS.
3. SIMULATION RESULTS SHOW THE EXTENT OF INJECTATE DISTRIBUTION AT THE END OF 2029 IN THE DEPTHS RANGING FROM APPROXIMATELY 7,400-9,000 FEET BELOW GROUND SURFACE.
4. AERIAL DATA SOURCE: TERRASERVER, 18 APRIL 2016

N

0 160 320

SCALE IN FEET

HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

ESTIMATED EXTENT OF INJECTATE IN THE PANOCHE INJECTION ZONE

FEBRUARY 2019

FIGURE A-4

GIS FILE PATH: \\haleyaldrich\share\oak_common\Panoche Energy Center\GIS\Maps\2019_01\39073_007_00A1_ESTIMATE_NET_PRESSURE_2029.mxd — USER: dfm — LAST SAVED: 1/10/2019 4:48:06 PM

EXHIBITS

(To be Submitted on CD)

ATTACHMENT B

Maps of Wells/Area and Area of Review

Table of Contents

List of Tables

List of Figures

ATTACHMENT B – MAPS OF WELLS/AREA AND AREA OF REVIEW

PERMIT APPLICATION REQUIREMENTS

As stated in the U.S. Environmental Protection Agency (USEPA) Underground Injection Control Permit Application Form 7520-06 (Rev. 12-08) instructions, the applicant shall "submit a topographic map, extending one mile beyond the property boundaries, showing the injection well(s) or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (if applicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following: (for) Class I (wells) The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located within one quarter mile of the facility property boundary. Only information of public record is required to be included in this map."

AREA OF REVIEW MAP

As shown on Figure B-1, the Panoche Energy Center (PEC) site is located at the center of the Area of Review (AOR), which is defined as the 42 pounds per square inch (psi) net-pressure increase in the Panoche Formation (see Attachment A). For context, ¼-mile and 1-mile fixed-radius are also shown on this map encircling PEC. The 2018 42 psi net-pressure increase circles is located approximately 2.3 miles from the PEC facility. The estimated extent of injectate in the Panoche Formation injection zone is also shown on Figure B-1.

As shown on Figure B-1, a total of 14 water supply wells outside of PEC facility boundaries were identified within 1-mile of PEC and only 3 were identified within ¼ mile (see Table B-1 for details). In addition, the two on-site supply wells used by PEC shown on Figure 3 are discussed in more detail in Attachment D. Additional water supply wells, further than the 1-mile radius from PEC, are also shown on Figure B-1.

A total of 20 plugged oil and gas wells (shown on Figure A-1, Figure B-1, and listed on Table A-1) were identified within 3 miles of the PEC site (these wells are discussed in more detail in Attachments C, D, and F). The closest oil and gas well is the England 1-31 well which is 1.25 miles away. Additional discussion of these wells is presented in Attachment C.

No springs were identified within 3 miles of the site. Based on aerial photo review and topographic mapping, all current surface water bodies and other area features are included on Figure B-1.

Sources of Information

As required, numerous publicly available data sources were reviewed and the following is a summary of the data sources that were reviewed:

- The California Statewide Groundwater Elevation Monitoring (CASGEM) Program, via the California Department of Water Resources (DWR), provided water well data within the AOR. Water well data was acquired using the CASGEM Search Tools of the Web Map Application found within the CASGEM Online System (DWR, n.d.). See Table B-1 for information of wells within 1-mile of PEC.
- The California Division of Oil, Gas, and Geothermal Resources (DOGGR), via the California Department of Conservation, provided oil and gas well data within the AOR. Oil and gas well data was acquired by navigating to the site and using the Data Grid export functionality of the DOGGR Well Finder (DOGGR, n.d.). See Table A-1 in Attachment A and Attachment C for well information. Note that no active or idled oil and gas wells were found in the mapped area. All plugged dry hole and plugged and abandoned wells found within approximately 3 miles of the site are plotted on Figure B-1.
- Sites that impact, or have the potential to impact, water quality within the AOR were provided by the California State Water Resources Control Board (Water Board) via the GeoTracker Data Management System. GeoTracker is an online database that provides access to California statewide environmental data and tracks regulatory data for the following types of sites: Leaking Underground Storage Tanks (LUST) cleanup sites; Water Board Cleanup Program Sites, California Department of Toxic Substances Control cleanup sites, Military sites, Land Disposal sites; Permitted Underground Storage Tank (UST) facilities, Waste Discharge Requirement sites; and the Agricultural Waivers Program (Irrigated Lands Regulatory Program) sites. Data posted on Figure B-1 were acquired by navigating to the GeoTracker site (Water Board, n.d.) and using the GeoTracker Map Tool (DOGGR, n.d.) with a 2.75-mile applied buffer from the center of PEC's site outline. The following sites were identified, and are shown on Figure B-1:
  - Silver Creek Ranch Site is located at 43106 North Avenue, Firebaugh, California LUST Clean-up Site (T0601900427) COMPLETED – CASE CLOSED.
  - D & L Shell Site is located at 46370 Panoche Road, Firebaugh, California LUST Clean-up Site (T0601993687) COMPLETED – CASE CLOSED.
  - Chaney Ranch is located at Fairfax and Panoche Road, Firebaugh, California LUST Clean-up Site (T0601993687) COMPLETED – CASE CLOSED.
  - Chevron Station # 92316/1554 is located at 46330 West Panoche Road, Firebaugh, California PERMITTED UST (Facility FAO170609).
- Base data was provided by ESRI as map services, including *World Topographic Map*, *USA Topographic Maps* and *World Imagery*. The *World Topographic Map* service was used primarily at small scales, providing administrative boundaries, cities, water features, physiographic features, parks, landmarks, transportation, and relief imagery as compiled data from the United States Geological Survey (USGS), USEPA, United States National Park Service, and other data providers. The *USA Topo Maps* service provides topographic maps as 1:24,000-scale, seamless, scanned images of USGS paper topographic maps, with detailed information about municipal boundaries and geographic names, elevation contours and benchmarks, transportation,

elevation, hydrography, land cover, and geographic name data. The *World Imagery* service provides 0.3-meter high-resolution color satellite and aerial imagery of the continental United States.

- High-resolution hydrographic data was provided by the USGS via the National Map Program as the National Hydrography Dataset. Hydrographic data was acquired using the National Map Download Viewer (USGS, n.d.), although not included for display within the AOR.
- Aerial photographic evaluation of the area was used to determine the current location of surface water features (see Figure B-1) in the mapped area. Only the outline was shown on Figure B-1 of all the water features viewable on the Farm Services Agency's National Maps 10:1 NAIP Imagery (3.75 x 3.75 minute, PEG2000 from 2016-10-21).

References

1. California Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR). n.d. "Well Finder DOGGR GIS." https://maps.conservation.ca.gov/doggr/wellfinder.

2. California Department of Water Resources. n.d. "Groundwater Monitoring (CASGEM)." https://water.ca.gov/Programs/Groundwater-Management/Groundwater-Elevation-Monitoring--CASGEM.

3. California State Water Resources Control Board. n.d. "GeoTracker." https://geotracker.waterboards.ca.gov/

4. United States Geological Survey. n.d. "The National Map." https://viewer.nationalmap.gov/basic.

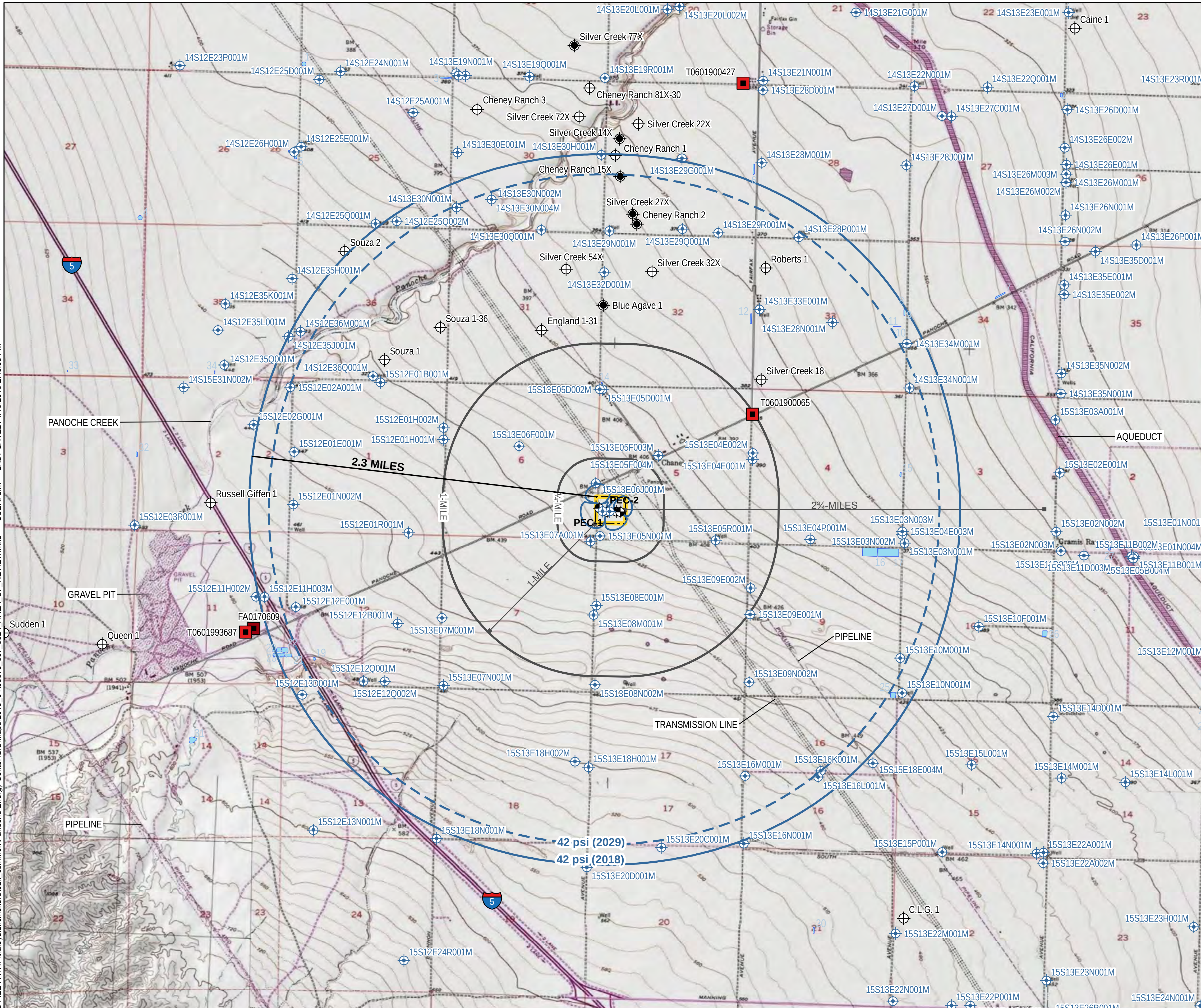
TABLE

TABLE B-1
WATER PRODUCTION WELL DATA
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

State Well Number	Distance from PEC	Screened Interval (feet bgs)	Ground Elevation (feet MSL)	Total Well Depth (feet bgs)	Well Construction	Monitoring Entity	Groundwater Basin	Hydrologic Region	Well Use	Casgem Well	Status	Latitude	Longitude
15S13E04E001M	Within 1-mile	not available	399.61	not available	No	Not Available	Not Available	Not Available	Unknown	No	Active	36.6558	-120.5679
15S13E04E002M	Within 1-mile	not available	391.61	not available	No	Not Available	Not Available	Not Available	Unknown	No	Active	36.6564	-120.5679
15S13E05D001M	Within 1-mile	not available	403.66	not available	No	Not Available	Not Available	Not Available	Unknown	No	Active	36.6622	-120.5857
15S13E05D002M	Within 1-mile	800-1,200	403.70	1200	Yes	Westlands Water District	Westside	Tulare Lake	Irrigation	No	Active	36.662544	-120.585461
15S13E05F003M	Within 1-mile	623-633	408.64	638	Yes	Westlands Water District	Westside	Tulare Lake	Observation	No	Active	36.656291	-120.578725
15S13E05F004M	Within 1-mile	199-209	408.64	215	Yes	Westlands Water District	Westside	Tulare Lake	Observation	Yes	Active	36.656379	-120.578729
15S13E05N001M	Within 0.25-mile	not available	424.67	not available	No	Not Available	Not Available	Not Available	Unknown	No	Active	36.6483	-120.5857
15S13E05R001M	Within 1-mile	not available	409.63	not available	No	Not Available	Not Available	Not Available	Unknown	No	Active	36.6481	-120.5721
15S13E06F001M	Within 1-mile	760-1,160	422.70	1200	Yes	Westlands Water District	Westside	Tulare Lake	Irrigation	No	Active	36.656922	-120.595711
15S13E06J001M	Within 0.25-mile	727-1,399	417.00	1399	Yes	Westlands Water District	Westside	Tulare Lake	Irrigation	No	Active	36.653094	-120.586922
15S13E07A001M	Within 0.25-mile	not available	427.68	not available	No	Not Available	Not Available	Not Available	Unknown	No	Active	36.6478	-120.5868
15S13E08E001M	Within 1-mile	not available	440.69	not available	No	Not Available	Not Available	Not Available	Unknown	No	Active	36.6417	-120.586
15S13E08M001M	Within 1-mile	not available	442.69	not available	No	Not Available	Not Available	Not Available	Unknown	No	Active	36.6408	-120.5863
15S13E09E002M	Within 1-mile	842-1,426	421.60	1426	Yes	Westlands Water District	Westside	Tulare Lake	Irrigation	No	Active	36.644	-120.568117

Notes:
bgs = below ground surface
MSL = mean sea level
PEC= Panoche Energy Center

FIGURE



LEGEND

- PERMITTED UST
- LUST CLEANUP SITE
- INJECTION WELL
- WATER RESOURCES WELL

OIL AND GAS WELLS

- PLUGGED, DRY HOLE
- PLUGGED AND ABANDONED
- NET PRESSURE HEAD CONTOUR (2018)
- NET PRESSURE HEAD CONTOUR (2029)
- SIMULATED EXTENT OF INJECTATE (2029)
- 1-MILE FIXED RADIUS OF REVIEW
- WATER FEATURE - POND
- SITE BOUNDARY

NOTES

1. ALL LOCATIONS AND DIMENSIONS ARE APPROXIMATE.

2. WATER WELL DATA PROVIDED BY THE DEPARTMENT OF WATER RESOURCES (DWR) VIA THE CALIFORNIA STATEWIDE GROUNDWATER ELEVATION MONITORING (CASGEM) PROGRAM USING THE CASGEM ONLINE SYSTEM (http://www.water.ca.gov/groundwater/casgem/).

3. OIL AND GAS DATA PROVIDED BY THE CALIFORNIA DEPARTMENT OF CONSERVATION, DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES (DOGGR) USING THE DOGGR WELL FINDER (https://maps.conservation.ca.gov/doggr/wellfinder).

4. HAZARDOUS DATA PROVIDED BY THE CALIFORNIA STATE WATER RESOURCES CONTROL BOARD, AND ACQUIRED USING GEOTRACKER (https://geotracker.waterboards.ca.gov/).

5. TOTAL OF 34 PONDS IDENTIFIED IN THE VICINITY OF THE SITE FROM AERIAL PHOTO. (TOTAL AREA = 916,317 SQ FEET)
19 PONDS ARE IN DISTANCE OF 2.75 MILES OF THE SITE. (TOTAL AREA = 571,490 SQ FEET)

AERIAL PHOTO SOURCE: USGS FROM NATIONAL MAP DATED; MAY/JUNE 2016

7. NO SPRING FOUND IN THE VICINITY OF THE SITE BASED ON USGS NATIONAL HYDROGRAPHY DATASET (NHD) FOR HYDROLIC UNIT (HU) 8

8. BASE DATA SOURCE: USGS, 1:24,000 QUADRANGLE (ESRI)

N

0 3,500 7,000

SCALE IN FEET

HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

AREA OF REVIEW MAP

JANUARY 2019

FIGURE B-1

ATTACHMENT C

Corrective Action Plan and Well Data

Table of Contents

List of Tables

List of Figures

List of Exhibits

ATTACHMENT C – CORRECTIVE ACTION PLAN AND WELL DATA

PERMIT APPLICATION REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Underground Injection Control Permit Application Form 7520-06 (Rev. 12-08) instructions, the applicant shall "submit a tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review, including those on the map required in B, which penetrate the proposed injection zone. Such data shall include the following:

> *(for) Class I "a description of each well's types, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. In the case of new injection wells, include the corrective action proposed to be taken by the applicant under 40 CFR 144.55."*

AREA OF REVIEW BACKGROUND

Figure A-1 indicates the area of review (AOR) and the artificial penetrations of concern for this corrective action evaluation. The required information for wells within the AOR that penetrate to the injection zone is summarized in Table C-1. The criteria used to establish the AOR is discussed in Attachment A. In general, because the Panoche Formation injection reservoir is over-pressured under natural conditions, it is assumed that all uncased boreholes were left in a balanced to overbalanced condition at the end of drilling operations and contained a remaining column of drilling fluid or "mud". Convention dictates that this mud column would apply sufficient hydrostatic pressure to maintain well control and prevent flow at the surface. In addition, the mud column would have inherent gel strength due to the thixotropic nature of the mud. It is known that time, temperature, and borehole irregularities increase this gel strength, which must be overcome in order for pressure to enter the wellbore as discussed in Attachment A. Based on this reasoning, the extent of the AOR was established at the line indicating 42 pounds per square inch (psi) of pressure increase from injection activities associated with the Panoche Energy Center (PEC) based on an analysis of boreholes located within a 3-mile radius of the PEC facility (Table A-1).

In the PEC vicinity, the offset boreholes for non-freshwater artificial penetrations are associated with oil and gas exploration and production activities connected to the former Cheney Ranch hydrocarbon field and several off field exploratory (wildcat) wells. As listed in California Department of Oil, Gas, and Geothermal Resources report (DOGGR, 1998), the Cheney Ranch Field, which generally was located in a span from 1.2 to 3.5 of miles north of the PEC facility, was discovered in January 1941 and was originally classified as an oil field, with two producing wells. The discovery well, the Cheney Ranch #2 had a total depth was 7,354 feet. The last oil production was in 1951 and the field was abandoned 1964. The field was reactivated in 1972 as a natural gas field and was re-abandoned in 1994. Peak production occurred in 1973 and was reported 30,860 barrels (bbl) of oil and 651,117 thousand cubic feet of gas. Production was from an approximately 200-foot thick net sand interval named the "Jergins Zone" associated with the Dosados Member of the Moreno Formation, encountered at an average depth of approximately 7,000 feet below ground surface. The deepest well in this field was drilled to a depth of 10,887 feet. Overall, approximately 17 wells were drilled in the field throughout its existence and all of the wells are now plugged and abandoned.

In accordance with regulatory requirements in place at the time, it was common for wells to be plugged with cement plugs placed at the brackish water - fresh water interface. This practice was acceptable into the 2000s. This plugging methodology was protective of the base of the water considered usable for agricultural irrigation. As such, several of the boreholes in the AOR lack plugs between the top of the PEC injection reservoir and the base of the established underground source of drinking water (USDW) defined in Attachment D. In general, the regional utilized aquifer system is associated with strata less than 2,000 feet deep in the PEC vicinity and consists of an upper water table aquifer and a deeper confined aquifer as discussed in Attachment D. However, several isolated sands on the order of 20 to 50 feet thick (Table D-2) were identified below the base of the utilized aquifer system extending to the approximate top of the Kreyenhagen Formation in the PEC IW2 well log. Although these sands do not appear to be substantial, they meet the definition of USDW based on the apparent salinity calculated. Overall, It is unlikely that any of these deeper isolated sands located below the recognized regional aquifer would be developed or utilized as they are: 1) relatively thin isolated zones, 2) deep below the surface and would be expensive to develop, and 3) contain poor quality water, which is not fit for consumption or agricultural irrigation, in comparison to the readily available water in the overlying shallow aquifers.

CORRECTIVE ACTION EVALUATION METHODS

Corrective action analysis was performed for the identified artificial penetrations within the line representing 42 psi of injection pressure buildup as indicated by modeling (Attachment A). This was done to determine if any of the penetrations represent a potential pathway for the migration of fluids out of the injection reservoir into the overlying deepest USDW in response to pressure increases from injection.

For the corrective action evaluation, the maximum expected entry pressure into a wellbore at each specific penetration location was evaluated considering the presence of physical obstructions to entry (i.e. mechanical and/or cement plugs) and wellbore conditions that resist pressure entry. These wellbore conditions consist of the hydrostatic pressure of the mud column resulting from fluid density, the gel strength of the mud column, and natural pressure head of the USDW. These conditions impart resisting pressures that counteract the entry pressure, which is attributed to native formation pressure of the injection zone combined with the pressure buildup in the injection zone resulting from injection.

Pressure in the Injection Zone

The expected pressure buildup in the injection zone was modeled as explained in Attachment A. The initial formation pressure of the Panoche Formation injection zone at PEC was measured on 10 February 2009 prior to the step rate testing (SRT) at IW2 (performed to quantify the maximum allowable surface injection pressure for the PEC wells). Prior to the SRT, the well had been swabbed in and developed via back-flowing for the collection of reservoir fluid samples. Completion activity daily reports indicated a positive surface pressure ranging from 25 to 35 psi during the swabbing operations conducted at IW1 and IW2 after the wells were static overnight (URS, 2009a and 2009b). Following collection of fluid samples at IW2, the well was killed with 60 bbl of 9.4 pounds per gallon (ppg) potassium chloride (KCl) brine and no further well activity occurred prior to the SRT, which was conducted 13 days later. Immediately prior to the SRT, a downhole pressure gauge was hung at 7,604 feet relative to kelly bushing (KB) and indicated a pressure of 3,510 psi. The fluid level in the well was reported at a depth of 80 feet below KB. Based on the 5.5-inch, 17 pound-per-foot tubing volume of 175 bbl, this would indicate that the wellbore fluid column consisted of approximately 60 bbl of 9.4 ppg fluid and 115 bbl of reservoir fluid having a calculated weight of 8.75 ppg and an overall kill weight of approximately 8.97 ppg. The fluid gradient of the combined wellbore fluid column, consisting of reservoir fluid and 9.4 ppg KCL brine is 0.466 pounds per square inch per foot (psi/ft). As such, for the initial reservoir pressure calculation, a conservative pressure gradient of 0.47 psi/ft. was selected for the injection zone prior to injection activities based on the measured bottom pressure prior to any injection into the reservoir. The uppermost point of possible pressure entry at offset wellbores was considered the top of the uppermost sand in the Panoche Formation as indicated by open hole logs for each well. This depth multiplied by the Panoche Formation injection zone pressure gradient (0.47 psi/ft) represents the borehole entry pressure in the absence of injection. The maximum modeled injection pressure buildup at each location was then added to this initial pressure to determine the overall entry pressure at the top of the injection zone uppermost sand at the individual penetrations in the AOR. As discussed in Attachment A, this pressure from injection is at its maximum currently and will diminish in the future because of a reduction in injection volume due to the operation of the newly installed enhanced wastewater system.

Resisting Pressure in Boreholes in the AOR

The most desirable method of isolating entry pressure in a wellbore is a physical barrier consisting of mechanical and/or cement plugs emplaced between the entry point and the USDW. In the absence of plugs, the hydrostatic pressure of the mud column resulting from its density, the gel strength of the mud column, and the pressure head of the USDW provide resistance to the entry pressure. Mud weight, gel strength, and filter cake buildup on the borehole wall are desirable mud qualities characteristic to rotary drilling as they are extremely important to maintaining hole stability. A borehole standing open with drilling mud is essentially a vessel that is open at the surface. However, once a cement plug is placed in the well, the plug isolates the overlying hydrostatic pressure exerted by the mud column above the plug from the hydrostatic pressure below the plug. For the corrective action evaluation performed, the hydrostatic pressure exerted by the mud column was limited to the length of the mud column between the point where pressure could enter the wellbore at the top of the injection zone and the base of the lowermost USDW providing a conservative estimate of hydrostatic pressure provided by the mud column.

Additional resistance to pressure or fluid entry into the wellbore is provided by the drilling mud gel strength of the mud column remaining in the wellbore. As discussed in Attachment A, drilling mud has an inherent gel strength that allows drill cuttings to be suspended in the wellbore when fluid movement stops. The gel strength imparts a semi-solid rigid structure to the fluid column that must be overcome in order for flow to resume. It is also known that gel strength increases with time, temperature, and irregular borehole geometry. For this corrective action evaluation, the gel strength was calculated based on the length of the continuous mud column below the lowermost plug isolating the mud column and the top of the injection zone using a conservative gel strength of 25 pounds/100 square feet of borehole exposure based on literature review (Johnston and Knape, 1986; Collins and Kortum, 1989). Using this approach, the gel strength of the borehole mud column calculated is considered to be conservative.

Additional resistance to pressure entry into the borehole is also supplied by the natural pressure head of the lowermost USDW. The resisting pressure of the hydrostatic fluid pressure in the lowermost USDW was calculated by multiplying a freshwater fluid gradient (0.433 psi/ft) by the depth of the base of the lowermost USDW where first entry would be possible and where the hydrostatic pressure provided by the mud column in the wellbore is at its least. The selected gradient is conservative because it assumes zero total dissolved solids (TDS) in the aquifer fluid. It is known by calculation performed in

Attachment D that the TDS of the lowermost USDW has a minimum TDS of approximately 8,200 milligrams per liter and would produce a higher fluid gradient. As per Attachment D, the lowermost USDW identified for this application occurs at a depth of approximately 3,400 feet from log analysis of IW2, which generally correlates to the top of the Kreyenhagen Formation. The identified lowermost USDW lies much deeper, and is separated by a thick sequence of predominantly clay, from the overlying lower water-bearing zone of the upper utilized aquifer system whose base located at approximately 1,900 feet depth at PEC (see Exhibit D-2). For the corrective action evaluation, it is assumed that the hydrostatic fluid column from the USDW would stand to the surface. Based on early investigation in the San Joaquin Valley by Mendenhall et al., (1916) and Davis and Poland (1957) it is expected that the lowermost USDW could be artesian and has a head level that extends above the land surface. Davis and Poland (1957) reported that the undisturbed natural gradient and potentiometric surface of the area is unknown as flowing artesian wells in the San Joaquin Valley were reported as early as 1869 and that there was appreciable draft of the lower water-bearing zone from these early wells. Additionally, it was reported that initial heads in the confined lower water-bearing zone beneath the Corcoran clay had artesian wells that flowed at the land surface in 1905 in the vicinity of Mendota to the east of the PEC site. These observations precede large scale pumping in the area, which began with major agricultural development in approximately 1917 at the time of World War I. Irrigation with ground water then rapidly expanded in the 1920s and steadily increased until World War II. By the early 1950s, over one million acre-feet of groundwater was being pumped from the aquifer beneath the Corcoran Clay (Belitz and Heimes, 1990) annually in the vicinity of Mendota. Davis and Poland (1957) further reported that heavy irrigation draft from the lower water bearing zone had lowered the original piezometric surface "very much" (by 1957). Miller et al. (1971) observed that intensive pumping had lowered the artesian head several hundred feet and caused the water-bearing deposits to compact by in excess of four feet regionally and 20 feet in places. Additionally, because the deeper stratigraphic section is of similar marine origin to the Panoche Formation and outcrops are recharged to the west at higher elevations in the Coast Range, the strata down dip in the valley are typically over-pressured. This is evidenced by the high mud weights used in offset hydrocarbon exploration wells used to maintain borehole stability and control pressure (Table A-1). Because it is highly unlikely that any pumping has occurred in the lowermost USDW identified based on its great depth, poor quality, and the availability of better quality water from much shallower depths, it is believed that the unit would be artesian. Based on this information, it is not unreasonable to assume a head level in the lowermost USDW at ground surface, which is believed to be conservative.

CORRECTIVE ACTION EVALUATION FOR PEC AOR

Twelve penetrations located inside of the 42-psi pressure contour, which delineates the PEC AOR, were evaluated for corrective action. The locations of the penetrations are indicated on Figure A-3 and required information is summarized in Table C-1. Additionally, wellbore schematics, included as Figures C-1 through C-12, were constructed for each penetration and where necessary the entry and resisting pressures were calculated and are indicated on each schematic. The current existing conditions at each penetration are discussed individually as follows:

AOR Penetration #1 (Cheney Ranch #1)

This well (Figure C-1) is a former hydrocarbon producer located approximately 11,750 feet to the north-northeast of the PEC injection wells. The model predicted pressure buildup due to injection at this location is 43 psi at the end of 2018. The well was drilled in 1939 and plugged in 1951 and includes an original abandoned completion and sidetrack completion. The original hole was drilled to 9,284 feet and

HALEY ALDRICH

the sidetrack was drilled to 7,215 feet. As indicated on the schematic, this well contains steel long-string casing that was shot off and recovered to 908 feet during abandonment and an associated cement sheath that extends up beyond the top of the PEC injection strata. Based on the records available, the initial borehole, which penetrated through the PEC injection zone, was abandoned and a sidetrack was drilled off of a cement kick plug. The sidetrack did not reach to the top of the PEC injection zone. Additionally, none of the perforations in the original hole reached to the depth of the PEC injection zone. With regard to plugging, there are two mechanical bridge plugs and four cement plugs emplaced in the long-string casing between the top of the PEC injection zone and the base of the lowermost USDW. This well is adequately plugged and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #2 (Cheney Ranch #2)

This well (Figure C-2) is a former hydrocarbon producer located approximately 9,550 feet to the north-northeast of the PEC injection wells. The model predicted pressure buildup due to injection at this location is 58 psi at the end of 2018. The well was drilled in 1940 and plugged in 1964 in accordance with regulatory requirements in existence at the time. The total depth of the well was 7,354 feet, but the well was plugged back with cement to 7,280 feet, which is above the top of the PEC injection zone. As indicated on the schematic, this well contains steel long-string casing extending up into the surface casing and an associated cement sheath that extends up beyond the top of the PEC injection strata. In addition, two cement plugs are emplaced in the long-string casing between the top of the injection zone and the base of the lowermost USDW. This well is adequately plugged and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #4 (England #1-31)

This well (Figure C-3) is a former hydrocarbon producer located approximately 6,350 feet to the north-northwest of the PEC injection wells. The model predicted pressure buildup due to injection is 83 psi at this location at the end of 2018. The well was drilled in 1950 and plugged in 1964 in accordance with regulatory requirements in existence at the time. The total depth of the well was 10,357 feet and it was plugged back to 10,169 feet with cement. As indicated on the schematic, this well contains steel long-string casing that was shot off during abandonment at 782 feet and an associated cement sheath that extends up to approximately 9,071 feet per volumetric calculation. There are no plugs between the injection zone and the base of the USDW. Perforations at 10,017 feet are plugged with cement. The potential exist for pressure to enter the annulus behind the casing. However, based on the high mud weight in the annulus (11.23 ppg) and the calculations presented on the schematic, the counter-pressure provided by the USDW and hydrostatic mud weight exceeds the entry pressure from the injection strata by 235 psi. In addition, the conservative estimate of mud gel strength adds an additional 102 psi of resistance to entry. This counter-pressure is protective of the USDW and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #5 (Souza #1-36)

This well (Figure C-4) is a plugged dry hole associated with hydrocarbon exploration located approximately 8,400 feet to the northwest of the PEC injection wells. The model predicted pressure buildup due to injection is 67 psi at this location at the end of 2018. The well was drilled and plugged in 1951 in accordance with regulatory requirements in existence at the time. The well has a total depth of 10,635 feet. This penetration has no long-string casing and no cement plugs between the PEC injection zone and the base of the USDW. The potential exist for pressure to enter the wellbore and move fluids into the USDW. However, based on the high mud weight (11.76 ppg) and the calculations presented on the schematic, the counter-pressure provided by the USDW and hydrostatic mud weight exceeds the entry pressure from the injection strata by 603 psi. In addition, the conservative estimate of mud gel strength adds an additional 43 psi of resistance to entry. This counter-pressure is protective of the USDW and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #6 (Roberts #1)

This well (Figure C-5) is a plugged dry hole associated with hydrocarbon exploration located approximately 9,450 feet to the northeast of the PEC injection wells. The model predicted pressure buildup due to injection is 56 psi at this location at the end of 2018. The well was drilled and plugged in 1963 through 1964. The well has a total depth of 8,772 feet. This well has no long-string casing and no cement plugs between the PEC injection zone and the base of the USDW but was plugged in accordance with regulatory requirements in existence at the time. The potential exist for pressure to enter the wellbore and move fluids into the USDW. However, based on the high mud weight in the wellbore (10.83 ppg) and the calculations presented on the schematic, the counter-pressure provided by the USDW and hydrostatic mud weight exceeds the entry pressure from the injection strata by 141 psi. In addition, the conservative estimate of mud gel strength adds an additional 56 psi of resistance to entry. This counter-pressure is protective of the USDW and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #11 (Silver Creek #27X)

This well (Figure C-6) is a former hydrocarbon producer located approximately 10,000 feet to the north-northeast of the PEC injection wells. The model predicted pressure buildup due to injection at this location is 53 psi at the end of 2018. The well was drilled in 1972 and plugged in 1994 in accordance with regulatory requirements in existence at the time. The total depth of the well was 7,460 feet. The well was plugged back with cement to 7,286 feet, which is the level of the top of the PEC injection zone. As indicated on the schematic, this well contains steel long-string casing to the surface and a cement sheath that extends up beyond the top of the PEC injection zone strata based on volumetric calculation. In addition, a cement plug is consisting of 53 cubic feet of cement was emplaced in the long-string casing between the top of the injection zone and the base of the lowermost USDW. This well is adequately plugged and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #12 (Silver Creek #54X)

This well (Figure C-7) is a plugged dry hole associated with hydrocarbon exploration located approximately 8,050 feet to the north-northwest of the PEC injection wells. The model predicted pressure buildup due to injection is 64 psi at this location at the end of 2018. The well was drilled and plugged in 1973 in accordance with regulatory requirements in existence at the time. The total depth of the penetration is 10,887 feet. This well has no long-string casing. However, a cement plug consisting of 70 sacks (sx) of Class G cement was emplaced in the borehole from 7,180 to 6,953 feet and was confirmed by tag. This plug isolates the top of the injection zone from the base of the lowermost USDW. This well is adequately plugged and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #13 (Silver Creek #32X)

This well (Figure C-8) is a plugged dry hole associated with hydrocarbon exploration located approximately 8,000 feet to the north-northeast of the PEC injection wells. The model predicted pressure buildup due to injection is 68 psi at this location at the end of 2018. The well was drilled and plugged in 1973 in accordance with regulatory requirements in existence at the time. The total depth of the penetration is 7,531 feet. This well has no long-string casing. However, a cement plug consisting of 100 sx of Class G cement was emplaced in the borehole from 7,296 to 6,956 feet. This plug isolates the top of the injection zone from the base of the lowermost USDW. This well is adequately plugged and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #14 (Silver Creek #18)

This well (Figure C-9) is a plugged dry hole associated with hydrocarbon exploration located approximately 6,350 feet to the northeast of the PEC injection wells. The model predicted pressure buildup due to injection is 79 psi at this location at the end of 2018. The well was drilled and plugged in 1974 in accordance with regulatory requirements in existence at the time. The total depth of the penetration is 8,698 feet. This well has no long-string casing and no cement plugs between the PEC injection zone and the base of the USDW. The potential exist for pressure to enter the wellbore and move fluids into the USDW. Based on the calculations presented on the schematic, the entry pressure exceeds the counter-pressure provided by the USDW and hydrostatic mud weight by 32 psi. However, a conservative estimate of mud gel strength adds an additional 59 psi of resistance to entry resulting in a total counter pressure of 27 psi overbalance. This overbalance is protective of the USDW and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #16 (Cheney Ranch #15X)

This well (Figure C-10) is a former hydrocarbon producer located approximately 10,950 feet to the north-northeast of the PEC injection wells. The model predicted pressure buildup due to injection at this location is 48 psi at the end of 2018. The well was drilled in 1981 and plugged in 1994 in accordance with regulatory requirements in existence at the time. The total depth of the well was 7,300 feet, which is approximately the level of the top of the PEC injection zone. As indicated on the schematic, this well contains steel long-string casing to the surface and a cement sheath that extends up beyond the top of the PEC injection zone strata. In addition, a cement plug consisting of 36 cubic feet of cement is emplaced in the long-string casing between the top of the injection zone and the base of the lowermost USDW. This well is adequately plugged and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #17 (Silver Creek #32X)

This well (Figure C-11) is a plugged dry hole associated with hydrocarbon exploration located approximately 8,800 feet to the northwest of the PEC injection wells. The model predicted pressure buildup due to injection is 62 psi at this location at the end of 2018. The well was drilled in 1983 and plugged in 1984 in accordance with regulatory requirements in existence at the time. The well has a total depth of 10,217 feet and multiple zones were tested but it never produced. This well has long-string casing to surface that has a cement sheath extending into the surface casing. The well has four mechanical bridge plugs and four cement plugs isolating the lower wellbore and deeper perforated zones. The cement plug from 6,155 to 6,330 feet isolates the uppermost perforations in the Panoche

Formation from the base of the lowermost USDW. This well is adequately plugged and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

AOR Penetration #20 (Blue Agave #1)

This well (Figure C-12) is a plugged dry hole associated with hydrocarbon exploration located approximately 6,650 feet to the north of the PEC injection wells. The model predicted pressure buildup due to injection is 79 psi at this location at the end of 2018. The well was drilled in 2002 and plugged in 2002 and 2015. The well has an original borehole and sidetrack borehole but no long-string casing was run. The original hole had a measured depth (MD) of 7,612 feet and a true vertical depth (TVD) of 7,442 feet. The sidetrack hole has a MD of 7,753 feet and a TVD of 7,420 feet off of a cement kick plug from 6,012 to approximately 5,751 feet depth. The top of the PEC injection zone in the original hole is isolated from the USDW by this cement plug. This well has no plugs between the PEC injection zone and the base of the USDW in the sidetrack hole but was plugged in accordance with regulatory requirements in existence at the time. The potential exist for pressure to enter the wellbore and move fluids into the USDW. However, based on the high mud weight in the borehole (10.9 ppg) and the calculations presented on the schematic, the counter-pressure provided by the USDW and hydrostatic mud weight exceeds the entry pressure from the injection strata by 149 psi. In addition, a conservative estimate of mud gel strength adds an additional 55 psi of resistance to entry. This counter-pressure is protective of the USDW and no corrective action is necessary. Copies of the well records for this penetration are included in Exhibit C-1.

CONCLUSION

Based on the corrective action evaluation performed for the artificial penetrations located in the defined AOR (Table C-1), no wells in the PEC AOR require corrective action.

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TABLE

TABLE C-1
NON-FRESHWATER ARTIFICIAL PENETRATIONS WITHIN THE 41.96 PSI PRESSURE DIFFERENTIAL AREA OF REVIEW
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

AOR No.	API No.	TYPE WELL	Operator	Operator and Well No.	Spud Date	Location	Total Depth (feet KB)	Perforated or Screened Interval (feet KB)	Surface Casing Detail	Longstring Casing Detail	Plugged Interval Details (feet KB)	Plug Date
1	1900190	Plugged Hydrocarbon Producer	Exxon Corporation originally Jergins Oil Co.	Cheney Ranch #1	11/19/1939	Sect 29, T14S, R13E, Fresno Cnty, CA (11,750 feet NNE PEC Plant)	9,284 Original hole; 7,215 Sidetrack	Orig. hole: Perf'd 6 5/8" Liner from 6,720' to 7,188': ST hole: 6 5/8" Liner perf/screen = 6,718' to 7,215'	13 3/8" 54# to 529 ft with 320 sx cement (17 1/2" hole)	8 5/8" to 6,676 ft(12.25" hole) with 350 sx. Shot and recovered from 908 feet	**Orig. Hole:** 7,775 to 7,662 (30 sx); 7,326 to 7,191 (39 sx); 6,720 to 6,691 (70 sx) with junk at 6,720 to 6,723. **ST hole:** 6,720 to 6,480 (23 sx); 5037 (CBP + 9 sx); 4016 (CBP + 20 sx); 908 (14 sx); 549 to 503 (35 sx); 503 to 26 (dirt); 26 to 5 (8 sx)	**1952**
2	1900191	Plugged Hydrocarbon Producer	Exxon Corporation (Orig. Jergins Oil Co.)	Cheney Ranch #2	11/23/1940	Sect 29, T14S, R13E, Fresno Cnty, CA (9,550 feet NNE PEC Plant)	7,354 (Plugged back to 7,280)	7,192 - 7,273 5", 20#, Screened Liner - 80 mesh	11 3/4" 54# to 538 ft with 315 sx cement (15.5" hole)	7", 26 & 28#, to 7,200 ft with 300 sx. Shot off and recovered from 457 feet (10.625" hole)	7,354 to 7280 (50 sx); 7,082 to 6,802 (50 sx); 5,680 to 5,635' (8 sx); 3,100 to 2,960' (25 sx); 2,000' to 1,944' (10 sx); 457' to 421' (20sx); 421' to 27' (dirt); 27' to 7' (12 sx)	**1964**
4	1900193	Plugged Hydrocarbon Producer	L. M. Lockhart	England #1-31	11/27/1950	Sect 31, T14S, R13E, Fresno Cnty, CA (6,350 feet NNW PEC Plant)	10,357 (Plugged back to 10,169	Perforations @ 10,017'	14" to 609 ft 47.5# with 700 sx cement (20" hole)	5 .5" 20# to 10,038 ft with 300 sx, shot and recovered 782 ft (10.625" hole to 7,425'; 9.875" hole to 9,995'; 7.625" hole to TD)	10,357' to 10,169' (50 sx); 10,167' to 9,880' (50 sx);1,045' to 987' (6 sx); Wood Plug driven from 782' to 794'; 794' to 744' (26 sx); 629' to 552' (33 sx); 15' to surf (14 sx)	**1964**
5	1906032	Plugged Dry Hole	L. M. Lockhart	Souza #1-36	7/13/1951	Sect 36, T14S, R13E, Fresno Cnty, CA (8,400 feet NW PEC Plant)	10,635	-	14" 47.5# to 376 feet with 650 sx cement (20" hole) (stuck running surface casing)	Not Run	1,200' to 1,146' (40 sx), 396' to 350' (40sx); 10' to surface	**1951**
6	1906039	Plugged Dry Hole	Atlantic Richfield Company	Roberts #1	12/22/1963	Sect 33, T14S, R13E, Fresno Cnty, CA (9,450 feet NE PEC Plant)	8,772	-	10 3/4", 40.5# to 506 ft with 300 sx cement (15" hole)	Not Run	1,845' to 1,692' (75 sx) , 550' to 485' (50 sx), 29' to 19'	**1964**
11	1920726	Plugged Hydrocarbon Producer	Cencal Drilling Inc. (Orig. E.A. Bender)	Silver Creek #27X	12/7/1972	Sect 29, T14S, R13E, Fresno Cnty, CA (10,000 feet NNE PEC Plant)	7,460 (Plugged back to 7,286	Perforations @ 6,876; 6,960 to 6,984; 7,235 to 7,250	9" 45# to 1,710 ft with 537 sx cement (12.25" hole)	4.5" 9.5 & 10.5# to 7,332 ft with 270 sx (7 7/8" hole)	7,332' to 7,290' (53 ft^3); 7,290' to 7,286' (35 sx); 7,280' to 6,686' (53 ft^3); 1,601' to 1,510' (35 ft^3); 30' to 5' (12 sx)	**1994**
12	1920758	Plugged Dry Hole	E. A. Bender, Operator	Silver Creek #54X	3/27/1973	Sect 31, T14S, R13E, Fresno Cnty, CA (11,750 feet NNE PEC Plant)	10,887 (plugged back to 6,958') and redrilled to 7,183 for Test	-	9 5/8" 36# to 1,752 ft with 930 sx cement (13.75" hole)	Not Run	7,260' to 7,183' (210 sx); 7,180 to 6,953' (70 sx) ; 1,807 to 1,654 (80 sx)	**1973**
13	1920776	Plugged Dry Hole	E. A. Bender, Operator	Silver Creek #32X	9/19/1973	Sect 32, T14S, R13E, Fresno Cnty, CA (11,750 feet NNE PEC Plant)	7,531	-	9 5/8" 40# to 750 ft with 550 sx cement (13.75" hole) to surface	Not Run	7,296' to 6,956' (100 sx); 1,744' to 1,550' (100 sx); 791' to 633' (60 sx)	**1973**
14	1920804	Plugged Dry Hole	E. A. Bender, Operator	Silver Creek #18	3/23/1974	Sect 33, T14S, R13E, Fresno Cnty, CA (11,750 feet NNE PEC Plant)	8,698	-	9 5/8" 47# to 768 ft with 500 sx cement (13.75" hole)	Not Run	1,700' to 1,437' (100 sx); 817' to 678' (50 sx); 35' to 8'	**1974**
16	1921446	Plugged Hydrocarbon Producer	Cencal Drilling Inc. (Orig. E.A. Bender)	Cheney Ranch #15X	7/21/1981	Sect 29, T14S, R13E, Fresno Cnty, CA (11,750 feet NNE PEC Plant)	7,300	Perforations @ 7,172 to 7,192; 7,216 to 7,226	9 5/8" K-55 to 770 ft with 206 sx cement (12.25" hole)	4.5", 11.6#, K-55 to 7,300 ft with 400 ft^3 cement calculated at 5,501' KB. (in 7.875" hole)	7,300 to 6,920 (36 ft^3); 1,585 to 1,385 (16 sx); 30 to 5 (8 sx)	**1994**
17	1921924	Plugged Dry Hole	American Hunter Exploration Ltd.	Souza #1	11/4/1983	Sect 36, T14S, R13E, Fresno Cnty, CA (11,750 feet NNE PEC Plant)	10,217	Perforations @ 10,045 to 9,967 sqzd; 9,689 to 9,832; 9,380 to 9,423 sqzd; 9,159 to 9,199; 6552 sqzd; 6,466 to 6,491; 6,310 to 6330	9 5/8" 36# to 1,709 ft with 796 ft^3 cement (12.25" hole)	5.5" 20# to 10,213 ft with 2,287 ft^3 cement calculated at 1,066 feet KB (8.75" hole)	Ret @ 9,862 (50 sx); Ret @ 9,460 (50 sx); Ret @ 9,340 (50 sx); Ret @ 6,545 (50 sx), 6,155 to 6,330 (6 bbls); 1,400 to 1,200 (15 bbls); 90 to 5' (2 bbls) - Bridge Plugs @ 10,177, 9,670, 9,145, 6,401	**1984**
20	1924225	Plugged Dry Hole	R&R Resources, LLC	Blue Agave #1	9/28/2002	Sect 32, T14S, R13E, Fresno Cnty, CA (11,750 feet NNE PEC Plant)	7,612 MD (7,442 TVD) Orig hole; 7,753 MD (7,420 TVD) Sidetrack hole	-	9 5/8" 36# to 820 ft with 260 sx cement (12.25" hole)	Not Run	6,012 to 5,741 (70 sx) original hole; 1,465 to 1,160 (130 sx); 894 to 382' (73 bbls);	**2002 & 2015**

Notes:
bbls - barrels
ft^3 - cubic feet
KB = kelly bushing
sx = sacks
TD = total depth
TVD = true vertical depth

FIGURES

Figure C-1

Map ID No.: 1

Type of Well: Hydrocarbon Producer

Operator: Jergins Oil Company

Well Status: Plugged and Abandoned (1952)

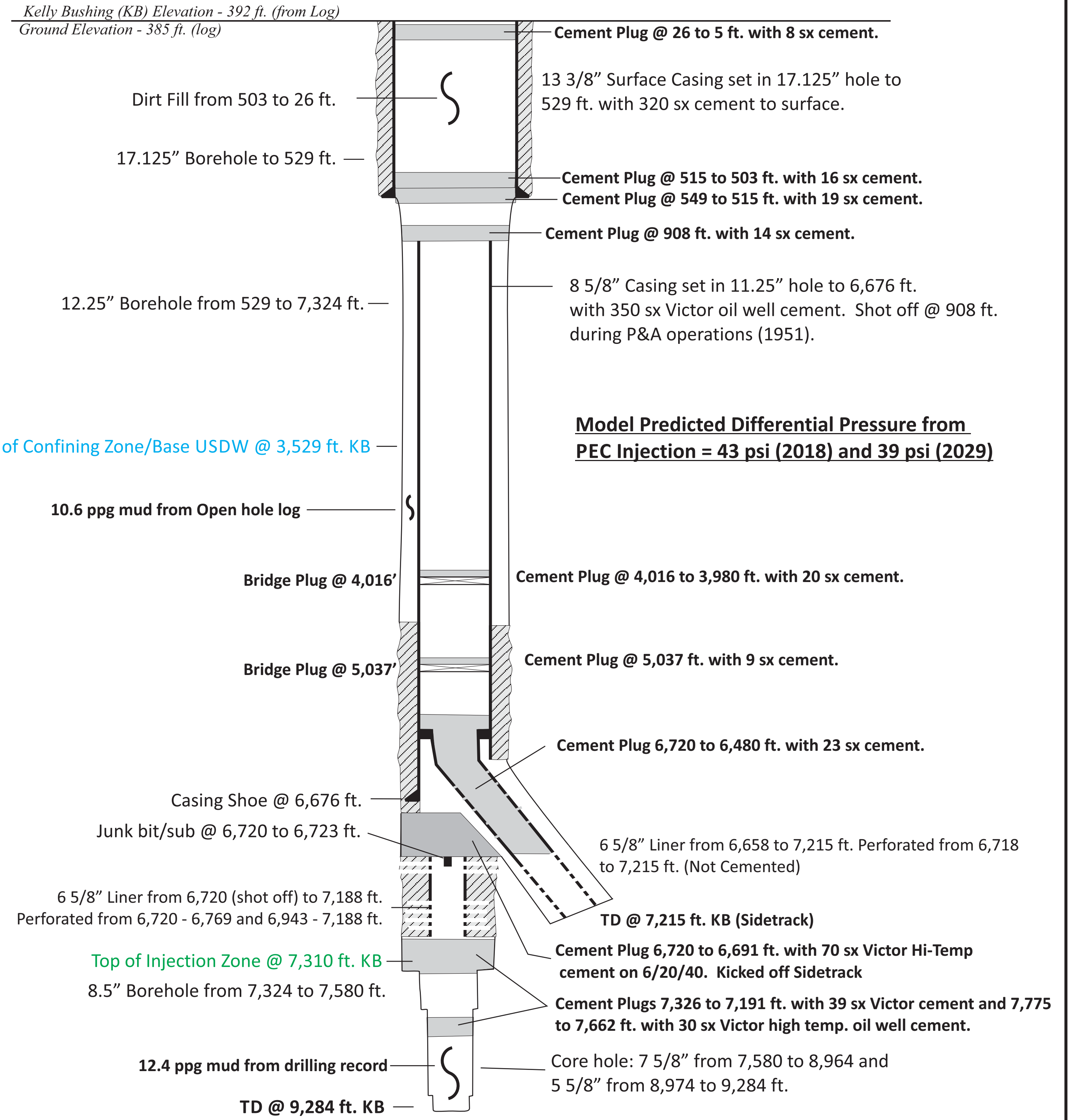
Lease: Cheney Ranch

Records: DOGGR Forms: OG100, OG101, OG103, OG105, OG108, OG109B, OG109D, OG111, OG123, OG,136, OG159

Well Number: 1 *(1939 spud)*

Distance from nearest injection well: 11,750 ft. NNE

API Number 42-019-24225



<u>SYNOPSIS</u>: The model predicted pressure differential at this location is 43 psi at the end of 2018. This is a sidetracked well. There are multiple plugs (cement and bridge plugs) between the top of the injection zone and the base of the USDW. Additionally, based on well records, none of the perforated intervals in the original hole or sidetrack liner section reached the depth of the top of the injection zone. This well is plugged in a manner that is protective of the USDW and no corrective action is necessary.

Figure C-2

Map ID No.: 2

Operator: Jergins Oil Company

Lease: Cheney Ranch

Well Number: 2 (1940 spud)

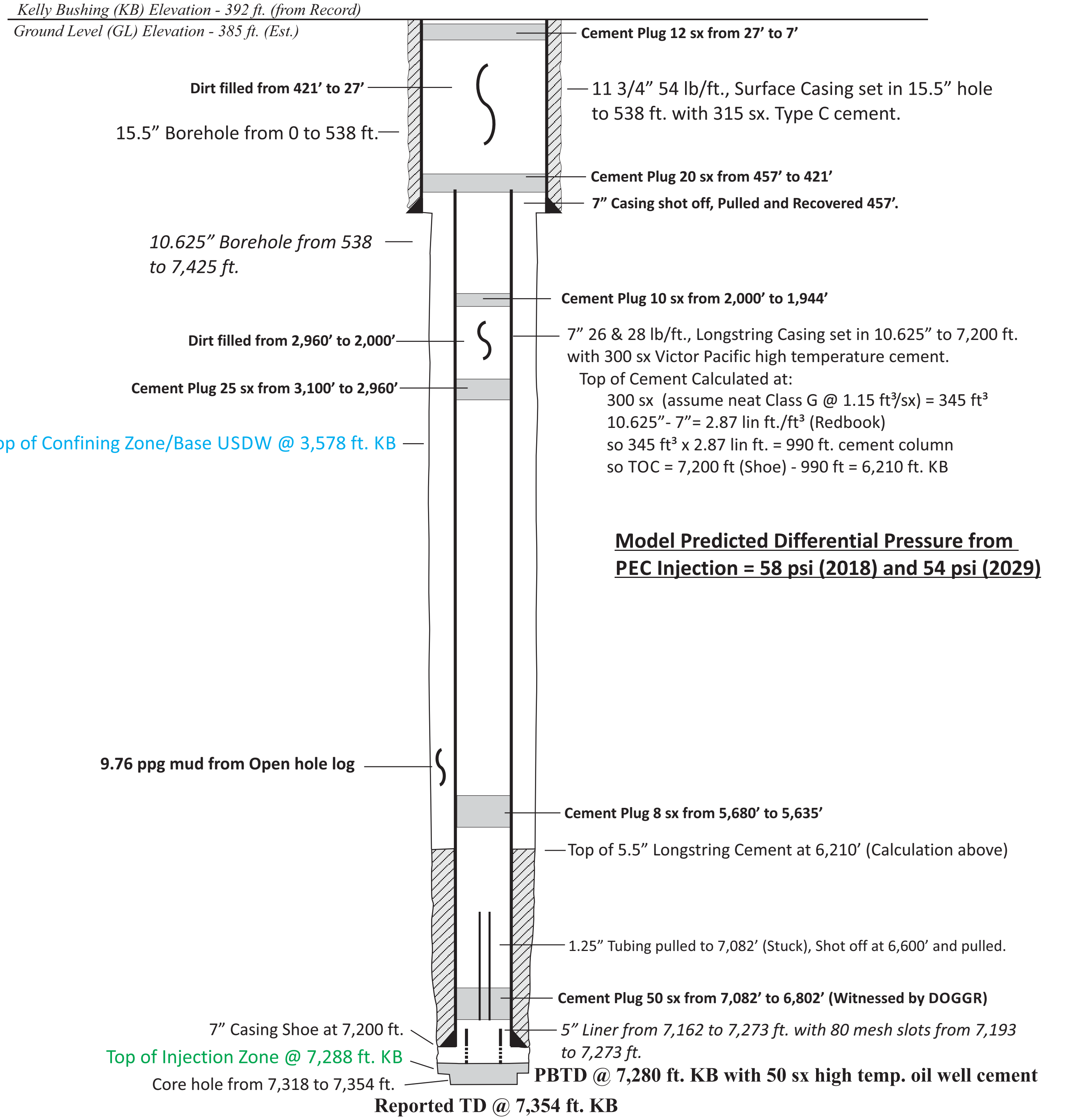
API Number 42-019-00191

Type of Well: Hydrocarbon Producer

Well Status: Plugged and Abandoned (1964)

Records: Doggr Forms: 100, 101,103, 108, 109B&D, 111, 136A, 156, 159

Distance from nearest injection well: 9,550 ft. NNE



SYNOPSIS: The model predicted pressure differential at this location is 58 psi at the end of 2018. This well was plugged back with cement to a level above the PEC injection zone. This well has a 7-inch steel casing and based on the volume of cement pumped, has a cement sheath that extends up to approximately 6,210 ft KB based on calculation, which is well above the top of the injection zone. Additionally, the longstring casing conains two cement plugs between the top of the injection zone and the base of the lowermost USDW. This well is adequately completed and plugged to be protective of the USDW and no corrective action is necessary.

Figure C-3

Map ID No.: 4

Operator: L. M. Lockhart

Lease: England

Well Number: 1-31 *(1950 spud)*

API Number 42-019-00193

Type of Well: Hydrocarbon Producer

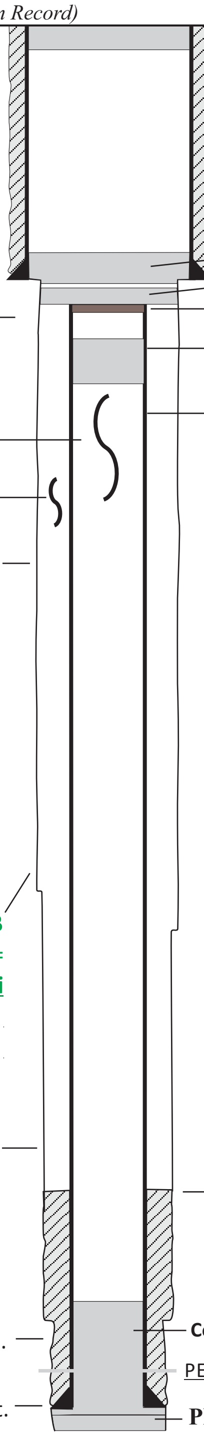
Well Status: Plugged and Abandoned *(1964)*

Records: Doggr Forms: 100, 103, 105, 109, 111, 123, 159, 165

Distance from nearest injection well: 6,350 ft. NNW

Kelly Bushing (KB) Elevation - 419 ft. (from Record)

Ground Elevation - 407 ft. (from Record)



Cement Plug 14 sx from 15' to surface (observed)

14" 47.5 lb/ft., K-55 Surface Casing set in 20" hole to 609 ft. with 700 sx. Type C cement.

20" Borehole from 0 to 609 ft.

Cement Plug 33 sx from 629' to 552' (Tagged)

Cement Plug 26 sx from 794' to 744' (calculated)

Casing shot off and pulled to 782'. Wooden Plug driven to 794'

Cement Plug 6 sx from 1045' to 987' (calculated)

10.625" Borehole from 609 to 7,425 ft.

5 1/2" 17 & 20 lb/ft., J-55 & N-80 Longstring Casing set in 10.625 x 9.875 x 7.625" hole to 10,038 ft. with 300 sx Permanente cement.

Top of Cement Calculated at:

300 sx (assume neat Class G @ 1.15 ft^3/sx) = 345 ft^3

7.625"- 5.5"= 6.57 lin ft./ft^3 (Redbook)

43 lin ft. = 6.5 ft^3 of cement to fill

so 345 ft^3 - 6.5 ft^3 = 338.5 ft^3 cement remaining in 9.875" x 5.5" fill

9.875" - 5.5" = 2.73 /lin ft./ft^3 (Redbook) so

338.5 ft^3 x 2.73 lin ft/ft^3. = 924 ft. cement column (in 9.875" x 5.5")

so TOC = 10,038 ft (TD) - (924 ft + 43 ft) = 9,071 ft. KB

Very heavy mud encountered according to DOGGR representative in 1964 as observed in bailer sample

11.23 ppg mud from Open hole log

Top of Confining Zone/Base USDW @ 3,240 ft. KB

3,240' x 0.433 = 1,403 psi

Pressure Exerted by Mud Column (Base USDW to Top Panoche Sand = 7077' - 3240' = 3837' x 11.23 ppg (0.584 psi/ft) = 2,241 psi

Entry Pressure = (Formation P + Model differential P) = 3,326 psi + 83 psi = 3,409 psi

Resisting Pressure = (USDW P + Mud Column P) = 1,403 psi + 2,241 psi = 3,644 psi

Resisting pressure exceeds entry pressure by 235 psi and gel strength provides an added 102 psi of resistance

Top of Injection Zone @ 7,077 ft. KB

Pressure Expected using PEC initial FG of 0.47 psi/ft = (0.47 psi/ft) x 7,077' = **3,326 psi**

Model Predicted Differential Pressure from PEC Injection = 83 psi (2018) and 81 psi (2029)

Minimum Expected gel strength of the mud column, which can be calculated from the following equation using a gel strength default of *25 lb/100 ft^2:

Entry Pressure (EP) in psi = $\frac{(0.00333)\ (25\ lb/100\ ft^2)\ (h\ (ft.))}{D\ (in.)}$

Where:

(h) is the height of the mud column at the point where reservoir fluid could enter the borehole (7077 ft. KB - base uppermost plug) = 7,077 ft. KB - 794 ft. KB = 6,283 ft.

(D) = 10.625 " - 5.5" = 5.125" from Drilling record

Calculation

EP in psi = $\frac{(0.00333)\ (*25\ lb/100\ ft^2)\ (6{,}283\ ft.)}{(5.125\ in.)}$ = 102.1 psi

9.875" Borehole from 7,425 to 9,995 ft.

Top of 5.5" Longstring Cement at 9,071' (Calculation above)

Cement Plug 50 sx from 10,167' to 9,880'

7.625" Borehole from 9,995 to 10,357 ft.

PERFORATIONS: 10,017'

5.5" Casing Shoe at 10,038 ft.

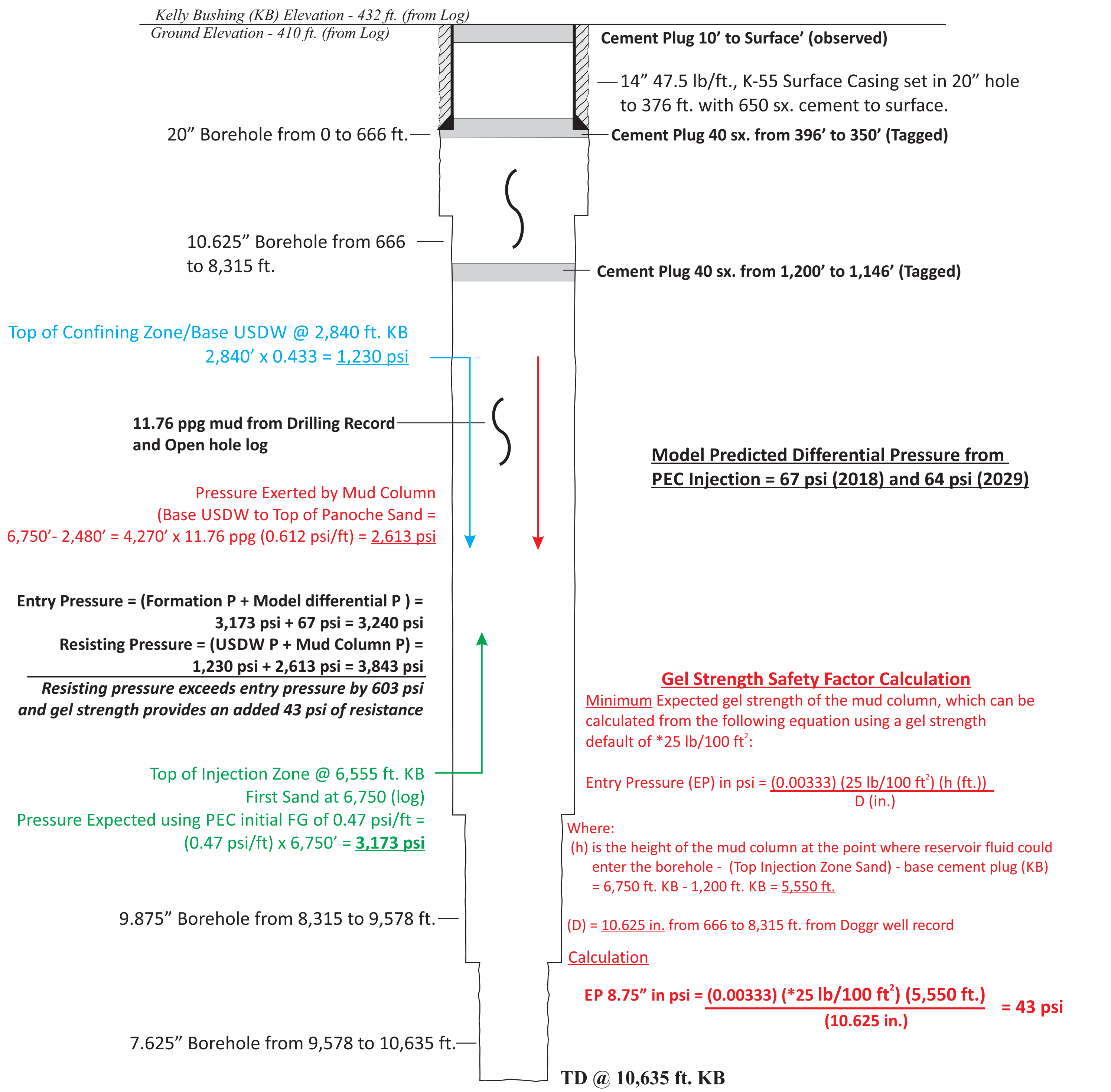
PBTD @ 10,169 ft. KB with 50 sx cement

TD @ 10,357 ft. KB

SYNOPSIS: The model predicted pressure differential at this location is 83 psi at the end of 2018. This wellbore has 5.5-inch steel casing and based on the volume of cement pumped, has a cement sheath that extends up to approximately 9,071 ft KB based on calculation. There are no plugs between the injection interval and the base of the USDW. The perforations at 10,017 are plugged with cement. The potential exist for pressure to enter the annulus behind the casing. However, based on the high mud weight in the annulus, the counter-pressure provided by the USDW and hydrostatic mud weight exceeds the entry pressure from the injection strata including the modeled differential pressure by 235 psi. The minimum drilling mud gel strength provides an additional safety factor of 102 psi. This counter-pressure is protective of the USDW and no corrective action is necessary.

Figure C-4

Map ID No.:	5	Type of Well:	Dry Hole
Operator:	L. M. Lockhart	Well Status:	Plugged and Abandoned (1951)
Lease:	Souza	Records:	DOGGR Forms: 100, 101, 103, 105, 108, 111, 159
Well Number:	1-36 *(1951 spud)*	Distance from nearest injection well:	8,400 ft. NW
API Number	42-019-06032		



SYNOPSIS: The model predicted pressure differential at this location is 67 psi at the end of 2018. There are no plugs between the top of the injection zone first sand at 6,750 ft. KB (log) and the base of the lowermost USDW at 2,840 ft. KB. The resistance to entry pressure provided by USDW pressure and hydrostatic pressure of the mud column is 603 psi higher than the expected reservoir pressure using PEC original bottom hole pressure measurement and the pressure differential modeled due to injection. The minimum drilling mud gel strength provides an additional safety factor of 43 psi. This well is plugged in a manner that is protective of the USDW and no corrective action is necessary.

Figure C-5

Map ID No.: 6

Operator: Atlantic Richfield Co.

Lease: Roberts

Well Number: 1 *(12/22/63 spud)*

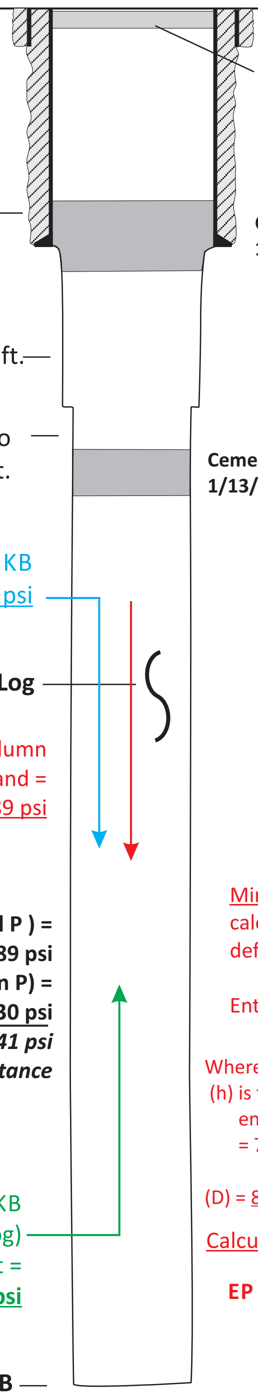
API Number 42-019-06039

Type of Well: Dry Hole

Well Status: Plugged and Abandoned (1964)

Records: DOGGR Forms: 105, 108, 109, 111, 136A, 159

Distance from nearest injection well: 9,450 ft. NE



Entry Pressure = (Formation P + Model differential P) =
3,633 psi + 56 psi = 3,689 psi
Resisting Pressure = (USDW P + Mud Column P) =
1,741 psi + 2,089 psi = 3,830 psi

Resisting pressure exceeds entry pressure by 141 psi and gel strength provides an added 56 psi of resistance

Model Predicted Differential Pressure from PEC Injection = 56 psi (2018) and 51 psi (2029)

Gel Strength Safety Factor Calculation

Minimum Expected gel strength of the mud column, which can be calculated from the following equation using a gel strength default of *25 lb/100 ft^2:

$$\text{Entry Pressure (EP) in psi} = \frac{(0.00333)\ (25\ lb/100\ ft^2)\ (h\ (ft.))}{D\ (in.)}$$

Where:

(h) is the height of the mud column at the point where reservoir fluid could enter the borehole - (Top Injection Zone Sand) - (base cement plug KB) = 7,730 ft. KB - 1,845 ft. KB = 5,885 ft.

(D) = 8.75 in. from 1413 to 7730 ft. from Doggr well record

Calculation

$$\textbf{EP 8.75" in psi} = \frac{(0.00333)\ (*25\ lb/100\ ft^2)\ (5,885\ ft.)}{(8.75\ in.)} = \textbf{56 psi}$$

SYNOPSIS: The model predicted pressure differential at this location is 56 psi at the end of 2018. There are no plugs between the top of the injection zone first sand at 7,730 ft. KB (log) and the base of the lowermost USDW at 4,020 ft. KB. The resistance to entry pressure provided by USDW pressure and hydrostatic pressure of the mud column is 141 psi higher than the expected reservoir pressure using PEC original bottom hole pressure measurement and the pressure differential modeled due to injection. Additionally, the minimum drilling mud gel strength provides an additional safety factor of 56 psi. This well is plugged in a manner that is protective of the USDW and no corrective action is necessary.

Figure C-6

Map ID No.: 11

Operator: E.A. Bender

Lease: Silver Creek

Well Number: 27X *(12/7/72 spud)*

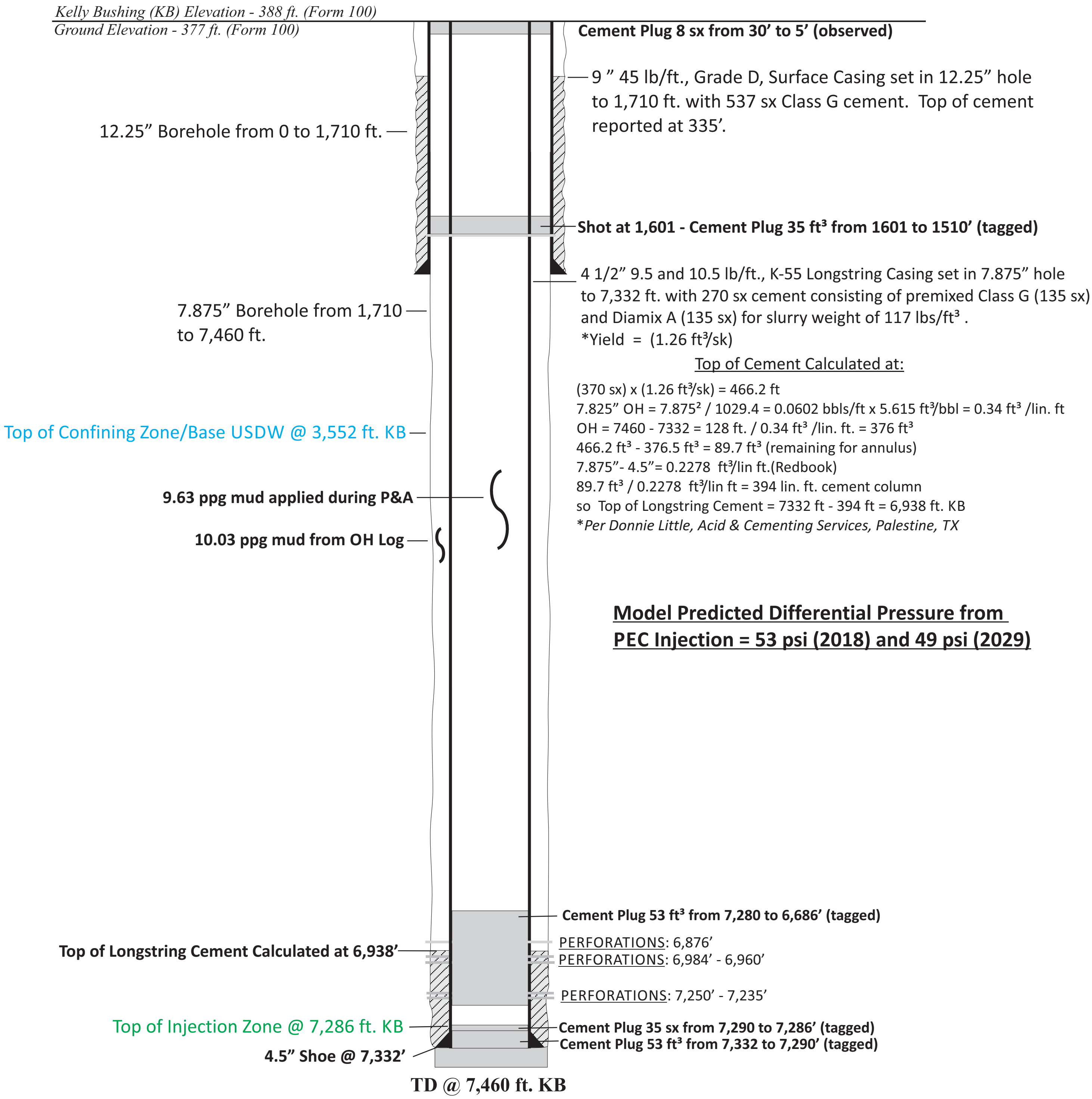
API Number 42-019-21924

Type of Well: Hydrocarbon Producer

Well Status: Plugged and Abandoned (1994)

Records: Doggr Forms: OGD10, OG100, OG103, OG105, OG107 OG108, OG109, OG111, OG159

Distance from nearest injection well: 10,000 ft. NNE



SYNOPSIS: The model predicted pressure differential at this location is 53 psi at the end of 2018. This well was plugged back to the top of the injection zone. The well has a 4.5-inch steel casing and based on the volume of cement pumped, has a cement sheath that extends up above the top of the injection zone. A cement plug is located in the casing extending above the top of the injection zone and covering all perforations in the well. This well is adequately completed and plugged to be protective of the USDW and no corrective action is necessary.

Figure C-7

Map ID No.: 12

Type of Well: Dry Hole

Operator: E. A. Bender

Well Status: Plugged and Abandoned (1973)

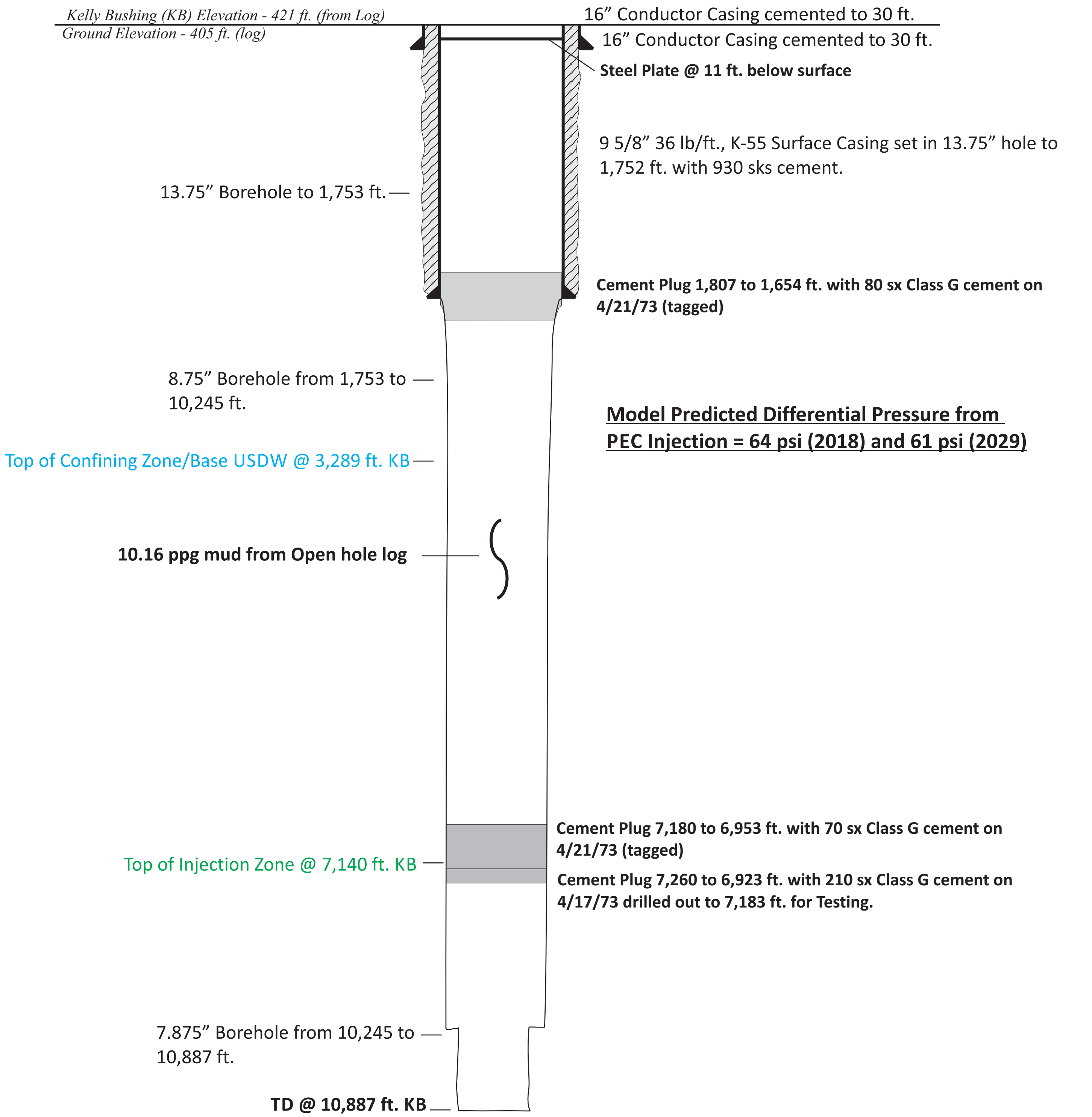
Lease: Silver Creek

Records: DOGGR Forms: 100, 103, 105, 107, 108, 109, 111, 157, 159

Well Number: 54X *(1973 spud)*

Distance from nearest injection well: 8,050 ft. NNW

API Number 42-019-20758



SYNOPSIS: The model predicted pressure differential at this location is 64 psi at the end of 2018. The wellbore contains no casing from the surface casing shoe to total depth. However, a cement plug is present between the top of the injection zone and the base of the USDW from 7,260 to 6,953 ft. isolating the pressure buildup from the borehole. This well is adequately plugged to be protective of the USDW and no corrective action is necessary.

Figure C-8

Map ID No.: 13

Type of Well: Dry Hole

Operator: E. A. Bender

Well Status: Plugged and Abandoned (1973)

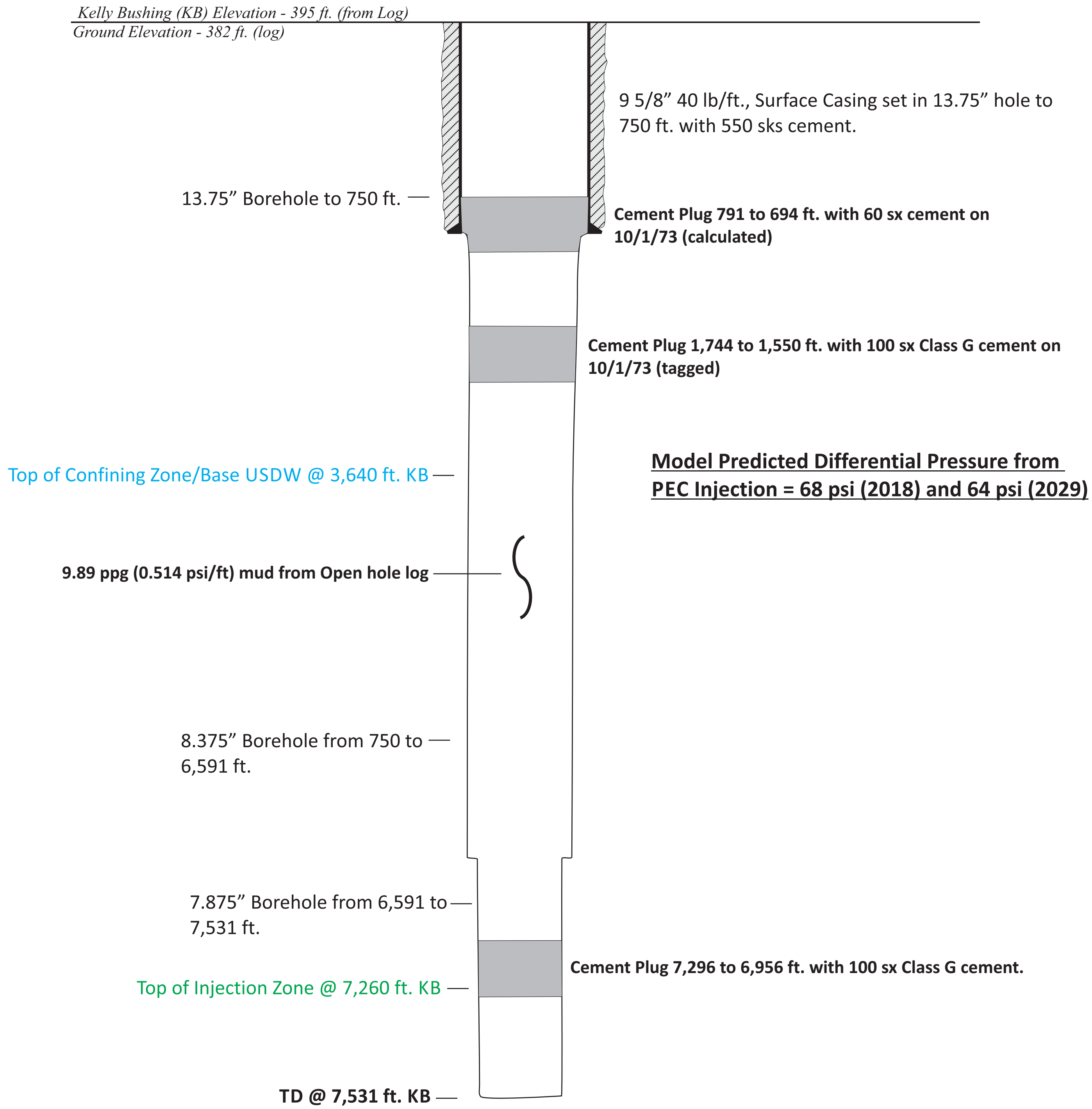
Lease: Silver Creek

Records: DOGGR Forms: 100, 103, 105, 108, 109, 111

Well Number: 32X *(1973 spud)*

Distance from nearest injection well: 8,000 ft. NNE

API Number 42-019-20776



SYNOPSIS: The model predicted pressure differential at this location is 68 psi at the end of 2018. The wellbore contains no casing from the surface casing shoe to total depth. However, a cement plug is present between the top of the injection zone and the base of the USDW from 7,296 to 6,956 ft. isolating the pressure buildup from the borehole. This well is adequately plugged to be protective of the USDW and no corrective action is necessary.

Figure C-9

Map ID No.: 14

Operator: E. A. Bender

Lease: Silver Creek

Well Number: 18 *(1974 spud)*

API Number 42-019-20804

Type of Well: Dry Hole

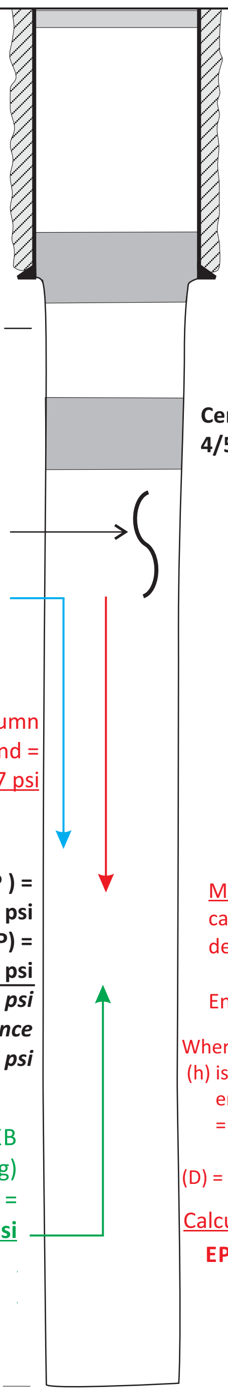
Well Status: Plugged and Abandoned (1974)

Records: DOGGR Forms: 100, 103, 105, 108, 109, 111, 136A, 159

Distance from nearest injection well: 6,350 ft. NE

Kelly Bushing (KB) Elevation - 391 ft. (from Log)

Ground Elevation - 379 ft. (log)



Cement Plug 35 to 8 ft. 4/6/74

9 5/8" 47 lb/ft., J-55, Surface Casing set in 13.75" hole to 768 ft. with 500 sks cement to surface.

13.75" Borehole to 768 ft.

Cement Plug 817 to 678 ft. with 50 sx cement on 4/5/74 (tagged)

8.5" Borehole from 768 to 8,698 ft.

Cement Plug 1,700 to 1,437 ft. with 100 sx Class G cement on 4/5/74 (tagged)

10.03 ppg mud from Drilling Record

Top of Confining Zone/Base USDW @ 3,967 ft. KB
3,967' x 0.433 = 1,718 psi

Model Predicted Differential Pressure from PEC Injection = 79 psi (2018) and 76 psi (2029)

Pressure Exerted by Mud Column
(base USDW to Top Panoche Sand =
7,740' - 3,967' = 3,773' ft. x 10.03 ppg (0.521 psi/ft) = 1,967 psi

Entry Pressure = (Formation P + Model differential P) =
3,638 psi + 79 psi = 3,717 psi
Resisting Pressure = (USDW P + Mud Column P) =
1,718 psi + 1,967 psi =3,685 psi

Entry pressure exceeds resisting pressure by 32 psi
however gel strength provides an added 59 psi of resistance
Resulting in an overbalance of resisting pressure of 27 psi

Top of Injection Zone @ 7,440 ft. KB
First Sand at 7,740 (log)
Pressure Expected using PEC initial FG of 0.47 psi/ft =
(0.47 psi/ft) x 7,740' = **3,638 psi**

Gel Strength Safety Factor Calculation

Minimum Expected gel strength of the mud column, which can be calculated from the following equation using a gel strength default of *25 lb/100 ft^2:

Entry Pressure (EP) in psi = $\frac{(0.00333)\ (25\ lb/100\ ft^2)\ (h\ (ft.))}{D\ (in.)}$

Where:
(h) is the height of the mud column at the point where reservoir fluid could enter the borehole = 7,740 ft. KB (Top Injection Zone Sand) - base lowermost plug KB = 7,740 ft. KB - 1,700 ft. KB = 6,040 ft.

(D) = 8.5 in. from 1,700 to 7,740 ft. from Doggr well record

Calculation

EP 8.5" in psi = $\frac{(0.00333)\ (*25\ lb/100\ ft^2)\ (6{,}040\ ft.)}{(8.5\ in.)} = 59\ psi$

TD @ 8,698 ft. KB

SYNOPSIS: The model predicted pressure differential at this location is 79 psi at the end of 2018. There are no plugs between the top of the correlative injection zone uppermost sand at 7,740 ft. KB (log) and the base of the USDW at 3,967 ft. KB. The calculated entry pressure exceeds the resisting pressure by 32 psi using the expected reservoir pressure from the PEC original bottom hole pressure measurement and the pressure differential modeled due to injection. However, the conservative estimate of minimum drilling mud gel strength provides an additional safety factor of 59 psi resulting in an overbalance of 27 psi. This well is adequately plugged to be protective of the USDW and no corrective action is necessary.

Figure C-10

Map ID No.: 16

Operator: Cencal Oil Company

Lease: Cheney Ranch

Well Number: 15X *(7/12/81 spud)*

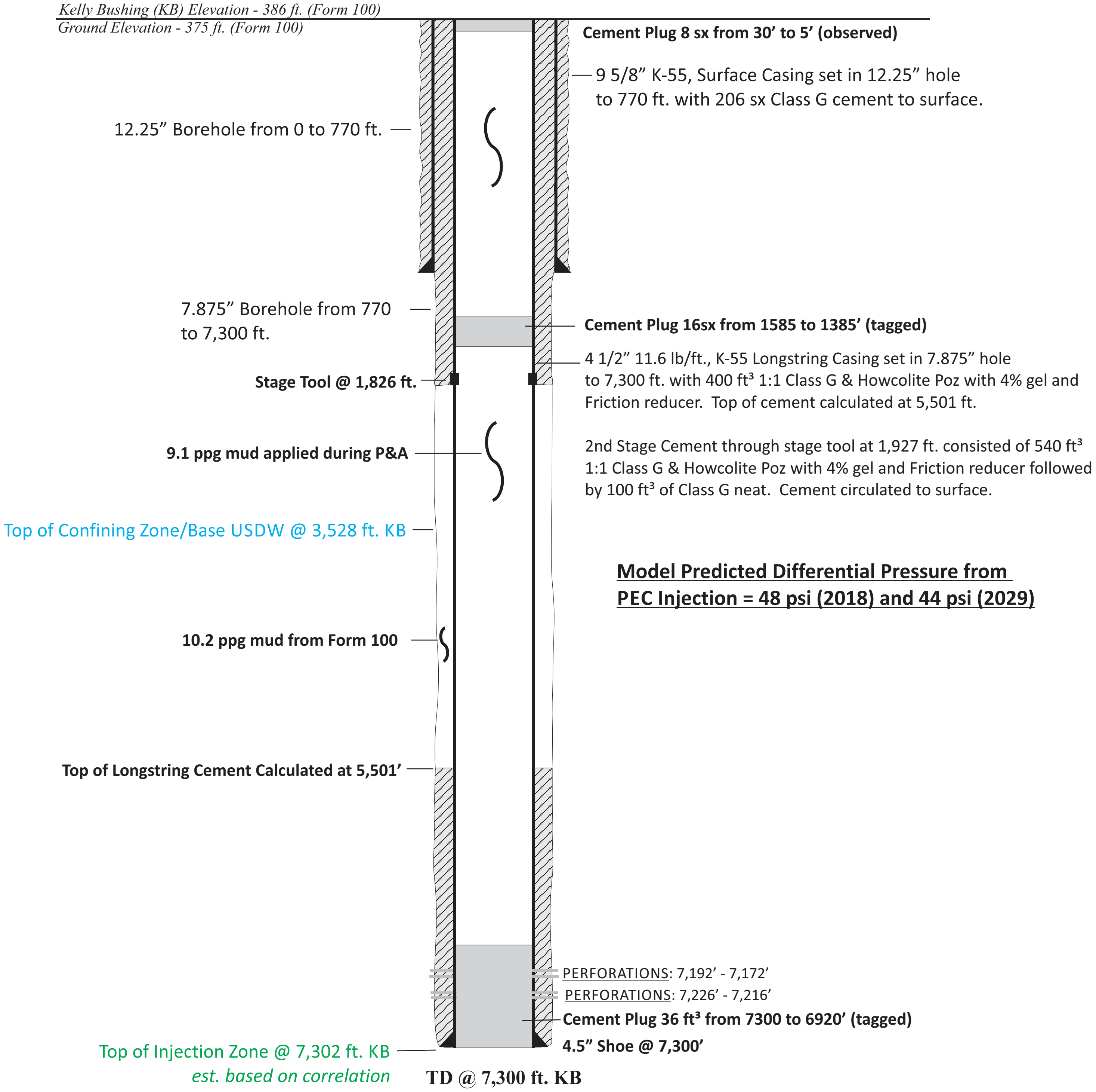
API Number 42-019-21446

Type of Well: Hydrocarbon Producer

Well Status: Plugged and Abandoned (1994)

Records: Doggr Forms: OGD10, OG100, OG105, OG108, OG109, OG111, OG123, OG136, OG159, OG170

Distance from nearest injection well: 10,950 ft. NNE



SYNOPSIS: The model predicted pressure differential at this location is 48 psi at the end of 2018. This wellbore has steel casing and based on the volume of cement pumped, has a cement sheath that extends up above the top of the injection zone. A cement plug is emplaced in the casing extending above the top of the injection zone and covering all perforations in the well. This well is adequately completed and plugged to be protective of the USDW and no corrective action is necessary.

Figure C-11

Map ID No.: 17

Type of Well: Dry Hole

Operator: American Hunter Exploration Ltd.

Well Status: Plugged and Abandoned (1984)

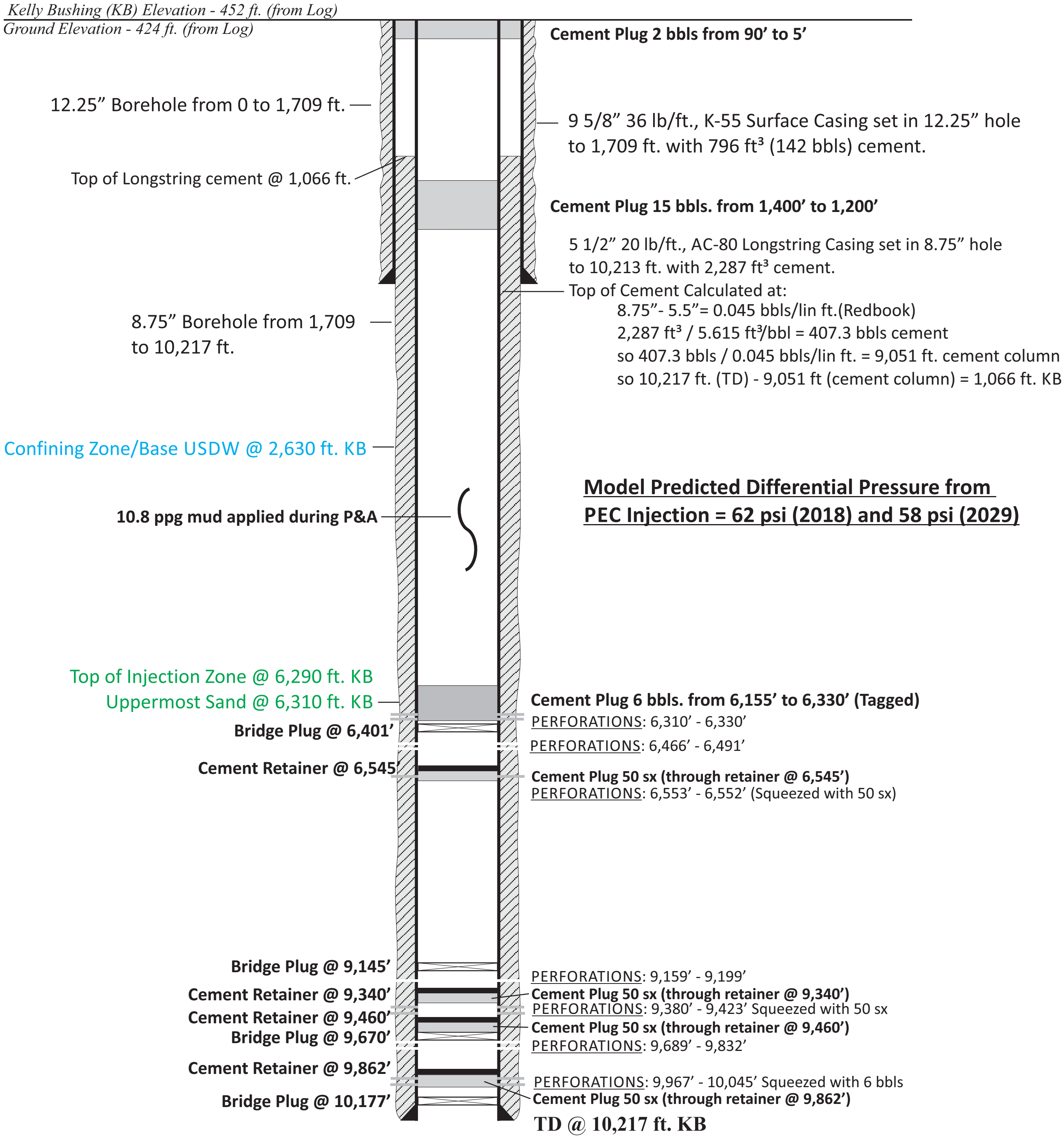
Lease: Souza

Records: Doggr Forms: OGD10, OG100, OG105, OG109, OG111, OG136, OG159

Well Number: 1 *(1983 spud)*

Distance from nearest injection well: 8,800 ft. NW

API Number 42-019-21924



SYNOPSIS: The model predicted pressure differential at this location is 62 psi at the end of 2018. This wellbore has steel casing and based on the volume of cement pumped, has a cement sheath that extends up into the surface casing. The well has four mechanical bridge plugs and four cement plugs isolating the lower wellbore. The cement plug above the uppermost perforations in the Panoche Formation isolates the PEC injection zone from the base of the lowermost USDW. Additionally, based on available records, 10.8 ppg mud was emplaced in the casing during plugging and abandonment on 6/20/84. This well is adequately completed and plugged to be protective of the USDW and no corrective action is necessary.

Figure C-12

Map ID No.: 20

Operator: R&R Resources, LLC

Lease: Blue Agave

Well Number: 1 *(2002 spud)*

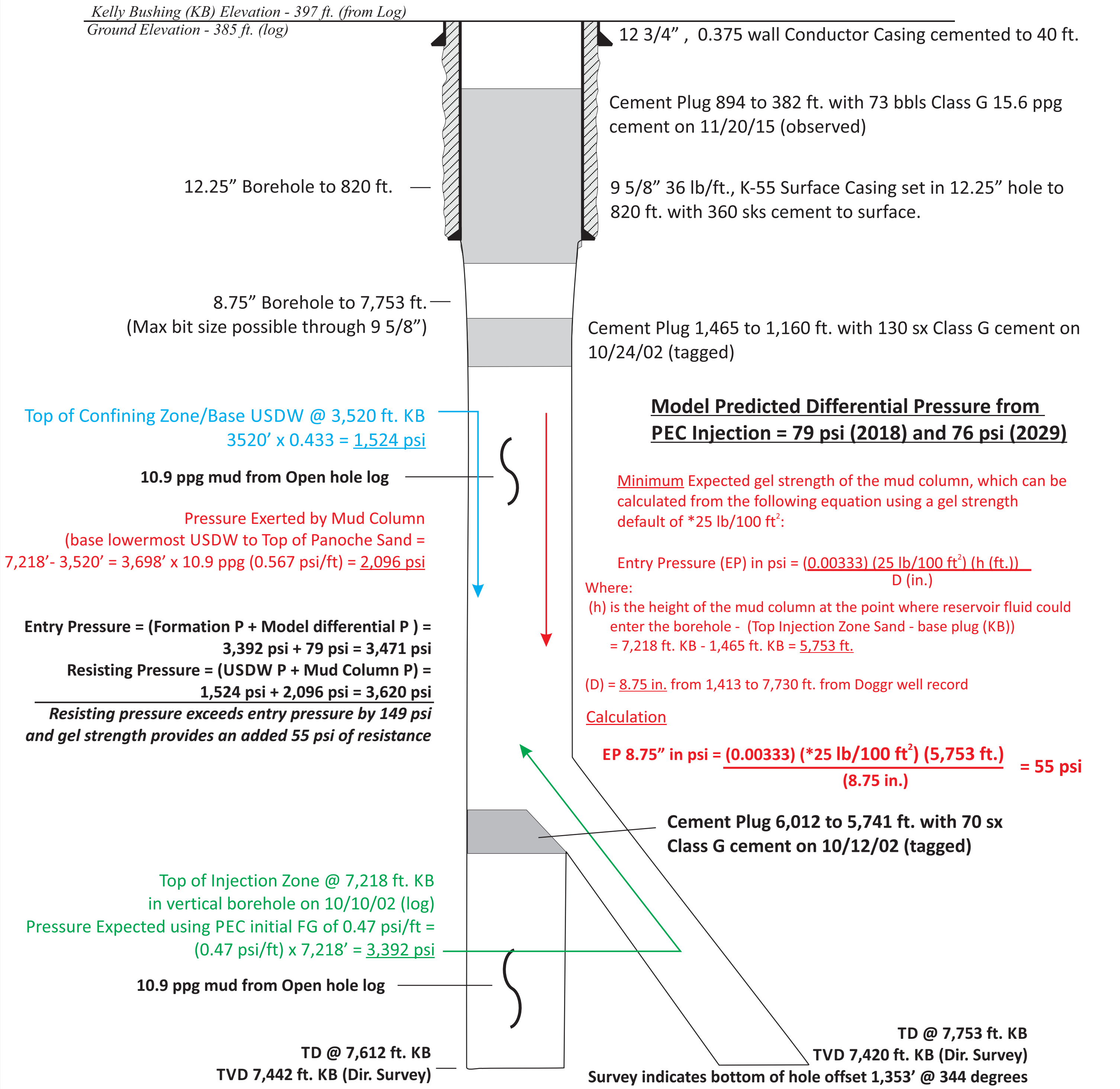
API Number 42-019-24225

Type of Well: Dry Hole

Well Status: Plugged and Abandoned (2002 and 2015)

Records: DOGGR Forms: OGD10, OG103, OG108, OG109, OG111, OG157, OG159

Distance from nearest injection well: 6,650 ft. North



SYNOPSIS: The model predicted pressure differential at this location is 79 psi at the end of 2018. There are no plugs between the top of the top of the injection zone at 7,218 ft. KB (log) and the base of the USDW at 3,520 ft. KB. The resistance to entry pressure provided by USDW pressure and hydrostatic pressure of the mud column is 149 psi higher than the expected reservoir pressure using PEC original bottom hole pressure measurement and the pressure differential modeled due to injection. The minimum drilling mud gel strength provides an additional safety factor of 55 psi. This well is plugged in a manner that is protective of the USDW and no corrective action is necessary.

EXHIBITS

(To be Submitted on CD)

ATTACHMENT D

Maps and Cross Section of USDWs

Table of Contents

List of Tables

List of Figures

List of Exhibits

ATTACHMENT D – MAPS AND CROSS SECTION OF USDWs

PERMIT APPLICATION REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Underground Injection Control (UIC) Permit Application Form 7520-06 (Rev. 12-08) instructions, the applicant shall "submit maps and cross sections indicating the vertical limits of all underground sources of drinking water within the area of review (both vertical and lateral limits for Class I), their position relative to the injection formation and the direction of water movement, where known, in every underground position relative to the injection formation and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection."

REGIONAL HYDROGEOLOGY

The Panoche Energy Center (PEC) site is located in the San Joaquin Basin of central California (Figure D-1). The basin is a structural trough approximately 400 miles long and 20 to 70 miles wide and extends over more than 20,000 square miles (Planert and Williams, 1995). In general, the Sierra Nevada Mountains form the eastern boundary of the basin and the Coastal Ranges the western boundary. The north and south boundaries of the basin are generally delineated by the Cascade Range and the Tehachapi Mountains respectively. The depth of the predominantly siliciclastic sediment fill in the basin is generally 30,000 feet with up to 50,000 feet of sediment in the Sacramento Valley sub-basin area to the north. Several sub-basins have been identified in the San Joaquin Basin with varying naming schemes and extents depending on the source of the information (Planert and Williams, 1995; California Department of Water Resources [CDWR], 2003).

Utilizing CDWR (2003) nomenclature, the PEC site is more specifically located in the Westside Sub-basin of the Tulare Lake Hydrologic Region. The Tulare Lake Hydrologic Region covers approximately 10.9 million acres (17,000 square miles) and includes all of Kings and Tulare counties and most of Fresno and Kern counties (CDWR, 2003). The Westside sub-basin has an area of approximately 1,000 square miles (640,000 acres) and is located between the Coast Range foothills on the west and the San Joaquin River Drainage and Fresno Slough on the east (Figure D-2). The sub-basin is bordered on the southwest by the Pleasant Valley Groundwater Sub-basin and on the west by Tertiary marine sediments of the Coast Ranges, on the north and northeast by the Delta-Mendota Groundwater Sub-basin, and on the east and southeast by the Kings and Tulare Lake Groundwater Sub-basins.

The topography of the area in the vicinity of the PEC plant is relatively flat and generally sloping to the east into the valley axis corresponding to the distal portion of the Panoche Creek alluvial fan (see Figure B-1 in Attachment B). The land use in the area is predominantly agricultural with nut and fruit trees being the primary crop. The climate is classified as Mediterranean, arid to semiarid with hot dry summers and cool moist winters (NOAA, 2018). Average rainfall ranges from approximately 6 to 9 inches with the majority occurring in the winter months (Mathany, et al., 2013). Average evapotranspiration is approximately 52 inches per year (Faunt, 2009).

In general, groundwater within the basin includes a freshwater upper aquifer system consisting of unconsolidated continental deposits of Tertiary and Quaternary age and a lower saline aquifer system consisting of more consolidated Cretaceous and Tertiary aged marine deposits that extend down to the crystalline basement. Based on the literature reviewed, no definitive demarcation is indicated between the fresh and brackish water and the deep basin saline waters. Most sources indicate the presence of saline water is associated with the Eocene and older “marine” sediments (Page, 1986; Bertoldi, et al., 1991; Faunt, 2009).

USABLE AQUIFER SYSTEM

The primary aquifer, according to CDWR (2006) information, occurs in unconsolidated alluvial and continental deposit of the Pliocene to Pleistocene aged Tulare Formation (Figure D-3). In the vicinity of the PEC site, the primary aquifer consists of an unconfined to semi-confined upper aquifer and a confined lower aquifer separated by an aquitard named the Corcoran Clay, also known as the E-Clay, which is a member of the Tulare Formation. The Corcoran Clay is described as dark colored, highly diatomaceous, massive silty clay, which is thought to be of lacustrine origin (Frink and Kues, 1954). The Corcoran Clay is recognized hydrogeologically as an aquitard that extends over an area of approximately 5,000 square miles and is found throughout the study area as indicated on Figure D-2. The depth to the Corcoran Clay ranges from approximately 100 to 850 feet and the strata is up to 160 feet thick. At the PEC site the Corcoran Clay occurs at a depth of approximately 620 feet below ground level (bgl) and is 75 feet thick based on core hole information associated with the PEC plant water supply well(s). Figure D-4 shows the location, approximate depth, and extent of the Corcoran Clay aquitard in relation to the study area according to Westlands Water District (2015). Figure D-5 shows schematically, in cross section, the general configuration of the upper utilized aquifer system including both the upper and lower zones and their relationship to the Corcoran Clay. The location of the cross sections is indicated on Figure D-4. The thickness of the overall primary aquifer system, estimated from the thickness of continental deposits originally reported in Williamson et al. (1989), is shown on Figure D-6. In the vicinity of the PEC plant the overall aquifer is estimated to be less than 1,000 feet thick.

Under current conditions the utilized aquifer is generally recharged by percolation of applied surface water from irrigation. In addition, infiltration of stream water draining from the Coast range to the west can provide some recharge but annual average precipitation rates are low. Groundwater flow in the unconfined portion of the aquifer is generally to the east from high to low topography. In the lower confined portion of the aquifer flow is generally eastward toward the valley axis but has been observed to be influenced by large scale pumping activities on the west side of the basin which has caused the flow in the lower confined portion of the aquifer to reverse direction toward the west (Bertoldi, et al, 1991). Additionally, land subsidence issues are associated with the surficial deposits in the site vicinity associated with the removal groundwater for irrigation (Miller et., 1971; Belitz and Heimes, 1990).

In general, dissolved solids content increases with depth (as expected) in the San Joaquin Basin aquifer system (Planert and Williams, 1995). As indicated in CDWR (2003), in the Westside Sub-basin, the waters of the upper aquifer, generally, are high in calcium and magnesium sulfate (Davis and Poland, 1957). Groundwater below 300 feet and above the Corcoran Clay shows a tendency of decreased dissolved solids with increased depth. Most of the groundwater of the lower aquifer is of the sodium sulfate type (Davis and Poland, 1957). In the vicinity of PEC, the lower confined zone contains less dissolved solids. As reported, groundwater in western Fresno County can have an upper range between 2,000 and 3,000 milligrams per liter (mg/L) of total dissolved solids (TDS; Davis, et al., 1959). However, TDS in the shallow groundwater can be greater than 10,000 mg/L and as high as 35,000 mg/L as reported by Dubrovsky et al., (1993). Figure D-7 illustrates the elevation or altitude to the base of fresh water.

Screened intervals for some of the water wells within 1 mile of PEC are listed on Table B-1 and range in depth from 199 to 209 feet for the upper aquifer and from 623 to 1,426 feet for the lower aquifer. In addition, the depth to the base of freshwater for 19 oil and gas wells associated with the abandoned Cheney Ranch field is presented in Table C-1 and range from 500 to 1,750 feet bgl.

DELINEATION OF LOWERMOST UNDERGROUND SOURCE OF DRINKING WATER

An underground source of drinking water (USDW) is defined per Code of Federal Regulations Title 40 §144.3 as an aquifer or its portion which:

- Supplies any public water system; or
- Contains a sufficient quantity of ground water to supply a public water system; or
- Currently supplies drinking water for human consumption; or
- Contains fewer than 10,000 mg/L TDS; and
- Is not an exempted aquifer.

A large quantity of published information (Davis and Poland, 1957; Miller, et al., 1971; Page, 1973; Page, 1986; Planert and Williams, 1995; Faunt, 2009; Matheny et al., 2013) is available regarding the upper usable aquifer system in the PEC regional study area. As a result, the base of the fresh water system is reasonably well understood because of its importance to agricultural irrigation needs in the study area. Discussion concerning the character and distribution of regional freshwater aquifer units, including information on name, depth, thickness, lithology, concentration of TDS, the depth to base of fresh water, and how the base of the lowermost USDW was determined, has been presented above and previously in the initial permit application (URS, 2006) and the IW1 Well Completion Report (URS, 2009). However, no definitive source of information was identified concerning the position and extent of the lowermost USDW in the regional study area. As such, information regarding the definition of, depth, and extent of the lowermost USDW was developed for previous reports related to the PEC UIC permit (URS, 2006; URS, 2009).

The initial PEC permit application included a figure and discussion of the base of fresh water in the regional study area (URS, 2006). The figure included here as Figure D-8 (Wilson et al., 1999), is specifically a model output of a conservative tracer normalized based on seawater (~35,000 mg/L TDS). The figure shows the salinity profile of the southern portion of the San Joaquin Basin in the vicinity of the Bakersfield Arch. The model simulates the "recent" or projected current configuration of salinity modeled forward from an initial steady-state with regard to hydraulic head, temperature, and solute concentration starting approximately 23.1 million years ago. As indicated in Figure D-8, everything exceeding the 0.3 contour would represent groundwater having TDS concentration in excess of 10,000 mg/L. By projecting the PEC location on to the cross section, based on topographic position relative to the basin boundaries, the base of the USDW is suggested at a depth of approximately 3,000 feet.

With regard to Figure D-8, it is interesting to note the overall salinity profile indicating the salinity in the basin decreases with depth (but still exceeds USDW quality). Typically, in sedimentary basins the salinity increases with depth. Wilson et al. (1999) observed that although salinity in sedimentary basins typically greatly exceeds the salinity of seawater; in the San Joaquin Basin TDS values rarely exceed 40,000 mg/L. The reason for this is suggested to be the lack of bedded evaporites that are typical in many sedimentary basins. Other factors possibly contributing to this phenomenon include a large influx of meteoric water and diagenetic dehydration reactions. Wilson et al. (1999) suggests that because of its location and tectonic history, the deep basin waters in the San Joaquin Basin are generally stagnant modified marine waters.

PEC also performed a log analysis as discussed in Section 1.4 of the PEC IW1 Well Completion Report (URS, 2009). The analysis resulted in a chart comparing calculated salinity to depth, based on geophysical log calculations from the IW1 borehole and is presented as Figure 6 of that report and as Figure D-9 of this report. This salinity profile for well IW1 was calculated using a form of Archie's law relating salinity to resistivity with respect to porosity derived from crossplot (URS, 2009). The resulting resistivity of solution was then converted to a sodium chloride (salinity) concentration based on a nomograph that compensates for temperature (Schlumberger, 2009). The data supporting the figure could not be located as it was performed by a previous consultant. However, the results of the analysis (URS, 2009) were reported as "water bearing units below the confined aquifer underlying the Corcoran Clay appear to be below the base of fresh water and contain greater than 10,000 mg/L TDS. The base of this aquifer appears to be within undifferentiated marine sandstones and shales underlying the Oro Loma formation to a depth of approximately 1,930 feet kelly bushing (KB). Aquifers below these units are not considered USDWs." Based on the chart a significant number of data were generated from the analysis.

Formation fluid samples collected during the completion of IW1, IW2, and IW3 are summarized in Table D-1. The results for IW1 and IW2 indicate TDS range of 34,800 to 112,000 mg/L for the Panoche Formation injection interval with an average of 72,875 mg/L with chloride being the dominant constituent. The results for IW3, which was completed in the Cima Sand of the Moreno Formation (top reported at 6,170 feet KB), indicate a TDS range of 14,000 to 18,600 mg/L with an average of 16,274 mg/L, with chloride being the dominant constituent. The analytical data used to prepare Table D-1 are contained in Exhibit D-1. Based on this information, all other the strata below a depth of 6,170 feet KB are considered below the base of the USDW based on formation fluid samples.

For this submittal, an analysis of the TDS content of the deep groundwater at IW1 was performed using the Schlumberger Platform Express log (run 2) over the interval from 1,630 to 4,942 feet KB and is included as Exhibit D-2. The logged interval includes the stratigraphic section above the marine Moreno Formation to the surface casing shoe for the well at 1,630 feet KB. The strata indicated in the log consists of interbedded clastics including (oldest to youngest) the Lodo Formation, the Domengine Formation, Kreyenhagen Formation, Tumey Formation, and basal undifferentiated nonmarine strata which correspond to the primary usable aquifer system in the regional study area. The analysis utilized the Archie Method (American Association of Petroleum Geologists [AAPG], 2018; Crain, 2018), which is similar to the methodology used in previous reporting of the base of the USDW as presented in Figure D-9 (URS, 2009). The Archie method is based on the well-known Archie (1942) equation and calculates formation water resistivity (Rw) taking into account deep resistivity (Rt) measurements and porosity (Ø) measurements in a water saturated zone of interest. The Equation is as follows:

$$Rw = Ø2 \times Rt$$

The principle requires a clean, permeable water-bearing zone that is thick enough that the deep resistivity measurement is not affected by shoulder beds. For induction tools, as were used for the log investigated, the minimum thickness is approximately 15 feet (AAPG, 2018). Since modern logging tools were utilized no borehole corrections were made as these tools typically have corrections built in (Crain, 2018). In addition, analysis of the log caliper measurement indicates gauge borehole conditions over the intervals of interest. The Rt values used in the calculation were from the 90-inch resistivity measurement and the Ø values used are from the alpha processed neutron density measurements.

Based on gamma ray and SP log measurements, the logged interval consists of interbedded and intermixed sand, silt, and clay and/or shale. Six zones that met the above noted criteria over the logged interval between the depths of 1,640 feet to 4,030 feet KB were selected and analyzed. Additional sand zones in the log appeared to be too thin or to "dirty" to produce valid results. The results of the analysis are summarized in Table D-2.

In addition, a second method using the logged apparent water resistivity (Rwa) curve was also employed and is summarized in Table D-2 as Method #2. For this analysis, the same zones were used and the Rwa was read directly off of the log. The Rwa measurement is a log calculated result using the Archie Method, similar to Method #1 above, but is calculated by the logging software. As indicated in Table D-2, more conservative values for Rw were produced from Method #1 (Archie Method).

After calculating Rw, the salinity was calculated using the method of Jorgensen (1995). This method relates TDS to specific conductance using the formula:

$$TDS = P \times (10{,}000)/Rw \text{ (at formation temperature)}$$

where

P = a constant plus a dimensional correlation factor

According to Jorgensen (1995), P-values range from 0.5 for sodium chloride water to 0.9 for alkaline waters with a P-value of about 0.67 being typical of many fresh ground waters. For the calculation in Table D-2, a P-value of 0.67 was used. Additionally, a second method for considering the TDS was utilized employing the Schlumberger (2009) Gen-9 nomograph. The results of the nomograph utilization for the calculated Rw and the measured Rwa are includes as Figures D-10 and D-11 respectively. The nomograph method provides more conservative TDS estimates. Both methods showed close agreement in calculated TDS results as indicated in Table D-2. Additionally, both methods report salinity in parts per million. Table D-2 also shows the conversion of parts per million to mg/L at formation temperature.

Previous information represented the base of the lowermost USDW occurred at a depth of 1,930 feet KB (URS, 2009) based on log analysis (Figure D-9). However, the actual calculations and input data were generated by a previous consultant and could not be obtained. Based on the analysis performed for this submittal, PEC believes that the base of the lowermost USDW extends to the base of the sandy interval at the stratigraphic contact between the Kreyenhagen Shale and the overlying Tumey Formation at a depth of 3,430 feet KB in IW1. Below this depth, the Kreyenhagen Shale indicates low overall deep resistivity character and a general lack of "clean" sand. One sand in the Kreyenhagen, at a midpoint depth of 4,025 feet KB indicating a minimum TDS of 16,076 mg/L based on the analysis (Table D-2). Below the Kreyenhagen Shale all of the sands in the log appear thin and "dirty". Additionally, no deep resistivity "spikes" are associated with any of the sands.

Geological cross-sections showing the lowermost USDW in relation to the injection and confining strata for the PEC injection wells are contained in Attachment F as Figure F-5 and F-6. Movement of groundwater in the lowermost USDW is expected to follow the general dip of the strata on the cross-sections and be to the east toward the axis of the San Joaquin Basin.

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TABLES

Table D-1

Summary of Formation Fluid Analytical Results

PANOCHE ENERGY CENTER Summary of Formation Fluid Analytical Results																		
Well Identification		IW-1 (Injection Well 1)								IW-2 (Injection Well 2)								
Sample Identification		1300-021309-PEC-IW1	1308-021309-PEC-IW1	1315-021309-PEC-IW1	1323-021309-PEC-IW1	1330-021309-PEC-IW1	1337-021309-PEC-IW1	1345-021309-PEC-IW1	1352-021309-PEC-IW1	1210-012709-PEC-IW2	1305-012709-PEC-IW2	1320-012709-PEC-IW2	1435-012709-PEC-IW2	1450-012709-PEC-IW2	1545-012709-PEC-IW2	1605-012709-PEC-IW2	1630-012709-PEC-IW2	1700-012709-PEC-IW2
Date Sampled		2/13/2009	2/13/2009	2/13/2009	2/13/2009	2/13/2009	2/13/2009	2/13/2009	2/13/2009	1/27/2009	1/27/2009	1/27/2009	1/27/2009	1/27/2009	1/27/2009	1/27/2009	1/27/2009	1/27/2009
Constituent or Parameter	Units	Time Sampled								Time Sampled								
		1300	1308	1315	1323	1330	1337	1345	1352	1210	1305	1320	1435	1450	1545	1605	1630	1700
Oil and Grease	mg/L[a]	< 5.0		< 5.0		< 5.0		< 5.0		<5.0	<5.0			<5.0		<5.0		
Boron	mg/L	120	110	110	120	110	100	100	100	82	48	77	74	43	40	38	39	41
Calcium	mg/L	280	270	290	290	290	280	290	290	120	230	250	280	280	290	270	290	300
Copper	mg/L	< 0.050	< 0.050	< 0.050	< 0.050	< 0.050	< 0.050	< 0.050	< 0.050	<0.050	<0.050	<0.050	<0.050	<0.050	<0.050	<0.050	<0.050	<0.050
Iron	mg/L	40	2.3	43	4.7	44	2.4	42	0.99	71	44	89	85	68	86	62	80	80
Magnesium	mg/L	48	47	49	50	49	49	48	50	20	21	22	22	20	19	19	18	18
Manganese	mg/L	0.72	0.71	0.71	0.70	0.74	0.73	0.73	0.72	0.62	0.51	0.51	0.54	0.55	0.51	0.58	0.54	0.54
Potassium	mg/L	14,000	14,000	14,000	16,000	14,000	14,000	14,000	12,000	33,000	42,000	41,000	43,000	48,000	54,000	52,000	55,000	57,000
Silver	mg/L	< 0.020	< 0.020	< 0.020	< 0.020	< 0.020	< 0.020	< 0.020	< 0.020	<0.020	<0.020	<0.020	<0.020	<0.020	<0.020	<0.020	<0.020	<0.020
Sodium	mg/L	5,700	5,700	5,800	5,300	5,800	5,900	5,800	5,600	4,700	4,500	4,500	4,500	4,200	4,300	3,900	4,200	4,300
Zinc	mg/L	0.054	0.052	< 0.050	< 0.050	0.059	< 0.050	0.055	< 0.050	0.75	<0.050	0.55	0.55	0.10	<0.050	0.83	<0.050	<0.050
Alkalinity as $CaCO_3$	mg/L	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,500	1,300	1,300	1,300	1,100	1,100	1,100	1,100	1,100
Bicarbonate as $CaCO_3$	mg/L	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,500	1,300	1,300	1,300	1,100	1,100	1,100	1,100	1,100
Carbonate as $CaCO_3$	mg/L	< 10	< 10	< 10	< 10	< 10	< 10	< 10	< 10	<10	<10	<10	<10	<10	<10	<10	<10	<10
Hydroxide as $CaCO_3$	mg/L	< 10	< 10	< 10	< 10	< 10	< 10	< 10	< 10	<10	<10	<10	<10	<10	<10	<10	<10	<10
Chloride	mg/L	25,000	25,000	22,000	26,000	27,000	27,000	24,000	24,000	57,000	64,000	64,000	56,000	72,000	76,000	71,000	75,000	73,000
Nitrate as NO_3	mg/L	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0
Sulfate	mg/L	< 0.50	< 0.50	< 0.50	< 0.50	< 0.50	< 0.50	< 0.50	< 0.50	530	670	210	660	550	570	550	560	540
Hardness	mg/L	910	870	930	940	910	900	910	940	380	650	720	780	770	790	760	790	810
MBAS	mg/L	0.44	0.50	0.42	0.43	0.44	0.46	0.45	0.49	2.5	2.2	2.3	2.2	2.5	1.9	2.1	2.3	2.3
pH	pH units	6.76	6.75	6.76	6.77	6.78	6.81	6.79	6.83	7.26	7.07	7.15	7.08	7.08	7.15	6.96	7.10	7.11
Specific Conductance (EC)	µmhos/cm [b]	63,000	51,000	85,000	70,000	80,000	91,000	90,000	45,000	120,000	150,000	130,000	140,000	190,000	210,000	170,000	150,000	150,000
Specific Gravity @20C (68F)	units	1.305		1.036		1.039		1.037		1.0493	1.0577			1.0657		1.0691		
Sulfide, Total	mg/L	< 1.0		< 1.0		< 1.0		< 1.0		3.6	<1.0			<1.0		<1.0		
Total Dissolved Solids	mg/L	47,900	37,800	48,300	48,900	52,700	49,800	49,000	34,800	76,200	89,000	86,800	88,600	99,800	112,000	109,000	112,000	112,000

[a] mg/L = milligrams per liter

[b] umhos/cm = micromhos per centimeter

Note: Analytical Data contained in Exhibit D-1.

Source: URS, 2009a, Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California, 678 pp. Consultants Report prepared for Panoche Energy Center

TABLE D-1 (cont.)

Summary of Formation Fluid Analytical Results

PANOCHE ENERGY CENTER
Summary of Formation Fluid Analytical Results

Well Identification		IW-3 (Injection Well 3)																						
Sample Identification		IW-3-1	IW-3-2	IW-3-3	IW-3-4	IW-3-5	IW-3-6	IW-3-7	IW-3-8	IW-3-9	IW-3-10	IW-3-11	IW-3-12	IW-3-13	IW-3-14	IW-3-15	IW-3-16	IW-3-17	IW-3-A	IW-3-B	IW-3-C	IW-3-D	IW-3-E	IW-3-F
Date Sampled		5/15/2009	5/15/2009	5/15/2009	5/15/2009	5/15/2009	5/15/2009	5/15/2009	5/15/2009	5/16/2009	5/16/2009	5/16/2009	5/16/2009	5/16/2009	5/16/2009	5/16/2009	5/16/2009	5/16/2009	5/15/2009	5/15/2009	5/16/2009	5/16/2009	5/16/2009	5/16/2009
Constituent or Parameter	Units	Time Sampled																						
		0900	0907	0931	0942	0947	0950	0952	0955	0310	0314	0318	0326	0330	0334	0342	0346	0350	0922	0957	0258	0322	0338	0354
Oil and Grease	mg/L[a]																		350	1,000	27.9	61.8	46.1	34.1
Boron	mg/L	91	91	92	90	91	88	91	96										87	92				
Calcium	mg/L	280	280	260	260	270	280	260	270										270	290	230	199	190	197
Copper	mg/L	0.090	0.071	0.061	< 0.050	0.083	0.060	0.077	< 0.050										0.085	0.15	0.361	0.229	0.407	0.525
Iron	mg/L	2.5	2.2	4.2	4.7	14	20	14	23										3.6	4.5	23.8	12.6	9.53	10.7
Magnesium	mg/L	21	21	23	23	24	24	23	24										21	23	39.9	36.9	36.1	36.8
Manganese	mg/L	0.37	0.31	0.89	1.0	1.2	1.2	1.2	0.80										0.79	0.77				
Potassium	mg/L	3,300	3,000	2,700	2,500	2,600	2,400	2,500	2,500										2,700	2,600				
Silver	mg/L	< 0.010	< 0.010	< 0.010	< 0.010	< 0.010	< 0.010	< 0.010	< 0.010										< 0.010	< 0.010				
Sodium	mg/L	4,600	4,400	4,400	4,400	4,600	4,200	4,400	4,600										4,300	4,600				
Zinc	mg/L	0.14	< 0.050	0.059	0.060	0.056	0.052	0.055	0.061										0.054	0.15	0.582	0.216	0.150	0.767
Alkalinity as $CaCO_3$	mg/L	2,700	2,800	2,800	2,800	2,800	2,800	2,800	2,800										2,800	2,900	3,080	2,420	2,380	3,000
Hydroxide as OH-	mg/L	2,700	2,800	2,800	2,800	2,800	2,800	2,800	2,800										2,800	2,900				
Bicarbonate as $CaCO_3$	mg/L	< 10	< 10	< 10	< 10	< 10	< 10	< 10	< 10										< 10	< 10	3,080	2,420	2,380	3,000
Carbonate as $CaCO_3$	mg/L	< 10	< 10	< 10	< 10	< 10	< 10	< 10	< 10										< 10	< 10	< 1.0	< 1.0	< 1.0	< 1.0
Hydroxide as $CaCO_3$	mg/L																				< 1.0	< 1.0	< 1.0	< 1.0
Chloride	mg/L	8,900	7,800	6,800	8,800	9,300	10,000	6,400	8,400										7,700	9,200	4,000	4,000	4,000	4,100
Nitrate as NO3	mg/L	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0										< 2.0	< 2.0				
Nitrate as N	mg/L																				< 2.5	< 2.5	< 2.5	< 2.5
Nitrite as N	mg/L																				< 2.5	< 2.5	< 2.5	< 2.5
Sulfate	mg/L	150	170	170	170	170	140	140	140										180	170	64	59	60	61
Hardness	mg/L	790	790	740	750	790	800	740	770										770	830	740	620	610	620
MBAS	mg/L	< 0.050	< 0.050	< 0.050	< 0.050	< 0.050	< 0.050	< 0.050	< 0.050										< 0.050	< 0.050				
pH	pH units	7.88	7.89	7.99	7.91	7.87	7.88	7.91	7.63										8.12	7.74	8.06	8.02	8.07	8.03
Specific Conductance (EC)	µmhos/cm[b]	25,000	25,000	24,000	23,000	23,000	23,000	23,000	23,000										24,000	23,000	19,000	19,000	19,000	19,000
Specific Gravity @20C (68F)	units	1.0150	1.0156	1.0148	1.0150	1.0145	1.0144	1.0143	1.0143										1.0149	1.0169				
Sulfide, Total	mg/L																		< 1.0	< 1.0	< 0.050	< 0.050	< 0.050	< 0.050
Total Dissolved Solids	mg/L	18,600	18,100	17,600	18,200	17,900	17,800	17,600	18,100	14,000	14,800	14,400	14,300	15,200	16,200	14,900	15,400	15,200	17,500	18,500	14,700	14,600	14,900	15,800

[a] mg/L = milligrams per liter
[b] umhos/cm = micromhos per centimeter

Note: Analytical Data contained in Exhibit D-1.

Source: URS, 2009b, Well Completion Report – UIC Well IW3 Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California, 678 pp. Consultants Report prepared for Panoche Energy Center

Table D-2

Open Hole Log Calculations for Rw and TDS for IW-1

Method #1 (Archie Equation)						
Zone Depth mid point (ft.)	**1,670**	**1,915**	**2,920**	**2,980**	**3,415**	**4,025**
Clean Sand Thickness ft.	50	20	20	40	35	15
Deep Resistivity (Rt) *from log* (ohmm)	8	9	8.8	5.2	4.5	1.7
Porosity (Ø) *from log* (v/v)	0.39	0.45	0.3	0.33	0.31	0.36
Rw (Archie Calculation) (ohmm)	1.22	1.82	0.79	0.57	0.43	0.22
*Formation Temp (F°)	91.08	94.91	110.61	111.54	118.34	127.87
^TDS using Rw and Gen-9 Chart (ppm)	3,800	2,400	4,975	6,950	8,300	16,300
GEN-9 ppm to Mg/L at Form. Temp (Mg/L)	3,779	2,385	4,750	6,892	8,206	16,076
TDS (Jorgensen) P=0.67 (ppm)	5,506	3,676	8,460	11,832	15,493	30,410
(Jorgensen) ppm to Mg/L at Form. Temp. (Mg/L)	5,477	3,654	8,380	11,717	15,317	29,991

Method #2 (Direct Rwa Measurement)						
Zone Depth mid point (ft.)	**1,670**	**1,915**	**2,920**	**2,980**	**3,415**	**4,025**
Rwa from log (ohmm)	0.46	0.45	0.37	0.25	0.29	0.17
*Formation Temp (F°)	91.08	94.91	110.61	111.54	118.34	127.87
^^TDS using Rw and Gen-9 Chart (ppm)	10,500	10,100	10,500	16,000	13,200	21,500
GEN-9 ppm to Mg/L at Form. Temp (Mg/L)	10,444	10,038	10,444	15,845	13,053	21,204
TDS (Jorgensen) P=0.67 (ppm)	14,565	14,889	18,108	26,800	23,103	39,412
(Jorgensen) ppm to Mg/L at Form. Temp. (Mg/L)	14,487	14,798	17,937	26,540	22,840	38,870

NOTES:

*Formation Temperature Calculated using (Temperature Gradient) x (Formation Depth)

Temperature Gradient from log = 0.01562 F/ from $\frac{BHT_{log} - \text{Mean Surf. Temp}}{TD_{log}}$

where: BHT = 142 F

Mean Surf Temp.= 65 F from NOAA, 2018

Td_{log} = 4,930 ft.

^ See Figure D-10 for Nomograph

^^ See Figure D-11 for Nomograph

FIGURES

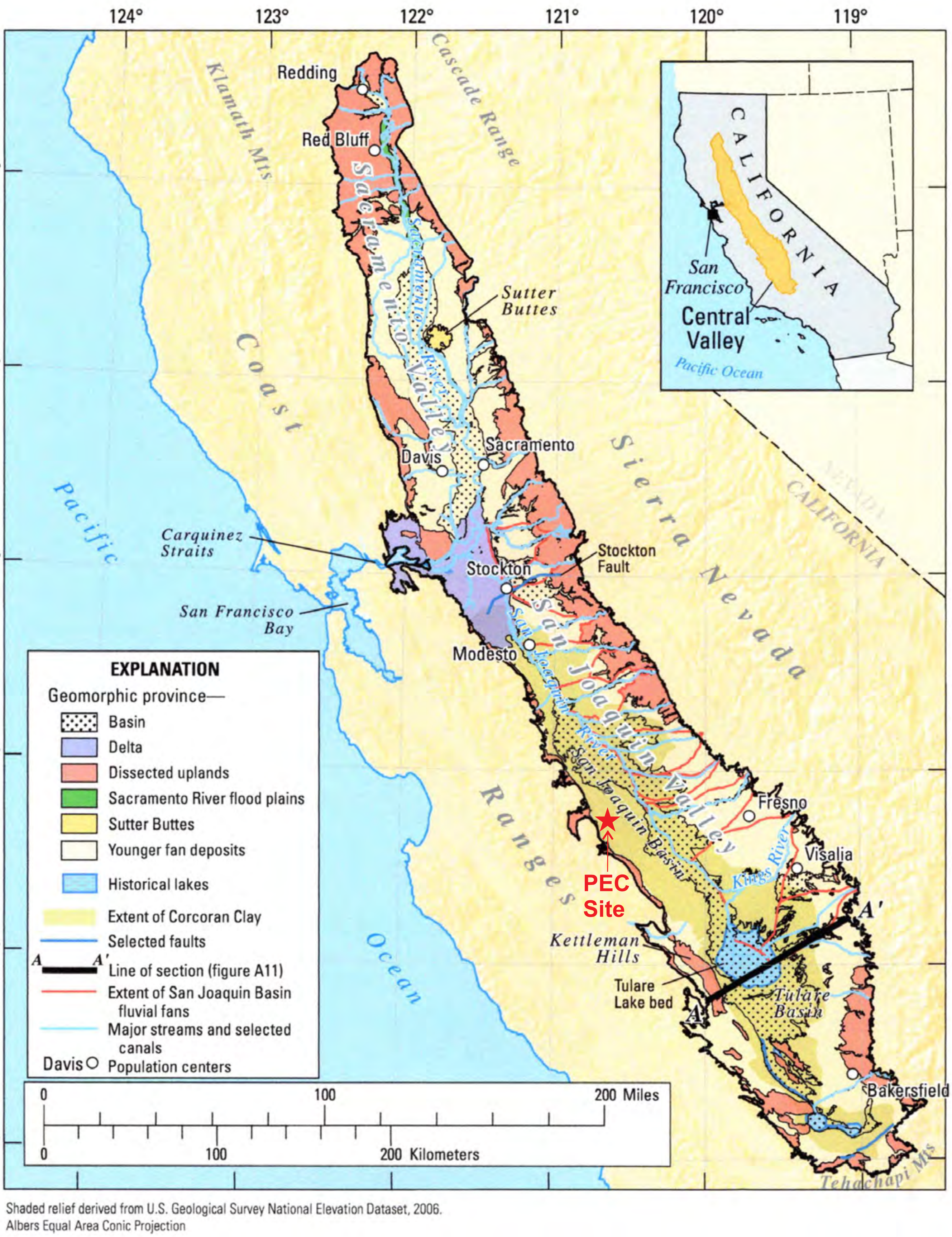


Figure D-1 Map Showing PEC Site Location and Major Features in the San Joaquin Basin of Central California

Source: Faunt, C.C, ed, 2009, Groundwater Availability of the Central Valley Aquifer, California, U.S. Geological Survey Professional Paper 1766, 225 pp.

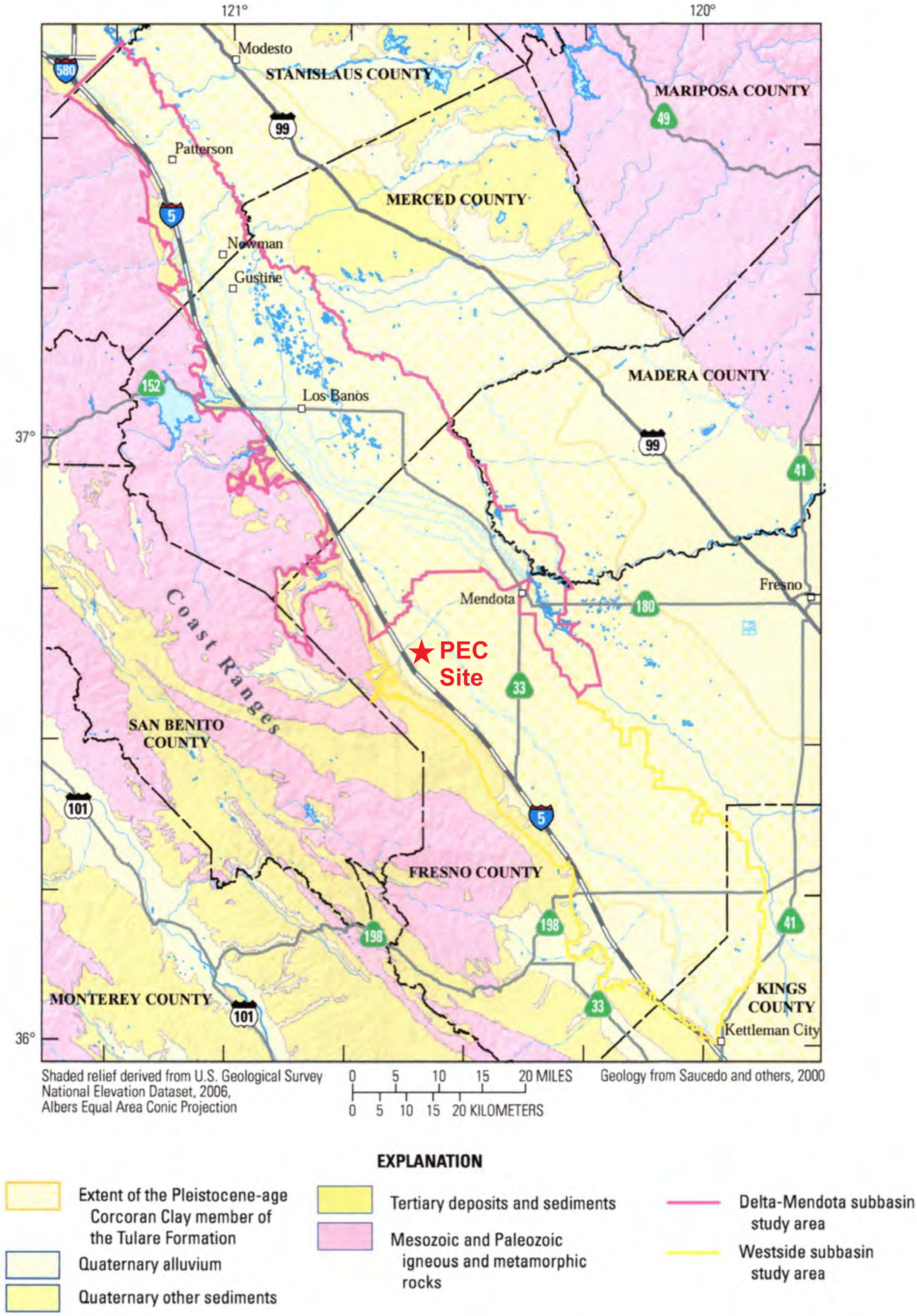


Figure D-2 Map Showing PEC Site Location and Major Features in the CDWR Designated Westside Sub-basin in the San Joaquin Valley of Central California

Source: Mathany, T.M. et al, 2013, Groundwater-Quality Data in the Western San Joaquin Valley Study Unit, 2010: Results from the California GAMA program, U.S. Geological Survey Data Series 706, 116 p.

AGE	FORMATION / UNIT	MAP SYMBOL	THICKNESS (FEET)	LITHOLOGY	GRAPHIC COLUMN	
Holocene	Alluvium	Qg	-	Gravel and sand of stream channels as mapped by Dibblee, 1975		Upper Unconfined/ Semi-confined Aquifer
	Alluvium	Qa	-	Clay and sand as mapped by Dibblee, 1975		
	Patterson Alluvium	Qps	20	Clay, silt, sand, and gravel derived from Coast Range		
Late Pleistocene-Early Holocene	San Luis Ranch Alluvium	Qs	135	Silt, sand, and gravel derived from Coast Range		
Middle-Late Pleistocene	Los Banos Alluvium	Ql	365	Silt, sand, and gravel derived from Coast Range		
Pleistocene-Pliocene	Tulare Formation, Upper Unit	QTt2	>600	Moderately consolidated clay, silt, sand, and gravel derived from Coast Range		
	Tulare Formation, Corcoran Clay Member	Qt2c				
	Tulare Formation, Lower Unit	QTt1				Lower Confined Aquifer
Pliocene-Miocene	Oro Loma Formation	Tol	400	Poorly to moderately consolidated nonmarine gravel, sand, silt, and minor clay		*Base USDW*
Eocene	Kreyenhagen Shale	Tk	470	Diatomaceous marine shale with common sandstone and limestone in lower portion		
Eocene	Domengine Sandstone	Tdy	130 - 400	Slightly friable to indurated, quartzose to arkosic marine sandstone		
Eocene-Paleocene	Laguna Seca Formation	Tls	530 - 800	Concretioary, fossiliferous, micaceous sandstone interbedded with shale and siltstone		
Paleocene-Upper Cretaceous	Moreno Formation	TKmd	1,870	Friable to moderately indurated shale with less abundant indurated arkosic sandstone		
Upper Cretaceous	Panoche Formation	Kp	>1,730	Predominantly shale in lower part becoming predominantly indurated arkosic sandstone with minor conglomerate in upper part		
Jurassic-Cretaceous	Franciscan Formation	KJf	-	Chaotic assemblage of coherent units of graywacke and metagraywake separated by zones of melange		
Pre-Tertiary	Sierra Nevada Batholith	gr	-	Granitic rocks		

Figure D-3 Regional Hydrostratigraphic Column, San Joaquin Valley of Central California

Modified from URS, 2009, Well Completion Report UIC Well IW1 Panoche Energy Center UIC Permit No. CA10600001, Fresno County, California. *Consultants Report Prepared for* Panoche Energy Center LLC. (Figure 5.3-3 from Appendix A of Report)

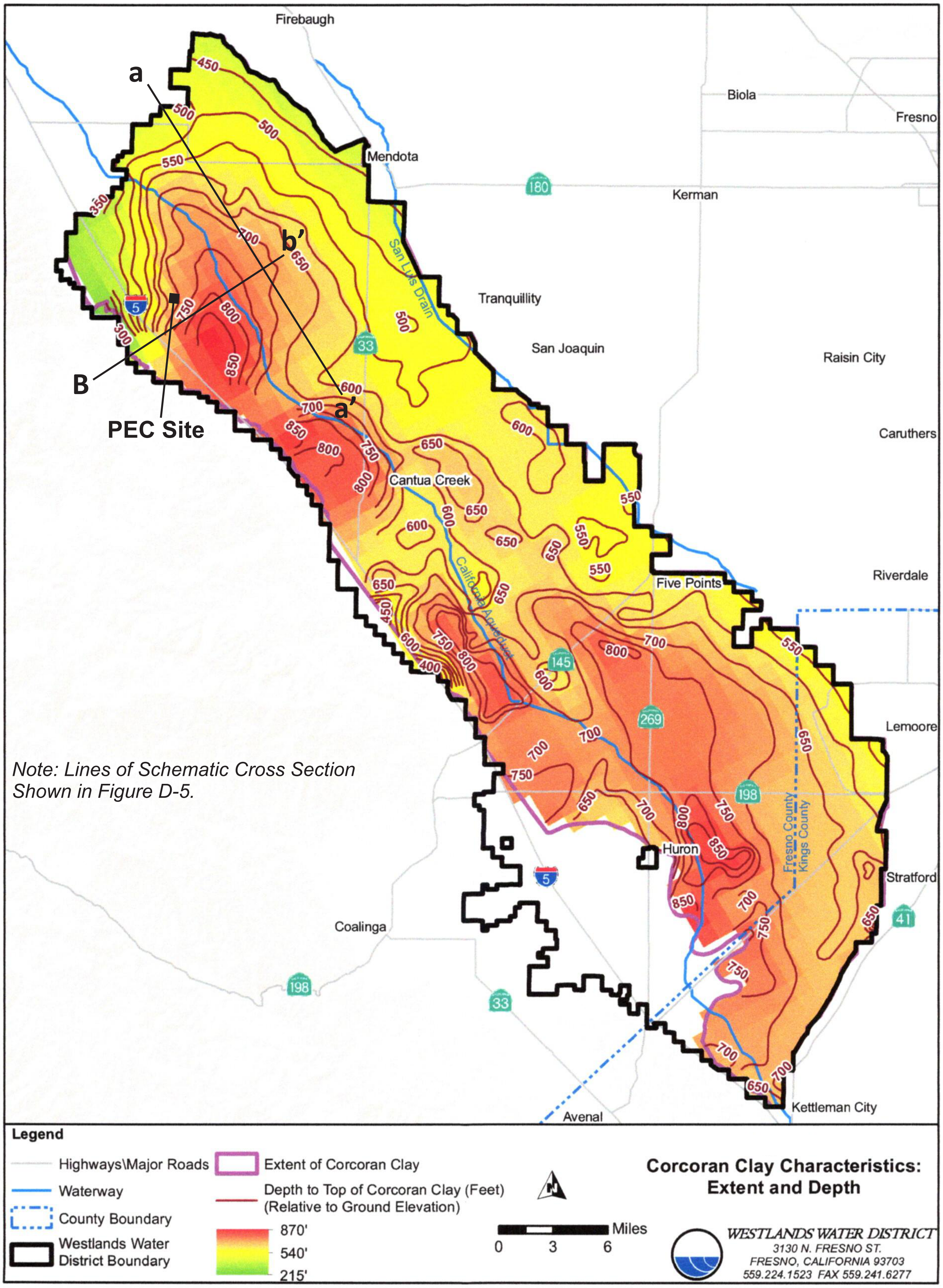
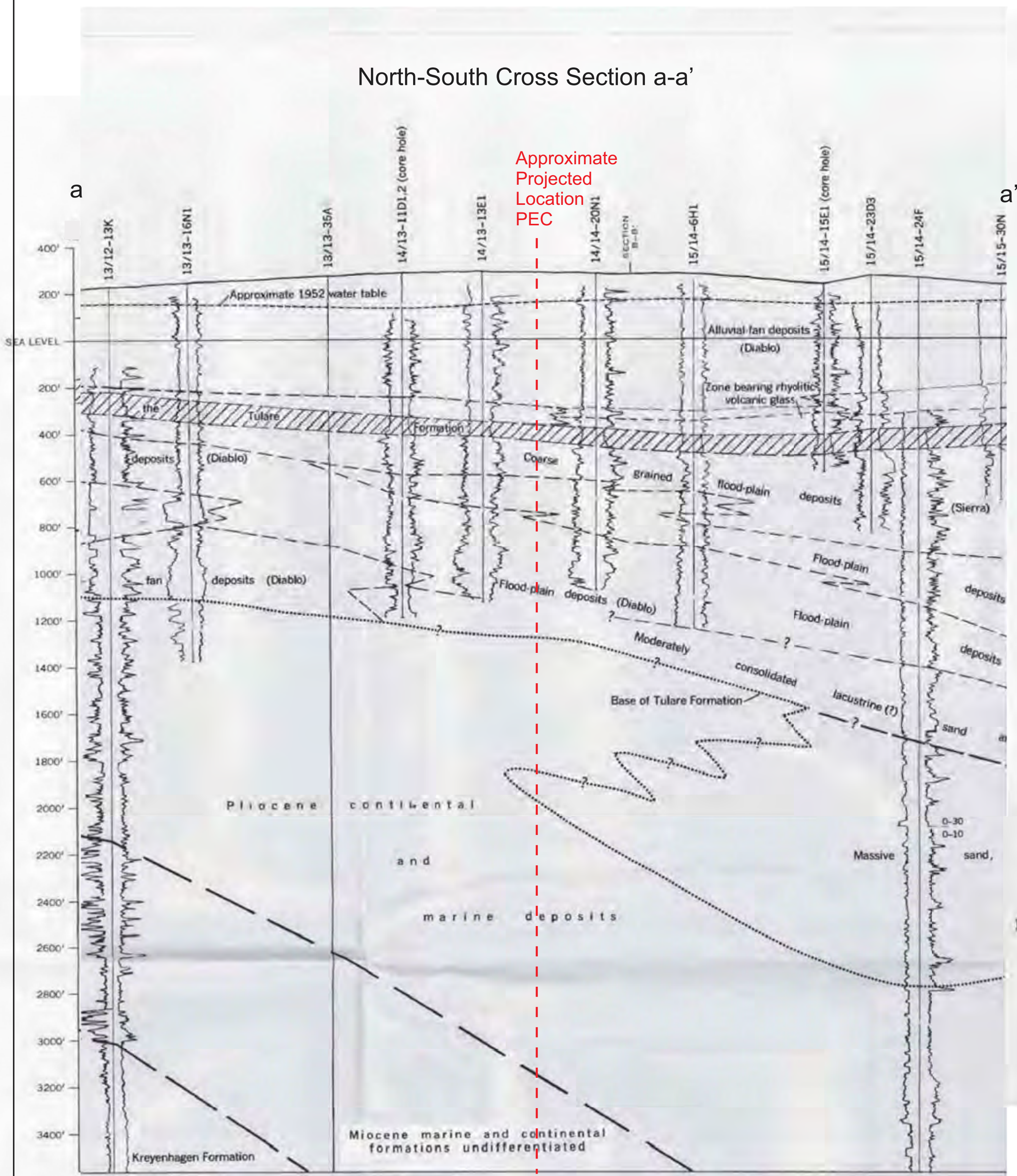
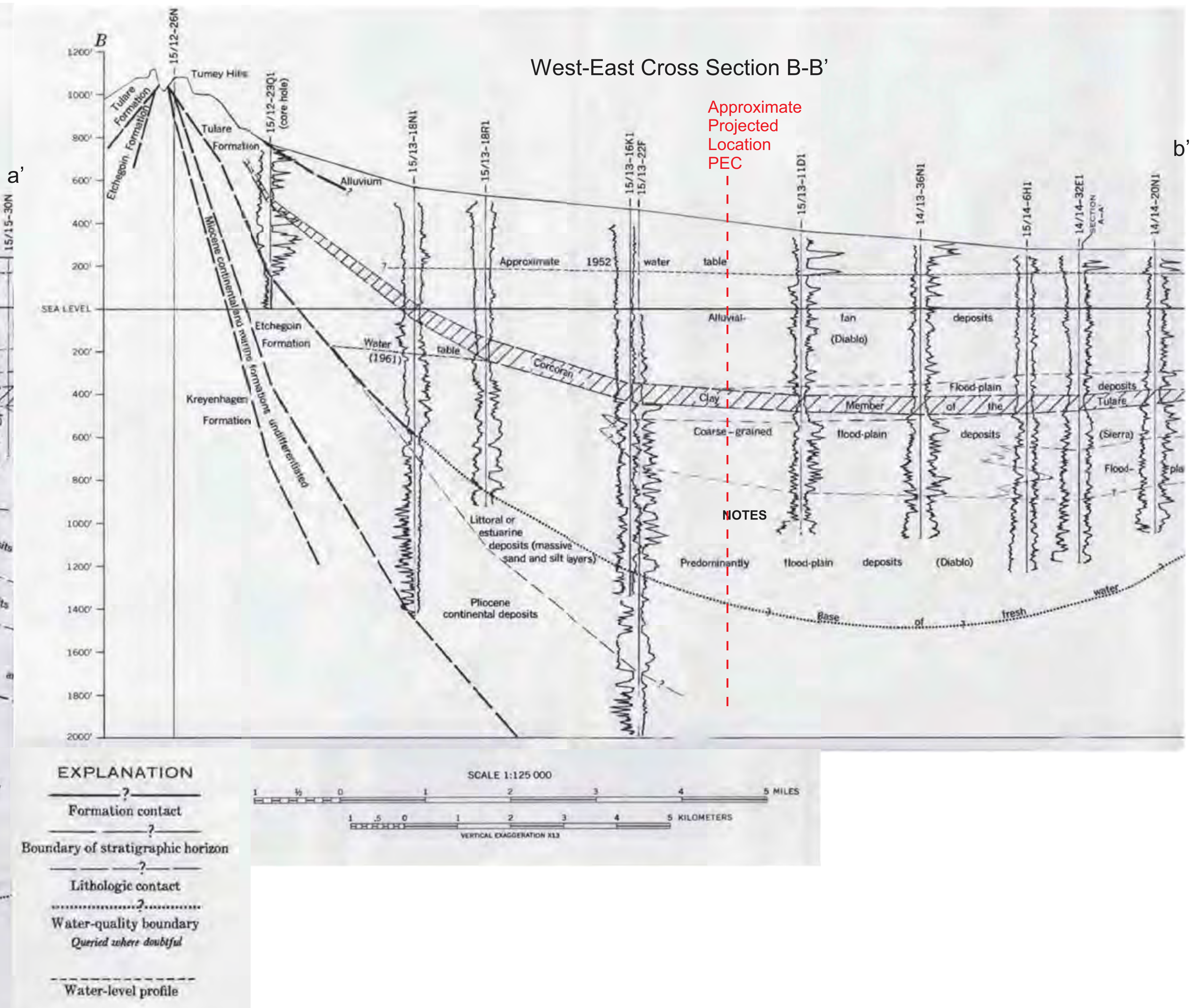


Figure D-4 Map Showing Extent and Depth of the Corcoran Clay in the Regional Study Area

Source: Westlands Water District, 2015, Deep Groundwater Conditions Report, December, 17 pp.





NOTES

MODIFIED FROM PLATES 3 AND 4 OF R.E. MILLER, J.H. GREEN, AND G.H. DAVIS, 1971, *GEOLOGY OF COMPACTING DEPOSITS IN THE LOS BANOS-KETTLEMAN CITY SUBSIDENCE AREA,CALIFORNIA*, GEOLOGICAL SURVEY PROFESSIONAL PAPER 497-E

See Figure D-4 for Location of These Modified Cross Section

HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

Figure D-5

Cross Sections Showing the Upper Aquifer System in the Vicinity of the PEC Plant

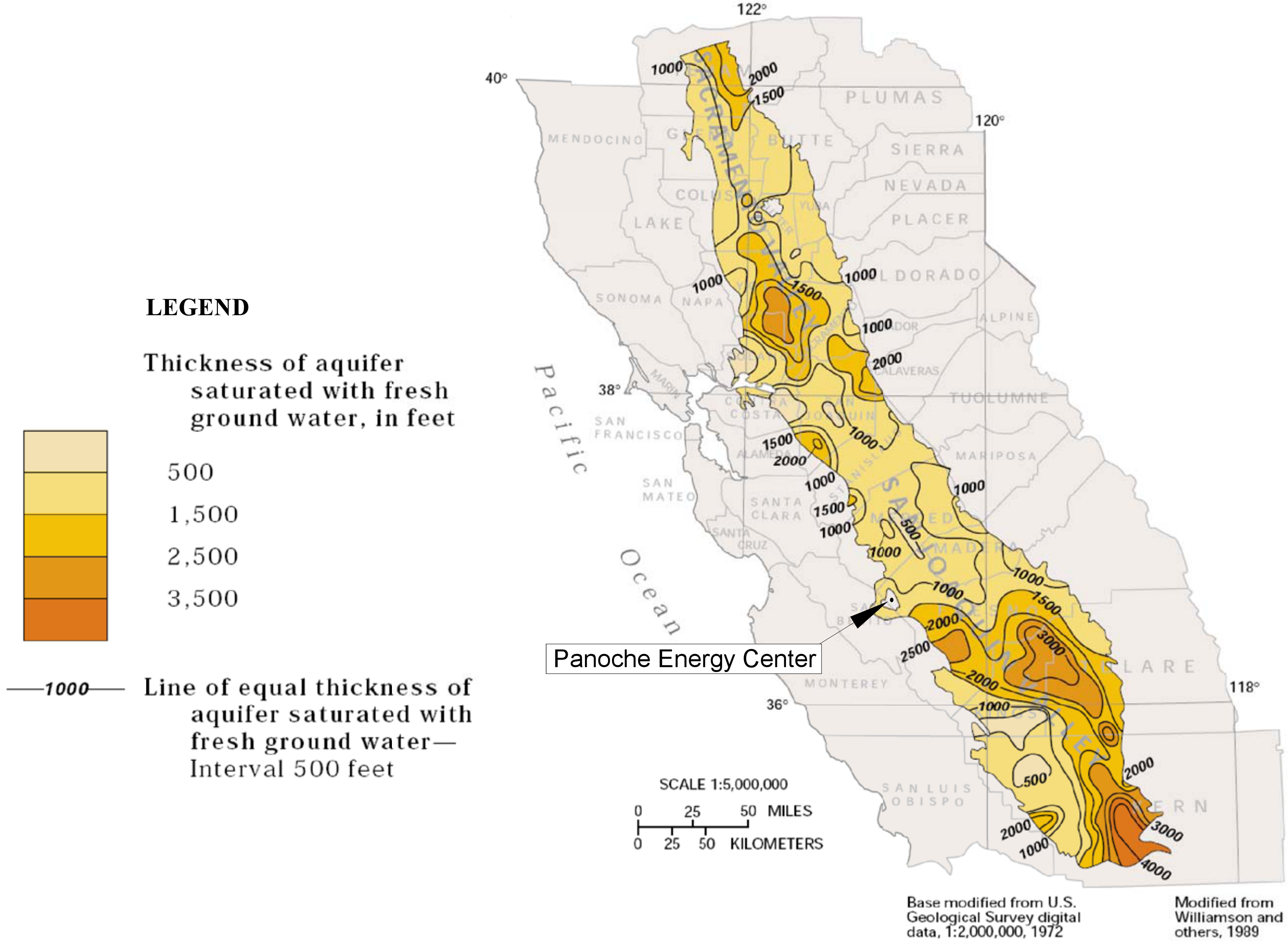


Figure D-6 Map Showing the Thickness of the Saturated Upper Usable Aquifer System

Source: URS Corporation, 2006, Underground Injection Control Draft Permit Application, Panoche Energy Center, Cheney Ranch, Panoche Road, Fresno County, California,
-Note original illustration from Planert, M., and Williams, J.S., 1995, Ground Water Atlas of the United States, Segment 1 California and Neveda, U.S. Geological Survey Hydrologic Investigations Atlas 730-B, 30 pp. (Noted as modified from Williamson and other, 1989, from USGS PP 1401-D)

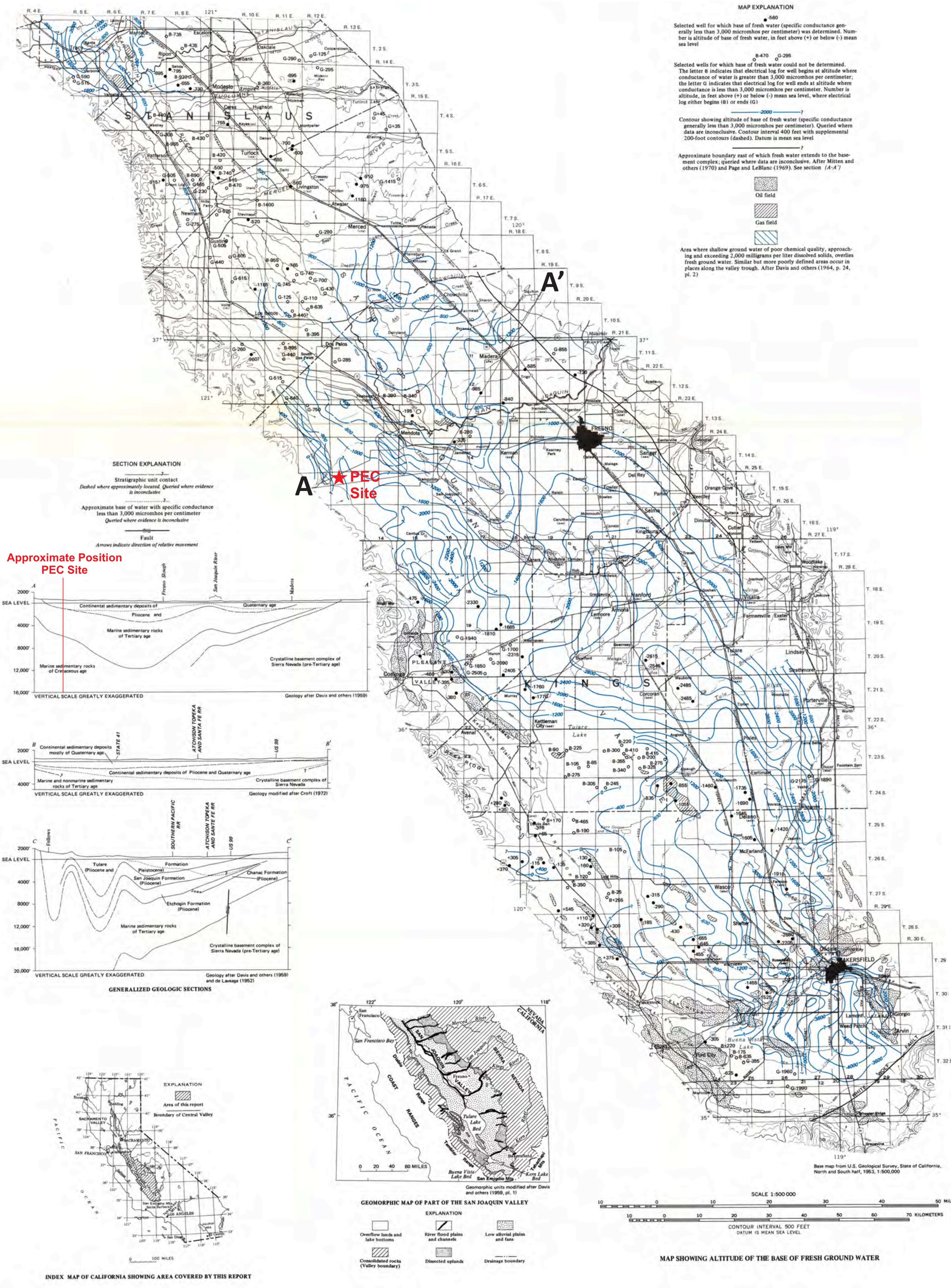
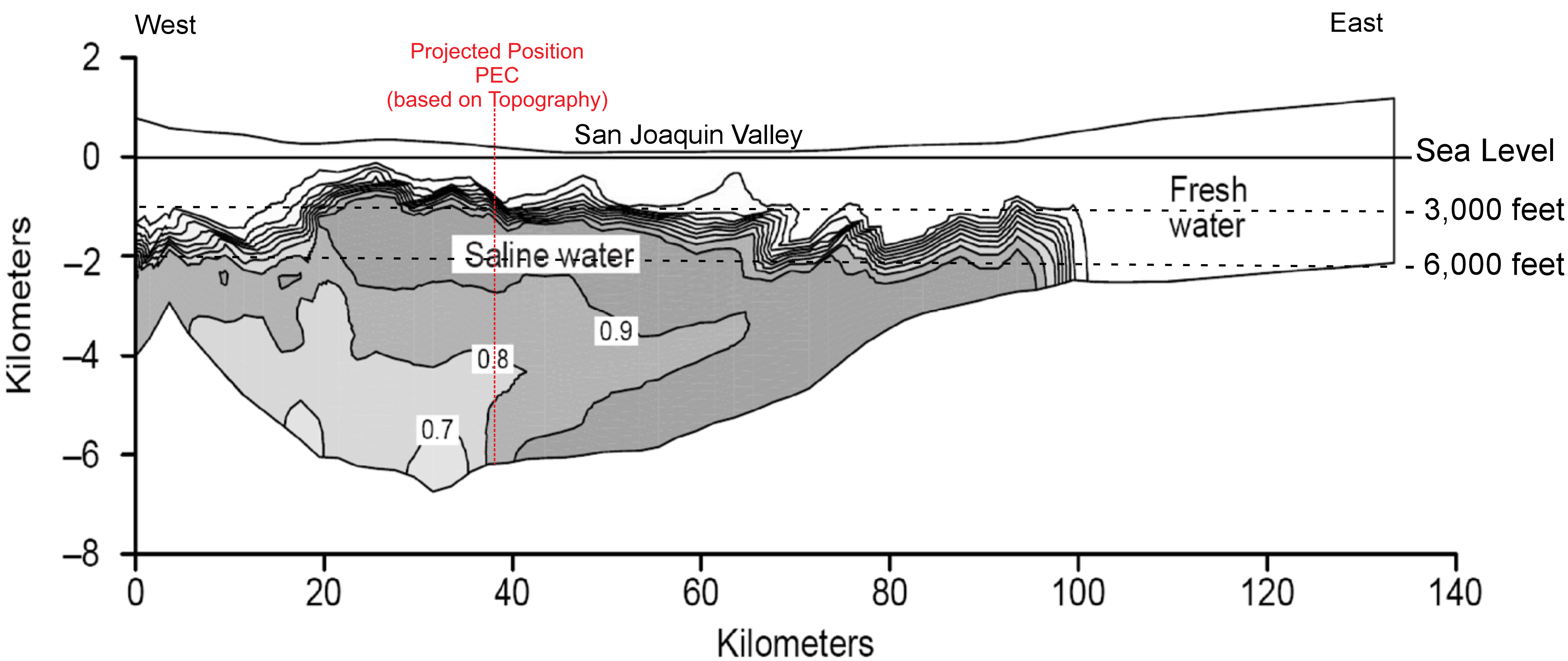


Figure D-7 Map showing Elevation/Altitude of the Base of Fresh Groundwater in the Regional Study Area

Source: Page, R.W., 1973, Base of Fresh Ground Water (Approximately 3,000 micromhos) in the San Joaquin Valley, California, U.S. Geological Survey Hydrologic Investigations Atlas HA-489.



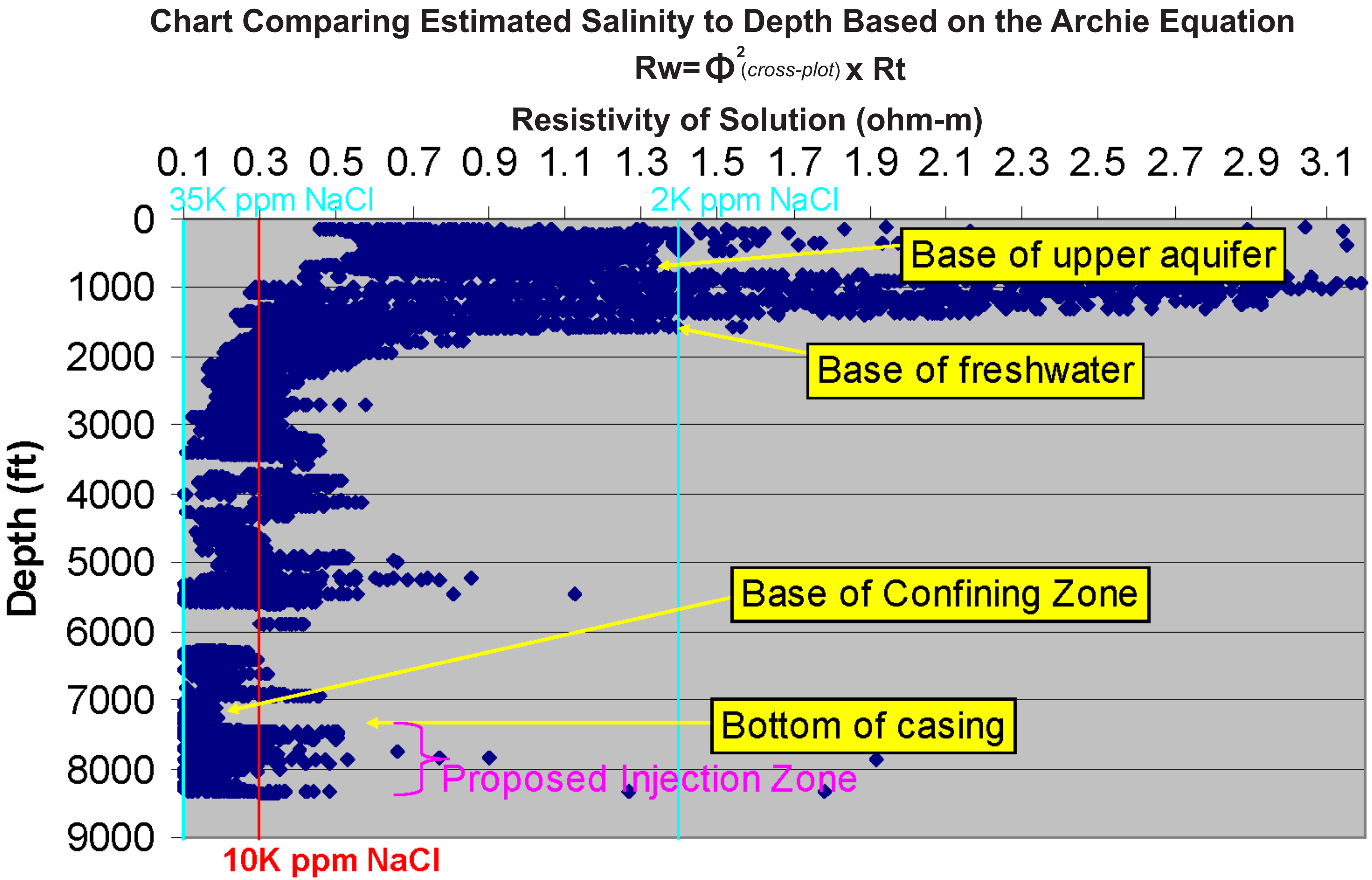
Distribution of salinity, based on seawater concentrations.
Fresh water=0; Seawater=1.
USDW (10,000 mg/L) = 0.29

Profile along the Bakerfield Arch in southern San Joaquin Basin.

Figure D-8 Model Generated Salinity Profile for Recent Time in the Southern San Joaquin Basin

Source: U.S. Corporation, 2006, Underground Injection Control Draft Permit Application, Panoche Energy Center, Cheney Ranch, Panoche Road, Fresno County, California,
-Note - Original illustration from Wilson et al., 1999, Paleohydrogeology of the San Joaquin Basin, California, Geological Society of America Bulletin, v. 111, no. 3, p. 432-449 (Figure 15D).
-Note - Modified 2018, for Panoche Energy Center UIC Permit Renewal Application.

Figure D-9 Salinity Profile - PEC IW-1



Source: URS, 2009, Well Completion Report UIC Well IW1 Panoche Energy Center UIC Permit No. CA10600001, Fresno County, California. *Consultants Report Prepared for* Panoche Energy Center LLC. (Figure 6 from Report).

-Note - Modified 2018, for Panoche Energy Center UIC Permit Renewal Application.

Schlumberger

Resistivity of NaCl Solutions

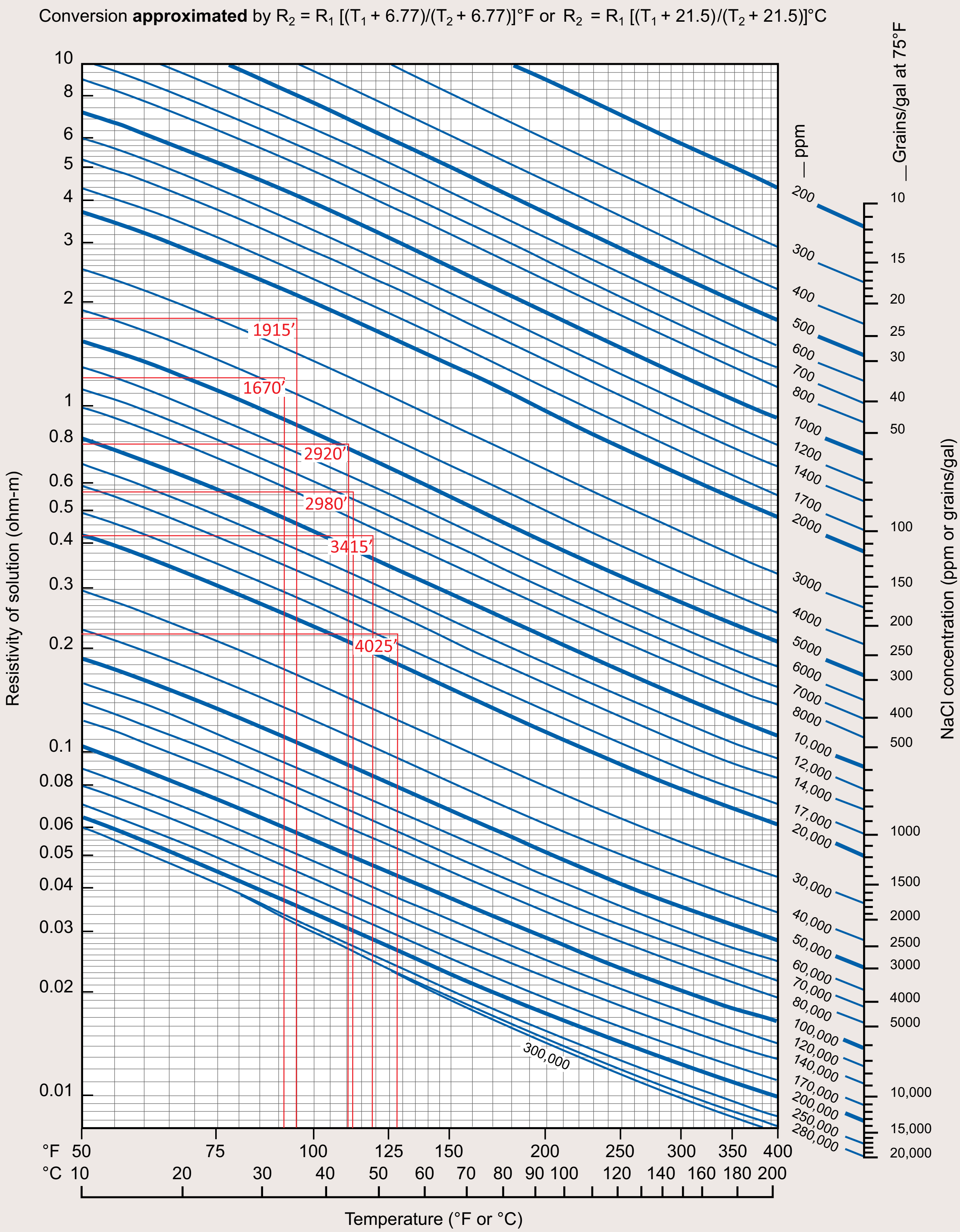


Figure D-10 Nomograph Showing Salinity Determined from Calculated Rw from Method #1

Schlumberger

Resistivity of NaCl Solutions

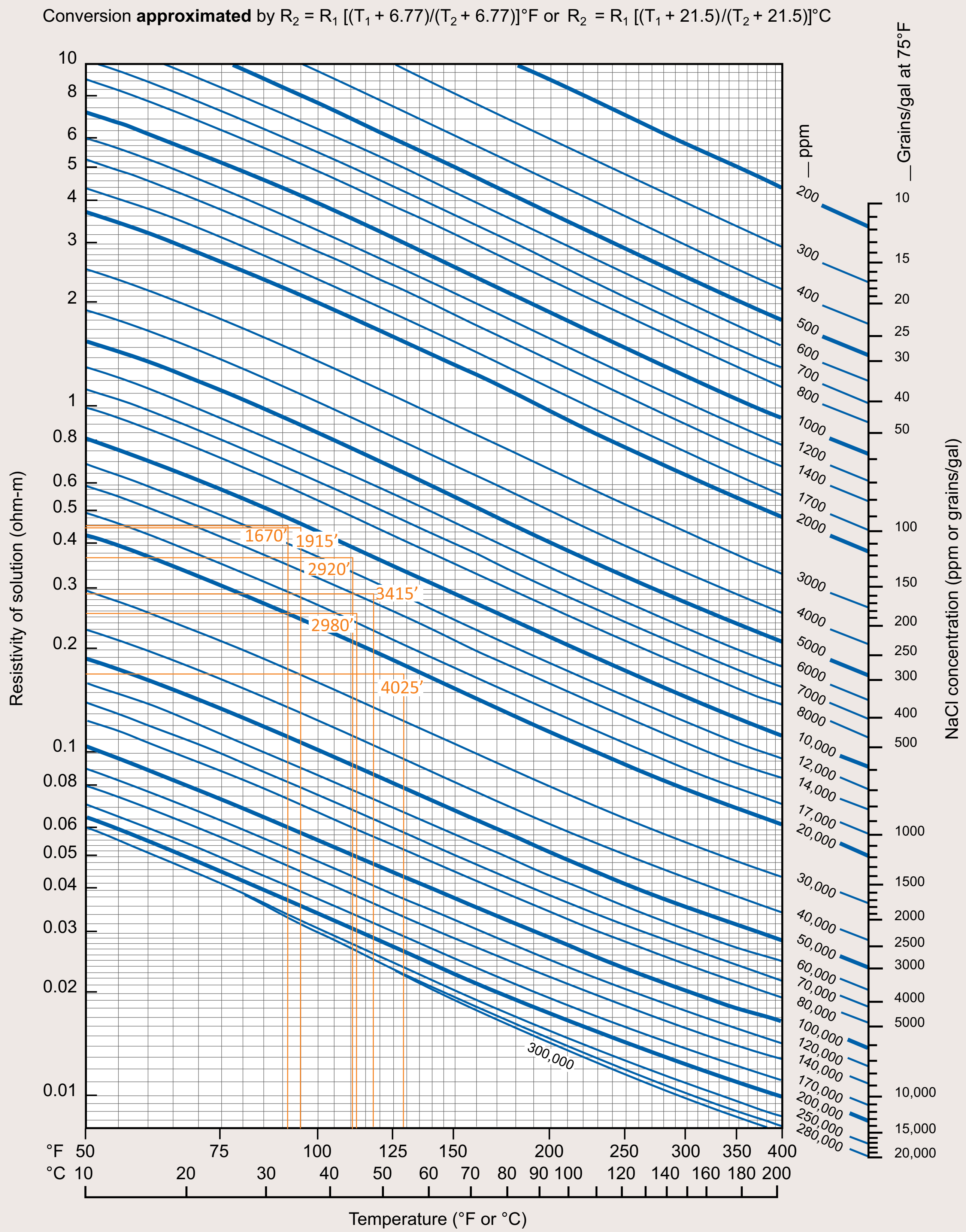


Figure D-11 Nomograph Showing Salinity Determined from Measured Rwa from Method #2

EXHIBITS

(To be Submitted on CD)

ATTACHMENT F

Maps and Cross Sections of Geologic Structure of Area

Table of Contents

List of Tables

List of Figures

List of Exhibits

ATTACHMENT F – MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA

PERMIT APPLICATION REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Underground Injection Control Permit Application Form 7520-06 (Rev. 12-08) instructions, the applicant shall “submit maps and cross sections detailing the geologic structure of the local area (including the lithology of injection and confining intervals) and generalized maps and cross section illustrating the regional geologic setting.”

REGIONAL GEOLOGY

Geologic mapping data, at a scale of 1:250,000 (presented in Figure F-1), was provided by the California Geological Survey (CGS) via the State of California Department of Natural Resources, published in 1958 by the California Division of Mines and Geology. The geologic map was acquired using the National Geologic Map Database (United States Geological Survey [USGS], 2017) and georeferenced using ESRI ArcMap 10.3.1 software. The location of quaternary faults and folds was provided by the USGS and the CGS and acquired from the Quaternary Fault and Fold Database website (USGS, 2006).

The following is a regional overview of extent and brief geological description (including name, age, depth, thickness, and lithology) of the rock units penetrated during the drilling of Injection wells IW1 through IW4. A large amount of data is available from the mapping and study of the extensive outcrop exposures to the west, and their correlative representation in logs from the Cheney Field to the north (Bartow, 1996; Dibblee, 1975, California Department of Conservation Division of Oil, Gas and Geothermal Resources [DOGGR], 1998; McGuire, 1988a; Payne, 1951 and 1974). Figure F-2 summarizes the stratigraphy of both Chaney Ranch and the Panoche Hills. Additional description is provided in URS’s IW1 Completion Report (URS, 2009a), IW2 Completion Report (URS, 2009b) as Exhibit F-1 and Exhibit F-2, respectively and in AMEC Geomatrix’s IW3 and IW4 Re-completion Report (AMEC, 2012) as Exhibit F-3.

The Panoche and Moreno formations are part of the Great Valley sequence, a thick marine clastic sequence deposited in an elongate forearc basin of late Jurassic to late Cretaceous/earliest Tertiary age (Callaway, 1990; Bartow and Nilsen, 1990). The source material for the Great Valley sequence was exhumed plutonic rocks in the southern Sierra Nevada magmatic arc and later from sediment derived from the west from exhumation of the Franciscan complex (Ingersoll, 1979). This forearc was a persistent feature that formed due to Pacific plate subduction beginning in the Late Jurassic until transformation into a transform margin during the late Cenozoic (Atwater and Molnar, 1973). The Panoche and Moreno Formations of the Great Valley sequence are regionally correlative and outcrop throughout the Diablo Range and part of the Coast Ranges (Dibblee, 1975; Bartow and Nilsen, 1990). The Panoche and Moreno Formations are exposed within the Diablo Range west of the site and extend through a 6- to 9-mile-wide belt in the Coast Ranges west and northwest of the site (mapped as Cretaceous units on Figure F-1 by Jennings, 1958). These formations contain mappable units that maintain grossly consistent lithologies along strike, with each formation representing significantly different depositional facies (Dibblee, 1975; Bartow, 1996). The Panoche Formation consists mostly of submarine fan deposits and the Moreno Formation consists mostly of slope deposits (Bartow, 1996). The Panoche Formation is a sandstone-rich succession that changes from submarine turbidite-fan deposits to amalgamated channelized-fan complexes in its uppermost part (Ingersoll, 1979).

The Panoche Formation in the Panoche Hill Area is Upper Cretaceous in age and has been divided into to an upper group (Campanian to Maastrichtian) and an uncomfortable lower group (Santonian to Cenomanian) (Bartow and Nilsen, 1990) and has been described by Anderson and Pack (1915) as the sedimentary formation observed in the Panoche Hills that stratigraphically lies between the Franciscan Complex and the Moreno Formation. In outcrop along in the hills to the west of the Panoche Energy Center (PEC) site, the Panoche Formation is composed of alternating layers of gray to brown arkosic sandstone with thin interbeds of siltstone and shale, and layers of gray mudstone, shale, silty shale, or siltstone with thin sandstone interbeds deposited in a deep-water environment (Bartow, 1996). The oldest sandstone is described as thickly bedded by Bartow (1996) and the uppermost layer of arkosic sandstone is described as having beds of varying thickness while the middle sandstone layer is described as massively bedded. The uppermost sandstone units of the Panoche Formation also exhibit evidence of channelization and suggesting deposition in a proximal fan environment (Ingersoll, 1979).

In the subsurface, the upper part of the Panoche Formation is at least 1,818 feet thick at the PEC site, with the base of the Panoche Formation not encountered in the PEC wells or Cheney Field wells. Foraminifera Assemblages of Goudkoff (1945) have been used for subsurface identification of units and DOGGR has defined the upper three sandstone bodies of the Panoche Formation to range from D-1 Zone to the top of the F Zone in age (DOGGR, 1998, see Figure F-3 for stratigraphic column of the type Cheney Field log). The depth to the top of the Panoche Formation encountered in wells IW1 through IW4 is consistent with depths reported for the Cheney Ranch gas field to the north and northeast of the site. More than 1,730 feet of upper part of the Panoche Formation has been encountered in gas wells in the Chaney Ranch Gas Field located north of the site (DOGGR, 1998). The depth to the top of the Panoche Formation (in the typical electric log for this field) ranges from approximately 5,730 to 7,440 feet below kelly bushing (BKB), where a general trend for the Panoche is observed where this formation is encountered at shallower depths in wells located further to the west relative to wells located to the east (DOGGR, 1998; see Table F-1 and Figure F-3). Additionally, Plate 1 of the IW3 and IW4 completion report (AMEC, 2012) is a correlation diagram of all four wells with the DOGGR stratigraphic column (DOGGR, 1998) of the Cheney Field to the north. Figure F-4 shows the location of two cross section lines that run along strike and along dip direction within an area of approximately 3-mile in radius surrounding PEC. One of these cross sections is marked A-A' is a strike section B-B' and is shown of Figure F-4.and Figure F-3, respectively. In addition, a structural subsurface map and thickness of the Panoche Formation injections zone as shown on Figure F-7 and Figure F-8, respectively.

The overlying Moreno Formation is an upper Cretaceous to lower Tertiary (middle Maastrichtian through middle Paleocene) sequence of marine sediments comprised predominantly of shales, mudstones, diatomaceous shales, and sandstones that outcrop in the western San Joaquin Valley of Fresno County, California (McGuire, 1988b). See Figure F-2 for a stratigraphic column for the Cheney Gas Field (DOGGR, 1998) and the Panoche Hills area (McGuire, 1988a). The Moreno Formation is approximately 1,870 feet thick and has been encountered in gas wells in the Cheney Ranch Gas Field located north of the site (DOGGR, 1998).

The Moreno is mapped in outcrops from the type locality in the Panoche Hills to Garzas Creek (approximately 30 miles to the north) and to Ciervo Mountain (approximately 30 miles to the south) (Payne, 1951). Figure F-3 shows the outcrop distribution of the Moreno Formation and a cross section from Escarpado Canyon area to the west to the Cheney Field to the east (just north of PEC). A structural subsurface map thickness map of the confining zone of the Moreno (the Terra Loma Shale, Marca Shale and lower Dos Paos (as discussed below) are presented as Figures F-9 and F-10, respectively.

The Moreno Formation consists of the Dosados Sandstone, Marca Shale, Tierra Loma Shale, the upper and lower Dos Palos and the Cima Sand members (Bartow, 1996; McGuire 1988b). The formation was divided into four distinct members by Payne (1951). In order of stratigraphic ascension, the Moreno is separated into the Dosados Sand and Shale Member, the Tierra Loma Shale Member, the Marca Shale Member, and the Dos Palos Shale Member, which collectively records shoaling in the central San Joaquin basin during the upper Cretaceous through the lower Tertiary (McGuire, 1988a):

- **Dosados Sand and Shale Member.** This consists of approximately 200 feet of brown to maroon silty shales, turbidites, and interbedded tan-buff colored sandstones in Escarpado Canyon. The Dosados Sandstone is a basal unit exposed in the Escarpado Canyon to the west of PEC (McGuire, 1988a; Payne, 1974), as shown on Figure F-2. The contact between the Dosados Member and the underlying Panoche Formation is conformable and gradational, marked by massive lenticular concretionary beds that are irregularly bedded between brown shales at the base of the Dosados (Payne, 1951; McGuire, 1988a). Sandstones show evidence of erosion with deposition, which are typically channelized with their bases incised into underlying rock (McGuire, 1988a). These features suggest a high energy depositional environment where incision of channels into underlying sediments was the primary mode of deposition for coarse grained sediments (McGuire, 1988a). The depositional facies of the Dasados Member have been interpreted as a base-of-slope turbidite and channel sandstone facies. Channelized sandstones generally thicken and coarsen as one moves up section. The sands then terminate into a dark brown-maroon clay-rich shale and mudstone marking beginning of the Tierra Loma Member (McGuire, 1988a).
- **Tierra Loma Member.** The Tierra Loma is approximately 1,148 feet thick at Escarpado Canyon and is predominantly comprised of slightly laminated dark shales and mudstones. Thin tabular to lenticular siltstones are typically bedded between these fine-grained sequences, characterized by both lamination and cross lamination (McGuire, 1988a). Interbedded sandstones have also been identified and generally increase in sand content as one moves north from the Escarpado Canyon. Sandstones that outcrop in Panoche Hills however, are intrusive, emanating from the underlying Panoche and lower Moreno Formations (McGuire, 1988a). Because of its stratigraphic position between the underlying Panoche and upper Moreno Formation, the Tierra Loma sequence has been interpreted as a basin-slope deposit, where pelagic clays and silts were deposited by settling from suspension or under low-density energy currents (McGuire, 1988a). The presence of phosphatic material and laminations observed in the fine-grained shales and mudstones also suggest that the Tierra Loma was deposited in an oxygen deficient environment. The depositional facies of the Tierra Loma has been interpreted as an oxygen deficient lower to middle slope shale facies by McGuire (1988a).
- **Marca Member.** The Marca Member is approximately 308 feet thick at Escarado Canyon and is comprised of finely-laminated tan-buff colored siliceous and diatomaceous shales (McGuire, 1988a). The contact between the Tierra Loma and Marca is gradational, often marked by a discrete and irregular layer of phosphatic nodules, and a transition from a dark to light gray-tan colored shale. Biogenic silica in the form of diatom frustrules is a significant component of the Marca Member. Depending on whether the biogenic silica present is in the form of Opal-A or Opal-CT largely defines the shale’s resistance to weathering. The most defining characteristic of the Marca Member, however, are the preserved, undisturbed, submillimeter-scale, coupled laminations. The undisturbed submillimeter-scale laminations suggest a stable anoxic depositional environment, whereas the coupled light and dark varves reflect a seasonal pattern of deposition within the basin. Diatoms identified in the light-colored laminae are

predominantly planktonic forms, whereas those classified in the dark laminae are predominantly shelf-dwelling. This in turn suggest that periods of high primary productivity were coupled with periods of oxygen depletion, collectively suggesting that strong seasonal upwelling played a critical role within the San Joaquin basin (McGuire, 1988a).

- **Dos Palos Member.** The Dos Palos Member is 820 feet at Escarpado Canyon and is comprised of chocolate-brown-gray clay shales, silty shales, glauconitic sandstones and siltstones conformably overlying the Marca Member. Sandstone within the Dos Palos generally outcrops as one massive unit located in the upper section of the formation. The sandstone was named the Cima sand lentil by Payne (1951) and is 78 feet thick in the Escarpado Canyon locality. South of Escarpado Canyon, the Cima lentil appears to pinch out into Dos Palos Shales, whereas to the north of Escarpado Canyon, the thickness of the Cima is determined by an unconformity marking the top of the Moreno Formation (McGuire, 1988a). The Cima itself is a fine-grained, fossiliferous, highly bioturbated, glauconitic sand containing shelly and calcareous layers. Megafauna present within the sand includes gastropods, pelecypods, and hexacorals corals, suggesting that the depositional environment of the Cima is a shallow-water middle to outer shelf sand (Payne, 1951). Below the Cima, the Dos Palos member primarily consists of fine-grained, non-laminated chocolate-brown-gray clay shales that progressively become siltier as they grade into the Cima sand lentil. A highly diverse foraminifera fauna has been identified at 164 feet and 426 feet below the Cima sand, and in turn suggests that shales within this section of the Dos Palos were deposited in upper shelf depositional environment (McGuire, 1988a). The Dos Palos is also divided into a lower and upper unit (separated by the Cima) and only the lower, in combination with the Marca and Tierra Loma for the lower confining interval shown on Figures F-5 and F-6.

A paleoseep system that developed on the western margin of the Great Valley forearc basin and which is contained within the uppermost part of the Moreno Formation (consisting of numerous sand injectates' and authigenic carbonate structures) crops out in the Panoche and Tumey Hills of central California (PGS, 2004; Minisini, 2007). The close stratigraphic associations and compositional similarity of paleoseep carbonate structures with some of the injectites suggest they are genetically related, with the injectites controlling where the seeps developed on the Moreno seafloor (Schwartz, 2003; Minisini, 2007). No dikes appear shallower in the Moreno section than approximately 98 to 4,131 feet below the Cima Sand Lentil of the Moreno (Schwartz, 2003). The carbonates are most abundant in the Cima Sandstone and are also present, with less frequency, throughout the Dos Palos Shale Member of the Moreno Formation (Schwartz, 2003).

Younger consolidated marine and non-marine sedimentary rocks of Tertiary age unconformably overlie the Moreno Formation (Figure F-1). These rocks have been divided into numerous formations and members with names that vary in the region (Croft, 1972). Locally, the Tertiary-age section includes the Lodo Formation of Eocene and Paleocene age. Lodo Formation rocks, ranging from about 530 to 800 feet thick, have been encountered in nearby gas wells (DOGGR, 1998), as shown on Figure F-2. Members of the Lodo Formation include the Cerros, Cantua, and Arroyo Hondo. An unconformity separates the overlying Domengine Sandstone and Kreyenhagen Shale of Eocene age from the Lodo Formation (DOGGR, 1998). The Domengine Sandstone ranges from about 130 to 400 feet thick and the Reengaged Shale is about 470 feet thick in nearby gas wells (DOGGR, 1998; URS, 2009b).

The Kreyenhagen Formation was deposited during a major transgression in the middle Eocene, recording slope and basin deposition during the seal-level highstand. The formation is predominantly a bathyal shale with fine-grained siliceous and calcareous biogenic facies that suggest deposition under low-oxygen conditions (Milam, 1985). Generally, as one moves west, the fine-grained units thicken across the San Joaquin basin (Johnson, 2007). Transgressive shallow-marine sandstones have been identified at its base along the Domengine-Kreyenhagen boundary and turbidite sandstone members within the formation, which have been interpreted as a base-of-slope turbidite fans (Clarke, 1973). Hydraulically-emplaced sandstone sills, saucer-shaped intrusions and bedding-discordant dykes that originate from the turbiditic sandstone in the Kreyenhagen Formation, are contained within the Kreyenhagen Formation mudstone (Gustavo, 2017). The Tumey sandstone lentil (Gustavo, 2017) overlies the Kreyenhagen and above are non-marine unconsolidated units (see Attachment D), as shown on Figures F-5 and F-6. A structural subsurface map and thickness map of the Kreyenhagen are presented as Figures F-11 and F-12, respectively.

INJECTION ZONE AND CONFINING INTERVAL

Wells IW1 and IW2 were drilled and completed into the upper sand member of the Panoche Formation as a Plan B completion (URS, 2009b). Wells IW3 and IW4 were originally drilled to the bottom of an unnamed sandstone in the Moreno Formation as a Plan A completion (URS, 2009c and 2009d). Wells IW3 and IW4 were later deepened (per a USEPA approved permit modification) and competed in the upper Panoche Formation (AMEC, 2012). Plates 1 and 2 in the IW3 and IW4 Deepening and Recompletion Report (AMEC, 2012) show the boring logs and the completion intervals in the current injection zone (Panoche Formation) for wells IW1 and IW2, and the sidetracked and deepened wells IW3 and IW4. Note that the upper perforated interval in IW4 was perforated in 2014 (see Attachment L). Based upon interpretation of gamma and spontaneous potential geophysical logs, offset logs, regional geologic maps, and the geologic correlation with the well logs from the Cheney Field wells England 1-3 and Chaney Ranch #1 (Plate 1 in AMEC, 2012), the top of Panoche injection zone was encountered in wells IW1, IW2, IW3, and IW4 at depths of 7,152; 7142; 7,182 and 7,109 feet BKB, respectively. Additionally, both strike cross and dip geologic cross sections were constructed, (their locations are presented on Figure F-4) with the upper and a lower confining interval and the injection zone in the upper Panoche Formation are shown on both the strike cross section A-A’ (Figure F5) and on the dip section B-B’ (Figure F-6). In addition, structural contours on the top of the two confining intervals and thickness maps of these intervals are provided in Figures F-7 through F-12. Physical properties were described above in the general geology section above and the specific characteristic (porosity, permeability, rock strength, etc.) of the injection zone and confining intervals are discussed in more detail in Attachment I of this document submittal.

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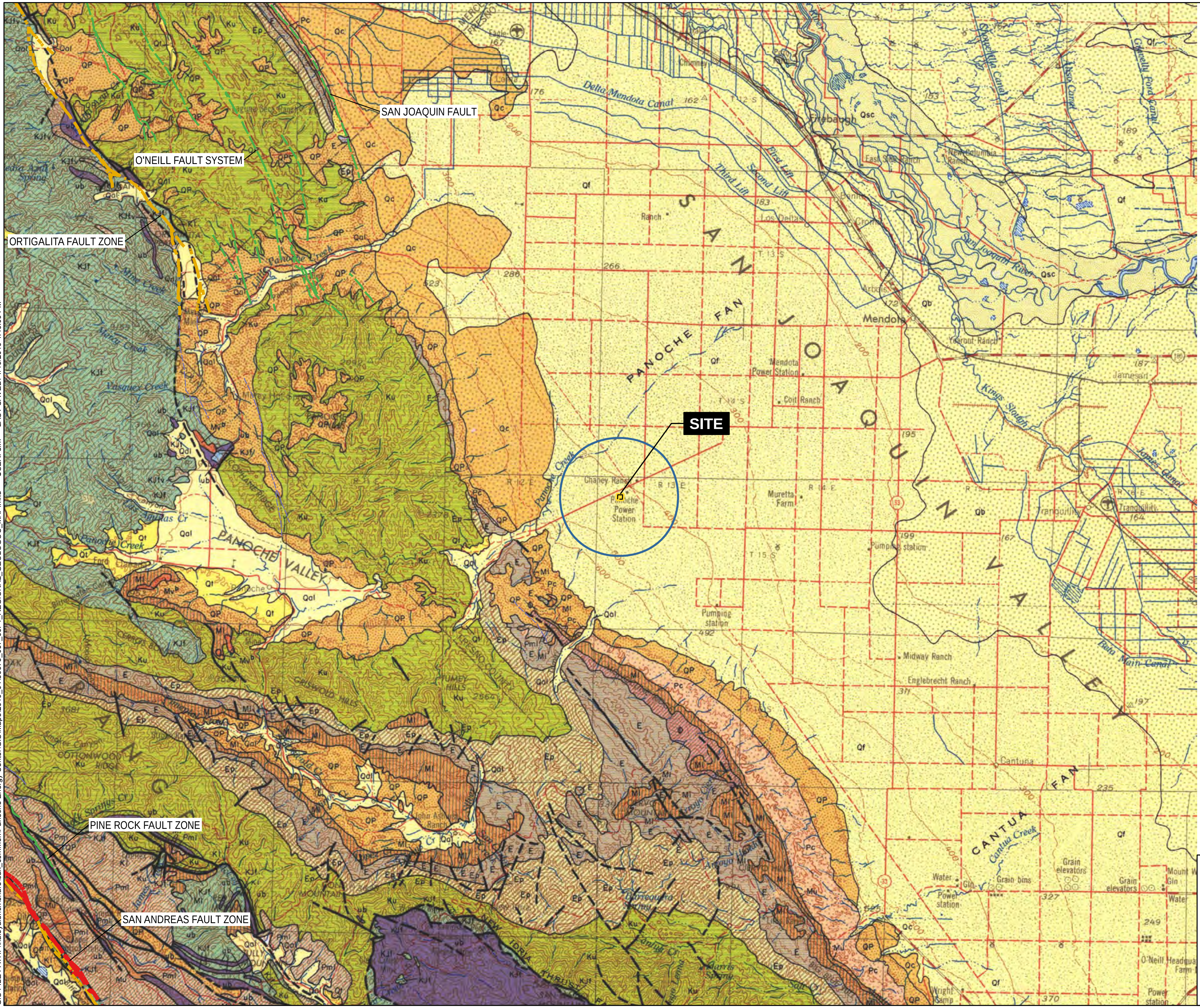
TABLE

TABLE F-1
DATA TABLE OF FORMATION TOP DEPTHS AND ELEVATIONS
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

		Total Measured Depth	KB Elevation	Base of Panoche Fm Sand 3		Panoche Fm Top		Gross Thickness of Upper Panoche Fm Injection Zone (Sands 1-3)	Base of the Tierra Loma Shale Member of the Moreno Fm		Top of Lower Dos Palos Members of the Moreno/Base of Cima Sand		Thickness of the Tierra Loma Shale, Marca Shale, and Lower Dos Palos Members of the Moreno	Base of Kreynheugen Fm.		Top of Kreyenhagen Fm.		Kreyenhagen Thickness
API	Operator Well ID	BKB (ft)	(ft)	BKB (ft)	Elevation (ft msl)	BKB (ft)	Elevation (ft msl)	(ft)	BKB (ft)	Elevation (ft msl)	BKB (ft)	Elevation (ft msl)	(ft)	BKB (ft)	Elevation (ft msl)	BKB (ft)	Elevation (ft msl)	(ft)
01900190	Cheney Ranch 1	9,284	392	8,942	*-8,526*	7,310	-6,918	1,632	7,160	-6,768	5,780	-5,388	1,380	4,580	-4,188	3,529	-3,137	1,051
01900191	Cheney Ranch 2	7,354	392	*8,918*	*-8,526*	7,288	-6,896	1,630	7,280	-6,888	5,766	-5,374	1,514	4,542	-4,150	3,578	-3,186	964
01900192	Cheney Ranch 3	7,702	404	*8,490*	*8,086*	7,190	-6,786	*1,300*	7,150	-6,746	5,386	-4,982	1,764	3,978	-3,574	2,982	-2,578	996
01900193	England 1-31	10,357	419	8,945	-8,526	7,077	-6,658	1,868	7,038	-6,619	5,546	-5,127	1,492	4,200	-3,781	3,240	-2,821	960
01906032	Souza"" 1-36	10,634	433	8,170	-7,737	6,555	-6,122	1,615	6,370	-5,937	5,146	-4,713	1,224	3,774	-3,341	2,840	-2,407	934
01906039	Robert 1	8,772	384	*9,285*	*-8,901*	7,650	-7,266	1,635	7,388	-7,004	6,270	-5,886	1,118	4,918	-4,534	4,020	-3,636	898
01906040	Caine 1	8,240	335	ND	ND	*8,340*	*-8,005*	NA	8,100	-7,765	6,900	-6,565	1,200	5,410	-5,075	4,655	-4,222	755
01906071	Russell Giffen 1	7,671	480	7,205	-6,725	5,730	-5,250	1,475	5,324	-4,844	4,264	-3,784	1,060	3,150	-2,670	1,855	-1,375	1,295
01906072	Sudden 1	4,000	574	ND	ND	ND	ND	NA	ND	ND	ND	ND	NA	2,130	-1,556	660	-94	1,470
01906074	C.L.G.	7,000	495	ND	ND	ND	ND	NA	ND	ND	6,895	-6,400	NA	5,820	-5,246	4,550	-4,055	1,270
01920687	Cheney Ranch 77X	7,250	377	ND	ND	*7,298*	*-6,921*	NA	7,200	-6,823	5,575	-5,198	1,625	4,270	-3,775	3,420	-3,043	850
01920710	Silver Creek 72X	7,827	389	ND	ND	7,310	-6,921	NA	7,465	-7,076	5,550	-5,161	1,915	4,324	-3,947	3,360	-2,971	964
1920711	Silver Creek 73X	7,496	373	ND	ND	7,310	-6,937	NA	7,245	-6,872	5,618	-5,245	1,627	4,290	-3,901	3,450	-3,077	840
1920808	Silver Creek 64	10,206	383	*8,285*	-7,902	7,070	-6,687	1,215	6,910	-6,527	5,132	-4,749	1,778	3,745	-3,372	2,854	-2,471	891
1920712	Chaney Ranckh 14X	7,394	373	ND	ND	7,300	-6,927	NA	7,130	-6,757	5,777	-5,404	1,353	4,454	-4,071	3,538	-3,165	916
1920726	Silver Creek 27X	7,460	377	ND	ND	7,286	-6,909	NA	7,220	-6,843	5,730	-5,353	1,490	4,515	-4,142	3,572	-3,195	943
1920758	Silver Creek 54X	10,887	421	8,651	-8,230	7,140	-6,719	1,511	6,910	-6,489	5,690	-5,269	1,220	4,298	-3,921	3,289	-2,868	1,009
1920776	Silver Creek 32X	7,531	392	ND	ND	7,260	-6,868	NA	7,260	-6,868	5,830	-5,438	1,430	4,560	-4,139	3,640	-3,248	920
1920804	Silver Creek 18	8,698	391	ND	ND	7,440	-7,049	NA	7,628	-7,237	6,071	-5,680	1,557	4,968	-4,576	3,967	-3,576	1,001
1920830	Silver Creek 22X	7,500	382	ND	ND	7,355	-6,973	NA	7,318	-6,936	5,912	-5,530	1,406	4,512	-4,121	3,550	-3,168	962
1921446	Cheney Ranch 15X	7,300	375	ND	ND	*7,302*	*-6,927*	NA	7,160	-6,785	5,740	-5,365	1,420	4,450	-4,068	3,528	-3,153	922
1921924	Souza 1	10,217	452	7,905	-7,453	6,290	-5,838	1,615	6,140	-5,688	5,130	-4,678	1,010	3,650	-3,198	2,630	-2,178	1,020
1922412	Souza 2	6,587	434	ND	ND	6,252	-5,818	NA	5,846	-5,412	4,911	-4,477	935	3,433	-2,999	2,435	-2,001	998
1923117	Cheney Ranch 81X-30	7,400	386	ND	ND	7,315	-6,929	NA	7,315	-6,929	5,580	-5,194	1,735	4,330	-3,944	3,425	-3,039	905
1924225	Blue Agave 1	7,612	397	*8,974*	*-8,577*	7,218	-6,821	1,756	7,180	-6,783	5,775	-5,378	1,405	4,423	-4,026	3,520	-3,123	903
(EPA UIC)	IW2	8,901	402	8,790	-8,388	7,141	-6,739	1,649	6,905	-6,503	5,790	-5,388	1,351	4,470	-4,068	3,505	-3,103	965

Notes:
ft = feet
ft msl = feet mean sea level
italic = estimated depth
BKB = Below Kelley Bushing
Fm = formation
KB = kelly bushing
MSL = mean sealevel
NA = Not Available
ND = No Data
st = sidetrack

FIGURES



LEGEND

AREA OF REVIEW (2.3 MILES RADIUS)

SITE BOUNDARY

QUATERNARY FAULTS AND FOLDS

ACTIVE (<150 YEARS)

HOLOCENE TO PLEISTOCENE (<15,000 YEARS)

LATE QUATERNARY (<130,000 YEARS)

QUATERNARY (<1,600,000 YEARS)

- Qal — Alluvium
- Qsc — Stream channel deposits (GREAT VALLEY)
- Qf — Fan deposits (GREAT VALLEY)
- Qb — Basin deposits (GREAT VALLEY)
- Qt — River terrace deposits
- Qc — Pleistocene nonmarine
- QP — Plio-Pleistocene nonmarine
- Pc — Undivided Pliocene nonmarine
- Pml — Middle and/or lower Pliocene marine
- Mu — Upper Miocene marine
- Mv — Miocene volcanic: Mv^r—rhyolite; Mv^a—andesite; Mv^b—basalt; Mv^p—pyroclastic rocks
- Ml — Lower Miocene marine
- Φ — Oligocene marine
- E — Eocene marine
- Ep — Paleocene marine
- Ku — Upper Cretaceous marine
- Kl — Lower Cretaceous marine
- KJfv — Franciscan volcanic and metavolcanic rocks (Franciscan group)
- ub — Mesozoic ultrabasic intrusive rocks
- KJf — Franciscan group

NOTES

1. ALL LOCATIONS AND DIMENSIONS ARE APPROXIMATE.
2. GEOLOGIC DATA PROVIDED BY THE STATE OF CALIFORNIA DEPARTMENT OF NATURAL RESOURCES, SANTA CRUZ SHEET NJ 10-12, 1:250,000, 1958, AND ACQUIRED USING THE NATIONAL GEOLOGIC MAP DATABASE (https://ngmdb.usgs.gov/mapview/).
3. QUATERNARY FAULT AND FOLD DATA PROVIDED BY THE UNITED STATES GEOLOGICAL SURVEY (USGS) AND CALIFORNIA GEOLOGICAL SURVEY, 2006, QUATERNARY FAULT AND FOLD DATABASE FOR THE UNITED STATES (http://earthquake.usgs.gov/hazards/qfaults/).

N

0 20,000 40,000

SCALE IN FEET

HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

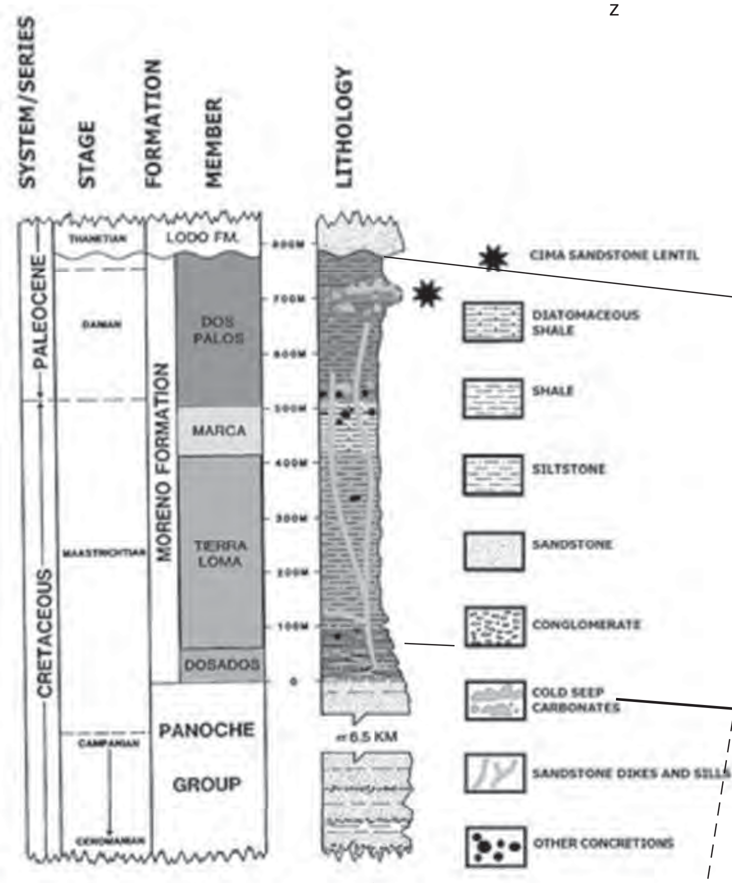
REGIONAL GEOLOGIC MAP

JANUARY 2019

FIGURE F-1

GIS FILE PATH: \\haleyaldrich\share\oak_common\Panoche Energy Center\GIS\Maps\2019_01\139073_007_00F1_REGIONAL_GEOLOGOC_MAP.mxd — USER: dfm — LAST SAVED: 1/10/2019 4:46:09 PM

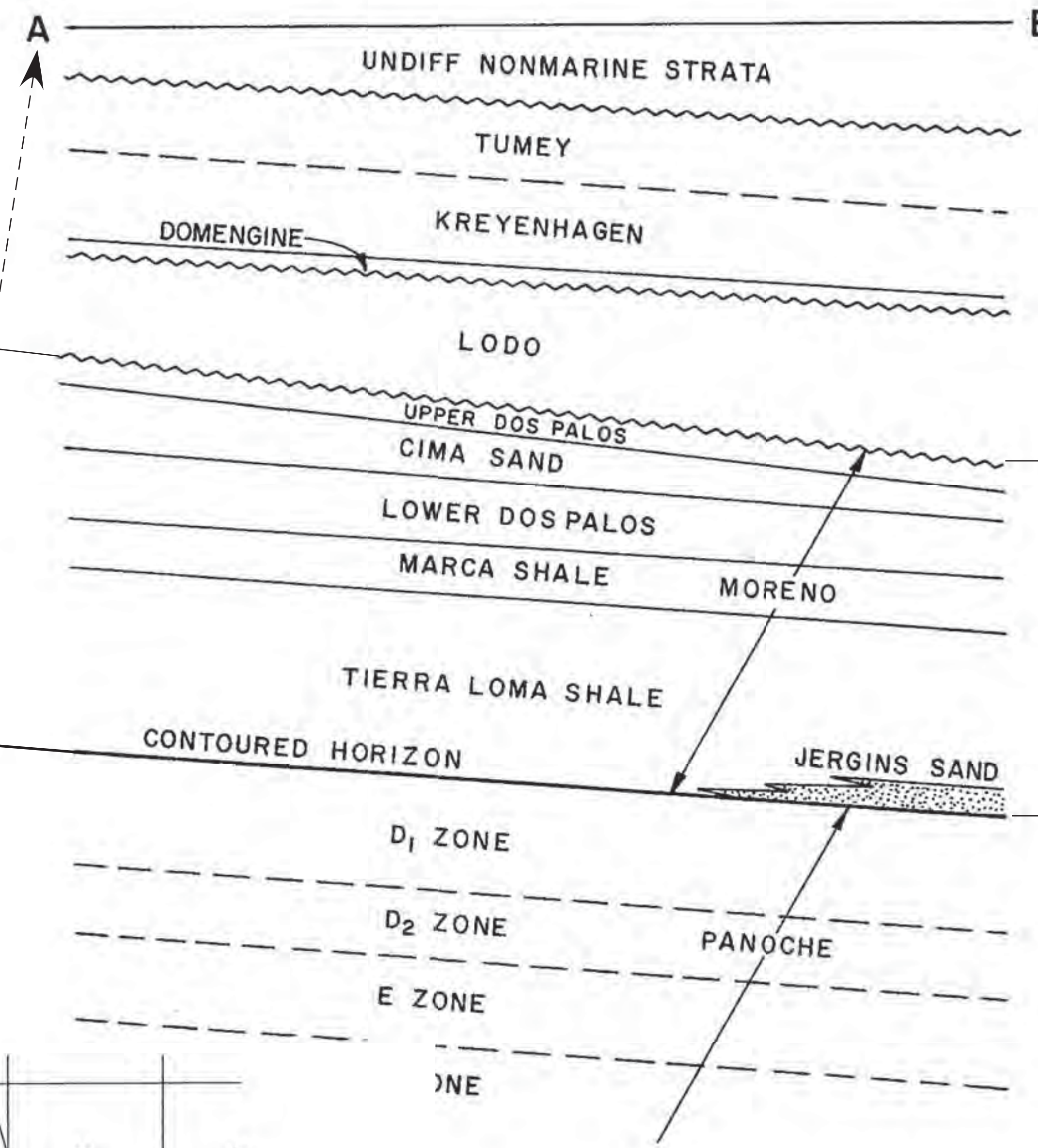
Stratigraphic Column from the Escarpado Canyon Region of the Panoche Hills

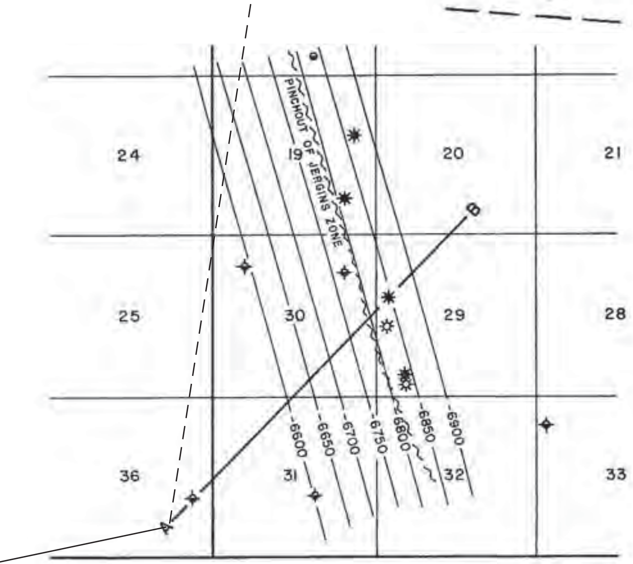


Panoche Hill Stratigraphic column from Figure 3 in Peninsula Geological Society and UCSC Hellindite Field Trip, 2004, A Paleocene Cold Seep System in the Panoche Hills, California, April.

Originally from McGuire, D.J., 1988a, Stratigraphy, depositional history, and hydrocarbon source-rock potential of the Upper Cretaceous-Lower Tertiary Moreno Formation, central San Joaquin basin, California: Doctoral thesis, Stanford University, 231 pp.

Cheney Ranch Gas Field Cross Section



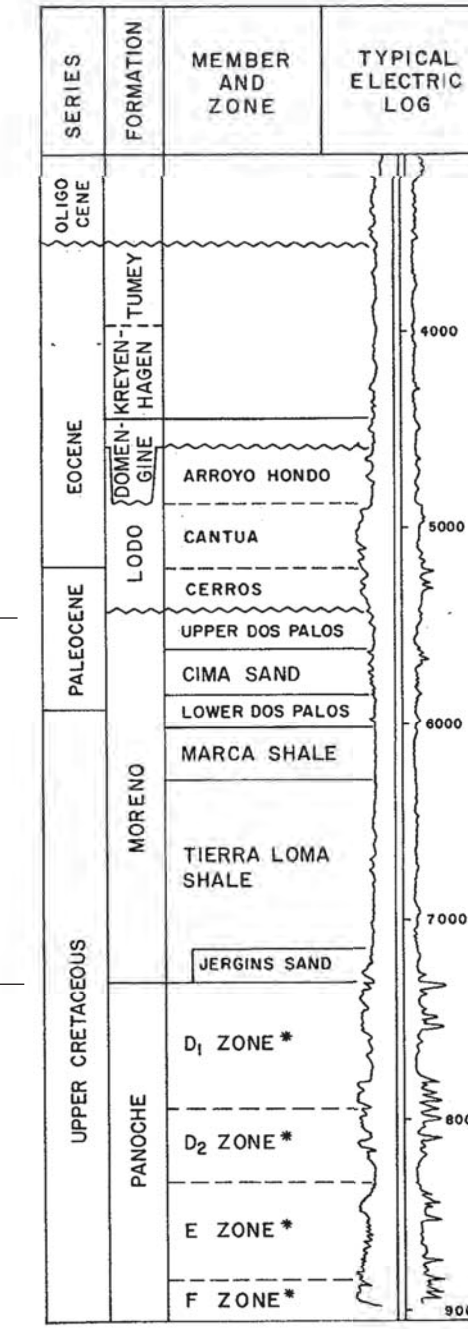


CONTOURS ON TOP OF PANOCHE

Panoche Hills

PEC

Modified from Page 88 of the California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR), 1998, California Oil and Gas Fields, Volume 1 – Central California (CD-1), Contour Maps, Cross Sections and Data Sheets for California's Oil and Gas Fields: Publication TR-11.



Cheney Ranch Gas Field Type Log

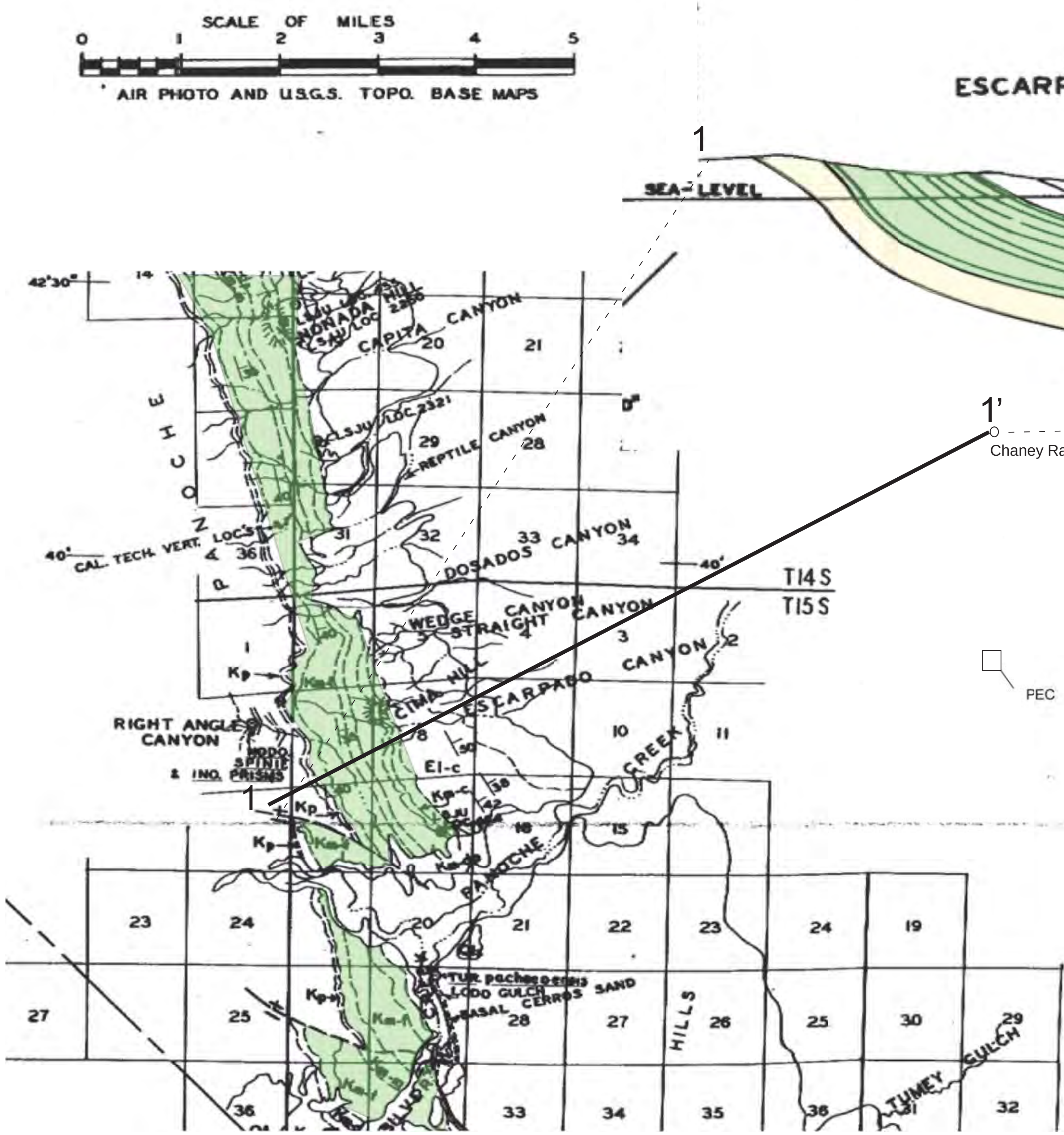
HALEY ALDRICH

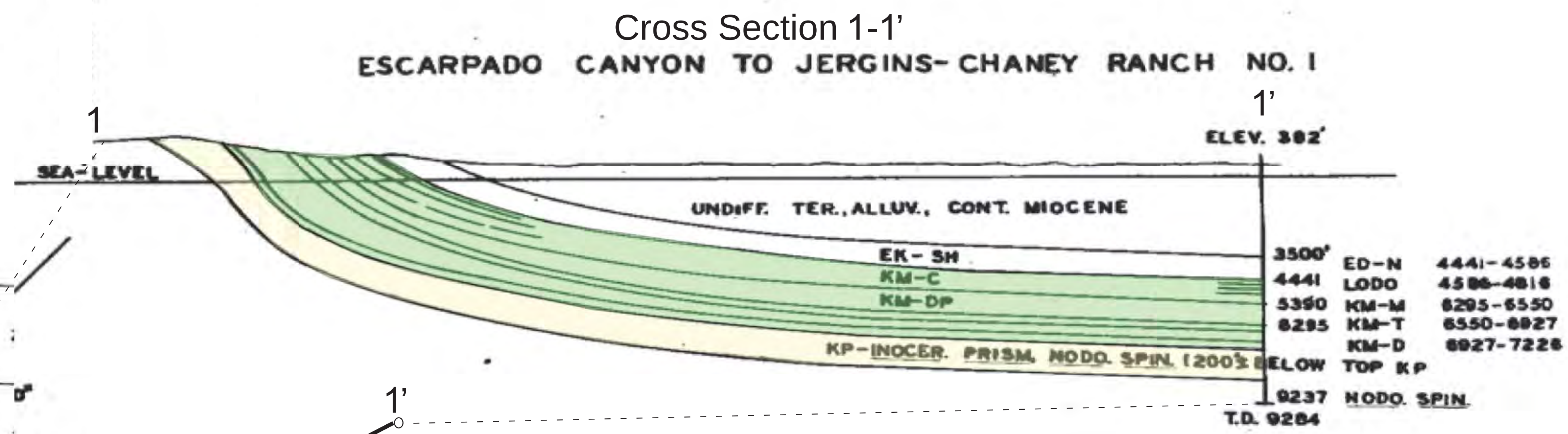
PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

REGIONAL STRATIGRAPHIC COLUMNS AND CORRELATION DIAGRAM

JANUARY 2019

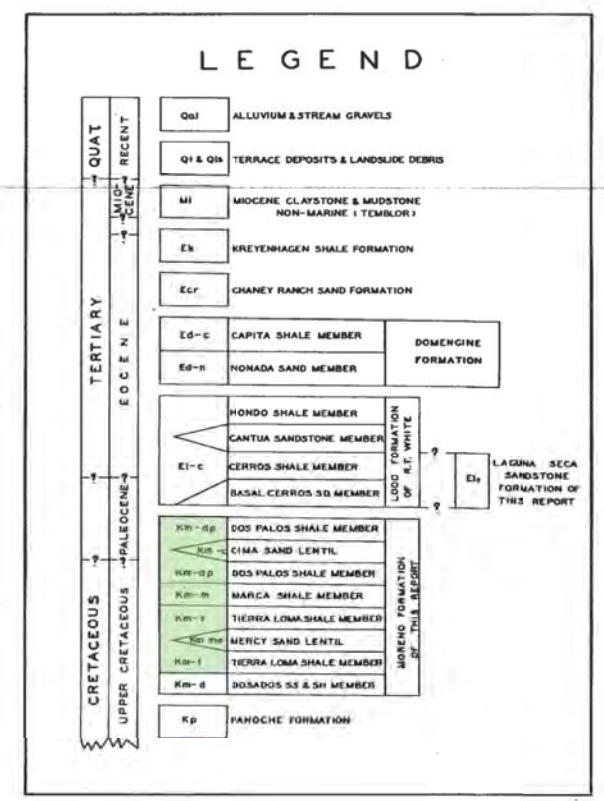
FIGURE F-2





NOTES

Modified form Plate 1 of Payne (1941) outcrop map



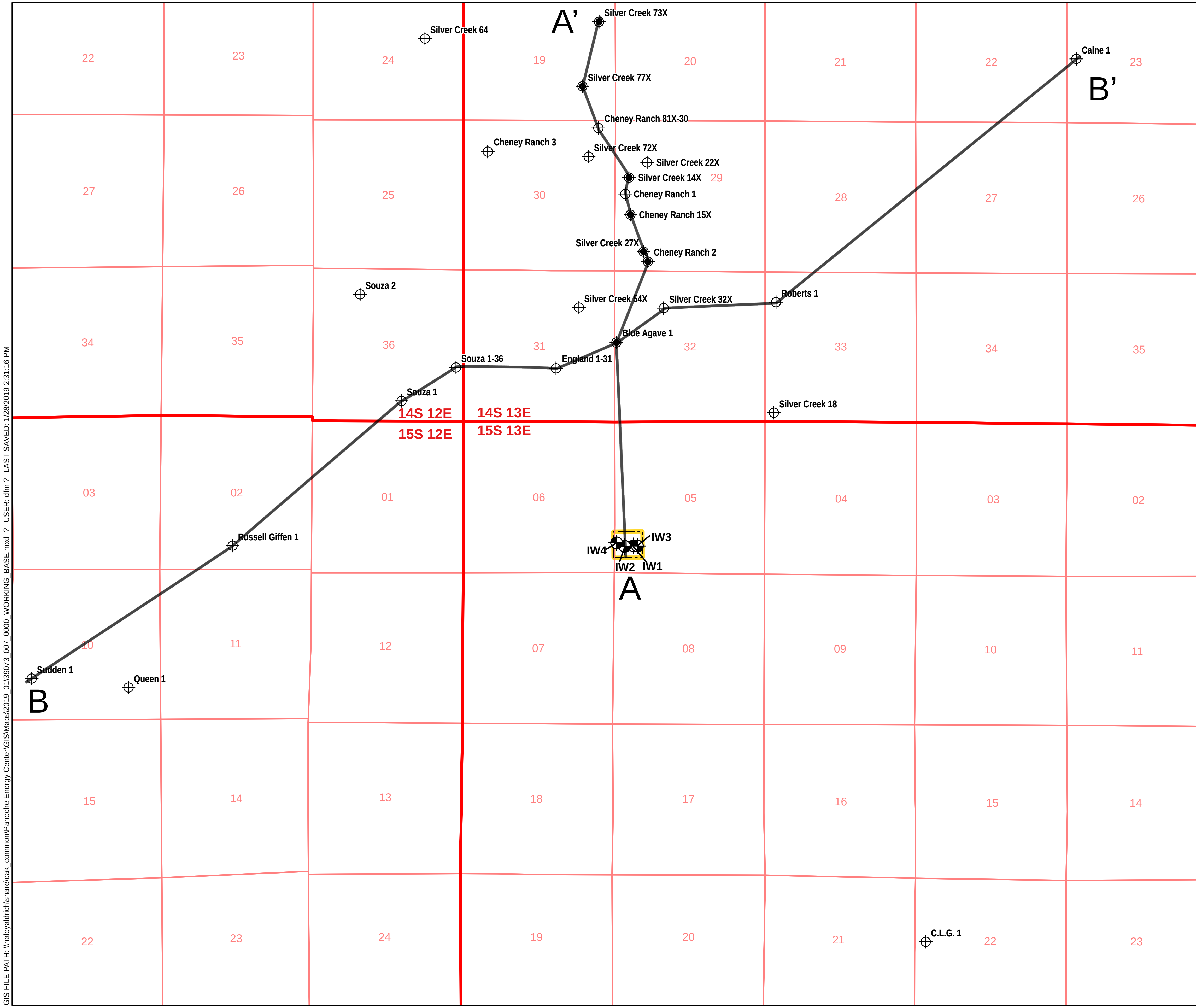
HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

REGIONAL GEOLOGIC CROSS SECTION FROM ESCARPADO CANYON TO CHANEY RANCH FIELD

JANUARY 2019

FIGURE F-3



HALEY ALDRICH

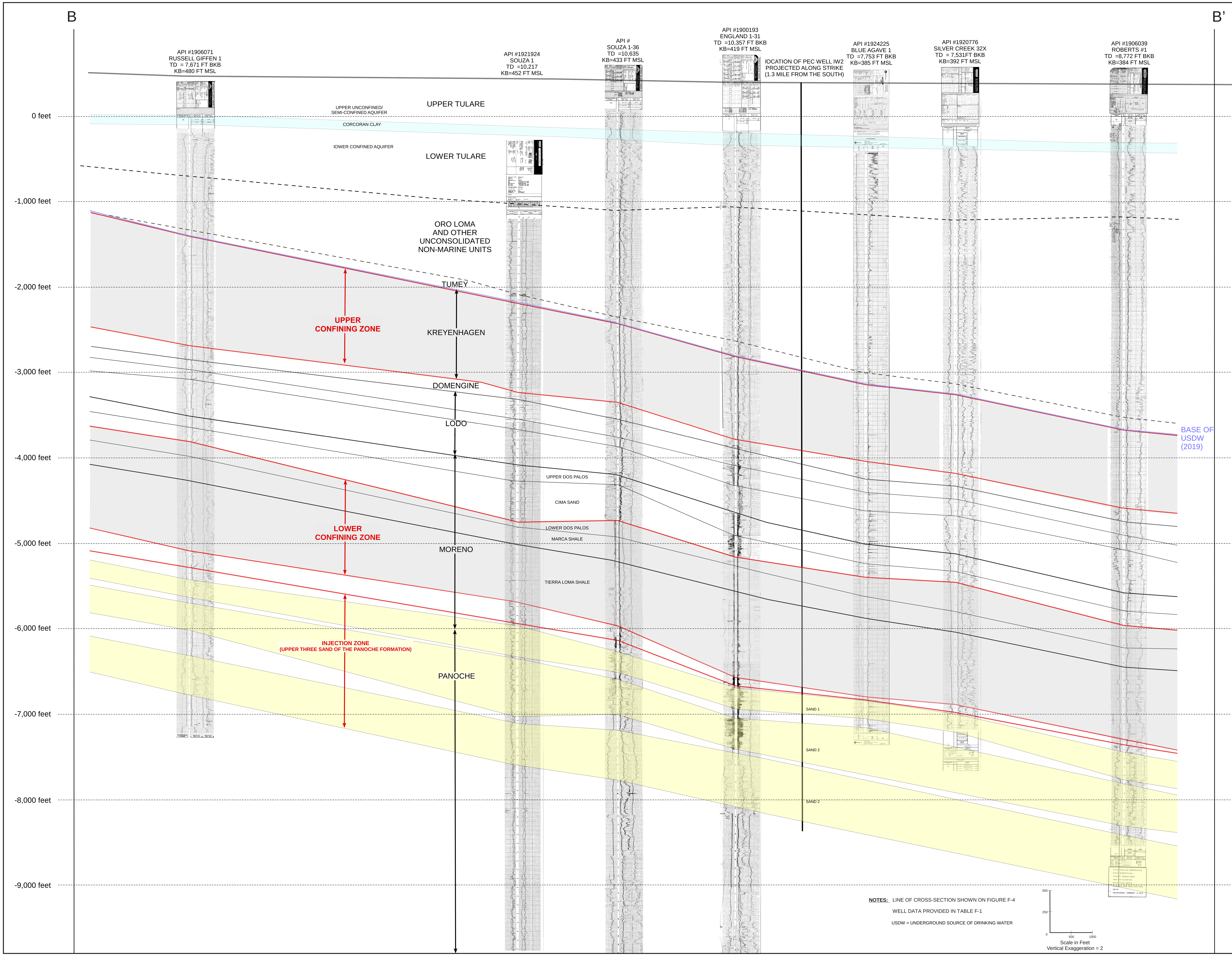
PANOCHE ENERGY CENT ER
43833 WEST PANOCHE ROAD
FIREBAUGH, CAL FORNIA

LOCATION OF LOCAL GEOLOGIC CROSS SECTION LINES

JANUARY 2019

FIGURE F-4

DOGGR CHANEY FIELD
CORRELATION DIAGRAM
SERIES
FORMATION
MEMBER AND ZONE
TYPICAL ELECTRIC LOG
MIOCENE TO HOLOCENE
OLIGO-CENE
EOCENE
PALEOCENE
UPPER CRETACEOUS
UNDIFF NONMARINE STRATA
TUMEY
KREYEN-HAGEN
DOMEN-GINE
LODO
MORENO
PANOCHE
ARROYO HONDO
CANTUA
CERROS
UPPER DOS PALOS
CIMA SAND
LOWER DOS PALOS
MARCA SHALE
TIERRA LOMA SHALE
JERGINS SAND
D1 ZONE*
D2 ZONE*
E ZONE*
F ZONE*
1000
2000
3000
4000
5000
6000
7000
8000
9000
* GOUDKOFF ASSEMBLAGE ZONE
November 1997
Modified from California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR), 1998, California Oil and Gas Fields, Volume 1 – Central California (CD-1), Contour Maps, Cross Sections and Data Sheets for California's Oil and Gas Fields: Publication TR-11.
A
A'
PEC INJECTION WELL IW2
TD = 8,901 FT BKB
KB=402 FT MSL
GAMMA RAY
SP
RESISTIVITY
API #1924225
BLUE AGAVE 1
TD = 7,612 FT BKB
KB=385 FT MSL
API #1900191
CHENEY RANCH 2
TD = 7,354 FT BKB
KB=404 FT MSL
API #1920726
SILVER CREEK 27X
TD = 7,460 FT BKB
KB=377 FT MSL
API #1921446
CHENEY RANCH 15X
TD = 7,290 FT BKB
KB=375 FT MSL
API #1900190
CHENEY RANCH 1
TD = 9,284 FT BKB
KB=392 FT MSL
API #1920712
CHENEY RANCH 14X
TD = 7,394 FT BKB
KB=373 FT MSL
API #1923117
CHENEY RANCH 81X-30
TD = 7,400 BKB
KB=386 FT MSL
API #1920687
SILVER CREEK 77X
TD = 7,250 BKB
KB=377 FT MSL
API #1920711
SILVER CREEK 73X
TD = 7,496 BKB
KB=373 FT MSL
FORMATION
0 feet
-1,000 feet
-2,000 feet
-3,000 feet
-4,000 feet
-5,000 feet
-6,000 feet
-7,000 feet
-8,000 feet
-9,000 feet
UPPER UNCONFINED/ SEMI-CONFINED AQUIFER
UPPER TULARE
CORCORAN CLAY
LOWER CONFINED AQUIFER
LOWER TULARE
ORO LOMA AND OTHER UNCONSOLIDATED NON-MARINE UNITS
TUMEY
BASE OF USDW (2019)
UPPER CONFINING ZONE
KREYENHAGEN
DOMENGINE
LODO
MORENO
LOWER CONFINING ZONE
DOSADOS MEMBER OF THE MORENO FORMATION
SAND 1
SAND 2
SAND 3
Slotted liner
INJECTION ZONE (UPPER THREE SANDSTONE UNITS OF THE PANOCHE FORMATION)
PANOCHE
NOTES: LINE OF CROSS-SECTION SHOWN ON FIGURE F-4
WELL DATA PROVIDED IN TABLE F-1
USDW = UNDERGROUND SOURCE OF DRINKING WATER
500
250
0
500
1000
Scale in Feet
Vertical Exaggeration = 2
HALEY ALDRICH
PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CAL FORNIA
STRIKE-ORIENTED LOCAL STRUCTURAL CROSS-SECTION A-A'
FEBRUARY 2019
FIGURE F-5



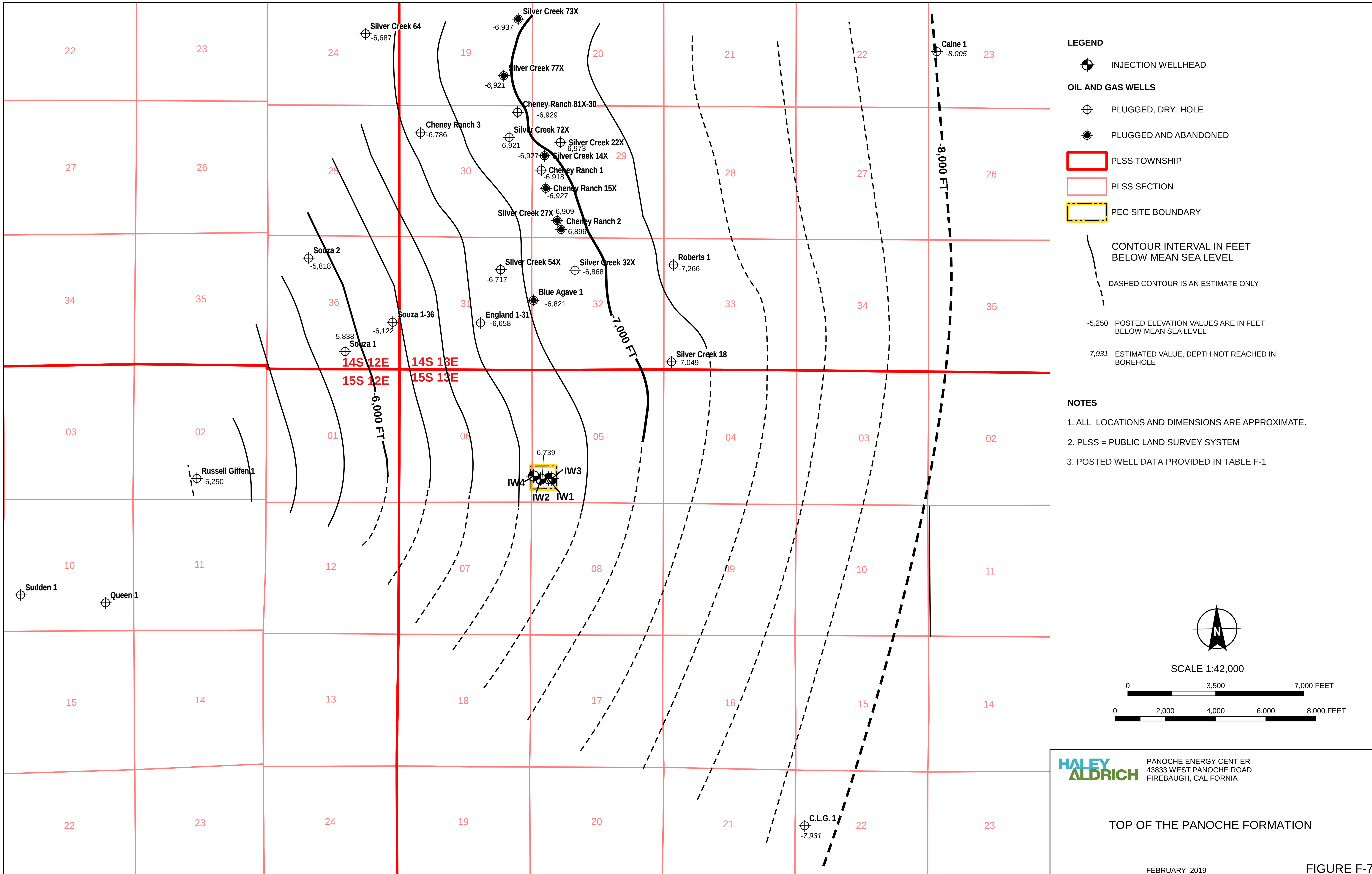
HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

DIP-ORIENTED LOCAL STRUCTURAL CROSS-SECTION B-B'

JANUARY 2019

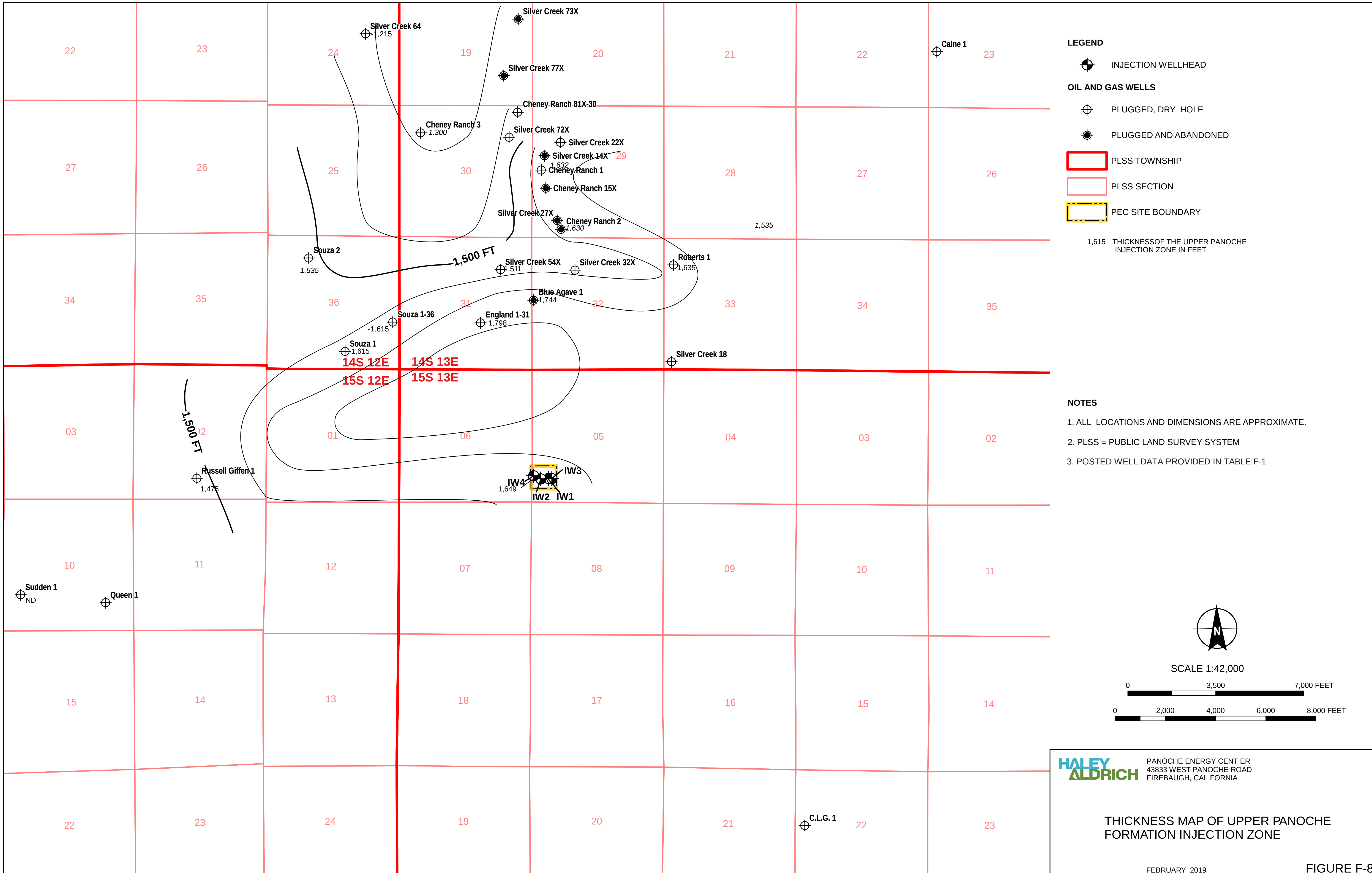
FIGURE F-6



TOP OF THE PANOCHE FORMATION

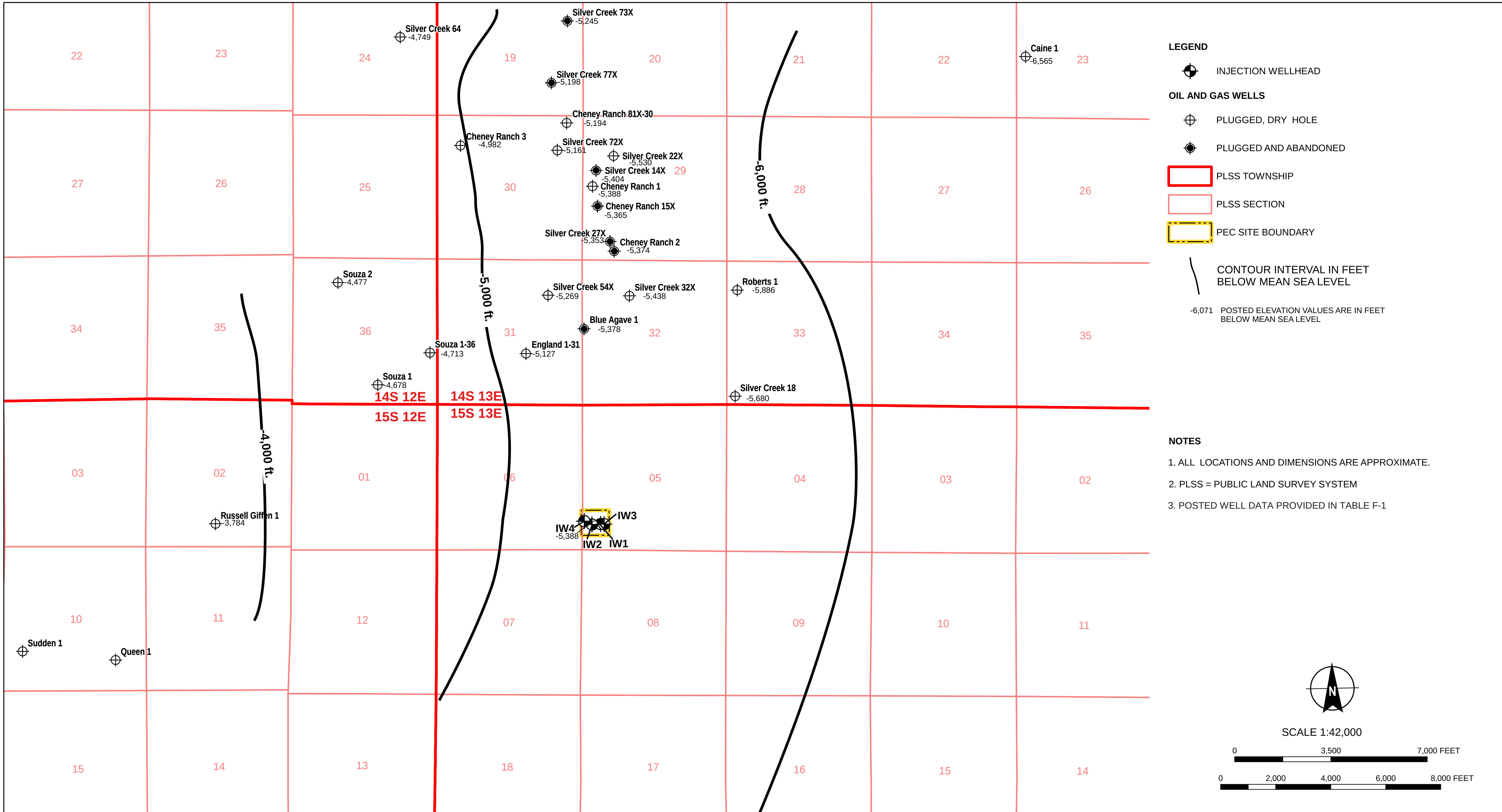
FEBRUARY 2019

FIGURE F-7



THICKNESS MAP OF UPPER PANOCHE FORMATION INJECTION ZONE

FIGURE F-8



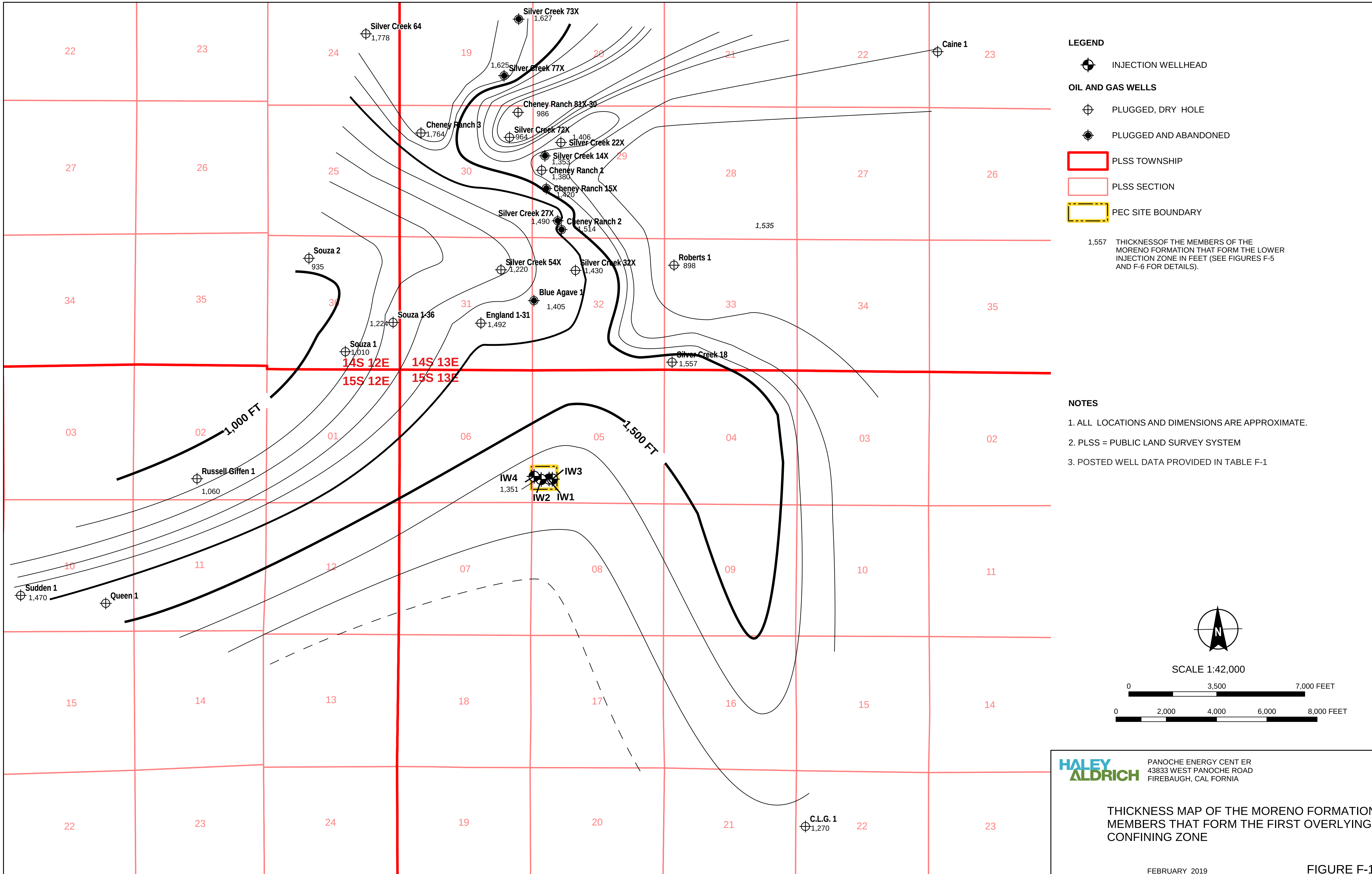
HALEY ALDRICH

PANOCHE ENERGY CENT ER
43833 WEST PANOCHE ROAD
FIREBAUGH, CAL FORNIA

TOP OF MORENO FORMATION MEMBERS THAT FORM THE FIRST OVERLYING CONFINING ZONE

FEBRUARY 2019

FIGURE F-9



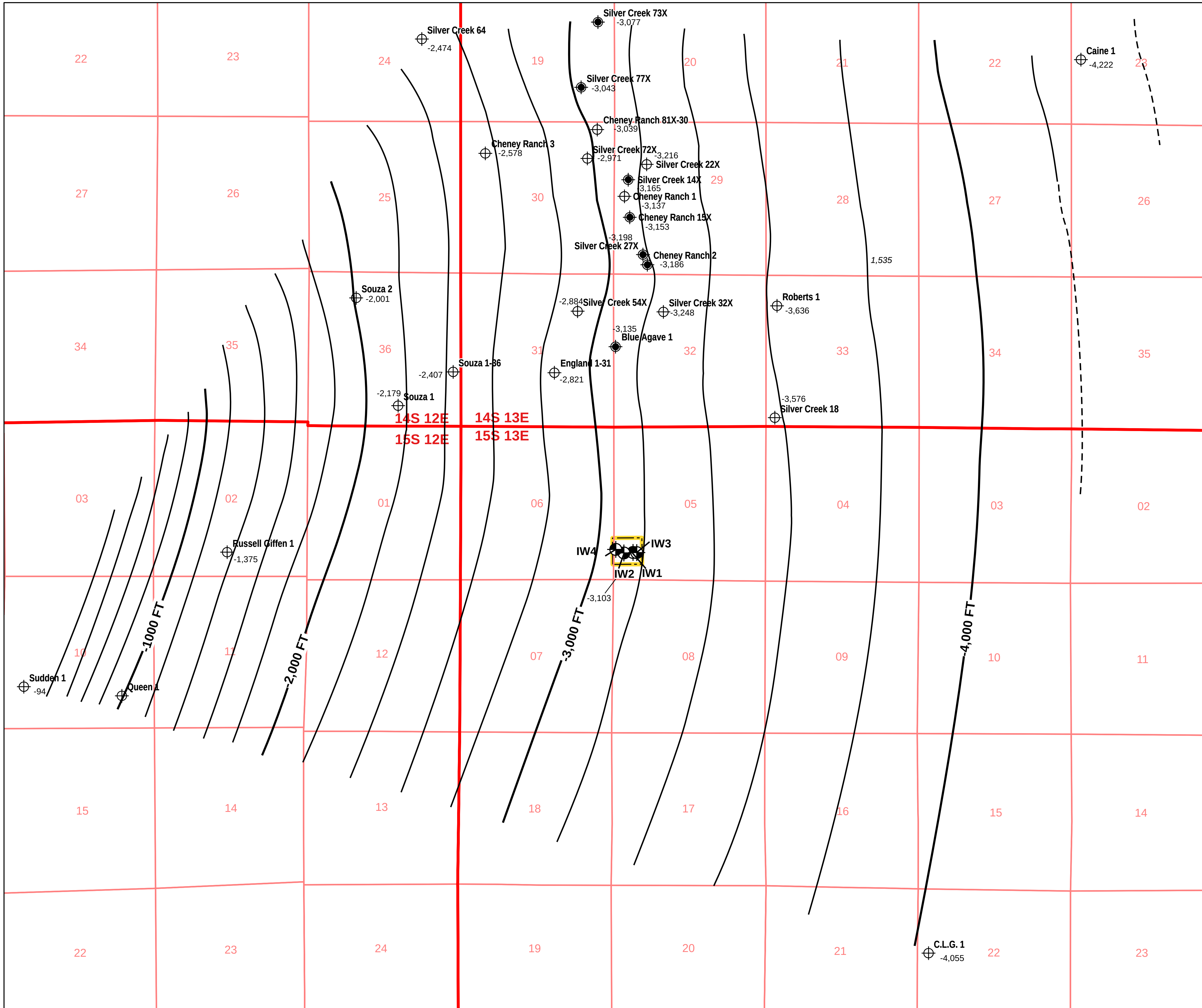
HALEY ALDRICH

PANOCHE ENERGY CENT ER
43833 WEST PANOCHE ROAD
FIREBAUGH, CAL FORNIA

THICKNESS MAP OF THE MORENO FORMATION MEMBERS THAT FORM THE FIRST OVERLYING CONFINING ZONE

FEBRUARY 2019

FIGURE F-10



LEGEND

INJECTION WELLHEAD

OIL AND GAS WELLS

PLUGGED, DRY HOLE

PLUGGED AND ABANDONED

PLSS TOWNSHIP

PLSS SECTION

PEC SITE BOUNDARY

CONTOUR INTERVAL IN FEET BELOW MEAN SEA LEVEL

DASHED CONTOUR IS AN ESTIMATE ONLY

-3,576 POSTED ELEVATION VALUES ARE IN FEET BELOW MEAN SEA LEVEL

NOTES

1. ALL LOCATIONS AND DIMENSIONS ARE APPROXIMATE.
2. PLSS = PUBLIC LAND SURVEY SYSTEM
3. POSTED WELL DATA PROVIDED IN TABLE F-1

SCALE 1:42,000

0 3,500 7,000 FEET

0 2,000 4,000 6,000 8,000 FEET

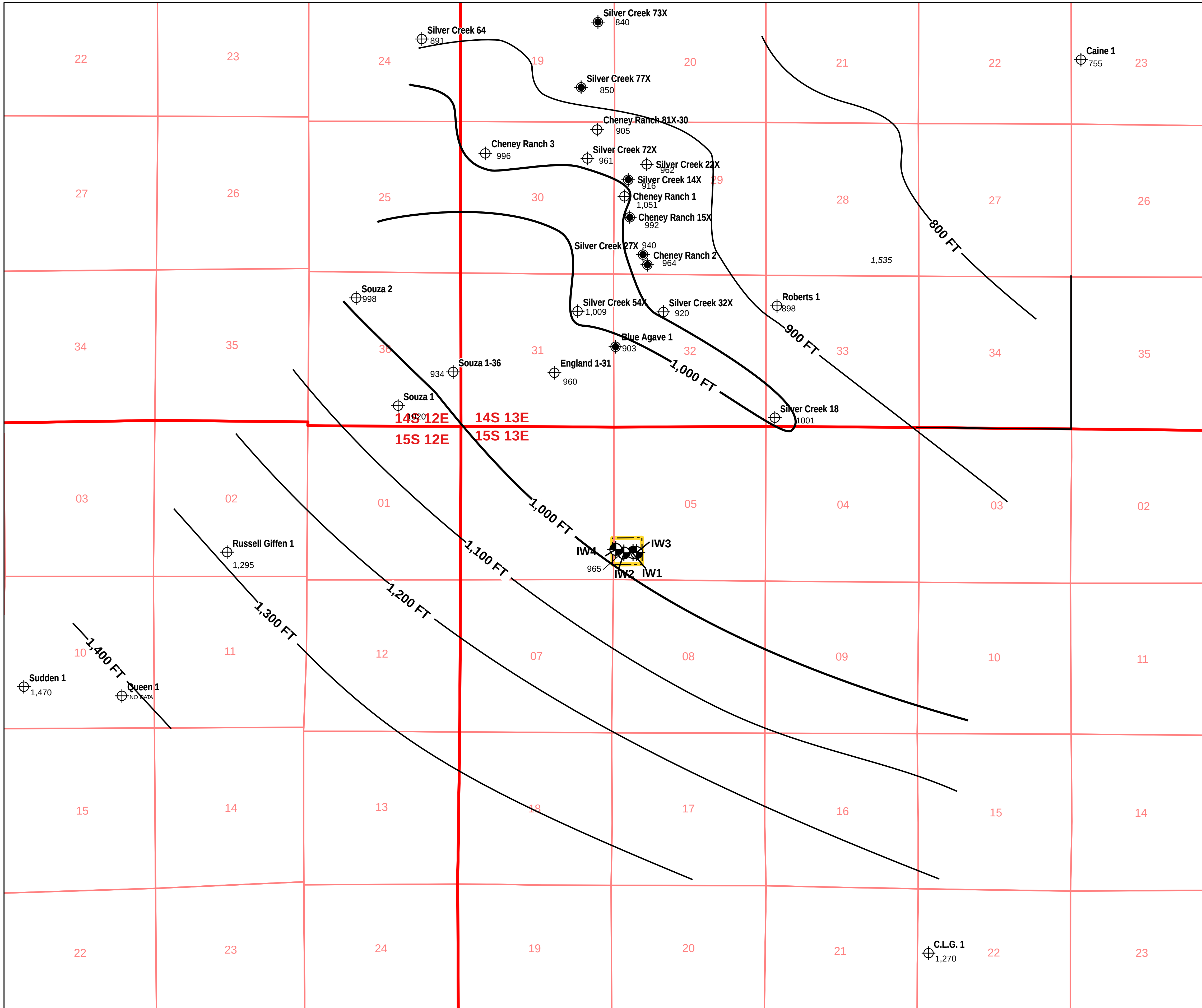
HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

TOP OF KREYENHAGEN FORMATION (SECOND) CONFINING ZONE MAP

FEBRUARY 2019

FIGURE F-11



LEGEND

INJECTION WELLHEAD

OIL AND GAS WELLS

PLUGGED, DRY HOLE

PLUGGED AND ABANDONED

PLSS TOWNSHIP

PLSS SECTION

PEC SITE BOUNDARY

1,009 THICKNESSOF THE UPPER PANOCHE INJECTION ZONE IN FEET

NOTES

1. ALL LOCATIONS AND DIMENSIONS ARE APPROXIMATE.
2. PLSS = PUBLIC LAND SURVEY SYSTEM
3. POSTED WELL DATA PROVIDED IN TABLE F-1

N

SCALE 1:42,000

0 3,500 7,000 FEET

0 2,000 4,000 6,000 8,000 FEET

HALEY ALDRICH

PANOCHE ENERGY CENT ER
43833 WEST PANOCHE ROAD
FIREBAUGH, CAL FORNIA

THICKNESS MAP OF THE KREYENHAGEN FORMATION (SECOND) CONFINING ZONE

FEBRUARY 2019

FIGURE F-12

EXHIBITS

(To be Submitted on CD)

ATTACHMENT H

Operating Data

Table of Contents

HALEY ALDRICH

List of Tables

List of Exhibits

H-8 URS. 2010. Second Quarter 2010 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. July.

H-9 URS. 2010. Third Quarter 2010 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.

H-10 BSK Analytical Laboratories. 2010. Fourth Quarter 2010 Laboratory Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. November.

H-11 AMEC Geomatrix, Inc. 2011. First Quarter 2011 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. April.

H-12 AMEC Geomatrix, Inc. 2011. Second Quarter 2011 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. July.

H-13 AMEC Geomatrix, Inc. 2011. Third Quarter 2011 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.

H-14 AMEC Environmental and Infrastructure. 2012. Fourth Quarter 2011 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. January.

H-15 AMEC Environmental and Infrastructure. 2012. First Quarter 2012 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. April.

H-16 Haley & Aldrich, Inc. (Haley & Aldrich). 2012. Second Quarter 2012 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. July.

H-17 Haley & Aldrich. 2012. Third Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.

H-18 Haley & Aldrich. 2013. Fourth Quarter 2012 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. January.

H-19 Haley & Aldrich. 2013. First Quarter 2013 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. April.

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H-21 Haley & Aldrich. 2013. Third Quarter 2013 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.

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H-24 Haley & Aldrich. 2014. Second Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. July.

H-25 Haley & Aldrich. 2014. Third Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.

H-26 Haley & Aldrich. 2015. Fourth Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. January.

H-27 Haley & Aldrich. 2015. First Quarter 2015 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. April.

H-28 Haley & Aldrich. 2015. Second Quarter 2015 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. July.

H-29 Haley & Aldrich. 2015. Third Quarter 2015 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.

H-30 Haley & Aldrich. 2016. Fourth Quarter 2015 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. January.

H-31 Haley & Aldrich. 2016. First Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. April.

H-32 Haley & Aldrich. 2016. Second Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. July.

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H-34 Haley & Aldrich. 2017. Fourth Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. January.

H-35 Haley & Aldrich. 2017. First Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. April.

H-36 Haley & Aldrich. 2017. Second Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. July.

H-37 Haley & Aldrich. 2017. Third Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.

H-38 Haley & Aldrich. 2018. Fourth Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. January.

H-39 Haley & Aldrich. 2018. First Quarter 2018 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. April.

H-40 Haley & Aldrich. 2018. Second Quarter 2018 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. July.

H-41 Haley & Aldrich. 2018. Third Quarter 2018 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.

Other Reports

H-42 Haley & Aldrich. 2013. IW3 Fracture Stimulation Report and Request to Operate Well IW3, Class 1 Nonhazardous Waste Injection Wells, UIC Permit Number CA10600001, Panoche Energy Center, LLC, Fresno County, California. July.

H-43 URS. 2009a. Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California, March.

H-44 URS. 2009b. Well Completion Report – UIC Well IW2, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California. March.

ATTACHMENT H – OPERATING DATA

PERMIT REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment H requires the applicant to submit the following proposed "operating data for each well (including all those to be covered by area permits):

(1) average and maximum daily rate and volume of the fluids to be injected;

(2) average and maximum injection pressure;

(3) nature of annulus fluid;

(4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids."

AVERAGE AND MAXIMUM FLUID INJECTION RATES, VOLUMES, AND OPERATING PRESSURE

As described in Attachment P, all quarterly data can be found in the Quarterly Injection monitoring reports (tables and raw data spreadsheets) and in the Annual Monitoring Reports (USEPA Form 7520-11) submitted to USEPA for the last 10 years (See Exhibits folder on compact disc). A summary of an example set of consecutive four quarters of submitted operating data, including the average and maximum injection rate, daily volume of injectate, and injection pressure, are presented for each injection well in Table H-1. As the wells operate on an intermittent basis (only a few hours at a time) and thus, injection rates are presented in gallons per minute (gpm) as measure just during these injection periods rather than daily rates.

As described in Attachment K and previously discussed in Attachment A, the construction of the enhanced wastewater system (EWS) caused a decrease in wastewater injection at the Panoche Energy Center (PEC) facility starting in June 2016 (Haley & Aldrich, 2016). As a result, the anticipated wastewater injection rate is expected to be less between 2018 and 2027 than the wastewater injection rate that occurred between 2009 and 2016. Therefore, the data shown in Table H-1 was aggregated from the four most recent quarters of monitoring data (Haley & Aldrich, 2016, Haley & Aldrich, 2017a, Haley & Aldrich, 2017b, Haley & Aldrich, 2017c).

Maximum historic recorded daily injection volumes for each well are as follows: 144,039 gallons in IW1 during August 2013; 172,041 gallons in IW2 during September 2014; 155,147 gallons in IW3 during July 2013; and 164,002 gallons in IW4 during October 2014 (Haley & Aldrich, 2013b, Haley & Aldrich, 2014b, Haley & Aldrich, 2014c). While it is anticipated that future injection rates will be significantly lower most of the time due to the installation of the EWS, similar maximum daily injection volumes may occur when the EWS maintenance is required during a high electricity demand season. Therefore, we propose that the maximum daily injection volumes for the next permit period are set to be the same as the previous historic daily maximums. Similarly, the highest historical daily average volumes and maximum daily injection rates for individual wells reported in the quarterly reports are used as the proposed future values. The proposed average daily injection rates are estimated by the ratios of the proposed maximum daily volumes (in gallons) to 1,440 minutes; these estimates represent potential daily average rates that may occur when the EWS maintenance is required during a high electricity demand season.

Based on Attachment I, the proposed maximum injection pressures at well head are 2,478 pounds per square inch (psi) for IW1, IW3, and IW4; and 2,416 psi for IW2. The proposed average injection pressure at well head is 2,065 psi based on the historical maximum injection pressure for all wells. Note that the current injection pressure is limited by the capability of injection pumps (approximately 2,000 psi). The injection pumps can be upgraded to have the capability of performing injection at around 2,400 psi at well head.

The proposed average and maximum injection pressures, as well as the proposed average and maximum daily rate and volume of the fluids to be injected, are summarized in Table H-2.

NATURE OF ANNULUS FLUID

The annular fluid used in wells IW1 and IW2 consists of Amber Chemical's corrosion inhibitor packer fluid, which is composed of sodium bisulfite with a bio-filming amine (URS, 2009a; URS, 2009b). On 21 May 2013, IW3 was topped off with 10 pounds per gallon (ppg) inhibited fluid, and a packer was set in-place during the re-installation of injection tubing after fracture stimulation of this well (Haley & Aldrich, 2013a). On 16 June 2014, during the well repair of IW4, approximately 150 barrels (bbls) of 10.5 ppg calcium chloride inhibited with Geo Drilling Fluids, Inc.'s Amberguard COS and CAP was emplaced down the backside of the injection tube prior to setting the tubing sting packer (Haley & Aldrich, 2014a).

INJECTION FLUID CHARACTERISTICS

When it became operational, PEC performed a hazardous waste determination of the injection fluids on 28 April 2009, per the requirements of Code of Federal Regulations Title 40 (40 CFR) §262.11. The results of that determination indicated that the injection fluids did not meet the definition of hazardous waste as defined in 40 CFR §146.3 and §261. In addition, PEC performed a new hazardous waste injectate determination in the third quarter of 2016, per the above listed requirements and according to Section C, paragraph 1(b)(ii) of the Underground Injection Control (UIC) Permit, once an on-demand wastewater treatment system became operational and began contributing to the combined injectate flow. This Hazardous Waste Determination document concludes that the injectate still does not meet the definition of hazardous waste as defined in 40 CFR §146.3 and §261 and demonstrates that PEC continues to comply with the injection fluid limitations as required by Section C, paragraph 5(a) of the current UIC Permit. The Hazardous Waste Determination document prepared by PEC is presented as Appendix C of the Third Quarter 2016 Injection Monitoring Report (Haley & Aldrich, 2016).

In accordance with the Permit, injection fluid is analyzed on a quarterly basis (See Attachment P for details). The injection fluids for wells IW1 through IW4 originate from the same wastewater storage tank. Therefore, a single sample of injection fluid (a composite of all the wells) is collected and analyzed. A summary of the past four quarters of analytical results for injection fluids is presented in Table H-3. This time frame (previous four quarters) was selected because, as described above, the EWS system is in operation and the future injectate is expected to closely match the analytical results from the last four quarters.

References

1. Haley & Aldrich, Inc. (Haley & Aldrich). 2013a. IW3 Fracture Stimulation Report and Request to Operate Well IW3, Class 1 Nonhazardous Waste Injection Wells, UIC Permit Number CA10600001, Panoche Energy Center, LLC, Fresno County, California. July.

2. Haley & Aldrich. 2013b. Third Quarter 2013 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

3. Haley & Aldrich. 2014a. Second Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

4. Haley & Aldrich. 2014b. Third Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

5. Haley & Aldrich. 2014c. Fourth Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

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7. Haley & Aldrich. 2017a. Fourth Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

8. Haley & Aldrich. 2017b. First Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

9. Haley & Aldrich. 2017c. Second Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

10. URS. 2009a. Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California. March.

11. URS. 2009b. Well Completion Report – UIC Well IW2, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

TABLES

TABLE H-1
INJECTION WELL OPERATIONAL DATA
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Month	IW1						IW2						IW3						IW4					
	Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)		Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)		Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)		Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)	
	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
July, 2016	17,698.0	90,730.0	1,856.6	1,993.4	104.0	156.0	19,472.4	108,765.0	1,849.7	1,994.3	140.2	234.9	7,910.9	52,917.0	1,840.7	1,913.3	88.6	179.6	5,298.5	70,769.0	1,814.9	1,935.9	134.6	162.8
August, 2016	27,265.3	87,759.0	1,889.1	2,004.8	99.1	145.1	28,235.3	88,500.0	1,885.9	1,993.4	132.0	186.6	13,983.4	42,859.0	1,893.7	1,949.7	82.0	111.8	--	--	--	--	--	--
September, 2016	6,709.2	46,000.0	1,837.6	1,922.2	103.8	143.9	13,915.4	129,051.0	1,862.1	2,001.2	140.5	253.1	7,266.0	71,004.0	1,887.2	1,998.0	89.5	150.2	11,598.9	59,125.0	1,857.4	1,953.3	150.4	230.7
October, 2016	5,994.1	107,000.0	1,885.1	1,998.6	106.3	147.5	11,792.6	113,046.0	1,862.8	1,997.7	143.3	186.7	5,510.1	32,101.0	1,878.1	1,978.3	90.0	124.4	10,302.0	61,830.0	1,867.8	1,977.4	145.6	203.3
November, 2016	2,367.6	31,110.0	1,849.7	1,955.6	112.7	131.9	7,888.2	56,495.0	1,873.3	1,979.9	143.5	204.6	3,991.0	33,940.0	1,870.4	1,976.9	94.3	130.3	5,474.0	58,842.0	1,852.7	1,909.6	142.4	163.9
November, 2016	7,311.0	93,612.0	1,885.6	1,972.8	106.6	234.7	7,792.3	102,000.0	1,779.2	1,977.1	125.9	199.4	6,130.9	67,002.0	1,923.3	1,978.3	87.2	111.8	6,157.8	49,913.0	1,895.1	1,977.1	143.3	181.9
January, 2017	5,987.9	45,472.0	1,879.6	1,989.5	101.6	178.0	13,849.9	62,445.0	1,906.5	1,999.3	134.3	166.0	4,359.7	21,170.0	1,899.5	1,991.3	96.0	135.9	16,041.7	65,650.0	1,922.9	1,996.6	141.4	206.9
February, 2017	2,440.9	33,221.0	1,942.6	1,989.7	118.5	139.5	6,202.1	42,502.0	1,931.6	1,977.4	144.0	197.8	--	--	--	--	--	--	9,677.9	47,244.0	1,952.4	1,992.2	146.0	186.3
March, 2017	1,859.1	39,582.0	1,860.0	1,902.1	103.4	126.3	7,898.2	43,213.0	1,907.2	1,988.8	146.8	251.3	--	--	--	--	--	--	8,994.0	44,583.0	1,930.7	1,998.0	143.6	182.5
April, 2017	5,963.4	33,000.0	1,884.7	1,981.0	99.6	121.6	9,839.6	54,463.0	1,891.9	1,984.0	139.0	174.2	2,353.6	21,768.0	1,859.1	1,897.7	103.4	151.2	10,779.5	61,731.0	1,903.4	1,991.5	140.3	161.3
May, 2017	4,888.6	37,627.0	1,855.7	1,968.4	98.8	139.2	7,713.9	34,002.0	1,857.0	1,969.6	140.6	200.1	1,762.3	33,009.0	1,949.5	1,991.3	104.8	117.2	12,133.0	41,989.0	1,908.8	1,990.9	141.6	168.1
June, 2017	13,922.5	71,285.0	1,856.0	1,958.1	74.2	141.6	25,292.4	97,581.0	1,879.6	2,000.7	113.7	172.5	5,803.4	44,981.0	1,867.8	1,919.0	89.6	122.3	27,859.0	97,792.0	1,898.9	1,998.6	121.3	170.3
Historical Operating Parameters (12-month average, 12-month maximum)	8,534.0	107,000.0	1,873.5	2,004.8	102.4	234.7	13,324.4	129,051.0	1,873.9	2,001.2	137.0	253.1	5,907.1	71,004.0	1,886.9	1,998.0	92.5	179.6	11,301.5	97,792.0	1,891.4	1,998.6	141.0	230.7

Abbreviations:
-- = not applicable
gal = gallons
gpm = gallons per minute

TABLE H-2
PROPOSED INJECTION PRESSURES, RATES, AND VOLUMES
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Operation Parameter		Proposed Quantity			
		IW1	IW2	IW3	IW4
Injection Pressure (psi)	Average	2,065	2,065	2,065	2,065
	Maximum	2,478	2,416	2,478	2,478
Injection Rate (gpm)	Average	98	119	108	114
	Maximum	240	224	181	253
Daily Volume (gallons)	Average	7,808	149,555	99,458	123,890
	Maximum	141,039	172,041	155,147	164,002

Operation Parameter		Rationale fofr Proposed Quantity			
		IW1	IW2	IW3	Iw4
Injection Pressure (psi)	Average	Historical Maximum Pressure			
	Maximum	See Attachment I			
Injection Rate (gpm)	Average	Based on maximum daily volume (÷1440)			
	Maximum*	2Q-2016	2Q-2016	4Q-2014	3Q-2014
Daily Volume (gallons)	Average*	3Q-2015	3Q-2015	3Q-2013	3Q-2015
	Maximum*	3Q-2013	3Q-2014	3Q-2013	3Q-2015

Notes:
* = based on the historical values reported in a quarterly report (2Q2016 = second quarter 2016 monitoring report)
gpm = gallons per minute
psi = pounds per square inch

TABLE H-3
LABORATORY ANALYTICAL RESULTS FOR INJECTION FLUIDS
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Sample Date:		17-Aug-16	9-Dec-16	1-Mar-17	12-May-17
	Units	**Results**	**Results**	**Results**	**Results**
Physical/Chemical Properties					
pH	pH Units	8.0	7.4 J	7.3 J[1]	7.2 J [1]
Specific Conductivity	µmhos/cm @ 25°C[1]	13,000	9,900	14,000	15,000
Specific Gravity	@ 60/60°F[2]	1.008	1.0054	1.0107	1.011
Density	g/mL @ 60°F[3]	1.007	1.0054	1.0097	1.01
Viscosity	cSt @ 100°F[4]	0.7	0.71	1.1	0.76
Total Dissolved Solid	mg/L[5]	8,900	5,400	10,000	8,300
Total Suspended Solid	mg/L	17	21	32	22
Turbidity	NTU[6]	0.31	2.7	7.4	0.86
Alkalinity, as $CaCO_3$[7]	mg/L	410	270	280	260
Inorganic Analytes - Cations/Metals					
Aluminum	mg/L	< 0.050	< 0.050	< 0.050[9]	< 0.050[9]
Antimony	mg/L	< 0.0020	< 0.0040	< 0.0040	< 0.0020
Arsenic	mg/L	0.190	0.079	0.150	0.210
Barium	mg/L	0.019	0.019	0.037	0.021
Beryllium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010
Cadmium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010
Calcium	mg/L	37	61	18	15
Chromium	mg/L	< 0.010	< 0.020	< 0.020	0.010
Cobalt	mg/L	0.011	0.32	0.081	0.087
Copper	mg/L	0.041	0.050	0.200	0.130
Fluoride	mg/L	2.2	1.6	2.3	2.7
Iron	mg/L	0.60	3.1	23	1.9
Lead	mg/L	< 0.0050	< 0.010	< 0.002	< 0.001
Magnesium	mg/L	14	21	5.2	7.2
Manganese	mg/L	0.023	0.054	0.29	0.029
Mercury	mg/L	< 0.00020 J	< 0.0010	< 0.0002	< 0.0002
Molybdenum	mg/L	0.490	0.44	0.390	0.650
Nickel	mg/L	< 0.010	< 0.020	0.020	0.010
Phosphorus	mg/L	1.2	0.79	1.9	0.59
Potassium	mg/L	25	100	70	50
Selenium	mg/L	0.180	0.084	0.079	0.150
Silica (SiO_2)[9], total	mg/L	180	150	170	180
Silica (SiO_2), dissolved	mg/L	190	140	150	180
Silver	mg/L	< 0.010	< 0.020	< 0.020	< 0.010
Sodium	mg/L	3,900	2,600	3,900	4,900
Strontium	mg/L	0.500	0.70	0.660	0.460
Thallium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010 UJ [14]
Thorium	mg/L	< 0.00050	< 0.00050	< 0.00050	< 0.00050
Uranium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010
Vanadium	mg/L	0.013	< 0.0060	< 0.0060	0.010
Zinc	mg/L	0.067	0.160	< 0.100	0.058
Inorganic Analytes - Anions					
Bicarbonate, as $CaCO_3$	mg/L	410	270	280	260
Carbonate, as $CaCO_3$	mg/L	< 3.0	< 3.0	< 3.0	< 3.0
Hydroxide, as $CaCO_3$	mg/L	< 3.0	< 3.0	< 3.0	< 3.0
Chloride	mg/L	810	650	1,100	940
Sulfate, as SO_4[10]	mg/L	4,900	3,900	6,400	6,500
Nitrate, as NO_3[11]	mg/L	< 20	< 1.0	< 50	< 100
Orthophosphate, as P [12]	mg/L	< 4.0	< 0.20	< 10	< 20
Mass Balance					
Anions	meq/L[13]	130	110	170	170
Cations	meq/L	170	120	170	220
Non-Ionic Analytes					
Biochemical Oxygen Demand	mg/L	2.0	47 J	17 J	8.0
Detected Organic Analytes					
Acetone	mg/L	0.022	0.035	0.080	0.064
Dibromomethane	mg/L	< 0.00050	0.0086	0.0026	0.0022
Dibromochloromethane	mg/L	< 0.00050	0.0014	< 0.00050	0.0011
Bromoform	mg/L	0.0086	0.057	0.015	< 0.00050

Notes:

µmhos/cm @ 25°C = micromhos per centimeter at 25 degrees Celsius
g/mL @ 60°F = grams per milliliter at standadization temperture in degrees Fahrenheit
meq/L = milliequivalents per liter
mg/L = milligrams per liter
@ 60/60°F = standardization temperature in degrees Fahrenheit
< = not detected at or above the reporting limit shown
$CaCO_3$ = calcium carbonate
cSt @ 100°F = centistokes at 100 degrees Fahrenheit
NO_3 = nitrate
NTU = nephelometric turbidity units
P = phosphorus
SiO_2 = silicon dioxide
SO_4 = sulfate

EXHIBITS

(To be Submitted on CD)

ATTACHMENT I

Formation Testing Program

Table of Contents

List of Exhibits

ATTACHMENT I – FORMATION TESTING PROGRAM

PERMIT APPLICATION REQUIREMENTS

According to in the Underground Injection Control (UIC) permit application instructions, it is required that the applicant "describe the proposed formation testing program. For Class I wells, the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids."

INITIAL FLUID PRESSURE AND TEMPERATURE

The Panoche Formation was initially observed to be over-pressurized in its native state preceding any injection occurring at Panoche Energy Center (PEC). This observation is based on a review of static surface shut-in pressures reported after well development via swabbing and backflowing, which was conducted during the IW1 and IW2 well completions in January of 2009 prior to the collection of reservoir fluid samples. The initial pressure ranged from 25 to 35 pounds per square inch (psi), respectively, based on field activity reports (URS Corporation [URS], 2009a; URS, 2009b). Additionally, although a fluid level of 67 feet below ground level (80 feet below kelly bushing [BKB]) was reported prior to the step rate testing (SRT) at IW2 on 10 February 2009, review of daily reports indicates that the well was killed with the addition of 9.4 pounds per gallon (lb/gal) fluid on 28 January 2009, and no further well activity was reported prior to the SRT. This positive surface wellhead pressure indicates that the reservoir is "over pressured" or artisan and would naturally flow at the surface. The Panoche Formation fluid pressure was measured at 3,510 psi at 7,604 feet BKB during the 10 February 2009 SRT for well IW2 (URS, 2009b). The initial surface static shut-in formation fluid pressure during the startup period of IW2 in March 2009 was approximately 260 pounds-force per square inch gauged (psig) (URS, 2009b). Shut-in surface tubing pressure was measured at approximately 280 and 300 psig in IW3 and IW4, respectively, during well development, after deepening and re-completion in the Panoche Formation (AMEC, 2012).

The maximum temperature encountered in well IW2 was approximately 221 degrees Fahrenheit (°F) (URS, 2009b). A maximum bottom-hole temperature of 191°F was recorded during geophysical logging of well IW3 (AMEC, 2012). Numerous dual or "decay" temperature profiles have been run in these wells during annual external mechanical integrity tests (MITs) and summary figures have been presented in the subsequent reports submitted to the United States Environmental Protection Agency (USEPA); a copy of the most recently submitted MIT and fall-off testing (FOT) report (Haley & Aldrich, 2018) and logs are included as Exhibit I-8 in this Attachment. All MIT and FOT reports are included as Exhibits in Attachment P.

FRACTURE PRESSURE DETERMINATION

Summary of Permitted Maximum Allowable Injection Pressure

Maximum allowable injection pressure (MAIP) values for well IW1 and IW2 were approved by the USEPA on April 23, 2009 (USEPA, 2009). These values were determined in accordance with the requirements of the UIC Program Class I Non-Hazardous Waste Injection Wells Permit Number CA10600001 (Permit) for wells IW1 and IW2, via a SRT performed on both wells (URS, 2009a; URS 2009b; USEPA, 2009) and through selection of a conservative value for the deepened wells IW3 and IW4 (see discussion below for details).

HALEY ALDRICH

To summarize, the current MAIPs allowed by the Permit are the following:

- IW1 maximum bottom-hole pressure (BHPmax) = 5,800 psi (measured at 7,460 feet)
  IW1 maximum well-head pressure (WHPmax) = 2,478 psi
- IW2 BHPmax = 5,913 psi (measured at 7,604 feet)
  IW2 WHPmax = 2,416 psi
- IW3 BHPmax = 5,800 psi
  IW3 WHPmax = 2,478 psi (based on IW1 MAIP)
- IW4 BHPmax = 5,800 psi
  IW4 WHPmax = 2,478 psi (based on IW1 MAIP)

Currently PEC does not have pumps that can attain these injection pressures; PEC will only revisit this issue if, in the future, these or high MAIP pressures are required. The Sections below summarize how these MAIPs were determined using SRT methodologies and why the MAIPs are considered conservative values.

Step-Rate Testing

URS recommended in the IW1 SRT report (URS, 2009a), submitted to the USEPA on April 13, 2009, that injection well IW1 be permitted to operate with a maximum downhole pressure of 80 percent of the minimum apparent formation parting pressure (FPP) achieved during the SRT performed on 6 April 2009. This recommendation is based on the conclusion that FPP was achieved during the IW1 SRT. Based on USEPA Region 8 guidance, which is to use instantaneous shut-in pressure as the pressure where fracture initiation will occur, URS used 7,250 psig measured at 7,460 feet BKB as a conservative estimate of the fracture pressure (fracture gradient [FG] = 0.972 psi per foot [psi/ft]). URS then calculated 80 percent of that value as the BHPmax, or 5,800 psi. A calculated 80-percent value comes from a requirement in the USEPA permit for PEC. URS also recorded a WHP of 2,478 psi at an injection rate of five barrels per minute (BPM) with a BHP of 5,800 psi during the SRT. Therefore, URS recommended a WHPmax of 2,478 psi. URS extrapolated for well IW2 using the FG of 0.972 psi/ft derived from IW1 to obtain a fracture pressure of 7,391 psi at 7,604 feet. Then applying 80 percent of that value yielded a BHPmax of 5,913 psi. URS measured 2,416 psi WHP at an injection rate of 6 BPM, with a 5,913 psi BHP during the February 10, 2009 well test at IW2. Based on this, URS recommended a WHPmax of 2,416 psi.

After deepening wells IW3 and IW4 in 2012, AMEC (2012a) presented additional MAIP calculations based on the previous step-rate data discussed above. AMEC noted that the measurement at IW1 was made with 3 percent potassium chloride water (8.5 pounds per gallon) in the hole. Therefore, the wellhead pressure will be somewhat higher for the PEC injectate, which is relatively fresh water (approximately 3,600 parts per million [ppm] of total dissolved solids [TDS]). Thus, using an estimate of 50 psi of friction, 5,800 psi of fracture BHP, and 0.98 specific gravity at 79.1 degrees Celsius (°C) for the injectate in the hole, the WHPmax at 7,460 feet for well IW1 is 2,681 psi instead of the 2,478 psi URS measured with 3 percent potassium chloride in the hole. This results in a difference of about 11 percent, with the selected WHPmax being the more conservative of the two values.

Well Deepening and Additional Testing in 2013

After wells IW3 and IW4 were deepened and recompleted in the Panoche Formation, new MAIPs were assigned for those wells (the previous MAIPs were based on the older conditions where the wells were completed in the shallower Moreno Formation). Immediately after submittal of the well deepening and recompletion report in 2012, PEC requested that the MAIP for IW1 (2,478 psi) be used for wells IW3 and IW4 (Haley & Aldrich, 2012) on the condition that the top of the perforation interval of IW3 and IW4 remains below the top of the IW1 injection zone (7,459 feet BKB). This request for updated MAIPs, which was conservative, was made because the plant needed to immediately operate wells IW3 and IW4 (Haley & Aldrich, 2012).

Later, PEC performed a fracture stimulation of IW3, which supplied new data to support higher MAIP in wells IW3 and IW4. These MAIP calculations for wells IW3 and IW4, presented in the IW3 Fracture Stimulation Report (Haley & Aldrich, 2013), were based on data from URS's SRT of well IW1 and from the FG determined during the fracture stimulation of IW3 (using the more conservative FG measured at the end of the Day 1). As described in Section 3.2 of the Fracture Stimulation Report (Haley & Aldrich, 2013), the initial FG measured at IW3 was calculated on Day 1 of the fracture stimulation to be 0.872 psi/ft. However, by the end of Day 1, it rose to 0.972 psi/ft and the FG rose still higher at the end of Day 2 to a value of 1.080 psi/ft. During the fracturing event, it was found that significant fracture development was only possible when the injection WHP reached above 5,500 psi, which is approximately 8,900 psi in terms of BHP (see Appendix C of the Fracture Stimulation Report). This pressure requirement is significantly larger than the estimated formation parting pressure (7,989 psi) based on the conservative FG of 0.972 psi/ft estimated by URS using the SRT for IW1 and as calculated for the top of the IW3 perforated interval (8,220 feet BKB). These findings indicate that the deeper Panoche Formation is more competent and resistant to hydraulic fracturing than initially modeled prior to stimulation.

Although higher MIAPs were calculated and presented in the IW3 and IW4 Well Deepening and Recompletion Report (AMEC, 2012) and after fracture stimulation (Haley & Aldrich, 2013), it is recognized that using the same MAIP value calculated for IW2 is conservative. Because the plant does not have the capacity to attain high pressures, and because the plant did not have the time to perform an SRT due to requirements for wastewater injection immediately after deepening these wells, a request for a high MAIP was not necessary at that time. The current MAIP for all four wells (as listed above) is requested to continue in this new permit application. If conditions change regarding plant requirements, new SRTs would be performed in new or current wells.

OTHER PHYSICAL, CHEMICAL, AND RADIOLOGICAL CHARACTERISTICS OF THE INJECTION MATRIX AND CONFINING INTERVALS

In Attachment F, cross sections A-A' and B'-B' (Figures F-5 and F-6) and isopach and structural maps (Figure F-7 and F-8) were presented to document the depth and thickness of the Panoche sandstone intervals (Sands 1 through 3) within the Area of Review (AOR). At PEC, well logs were presented in URS's IW1 and IW2 Completion Reports (URS, 2009a and URS, 2009b) and are included as Exhibits I-1 and I-2 in this report. Original logs for IW3 and IW4 are included in URS's IW3 and IW4 completion reports (URS, 2009c and 2009d) and in AMEC's Recompletion Report (AMEC, 2012) are included in Exhibits I-3 through I-5.

Sidewall core descriptions (from samples taken within the Panoche Formation in well IW2 generally consisted of an olive gray to gray fine-grained sandstone/siltstone, with 75 to 95 percent fine sand and up to 5 to 25 percent silt, fresh to slightly weathered, with weak cementation (URS, 2009b) and is presented in Exhibit I-2 in this report. Lithological descriptions by Core Laboratories of sidewall cores from the Panoche Formation in well IW3 indicate that the Panoche Formation predominantly consists of a gray fine to very fine-grained sandstone, having calcareous to slightly calcareous cementation, with no visible staining or fluorescence when exposed to ultraviolet light (AMEC, 2012). Additional point counting of five of these cores indicates that these sandstone beds are composed of either lithic arkose or feldspathic arenite. Core descriptions and select x-ray diffraction and thin section preparation and evaluation are presented in Appendix A-1 of the IW3 and IW4 completion report (AMEC, 2012) and are included in Exhibit I-6 in this report.

As reported in the IW3 and W4 completion report (AMEC, 2012), porosity measured from 13 Panoche Formation core samples collected during the deepening of IW3 ranged from 22.5 to 27.7 percent. Porosity estimates for the injection zone in well IW2 ranged from 13.1 percent to 24.0 percent with an average of 21.1 percent for sidewall core samples (URS, 2009b); see Exhibit I-2 for core evaluation report data. Core-derived permeability estimates for the injection zone in well IW3 ranged from 2.2 to 6.0 millidarcies (md) with an average permeability of 3.3 md (AMEC, 2012); see Exhibit I-6 in this report for source data reports. Permeability estimates for the injection zone in well IW2 ranged from 0.005 to 10.7 md with an average permeability of 6.34 md for sidewall core samples (URS, 2009b); see Exhibit I-2 in this report for core evaluation report data.

Flow capacity and a skin factor of the injection zone have been determined during numerous annual FOT in IW2 (which is representative of the Panoche injection zone). Results of these tests are presented as exhibits in Attachment P. For example, during the 2018 FOT evaluation (Haley & Aldrich, 2018) in Exhibit I-8 physical parameters, including the viscosity of the injectate (determined using Quarterly sampling data), porosity measured in core samples (as discussed above) and the formation fluid compressibility were used in these calculations. In addition, using this sodium chloride brine concentration of samples taken during the 2012 sidetrack operations at IW3 and IW4, of 11,642 ppm, the fluid compressibility at 174.4°F bottom-hole conditions is estimated to be 2.825E-6/psi (Earlougher, 1977). The rock compressibility from Halls correlation is estimated to be 3.381E-6/psi. Therefore, the total compressibility used in the FOT analysis in 2017 was 6.206E-6/psi.

For the upper confining interval, the Kreyenhagen, the permeability below the PEC was estimated to be 1 md based on the intrinsic permeabilities for clay, silt, sandy silts, and clayey sands, with an estimated hydraulic conductivity of 1.08 x 10-06 centimeters per second (Fettzer, 1994, p. 98). In a separate analysis conducted in Kings County, CA, Zodiac Exploration Inc. estimated that the Kreyenhagen shale exhibits a porosity averaging 5.7 percent and a permeability of .06 md (URS's Feasibility of Wastewater Disposal by Deep Injection Wells).

PANOCHE FORMATION CHEMICAL DATA AND SALINITY CALCUATIONS OF OTHER FORMATIONS

Formation fluid samples collected during the completion of IW1, IW2, and IW3 (URS, 2009a, b, and c; see Exhibits I-1, I-2, and I-3 for copies of these reports) are summarized in Table D-1 of Attachment D. The results for IW1 and IW2 indicate a TDS range of 34,800 to 112,000 milligrams per liter (mg/L) for the Panoche Formation injection interval with an average of 72,875 mg/L, with chloride being the dominant constituent. The results for IW3, which was completed in the Cima Sand of the Moreno Formation (top reported at 6,170 feet KB), indicate a TDS range of 14,000 to 18,600 mg/L with an average of 16,274 mg/L, with chloride being the dominant constituent. The analytical data used to prepare Table D-1 are contained in Exhibit D-1. Based on this information, all other strata below a depth of 6,170 feet KB are considered below the base of the underground source of drinking water (USDW) based on formation fluid samples.

A subset of these fluid samples was submitted for analytical laboratory testing using the following methods:

- TDS (Standard Method [SM] 2540C);
- Alkalinity (SM 2320B);
- Anions and Cations (USEPA Test Method 300.0);
- Hardness (SM 2340B - Inductively Coupled Plasma);
- pH (USEPA Test Method 150.1);
- Specific Conductance (SM 2510B);
- Specific Gravity of Liquids (ASTM International Standard D4052);
- Sulfide, Total (USEPA Test Method 376.1);
- Oil & Grease (USEPA Test Method 1664);
- Metals - Total with Turbidity < 1 Nephelometric Turbidity Unit (USEPA Test Method 200.7); and
- Surfactants (SM 5540C).

This direct TDS analysis of target injection formation water indicated that the injection zone is not an aquifer designated as a USDW. Additionally, fluid analysis was performed during the deepening of IW3 and IW4 (AMEC, 2012) to determine the chemical characteristics of formation fluid in these wells. The results of the analysis indicated TDS concentrations ranging from 11,000 to 12,000 mg/L in groundwater samples collected from the injection zone. Please note that these values are lower than initially measured in IW1 and IW2 because the Panoche Formation had been receiving relatively fresh wastewater (from injection into IW1 and IW2) for a few years prior to deepening of IW3 and IW4. The analytical laboratory data are summarized in Table 1 of AMEC's IW3 and IW4 Well Deepening Completion Report submitted to the USEPA in 2012 (see Exhibit I-5). Compatibility analysis of formation water and wastewater was preformed and reported in URS's Well Completion Report, UIC Well IW2 (URS, 2009b) in Exhibit I-2.

As discussed in Attachment D, previous information representing the base of the lowermost USDW occurred at a depth of 1,930 feet KB (URS, 2009a) based on log analysis (Figure D-9). However, the actual calculations and input data were generated by a previous consultant and could not be obtained. For this submittal, an analysis of the TDS content of the deep groundwater at IW1 was performed using the Schlumberger Platform Express log (run 2) over the interval from 1,630 to 4,942 feet KB and is included as Exhibit D-2. The logged interval includes the stratigraphic section above the marine Moreno Formation to the surface casing shoe for the well at 1,630 feet KB. The strata indicated in the log consists of interbedded clastics including (oldest to youngest) the Lodo Formation, the Domengine Formation, the Kreyenhagen Formation, the Tumey Formation, and basal undifferentiated nonmarine strata which correspond to the primary usable aquifer system in the regional study area. Based on the analysis performed for this submittal, PEC believes that the base of the lowermost USDW extends to the base of the sandy interval at the stratigraphic contact between the Kreyenhagen Shale and the overlying Tumey Formation at a depth of 3,430 feet KB in IW1. Below this depth, the Kreyenhagen Shale indicates low overall deep resistivity character and a general lack of "clean" sand. One sand in the Kreyenhagen, at a midpoint depth of 4,025 feet KB, indicated a minimum TDS of 16,076 mg/L based on the analysis (Table D-2). Spontaneous potential logs have shown that the Kreyenhagen Formation responds like a "baseline" shale, where a positive millivolt deflection by saline formations is observed in low-salinity drilling fluids (URS, 2006). This observation is characteristic of rocks that have negligible porosity and permeability, and in turn, rocks exhibiting this deflection have been interpreted as impermeable (URS, 2006). Below the Kreyenhagen Shale, all of the sands in the log appear thin and “dirty” and, additionally, no deep resistivity “spikes” are associated with any of the sands.

References

1. AMEC, 2012. Deepening and Recompletion of Wells IW3 and IW4, Class 1 Nonhazardous Waste Injection Wells UIC Permit No. CA10600001 Panoche Energy Center, LLC s Near Firebaugh, Fresno County, California.

2. Earlougher, R. C., 1977. Advances in Well Test Analysis, Monograph v. 5, H. L. Doherty Series, Society of Petroleum Engineers, Dallas, Texas.

3. Fettzer, C. W. Jr., 1994. Applied Hydrogeology, University of Wisconsin, Person publishing.

4. Haley & Aldrich, 2012. Post Webinar Memo Re: Deepening and Recompletion of Wells IW3 and IW4 Class 1 Nonhazardous Waste Injection Wells UIC Permit No. CA10600001 Panoche Energy Center, LLC.

5. Haley & Aldrich, 2013. IW3 Fracture Stimulation Report and Request to Operate Well IW3, Class 1 Nonhazardous Waste Injection Wells, UIC Permit Number CA10600001, Panoche Energy Center, LLC, Fresno County, California.

6. Haley & Aldrich, 2018. 2017 External Mechanical Integrity Testing and Pressure Fall-off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

7. URS Corporation (URS), 2006. Deep Well Feasibility Assessment. Appendix P in the Application for Certification submitted to the California Energy Commission. https://www.energy.ca.gov/sitingcases//panoche/documents/applicant/AFC_CD-ROM/Appendices/Appendix%20P.pdf

8. URS, 2009a. Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

9. URS, 2009b. Well Completion Report – UIC Well IW2, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

10. URS, 2009c. Well Completion Report – UIC Well IW3, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

11. URS, 2009d. Well Completion Report – UIC Well IW4, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

12. United States Environmental Protection Agency, 2009. Revised Maximum Allowed Injection Pressure and Rate, Panoche Energy Center IW1 and IW2, Underground Injection Control (UIC) Permit No. CA10600001, Panoche Energy Center, LLC.

EXHIBITS

(To be Submitted on CD)

ATTACHMENT J

Stimulation

Table of Contents

List of Exhibits

Exhibit No.	Title
J-1	Haley & Aldrich, Inc. (Haley & Aldrich). 2013. Request for Acid Stimulation of Wells IW1 and IW2, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. August.
J-2	Haley & Aldrich. 2014. Request for Acid Stimulation of Wells IW1 IW2, IW3, and IW4, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. February.
J-3	Haley & Aldrich. 2014. Second Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Fresno County, California. July.
J-4	Haley & Aldrich. 2014. Third Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.
J-5	Haley & Aldrich. 2014. Second 2014 Request for Acid Stimulation of Wells IW1 IW2, IW3, and IW4, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. June.
J-6	Haley & Aldrich. 2015. Third Quarter 2015 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.
J-7	Haley & Aldrich. 2016. Third Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California. October.
J-8	Haley & Aldrich. 2013. Addendum to Approved Contingency Plan for Post Fracture-Stimulation Well Development for IW3 via Nitrogen Lift and Acid Stimulation, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. September.
J-9	AMEC Geomatrix, Inc. (AMEC). 2011. Work Plan for Acid Stimulation, External Mechanical Integrity Testing and Pressure Fall-Off Testing, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. March.

J-10	AMEC. 2011. Acid Stimulation, Annual External Mechanical Integrity Testing and Pressure Fall-Off Testing Report, Panoche Energy Center, LLC, Firebaugh, Fresno County, California. June.
J-11	Haley & Aldrich. 2013. Schedule for Annual External Mechanical Integrity Testing of IW1 and IW2, Falloff Testing of IW2, and Coil Tubing Lift and Acid Stimulation of IW3 and IW4, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001. October.

ATTACHMENT J – STIMULATION

PERMIT APPLICATION REQUIREMENTS

As stated in United States Environmental Protection Agency (USEPA) Form 7520-6, Attachment J requires the applicant to "outline any proposed stimulation program."

REGULAR ACID STIMULATION

Panoche Energy Center (PEC) currently operates four Class I nonhazardous injection wells (IW1, IW2, IW3, and IW4) under USEPA Region 9 permit number CA10600001 (Permit). The Permit authorizes the injection of nonhazardous waste streams below underground sources of drinking water (USDWs) from various plant processes with cooling tower blowdown water comprising the majority of the injectate. The injectate is filtered to 10 microns prior to injection. However, historical observation has shown that occasional acid stimulations are advantageous in restoring injectivity lost over time due to normal operations.

Background

Based on numerous proposed and USEPA-approved acid stimulation treatments of PEC wells (AMEC Geomatrix, Inc. [AMEC], 2011a; AMEC, 2011b; Haley & Aldrich, 2013a, Haley & Aldrich, 2013b; Haley & Aldrich, 2013c; Haley & Aldrich, 2014a; Haley & Aldrich, 2014b; Haley & Aldrich, 2014c; Haley & Aldrich, 2014d; Haley & Aldrich, 2015; and Haley & Aldrich, 2016), this application proposes that the following program for regular stimulation treatment, including using hydrochloric acid (HCl) and a mixture of hydrofluoric (HF) and hydrochloric acid (mud acid) pumped in alternating stages, be authorized by permit. If approved, a 30-day notification would be submitted to USEPA prior to any treatment and will follow the outline procedures listed below.

The following shows the approximate total treatment volumes, pumped at a rate of approximately 84 gallons per minute (gpm), for each well stimulation:

- 4,000 gallons of 10 percent HCl;
- 4,000 gallons of 9 percent HCl/1 percent HF;
- 4,000 gallons of 10 percent HCl; and
- 7,000 gallons of wastewater flush.

A summary of the pumping schedule including pressures, rates and volumes for the acid treatments, and a narrative of site activities will be included in the next quarterly report following completion of stimulation. It is expected that, using the specific procedures listed below, regular acid stimulation of each well will improve injection rates immediately after stimulation.

Proposed Procedures

A general acid stimulation program for each well is outlined as follows:

Location Preparation, Mobilization, and Rig-Up

1. Deliver, connect, and plumb portable wastewater storage tanks (frac tanks), as necessary (number of tanks depends on service company displacement fluid and over-flush recommendation). Fill tanks with the required type and volume of displacement fluid. Shut-in all flowlines valves and the main valve on the wellhead in preparation for moving-in and rigging-up pumping truck and flowlines.
2. Adjust annulus pressure on well as needed to provide minimal pressure differential at the packer during stimulation pumping, and to maintain a positive annulus pressure. Note that annular pressure will be monitored continuously during all operations.
3. Once all personnel are on location, proceed to PEC for formal plant orientation. Return to work location for safety meeting performed by the stimulation service company prior to moving in and rigging up.
4. For a bullhead (to attach flow lines directly to wellhead and pump down well) acid job, mobilize acid pumping unit and acid transports and place on plastic sheeting. For a coiled tubing-type acid job, mobilize coiled tubing (CT) unit, in addition to acid pumping unit and acid transports. Pace all equipment on plastic sheeting.
5. Layout and manifold all suction lines to pumping unit. If using CT, layout flowline tubing iron from pumping unit to CT unit, apply recommended nozzle to CT per service company recommendation, and connect CT blowout preventer (BOP) to wellhead. If performing a bullhead acid job, layout of flow iron from pumping unit to wellhead and make necessary connections.
6. Layout and connect necessary monitoring equipment (consisting of tubing pressure/ temperature and annulus pressure/temperature transducers) to the wellhead. Initiate gauges and synchronize time.

Establishing Injection and Stimulation Program

1. Once all equipment is set-up, conduct a site operations meeting to discuss program implementation and safety.
2. Prime pumps: If using CT, fill reel and conduct a pressure test. If performing bullhead job, fill all lines and pressure test against service company valve. Bleed pressure and address any leaks prior to proceeding.
3. If using CT, open well and run in hole with pump on idle. Perform a weight check every 2,000 feet. If performing a bullhead job, open well and observe and record all pressures, temperatures, flow rates, and events.
4. If using CT, once treatment depth is achieved, begin pumping stimulation program using recommended stimulation fluids and recommended rates across the perforated (IW3 and IW4) or screened interval (IW1 and IW2). If performing a bullhead job, begin pumping recommended stimulation program fluids at recommended rates. Do not allow treating pressure to exceed the

specified Maximum Allowable Injection Pressure (MAIP) for each well. If bottom-hole pressure approaches MAIP (considering fluid gradient), decrease pumping rate. Note that surface treating pressure for CT will be higher due to small diameter tubing.

5. Regular treatment generally consists of 10 percent HCl with a low concentration of corrosion inhibitor, surfactant, penetrating agent, and iron control agent as recommended by the service company. This treatment is optionally supplemented with a mud acid treatment consisting of 9 percent HCl and 1 percent HF mixture. The mud acid typically includes low concentrations of corrosion inhibitor, surfactant, penetrating agent, and an iron control agent. The overall treatment typically consists of three acid stages (HCl, mud acid, and HCl) but may be varied depending on the service company recommendation.

   The volume of treatment will vary depending on the service company recommendation. The typical volume in a three-stage treatment like described above would be approximately 4,000 gallons of HCl solution followed by 4,000 gallons of HCl/HF mud acid, followed by 4,000 gallons of HCl.

6. Continue pumping recommended program until treatment is complete. Monitor and record pressures, temperatures, and rates throughout the stimulation program.

Post-Treatment and Rig-Down

1. Once the treatment is complete, pump the recommended type and volume of displacement fluid (to move all acid out of well casing and into the formation) per the service company recommendation. Continue monitoring and recording pressures, temperature, and rates during displacement.
2. Once displacement is complete, continue to pump an over-flush volume (to move all acid beyond the perforated or screened casing section) as recommended by the service company and/or company man. If using CT, continue to flush while pulling out of the hole. Continue monitoring and recording pressures, temperature, and rates during displacement.
3. Once over-flush is complete or CT is at the surface, close the well and discontinue data recording and monitoring. Note final events.
4. Move out equipment from location as necessary. Clean up location and remove plastic sheeting. Blowdown CT with nitrogen to frac tank if CT used for program.
5. Once all equipment is rigged down, open well and flow valves at wellhead and return well to plant service. Receive preliminary data report from service company and end job. Clean up and release ancillary equipment as needed.

ENHANCED PERMEABILTIY STIMULATION OF PROPOSED NEW WELLS IW5 AND IW6

Background

As discussed in Attachment L, currently only well IW3 has been fracture stimulated; however, improvement in injection rates have been minimal (see *IW3 Fracture Stimulation Report* [Haley & Aldrich, 2013b] for details). Based on the outcome of the fracture stimulation at IW3, PEC concluded that the effectiveness of the fracture stimulation was inhibited by the nature of the well completion, specifically the location of the perforations. Additionally, based on this experience it is believed that wells IW1 and IW2, which have screen and gravel pack type completions, would also be poor candidates for fracture stimulation. However, based on the proposed completions of undrilled IW5 and IW6, the following procedure has been prepared to maximize the potential for successful fracture stimulation of any new well drilled at PEC. In general, during the completion of IW-5 and IW-6, the perforations installed within the injection interval will be placed such that isolation of perforated intervals is more likely, thus increasing the chances for a better fracture stimulation.

Proposed Procedures

The general fracture stimulation program is outlined as follows.

1. Develop specific fracture stimulation program (frac program) to determine fluid and proppant volumes, pressures, rates, equipment, and logistics with the program's pumping service company (Services Co.) and hold pre-frac meeting at PEC location.
2. Clear location and provide necessary space for frac equipment and operation per Services Co. recommendation. Mobilize and position secondary containment lining, berms, and associated equipment such that fluid is not allowed to encounter the soil.
3. Mobilize tanks required to hold total volume specified in frac program. Verify that all outlet valves are functional and do not leak. Include sufficient capacity for 50-barrel (bbl) tank bottoms and 1 foot of headspace in tanks.
4. Mobilize and rig-up any required water transfer pumps, manifold(s), or other equipment as designated by Services Co. Field Supervisor or equivalent personnel. Fill frac tanks with base frac fluid.
5. Coordinate with Services Co. Field Supervisor or equivalent personnel to move in and position proppant delivery units as specified in frac program. Coordinate with Services Co. Field Supervisor or equivalent personnel to have proppant delivered and offloaded into appropriate compartments.
6. Set 7-1/16 inch, 5,000 pounds per square inch (psi) rated BOP with blind rams and pipe rams for 2-7/8-inch tubing. Move-in and rig-up a kill-truck (used to pump heavy brine into well to prevent the well flowing during installation) and test BOP to 5,000 psi as per BOP rental company procedure. Preform chart-recording pressure test.
7. Move-in and rig-up:
    - Flow-back tank and flow iron;
    - Frac equipment (pumps, flow iron, manifolds, etc.);
    - Wellhead isolation equipment; and
    - Wireline truck and perforating equipment.
8. Connect wellhead isolation tool (with frac head and wireline adapter) to 7-1/16-inch 5M BOP and sting into secondary seal in 11-inch 5M B-section of wellhead.
9. Batch mix frac fluids as specified in approved frac program.
10. Perform quality control testing of frac fluids, proppants, and chemical delivery systems.

11. Conduct Safety Meeting with all involved personnel, then pressure test all frac iron to 75 percent of internal yield pressure for 5-1/2-inch 17# L-80 casing (approximately 5,800 psi). Set automatic frac pump kills to this value and function-test automatic frac pump kills.
12. Install pressure transducer on 5-1/2-inch tubing and 7-5/8-inch casing annulus. Apply 1,000 psi pressure to annulus. Monitor annulus pressure during frac job.
13. Route frac pressure bleed off line to flow-back tank.
14. Pump frac stage as per Services Co. pump schedule and shut down. Record Instantaneous Shut-in Pressure and monitor pressure decline for 15 minutes.
15. Shut-in master valve at wellhead isolation tool and bleed off residual pressure on frac iron.
16. Rig-up wireline with full lubricator, run in hole with composite bridge plug and perforation guns. Perforate casing at predetermined depths. Perforation intervals, shot density, and phasing to be determined from open-hole logs and approved by PEC. Pull out of hole with wireline tools.
17. Repeat steps 14 through 16 for as many frac stages as designated in frac program.
18. At completion of frac job, shut in master valve at wellhead isolation tool and bleed pressure off frac iron.
19. Equalize pressure on wellhead isolation tool, sting out of casing and fully retract pack-off tool. Close blind rams on BOP and rig-down wellhead isolation tool and equipment. Move out wellhead isolation tool and equipment.
20. Evacuate tank manifold(s), surface tubulars, and any spillage within secondary containment with a vacuum truck. Transfer fluid from frac tank bottoms to frac tanks used for drill-out operation. Haul off remaining proppant and frac fluid.
21. Rig-down and move out wireline truck and equipment.
22. Rig-down and move out frac equipment.
23. Move out frac tanks not required for drill out. Clean up location and prepare for drill out operation associated with the drilling and completion of the new well (see Attachment L for drilling procedures).

References

1. AMEC Geomatrix, Inc. (AMEC). 2011a. Work Plan for Acid Stimulation, External Mechanical Integrity Testing, and Pressure Fall-Off Testing, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

2. AMEC. 2011b. Acid Stimulation, Annual External Mechanical Integrity Testing and Pressure Fall-Off Testing Report, Panoche Energy Center, LLC, Firebaugh, Fresno County, California.

3. Haley & Aldrich, Inc. (Haley & Aldrich). 2013a. Request for Acid Stimulation of Wells IW1 and IW2, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

4. Haley & Aldrich. 2013b. Addendum to Perform Nitrogen Lift and Coil Tubing Acid Stimulation of IW3 (and IW4), Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

5. Haley & Aldrich. 2013c. Schedule for Annual External Mechanical Integrity Testing of IW1 and IW2, Falloff Testing of IW2, and Coil Tubing Lift and Acid Stimulation of IW3 and IW4, EPA UIC Permit No. CA10600001, Panoche Energy Center, Firebaugh, California.

6. Haley & Aldrich. 2014a. Request for Acid Stimulation of Wells IW1, IW2, IW3, and IW4, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

7. Haley & Aldrich. 2014b. Second Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

8. Haley & Aldrich. 2014c. Second 2014 Request for Acid Stimulation of Wells IW1, IW2, IW3, and IW4, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

9. Haley & Aldrich. 2014d. Third Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

10. Haley & Aldrich. 2015. 3Q2015 Injection Monitoring Report, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

11. Haley & Aldrich. 2016. 3Q2016 Injection Monitoring Report, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

EXHIBITS

(To be Submitted on CD)

ATTACHMENT K

Injection Procedures

Table of Contents

List of Figures

List of Exhibits

ATTACHMENT K – INJECTION PROCEDURES

PERMIT APPLICATION REQUIREMENTS

As stated in United States Environmental Protection Agency (USEPA) Form 7520-6, Attachment K requires the applicant to submit "information regarding the surface equipment associated with the injection wells (i.e., holding tanks, flow lines, filters, and injection pumps)."

WATER USE AND WASTEWATER GENERATION

Figure K-1 shows the plant layout and Figures K-2 and K-3 show the water use and wastewater generation at the Panoche Energy Center (PEC). Also listed on these figures and referenced in the following text in parentheses are Piping and Instrumentation Diagram (P&ID) numbers that reference specific equipment installed at PEC.

With the exception of limited quantities of vendor-supplied drinking water (bottled water), all water utilized at PEC is supplied by two on-site groundwater wells (Owner's Well number PEC-1 and PEC-2 and named P-RW-001A and P-RW-001B, internally with P&IDs, respectively) permitted through the Fresno County Department of Community Health. Groundwater produced by the two wells is stored in the 500,000-gallon service water tank (TK-SW-001). Service water is supplied untreated from the service water tank to a number of plant systems or treated as required for certain applications. Water usage at the PEC includes the following systems:

- Untreated Service Water:
  - Cooling tower and circulating water system;
  - Fire water system;
  - Water treatment system; and
  - Potable water system.
- Demineralized Water:
  - Combustion turbine nitrogen oxide (NOx) water system;
  - Combustion turbine evaporative cooler systems;
  - Combustion turbine water wash system; and
  - Potable water system.

Figure K-1 is an overview schematic showing all water uses, wastewater sources, and wastewater disposal systems at the facility. Each of these elements of the water system will be discussed in further detail below.

Cooling Tower and Circulating Water System

The combustion turbine intercooler and various auxiliary lubricating systems require cooling water which is supplied by the circulating water system. Cool circulating water is supplied to online combustion turbines by the circulating water pumps and returned warm to the Cooling Tower. Heat is removed from the warmed circulating water in the cooling tower through evaporative cooling.

When in service, water is continually lost from the cooling tower through drift and evaporation. To maintain optimal total dissolved solids concentration, a fraction of the cooling tower water is blown down (removed) and pumped to the 500,000-gallon blowdown collection tank (TK-EWS-01-1-1). Water in the blowdown collection tank is sent either to the enhanced wastewater system (EWS) for treatment and reclamation as cooling tower make-up water, or to the 500,000-gallon wastewater collection tank (TK-EWS-03-1-1) for disposal via the wastewater injection well system. Make-up water is supplied to the cooling tower from both the service water tank (TK-SW-001) and permeate collection tank (T-EWS-02-1-1). Both untreated service water and reclaimed water from the EWS are utilized for cooling tower make-up water.

Various water treatment chemicals and products are added to the cooling tower to control pH, scale formation, minimize corrosion of circulating system components, and prevent microbial growth and foam formation. In compliance with the facility's Title V Air Permit, chromium-containing water treatment products have never been used at the facility and will not be used in the future.

Sulfuric acid is fed into the cooling tower as required for pH control and alkalinity reduction to control scale formation. The acid feed equipment consists of a bulk sulfuric acid storage tank, two full-capacity sulfuric acid metering pumps, and piping.

To control biofouling, sodium hypochlorite is added to the cooling tower as needed to maintain the total residual chlorine level between 0.2 and 0.7 parts per million (ppm). The sodium hypochlorite feed equipment consists of a bulk storage tank, two full-capacity metering pumps, and piping. In addition to routine use of sodium hypochlorite, sodium bromide and non-oxidizing bio-fouling control products are also used as needed. As with sodium hypochlorite, the feed systems for the sodium bromide and non-oxidizing microbial control products each consist of a tank and two metering pumps. Corrosion inhibitors are added to protect mild steel and yellow metal circulating water system components.

Fire Water System

At the heart of the facility's water-based fire protection system are the electric fire pump and emergency back-up diesel fire pump. Both of these pumps take suction from the 500,000-gallon service water tank (TK-SW-001). Fire hydrants are arranged throughout the facility in a closed loop with fire water constantly circulating back to the service water tank. No wastewater is generated by the fire water system.

Water Treatment System

High-purity, low-conductivity water is required by the combustion turbine evaporative coolers and NOx water injection systems. This high-purity water is produced onsite by the water treatment system. Untreated water from the service water tank is pumped by the ultra-filter feed pumps through a bank of ultra-filters (Ultra-filter Skid), with the filtrate collected in the UF filtrate storage tank (TK-SWT-001). The ultra-filters are routinely backwashed with the backwash collected in the UF backwash break tank (TK-SWT-002), which is then pumped to the oil-water separator and from there to the 500,000-gallon wastewater collection tank (T-EWS-03-1-1).

From the UF filtrate storage tank, the filtrate is pumped first through one of the reverse osmosis (RO) first pass trains (A or B) and then through one of the second pass trains (A or B) where impurities are removed. The UF filtrate is filtered through a 5-micron filter (either FL-DWT-001A or FL-DWT-001B) prior to entering the RO system. The RO permeate is collected and stored in the 240,000-gallon demineralized water tank (TK-DW-001). RO reject water is pumped to the 500,000-gallon wastewater collection tank (T-EWS-03-1-1).

A number of water treatment chemicals are added to the RO system to prevent formation of scale and deposits and protect the RO membranes. Sodium bisulfite (SBS) is added to the suction of the RO first pass booster pumps (pumps P-DWT-001A and P-DWT-001B) to dechlorinate the filtrate water to protect the RO membranes. Anti-scalant is also added to the suction of the RO first pass booster pumps to prevent scale formation within the RO system.

Periodic cleaning of the ultra-filters is necessary to maintain throughput. These cleanings involve first injecting a low pH cleaner (e.g., citric acid, sulfuric acid, etc.) and allowing to soak for a predetermined time, followed by injection of a biocide (e.g., sodium hypochlorite at 12.5 percent) and again allowing to soak. Once the soak cycle has been completed, the wastewater is pumped to the UF backwash break tank (TK-SWT-002) and from there to the 500,000-gallon wastewater collection tank (T-EWS-03-1-1).

Likewise, the RO first (A or B) and RO second pass trains require periodic cleaning to maintain optimal RO permeate generation rates. The RO trains are cleaned using the Clean-in-Place system and an appropriate RO cleaner. Wastewater from the RO Clean-in-Place system is pumped to the 20,000-gallon wastewater collection tank (TK-WD-001) for disposal by injection.

Potable Water System

The potable water system produces a 50:50 chlorinated blend of demineralized water and service water which supplies the facility’s kitchen, restrooms, and emergency safety shower and eyewash stations. Domestic wastewater from the kitchen and restrooms is sent to the on-site septic tank and leach field for treatment.

Combustion Turbine NOx Water System

High-purity water generated in the water treatment system and stored in the demineralized water tank (TK-DW-001) is injected into the combustion chamber of the turbines to reduce ignition temperatures and thus NOx emissions. Essentially all of this water is exhausted. Occasional small NOx water system leaks may develop which are diverted by the combustion turbine package drains to the oil-water separator. The oil-water separator in turn discharges to the wastewater collection tank (TK-EWS-03-1-1).

Combustion Turbine Evaporative Cooling System

At the air inlet of each combustion turbine is an evaporative cooling system designed to lower the inlet air temperature thus improving power generation efficiency. A blend of demineralized water and untreated service water is pumped to the evaporative cooling system sump. From the sump, the water is pumped up to a header which distributes flow across the face of a wetted water baffle. As inlet air is drawn through the wetted baffle, it is cooled due to evaporative cooling. To maintain the quality of the circulated water, a portion is continually blown down (removed). The evaporator blowdown is normally directed to the condensate recovery tank, though it can also be directed to the oil-water separator. The condensate recovery tank is pumped to the cooling tower while the oil-water separator is pumped to the 20,000-gallon wastewater collection tank (TK-WD-001). Makeup water replaces losses due to evaporation and blowdown.

Intercooler

The intercooler is a heat exchanger that removes heat from the inlet air following compression in the low-pressure compressor section of the LMS-100. Cool circulating water is pumped from the cooling tower to the intercooler, where heat is transferred from the air to the circulating water. The warmed circulating water is returned to the cooling tower. Condensate from the cooled air is drained to the condensate recovery tank, which is normally pumped to the cooling tower but can also be directed to the oil-water separator.

Combustion Turbine Water Wash

Deposit formations within the combustion turbines are periodically removed by either on-line or off-line water washes. The water wash system, located within each turbine's auxiliary skid, consists of a 50-gallon tank, pump, and tank heaters. A surfactant is diluted with demineralized water in the tank. With an on-line water wash, no wastewater is generated as all wash water is evaporated and exhausted out of the engine. Non-hazardous wastewater generated with off-line water washes is directed to the respective engine's combustion turbine drain tank from which it is disposed of offsite at an approved facility.

WASTEWATER SYSTEM COLLECTION AND TREATMENT SYSTEM

With the exception of domestic wastewater and turbine wash water (which is disposed of at a permitted off-site disposal facility), all non-hazardous wastewater generated at the facility is disposed of onsite by deep-well injection in conformance with the facility's Underground Injection Control (UIC) Permit. As stated previously, domestic wastewater is directed to the on-site septic system while non-hazardous turbine wash water is removed for disposal offsite at an approved disposal facility.

The wastewater system collects cooling tower blowdown, RO system rejects, evaporative cooler blowdown, intercooler condensate, and water from the water treatment building and combustion turbine drains. The wastewater system includes the following systems and components:

- Oil-water separator;
- Wastewater storage tanks; and
- Enhanced wastewater system.

The individual wastewater subsystems are discussed in further detail below.

Oil-Water Separator

The oil-water separator is an underground, double-walled, flow-through process vessel designed to remove free oils and grease to better than 10 ppm. The oil-water separator receives effluent from the following wastewater sources:

- Water treatment building drains;
- Combustion turbine package drains; and
- Occasionally, evaporative cooler blowdown and intercooler condensate.

Effluent from the oil-water separator is pumped to the wastewater collection tank (TK-WD-001).

Wastewater Storage Tanks

The EWS project included construction of three new above-ground water storage tanks: the 500,000-gallon blowdown collection tank (T-EWS-01-1-1), the 500,000-gallon wastewater collection tank (T-EWS-03-1-1), the permeate collection tank (T-EWS-02-1-1), and a number of other smaller process storage tanks.

The blowdown collection tank receives RO reject from the water treatment system and blowdown from the cooling tower. From the blowdown collection tank, water is transferred to the EWS for processing and recovery of water for use as cooling tower blowdown.

Permeate water from the EWS is stored in the permeate collection tank, from which it is pumped as needed to the cooling tower as make-up water.

The wastewater collection tank can receive water from the EWS (RO reject) and also directly from the blowdown collection tank, bypassing the EWS. Two redundant feed pumps pump wastewater from the wastewater collection tank to the 20,000-gallon wastewater tank (TK-WD-001), which feeds the wastewater injection system. The 20,000-gallon wastewater tank predates the EWS and was the only wastewater storage tank when the facility was initially constructed.

Enhanced Wastewater System

The lower-than-anticipated performance of the injection system, as compared to the original design requirements for disposal of approximately 500 gallons per minute by the well field, presented a significant challenge to the operation of the facility prior to 2015. The reason for the poor performance is primarily due to low permeability of the injection zone rock (Panoche Formation). Core-derived permeability estimates for the injection zone in well IW3 ranged from 2.2 to 6.0 millidarcies (md), with an average permeability of 3.3 md (AMEC, 2012). Permeability estimates for the injection zone in well IW1 ranged from 0.005 to 10.7 md with an average permeability of 6.34 md for sidewall core samples from comparable depths in well IW2 (URS, 2009a). Therefore, the EWS was designed to process cooling tower blowdown and RO reject with the goal of recovering re-useable water for use as circulating cooling water to reduce the amount of wastewater destined for disposal by underground injection.

The following is a summary of the permitting and construction milestones for the EWS. On 13 October 2014, Sage Environmental Consulting filed a Petition to Amend (2014 PTA) the California Energy Commission's (CEC) 19 December 2007, Final Decision approving the Application for Certification for the PEC. The 2014 PTA proposed construction of an EWS consisting of three new water storage tanks and a new standby wastewater treatment facility, designed to provide greater flexibility and control of wastewater injection. On 11 March 2015, the CEC approved the 2014 PTA. Construction of the EWS commenced in August 2015 and by the end of June 2016 was functionally complete; the EWS has been operating as designed since the third quarter of 2016.

As approved by the CEC, the EWS consists of the following systems and components:

- Wastewater treatment system;
- Blowdown collection tank (T-EWS-01-1-1);
- Permeate water collection tank (T-EWS-02-1-1); and
- Wastewater collection tank (T-EWS-03-1-1).

The EWS was commissioned in mid-2016. At that time, an Injectate Hazardous Waste Determination was performed in accordance with Condition II.C.(b) of UIC Permit 10600001. This Hazardous Waste Determination, along with a description of the newly completed EWS process, was previously submitted to the USEPA in the 3rd Quarter 2016 Monitoring Report (Haley & Aldrich, 2016).

The EWS removes silica, hardness, metals, and salts by employing chemical pretreatment, microfiltration solid/liquid separation, RO water purification, and solid dewatering processes. The following is a brief outline of the EWS water treatment process (see Figure K-2 for a schematic of the EWS water treatment system):

1. Blowdown from the cooling tower and RO reject from the water treatment system is collected in the newly constructed blowdown collection tank (T-EWS-01-1-1).
2. Blended blowdown and RO reject water is transferred from the blowdown collection tank to a two-stage chemical pretreatment system for precipitation of silica, hardness, and residual metals. Conversion of soluble silica, hardness, and metals to an insoluble state takes place in this system by the addition of magnesium oxide, ferric coagulant (ferric chloride), and pH adjustment with sodium hydroxide.
3. The pretreated water then flows to a concentration tank.
4. Pretreated water is then pumped to a membrane microfiltration system for removal of precipitated contaminants and suspended solids.
5. The microfilter filtrate is then pumped to an RO pretreatment tank where the pH is adjusted to near neutral. Small doses of anti-scalant are added at this stage. SBS is also added to neutralize oxidizers present in the filtrate water.
6. Microfilter filtrate is then pumped to the RO water purification system for removal of water-soluble salts and other dissolved contaminants.
7. RO permeate is pumped to the 250,000-gallon permeate collection tank (T-EWS-02-1-1) from which it is then pumped to the cooling tower as useable make-up water.
8. RO reject is pumped to the 500,000-gallon wastewater collection tank (T-EWS-03-1-1) for eventual disposal by deep-well injection.
9. Filtered solids are periodically removed from the microfiltration system to a slurry collection tank. Slurry is pumped from the slurry collection tank to a filter press for further solids concentration and dewatering. The non-hazardous dewatered filter press cake is collected in a roll-off bin and disposed of offsite at an approved disposal facility.
10. The microfiltration and RO membranes require periodic chemical cleaning to restore flow. Chemical cleanings are performed with sulfuric acid, hydrochloric acid, and sodium hydroxide solutions. Spent cleaning solutions are reprocessed by reincorporating the into the water treatment process.

Wastewater Injection System Configuration and Operation

The purpose of the wastewater injection system is to treat and dispose of, by underground injection, the various wastewater effluents directed to the wastewater tank (TK-WD-001) at the facility.

The wastewater injection system consists of the following subsystems, components, and processes (see Figure K-3 for a schematic of the water injection system):

- Charge pump skid;
- Back end filters;
- Wastewater injection pumps;
- Piping and instrumentation;
- Injection wells; and
- Monitoring equipment (temperature, pressure, flow, and pH conductivity).

Wastewater injection flow, pressure, and temperature are monitored using the PEC Emerson Ovation Distributed Control System (see Attachment P for details on the monitoring program). In addition, this information is archived by the plant. These measurements are made downstream of the injection pumps, before the injection piping goes underground. The instruments used in the continuous monitoring injection rate, well head pressure, flow volume, and injection fluid temperature are located on each individual flow line. Annulus pressure is measured at the wellhead. This equipment is calibrated on a regular schedule as required by the manufacturer.

Detailed information regarding the surface equipment associated with the injection wells (i.e., holding tanks, flow lines, filters, and injection pumps) can be reviewed in the Well Completion Report – UIC Well IW4 (URS, 2009b) submitted to the USEPA in early 2009.

Description and Operation

Though not necessarily a component of the wastewater injection system, the 20,000-gallon wastewater tank (TK-WD-001) is a good starting point for discussing the wastewater injection system because all wastewater to be disposed of by underground injection is directed to this tank, and the injection well charge pumps take suction from this tank. As a reminder, the wastewater tank receives effluent from the oil-water separator and 500,000-gallon wastewater collection tank (T-EWS-03-1-1).

Two wastewater injection charge pumps (P-WD-002A and P-WD-002B) take suction from the wastewater tank and serve the dual purpose of pumping wastewater through a series of particulate filters and providing suction pressure to the two down-stream high pressure wastewater injection pumps (P-WD-003A and P-WD-003B). Each wastewater injection charge pump is a vertical in-line centrifugal type pump with a 460-volt AC induction motor.

From the wastewater injection charge pumps, wastewater is passed through one or both of two 20-micron charge pump discharge filters (FL-WD-001A and FL-WD-001B) plumbed in series. Filtrate from the 20-micron charge pump discharge filters is then passed through one or both of two banks of particle filters (back end filters). Each back-end filter bank consists of four filter vessels plumbed in series. The four vessels contain filter media of diminishing pore size with the first, second, third, and fourth filter vessels containing 5-micron, 1-micron, 0.5-micron nominal, and 0.5-micron absolute filter elements respectively. The two high-pressure wastewater injection well pumps take suction from a header connecting the two banks of back end filters.

The wastewater injection pumps (P-WD-003A and P-WD-003B) are horizontal, multistage, centrifugal pumps with a 4,160-volt AC induction driven motor and provide injection pressure of up to approximately 1,950 pounds per square inch (psi); injection pressure is limited by the capability of the injection pumps. A wastewater recirculation valve provides a water path if the injection well(s) are not accepting the minimum amount of water required to prevent water hammer (pressure surge caused by fluid momentum change) and wastewater injection pump overheating. As currently constructed, wastewater injection pump A (P-WD-003A) services existing well IW2 with a tie-in point for a potential future injection well IW5. Wastewater injection pump B (P-WD-003B) services existing wells IW1, IW3, and IW4 with a tie-in for a potential future injection well IW6. The injection wells are typically operated only when the plant is running. If necessary due to excessive generation of water, the wells are also operated when the power plant is not operating, but, the parasitic electrical load is not desirable.

Injection flow to each injection wellhead is controlled separately by flow control valves FCV-96191, FCV-96181, FCV-96193, and FCV-96184 located downstream of the wastewater injection pumps. Immediately downstream of each flow control valve are wastewater motor control block valves YV-96192, YV-96182, YV-96193, and YV-96184 that provide positive shutoff for the flow control valves.

Operation of the injection wells is performed in accordance with Operating Procedure OP-701: *Wastewater System* (internal document available upon request). OP-701 defines responsibilities and provides pre-operational checks and operating procedures for system startup, normal operation, and shutdown. In addition, OP-701 contains a pre-start valve line-up checklist and a pre-start electrical controls line-up checklist, and instructions to follow all USEPA-approved Maximum Allowable Injection Pressures.

Annular Pressure Equalization System

During the period immediately following shut-in of the wells, the annular pressure in the wells is frequently below 100 psi initially, then rises a few hours later when the annulus fluids heat up, and then slowly continues to rise during periods of non-injection. As the annulus fluid temperature rises, so does the annulus pressure. The pressure changes are cyclic and predictable. The inverse relationship between annular pressures and injection rates indicates that the increases in annular pressures are due to slow heating of the annular fluids during periods of non-injection and do not indicate a lack of physical integrity in any of the well seals.

Pressure in the annuli is maintained at or above 100 psi above injection tubing pressure during shut-in. Automated annulus pressure equalization systems have been installed on wells IW3 and IW4, while annulus pressure control has been manual on wells IW1 and IW2. However, two new automated annulus pressure equalization systems have now been purchased and are in the process of being installed and commissioned. These systems reduce the potential for damage to the packer or wellhead caused by large differences in pressure between the annulus and the injection tubing during numerous intermittent injection operations.

Automated annulus pressure equalization systems were successfully operated on well IW3 and IW4 during various periods in 2014 through 2016 (see Haley & Aldrich [2014] for design details). In early 2017, the IW3 location was prepared for installation of a newly purchased system and the previous system removed from IW3 was positioned for service at IW2. Also, a second newly purchased annular pressurization system was installed at IW1. Thus, automated annulus pressure equalization skids on

IW1, IW2, and IW3 have been installed and commissioned and, after additional minor modifications were made to these systems, all four systems have been operational at each well in 2018.

Wastewater Pretreatment

Prior to injection, the wastewater is filtered and chemically treated to minimize potential deposit formation and plugging within the injection formation and to protect the injection well tubing from corrosion (see Figure K-3 for wastewater system filters and pre-treatment chemical injection locations).

Chemical Pre-Treatment

Sulfuric acid, sodium hypochlorite, and SBS are added to the 20,000-gallon wastewater tank's (TK-WD-001) recirculation loop to pretreat the wastewater prior to injection. The sulfuric acid provides optimal pH control between 6.5 and 6.9. The sulfuric acid feed pump shuts off automatically at pH 6.5.

Sodium hypochlorite is added to control wastewater bio-fouling within the wastewater tank. SBS is a strong reducing agent that is added in liquid form to the wastewater prior to injection. SBS scavenges oxygen in the wastewater, converting the bisulfite to sulfate. Liquid SBS is added via an injection pump located upstream from the injection pumps.

When injecting, scale inhibitor and corrosion inhibitor are injected at a fixed rate to the suction side of the wastewater injection charge pumps to minimize scale and deposit formation within the injection formation and to protect the injection well tubing from corrosion.

Physical Filtration

As discussed previously, the wastewater is filtered prior to injection to remove suspended solids and prevent plugging of the injection formation. From the wastewater tank (TK-WD-001), the wastewater is first filtered through one or both of the 20-micron charge pump discharge filters (FL-WD-001A and FL-WD-001B) and is then introduced to the back-end filters.

The back-end filters are arranged in two parallel banks of four filter vessels. The four vessels contain filter media of diminishing pore size with the first, second, third, and fourth filter vessels containing 5-micron, 1-micron, 0.5-micron (nominal), and 0.5-micron (absolute) filter elements, respectively. Thus, prior to injection, the wastewater is passed through a series of filters with the last passing only particles of 0.5 micron in diameter (absolute) or smaller.

The performance and maintenance of the filtration system currently relies on monitoring differential pressure through the pressure gauges on individual filter units. The trends of pressure buildup are used to monitor the status of a filter and can allow for detection of abnormal pressure trends, which may be indicative of filter plugging or flow bypassing.

Periodic Backflowing of Wells

Because the wells are under artesian conditions, opening the valve at the wellhead will allow water from the injection interval to flow back up and out of the wells. This reversal of flow is used to periodically remove sediment, particulate matter, and scaling that reduce injection rates over time. The flowback water is captured at the surface and filtered to remove particulate matter before reinjecting back down the well.

Permanent back-flushing equipment will potentially be installed in the future. To date, all back-flushing operations have been performed using one to two rented fractionation tanks (frac tank) temporarily brought on site and attached to the well head with a fire hose.

With the frac tank attached to an injection well side flange, the well master valve is opened and water begins to flow from the well into the frac tank. The total volume of water discharged from each well will be recorded by measuring the initial water level in the frac tanks prior to flowback and using the volume conversion table attached to each tank to calculate the volume of water discharged from the well. Samples of the settled material removed with the flowback water are saved in plastic bags for examination.

Periodic back-flushing is performed in accordance with the most recent version of Operating Procedure OP-701.1: *Wastewater Injection Well Backflush Procedure* (internal document available upon request). The following is the current PEC Standard Operating Procedure for back-flushing:

1. Ensure the PEC's Operations Manager has authorized the backflow of the selected injection well to be back-flowed.
2. At the selected injection well, ensure the well head valves are closed before installing the backflow fittings and that the well is placed under Lock-Out-Tag-Out (LOTO) protocol. Before removing the plug from the well head, stand to the side and slowly remove the plug in case there is leak-by.

   Install the backflow fittings to the well head and connect the hoses from the selected well to the east or west well settling tanks. Ensure the settling tanks have enough room to back flow approximately 20,000 gallons of water.

   <u>NOTE:</u> Ensure the hoses do not have any kinks or blockages. When you first release the pressure from the injection well, it will be at a very high pressure (the initial well pressure could be 500 to 1,900 psi).

   <u>NOTE:</u> If hoses are kinked or blocked, take the necessary steps to correct the issue before proceeding forward. Record the well settling tank levels and the start time of the well back flow.
3. Slowly crack open the 2-inch well head valve. Do not open the valve more than one-quarter of the way open to prevent over pressurizing the hoses.
4. Open the large well head valve fully open.
5. Monitor the well head pressure.
6. When the well head pressure has decreased to around 1,000 psi, slowly open the 2-inch well head valve to one-half of the way open and continue to monitor the well head pressure.
7. When the well head pressure has decreased to around 500 psi, slowly open the 2-inch well head valve to three-quarters of the way open and continue to monitor well head pressure.
8. When the well head pressure has decreased to around 150 psi, slowly open the 2-inch well head valve to fully open. The time from closed to fully open is normally 10 to 15 minutes.

9. Periodically monitor the hoses and tank levels.

   NOTE: The well settling tanks do not have a high-level alarm and could overflow if the tank level is not properly monitored.

10. Every 45 minutes record the time, tank levels, and water clarity from the sample port at the well settling tank. Record the nature of any sediment such as fine sand, black flakes, etc.
11. Remove approximately 18,900 gallons (450 barrels) of backflow water from the injection well. Ensure the water clarity is clear. (More water may need to be removed from the injection well to get to the point where the clarity is clear).
12. When the water clarity is clear and at least 18,900 gallons of backflow water has been removed from the well, the backflow procedure is completed.
13. Once enough water has been removed from the injection well, slowly close the 2-inch valve on the well head completely.
14. Close the large well head valve completely.
15. Ensure that all valves on the injection well head are closed prior to removing any fittings or hoses.
16. Remove the hoses from the backflow fittings at the well head.
17. At the well head, remove the backflow fittings from the well head as required.
18. At the well head, be sure to reinstall the plug for the opening that was used to backflow the injection well.
19. Remove the LOTO for the injection well. Ensure all hoses are moved out of the way from the injection well to well settling tanks.

References

1. AMEC. 2012. Deepening and Recompletion of Wells IW3 and IW4, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

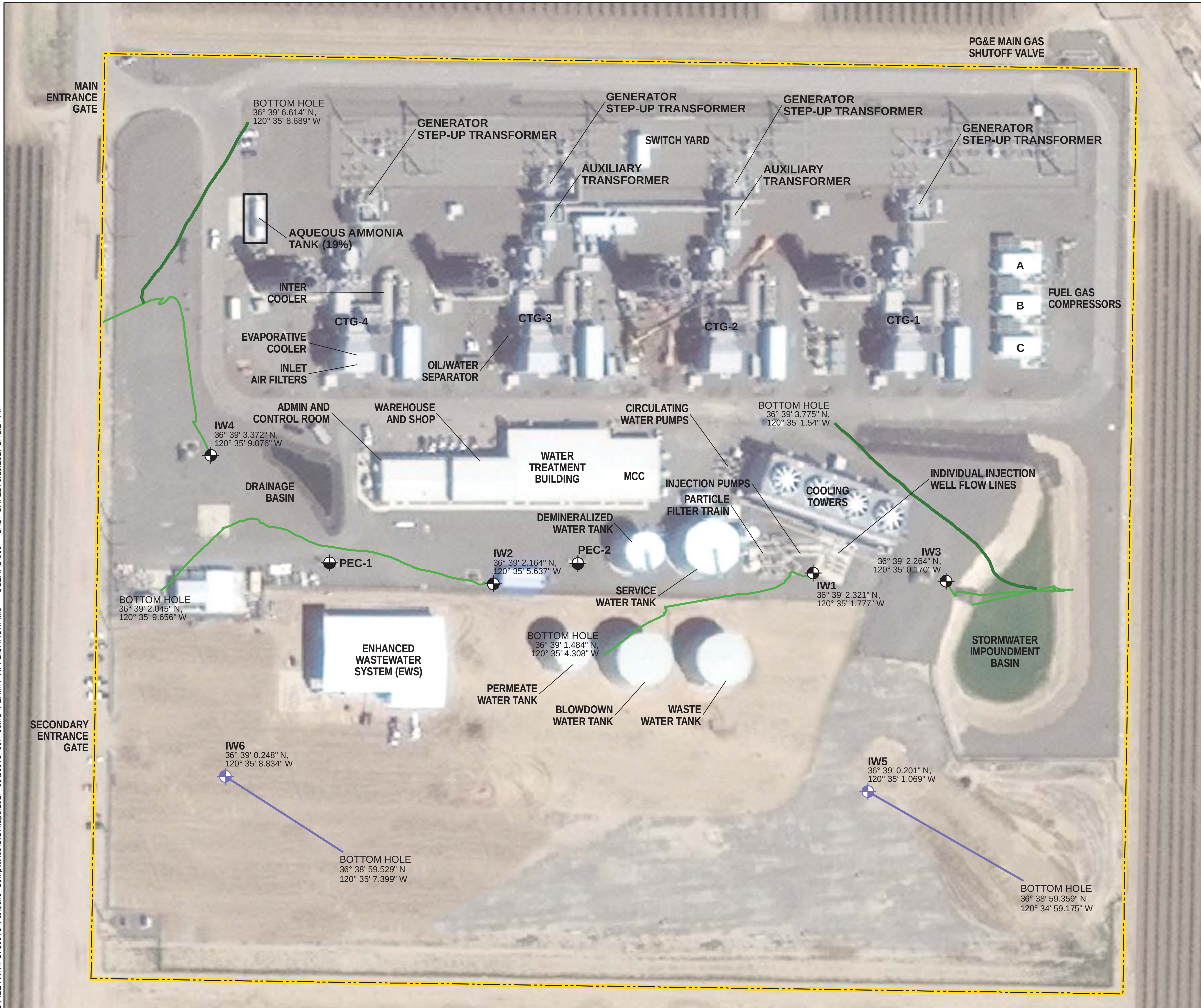
2. Haley & Aldrich, Inc. (Haley & Aldrich). 2014. First Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California, April.

3. Haley & Aldrich. 2016. Third Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

4. URS. 2009a. Well Completion Report – UIC Well IW3, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

5. URS, 2009b. Well Completion Report – UIC Well IW4, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

FIGURES



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LEGEND

- INJECTION WELL
- SUPPLY WELL
- PROPOSED WELL LOCATION
- ORIGINAL WELL PATH
- DEEPENED WELL PATH
- PROPOSED WELL PATH
- SITE BOUNDARY

NOTES

1. ALL LOCATIONS AND DIMENSIONS ARE APPROXIMATE.
2. AERIAL DATA SOURCE: TERRASERVER, MULTISPECTRAL, 1-METER RESOLUTION, 18 APRIL 2016, MODIFIED TO REFLECT EXISTING CONDITIONS

N

0 100 200

SCALE IN FEET

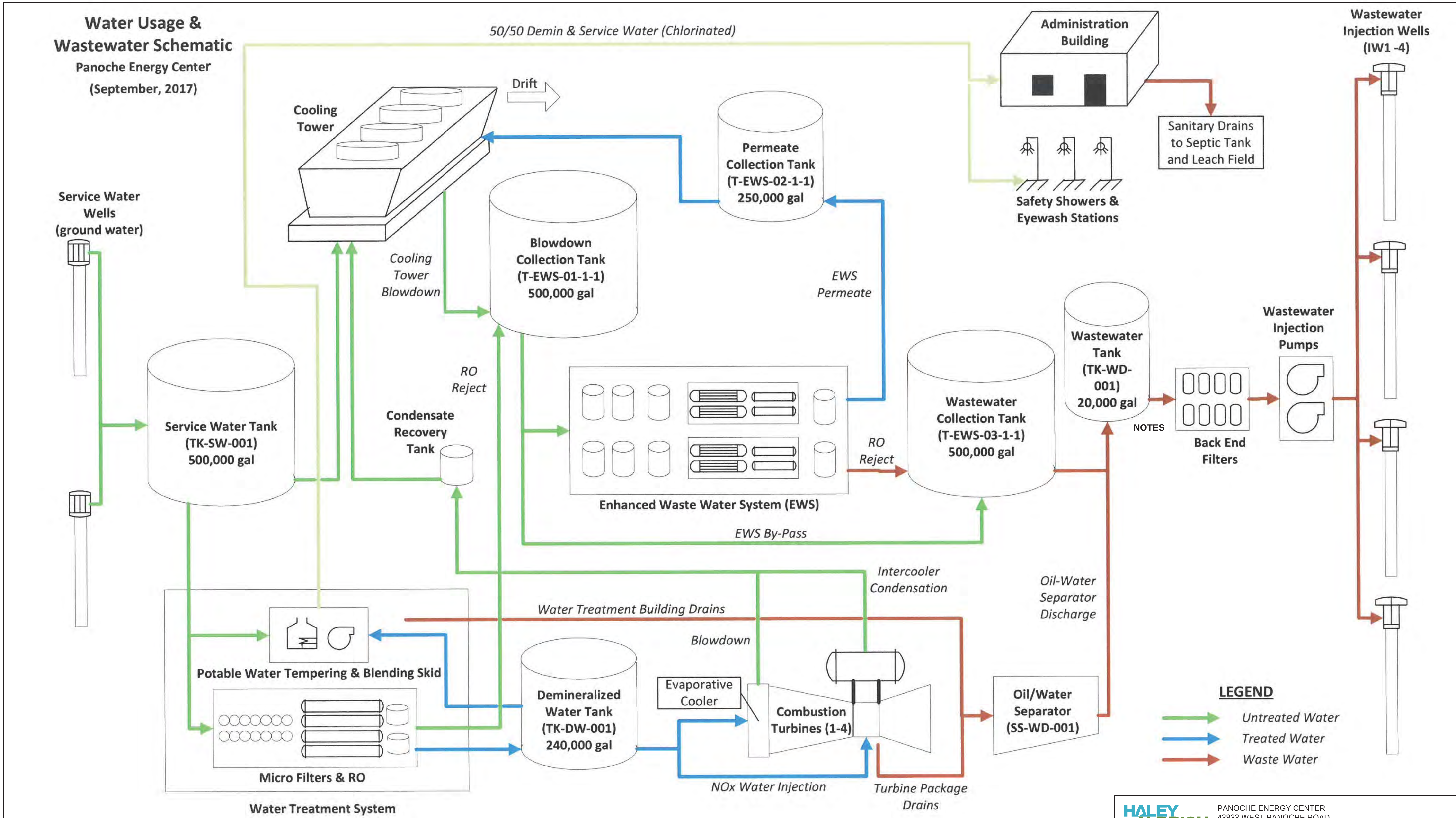
HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

FACILITY LAYOUT

SEPTEMBER 2017

FIGURE K-1



Provided by Panoche Energy Center

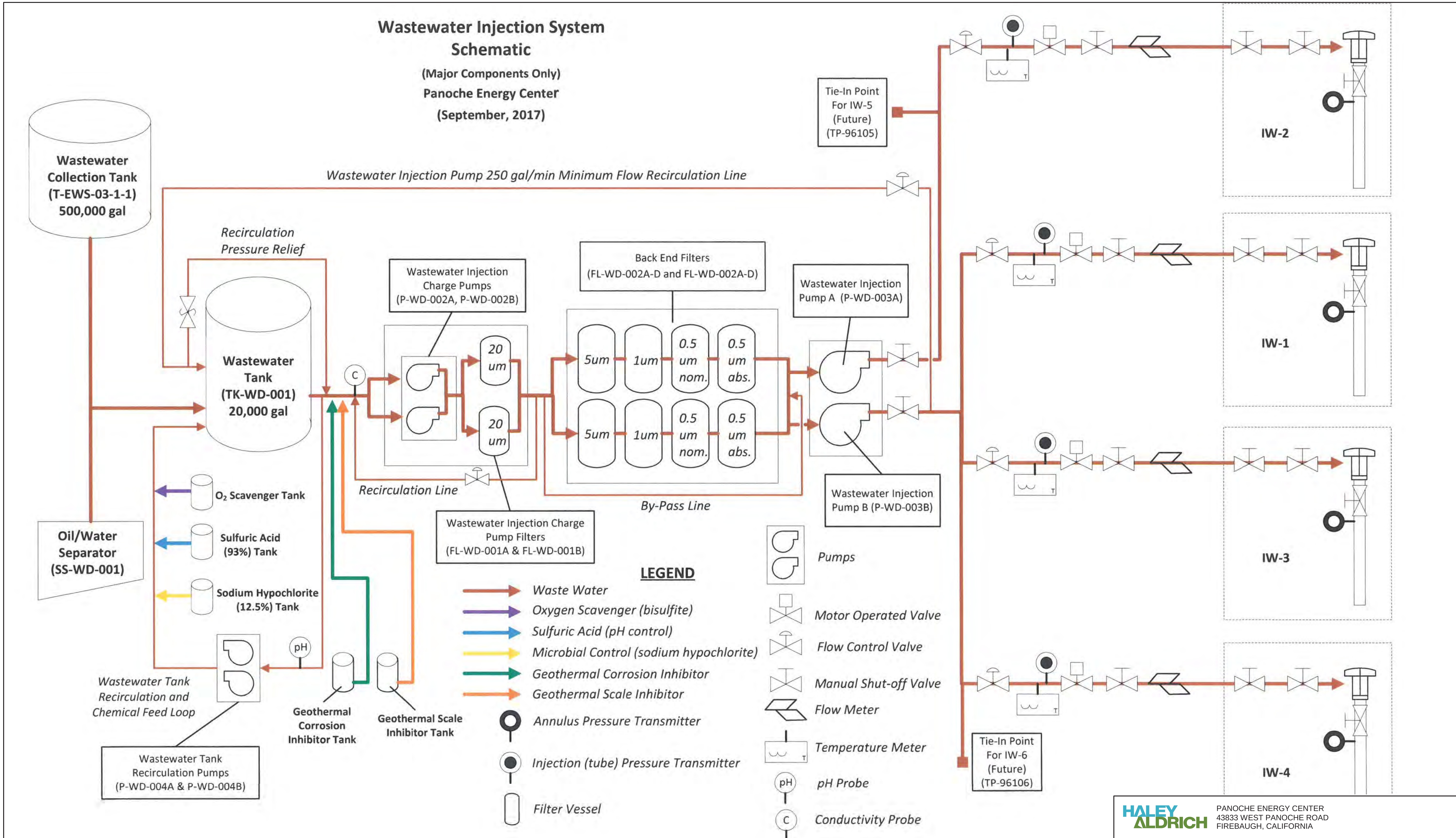
HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

WASTEWATER FLOW SCHEMATIC

SEPTEMBER 2017

FIGURE K-2



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HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

WASTEWATER INJECTION SYSTEM SCHEMATIC

SEPTEMBER 2017

FIGURE K-3

EXHIBITS

(To be Submitted on CD)

ATTACHMENT L

Construction Procedures

Table of Contents

Page

List of Figures

List of Exhibits

L-8 AMEC Environment and Infrastructure, Inc. 2011. Notification of Intent to Start Work to Deepen and Recomplete Wells IW3 and IW4 and Minor Operational Changes to the Procedures and Schedule, Class 1 Nonhazardous Waste Injection Wells, UIC Permit Number CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. September.

L-9 URS. 2009. Well Completion Report, UIC Well IW1, Panoche Energy Center, UIC Permit No CA10600001, Firebaugh, Fresno County. March.

L-10 URS. 2009. Well Completion Report, UIC Well IW2, Panoche Energy Center, UIC Permit No CA10600001, Firebaugh, Fresno County. March.

L-11 URS. 2009. Well Completion Report, UIC Well IW3, Panoche Energy Center, UIC Permit No CA10600001, Firebaugh, Fresno County. July.

L-12 URS. 2009. Well Completion Report, UIC Well IW4, Panoche Energy Center, UIC Permit No CA10600001, Firebaugh, Fresno County. July.

L-13 AMEC Environment and Infrastructure, Inc., 2012. Deepening and Recompletion of Wells IW3 and IW4 Class 1 Nonhazardous Waste Injection Wells, UIC Permit Number CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. May.

ATTACHMENT L – CONSTRUCTION PROCEDURES

PERMIT APPLICATION REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment L requires the applicant to "discuss the construction procedures (according to §146.12 for Class I) to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring program, and proposed annulus fluid. (Request and submission of justifying data must be made to use an alternative to packer for Class I.)"

SUMMARY OF CURRENT PERMITTED WELLS WITH MINOR MODIFICATIONS INCLUDED

Drilling, work-over, and plugging procedures that have been generated and applied to each well construction operation have complied with the California Division of Oil, Gas, and Geothermal Resource's (DOGGR) "Onshore Well Regulations" of the California Code of Regulations, found in Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Article 3, Section 1722-1723.

The current permit requires that drilling procedures shall also include details for:

- Staging long-string cementing or justification for cementing without staging;
- Reporting to USEPA shall include records of Daily Drilling Reports (electronic and hard copies);
- Casing and other tubular and accessory measurement tallies; and
- Blowout Preventer (BOP) System tests must be documented with complete explanatory notes throughout the tests.

Casing and Cement Configuration

The current permit requires that the well must be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water (USDWs). The following is a summary of the casing and cement configuration for the currently constructed wells (IW1, IW2, IW3, and IW4). Details are provided in URS's four completion reports (URS, 2009a, b, c, and d); AMEC's IW3 and IW4 well deepening and completion Report (AMEC, 2012b); Haley & Aldrich's Fracture Stimulations report (Haley & Aldrich, 2013c); and Haley & Aldrich's Second Quarter 2014 (2Q2014) Injection Monitoring report (Haley & Aldrich, 2014b).

- **Conductor Casing:** 16- or 20-inch certified AB/A-grade Mild Steel cemented to surface.
- **Surface Casing:** IW1: 13-3/8-inch, 54.5 pounds per foot (lb/foot), K-55 casing type set to 975 feet; and 9-5/8-inch, 36 and 40 lb/foot, K-55 set to 4,980 feet. For IW2, IW3, and IW4: 10-3/4-inch, 40.5 lb/foot, K-55 set to approximately 1,612, 1,652, and 1,617 feet, respectively. All surface casings cemented to surface.
- **Long-String Casing:** IW1: 9-5/8-inch, 36 and 40 lb/foot, K-55, set to 4,980 feet; and liner from 4,700 to 7,470 feet consisting of 7-5/8-inch, 26.4 lb/foot, K-55 and 29.7 lb/foot N-80 and P-110 casing type. For wells IW2, IW3, and IW4: 7-5/8-inch, 26.4 and 29.7 lb/foot K-55 or N-55 set to 7,609 feet, 6,147 feet and 6,258 feet, respectively. All long-string casings are cemented to surface except IW2, which has top of cement at approximately 4,826 feet (note: see 2017 Mechanical Integrity Testing [MIT] and Falloff Testing report, presented as an exhibit to this

Attachment, that shows no upward movement from the Eocene section or any other inter-formational flow of fluid in IW2 along the long-string interval).

Injection Configuration

Injection currently takes place through a system with a tubing string and a liner requirement as specified by the current permit. The following is tubing configuration for the currently constructed wells (IW1, IW2, IW3, and IW4):

- **Tubing:** IW1 and IW2: 5-1/2-inch 17 lb/foot, N-80 or L-80 or equivalent. IW3 and IW4: 5-1/2-inch, L-80 or N-80 or equivalent crossed over to 3-1/2-inch, 9.3 lb/foot L-80 or N-80 or equivalent set in packer with appropriate crossover subs. Note the 3-1/2-inch tubing currently in the sidetrack liner sections of IW3 and IW4 has special turned-down collars for increased clearance. Note equivalent/appropriate sizes, types, and grades of injection tubing will be used in subsequent wells or as replacements for existing tubing as necessary.
- **Packer:** Weatherford's HSP Packer with 6-foot Polished Borehole Receptacle (PBR) in wells IW1 and IW2, Weatherford Arrowset IXS packer in well IW3, and Weatherford Arrow-Drill sealbore packer in IW4. Note equivalent/appropriate type packers will be used in subsequent wells or as replacements for existing wells as necessary.
- **Slotted Liner:** IW1: 5-1/2-inch, 17lb/foot, L-80 from 7,351 to 8,330 feet; IW2: 5-1/2-inch, 17 lb/foot, L-80 from 7,502 to 8,781 feet. Note that abandoned slotted liner sections in IW3 and IW4, run to a depth of 6,531 feet and 6,704 feet, respectively, were abandoned in-place with cement plugs prior to sidetracking operations.
- **Sidetrack liner** (IW3 and IW4 only)**:** 5-1/2-inch, 17 lb/foot, N-80, LTC from 5,784 to 8,995 feet in IW3 and from 5,788 to 8,950 feet in IW4. Cemented from liner shoe to liner hanger. Select intervals were perforated from a depth of 8,220 to 8,800 feet in IW3 and from 7,380 to 8,785 feet in IW4 at 6 shots per foot and 60 degrees phasing.

PREVIOUS DRILLING HISTORY

A diagram for each well is shown for reference in Attachment M and all four wells, including the injection intervals, are shown on Plates 1 and 2 included in the IW3 and IW4 Well Completion Report (AMEC, 2012b). Note that the proposed upper perforations shown on these plates were added to IW4 in June of 2014 (Haley & Aldrich, 2014b). Details regarding the latest completion information for IW3 and IW4 are included in Attachment M and are also discussed in the 2013 Fracture Stimulation Report (Haley & Aldrich, 2013c) and 2Q2014 Monitoring Report (Haley & Aldrich, 2014b). The well paths and bottom-hole locations of the Panoche Energy Center (PEC) injection wells IW1, IW2, IW3, and IW4 are also shown on a Figure in the IW3 and IW4 Completion Report (AMEC, 2012b). The following is a brief history of construction milestones for these wells (see Attachment M for specific construction details for each well).

Original Drilling of IW1, IW2, IW3, and IW4

The borehole for injection well IW1 was drilled by Kenai Drilling (Kenai), utilizing a mud-rotary drilling rig (Kenai Rig Number 5). IW1 was spudded (to start the well drilling process) on 26 September 2008 and the well was completed on 17 December 2008; then on 7 February 2009 a sand control liner was installed. The borehole was initially drilled to a depth of 5,950 feet below kelly bushing (BKB) (Plan A completion, see Attachment F) and completed using a slotted liner. The slotted liner was ultimately removed and the borehole deepened (Plan B completion) to a total depth (TD) of 8,360 feet BKB. Following drilling and well construction, work-over operations were performed to develop the well and to install a sand control liner using Rival Well Services (RWS) work-over rig 9. The borehole for injection well IW2 was drilled by Kenai utilizing mud-rotary drilling rig (Kenai Rig Number 5). IW2 was spudded on 19 December 2008 and was drilled to a depth of 8,790 feet BKB. The well was completed using a slotted liner installed in the Panoche Formation on 18 January 2009. In early 2009, injection wells IW3 and IW4 were spudded on 30 April and 6 May, respectfully and completed as Plan A permit completions using a mud-rotary drilling rig system to depth of 6,847 and 6,800 feet, respectfully. The details of these operations were presented in URS's Underground Injection Control (UIC) IW3 and IW4 Well Completion Reports (2009c and 2009d). In 2011, IW3 and IW4 were deepened as described below.

Deepening of IW3 and IW4

Because of poor injection of the Plan A completions, in 2011 PEC decided to permanently plug the Moreno Formation injection zone in IW3 and IW4 and to convert the wells from a Plan A permit completion to a Plan B completion. A request for minor permit modification, which included a work plan for the sidetrack drilling and recompletion of Class 1 Nonhazardous Waste Injection Wells IW3 and IW4, was submitted to the USEPA on 4 August 2011 (AMEC, 2011a). The minor request, which documented the rationale for deepening wells IW3 and IW4, was approved by USEPA on 9 September 2011 to recomplete wells IW3 and IW4 to Plan B geologic sequence.

This request contained detailed sidetrack recompletion procedures, as follows:

- Plug-back of the previous Moreno Formation slotted-liner completion in each well.
- Mill a window in the long-string casing.
- Directionally drill a sidetrack borehole to the Panoche Formation.
- Cement a liner in place in the sidetracked borehole.
- Implement a perforated completion.
- Install injection tubing and packers in both wells.

On 15 September 2011, notification of Intent to Start Work was submitted to the USEPA (AMEC, 2011b). Upon completion of the workover activities, AMEC submitted a separate work plan on 25 January 2012 to the USEPA for Post-Workover Internal and External Mechanical Integrity Testing and Pressure Fall-Off Testing Class 1 Nonhazardous Waste Injection Wells IW3 and IW4 (AMEC, 2012a) to meet the requirements established in Part II, Section C.2(a)(i) and (iii) of PEC's UIC Permit and Part II, Section A.5(c) of PEC's UIC Permit.

AMEC prepared an Injection Wells IW3 and IW4 Deepening and Recompletion Report (AMEC, 2012b) in accordance with the requirements of USEPA UIC Program Class I Non-Hazardous Waste Injection Wells Permit Number CA10600001. Based on the reporting requirements outlined in the USEPA's Well Completion Form (7520-9), the IW3 and IW4 well Deepening Report (AMEC, 2012b) included a geological description of the rock units penetrated during sidetrack drilling, chemical characteristics of formation fluid, original slotted-liner abandonment documentation, and sidetrack well design and construction information. The testing program included a demonstration of mechanical integrity pursuant to Code of Federal Regulations Title 40 §146.08 and the results of the testing were included in that report. Finally, information on acid stimulation and fall-off testing conducted in April 2012, and the maximum recommended pressure at which the wells will operate were presented in that report.

Fracture Stimulation of IW3 and Monitoring in IW4

In 2012, PEC evaluated various options to increase the rate of waste water disposal, and a program of controlled, near well-bore hydraulic fracture stimulation in the deep Panoche Formation was one of PEC's preferred options identified to enhance the well field performance (Haley & Aldrich, 2012). During the planning phase of this project, numerous safeguards were identified to support the idea that any modest-sized fracture would be contained within the Panoche Formation, thus ensuring that hydraulic fracturing will not result in undesired preferential pathways or allow for injected waste water to flow into an undesignated formation or USDW.

The permit modification request submitted by PEC on 6 November 2012 was for fracture stimulation of both IW3 and IW4 injection wells (Haley & Aldrich, 2012). After evaluating other alternatives to augment the injectivity of the PEC well field, PEC decided to first fracture stimulate IW3 and to perform microseismic monitor in IW4 and to postpone fracture stimulation of IW4, as presented in the letter to the USEPA, Notification of Change in Fracture Stimulation Schedule and Procedure (Haley & Aldrich, 2013a).

All applicable regulatory agencies (which included the USEPA, DOGGR, the California Energy Commission, and the Central Valley Regional Water Quality Control Board) were notified prior to the start of site work, and all work was consistent with the applicable UIC Permit and DOGGR requirements. In addition, daily field logs were sent to USEPA for review and consultation while field activities were ongoing. Well workover operations at IW4 and IW3, including pulling tubing, installing fracture stimulation equipment, removal of this equipment, and re-installation of injection tubing and wellhead, proceeded sequentially with some overlap in activities at both wells and was accomplished using Orchard Petroleum, Inc.'s Rig 1 (completion rig) and crew. The fracture stimulation work was performed by Halliburton on 4 and 5 May 2013. During the fracture stimulation, FracTrac™ micro-seismic fracture mapping was a used as a safeguard tool to monitor real-time subsurface fracture development activity and to ensure that no undesired preferential pathways into an undesignated formation or USDW developed. Also, temperature, radioactive tracer (RAT), and continuous flowmeter surveys were performed prior to and after fracture stimulation, as well as multiple temperature logging passes soon after fracture stimulation (Haley & Aldrich, 2013b; Haley & Aldrich, 2013c).

Additional Perforation of IW3 and IW4 and Repair of IW4.

On 26 February 2014, a proposal to perform re-perforation of select intervals within the permitted zone of injection was submitted to the USEPA (Haley & Aldrich, 2014a). An e-mail was submitted to the USEPA on 8 April 2014 proposing to perform the following operations at each well: (1) flow profiling and correlation logging, (2) multiple wireline perforation runs, and (3) bullhead acid stimulation. This work was approved by USEPA on 10 April 2013. Later, it was determined that conventional wireline perforation methodology (using the same procedures presented in *Contingency Proposal to Perform Wireline Perforation in Additional Sections of the Panoche Formation in Wells IW3 and IW4*; Haley & Aldrich, 2014a), instead of the Hydrajet technology as originally proposed, would provide the best results for re-perforation of select zones in IW3 and IW4.

On 23 April 2014, IW3 and IW4 correlation logging was performed by Well Analysis Corporation. In addition, injection surveying was performed using an Iodine-131 RAT material injector, casing collar locator, temperature, and gamma detector. Wireline perforation of IW3 was performed on 30 April and 1 May 2014. Just before the last run, the logging tool became stuck in the well. After numerous attempts to pull out of the tool, the well was put on injection and then the well was back-flowed. This last procedure released the tool, which was then brought to surface. The last perforation run (number 13) was not performed because of the risk associated with becoming stuck.

Acid stimulation was performed on 4 and 5 May 2014 on IW4 and IW3, respectively (Haley & Aldrich, 2014b). During the latter part of the acid stimulation at IW4, annular pressure began to rise to several hundred pounds per square inch (psi) below the pressure in the tubing, and then the annular pressure tracked tubing pressure. Because of this response after acid stimulation, both the tubing and the annulus were pressure tested. On 4 May 2014, the USEPA was notified that IW4 lost mechanical integrity due to hydraulic communication between the tubing and the annulus, and after confirmation testing IW4 was taken out of service (see the daily field reports as Appendix G and the Halliburton job report for the acid stimulation at IW4 as Appendix E, both in the 2Q2014 Monitoring Report for details). PEC then prepared a plan to re-establish mechanical integrity, and a workover plan was submitted to USEPA for IW4 repairs on 2 June 2014. The plan included a statement of intent to perforate additional sections within the permitted injection zone as a modification to a previous proposal (Haley & Aldrich, 2014a), submitted to perform perforation of select intervals within the zone to now use tubing-conveyed perforation (TCP) methods, while the well is free of tubing, as an alternative to wireline perforation (Haley & Aldrich, 2014b).

As presented in Haley & Aldrich (2014b), the IW4 well work began on 5 June 2014. This work included:

- Well kill operations using heavy brine;
- Unseating the packer and pulling tubing from the well;
- Running a scraper in the well to clean the casing in preparation for casing inspection logging;
- Tubing conveyed perforation of IW4 performed on 12 and 13 June 2014;
- After perforation, the well was back-flowed to clear out any residual debris in the newly perforated intervals;
- Installing injection tubing and a new packer (Weatherford's Arrow-Drill Sealbore Packer) and reconnecting the wellhead;
- Performing an internal MIT to confirm mechanical integrity;
- Reconnecting the flowline and monitoring equipment; and
- Performing a bullhead acid stimulation to clean up any residual drilling mud uncovered after TCP perforation.

PEC received USEPA approval to operate the repaired well IW4 on 19 June 2014.

PROPOSED CONSTRUCTION PROCEDURES FOR WELLS IW5 AND IW6

The proposed drilling and completion procedure for IW5 and IW6 includes mobilization, drilling, completion, and post-completion testing operations, as detailed below. The completion program for both wells is identical and detailed in the following outlined drilling and completion program. Well schematics for both proposed wells are provided in Figures L-1 and L-2). Figure L-3 contains a proposed wellhead configuration for well IW5 and IW6 (the same wellhead configuration is proposed for both wells). In addition, optional proposed stimulation programs are outlined under specific headings in Attachment J of this application.

Location and Preparation Planning for Drill Rig Mobilization

The following steps will be implemented prior to rig mobilization:

1. Set aside approximately 70,000 square feet of plant area at the staked location to accept the rig layout. (Note that the actual location size will be dictated by the drilling rig selected).
2. Auger the conductor hole and set approximately 80 feet of 16-inch outer diameter (OD) steel conductor pipe. Drill rat-hole (used to store the kelly) and mouse-hole (connected to a storage area on a drilling rig where the next joint of drilling pipe is held) per drilling rig specifications and excavate well cellar before mobilizing rig.
3. Mobilize and rig-up drilling rig. Rig-up solids control equipment including a dual-shale shaker, de-sander, de-silter, mud cleaner, and centrifuge. Test equipment for proper operation before spudding in ground. Build spud mud as directed by the mud engineer.
4. Weld a temporary drilling flange on the 16-inch conductor pipe and install bell nipple and at least one diverter line.

Drilling of 14-3/4-inch Surface Borehole and Installation of Surface Casing

The following steps will be implemented after rig mobilization:

1. Pick up 14-3/4-inch bit, Bottom Hole Assembly (BHA) and 4-1/2-inch drill pipe. Drill a 14-3/4-inch hole from surface to approximately 2,000 feet. Take deviation surveys at least every 500 feet while drilling surface hole.
2. Use pre-hydrated spud-mud with mud weight of 8.8 to 9.2 pounds per gallon (lb/gal) and viscosity of 50 to 60 seconds per quart.
3. Make cleanup/wiper trip before logging surface hole. Circulate and condition hole prior to logging. Trip out of hole. Note: Lay down components not required in BHA to drill next segment of hole. Lay down and inspect 14-3/4-inch bit.
4. Run open-hole geophysical logs, consisting of spontaneous potential, caliper, and resistivity from 2,000 feet to surface.
5. Make cleanup/wiper trip to condition the hole for surface casing using 14-3/4-inch roller cone bit on drill pipe.
6. Rig-up casing crews and floor to run 10-3/4-inch surface casing using similar procedures as were used during the drilling phase of the other PEC injection wells.
7. Pick up 10-3/4-inch float shoe, one joint of surface casing and a 10-3/4-inch float collar. Thread lock from the float shoe to the bottom of the float collar. Run approximately 2,000 feet of 10-3/4-inch OD, 40.5 pound per foot (lb/foot), K-55 (or equivalent grade) long-thread and coupling (LT&C) surface casing using industry-recommended make-up torque and thread compound on each connection. Place centralizers on each joint of surface casing.

8. Circulate and condition mud to condition hole for cementing (at least one casing volume).
9. Cement surface casing with 660 sacks Type III lead slurry with 1.86 cubic foot/sack yield and 400 sacks Type III tail slurry with 1.34 cubic foot/sack yield or equivalent slurries as recommended by the cementing service company during final program development prior to installing the well. Note that the actual volumes will be determined from caliper log plus 20 percent excess except in intervals that are washed out beyond the capability of the caliper logging tool where an excess of 50 percent minimum will be used.
10. Displace cement with fresh water. Run temperature survey to confirm the top of the cement. Use optimum time at which the type of cement used is hydrating for best temperature log results.
11. Wait a minimum of 12 hours for cement to harden. Top out cement job if necessary.
12. Cut the 16-inch conductor pipe at the bottom of the cellar. Cut the 10-3/4-inch surface casing so that the wellhead may be installed at a height relative to ground level which accommodates the desired completed wellhead configuration. Weld on casing head.
13. Nipple-up (make ready for use) BOP, bell nipple, and diverter line. Pressure test BOP, choke manifold, lower and upper kelly valves, and standpipe (back to pumps) to 200 psi and 3,000 psi. Chart record the tests.
14. Run cement bond and variable density log from float collar to surface.

Drilling of 9-7/8-inch Borehole and Installation of Intermediate Casing

1. Trip in the hole with 9-7/8-inch bit on directional BHA and 4-1/2-inch drill pipe. Drill float collar and float joint to within 10 feet of the float shoe.
2. Test surface casing and BOPs to 1,000 psi for 30 minutes using mechanical pressure chart recorder.
3. Drill out guide shoe and 10 feet of formation. Perform shoe test as needed.
4. Drill 9-7/8-inch hole to approximately 7,500 feet with directional bottom hole assembly on 4-1/2-inch drill pipe. Rotate/slide drill as needed to maintain wellbore inclination and azimuth as outlined in directional plan, based on directional survey intervals of 100 feet or less. Maintain mud weight at 8.8 to 10.0 lb/gal and a funnel viscosity of 40 to 50 seconds/quart. Drill with minimum required mud weight and control gas returns. Offset well records indicate that mud weights of 13.0 to 15.0 lb/foot may be needed to stabilize wellbore (running shales). A mud weight of greater than 13 pounds per gallon (ppg) may be required at approximately 5,000 feet. Maintain a mud fluid loss of less than 6 cubic centimeters per foot before reaching 5,000 feet. Pump high viscosity sweeps periodically for hole cleaning. Back ream after each connection.
5. When TD is reached, sweep hole and circulate to clean returns. Trip out of hole and lay down directional BHA. Trip back to bottom in stages, with a 9-7/8-inch roller cone bit on drill pipe, circulating one bottoms up (mud and cuttings that come from the bottom of the hole) every 1,500 feet. Circulate/condition hole for logging. Trip out of hole.
6. Run open-hole geophysical logs consisting of spontaneous potential, resistivity, porosity, caliper, gamma ray log and fracture finder log across interval from approximately 7,500 feet to the 10-3/4-inch surface casing shoe at approximately 2,000 feet.

7. Make clean up trip with 9-7/8-inch roller cone bit on drill pipe to condition the hole in preparation to run 7-5/8-inch intermediate casing.
8. Rig-up casing crew laydown machine. Trip out of hole while laying down 4-1/2-inch drill pipe.
9. Pick up 7-5/8-inch standard valve float shoe, one joint of 7-5/8-inch casing, and a 7-5/8-inch standard valve float collar. Thread lock from the float shoe to the bottom of the float collar. Run approximately 7,500 feet of 7-5/8-inch OD, 29.7 lb/foot, N-80 (or equivalent grade), LT&C intermediate casing using industry recommended make-up torque and thread compound on each connection. Run mechanical diverting valve (DV) cementing stage tool for a position of approximately 4,800 feet measured depth when casing string is at the proposed installed TD. Centralize every joint to surface using bowspring centralizers.
10. Circulate and condition mud to condition hole for cementing (at least one casing volume).
11. Cement first stage of long-string casing cement job with 725 sacks Class G cement with 1.13 cubic foot/sack yield or an equivalent slurry as recommended by the cementing service company during final program development prior to installing the well. Note that the actual volumes will be determined from caliper log plus 20 percent excess, except in intervals that are washed out beyond the capability of the caliper logging tool where an excess of 50 percent minimum over the caliper diameter will be used.
12. Displace first stage cement with fresh water below the DV tool and drilling mud above the DV tool. Open DV tool and circulate system mud approximately 12 hours to allow first stage to harden.
13. Cement second stage of long-string casing cement job with 600 sacks 65:35:4 Pozzolan (Poz) Class G cement with 1.66 cubic foot/sack yield and 260 sacks Class G cement with 1.16 cubic foot/sack yield or equivalent slurries as recommended by the cementing service company during final program development prior to installing the well. Note that the actual volumes will be determined from caliper log plus 20 percent excess except in intervals that are washed out beyond the capability of the caliper where an excess of 50 percent minimum over the caliper diameter will be used.
14. Displace second stage cement with fresh water.
15. Set 7-5/8-inch wellhead packing in 11-inch 5M wellhead per wellhead tech's instructions. Cut off casing to measurement specified by well head company. Install secondary seal and 11-inch 5M X 11-inch 5M casing spool (be sure that a 7-1/2-inch bit will go through casing spool).
16. Wait on second stage cement to harden.

Drilling 7-1/2-inch (Under-Reamed While Drilling) Borehole and Installation of Production Liner

1. Nipple-up BOP and pressure test using a mechanical pressure chart recorder.
2. Pick up 6-3/4-inch bit, 4-inch Hevi-Wate Drill Pipe, and standard 4-inch drill pipe. Trip in hole to DV tool. Drill out and deburr DV tool.
3. Circulate to clean returns.
4. Trip to float collar and pressure test 7-5/8-inch casing per California State regulation.
5. Drill out float collar and half the shoe track. Send all float equipment and cement over the shakers.

6. Dump and clean mud pits, mix fresh polymer-based mud, displace hole with polymer-based mud system and drill the rest of the shoe track, the float shoe and 3 feet of formation, then trip out of hole.
7. Rig-up and run cased hole logs consisting of temperature log and cement bond and variable density log from float collar to surface.
8. Pick up Baker brand or equivalent 4-3/4-inch by 7-1/2-inch ream-while-drilling (RWD) Polycrystalline Diamond Compact (PDC) bit and a packed BHA, then trip to bottom.
9. Drill to 9,000 feet TD. Perform wiper trip to casing shoe after drilling each 500-foot interval or as otherwise needed.
10. At TD, circulate to clean returns and trip bit back inside 7-5/8-inch intermediate casing shoe. Wait one hour and then trip back to bottom to check for fill. Circulate to clean returns and trip out of hole for geophysical logging.
11. Run open-hole geophysical logs across interval from approximately 9,000 feet to the 7-5/8-inch intermediate casing shoe to approximately 7,500 feet (logs to consist of spontaneous potential, resistivity, porosity, caliper, gamma ray log and fracture finder log).
12. Pick up 4-3/4-inch by 7-1/2-inch RWD PDC bit on 4-inch drill pipe and trip to bottom. Ream and condition hole as required. Trip bit back inside 7-5/8-inch intermediate casing shoe. Wait one hour and then trip back to bottom to check for fill. Circulate/condition hole and mud for casing. Trip out of hole. Strap drill pipe on the way out.
13. Rig-up casing crew and laydown machine. Inspect and strap liner hanger. Run 5-1/2-inch, 17 lb/foot, N-80 LTC (or equivalent) liner casing. Rig-up and run hydraulic set liner hanger assembly with liner top packer and sealbore assembly with running tool. Rig down casing running tools and laydown machine. Trip liner and liner hanger assembly in hole on 4-inch Hevi-Wate drill pipe and 4-inch drill pipe. Position top of 5-1/2-inch liner at approximately 7,250 feet measured depth. Fill pipe with drilling mud, record weight, and circulate at the 7-5/8-inch shoe and at TD.
14. While circulating with the liner at setting depth, drop and displace setting ball to the landing collar. Apply pump pressure required to set liner hanger. Slack off weight recommended by liner hanger vendor to verify liner hanger is set. Apply weight for compression recommended by liner hanger vendor and rotate drill pipe to the right to release liner hanger running tool. Raise drill pipe the distance recommended by liner hanger vendor to confirm running tool has been released.
15. Slack off weight recommended by liner hanger vendor onto liner top. Apply pressure to shear setting ball seat and establish circulation. Circulate at least one hole-volume of mud.
16. Rig-up cementers and cement liner with 290 sacks 50:50:2 Poz Class G cement with a 1.21 cubic foot/sack yield or an equivalent slurry as recommended by the cementing service company during final program development prior to installing the well. Note that the actual volumes will be determined from caliper log plus 10 percent excess except in intervals that are washed out beyond the capability of the caliper logging tool where an excess of 50 percent minimum over the caliper diameter will be used. Displace liner cement with 2 percent potassium chloride water.
17. Check floats after landing cementing plug/dart. Pick up distance specified by liner hanger vendor to expose actuator dogs. Set down recommended weight required to set liner top packer.

Report shear values observed while setting liner hanger. Pick up distance specified by liner hanger vendor's procedure to circulate out excess cement. Circulate to clean returns.

18. Trip out of hole, standing back 4-inch Hevi-Wate drill pipe and 4-inch drill pipe. Inspect and report condition of the running tool when it is returned to the surface.
19. Pick-up polish-mill and trip in hole to liner top. Dress-off PBR. Circulate to clean returns using displacement fluid containing polymer breaker
20. Rig-up laydown machine. Lay down 4-inch Hevi-Wate drill pipe and 4-inch drill pipe.
21. Rig-up casers and run 5-1/2-inch, 17 lb/foot, N-80 LTC (or equivalent) tieback string and seal assembly. Ensure that tubing movement analysis has been done using correct pressure and temperature data for current and expected wellbore conditions. Circulate in annulus fluid consisting of 10 ppg filtered sodium chloride brine with corrosion inhibitor, biocide, and anti-foaming agents as appropriate.
22. Record up-and-down weights two joints above PBR. Lower the seal assembly into PBR until locator has landed on top of PBR. Close pipe rams and perform preliminary annulus pressure test.
23. Space out with pre-cut pup joints such that the seal assembly is positioned per the tubing movement analysis when the tubing hanger is installed in wellhead hanger. Land tubing hanger in 11-inch 5M X 11-inch 5M B-section spool as per wellhead company's field installation procedure.
24. Nipple-down BOP, install 11-inch 5M X 7-1/16-inch spool with secondary pack off for tubing hanger and 7-1/16-inch blind flange.
25. Rig down the drill rig and associated equipment. Repair location as necessary to accommodate workover rig and associated equipment.

Well Completion, Preliminary Testing, and Stimulation

1. Mobilize and rig-up well service unit rig. Rig-up frac tanks and other surface rental equipment. Nipple-up BOP and chart the test. Set pipe racks for work-string tubing. Unload, rack, and strap 2-7/8-inch work-string tubing.
2. Pick up 4-3/4-inch workover bit and trip in hole. Drill as required to plug back total depth (PBTD) at the top of 5-1/2-inch liner float collar or where determined by open hole logs. Circulate at PBTD a minimum of one bottoms-up and trip out of hole.
3. Pick up casing scraper on work-string and run in hole to PBTD. Trip out of hole with casing scraper.
4. Make up treating iron to tubing valve on wellhead, connect to rig pump and pressure test 5-1/2-inch liner and tieback casing.
5. Move in and rig-up wireline truck. Run cased hole geophysical logs (gamma, cement bond log, variable density log) on 5-1/2-inch liner casing section.
6. Run in hole with perforation guns and perforate as communicated by geologist per PEC approval.
7. Establish injection rate with rig pump. At shut down, monitor and record instantaneous shut-in pressure and record fall-off pressure.

8. If rate and pressure data indicate substandard performance, acidizing and/or fracture stimulation may be elected.

    a. If acid stimulation is elected:

        - Run in hole with service packer on 2-7/8-inch work-string, and set approximately 50 feet above top perforation. Perform acid stimulation per general procedure (see Attachment J).
        - Repeat steps 6, 7, and 8a as required.
        - If well performance is satisfactory after stimulation, rig-down and move-out well service unit.

    b. If fracture stimulation is elected:

        - Pull out of hole and laydown work-string.
        - Rig-down and move out well service unit.
        - Implement general fracture stimulation program as per Attachment J.
        - After fracture stimulation, acid stimulation may be necessary (Attachment J).

Post Completion Mechanical Integrity Testing

1. Move in and rig-up wireline unit with mast and lubricator and ancillary equipment as necessary (pump truck, tanks, fluids, and other required surface rentals).
2. Perform MIT activities, including annulus pressure test, static-bottomhole pressure measurement, RAT survey, and differential temperature survey. Perform reservoir buildup fall-off test if required.
3. Upon completion of successful MIT, rig-down and move-out wireline truck and all ancillary equipment.
4. Prepare and submit completion report to USEPA.

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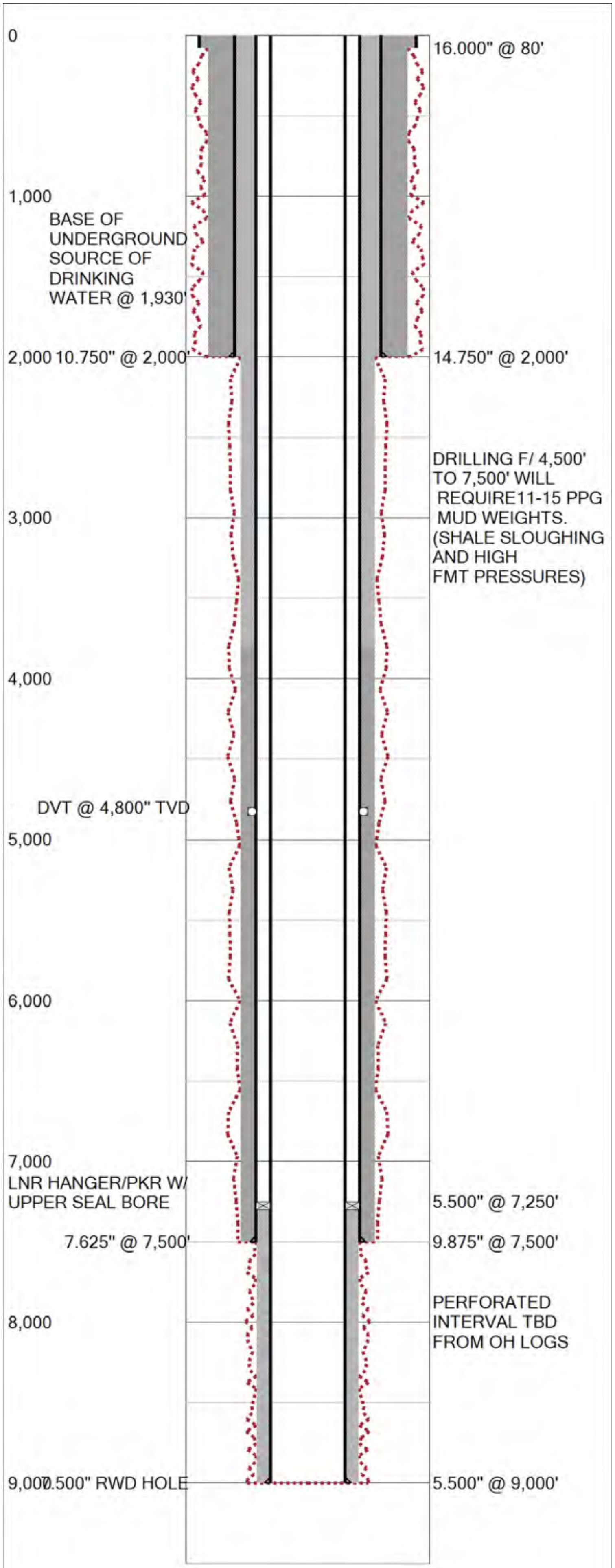
11. URS. 2009a. Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

12. URS. 2009b. Well Completion Report – UIC Well IW2, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

13. URS. 2009c. Well Completion Report – UIC Well IW3, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

14. URS. 2009d. Well Completion Report – UIC Well IW4, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

FIGURES



Provided by Hadaway Consulting & Engineering

FIGURE L-1

Field Name	Lease Name	Well No.
CHANEY RANCH	CLASS 1 DISPOSAL WELL	IW5

County	State	API No.
FRESNO	CALIFORNIA	______________

Version	Version Tag
1	Pre-Drill / Permitting

GL (ft)	KB (ft)	Section	Township/Block	Range/Survey
408.0		5	16S	13E

Operator	Well Status	Latitude	Longitude
PANOCHE ENERGY CENTER, LLC	PLANNING	36.650056	-120.58363

Dist. N/S (ft)	N/S Line	Dist. E/W (ft)	E/W Line	Footage From

Prop Num	Spud Date	Comp. Date

Additional Information

WELLHEAD INFORMATION
A-SECTION: 11" 5M X 10 3/4" SOW W/ 48" BASEPLATE

B-SECTION: 11" 5M X 11" 5M CASING SPOOL (LAND 5 1/2" TBG HANGER IN THIS SPOOL), 11" 5M X 7 1/16" 5M SPOOL

TREE: 7 1/6" 5M X 5 1/8" 3M ADAPTER, 5 1/8" 3M MASTER VALVE

SWAB TREE: 2 9/16" (2M) SWAB VALVE AND WING VALVE

BHL Latitude	BHL Longitude	KOP	OTHER
39.649822	-120.583104	2500'	

Prepared By	Updated By	Last Updated
HCE Geosteering 2	HCE Geosteering 2	8/23/2017 9:25 PM

Hole Summary

Date	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
	14.750	80	2,000	
	9.875	2,000	7,500	
	7.500	7,500	9,000	7.500" RWD HOLE

Tubular Summary

Date	Description	O.D. (in)	Wt (lb/ft)	Grade	Top (MD ft)	Bottom (MD ft)
	Conductor Casing	16.000			0	80
	Surface Casing	10.750	40.50	K-55	0	2,000
	Intermediate Casing	7.625	29.70	N-80	0	7,500
	Tubing	5.500	17.00	L-80	0	7,250
	Liner	5.500	17.00	L-80	7,250	9,000

Casing Cement Summary

C	Date	No. Sx	Csg. O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
		30	10.750	0	80	LEAD SURFACE CMT (PIP)
		630	10.750	80	1,398	LEAD SURFACE CMT (PIH)
		400	10.750	1,398	2,000	TAIL SURFACE CMT
		282	7.625	0	2,000	STG 2 LEAD INTERMEDIATE CMT (PIP)
		325	7.625	2,000	3,796	STG 2 LEAD (PIH) INTERMEDIATE CMT
		260	7.625	3,796	4,800	STG 2 TAIL INTERMEDIATE CMT
		725	7.625	4,800	7,500	STG 1 INTERMEDIATE CMT
		290	5.500	7,250	9,000	PRODUCTION LINER CMT

Figure L-1

Tools/Problems Summary

Date	Tool Type	O.D. (in)	I.D. (in)	Top (MD ft)	Bottom (MD ft)
	DVT, D/O	7.625	0.000	4,800	0
	Lnr Hngr, Seal	7.625	5.500	7,250	0

Formation Tops Summary

Formation	Top (TVD ft)	Comments
UNDIFFERENTIATED NONMARINE STRATA	0	CORCORAN CLAY @ 666' TVD
TUMEY	3,570	
KREYENHAGEN	3,970	
DOMENGINE	4,500	
LODO	4,940	
MORENO	5,420	
PANOCHE D1 SANDS	7,200	ESTIMATED RESERVOIR PRESSURE - 3140 PSI
PANOCHE D2 SANDS	7,700	ESTIMATED RESERVOIR PRESSURE AT TOP OF ZONE - 3420 PSI ESTIMATED RESERVOIR PRESSURE AT TD (9000') - 3897 PSI

Field Name	Lease Name	Well No.	County	State	API No.
CHANEY RANCH	CLASS 1 DISPOSAL WELL	IW5	FRESNO	CALIFORNIA	_______________

Version	Version Tag	Spud Date	Comp. Date	GL (ft)	KB (ft)
1	Pre-Drill / Permitting			408.0	

Section	Township/Block	Range/Survey	Dist. N/S (ft)	N/S Line	Dist. E/W (ft)	E/W Line	Footage From
5	16S	13E					

Operator	Well Status	Latitude	Longitude	Prop Num
PANOCHE ENERGY CENTER, LLC	PLANNING	36.650056	-120.58363	

BHL Latitude	BHL Longitude	KOP	OTHER
39.649822	-120.583104	2500'	

Last Updated	Prepared By	Updated By
08/23/2017 9:25 PM	HCE Geosteering 2	HCE Geosteering 2

Additional Information

WELLHEAD INFORMATION
A-SECTION: 11" 5M X 10 3/4" SOW W/ 48" BASEPLATE

B-SECTION: 11" 5M X 11" 5M CASING SPOOL (LAND 5 1/2" TBG HANGER IN THIS SPOOL), 11" 5M X 7 1/16" 5M SPOOL

TREE: 7 1/6" 5M X 5 1/8" 3M ADAPTER, 5 1/8" 3M MASTER VALVE

SWAB TREE: 2 9/16" (2M) SWAB VALVE AND WING VALVE

Hole Summary

Date	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
	14.750	80	2,000	
	9.875	2,000	7,500	
	7.500	7,500	9,000	7.500" RWD HOLE

Tubular Summary

Date	Description	No. Jts	O.D. (in)	Wt (lb/ft)	Grade	Coupling	Top (MD ft)	Bottom (MD ft)	Comments
	Conductor Casing		16.000				0	80	
	Surface Casing		10.750	40.50	K-55	LTC	0	2,000	INTERNAL YEILD: 3130 PSI
	Intermediate Casing		7.625	29.70	N-80	BTC	0	7,500	INTERNAL YEILD: 6890 PSI

Figure L-1

Date	Description	No. Jts	O.D. (in)	Wt (lb/ft)	Grade	Coupling	Top (MD ft)	Bottom (MD ft)	Comments
	Tubing		5.500	17.00	L-80	LTC	0	7,250	INTERNAL YEILD: 7740 PSI
	Liner		5.500	17.00	L-80	LTC	7,250	9,000	INTERNAL YEILD: 7740 PSI

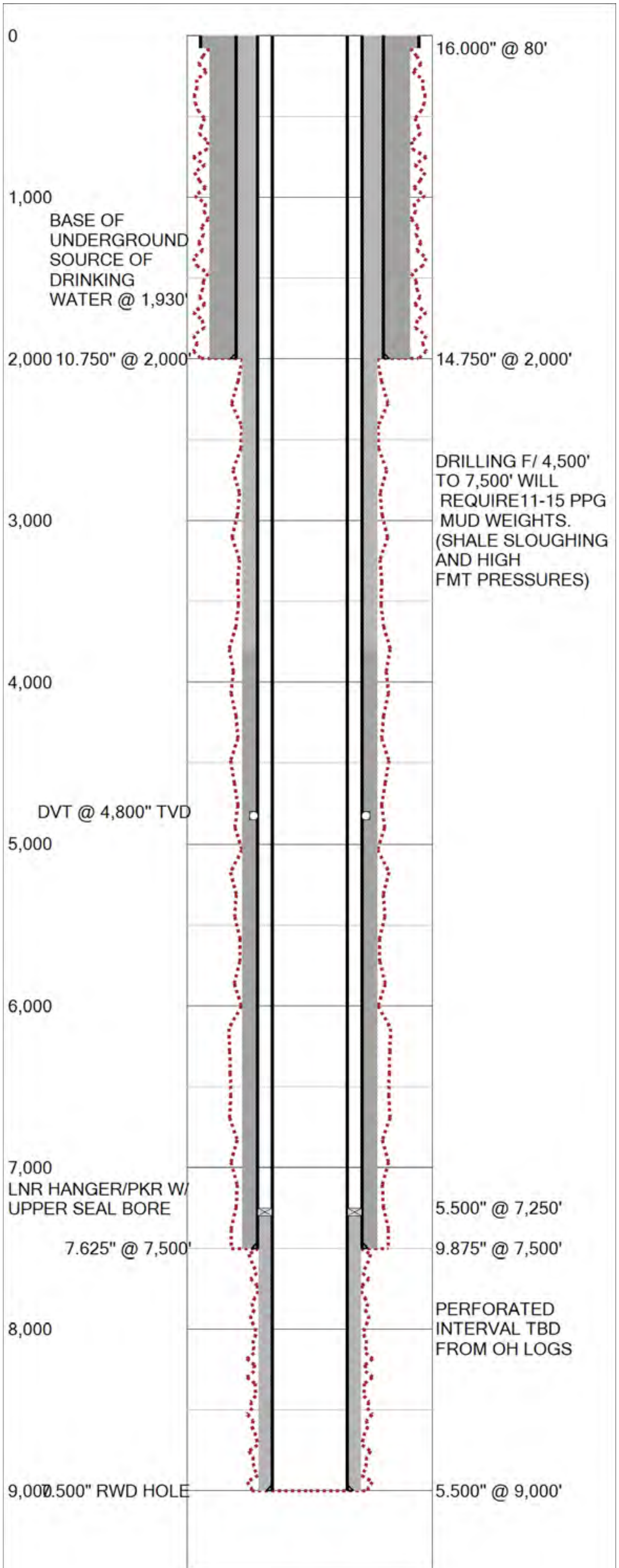
Casing Cement Summary

C	Date	No. Sx	Yield (ft3/sk)	Vol. (ft3)	Csg. O.D. (in)	Top (MD ft)	Bottom (MD ft)	Description	Comments
		30	1.86	56	10.750	0	80	TYPE III (PIPE IN PIPE)	LEAD SURFACE CMT (PIP)
		630	1.86	1,172	10.750	80	1,398	TYPE III (PIPE IN HOLE) - 60 % EXCESS CMT VOL (16.7" EQV OH DIA)	LEAD SURFACE CMT (PIH)
		400	1.34	536	10.750	1,398	2,000	TYPE III - 60% EXCESS CMT VOL (16.7" EQV OH DIA)	TAIL SURFACE CMT
		282	1.66	468	7.625	0	2,000	35:65:4 POZ G + ADDS (PIPE IN PIPE)	STG 2 LEAD INTERMEDIATE CMT (PIP)
		325	1.66	540	7.625	2,000	3,796	35:65:4 POZ G + ADDS (PIPE IN HOLE) 40% EXCESS CMT VOL (10.7" EQV OH DIA)	STG 2 LEAD (PIH) INTERMEDIATE CMT
		260	1.16	302	7.625	3,796	4,800	CLASS G + ADDS (PIPE IN HOLE) 40% EXCESS CMT VOL (10.7" EQV OH DIA)	STG 2 TAIL INTERMEDIATE CMT
		725	1.13	819	7.625	4,800	7,500	CLASS G + ADDS 40% EXCESS CMT VOL (10.7" EQV OH DIA)	STG 1 INTERMEDIATE CMT
		290	1.21	351	5.500	7,250	9,000	50:50:2 CLASS G + ADDS, 40 % EXCESS CMT VOL (8.2" EQV OH DIA)	PRODUCTION LINER CMT

Tools/Problems Summary

Date	Tool Type	O.D. (in)	I.D. (in)	Top (MD ft)	Bottom (MD ft)	Description	Comments
	DV tool (drilled out)	7.625	0.000	4,800	0		DVT @ 4,800" TVD
	Liner Hanger (sealed)	7.625	5.500	7,250	0		LNR HANGER/PKR W/ UPPER SEAL BORE

LAST UPDATED 8/23/17



Provide by Hadaway Consulting & Engineering

FIGURE L-2 pg.1 of 3

Field Name	Lease Name	Well No.
CHANEY RANCH	CLASS 1 DISPOSAL WELL	IW6

County	State	API No.
FRESNO	CALIFORNIA	____________

Version	Version Tag
3	PRE-DRILL / PERMITTING IW6

GL (ft)	KB (ft)	Section	Township/Block	Range/Survey
412.0		5	16S	13E

Operator	Well Status	Latitude	Longitude
PANOCHE ENERGY CENTER, LLC	PLANNING	36.650069	-120.585787

Dist. N/S (ft)	N/S Line	Dist. E/W (ft)	E/W Line	Footage From

Prop Num	Spud Date	Comp. Date

Additional Information

WELLHEAD INFORMATION
A-SECTION: 11" 5M X 10 3/4" SOW W/ 48" BASEPLATE

B-SECTION: 11" 5M X 11" 5M CASING SPOOL (LAND 5 1/2" TBG HANGER IN THIS SPOOL), 11" 5M X 7 1/16" 5M SPOOL

TREE: 7 1/6" 5M X 5 1/8" 3M ADAPTER, 5 1/8" 3M MASTER VALVE

SWAB TREE: 2 9/16" (2M) SWAB VALVE AND WING VALVE

BHL Latitude	BHL Longitude	KOP	OTHER
36.649869	-120.585389	2500'	

Prepared By	Updated By	Last Updated
HCE Geosteering 2	HCE Geosteering 2	8/23/2017 9:26 PM

Hole Summary

Date	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
	14.750	80	2,000	
	9.875	2,000	7,500	
	7.500	7,500	9,000	7.500" RWD HOLE

Tubular Summary

Date	Description	O.D. (in)	Wt (lb/ft)	Grade	Top (MD ft)	Bottom (MD ft)
	Conductor Casing	16.000			0	80
	Surface Casing	10.750	40.50	K-55	0	2,000
	Intermediate Casing	7.625	29.70	N-80	0	7,500
	Tubing	5.500	17.00	L-80	0	7,250
	Liner	5.500	17.00	L-80	7,250	9,000

Casing Cement Summary

C	Date	No. Sx	Csg. O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
		30	10.750	0	80	LEAD SURFACE CMT (PIP)
		630	10.750	80	1,398	LEAD SURFACE CMT (PIH)
		400	10.750	1,398	2,000	TAIL SURFACE CMT
		282	7.625	0	2,000	STG 2 LEAD INTERMEDIATE CMT (PIP)
		325	7.625	2,000	3,796	STG 2 LEAD (PIH) INTERMEDIATE CMT
		260	7.625	3,796	4,800	STG 2 TAIL INTERMEDIATE CMT
		725	7.625	4,800	7,500	STG 1 INTERMEDIATE CMT
		290	5.500	7,250	9,000	PRODUCTION LINER CMT

Tools/Problems Summary

Date	Tool Type	O.D. (in)	I.D. (in)	Top (MD ft)	Bottom (MD ft)
	DVT, D/O	7.625	0.000	4,800	0
	Lnr Hngr, Seal	7.625	5.500	7,250	0

Formation Tops Summary

Formation	Top (TVD ft)	Comments
UNDIFFERENTIATED NONMARINE STRATA	0	CORCORAN CLAY @ 666' TVD
TUMEY	3,530	
KREYENHAGEN	3,930	
DOMENGINE	4,450	
LODO	4,900	
MORENO	5,400	
PANOCHE D1 SANDS	7,170	ESTIMATED RESERVOIR PRESSURE - 3140 PSI
PANOCHE D2 SANDS	7,700	ESTIMATED RESERVOIR PRESSURE AT TOP OF ZONE - 3420 PSI ESTIMATED RESERVOIR PRESSURE AT TD (9000') - 3897 PSI

Field Name	Lease Name	Well No.	County	State	API No.
CHANEY RANCH	CLASS 1 DISPOSAL WELL	IW6	FRESNO	CALIFORNIA	______________

Version	Version Tag	Spud Date	Comp. Date	GL (ft)	KB (ft)
3	PRE-DRILL / PERMITTING IW6			412.0	

Section	Township/Block	Range/Survey	Dist. N/S (ft)	N/S Line	Dist. E/W (ft)	E/W Line	Footage From
5	16S	13E					

Operator	Well Status	Latitude	Longitude	Prop Num
PANOCHE ENERGY CENTER, LLC	PLANNING	36.650069	-120.585787	

BHL Latitude	BHL Longitude	KOP	OTHER
36.649869	-120.585389	2500'	

Last Updated	Prepared By	Updated By
08/23/2017 9:26 PM	HCE Geosteering 2	HCE Geosteering 2

Additional Information

WELLHEAD INFORMATION
A-SECTION: 11" 5M X 10 3/4" SOW W/ 48" BASEPLATE

B-SECTION: 11" 5M X 11" 5M CASING SPOOL (LAND 5 1/2" TBG HANGER IN THIS SPOOL), 11" 5M X 7 1/16" 5M SPOOL

TREE: 7 1/6" 5M X 5 1/8" 3M ADAPTER, 5 1/8" 3M MASTER VALVE

SWAB TREE: 2 9/16" (2M) SWAB VALVE AND WING VALVE

Hole Summary

Date	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
	14.750	80	2,000	
	9.875	2,000	7,500	
	7.500	7,500	9,000	7.500" RWD HOLE

Tubular Summary

Date	Description	No. Jts	O.D. (in)	Wt (lb/ft)	Grade	Coupling	Top (MD ft)	Bottom (MD ft)	Comments
	Conductor Casing		16.000				0	80	
	Surface Casing		10.750	40.50	K-55	LTC	0	2,000	INTERNAL YEILD: 3130 PSI
	Intermediate Casing		7.625	29.70	N-80	BTC	0	7,500	INTERNAL YEILD: 6890 PSI

Date	Description	No. Jts	O.D. (in)	Wt (lb/ft)	Grade	Coupling	Top (MD ft)	Bottom (MD ft)	Comments
	Tubing		5.500	17.00	L-80	LTC	0	7,250	INTERNAL YEILD: 7740 PSI
	Liner		5.500	17.00	L-80	LTC	7,250	9,000	INTERNAL YEILD: 7740 PSI

Casing Cement Summary

C	Date	No. Sx	Yield (ft3/sk)	Vol. (ft3)	Csg. O.D. (in)	Top (MD ft)	Bottom (MD ft)	Description	Comments
		30	1.86	56	10.750	0	80		LEAD SURFACE CMT (PIP)
		630	1.86	1,172	10.750	80	1,398		LEAD SURFACE CMT (PIH)
		400	1.34	536	10.750	1,398	2,000		TAIL SURFACE CMT
		282	1.66	468	7.625	0	2,000		STG 2 LEAD INTERMEDIATE CMT (PIP)
		325	1.66	540	7.625	2,000	3,796		STG 2 LEAD (PIH) INTERMEDIATE CMT
		260	1.16	302	7.625	3,796	4,800		STG 2 TAIL INTERMEDIATE CMT
		725	1.13	819	7.625	4,800	7,500		STG 1 INTERMEDIATE CMT
		290	1.21	351	5.500	7,250	9,000		PRODUCTION LINER CMT

Tools/Problems Summary

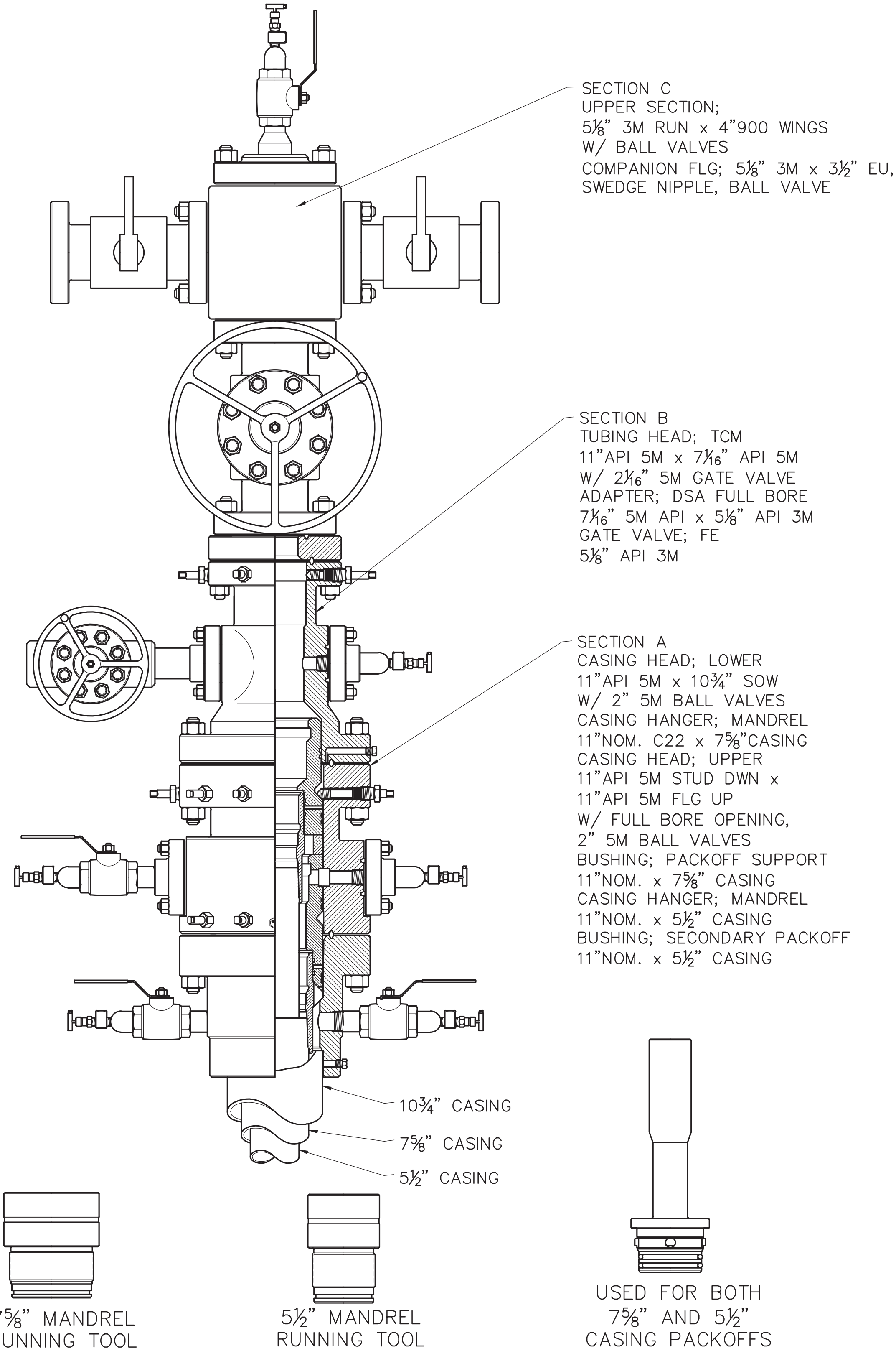
Date	Tool Type	O.D. (in)	I.D. (in)	Top (MD ft)	Bottom (MD ft)	Description	Comments
	DV tool (drilled out)	7.625	0.000	4,800	0		DVT @ 4,800" TVD
	Liner Hanger (sealed)	7.625	5.500	7,250	0		LNR HANGER/PKR W/ UPPER SEAL BORE

Formation Top Summary

Formation Name	Top(TVD ft)	Comments
UNDIFFERENTIATED NONMARINE STRATA	0	CORCORAN CLAY @ 666' TVD
TUMEY	3,567	
KREYENHAGEN	3,967	
DOMENGINE	4,434	
LODO	4,567	ZONE TOPS WITHIN LODO FORMATION - ARROYO HONDO @ 4567' TVD, CANTUA @ 4850' TVD, CERROS @ 5183' TVD
MORENO	5,383	ZONE TOPS WITHIN MORENO FORMATION - UPPER DOS PALOS @ 5383' TVD, CIMA SAND @ 5583' TVD, LOWER DOS PALOS @ 5816' TVD
PANOCHE D1 SANDS	7,500	ESTIMATED RESERVOIR PRESSURE - 3140 PSI
PANOCHE D2 SANDS	7,900	ESTIMATED RESERVOIR PRESSURE AT TOP OF ZONE - 3420 PSI ESTIMATED RESERVOIR PRESSURE AT TD (9000') - 3897 PSI

LAST UPDATED 8/23/17

FIGURE L-3



UNLESS OTHERWISE SPECIFIED: ALL DIMENSIONS ARE IN INCHES. BREAK ALL SHARP EDGES .01 - .03 R OR 45°.
INTERPRET DWG PER ANSI Y14.5 STANDARD. SEE B/M FOR MATERIAL AND SPECIAL REQUIREMENTS.
ITEM NUMBERS NOT APPEARING ON B/M DO NOT APPLY.

01
REV

CAD

TOLERANCE UNLESS OTHERWISE SPECIFIED
.X ±.
.XX ±.
.XXX ±.
ANGLES ±
AA ON ALL MACHINED SURFACES

SURFACE TREATMENT
MATERIAL & HEAT TREAT
SUPERSEDES
DATED

DO NOT SCALE
DRAWN BY: B SHANLEY | DATE: 08-18-17
CHECKED | DATE
APPROVED | DATE
INITIAL USE B/M: To Be Determined
SHEET 1 OF 1

CAMERON
Cooper Cameron Corporation
Cameron Division
P.O. Box 1212
Houston, TX 77251-1212

PANOCHE ENERGY
10-3/4" x 7-5/8" x 5-1/2"
MBS WELLHEAD ASSEMBLY

CAM-Q1532845

COT-21-K

D SIZE SHEET SWH

EXHIBITS

(To be Submitted on CD)

ATTACHMENT M

Construction Details

Table of Contents

List of Figures

List of Exhibits

ATTACHMENT M – CONSTRUCTION DETAILS

PERMIT APPLICATION REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment M requires the applicant to "submit schematic or other appropriate drawings of the surface and subsurface construction details of the well."

CONSTRUCTION SUMMARY AND WELL SCHEMATICS

Schematics for each existing injection well (IW1 through IW4) are provided as Figures M-1 through M-4. In addition, the following is a summary of the well completion data for each of the four injection wells at the Panoche Energy Center (PEC) site to accompany the well schematics (see Attachment I for reference to well construction history). All depths listed below and on the well schematics are relative to the applicable below kelly bushing (BKB) level at each well. In the case of IW1 and IW2, this BKB level is based on the original drilling rig used in 2009 to complete these wells (URS, 2009a; URS, 2009b). However, in the case of IW3 and IW4, this BKB level is based on the drilling rig used in late 2011 and early 2012 to side-track and deepen these wells (AMEC, 2012). Wells IW1 and IW2 are screened completions and IW3 and IW4 are perforated completions (URS, 2009a; URS, 2009b; AMEC, 2012; and Haley & Aldrich, 2014). All four current wells are completed and the additional proposed two wells (if needed) will be completed as Plan B injection wells, constructed to inject into the Upper Cretaceous age (Assemblage Zones D1, D2, E and F, see Cross Section B-B' in Attachment F) upper three sand members of the Panoche Formation, below the Marca and Tierra Loma Shale members of the Moreno Formation.

<u>IW1</u>

Original Screen Total Depth:	8,330 feet BKB (fill tagged at last Mechanical Integrity Test (MIT) at 8,245 feet BKB)
Screen Hanger Packer Depth:	7,351 feet BKB (see note below)
Uppermost Screen Top Depth:	7,460 feet BKB
Panoche Injection Zone Top Depth:	7,152 feet BKB
KB Depth Reference:	13 feet above ground level
Ground Level:	408 feet above mean sea level

Note that IW1 has a screen set inside a slotted liner with the screen packer set at 7,389 feet BKB and the outside slotted liner set with a liner hanger packer and polished bore receptacle assembly set at 7,351 feet BKB.

<u>IW2</u>

Original Screen Total Depth:	8,781 feet BKB (fill tagged at last MIT at 8,520 feet BKB)
Screen Hanger Packer Depth:	7,502 feet BKB (see note below)
Uppermost Screen Top Depth:	7,604 feet BKB
Panoche Injection Zone Top Depth:	7,142 feet BKB
KB Depth Reference:	13 feet above ground level
Ground Level:	408 feet above mean sea level

IW2 has a screen set on a liner packer at a depth of 7,502 feet BKB.

IW3

Plugged Back Total Depth:	8,947 feet BKB
Injection Packer Depth (center of element [COE]):	7,365 feet BKB
Uppermost Perforation Depth:	8,220 feet BKB
Bottom Perforation Depth:	8,880 feet BKB
Panoche Injection Zone Top Depth:	7,182 feet BKB
KB Depth Reference:	17 feet above ground level
Ground Level:	410 feet above mean sea level

The packer depth at IW3 is referenced to the COE of the packer seal assemblies in the well. Note that the wireline perforating tool used in IW3 during the May 2014 re-perforation operations became snagged entering the injection tubing (Haley & Aldrich, 2014). The tool was eventually able to be pulled through safely, but there could be a groove in the wireline re-entry guide at the bottom of the injection tubing (or some other irregularity) that could present a snagging hazard.

IW4

Plugged Back Total Depth:	8,903 feet BKB
Injection Packer Depth (COE):	7,290 feet BKB
Uppermost Perforation Depth:	7,380 feet BKB
Bottom Perforation Depth:	8,785 feet BKB
Panoche Injection Zone Top Depth:	7,109 feet BKB
KB Depth Reference:	17 feet above ground level
Ground Level:	408 feet above mean sea level

The packer depth at IW4 is referenced to the COE of the packer seal assemblies in the well.

References

1. AMEC. 2012. Deepening and Recompletion of Wells IW3 and IW4, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

2. Haley & Aldrich, Inc. 2014. Second Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

3. URS. 2009a. Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

4. URS. 2009b. Well Completion Report – UIC Well IW2, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

FIGURES

Panoche Energy Center
Well IW1

FIGURE M-1

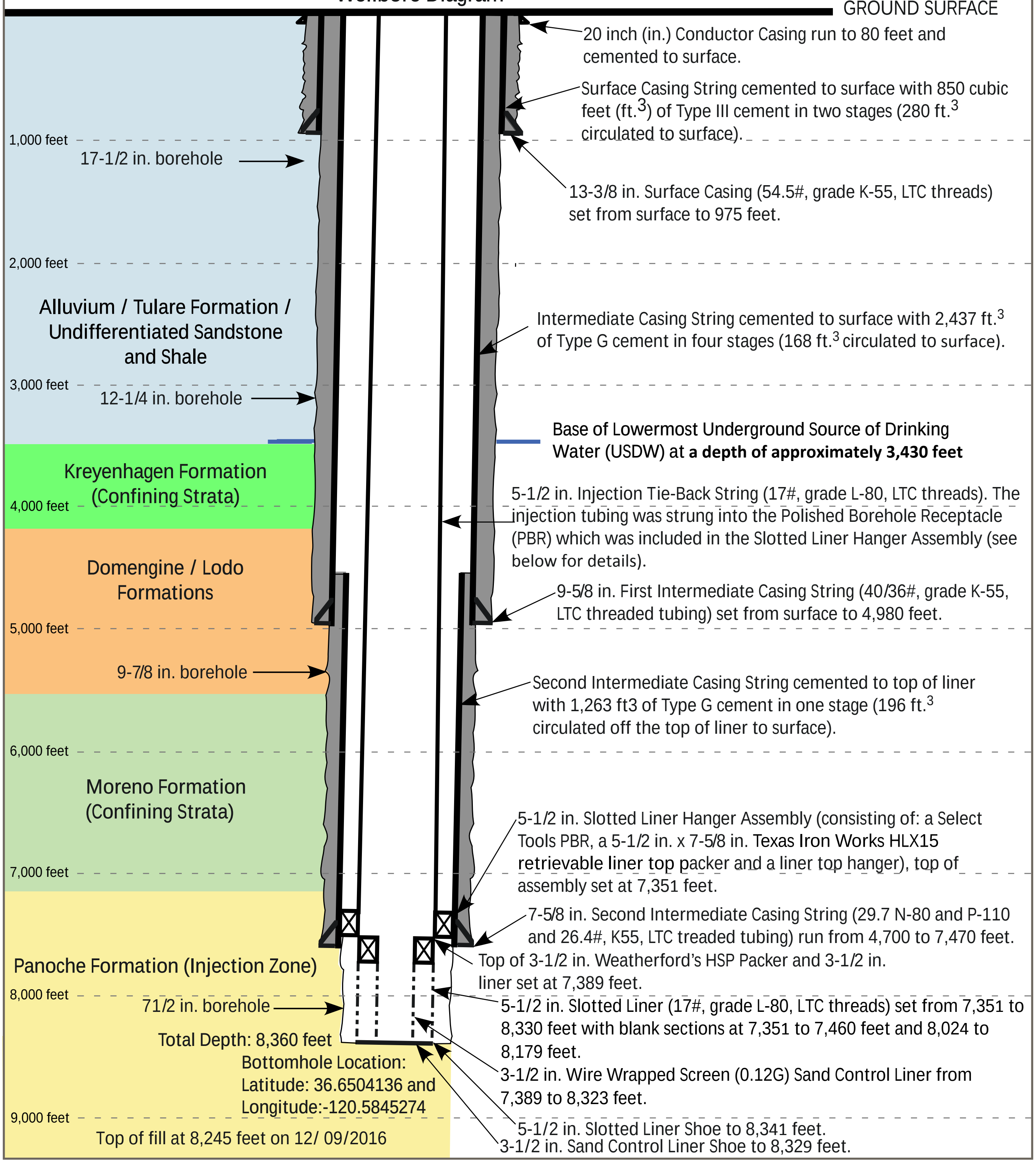
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.650645 and
Longitude:-120.5838281

Spud: September 26, 2008 Final Drilling Rig (Kenai #5)
Report: December 17, 2008 Final Completion Rig (Rival #9)
URS Completion Report: February 19, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth =13 feet (ft.) above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 12/18/2018

Panoche Energy Center
Well IW2

FIGURE M-2

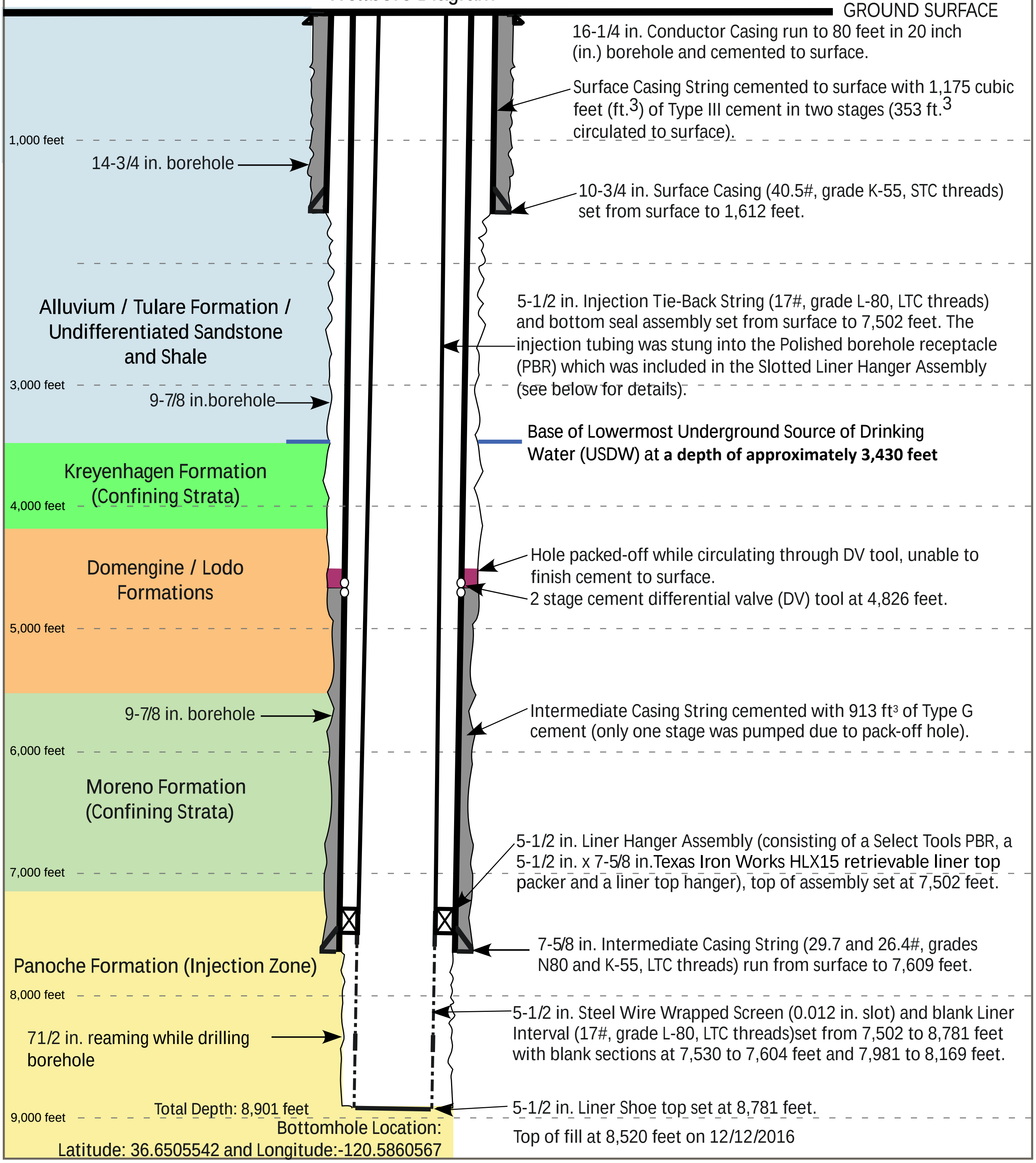
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.650588 and
Longitude:-120.5849399

Spud: December 19, 2008 Final Drilling Rig (Kenai #5)
Report: January 17, 2008 Final Completion Rig (Rival #9)
Report: January 29, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig **Kelly** busing (KB) depth =13 feet (ft.) above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 12/18/2018

Panoche Energy Center
Well IW3

FIGURE M-3

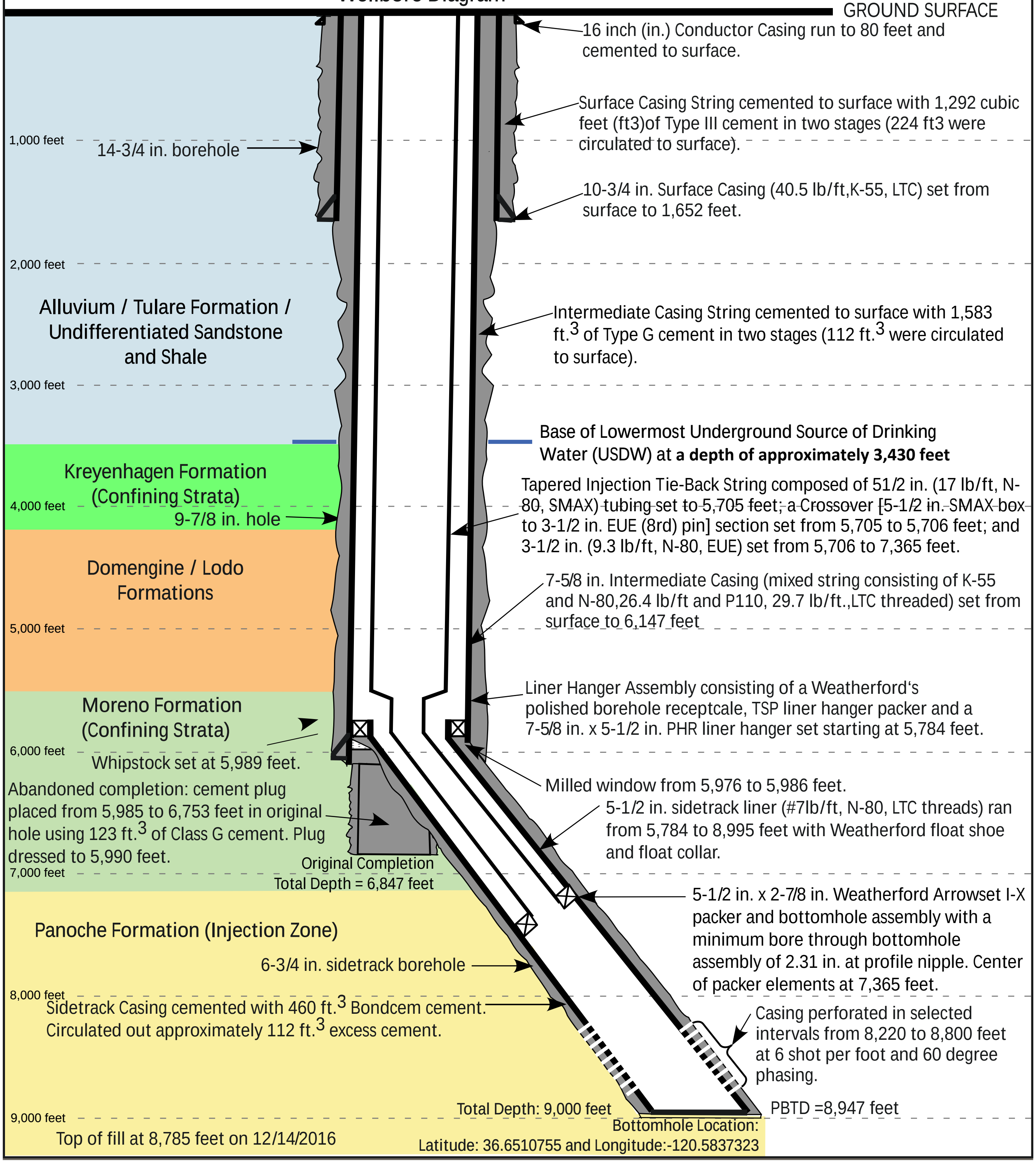
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.6506313 and
Longitude:-120.5833801

Spud: April 30, 2009
Final Original Hole Drilling Rig Report : May 25, 2009
Start of Well Deepening Sidetrack: October 19, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth = 19 feet (ft.) above Ground Surface (KB =427 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 12/18/2018

Panoche Energy Center
Well IW4

FIGURE M-4

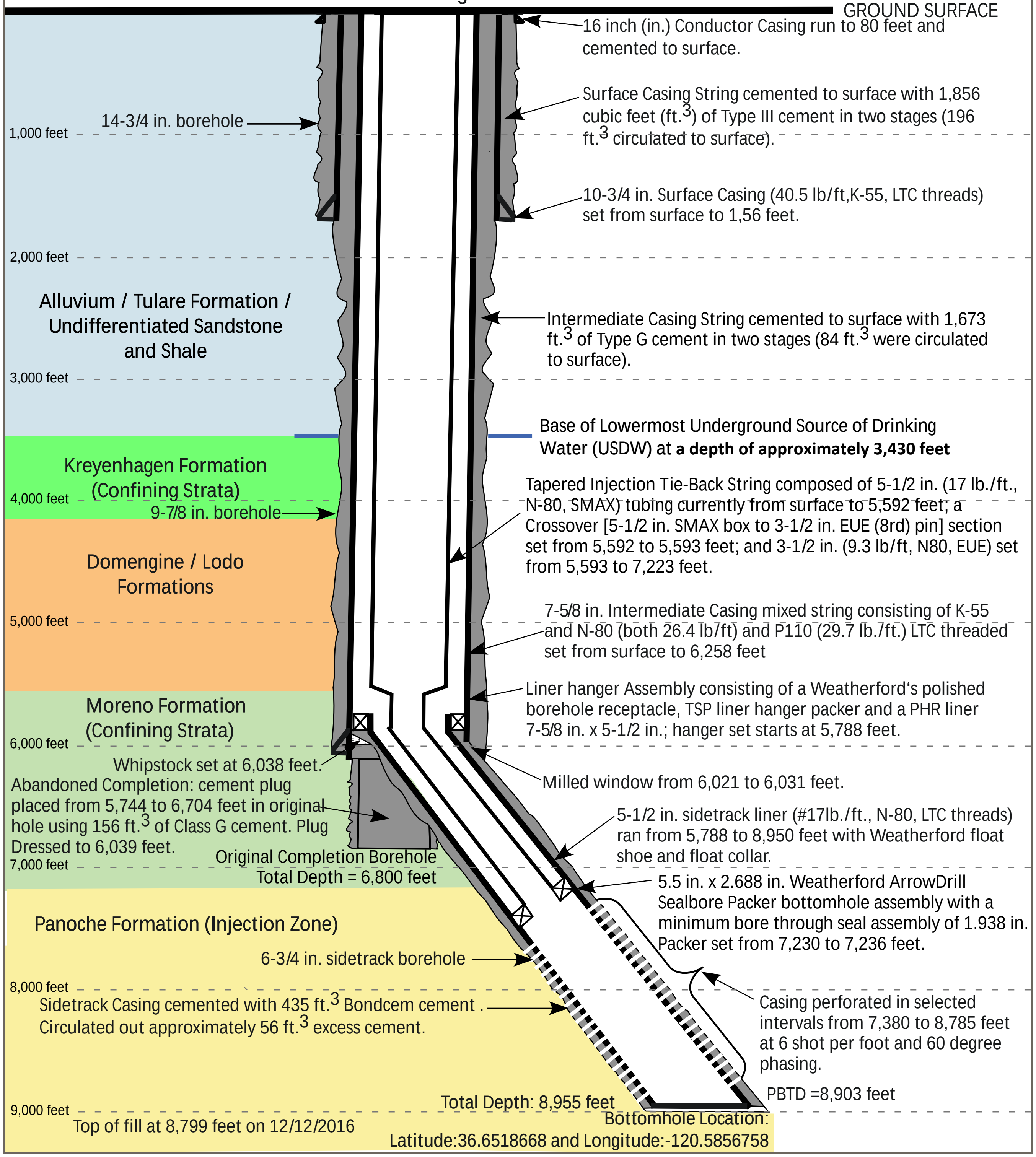
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.6509366 and
Longitude:-120.585846

Spud: May 6, 2009
Final Original Hole Drilling Rig Report: June 4, 2009
Start of Well Deepening Sidetrack: October 20, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 410 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth =19 feet (ft.) above Ground Surface (KB =429 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 12/18/2017

EXHIBITS

(To be Submitted on CD)

ATTACHMENT O

Plans for Well Failures

Table of Contents

ATTACHMENT O – PLANS FOR WELL FAILURES

PERMIT APPLICATION REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment O requires the applicant to prepare an "outline contingency plans (proposed plans, if any, for Class II) to cope with all shut-ins or wells failures, to prevent migration of fluids into any USDW."

WELL FAILURE RESPONSE

If a well is found to lack mechanical integrity, the well will be immediately shut-in and secured and the USEPA region 9 office will be notified. Once the well is secured, investigation activities will be immediately undertaken to determine if a possible release to the underground source of drinking water has occurred. In the event of tubing or packer leaks, injection at the faulty well will be suspended until the appropriate repair(s) can formulated. For pump failure, the pump, motor, or associated electrical system components will be replaced or repaired as appropriate. If the injection well is unable to be returned to service, the failed well will be abandoned in accordance with the approved plugging and abandonment plan (see Attachment Q). In addition, under the existing permit Panoche Energy Center (PEC) can drill two additional injection wells (IW5 and IW6) that can be used to replace a well that has failed beyond repair and/or provided additional long-term disposal capacity if needed.

GENERAL OPERATIONAL PLAN FOR WELL FAILURE

Wastewater at PEC primarily consists of reject water from the cooling tower system as described in Attachment H of this application. PEC currently has installed and operates four Class I injection wells (IW1, IW2, IW3, and IW4) to handle the plant's wastewater disposal needs. In addition, PEC has recently installed a new reverse osmosis wastewater treatment system to help minimize wastewater generation through enhanced treatment and reuse of cooling tower circulation water. Under typical injection operations, one or two wells are run for a relatively short period and shut-in until needed again. Also, PEC currently has approximately 700,00 gallons of available storage capacity in its wastewater storage system. As indicated in Attachment H, it is rare for PEC to use all four wells simultaneously. It is also rare for PEC to run wells for more than a continuous 24-hour period. Therefore, if a well were to lose the ability to inject, another of the facility's permitted wells would be used to inject wastewater. Because of this excess disposal capacity, any well that has failed can be shut in for the entirety of time required to investigate and remediate the well. This amount of time necessary to repair a given injection well is expected to be in the 30- to 60-day range and a maximum of 180 days. During the time that a well would be shut in, the remaining permitted facility wells would be available so that plant operations would not be affected.

Although PEC does not foresee any scenario in which injection capacity would be lost in all the facility's permitted wells at the same time, additional storage via temporary tanks could be utilized. A large amount of rental tankage is available in the local area due to agricultural needs and the proximity of developed large hydrocarbon fields in the nearby Coalinga area. Additionally, transporting waste to a commercial disposal facility permitted to accept Class I nonhazardous wastewater would be utilized as a final contingency. Several service companies have been identified in California that provide disposal of Class I nonhazardous wastes.

ATTACHMENT P

Current Monitoring Program

Table of Contents

List of Exhibits

Exhibit No.	Title
P-1	AMEC. 2011a. Work Plan for Acid Stimulation, External Mechanical Integrity Testing, and Pressure Fall-Off Testing, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.
P-2	AMEC. 2011b. Acid Stimulation, Annual External Mechanical Integrity Testing and Pressure Fall-Off Testing Report, Panoche Energy Center, LLC, Firebaugh, Fresno County, California.
P-3	AMEC. 2012a. Work Plan for Post-Workover Internal and External Mechanical Integrity Testing and Pressure Fall-Off Testing, Class 1 Nonhazardous Waste Injection Wells IW3 and IW4, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.
P-4	AMEC. 2012b, Deepening and Recompletion of Wells IW3 and IW4, Class 1 Nonhazardous Waste Injection Wells UIC Permit No. CA10600001 Panoche Energy Center, LLC s Near Firebaugh, Fresno County, California.
P-5	AMEC. 2012c, Work Plan for External Mechanical Integrity Testing of Wells IW1 and IW2, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.
P-6	AMEC. 2012d. External Mechanical Integrity Testing and Pressure Fall-Off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.
P-7	Haley & Aldrich, Inc. (Haley & Aldrich). 2012. Modified 2012 Work Plan for External Mechanical Integrity Testing and Falloff Testing, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.
P-8	Haley & Aldrich. 2013a. Procedures for Post-Fracture Stimulation External and Internal Mechanical Integrity Testing of IW3 and IW4 and Falloff Testing of IW3, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001.
P-9	Haley & Aldrich. July 2013b. IW3 Fracture Stimulation Report and Request to Operate Well IW3, Class 1 Nonhazardous Waste Injection Wells, UIC Permit Number CA10600001, Panoche Energy Center, LLC, Fresno County, California.

P-10 Haley & Aldrich. 2013c. Proposal to Perform Annual External Mechanical Integrity Testing of IW1 and IW2 and Falloff Testing of IW2, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001.

P-11 Haley & Aldrich. 2013d. 2013 External Mechanical Integrity Testing and Fall-Off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. December.

P-12 Haley & Aldrich. 2014a. First Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

P-13 Haley & Aldrich. 2014b. Second Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

P-14 Haley & Aldrich. 2014c. 2014 Work Plan for Annual External Mechanical Integrity Testing of IW1, IW2, IW3, and IW4 and Falloff Testing of IW2, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001.

P-15 Haley & Aldrich. 2014d, 2014 External Mechanical Integrity Testing and Fall-Off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

P-16 Haley & Aldrich. 2015, 2015 Work Plan for Annual External Mechanical Integrity Testing of IW1, IW2, IW3, and IW4 and Falloff Testing of IW2, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001.

P-17 Haley & Aldrich. 2016a. 2015 Annual External Mechanical Integrity Testing and Pressure Fall-Off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

P-18 Haley & Aldrich. 2016b. 2016 Work Plan for Annual External Mechanical Integrity Testing of IW1, IW2, IW3, and IW4 and Falloff Testing of IW2, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001.

P-19 Haley & Aldrich. 2017a. 2016 Annual External Mechanical Integrity Testing and Pressure Fall-Off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. January.

P-20 Haley & Aldrich. 2017b. revised 2017 Work Plan for Annual External Mechanical Integrity Testing of IW1, IW2, IW3, and IW4 and Falloff Testing of IW2, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001.

P-21	Haley & Aldrich. 2018. 2017 Annual External Mechanical Integrity Testing and Pressure Fall-Off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California. January.
P-22	URS. 2009a. Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.
P-23	URS. 2009b. Injection Well Monitoring Report, July 1 to September 30, 2009.

ATTACHMENT P – CURRENT MONITORING PROGRAM

PERMIT APPLICATION REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment P requires that the applicant "discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring."

MONITORING AND QUARTERLY REPORTING

Monitoring and recording injection pressure transducers, casing-tubing annulus pressure transducers, injection rate meters, and temperature meters were all installed in early 2009. Details of these systems can be reviewed in URS's *Well Completion Report – UIC Well IW1* (URS, 2009a) submitted to the USEPA in early 2009, and in the Second Quarter 2009 *Injection Well Monitoring Report* (URS, 2009b).

Continuous Monitoring

In accordance with the requirements of USEPA Underground Injection Control (UIC) Program Class I Non-Hazardous Waste Injection Wells Permit Number CA 10600001 (Permit), Panoche Energy Center (PEC) continuously monitors and records the following parameters for each injection well, as required by the Permit (Section D paragraph 3 [a]):

- Injection rate (gallons per minute [gpm]) – hourly;
- Wellhead injection pressure (pounds per square inch gauge [psig]) – hourly;
- Annular pressure (psig) – hourly;
- Injection fluid temperature (degrees Fahrenheit [F]) – hourly; and
- Total cumulative volume (gallons) – hourly.

The daily injection volume (in gallons) is calculated from the total cumulative volume recorded hourly. All instrumentation used to continuously monitor the parameters listed above transmit high-frequency digital data to the Emerson Ovation Distributive Control System and a plant historian stores the digital data for reporting and archiving purposes. The data collected are precise to at least one tenth of the unit measured for gallons, gpm, psig, and degrees F. All instruments are calibrated and maintained on a regular basis to maintain sufficient sensitivity and accuracy per the Permit requirements in Section D paragraph 3(b).

The dates and times of all recorded hourly monitoring data (extracted from the archived, high-frequency data discussed above) have been reported on a quarterly basis to the USEPA, presented on a compact disc included in each of these quarterly reports following the specific data format requirements listed in the current UIC Permit. Tables that show the monthly average values and the minimum and maximum values of the parameters monitored and show the monthly recordings of the total cumulative injectate volume for the total lifetime of each well. Wastewater is injected into the wells intermittently, depending on plant operations, and a second table that shows the values of the monitoring parameters for the injection periods is also submitted with each quarterly report.

All monitoring and recording equipment is calibrated and maintained on a regular basis to ensure proper working order of all equipment.

Quarterly Injection Fluid Characterization

The current permit requires that the injection fluids be analyzed to yield representative data on their physical, chemical, and other relevant characteristics on a quarterly basis, or when there is a significant change in injection fluid (Section D paragraph 1 of PEC's USEPA Permit). The injection fluids for wells IW1 through IW4 originate from the same wastewater storage tank before the injectate is split and sent to all four wellheads. Therefore, a single sample of injection fluid (a composite of all plant inputs) is collected by PEC staff each quarter and submitted to BSK Laboratories, Inc. of Fresno, California, a California Environmental Laboratory Accreditation Program-certified laboratory, for analysis of the constituents and parameters specified in the Permit (Section D paragraph 1[a]). Per the requirements of the current USEPA UIC permit, the following analyses are performed on a quarterly basis:

- Alkalinity, Bicarbonate, Carbonate, and Hydroxide all using Standard Method (SM) 2320B;
- Biochemical Oxygen Demand using SM 5210B;
- Chloride, Nitrate, Orthophosphate, and Sulfate using USEPA 300.0;
- Conductivity using SM 2510B;
- Fluoride using SM 4500-F C;
- Major anions and cations mass balance using SM 1030E (which is equivalent to USEPA method 300.0);
- pH using SM 4,500 H+B;
- Phosphorus using USEPA Method 365.4;
- Total dissolved solids and total suspended solids using SM 2540C and 2540D, respectively (both methods are equivalent to USEPA Methods 160.1 and 160.2);
- Turbidity using SM 2130B;
- Trace dissolved metals using USEPA Methods 200.7 and 200.8;
- Semi-volatile organic compounds using USEPA Method 8270C; and
- Volatile organic compounds using USEPA Method 8260B.

A summary table of these results and a copy of chain-of-custody documentation and the laboratory reports have been included in each quarterly report submitted to the USEPA since 2009. These analytical data were also evaluated using guidelines set forth in the USEPA's 2008 *Contract Laboratory Program National Functional Guidelines for Superfund Organic Methods Data Review* and the USEPA's 2010 *Contract Laboratory Program National Functional Guidelines for Inorganic Superfund Data Review*. The results of the data quality review show that the analytical results of these constituents listed above are valid and usable.

ANNUAL REPORTING AND TESTING

Annual Reporting

Determination of the cumulative behavior of the static shut-in reservoir pressure of the injection zones is required annually per Section A paragraph 5(c)(iii) of the Permit. Data to be collected from the most recent fall-off test (FOT), in conjunction with previously collected data, are used to further characterize the cumulative behavior of the shut-in static reservoir pressure of the Panoche Formation injection zone. In addition, a recalculation of the Zone of Endangering Influence is performed annually per Section B paragraph 2 of the Permit. The annual reporting summaries (Form 7520-14 in Appendix C of the Permit) for each well (IW1 through IW4) have been presented in all fourth quarter injection monitoring reports submitted to the USEPA over the last eight years.

Internal Mechanical Integrity Testing

As stated in the United States Code of Federal Regulations, Title 40,Part 146, Subpart A – General Provisions § 146.8 Mechanical integrity (b) "One of the following methods must be used to evaluate the absence of significant leaks under paragraph (a)(1) of this section: (1) Following an initial pressure test, monitoring of the tubing-casing annulus pressure with sufficient frequency to be representative, as determined by the Director, while maintaining an annulus pressure different from atmospheric pressure measured at the surface; (2) Pressure test with liquid or gas." (Office of the Federal Register, 2019)

PEC currently has installed and operates four Class I nonhazardous injection wells (IW1, IW2, IW3, and IW4) under USEPA Region 9 permit number CA10600001. In accordance with the UIC permit and with 40 CFR 146.8, a demonstration of internal (between the casing and tubing) mechanical integrity is required every five years during the life of the well and within 30 days from the completion of any workover that results in the unseating of the injection packer or where the wellhead assembly seal is broken (Section C paragraph 2(b)(i) of the current UIC Permit). Additionally, an internal mechanical integrity test (MIT) is required if the construction of the well is modified or if any loss of mechanical integrity becomes evident during well operation.

The following are the dates the latest internal MITs were successfully performed at PEC:

- **Well IW1:** 4 May 2014 (Haley & Aldrich, 2014b);
- **Well IW2:** 6 March 2014 after minor repair of the wellhead (Haley & Aldrich, 2014a);
- **Well IW3:** 15 May 2013 after fracture stimulation of IW3 (Haley & Aldrich, 2013b); and
- **Well IW4:** 16 June 2014 after successful repair of this well (Haley & Aldrich, 2014a).

Therefore, the next internal MIT of well IW3 is due in 2018; the next internal MITs for wells IW1, IW2, and IW4 are due in 2019.

Internal MIT procedures

The general internal mechanical integrity testing procedures are outlined as follows:

1. Insure all personnel performing mechanical integrity activities attend the required PEC formal plant orientation and safety training prior to beginning work. Note that a

minimum 12-hour static (no injection) stabilization period is recommended prior to performing the internal MIT test to allow the wellbore to thermally equilibrate.

2. Mobilize, connect, and plumb a calibrated testing gauge to the annulus port opposite the plant pressurization and monitoring system connection on the wellhead.
3. Adjust the annulus pressure on the well to slightly greater than the maximum permitted surface injection pressure using plant pressurization system or external high-pressure pump.
4. Disconnect or isolate the pressurization source and allow the annulus a short stabilization period while monitoring the annulus pressure. Observe the surface system and pressure gauge for leaks, and repair as necessary.
5. Once stabilization is achieved, continue monitoring and recording the internal mechanical integrity pressure test digitally or on chart recorder. Allow the annulus test to run for a minimum of 30 minutes. A successful test is achieved if the internal annulus pressure changes less than 5 percent over a 30-minute period.
6. Upon completion of a successful test, remove the pressure gauge and adjust the annulus pressure as necessary for plant operations.
7. Once all equipment is removed, receive the preliminary data report from the service company, including calibration documentation for the pressure gauge utilized. Clean up the location and release any ancillary equipment as needed.

External Mechanical Integrity Testing

External Mechanical Integrity Testing (MITs) are required annually in all operating injection wells in accordance with the requirements of PEC's UIC Permit. The purpose of these external MITs is to demonstrate that the fluid injected into the well is confined to the permitted injection zone and does not cause significant flow within or between underground sources of drinking water (USDWs). The external MITs consist of a baseline temperature log and temperature decay log combined with a radioactive tracer (RAT) survey at each well, as required to comply with annual well integrity testing requirements per Section C paragraph 2(b)(ii) of the Permit, USEPA Region 9 Temperature Guidelines (USEPA, 2008), and Draft Radioactive Tracer Survey Guideline (USEPA, 2012). A work plan that requests any specific changes to proposed procedures are to be submitted for USEPA's approval in advance of scheduling or conducting any of these operations. After receiving USEPA approval of a work plan, a start date is selected and the USEPA is will be notified at least 30 days in advance of beginning this work. An Annual MIT and FOT report will be submitted to USEPA within 60 days after completion of these operations.

The External MITs on IW1, IW2, IW3, and IW4 have consisted of a baseline survey and a temperature decay survey and a RAT survey (using radioisotope Iodine-131) performed at each injection well following the USEPA guidance discussed above. External MITs were proposed (AMEC, 2011a; AMEC, 2012a; AMEC, 2012c; Haley & Aldrich, Inc. [Haley & Aldrich], 2012; Haley & Aldrich, 2013a; Haley & Aldrich, 2013c; Haley & Aldrich, 2014c; Haley & Aldrich, 2015; and Haley & Aldrich, 2016b; and Haley & Aldrich, 2017b) and successfully performed annually for the duration of the current permit (AMEC, 2011b; AMEC, 2012b; AMEC, 2012d; Haley & Aldrich, 2013b; Haley & Aldrich, 2013d; Haley & Aldrich, 2014d; Haley & Aldrich, 2016a; Haley & Aldrich, 2017a; and Haley & Aldrich, 2018).

The temperature decay survey results are used to evaluate the containment of injection fluids within the permitted injection zone, and to assess whether injection is inducing significant fluid movement within or between USDWs. A temperature decay survey consists of two separate temperature logging passes under no-flow conditions. Prior to temperature logging, the well is shut-in for a minimum of 12 hours. A wireline unit and pressure lubricator are rigged up with the temperature, gamma ray and casing collar locator (CCL) tools. The logging tool is run in the well and then retrieved from the well to allow a minimum 4 hours of additional shut-in time before running the second temperature log. The logs presented in each annual report include full and complete heading information, and include all pertinent information, such as correct well name, location, and elevations. Temperature versus depth data from the 2013, 2014, and 2015 decay surveys (Haley & Aldrich, 2013b; Haley & Aldrich, 2013d; Haley & Aldrich 2014d; Haley & Aldrich, 2016a; and Haley & Aldrich, 2017b) were presented together for comparison in Figures 1 through 4 in the 2016 MIT and FOT Report (Haley & Aldrich, 2017a). These temperature profiles exhibit a general warming trend (with increasing depth) from the surface to the top of the fluid-receiving interval. The temperature differential curves exhibited some minor oscillations associated with lithology changes and thermal properties of the sediments. Below the top of the receiving interval, the profiles indicate a normal cooling trend resulting from 1) the lack the well annulus acting as an insulator for the tool and 2) the effects of the relatively cooler injectate entering the injection zone.

During the RAT surveys, the RAT slug (as described below) is tracked and recorded (i.e., profiled) utilizing gamma ray (GR) detectors from above the injection string packer until it dissipates into the injection zone, to verify that all flow into the well is passing into the injection zone and does not result in upward flow behind the well casings above the top of the injection zone. The presence or absence of upward flow is also evaluated through a RAT survey in a stationary time-drive mode with the GR detectors located above the uppermost screened section in each well. In addition, the RAT survey is used to determine the volumetric flow profile of the injection fluid as it passes into the injection zone by analyzing the velocity of the slug moving downward past the GR detectors.

External MIT Procedures

The following is a summary of the external MIT procedures that were submitted to the USEPA Region 9 office on 14 October 2016 (Haley & Aldrich, 2016b) and approved by USEPA on 2 November 2016. Note that an estimated daily work schedule is provided as Attachment A to that proposal (Haley & Aldrich, 2016b).

1. Arrive at site and sign in at main office. At the time of arrival, IW1 should have been shut-in for a minimum of 12 hours for temperature stabilization prior to temperature logging (if possible, a longer period of temperature stabilization of 24 hours or longer is preferred). Check with control room to verify that well IW1 has been shut-in as planned, and confirm the schedule for sequential shut-in of IW2, IW4, and IW3 as the field plan progresses. Check the master wellhead valve at IW1 to verify that wellhead is closed. Use a needle valve in top bull plug to vent any trapped pressure above master valve.
2. Rig-up logging truck at the IW1 wellhead. Tooling will consist of a temperature tool, dual GR detectors, and CCL. Tools can be combined based on logging contractor specifications. Load the logging tool(s) into a pressure lubricator and mount lubricator to wellhead. Pressurize the lubricator, open the master wellhead valve, and begin temperature logging as follows:

a. The tool will be run downward at a rate of 20 to 50 feet per minute (recommended speed is approximately 40 feet per minute).

b. Other recording tracks will include:

- Depth and logging speed,
- Gamma ray or spontaneous potential curve for lithologic correlation, and
- CCL.

3. The temperature log will be recorded with depth on a vertical scale of 1 or 2 inches = 100 feet and temperature on a horizontal scale of 5 degrees F per inch (1 degree F per log scale division). The logging tool will be run from the surface to the total well depth (all wells at PEC site are normally under positive pressure, such that the fluid level is always up to the top of the wellhead). Note that a differential temperature track may be added to the final log following data processing by the logging contractor.
4. Tag total depth of the well and perform a correlation check and depth adjustment relative to the packer setting depth using the CCL, and then pull the tool up to the surface. Repeat Step 3 after 4 hours has elapsed since the start of initial temperature logging.
5. Pull out of well and close the master valve, and then change the logging tool to a dual-detector RAT tool with ejector port (used to release and measure the Iodine-131 tracer) if the RAT tool is not already assembled as part of the original logging tool string.
6. If applicable, re-mount the lubricator to the wellhead, pressurize the lubricator, and open the master wellhead valve.
7. If sufficient supplies of process wastewater or firewater are available, begin pumping water into well at the maximum practicable rate (not to exceed maximum allowable injection pressure) that allows for proper RAT profiling, with at least three slug-catching well profiles. Normal operating wellhead pressure is approximately 1,900 psi and should serve as a practical limit for this testing. If insufficient water supplies available, delay the start of pumping until Step 14. Normal plant injection rates for all site wells range from approximately 40 to 120 gpm, depending on the specific well, how much recent injection activity it has received, and when the well was last stimulated with acid.
8. Lower the logging tool at maximum safe line speed to newly measured total depth (See Step 4).
9. Run a 400-foot test log within the screened/perforated injection zone (i.e., injection interval) and correlate logging depth using gamma ray log and CCL.
10. Run pre-test baseline survey from total depth upward to approximately 100 feet above the top of the injection zone. The recommended logging speed is approximately 30 feet per minute, and gamma scale will be determined by formation characteristics.
11. Lower the logging tool to the top of the injection zone and record a statistical check for 5 minutes.
12. Re-position the logging tool to 50 feet above the uppermost screened/perforated interval and record a statistical check for 5 minutes.
13. Re-position the logging tool to 100 feet above the injection zone top (inside injection tubing).
14. Ensure that the process water injection rate listed in Step 7 above is established, and release of an Iodine-131 tracer slug (RAT slug) and verify passage of slug with dual detectors.

15. Immediately lower the logging tool lower detector below the RAT slug and log upward at 60 feet per minute until the slug is completely passed. Log up to initial slug release depth of 100 feet above the top of the injection zone.
16. Lower the logging tool back down below the slug and log upward at 60 feet per minute until the slug has completely passed and the detector reaches the previous depth where the slug was caught.
17. Repeat Step 16 until the RAT slug is fully dissipated from the borehole and a representative profile is obtained of injection flow down the well and into the injection zone. If the initial injection rate is too high to enable accurate flow profiling (minimum of three slug catches), then reduce the injection rate as needed. If the flow can be increased and still allow for accurate flow profiling of at least three slug catches, then increase the flow rate accordingly.
18. Re-position the logging tool at 100 feet above the top of the injection zone and increase injection rate to normal plant conditions (as long as flow is not so high that it could pump the logging tool loose from the wireline socket) and release a second Iodine-131 slug (verifying passage of slug with dual detectors). Then lower the detector to a depth below the bottom of the injection tubing and wait for slug arrival, and then lower detector to 50 feet above uppermost screened/perforated interval and wait for slug passage. Once the slug passes, use this travel time from the previous catch depth below injection tubing to calculate "3t," which is the round-trip iodine tracer slug travel time from (1) the detector depth at 50 feet above the uppermost screened/perforated interval, down to (2) the top of the screen/perforations, and back to (3) the detector (100 feet round trip). If the slug is detected, profile upward to ensure that it does not reach the top of the permitted injection zone.
19. Repeat Steps 14 through 17 for duplicate profiling of Iodine-131 tracer slug.
20. Re-position the tool at total depth and log a post-test (final) survey upward to a depth of 100 feet above the injection zone top at a recommended logging speed of approximately 30 feet per minute using the same pumping conditions as used during the pre-test baseline survey in Step 10.
21. Compare the logs from the pre-test baseline survey from Step 10 and the final survey from Step 20 to determine mechanical integrity.
22. If the RAT survey results are normal, then complete velocity shots in the screened/perforated interval, discharge the remaining RAT material, shut off flow to the well, pull the tool to surface, close the master valve, and clean up the site. External MIT tasks at this well are now complete.
23. Move to IW2 and complete all applicable above-listed steps.
24. Move to IW4 and complete all applicable above-listed steps.
25. Move to IW3 and complete all applicable above-listed steps. As previously noted, the wireline perforating tool used in IW3 during May 2014 became snagged entering the injection tubing. The tool was eventually able to be pulled through safely, but there may be a groove in the wireline re-entry guide at the bottom of the injection tubing (or some other irregularity) that may present a snagging hazard. This should be kept in mind during all wireline work at IW3 until this issue is resolved, and for this reason, the MIT at IW3 should be completed last.
26. The temperature, RAT, and velocity shot survey data will be stored electronically (in Excel format) in addition to the hard copy logs, PDF files, and LAS files.

27. Remove all non-plant test equipment, clean up well site, and return the well back to its original configuration. All testing is complete. If all test results are normal, all the tested wells can be released back to the plant for normal injection operations.

Fall-Off Testing

As required by Title 40 CFR § 146.13, monitoring of the pressure buildup in the injection zone is required annually by shutting down the injection well for a time sufficient to conduct a valid observation of the pressure fall-off curve. Pressure FOTs are required to be run annually per Section C paragraph 2(b)(iii) of the Permit.

All the wells currently receiving wastewater injectate onsite at PEC are completed in the same injection zone, the Panoche Formation. Although an FOT that covers all four site injection wells (IW1, IW2, IW3, and IW4) is required on an annual basis, historically the FOT has been conducted at IW2 since this well is completed in a relatively extensive section of the Panoche Formation, and therefore, is representative of PEC's injection zone at all four wells. FOTs have been performed at IW2 annually beginning in 2011 and the results have been presented in subsequent Annual External Mechanical Integrity Testing and Pressure Fall-Off Testing Reports (AMEC, 2011b; AMEC, 2012b; AMEC, 2012d; Haley & Aldrich, 2012; Haley & Aldrich, 2013a; Haley & Aldrich, 2013d; Haley & Aldrich, 2014d; Haley & Aldrich, 2016a; and Haley & Aldrich, 2017a; and Haley & Aldrich, 2017a). During conventional reservoir pressure build-up/fall-off at well IW2, simultaneous monitoring of pressure interference at IW1, IW3 and IW4 is performed annually.

FOTs were also completed in the newly deepened wells IW3 and IW4 in 2012 (AMEC, 2012a). The separate analyses of the FOTs using the wellhead pressure data yield similar results for IW3 and IW4, showing flow capacities and the permeabilities that are within the same order of magnitude for both wells (Table 3 in AMEC, 2012a). Another FOT was also completed at IW3 in May of 2013 following the hydraulic fracture stimulation workover completed at that well (Haley & Aldrich, 2013b). This was done to provide a post-fracture basis of comparison regarding the reservoir characteristics at IW3 compared to the non-fractured reservoir response at IW2. Analysis of these additional test was presented in the 2014 Work Plan for annual MIT and FOT testing (Haley & Aldrich, 2014c). Comparison of both IW3 FOTs indicate that the hydraulic characteristics near IW3 before and after the fracture stimulation can be adequately described by a radial flow reservoir model. Additionally, these results indicate that the IW3 flow characteristics near the wellbore after the fracture stimulation remain similar to the pre-fracture-stimulation conditions and are comparable to the conditions at IW2. Based on the trends of injection rates and pressure fall-off due to the intermittent nature of plant operation, these four wells have shown similar injectivity and fall-off behavior. Thus, it has been proposed that FOT analysis of IW2 will be sufficient to characterize the current Panoche Formation injection zone.

Note that all wells at the PEC site are normally under positive pressure, and the fluid pressure level is generally above the top of the wellhead. The FOT is normally based on surface pressure data[1] recorded by either dedicated test transducers connected to the tubing and annulus, or the plant's normal

[1] In 2011, data was collected to confirmed that wellhead pressure gauges are accurate for FOT analysis, after it was shown that the fall-off curves of surface gauge and downhole memory gauge data were nearly identical (after accounting for the pressure difference between each gauge). See the *2011 Acid Stimulation, Annual External Mechanical Integrity Testing and pressure Fall-Off Testing Report* (Haley & Aldrich 2011b) for details. Therefore, it is appropriate to record the FOT using pressure transducers connected to the wellhead at the surface. This method has been shown to result in the collection of reliable and usable FOT data.

pressure monitoring system. These data allow for the test to be evaluated in real-time. A memory gauge is normally connected to the tubing and annulus to provide back-up data collection if the primary data source fails.

In addition, conventional analysis is performed using the data collected at well IW2, in accordance with the 2002 USEPA Region 9 UIC Pressure Fall- Off Requirements document (USEPA, 2002), and is included as Appendix E of PEC's Permit. This analysis of the data includes using diagnostic log-log and semi-log plots of the fall-off test data, generated using RDS's TRANS II Pressure Transient Analysis software or an equivalent software package, to determine if the calculated transmissivity value, using FOT test data, are within the expected range and to satisfy USEPA's overall requirements. Plant data from the other site wells are normally obtained and reviewed for evidence of interference associated with injection in the tested well.

Fall -Off Testing Injection Period Rational

After reviewing past FOT data and plant operations data, a 12-hour injection period or longer is considered sufficient because (1) the potential influence of intense injection prior to the FOT can be addressed by incorporating the pre-test injection rates into the FOT analysis (using the mathematical principle of superposition) and (2) the time to reach radial flow (1 to 2 hours), "t" is compliant with the USEPA's FOT guidance document, which provides a rule of thumb that the injection or fall-off time needs to be sustained for 3 to 5 times the time it takes to reach radial flow. A more detailed explanation was presented in the letter response to USEPA comment on the 2015 FOT and MIT proposal. This letter response focused on how the plant operations, prior to a FOT test, will affect the FOT results and what analysis method can be used to mitigate the influence of pre-test operations. It also should be noted that in all cases, real-time data are evaluated in the field to determine when each phase of a test can be terminated.

Proposed Fall-Off Testing of IW2 Procedures

The following is a summary of the FOT procedures that were submitted to the USEPA Region 9 office on 14 October 2016 and approved by USEPA on 2 November 2016. Note that an estimated daily work schedule is provided as Attachment A to that proposal (Haley & Aldrich, 2016b). After receiving USEPA approval of this work plan, a start date will be selected and the USEPA will be notified at least 30 days in advance of beginning this work. An Annual MIT and FOT report is submitted to USEPA within 60 after completion of these operations.

1. Shut-in IW2 for reservoir pressure stabilization a minimum of 48 hours prior to testing.
2. Install a memory gauge on the injection tubing side and annulus side of wellhead for back-up data collection. This will allow for approximately 48 hours of background data collection by the memory gauge before the start of injection into IW2. The recommended memory gauge minimum data recording frequency is one measurement every 15 seconds. Set the plant's injection tubing and annulus pressure monitoring frequency for IW2 (and all three other site wells if possible) at one measurement every 15 seconds or closest frequency within the capability of the plant's pressure monitoring system.
3. If possible, shut in all three of the other plant wells using normal plant procedures. If not possible, then monitor other site wells for pressure interference using plant's pressure

monitoring system while conducting reservoir testing at IW2. A constant injection rate will be maintained prior to and during the test.

4. Once relatively stable background pressure conditions are reached, begin injection at as constant a rate as possible. Based on an evaluation of the real-time field data from the plant's pressure monitoring system from the last FOT at IW2, as noted above, 12 hours of injection and 48 hours of pressure fall-off should be used as the testing duration targets.
5. Once radial flow conditions are reached based on a real-time field evaluation of the pressure data, shut down the injection flow to well IW2 as quickly as possible using normal plant procedures. However, leave the master valve and main (manual) flow valve to the well open so that the plant's pressure monitoring system can read pressure data from the tubing side of the wellhead (only the electronic flow valve to the well will be closed by plant operations staff). A data recording frequency of at least one measurement every 15 seconds is recommended.
6. Monitor pressure fall-off response in real-time using the plant's pressure monitoring system. Terminate the test once fully-analyzable data are obtained. Download and save multiple copies of all wellhead tubing and annulus pressure data, wellhead memory gauge data, and plant injection flow data.
7. Remove all non-plant test equipment, clean up well site, and return the well back to its original configuration.

References

1. AMEC. 2011a. Work Plan for Acid Stimulation, External Mechanical Integrity Testing, and Pressure Fall-Off Testing, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

2. AMEC. 2011b. Acid Stimulation, Annual External Mechanical Integrity Testing and Pressure Fall-Off Testing Report, Panoche Energy Center, LLC, Firebaugh, Fresno County, California.

3. AMEC. 2012a. Work Plan for Post-Workover Internal and External Mechanical Integrity Testing and Pressure Fall-Off Testing, Class 1 Nonhazardous Waste Injection Wells IW3 and IW4, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

4. AMEC. 2012b. Deepening and Recompletion of Wells IW3 and IW4, Class 1 Nonhazardous Waste Injection Wells UIC Permit No. CA10600001 Panoche Energy Center, LLC s Near Firebaugh, Fresno County, California.

5. AMEC. 2012c. Work Plan for External Mechanical Integrity Testing of Wells IW1 and IW2, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

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8. Haley & Aldrich. 2013a. Procedures for Post-Fracture Stimulation External and Internal Mechanical Integrity Testing of IW3 and IW4 and Falloff Testing of IW3, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001.

9. Haley & Aldrich. 2013b. IW3 Fracture Stimulation Report and Request to Operate Well IW3, Class 1 Nonhazardous Waste Injection Wells, UIC Permit Number CA10600001, Panoche Energy Center, LLC, Fresno County, California. July.

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12. Haley & Aldrich. 2014a. First Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

13. Haley & Aldrich. 2014b. Second Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

14. Haley & Aldrich. 2014c. 2014 Work Plan for Annual External Mechanical Integrity Testing of IW1, IW2, IW3, and IW4 and Falloff Testing of IW2, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001.

15. Haley & Aldrich. 2014d. 2014 External Mechanical Integrity Testing and Fall-Off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

16. Haley & Aldrich. 2015. 2015 Work Plan for Annual External Mechanical Integrity Testing of IW1, IW2, IW3, and IW4 and Falloff Testing of IW2, Panoche Energy Center, Firebaugh, California, EPA UIC Permit No. CA10600001.

17. Haley & Aldrich. 2016a. 2015 Annual External Mechanical Integrity Testing and Pressure Fall-Off Testing Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit No. CA10600001, Panoche Energy Center, LLC, Near Firebaugh, Fresno County, California.

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27. USEPA. 2008. Contract Laboratory Program National Functional Guidelines for Superfund Organic Methods Data Review.

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EXHIBITS

(To be Submitted on CD)

ATTACHMENT Q

Plugging and Abandonment Plan

Table of Contents

List of Tables

List of Figures

List of Exhibits

ATTACHMENT Q – PLUGGING AND ABANDONMENT PLAN

PERMIT APPLICATION REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment Q requires the applicant to “Submit a plan for plugging and abandonment of the well including:

1) describe the type, number, and placement (including the elevation of the top and bottom) of plugs to be used;
2) describe the type, grade, and quantity of cement to be used; and
3) describe the method to be used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs. Also for a Class III well that underlies or is in an exempted aquifer, demonstrate adequate protection of USDWs. Submit this information on EPA Form 7520-14, Plugging and Abandonment Plan.”

PLUG AND ABANDONMENT PLANS AND COST ESTIMATES

As requested by the USEPA in correspondence dated 7 September 2018, Panoche Energy Center has developed and plugging and abandonment plan for each well that will include the emplacement of a full column of cement in the respective wellbore thus exceeding the requirement of 40 CFR 146.10. Specific information as to the placement method and the type, grade, and quantity of cement to be used for each well is included in Tables Q-1 though Q-6 and in Figures Q-1 though Q-6. In addition, cost estimates for plugging and abandonment have been prepared and are included as Tables Q-7 through Q-12. The proposed plug and abandonment cementing programs for each existing well (IW1, IW2, IW3, and IW4) and undrilled but permitted wells IW5 and IW6 are included in Exhibit Q-1. In addition, a USEPA Form 7520-14 (Plugging and Abandonment Plan) has been prepared for each of the existing wells. The forms are included in Exhibit Q-2. Note that because IW5 and IW6 are undrilled, the required forms cannot be completed at this time because no specific location or construction information exists. Therefore, the required form will be prepared and submitted with the respective completion reports for these wells when they are installed.

TABLES

TABLE Q-1

IW1 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 220 bbls to kill tubing & 510 bbls to kill well with tubing removed)
4	e.	Rig up for laying down injection tubing. Kill injection tubing.
	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW1* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 185 bbls or approximately 670 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Pump second plug per cementing program for IW1* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 306 bbls or approximately 1085 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	p.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

TABLE Q-2

IW2 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 225 bbls to kill tubing & 385 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW2* through 2-inch coiled tubing from PBTD to approximately 4,830 ft. Plug to consists of approximately 175 bbls or approximately 630 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Rig up wireline and shoot approximately 5 feet of perforations at 4,820 ft. for squeeze cementing of 7 5/8-inch longstring casing.
	o.	POOH with perforating guns and run in hole with 7 5/8-inch cement retainer to set at approximately 4,805 feet.
	p.	Run in hole with coiled tubing and sting into retainer. Open backside and squeeze cement 7 5/8-inch x 9 7/8-inch hole and 7 5/8-inch x 10 3/4-inch casing with 725 sx premium cement mixed to 13.5 ppg as per squeeze cementing program for IW2*. Unsting from retainer and leave 20 feet of cement on top of retainer and reverse clean. Pull out of hole and wait on cement to cure.
8	q.	Rig up wireline and run CBL on squeezed interval.
	r.	Run in hole with CT to bottom.
	s.	Pump second plug per cementing program for IW2* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 224 bbls or approximately 805 sx premium cement.
	t.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
9	u.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	v.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	w.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

TABLE Q-3

IW3 Proposed Plugging Program

Day	Task	Task Description
1	**a.**	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	**b.**	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	**c.**	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 184 bbls to kill tubing & 346 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	**f.**	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5 x 3.5-inch injection tie-back string and lay out to pipe racks.
5	**i.**	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	**k.**	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW3* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 159 bbls or approximately 575 sx premium cement. Wait appropriate amount of time for plug to cure.
7	**m.**	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Pump second plug per cementing program for IW3* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 185 bbls or approximately 660 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	**p.**	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

TABLE Q-4

IW4 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 182 bbls to kill tubing & 346 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5 x 3.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW4* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 158 bbls or approximately 570 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	approximately 185 bbls or approximately 660 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	p.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

TABLE Q-5

IW5 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 210 bbls to kill tubing & 375 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW5* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 194 bbls or approximately 700 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Pump second plug per cementing program for IW5* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 185 bbls or approximately 660 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	p.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

TABLE Q-6

IW6 Proposed Plugging Program

Day	Task	Task Description
1	**a.**	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	**b.**	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	**c.**	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 210 bbls to kill tubing & 375 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	**f.**	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5-inch injection tie-back string and lay out to pipe racks.
5	**i.**	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	**k.**	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW6* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 194 bbls or approximately 700 sx premium cement. Wait appropriate amount of time for plug to cure.
7	**m.**	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Pump second plug per cementing program for IW6* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 185 bbls or approximately 660 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	**p.**	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

TABLE Q-7

ESTIMATED PLUGGING COST FOR IW1

	Description	Rate	Unit	No. of Units	Estimated Cost
1	Frac Tanks (2) with mob/demob/plumbing/cleaning	$125	day	8	$1,000.00
2	Location Services (Forklift, Transfer Pump, hoses, Trash Service, Latrine, etc.)	$250	day	8	$2,000.00
3	Mechanical Integrity Testing Wireline Work		job	-	$12,000.00
4	Workover Rig (with 1/2 day each for Mob & Demob)	$6,000	day	3	$18,000.00
5	Workover Fluids (10 lb/gal brine) delivered	$12	barrel	730	$8,760.00
6	Spear, accessories, & service tech for releasing tubing from hanger		job		$1,500.00
7	Injection Tubing Laydown Services (tongs, handling tools, laydown machine, etc.)		job		$7,500.00
8	Multifinger Caliper/Casing Inspection Log and running service		estimate		$29,000.00
9	Coiled Tubing Unit		estimate		$43,790.00
10	Plug Cement with pumping and transport (bid)		estimate		$97,189.00
11	Vacuum Truck Service (displacement of kill fluid & misc. hauling)	$95	hour	30	$2,850.00
12	Miscellaneous Disposal Costs		estimate		$4,000.00
13	Miscellaneous Trucking		estimate		$4,000.00
14	Welding Services		estimate		$1,200.00
	Subtotal for Services				**$232,789.00**
16	Field Supervision (with travel & per diem)	$1,800	day	8	$14,400.00
17	Report Preparation		job		$5,000.00
	TOTAL				**$252,189.00**

TABLE Q-8

ESTIMATED PLUGGING COSTS FOR IW2

	Description	Rate	Unit	No. of Units	Estimated Cost
1	Frac Tanks (2) with mob/demob/plumbing/cleaning	$125	day	9	$1,125.00
2	Location Services (Forklift, Transfer Pump, hoses, Trash Service, Latrine, etc.)	$250	day	9	$2,250.00
3	Mechanical Integrity Testing Wireline Work		job	-	$12,000.00
4	Workover Rig (with 1/2 day each for Mob & Demob)	$6,000	day	3	$18,000.00
5	Workover Fluids (10 lb/gal brine) delivered	$12	barrel	650	$7,800.00
6	Spear, accessories, & service tech for releasing tubing from hanger		job		$1,500.00
7	Injection Tubing Laydown Services (tongs, handling tools, laydown machine, etc.)		job		$7,500.00
8	Multifinger Caliper/Casing Inspection Log and running service		estimate		$29,000.00
9	Coiled Tubing Unit		estimate		$43,790.00
10	Plug Cement with pumping and transport (bid)		estimate		$81,164.00
11	Wireline Services - Perforating and Cement Retainer Placement		estimate		$8,000.00
12	Cement Retainer and Service		estimate		$5,000.00
13	Squeeze Cement with pumping and transport (bid)		estimate		$31,751.00
14	Wireline Service - Cement Bond Logging		estimate		$8,000.00
15	Vacuum Truck Service (displacement of kill fluid & misc. hauling)	$95	hour	30	$2,850.00
16	Miscellaneous Disposal Costs		estimate		$4,000.00
17	Miscellaneous Trucking		estimate		$4,000.00
18	Welding Services		estimate		$1,200.00
	Subtotal for Services				**$268,930.00**
16	Field Supervision (with travel & per diem)	$1,800	day	9	$16,200.00
17	Report Preparation		job		$5,000.00
	TOTAL				**$290,130.00**

TABLE Q-9

ESTIMATED PLUGGING COST FOR IW3

	Description	Rate	Unit	No. of Units	Estimated Cost
1	Frac Tanks (2) with mob/demob/plumbing/cleaning	$125	day	8	$1,000.00
2	Location Services (Forklift, Transfer Pump, hoses, Trash Service, Latrine, etc.)	$250	day	8	$2,000.00
3	Mechanical Integrity Testing Wireline Work		job	-	$12,000.00
4	Workover Rig (with 1/2 day each for Mob & Demob)	$6,000	day	3	$18,000.00
5	Workover Fluids (10 lb/gal brine) delivered	$12	barrel	550	$6,600.00
6	Packer Services		job		$2,500.00
7	Spear, accessories, & service tech for releasing tubing from hanger		job		$1,500.00
8	Injection Tubing Laydown Services (tongs, handling tools, laydown machine, etc.)		job		$7,500.00
9	Multifinger Caliper/Casing Inspection Log and running service		estimate		$29,000.00
10	Coiled Tubing Unit		estimate		$43,790.00
11	Plug Cement with pumping and transport (bid)		estimate		$72,816.00
12	Vacuum Truck Service (displacement of kill fluid & misc. hauling)	$95	hour	30	$2,850.00
13	Miscellaneous Disposal Costs		estimate		$4,000.00
14	Miscellaneous Trucking		estimate		$4,000.00
15	Welding Services		estimate		$1,200.00
	Subtotal for Services				**$208,756.00**
16	Field Supervision (with travel & per diem)	$1,800	day	8	$14,400.00
17	Report Preparation		job		$5,000.00
	TOTAL				**$228,156.00**

TABLE Q-10

ESTIMATED PLUGGING COST FOR IW4

	Description	Rate	Unit	No. of Units	Estimated Cost
1	Frac Tanks (2) with mob/demob/plumbing/cleaning	$125	day	8	$1,000.00
2	Location Services (Forklift, Transfer Pump, hoses, Trash Service, Latrine, etc.)	$250	day	8	$2,000.00
3	Mechanical Integrity Testing Wireline Work		job	-	$12,000.00
4	Workover Rig (with 1/2 day each for Mob & Demob)	$6,000	day	3	$18,000.00
5	Workover Fluids (10 lb/gal brine) delivered	$12	barrel	550	$6,600.00
6	Spear, accessories, & service tech for releasing tubing from hanger		job		$1,500.00
7	Injection Tubing Laydown Services (tongs, handling tools, laydown machine, etc.)		job		$7,500.00
8	Multifinger Caliper/Casing Inspection Log and running service		estimate		$29,000.00
9	Coiled Tubing Unit		estimate		$43,790.00
10	Plug Cement with pumping and transport (bid)		estimate		$72,519.00
11	Vacuum Truck Service (displacement of kill fluid & misc. hauling)	$95	hour	30	$2,850.00
12	Miscellaneous Disposal Costs		estimate		$4,000.00
13	Miscellaneous Trucking		estimate		$4,000.00
14	Welding Services		estimate		$1,200.00
	Subtotal for Services				**$205,959.00**
16	Field Supervision (with travel & per diem)	$1,800	day	8	$14,400.00
17	Report Preparation		job		$5,000.00
	TOTAL				**$225,359.00**

TABLE Q-11

ESTIMATED PLUGGING COST FOR IW5

	Description	Rate	Unit	No. of Units	Estimated Cost
1	Frac Tanks (2) with mob/demob/plumbing/cleaning	$125	day	8	$1,000.00
2	Location Services (Forklift, Transfer Pump, hoses, Trash Service, Latrine, etc.)	$250	day	8	$2,000.00
3	Mechanical Integrity Testing Wireline Work		job	-	$12,000.00
4	Workover Rig (with 1/2 day each for Mob & Demob)	$6,000	day	3	$18,000.00
5	Workover Fluids (10 lb/gal brine) delivered	$12	barrel	600	$7,200.00
6	Packer Services		job		$2,500.00
7	Spear, accessories, & service tech for releasing tubing from hanger		job		$1,500.00
8	Injection Tubing Laydown Services (tongs, handling tools, laydown machine, etc.)		job		$7,500.00
9	Multifinger Caliper/Casing Inspection Log and running service		estimate		$29,000.00
10	Coiled Tubing Unit		estimate		$43,790.00
11	Plug Cement with pumping and transport (bid)		estimate		$80,269.00
12	Vacuum Truck Service (displacement of kill fluid & misc. hauling)	$95	hour	30	$2,850.00
13	Miscellaneous Disposal Costs		estimate		$4,000.00
14	Miscellaneous Trucking		estimate		$4,000.00
15	Welding Services		estimate		$1,200.00
	Subtotal for Services				**$216,809.00**
16	Field Supervision (with travel & per diem)	$1,800	day	8	$14,400.00
17	Report Preparation		job		$5,000.00
	TOTAL				**$236,209.00**

TABLE Q-12

ESTIMATED PLUGGING COST FOR IW6

	Description	Rate	Unit	No. of Units	Estimated Cost
1	Frac Tanks (2) with mob/demob/plumbing/cleaning	$125	day	8	$1,000.00
2	Location Services (Forklift, Transfer Pump, hoses, Trash Service, Latrine, etc.)	$250	day	8	$2,000.00
3	Mechanical Integrity Testing Wireline Work		job	-	$12,000.00
4	Workover Rig (with 1/2 day each for Mob & Demob)	$6,000	day	3	$18,000.00
5	Workover Fluids (10 lb/gal brine) delivered	$12	barrel	600	$7,200.00
6	Packer Services		job		$2,500.00
7	Spear, accessories, & service tech for releasing tubing from hanger		job		$1,500.00
8	Injection Tubing Laydown Services (tongs, handling tools, laydown machine, etc.)		job		$7,500.00
9	Multifinger Caliper/Casing Inspection Log and running service		estimate		$29,000.00
10	Coiled Tubing Unit		estimate		$43,790.00
11	Plug Cement with pumping and transport (bid)		estimate		$80,269.00
12	Vacuum Truck Service (displacement of kill fluid & misc. hauling)	$95	hour	30	$2,850.00
13	Miscellaneous Disposal Costs		estimate		$4,000.00
14	Miscellaneous Trucking		estimate		$4,000.00
15	Welding Services		estimate		$1,200.00
	Subtotal for Services				**$216,809.00**
16	Field Supervision (with travel & per diem)	$1,800	day	8	$14,400.00
17	Report Preparation		job		$5,000.00
	TOTAL				**$236,209.00**

FIGURES

FIGURE Q-1
Plug and Abandonment Plan

Panoche Energy Center
Well IW1

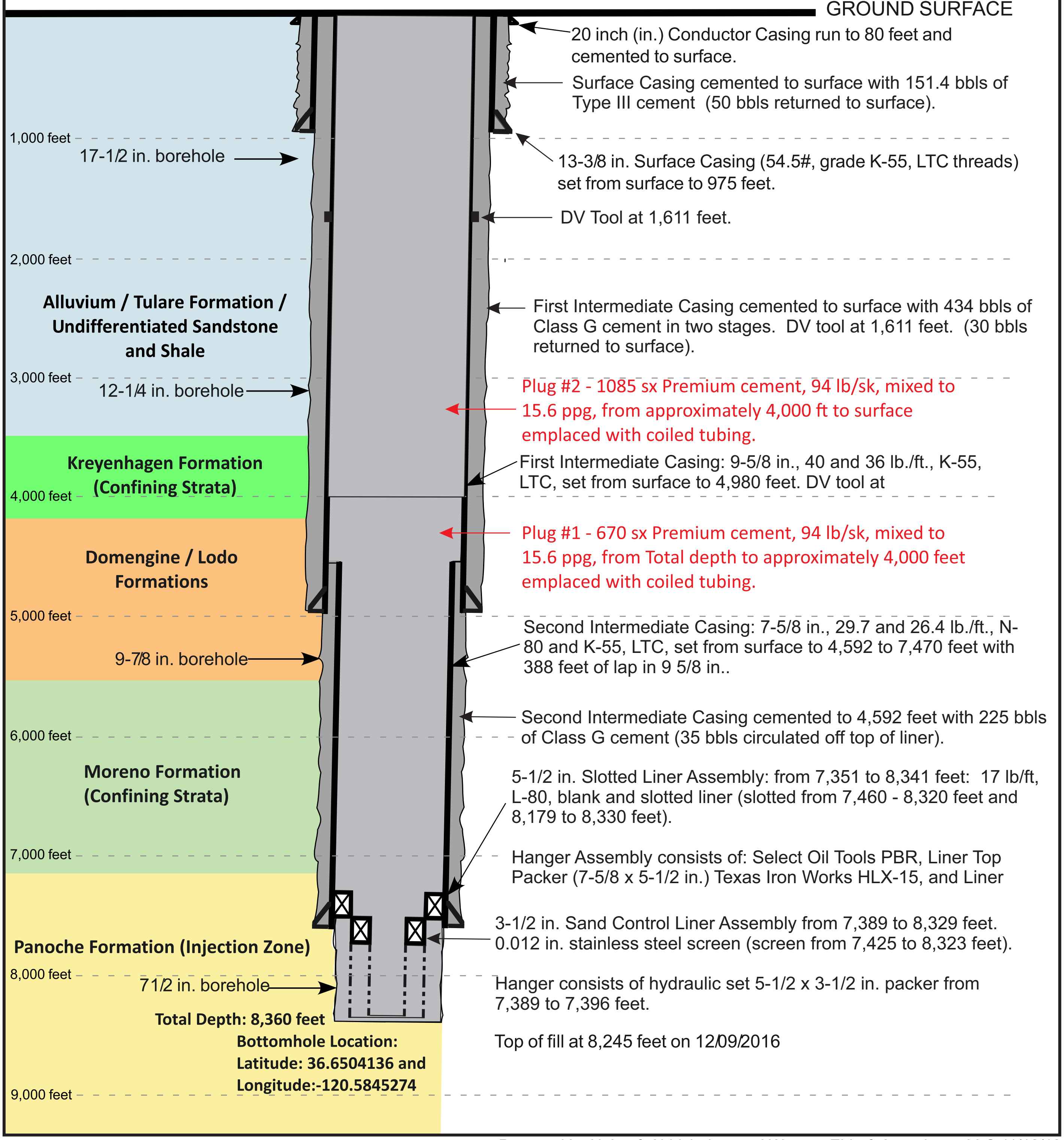
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.650645 and
Longitude:-120.5838281

CUT CASING OFF 3 FEET BELOW SURFACE AND PLACE STEEL PLATE WITH WELL IDENTIFICATION INFORMATION

Spud: September 26, 2008 Final Drilling Rig (Kenai #5)
Report: December 17, 2008 Final Completion Rig (Rival #9)
URS Completion Report: February 19, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

Panoche Energy Center
Well IW2

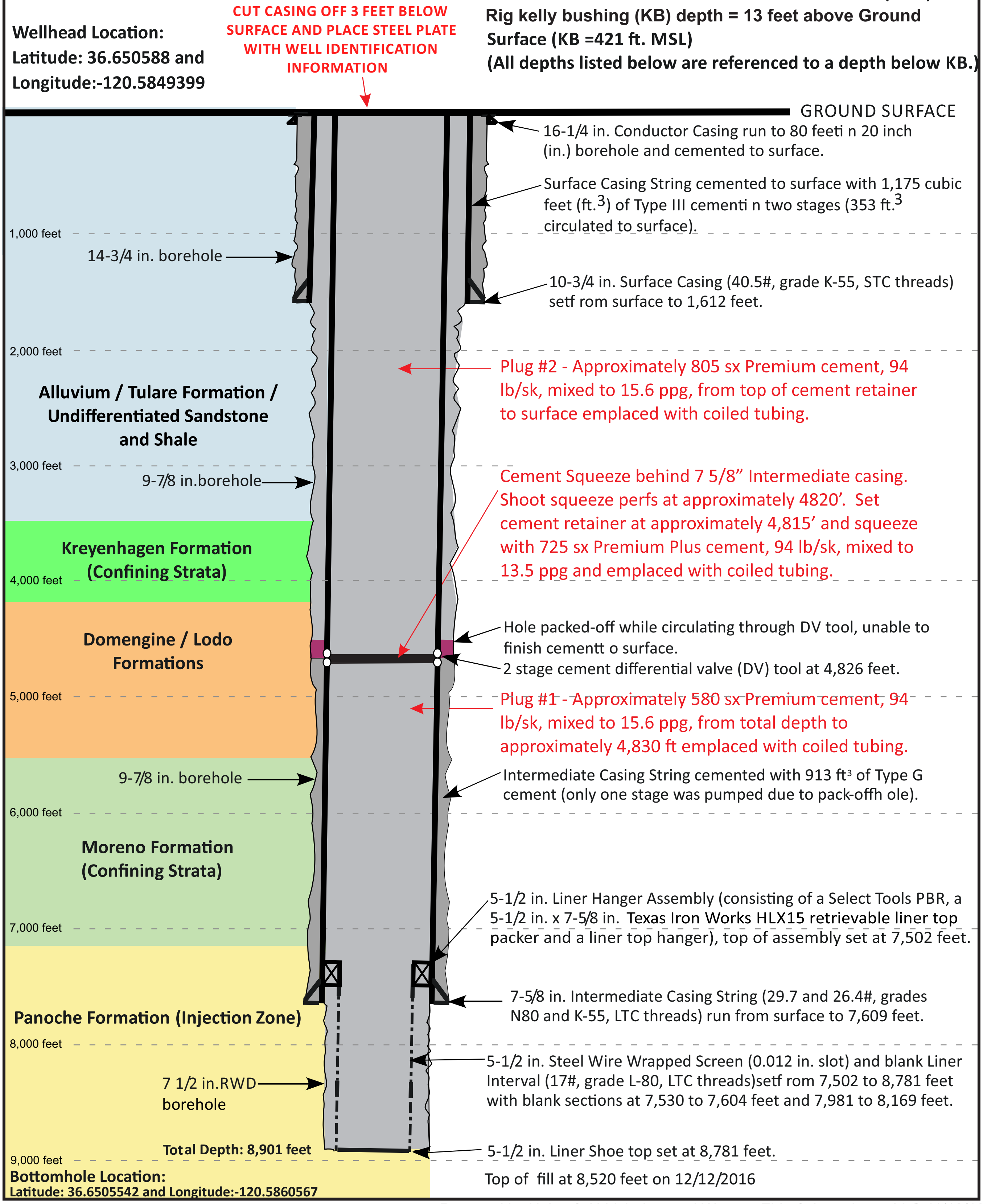
FIGURE Q-2
Plug and Abandonment Plan

EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.650588 and
Longitude:-120.5849399

Spud: December 19, 2008 Final Drilling Rig (Kenai #5)
Report: January 17, 2008 Final Completion Rig (Rival #9)
Report: January 29, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

Panoche Energy Center
Well IW3

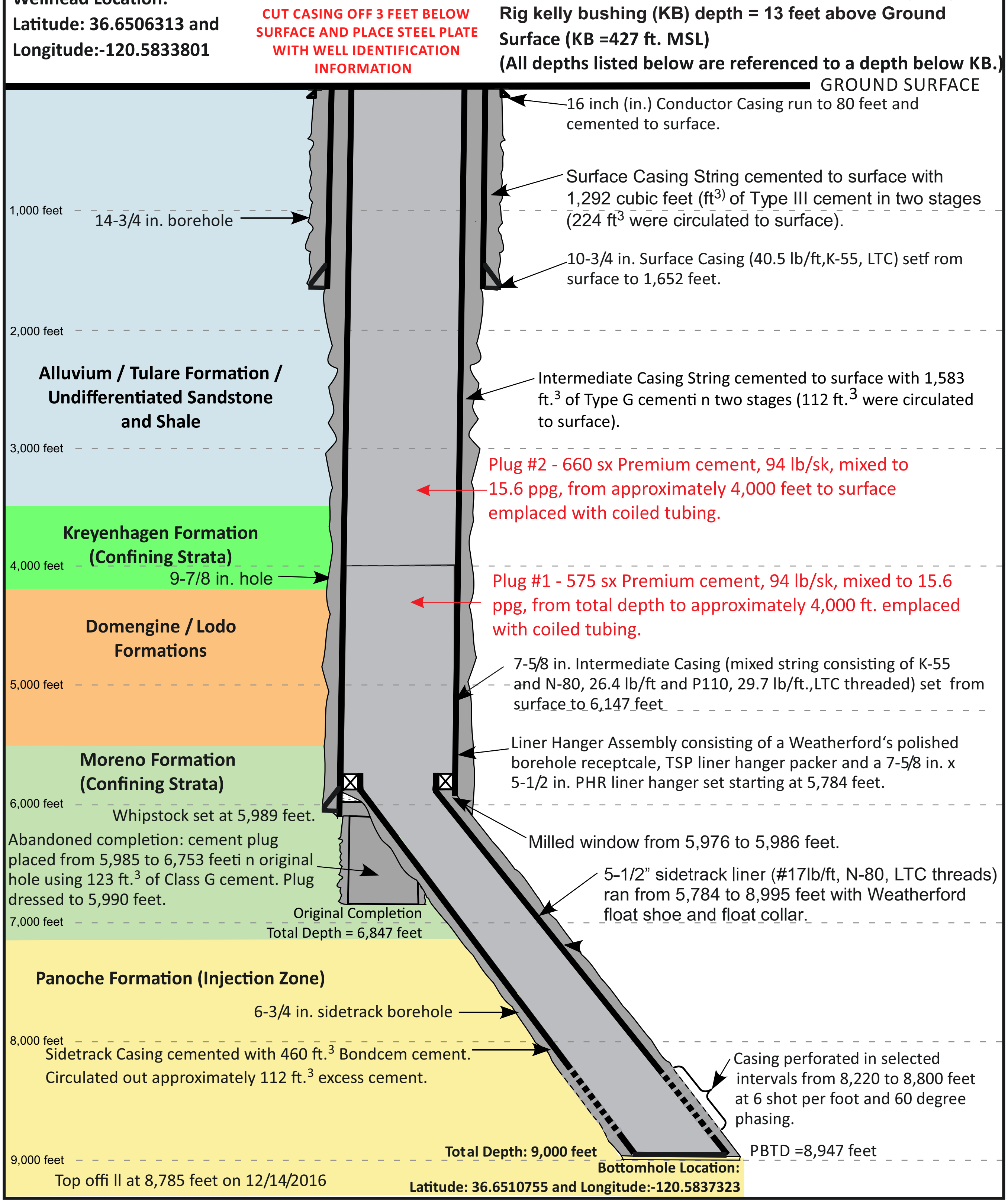
FIGURE Q-3
Plug and Abandonment Plan

EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.6506313 and
Longitude:-120.5833801

Spud: April 30, 2009
Final Original Hole Drilling Rig Report : May 25, 2009
Start of Well Deepening Sidetrack: October 19, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =427 ft. MSL)
(All depths listed below are referenced to a depth below KB.)



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

Panoche Energy Center
Well IW4

FIGURE Q-4
Plug and Abandonment Plan

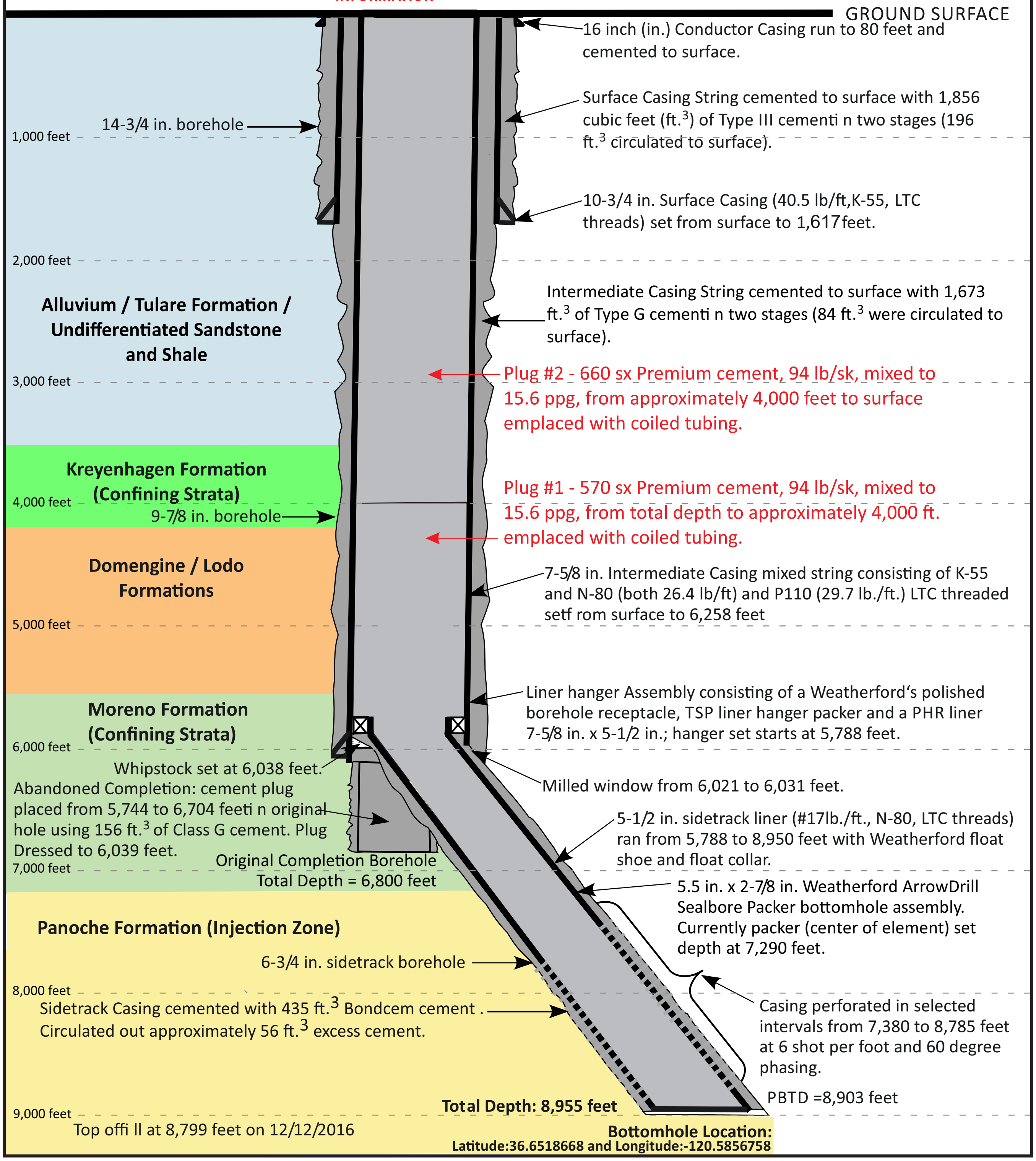
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.6509366 and
Longitude:-120.585846

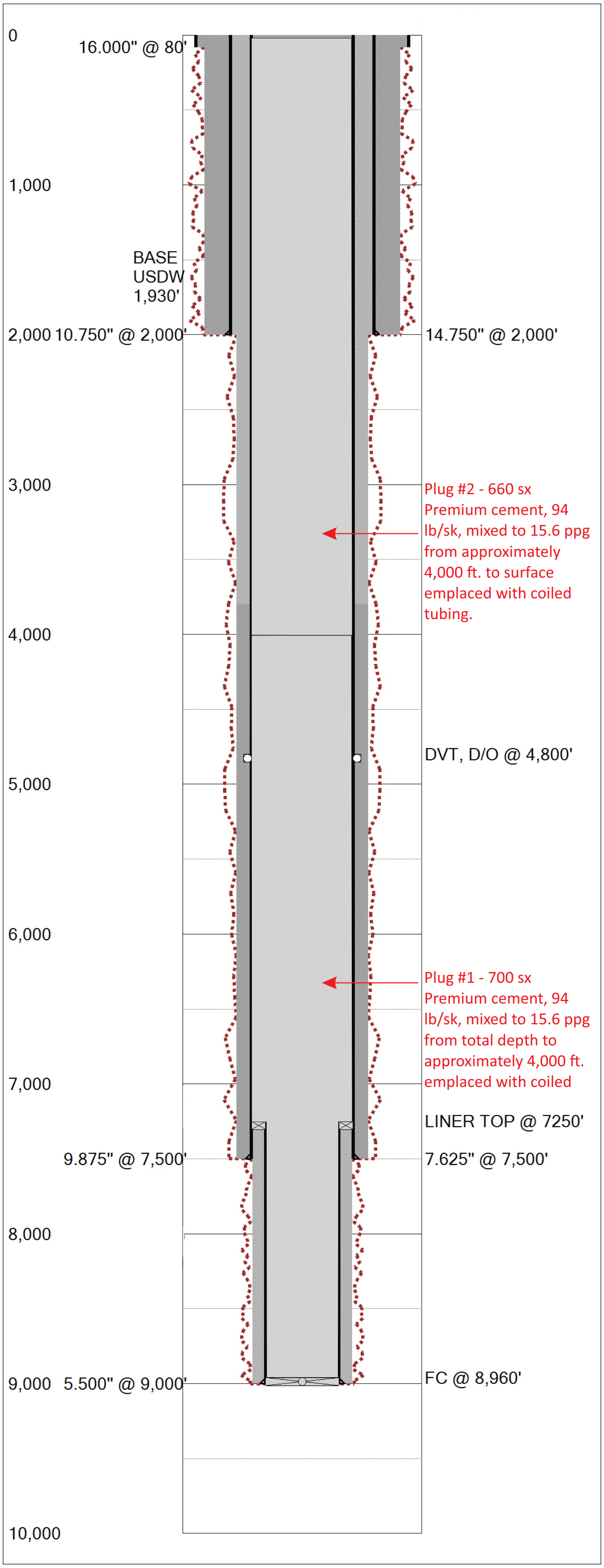
Spud: May 6, 2009
Final Original Hole Drilling Rig Report: June 4, 2009
Start of Well Deepening Sidetrack: October 20, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 410 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =429 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

CUT CASING OFF 3 FEET BELOW SURFACE AND PLACE STEEL PLATE WITH WELL IDENTIFICATION INFORMATION



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18



Last Updated: 11/12/18

FIGURE Q-5
Plug and Abandonment Plan

Field Name	Lease Name	Well No.
CHANEY RANCH	CLASS I DISPOSAL WELL	IW5

County	State	API No.
FRESNO	CALIFORNIA	____________

Version	Version Tag
2	IW5 PLUGS

GL (ft)	KB (ft)	Section	Township/Block	Range/Survey
408.0		5	15S	13E

Operator	Well Status	Latitude	Longitude
PANOCHE ENERGY CENTER, LLC	PLANNING	36.650056	-120.58363

Dist. N/S (ft)	N/S Line	Dist. E/W (ft)	E/W Line	Footage From

Prop Num	Spud Date	Comp. Date
	Proposed	Proposed

Additional Information
Proposed

BHL Latitude	BHL Longitude	KOP	OTHER
36.649822	-120.583104		

Prepared By	Updated By	Last Updated
HCE Geosteering 2	HCE Geosteering 2	10/10/18

Hole Summary

Date	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
	14.750	80	2,000	
	9.875	2,000	7,500	
	7.500	7,500	9,000	7.500" RWD HOLE

Tubular Summary

Date	Description	O.D. (in)	Wt (lb/ft)	Grade	Top (MD ft)	Bottom (MD ft)
	Conductor Casing	16.000			0	80
	Surface Casing	10.750	40.50	K-55	0	2,000
	Intermediate Casing	7.625	29.70	N-80	0	7,500
	Liner	5.500	17.00	L-80	7,250	9,000

Casing Cement Summary

C	Date	No. Sx	Csg. O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
		30	10.750	0	80	LEAD SURFACE CMT (PIP)
		630	10.750	80	1,398	LEAD SURFACE CMT (PIH)
		400	10.750	1,398	2,000	TAIL SURFACE CMT
		282	7.625	0	2,000	STG 2 LEAD INTERMEDIATE CMT (PIP)
		325	7.625	2,000	3,796	STG 2 LEAD (PIH) INTERMEDIATE CMT
		260	7.625	3,796	4,800	STG 2 TAIL INTERMEDIATE CMT
		725	7.625	4,800	7,500	STG 1 INTERMEDIATE CMT
		290	5.500	7,250	9,000	PRODUCTION LINER CMT

Tools/Problems Summary

Date	Tool Type	O.D. (in)	I.D. (in)	Top (MD ft)	Bottom (MD ft)
	DVT, D/O	7.625	0.000	4,800	0
	Lnr Hngr, Seal	7.625	5.500	7,250	0
	FC	5.500	0.000	8,960	0

Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

Last Updated: 10/10/18

Field Name	Lease Name	Well No.	County	State	API No.
CHANEY RANCH	CLASS I DISPOSAL WELL	IW5	FRESNO	CALIFORNIA	___________

Version	Version Tag	Spud Date	Comp. Date	GL (ft)	KB (ft)
2	IW5 PLUGS			408.0	

Section	Township/Block	Range/Survey	Dist. N/S (ft)	N/S Line	Dist. E/W (ft)	E/W Line	Footage From
5	15S	13E					

Operator	Well Status	Latitude	Longitude	Prop Num
PANOCHE ENERGY CENTER, LLC	PLANNING	36.650056	-120.58363	

BHL Latitude	BHL Longitude	KOP	OTHER
36.649822	-120.583104		

Last Updated	Prepared By	Updated By
10/10/18	HCE Geosteering 2	HCE Geosteering 2

Additional Information
Designed 8/17/18

Hole Summary

Date	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
	14.750	80	2,000	
	9.875	2,000	7,500	
	7.500	7,500	9,000	7.500" RWD HOLE

Tubular Summary

Date	Description	No. Jts	O.D. (in)	Wt (lb/ft)	Grade	Coupling	Top (MD ft)	Bottom (MD ft)	Comments
	Conductor Casing		16.000				0	80	
	Surface Casing		10.750	40.50	K-55	LTC	0	2,000	INTERNAL YEILD: 3130 PSI
	Intermediate Casing		7.625	29.70	N-80	BTC	0	7,500	INTERNAL YEILD: 6890 PSI
	Liner		5.500	17.00	L-80	LTC	7,250	9,000	INTERNAL YEILD: 7740 PSI

Casing Cement Summary

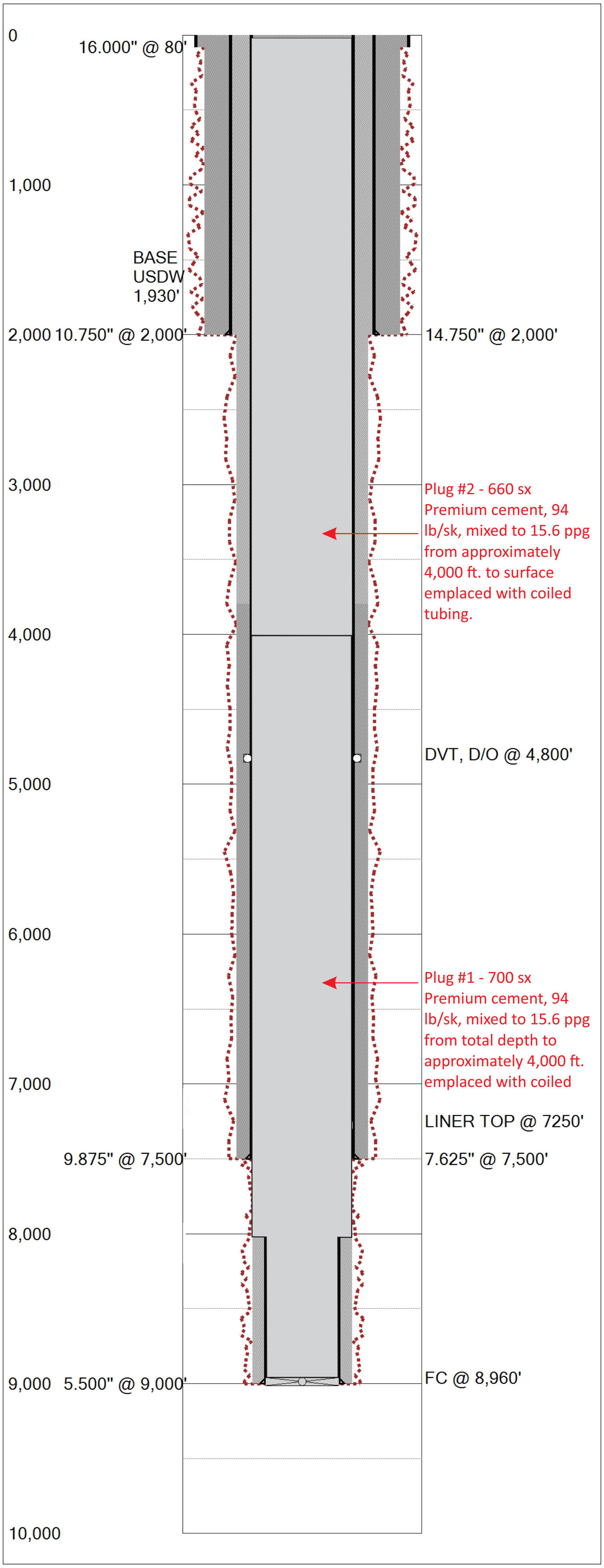
C	Date	No. Sx	Yield (ft3/sk)	Vol. (ft3)	Csg. O.D. (in)	Top (MD ft)	Bottom (MD ft)	Description	Comments
		30	1.86	56	10.750	0	80		LEAD SURFACE CMT (PIP)
		630	1.86	1,172	10.750	80	1,398		LEAD SURFACE CMT (PIH)
		400	1.34	536	10.750	1,398	2,000		TAIL SURFACE CMT
		282	1.66	468	7.625	0	2,000		STG 2 LEAD INTERMEDIATE CMT (PIP)
		325	1.66	540	7.625	2,000	3,796		STG 2 LEAD (PIH) INTERMEDIATE CMT
		260	1.16	302	7.625	3,796	4,800		STG 2 TAIL INTERMEDIATE CMT
		725	1.13	819	7.625	4,800	7,500		STG 1 INTERMEDIATE CMT
		290	1.21	351	5.500	7,250	9,000		PRODUCTION LINER CMT

Cement Plug Summary

Date	No. Sx	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
		7.625	0		Full Column of cement from PBTD to surface as indicated on drawing.
		7.625			
		7.625		7,250	
		5.500			
		5.500	8,930	9,000	PBTD @ 8960'

FIGURE Q-6
Plug and Abandonment Plan

Last Updated: 11/12/18



Field Name	Lease Name	Well No.
CHANEY RANCH	CLASS 1 DISPOSAL WELL	IW6

County	State	API No.
FRESNO	CALIFORNIA	___________

Version	Version Tag
0	IW6 PLUGS

GL (ft)	KB (ft)	Section	Township/Block	Range/Survey
408.0		5	15S	13E

Operator	Well Status	Latitude	Longitude
PANOCHE ENERGY CENTER, LLC	PLANNING	36.650069	-120.585787

Dist. N/S (ft)	N/S Line	Dist. E/W (ft)	E/W Line	Footage From

Prop Num	Spud Date	Comp. Date
	Proposed	Proposed

Additional Information
Proposed

BHL Latitude	BHL Longitude	KOP	OTHER
36.649869	-120.585389		

Prepared By	Updated By	Last Updated
HCE Geosteering 2	HCE Geosteering 2	10/10/18

Hole Summary

Date	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
	14.750	80	2,000	
	9.875	2,000	7,500	
	7.500	7,500	9,000	7.500" RWD HOLE

Tubular Summary

Date	Description	O.D. (in)	Wt (lb/ft)	Grade	Top (MD ft)	Bottom (MD ft)
	Conductor Casing	16.000			0	80
	Surface Casing	10.750	40.50	K-55	0	2,000
	Intermediate Casing	7.625	29.70	N-80	0	7,500
	Liner	5.500	17.00	L-80	7,250	9,000

Casing Cement Summary

C	Date	No. Sx	Csg. O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
		30	10.750	0	80	LEAD SURFACE CMT (PIP)
		630	10.750	80	1,398	LEAD SURFACE CMT (PIH)
		400	10.750	1,398	2,000	TAIL SURFACE CMT
		282	7.625	0	2,000	STG 2 LEAD INTERMEDIATE CMT (PIP)
		325	7.625	2,000	3,796	STG 2 LEAD (PIH) INTERMEDIATE CMT
		260	7.625	3,796	4,800	STG 2 TAIL INTERMEDIATE CMT
		725	7.625	4,800	7,500	STG 1 INTERMEDIATE CMT
		290	5.500	7,250	9,000	PRODUCTION LINER CMT

Tools/Problems Summary

Date	Tool Type	O.D. (in)	I.D. (in)	Top (MD ft)	Bottom (MD ft)
	DVT, D/O	7.625	0.000	4,800	0
	Lnr Hngr, Seal	7.625	5.500	7,250	0
	FC	5.500	0.000	8,960	0

Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

Last Updated: 10/10/18

Field Name	Lease Name	Well No.	County	State	API No.
CHANEY RANCH	CLASS 1 DISPOSAL WELL	IW6	FRESNO	CALIFORNIA	______________

Version	Version Tag	Spud Date	Comp. Date	GL (ft)	KB (ft)
0	IW6 PLUGS			408.0	

Section	Township/Block	Range/Survey	Dist. N/S (ft)	N/S Line	Dist. E/W (ft)	E/W Line	Footage From
5	15S	13E					

Operator	Well Status	Latitude	Longitude	Prop Num
PANOCHE ENERGY CENTER, LLC	PLANNING	36.650069	-120.585787	

BHL Latitude	BHL Longitude	KOP	OTHER
36.649869	-120.585389		

Last Updated	Prepared By	Updated By
10/10/18	HCE Geosteering 2	HCE Geosteering 2

Additional Information
Designed 8/17/18

Hole Summary

Date	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
	14.750	80	2,000	
	9.875	2,000	7,500	
	7.500	7,500	9,000	7.500" RWD HOLE

Tubular Summary

Date	Description	No. Jts	O.D. (in)	Wt (lb/ft)	Grade	Coupling	Top (MD ft)	Bottom (MD ft)	Comments
	Conductor Casing		16.000				0	80	
	Surface Casing		10.750	40.50	K-55	LTC	0	2,000	INTERNAL YEILD: 3130 PSI
	Intermediate Casing		7.625	29.70	N-80	BTC	0	7,500	INTERNAL YEILD: 6890 PSI

Casing Cement Summary

C	Date	No. Sx	Yield (ft3/sk)	Vol. (ft3)	Csg. O.D. (in)	Top (MD ft)	Bottom (MD ft)	Description	Comments
		30	1.86	56	10.750	0	80		LEAD SURFACE CMT (PIP)
		630	1.86	1,172	10.750	80	1,398		LEAD SURFACE CMT (PIH)
		400	1.34	536	10.750	1,398	2,000		TAIL SURFACE CMT
		282	1.66	468	7.625	0	2,000		STG 2 LEAD INTERMEDIATE CMT (PIP)
		325	1.66	540	7.625	2,000	3,796		STG 2 LEAD (PIH) INTERMEDIATE CMT
		260	1.16	302	7.625	3,796	4,800		STG 2 TAIL INTERMEDIATE CMT
		725	1.13	819	7.625	4,800	7,500		STG 1 INTERMEDIATE CMT
		290	1.21	351	5.500	7,250	9,000		PRODUCTION LINER CMT

Cement Plug Summary

Date	No. Sx	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Comments
		7.625	0		Full Column of cement from PBTD to surface as indicated on drawing
		7.625			
		7.625		7,250	
		5.500			
		5.500	8,930	9,000	PBTD @ 8960'

EXHIBITS

(To be Submitted on CD)

ATTACHMENT R

Necessary Resources

Table of Contents

ATTACHMENT R – NECESSARY RESOURCES

PERMIT APPLICATION REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment R requires the applicant to "Submit evidence such as a surety bond or financial statement to verify that the resources necessary to close, plug or abandon the well are available."

DISCUSSION AND DOCUMENTATION

Financial-assurance demonstration for the closing, plugging or abandonment of each well was required prior to construction of the four existing wells at Panoche Energy Center (PEC), as included in Part II, Section F, Paragraph (a) of the current USEPA Underground Injection Control (UIC) program UIC Permit CA10600001. Specifically, the Permittee was required to post a financial instrument such as a surety bond with a standby trust agreement of arrange other financial assurance for each well-constructed in the amount of $169,500 per well to guarantee closure. PEC provided documentation to USEPA prior to construction the current wells. For example, in a signed letter by David Albright of the USEPA dated 1 May 2009 to Power Plant Management Services, LLC, the USEPA verified that a Standby Trust agreement had been signed, amended and restated for wells IW1 and IW2 was accepted as replacement to the previous Financial Assurance Instrument that was in-place prior to drilling of these wells (USEPA, 2009). Finally, the Amended and Restated Standby Trust was updated to include all the wells (IW1, IW2, IW3, and, IW4) for a total value of $678,000 and was signed by PEC's Authorized Representative, the Vice President of Union Bank, notarized in 2009 and 2011, and was signed by USEPA's Regional Administrator.

Evidence to verify that additional resources necessary (above the current Standby Trust value listed above) to close, plug or abandon the wells, as listed in Tables Q9 through Q12 for only IW1 through IW4, will be provided to EPA at later date. In addition, PEC will provide additional documentation of any bond or other financial instruments acquired, prior to construction of either IW5 or IW6, for an amount that will guarantee closure, only of these well are needed. A cost estimate for each proposed well plug and abandonment is included in Attachment Q.

References

1. United States Environmental Regulatory Agency. 2009. Written Communication to Power Plant Management Services, LLC. May.

ATTACHMENT S

Aquifer Exemptions

Table of Contents

ATTACHMENT S – AQUIFER EXEMPTIONS

PERMIT APPLICATION REQUIREMENTS

As required by U.S. Environmental Protection Agency Form 7520-6, "If an aquifer exemption is requested, submit data necessary to demonstrate that the aquifer meets the following criteria: (1) does not serve as a source of drinking water; (2) cannot now and will not in the future serve as a source of drinking water; and (3) the TDS content of the ground water is more than 3,000 and less than 10,000 mg/L and is not reasonably expected to supply a public water system.

Data to demonstrate that the aquifer is expected to be mineral or hydrocarbon production, such as general description of the mining zone, analysis of the amenability of the mining zone to the proposed method, and time table for proposed development must also be included. For additional information on aquifer exemptions, see 40 CFR Sections 144.7 and 146.04."

INJECTION ZONE IS NOT A POTENTIAL SOURCE OF DRINKING WATER

This application is not requesting an exemption for the injection zone, which is located within the Panoche Formation. The following supports the conclusion the Panoche Formation is not a fresh-water aquifer and is therefore no aquifer exemption is needed:

- No publicly available data reviewed for the area around PEC (see Attachment B) indicates that any water from the Panoche Formation is used for human consumption.
- The Panoche Formation cannot now or will not in the future serve as a source of drinking water because, as discussed in Attachment D, water deeper than approximately 2,000 feet below ground surface is not an underground source of drinking water. The Panoche formation is at a depth of approximately 7,150 feet below ground surface.
- The produced water from the Panoche Formation has a concentration of total dissolved solids that exceeds the 10,000 milligrams per liter criteria cutoff (see Attachment I).

ATTACHMENT T

EPA Permits Held by Facility

Table of Contents

Page

ATTACHMENT T – USEPA PERMITS HELD BY FACILITY

PERMIT APPLICATION REQUIREMENTS

As stated in the U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment T requires the applicant to "List program and permit number of any existing USEPA permits, for example, NPDES, PSD, RCRA, etc.)."

In addition, regulations at 40 CFR 144.4 "Considerations under Federal Law" require an evaluation of whether each of the following laws apply to the project:

- Wild and Scenic Rivers Act,
- The National Historic Preservation Act of 1966,
- The Endangered Species Act,
- The Coastal Management Act,
- The Fish & Wildlife Act,
- The Fish and Wildlife Coordination Act, and
- Applicable Executive Orders.

Lastly, USEPA Region IX requested in their letter dated 20 November 2017 a list of all state laws that apply to the project.

LIST OF USEPA PERMITS HELD BY FACILITY

On 2 August 2006, the Panoche Energy Center (PEC) filed an Application for Certification (AFC) with the California Energy Commission (CEC) to construct and operate the PEC. The CEC is the clearing house for power plant licensing and permitting and their consideration of the proposed PEC included extensive assessment of potential environmental impacts and input from numerous local, state and federal agencies. On 19 December 2007, the CEC issued Final Commission Decision (06-AFC-5) approving and certifying the project as described in the AFC. The Final Commission Decision included Conditions of Certification (COC) incorporating requirements provided by the San Joaquin Valley Air Pollution Control District (SJVAPCD) in their Final Determination of Compliance (FDOC) and the requirement to obtain an Underground Injection Control (UIC) permit from USEPA Region IX. These permits are presented in Table T-1 and discussed in greater detail below.

TABLE T-1
EPA Programs Requiring Permits by PEC

Permit # or Program ID#	USEPA Program	Statute and Regulation	Implementing Agency	Medium
ORIS IS: 56803	Title IV Acid Rain Permit	Title IV (Acid Rain) of the Federal Clean Air Act as implemented by 40 CFR Part 72.	SJVAPCD(1)	Air
Facility ID: C-7220	Title V Operating Permit	Title V (Operating Permits) of the Federal Clean Air Act as implemented by 40 CFR Part 70. SJVAPCD Rules & Regulations	SJVAPCD(1)	Air
CA-10600001	UIC Program	40 CFR Part 124, 144, 145, 146, 147 and 148.	USEPA Region IX	Waste Water

Notes:

1. SJVAPCD delegated authority to administer and enforce Federal Title V Operating Permit program. PEC Title V Operating Permit contains applicable Acid Rain Program provisions.

Operating Permits (Title V of the Clean Air Act Amendments of 1990)

Title V of the 1990 Clean Air Act (CAA) establishes an operating permit program to ensure compliance with the applicable requirements of the CAA. Sources subject to the program must obtain an operating permit, states must develop and implement the program, and the USEPA must issue permit program regulations, review each state's program (State Implementation Plan), and oversee the state's efforts to implement any approved program. USEPA must also develop and implement a federal permit program when a state fails to adopt and implement its own program. California's State Implementation Plan has been approved by the USEPA and thus oversees implementation of the Title V requirements. However, the California Air Resources Board (CARB) does not have authority to issue permits directly to stationary sources of air pollution. Primary responsibility for permitting all sources, except vehicular sources, rests with the local and regional air pollution control authorities known as Air Pollution Control Districts or Air Quality Management Districts. PEC is located within the jurisdictional purview of SJVAPCD and it is SJVAPCD that issues and enforces the facility's Title V permit.

The Acid Rain Program established under Title IV of the CAA Amendments requires major emission reductions of sulfur dioxide (SO2) and nitrogen oxides (NOx), the primary precursors of acid rain, from the power sector. The SO2 program sets a permanent cap on the total amount of SO2 that may be emitted by electric generating units in the contiguous United States. The California Accidental Release Prevention (CalARP) Program was the first national cap and trade program in the country and it introduced a system of allowance trading that uses market-based incentives to reduce pollution.

As stated previously in the introduction to this section, the SJVAPC reviewed air quality impacts and applicable requirements related to air quality and regulatory compliance during the CEC's consideration of the PEC. The SJVAPCD issued a FDOC to the CEC dated 10 August 2006, which pursuant to SJVAPCD Rule 2201, Section 5.8, was functionally equivalent to an Authority to Construct review. The CEC's Final Commission Decision adopted 19 December 2007 incorporated the conditions and requirements contained in the SJVAPCD FDOC. An application for an initial Title V Operating Permit for the facility was submitted to the District on 30 April 2010 and a final Title V Operating Permit was received from the District on 19 May 2011.

Title V Operating Permits require renewal every five years. The PEC's Title V Operating Permit (Facility ID: C-7220) was most recently renewed by the SJVAPCD on 13 February 2017 and expires 31 January 2021. The Title V Operating Permit contains all applicable local (SJVAPCD) and federally enforceable requirements for the facility at large (facility wide requirements) and for the six permitted emissions sources at the facility (see Table T-2). Applicable requirements of the Federal Acid Rain Program are contained in the individual operating permits for the four GE LMS-100 combustion turbines (C-7220-1-2, C-7220-2-2, C-7220-3-2 and C-7220-4-2).

TABLE T-2
PEC Title V Operating Permit C-7220

Permit # or Program ID#	USEPA Program	Medium
C-7220-0-1	Facility wide requirements	Facility wide requirements including, but not limited to, upset reporting, record retention, architectural coating and fugitive dust limitations.
C-7220-1-2	Combustion Turbine 1	100 megawatts (MW) GE LMS-100 natural gas fired combustion turbine with selective catalytic reduction (SCR) and oxidation catalyst.
C-7220-2-2	Combustion Turbine 2	100 MW GE LMS-100 natural gas fired combustion turbine with SCR and oxidation catalyst.
C-7220-3-2	Combustion Turbine 3	100 MW GE LMS-100 natural gas fired combustion turbine with SCR and oxidation catalyst.
C-7220-4-2	Combustion Turbine 4	100 MW GE LMS-100 natural gas fired combustion turbine with SCR and oxidation catalyst.
C-7220-5-3	Emergency Diesel Firepump	160-horsepower John Deere 6068T Tier 2 Compliant diesel-fired emergency engine powering a firewater pump.
C-7220-6-2	27,600 gallons per minute (gpm) Cooling Tower	27,600 gpm cooling tower with four cells and drift eliminator.

Underground Injection Control Program

The PEC received final Class 1-NH UIC permit CA-10600001 on 25 April 2008 from the Ground Water Office of USEPA Region IX. Permit CA10600001 approved construction and operation of six non-hazardous waste injection wells (IW1, IW2, IW3, IW4, IW5 and IW6) pursuant to the construction, operation and monitoring requirements contained in the permit. To date, IW1, IW2, IW3 and IW4 have been completed and are operational. IW5 and IW6 may be constructed at a later date. The PEC has operated IW1, IW2, IW3 and IW4 in compliance with all conditions and requirements of UIC Permit CA10600001 since receipt of the permit and construction of the wells.

CONSIDERATIONS UNDER FEDERAL LAW

Pursuant to 40 CFR 144.4 the following list of federal laws may apply to the issuance of permits under the UIC rules. When any of these laws is applicable, its procedures must be followed.

- Wild and Scenic Rivers Act,
- The National Historic Preservation Act of 1966,
- The Endangered Species Act,
- The Coastal Management Act,

- The Fish & Wildlife Act,
- The Fish and Wildlife Coordination Act, and
- Applicable Executive Orders.

When the applicable law requires consideration or adoption of particular permit conditions or requires the denial of a permit, those requirements also must be met. Following are discussions of each of the above federal programs and a discussion of their applicability to the PEC UIC Permit Application.

Wild & Scenic Rivers Act

Scope

The National Wild and Scenic Rivers System was created by Congress in 1968 (Public Law 90-542; 16 U.S.C. 1271 et seq.) to preserve certain rivers with outstanding natural, cultural, and recreational values in a free-flowing condition for the enjoyment of present and future generations. The Act is notable for safeguarding the special character of these rivers, while also recognizing the potential for their appropriate use and development. It encourages river management that crosses political boundaries and promotes public participation in developing goals for river protection (National Wild and Scenic Rivers System n.d.).

Rivers may be designated by Congress or, if certain requirements are met, the Secretary of the Interior. Each river is administered by either a federal or state agency. Designated segments need not include the entire river and may include tributaries. For federally administered rivers, the designated boundaries generally average one-quarter mile on either bank in the lower 48 states and one-half mile on rivers outside national parks in Alaska in order to protect river-related values. Rivers are classified as wild, scenic, or recreational as follows:

- **Wild River Areas –** Those rivers or sections of rivers that are free of impoundments and generally inaccessible except by trail, with watersheds or shorelines essentially primitive and waters unpolluted. These represent vestiges of primitive America.
- **Scenic River Areas –** Those rivers or sections of rivers that are free of impoundments, with shorelines or watersheds still largely primitive and shorelines largely undeveloped, but accessible in places by roads.
- **Recreational River Areas –** Those rivers or sections of rivers that are readily accessible by road or railroad, that may have some development along their shorelines, and that may have undergone some impoundment or diversion in the past.

The Act purposefully strives to balance dam and other construction at appropriate sections of rivers with permanent protection for some of the country's most outstanding free-flowing rivers. To accomplish this, it prohibits federal support for actions such as the construction of dams or other instream activities that would harm the river's free-flowing condition, water quality, or outstanding resource values. However, designation does not affect existing water rights or the existing jurisdiction of states and the federal government over waters as determined by established principles of law (National Wild and Scenic Rivers System n.d.).

In California, sections of the following rivers (totaling 1,999.6 miles) have been designated as wild and scenic under the Act (approximately 1 percent of the state's river miles; National Wild and Scenic Rivers System, 2017):

- Amargosa River,
- American River (Lower),
- American River (North Fork),
- Bautista Creek,
- Big Sur River,
- Black Butte River,
- Cottonwood Creek,
- Eel River,
- Feather River,
- Fuller Mill Creek,
- Kern River,
- Kings River,
- Klamath River,
- Merced River,
- Owens River Headwaters,
- Palm Canyon Creek,
- Piru Creek,
- San Jacinto River (North Fork),
- Sespe Creek,
- Sisquoc River,
- Smith River,
- Trinity River, and
- Tuolumne River.

Applicability to Panoche Energy Center

The PEC is not located on or within 0.25 miles of any of the sections of designated wild and scenic waterways in California. The closest waterway, Panoche Creek, is approximately 1.75 miles to the northwest of the PEC. No portion of Panoche Creek has been designated under the Wild and Scenic Rivers Act. Therefore, the Wild and Scenic Rivers Act does not apply to the PEC. This is further evidenced by the fact that the no impacts to waterways subject to the Wild & Scenic Rivers Act were identified during the licensing of the PEC by the CEC.

The National Historic Preservation Act of 1966

Scope

The National Historic Preservation Act (NHPA) directs federal agencies to consider the effect of any undertaking (a federally funded or assisted project) on historic properties. "Historic property" is any district, building, structure, site, or object that is eligible for listing in the National Register of Historic Places because the property is significant at the national, state, or local level in American history, architecture, archeology, engineering, or culture. Typically, a historic property must be at least 50 years old and retain integrity (Preservation50, n.d.).

The law required individual states to take on much more responsibility for historic sites in their jurisdictions. Each state would now have its own historic preservation office and was required to complete an inventory of important sites. The law also created the President's Advisory Council on Historic Preservation and the National Register of Historic Places, an official list not only of individual buildings and structures, but also of districts, objects, and archeological sites that are important due to their connection with the past (National Park Service, n.d.).

The National Register of Historic Places is the nation's official list of buildings, structures, objects, sites, and districts worthy of preservation because of their significance in American history, architecture, archeology, engineering, and culture. The National Register recognizes resources of local, state and national significance which have been documented and evaluated according to uniform standards and criteria (Preservation50, n.d.).

Authorized under the National Historic Preservation Act of 1966, the National Register is part of a national program to coordinate and support public and private efforts to identify, evaluate, and protect historic and archeological resources. The National Register is administered by the National Park Service, which is part of the U. S. Department of the Interior. (Preservation50, n.d.).

Applicability to Panoche Energy Center

The CEC is responsible for the licensing of power plants in California. An Application for Certification (06-AFC-5) was filed with the CEC on behalf of the PEC on 2 August 2006. A draft Class I Nonhazardous Waste Injection Well Permit (Permit No. CA10600001) for six injection wells (IW1, IW2, IW3, IW4, IW5 and IW6) was provided to the CEC by USEPA via e-mail (George Robin, Email, 1 November 2007). The CEC issued its Final Commission Decision on 19 December 2007 approving construction and operation of the PEC. The Final Commission Decision included review of information related to the four constructed (IW1, IW2, IW3 and IW4) and two proposed (IW5 and IW6) wastewater injection wells subject to this application (CEC, 2007).

Potential impacts to cultural resources subject to the National Historic Preservation Act resulting from the construction of the PEC, including the injection wells, were considered by the CEC during the process of licensing the PEC. The following inventories and source of information related to historic properties were reviewed and consulted to determine the potential for impacts related to construction of the PEC:

- National Register of Historic Resources,
- California Register of Historical Resources,

- List of California Historic Landmarks,
- List of California Points of Historical Interest,
- Fresno County Assessor's Office,
- Fresno County Clerk's Office,
- Fresno County Planning Department, and
- First American Real Estate Property Solutions.

In addition, information related to local and regional history from the California State Library, the Shields Library at the University of California, Davis, the Central Library of the Fresno County Public Library System, and the Henry madden Library of California State University of Fresno were reviewed (CEC, 2007).

Though more than 45 years of age, none of the following resources located in the vicinity of the proposed PEC were found to be associated with any significant historical event or person or possessing of architectural merit or distinction:

- Three buildings older than 45 years (a large storage building, a residence, an and auxiliary building) in the agricultural complex at 43405 West Panoche Road, known historically as Chaney Ranch;
- A cluster of five farm worker houses located in the northwest corner of Section 5;
- Another cluster of three farm worker houses located north of, and just across West Panoche Road from the project site;
- West Panoche Road itself; and
- The Panoche Substation.

No archeological resources were found in the study area nor was any evidence of cultural material observed in soils from any of the 20 borings completed on-site for geotechnical study. In addition, the Native American Heritage Commission reported that no known native American cultural resources in its sacred lands database (CEC, 2007).

Although no historic resources were found within the vicinity of the proposed PEC, nor were any significant know archeological resources identified, the CEC did note that "…subsurface disturbance during construction has the potential to disturb as yet unknown archeological resources." The CEC therefore included COC to address potential impacts to unknown, subsurface cultural resources should they be encountered during site disturbance activities. As construction of the two proposed injection wells (IW5 and IW6) would require site disturbance and CEC notification and oversight, it is expected that applicable COC would be implemented to address potential impacts to unknown, subsurface cultural resources.

The Endangered Species Act

Scope

The Endangered Species Act of 1973 (ESA) provides a program for the conservation of threatened and endangered plants and animals and the habitats in which they are found. The lead federal agencies for implementing ESA are the U.S. Fish and Wildlife Service (FWS) and the U.S. National Oceanic and Atmospheric Administration (NOAA) Fisheries Service. The FWS maintains a worldwide list of endangered species including birds, insects, fish, reptiles, mammals, crustaceans, flowers, grasses, and trees.

The ESA mandates all Federal departments and agencies to conserve listed species and to utilize their authorities in furtherance of the purposes of the ESA. The ESA provides specific mechanisms to achieve its purposes and Section 7 is one of those. Section 7 requires that Federal agencies develop a conservation program for listed species (i.e., Section 7(a)(1)) and that they avoid actions that will further harm species and their critical habitat [i.e., Section 7(a)(2); see S7 Consultation Step-by-Step (U.S. Fish and Wildlife Service., 2017)].

Section 7(a)(2) directs all Federal agencies to ensure that any action they authorize, fund, or carry-out does not jeopardize the continued existence of an endangered or threatened species or designated or proposed critical habitat (collectively, referred to as protected resources). The implementing regulations, 50 CFR 402, specify how Federal agencies are to fulfill their section 7 consultation requirements and are summarized below (U.S. Fish and Wildlife Service, 2017).

Under the implementing regulations (50 CFR 402), Federal agencies must review their actions and determine whether the action may affect federally listed and proposed species or proposed or designated critical habitat. To accomplish this, Federal agencies must request from the Service a list of species and critical habitat that may be in the project area or they can request our concurrence with their species list. The Service must respond to either request within 30 days.

Once a species list is obtained or verified as accurate, Federal agencies need to determine whether their actions may affect any of those species or their critical habitat. If no species or their critical habitat are affected, no further consultation is required. If they may be affected, consultation with FWS is required. This consultation will conclude either informally with written concurrence from FWS or through formal consultation with a biological opinion provided to the Federal agency (U.S. Fish and Wildlife Service, 2017).

Applicability to Panoche Energy Center

The PEC is located in the western portion of the San Joaquin Valley in an unincorporated area of western Fresno County. Historically, this portion of the San Joaquin Valley contained many natural habitats that supported a variety of native plant and animal species. However, these natural environments have been largely converted to agricultural and urban land uses. The dominant land use in the vicinity of the PEC is agriculture with other uses including urban, industrial, and commercial facilities (CEC, 2007).

In California, the licensing of electric power generation facilities falls within the purview of the CEC. During the licensing of the PEC, the CEC considered impacts from construction and operation of the facility to biological resources including state and federally listed species, species of special concern, wetlands and unique biological habitats.

Biological field surveys were conducted by the Applicant in accordance with CEC regulations on 21 April 2006. The field survey included walk through of the proposed plant site, nearby construction laydown area, and visually scanning areas within a 1-mile buffer. A literature review was performed prior to the field survey including a search of the California Native Plant Society Inventory of Rare Plants Database, and the California Natural Diversity Database in order to determine what special status species were known to occur or could potentially occur within the project area. "Special-status species" considered included any species that had been afforded special recognition by federal, state, or local resource agencies and/or resource conservation organization (CEC, 2007).

Several special-status wildlife species were indented that are known to utilize agricultural habitat and thus had the potential to occur in the project area. These species include the short-eared owl (Asio flammeus), burrowing owl (Athene cunicularia), Swainson's hawk (Buteo swainsoni), California horned lark (Eremophelia alpestris actia), and the San Joaquin kit fox (Vulpes macrotis mutica). Of these, only the kit fox was expected to occur in the proposed project area (CEC, 2007).

The PEC signed a Memorandum of Understanding on 7 August 2007 with FWS, formalizing the Service's agreement to facilitate a Federal nexus for the purposes of conducting consultation pursuant to Section 7 of the Endangered Species Act as described in 50 CFR 402. PEC submitted a Biological Assessment to the FWS on 18 May 2007 and on 21 August 2007, the FWS issued a Biological Opinion (CEC, 2007).

The FWS stated that, upon implementation of the Reasonable and Prudent Measures contained in their Biological Opinion, incidental take of the San Joaquin kit fox associated with the construction and operation of the PEC would be exempt from the prohibitions described under Section 9 of the Endangered Species Act. The FWS went on to state that "… we determined that this level of anticipated take is not likely to result in jeopardy to the kit fox" (FWS, 2007).

The Reasonable and Prudent Measures contained in the Biological Opinion were incorporated into the CEC's Final Commission Decision as project required COC. In addition, the PEC was required to offset impacts to non-critical San Joaquin kit fox habitat through the purchase of conservation credits at the Krayenhagen Hills conservation bank (FWS, 2007).

The PEC continues to comply with all COC, including those related to biological resources and the San Joaquin kit fox.

Ultimately, the CEC made the following findings in the Final Commission Decision based on their review of the evidence (CEC, 2007):

- The PEC site provides little or no habitat value for common of special status plant or animal species.
- The only special status species known to exist on the project site or along the linear corridors is the San Joaquin kit fox.
- The project, constructed and operated in compliance with the mitigation measures and COC set forth in the Final Commission Decision, does not create significant impacts to any special status species.

The CEC went on to conclude that "… implementation of the Conditions of Compliance (mitigation measures) set forth ensure that construction and operation of the PEC will not create any significant direct, indirect, or cumulative impacts to biological resources, and that the project will conform with all applicable laws, ordinances, regulations, and standards relating to biological resources" (CEC, 2007). Operations at the PEC, including operation of the four completed injection wells, continue to comply with all COC imposed by the CEC at the time of licensing, including those applicable to biological resources as evidenced by quarterly and annual environmental reports submitted by the facility to the CEC.

The UIC injection well permit application submitted by the PEC on 20 October 2017 is for continued operation of IW1, IW2, IW3 and IW4 and potential construction of proposed wells IW5 and IW6. The construction and operational phase impacts of these wells to the San Joaquin kit fox were the subject of the FWS 2007 Biological Opinion. Construction of proposed wells IW5 and IW6 will occur within the existing facility boundary and will not result in additional loss of habitat. During construction of proposed IW5 and IW6, all Conditions of Compliance related to biological resources, including those presented in the FWS's Biological Opinion, will be adhered to.

The Coastal Zone Management Act

Scope

The Coastal Zone Management Act (CZMA) of 1972 provides for the management of the nation's coastal resources, including the Great Lakes. The goal is to "preserve, protect, develop, and where possible, to restore or enhance the resources of the nation's coastal zone." It is administered by the National Oceanic and Atmospheric Administration (NOAA).

The CZMA outlines three national programs, the National Coastal Zone Management Program, the National Estuarine Research Reserve System, and the Coastal and Estuarine Land Conservation Program. The National Coastal Zone Management Program aims to balance competing land and water issues through state and territorial coastal management programs, the reserves serve as field laboratories that provide a greater understanding of estuaries and how humans impact them. The Coastal and Estuarine Land Conservation Program provides matching funds to state and local governments to purchase threatened coastal and estuarine lands or obtain conservation easements (FEMA, 2019).

The CZMA defines the coastal zones wherein development must be managed to protect areas of natural resources unique to coastal regions. States are required to define the area that will comprise their coastal zone and develop management plans that will protect these unique resources through enforceable policies of state coastal zone management (CZM) programs. Federal as well as local actions must be determined to be consistent with the CZM plans and policies before they can proceed. As defined in the CZMA, the coastal zone includes coastal waters extending to the outer limit of state submerged land title and ownership, adjacent shorelines, and land extending inward to the extent necessary to control shorelines. Generally, the coastal zone includes all territorial U.S. waters and adjacent land areas. The coastal zone includes beaches, islands, salt marshes, and wetlands, and some adjacent inlands. Each state designates the area of land and water resources that are included in their coastal zone and is regulated by a state coastal zone management program (U.S. Department of Homeland Security, 2017). In California, the three designated coastal management agencies are: the Bay

Conservation and Development Commission, the California Coastal Conservancy, and the California Coastal Commission.

The California Coastal zone extends from the Oregon border to the border of the Republic of Mexico, seaward to the state's outer limit of jurisdiction, and inland generally a distance of 1,000 yards from the mean high tide line. In significant coastal estuarine, habitat, and recreational areas it extends inland to the first major ridgeline paralleling the sea or five miles, whichever is less (Data Basin, 2017).

Applicability to Panoche Energy Center

The PEC is located 65 miles east (inland) of the Pacific Ocean and is not within the coastal zone and thus not subject to the Coastal Zone Management Act.

The Fish & Wildlife Coordination Act

Scope (Applies only to federally constructed, permitted or licensed water projects)

The Fish and Wildlife Coordination Act (FWCA) requires that federal agencies consult with the U.S. FWS, the National Marine Fisheries Service and State wildlife agencies for activities that affect, control or modify waters of any stream or bodies of water, in order to minimize the adverse impacts of such actions on fish and wildlife resources and habitat. This consultation is generally incorporated into the process of complying with Section 404 of the Clean Water Act, NEPA or other federal permit, license or review requirements (U.S. Department of Commerce, n.d.).

FWCA is one of the FWS major authorities for providing fish and wildlife evaluations and recommendations and provides a basic procedural framework for the orderly consideration of fish and wildlife conservation and enhancement measures in federally constructed, permitted, or licensed water development projects. The FWCA provides that, whenever any water body is proposed to be controlled or modified, for any purpose whatever, by a Federal agency or by any public or private agency under a Federal permit or license, consultation with wildlife agencies is required with the goal of conserving fish and wildlife resources in connection with that project.

To comply with the requirements laid out in the FWCA, Federal agencies must first determine whether a proposed activity will result in the control or modification of a body of water. Typical actions that would fall under the jurisdiction of the FWCA include:

- Discharges of pollutants, including industrial, mining, and municipal wastes or dredged and fill material into a body of water or wetlands; and
- Projects involving construction of dams, levees, impoundments, stream relocation, and water-diversion structure.

Applicability to Panoche Energy Center

The FWCA is not applicable to the permitting of six injection wells (four constructed and two proposed) at the PEC as the permitting action does not involve a body of water subject to the act (i.e., streams, lakes or other water courses). It is important to note that the Biological Opinion prepared by the FWS dated 21 August 2007 for the initial licensing of the PEC cites Section 7 of the Endangered Species Act (50 CFR 402) as the implementing regulation for performing the consultation, not the FWCA.

APPLICABLE STATE REGULATIONS

This section presents, as requested by USEPA Region IX in their letter dated 20 November 2017, a list of all state regulations that apply to regulating the facility's operation.

Air Toxics "Hot Spots" Information and Assessment Act of 1987 (Health and Safety Code Section 44300 et seq.)

The Air Toxics "Hot Spots" Information and Assessment Act (Act; AB 2588, 1987, Connelly) was enacted in 1987, and requires stationary sources to report the types and quantities of certain substances routinely released into the air. The goals of the Act are to collect emission data, to identify facilities having localized impacts, to ascertain health risks, to notify nearby residents of significant risks, and to reduce those significant risks to acceptable levels (CARB, 2017).

The PEC is subject to the Act and in 2017 prepared and submitted a Toxic Emission Inventory Plan and Toxic Emission Inventory Report for reporting year 2015 to the SJVAPCD.

California Global Warming Solutions Act of 2006 (Health and Safety Code §38530 & California Code of Regulations, Title 17, Division 3, Chapter 1)

The requirements of California Global Warming Solutions Act of 2006, commonly referred to as AB-32, are codified in Health and Safety Code §38530 and Title 17, of the California Code of Regulations, Division 3, Chapter 1. The PEC is subject to Article 2: Mandatory Greenhouse Gas Emissions Reporting, Article 3: Fees and Article 5: California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms of Chapter 1 of the regulation.

As such, PEC submits annual greenhouse gas reports to the California Air Resources Control Board through their Cal-eGGRT online reporting tool and submits annual payment as invoiced by CARB for oversight of the greenhouse gas reporting program. PEC participates in California's greenhouse gas cap-and-trade program through registration in the state's Compliance Instruments Tracking System Service where adequate allowances are banked to cover reported greenhouse gas emissions.

California Accidental Release Prevention Program

The CalARP, codified at California Code of Regulations, Title 19, §§ 2735.1 to 2785.1, provides information to initial responders and satisfies federal and state Community Right-to-Know laws regarding the storage of hazardous materials above threshold quantities.

The PEC utilizes aqueous ammonia (19 percent) to reduce NOx emissions from the four gas turbine engines. Up to 19,000 gallons of aqueous ammonia is stored at one time in a single tank. At a concentration of 19 percent, aqueous ammonia storage at the PEC does not trigger the Federal Risk Management Program (RMP)threshold for ammonia storage and the PEC is therefore not subject to the Federal RMP regulations. However, the storage of up to 19,000 gallons of aqueous ammonia (19 percent) is above the California Accidental Release Program thresholds. Based on modeling and analysis of worst case and most probable case release scenarios, PEC has been designated a Program Level 2 facility. In accordance with the CalARP requirements, PEC maintains a current Risk Management Plan and registration with the Fresno County Department of Environmental Health (Certified Unified Program Administrator).

California Energy Commission (Final Commission Decision)

The CEC is the state's primary energy policy and planning agency. The agency was established by the Warren-Alquist Act in 1974 in response to the energy crisis of the early 1970s and the state's unsustainable growing demand for energy resources. The Energy Commission is made up of five Commissioners appointed by the Governor and confirmed by the Senate. Commissioners serve staggered five-year terms. The Governor also designates a Chair and Vice Chair as primary agency leads. The Commissioners represent specific areas of expertise: law, environment, economics, science/engineering, and the public at large (CEC n.d.).

The Energy Commission is responsible for the certification and compliance of thermal power plants 50 MW and larger including all project-related facilities in California. The agency's transparent certification process consists of reviewing the engineering design and evaluating the environmental impacts of power plant projects under a certified regulatory program to ensure that projects meet all engineering and environmental regulatory requirements and reduce significant impacts. For projects it certifies, the CEC oversees project construction, operation, and closure (CEC n.d.).

On 2 August 2006, PEC, LLC filed an Application for Certification (AFC) with the CEC to construct and operate the 400 MW PEC. The project description for the plant included wastewater disposal using deep injection wells. Prior to issuance of the CEC's Final Commission Decision approving the PEC project, USEPA Region IX sent the CEC a draft copy of Permit No CA10600001 (Class I nonhazardous waste injection wells) for construction and operation of six injection wells (IW1, IW2, IW3, IW4, IW5 and IW6). Of the six wells, only four were constructed (IW1, IW2, IW3 and IW4).

The CEC's Final Commission Decision was adopted on 19 December 2007 conditionally approving construction and operation of the PEC (CEC, 2007). The CEC's Final Commission Decision contains a comprehensive list of construction and operational phase COC that the PEC is required adhere to. COC Soil & Water-6 requires the PEC to obtain a Class 1 Non-hazardous UIC permit from the USEPA for construction and operation of six deep injection wells (CEC, 2007). In accordance with COC Compliance-7, PEC submits an Annual Compliance Report to the CEC.

Hazardous Materials Business Plan (Health & Safety Code, Division 20, Chapter 6.95 [25500 –25547.8])

The State of California requires an owner or operator of a facility to complete and submit a Hazardous Material Business Plan (HMBP) if the facility handles a hazardous material or mixture containing a hazardous material that has a quantity at any one time during the reporting year equal to or greater than:

- 55 gallons (liquids),
- 500 pounds (solids), or
- 200 cubic feet for a compressed gas (California Department of Emergency Services, n.d.).

Other thresholds exist but are not relevant to the PEC.

A HMBP is a document is required to contain the following detailed information (California Department of Emergency Services, n.d.):

- Inventory of hazardous materials at a facility;
- Emergency response plans and procedures in the event of a reportable release or threatened release of a hazardous material;
- Training for all new employees and annual training, including refresher courses, for all employees in safety procedures in the event of a release or threatened release of a hazardous material; and
- A site map that contains north orientation, loading areas, internal roads, adjacent streets, storm and sewer drains, access and exit points, emergency shutoffs, evacuation staging areas, hazardous material handling and storage areas, and emergency response equipment.

Various hazardous materials (i.e., oil, aqueous ammonia, diesel fuel, sulfuric acid, sodium hypochlorite, sodium hydroxide, etc.) are stored at the PEC above HMBP thresholds thus requiring the facility to submit and maintain a HMBP with the Fresno County Department of Environmental Health (the Certified Unified Program Administrator). The PEC HMBP is maintained on the Fresno County Department of Environmental Health's HMBP online database. The Panoche HMBP is updated as required (within 30 days of a chemical change) and certified annually.

Hazardous Waste Generator (Health & Safety Code Chapter 6.5 (commencing with 25100) and Title 22 California Code of Regulations, Division 4.5)

The PEC periodically generates and stores more than 1,000 kilograms (kg; 2,200 pounds [lbs]) of waste in a month meeting the definition of a California only Hazardous Waste as defined in Section 66261 of Title 22 of the California Code of Regulations. The PEC therefore manages hazardous waste under the Large Quantity Generator regulations contained in Section 66262.34 of Title 22. Because the PEC does not routinely generate and store more than 100 kg (220 lbs) of waste in a month meeting the federal definition of a hazardous, PEC is not required to obtain a Federal EPA ID number. The California Department of Toxic Substance Control has issued California EPA ID CAL000336991 to PEC for the generation and management of hazardous waste.

All hazardous waste generated by the PEC is disposed of at licensed Treatment Storage and Disposal Facilities (TSDF) and transported by licensed hazmat transporters.

General Industrial Storm Water Permit

The Statewide General Permit for Storm Water Discharges Associated with Industrial Activities, Order 2014-0057-DWQ (Industrial General Permit [IGP]) implements the federally required storm water regulations in California for storm water associated with industrial activities discharging to waters of the United States. The IGP regulates discharges associated with 10 federally defined categories of industrial activities.

All storm water incident within the boundaries of the PEC is directed to the on-site storm water impoundment basin. No storm water is discharged from the site and the facility is therefore not subject to the requirements of Order 2014-0057-DWQ.

General Industrial Storm Water Permit

Dischargers whose projects disturb one or more acres of soil or whose projects disturb less than one acre but are part of a larger common plan of development that in total disturbs one or more acres, are required to obtain coverage under the General Permit for Discharges of Storm Water Associated with Construction Activity Construction General Permit Order 2009-0009-DWQ. Construction activity subject to this permit includes clearing, grading and disturbances to the ground such as stockpiling, or excavation, but does not include regular maintenance activities performed to restore the original line, grade, or capacity of the facility.

In July 2016, prior to commencement of construction of the Enhanced Wastewater System, PEC submitted a Notice of Intent (NOI) for coverage under the Construction General Permit due to ground disturbance and grading in excess of the threshold level. During the project, storm water best management practices were implemented including monitoring. With project completion, a Notice of Termination was submitted along with final reports thus ending coverage under the Construction General Permit.

Any future construction or grading projects with the potential to exceed the Construction General Permit threshold would be required to submit an NOI for coverage under the Construction General Permit and would be required to comply with all applicable requirements contained therein.

OTHER FEDERAL PROGRAMS APPLICABLE TO OPERATIONS AT THE PANOCHE ENERGY CENTER

This section provides a discussion of other federal environmental programs relevant to operation of the PEC.

Spill Prevention Control and Counter Measures

The PEC stores various oil products subject to the regulation under 40 CFR 112 in quantities above threshold values and thus maintains a current Spill Prevention Control and Counter Measures Plan (SPCC). The Fresno County Department of Environmental Health is the Certified Unified Program Administrator delegated authority to oversee compliance with SPCC regulations in Fresno County.

Resource Conservation Recovery Act

Though the PEC does not store waste meeting the definition of a hazardous waste pursuant to 40 CFR 261: Identification and Listing of Hazardous Waste, above quantities requiring a Federal EPA ID number, PEC is subject to the requirements contained in 40 CFR 261 and 40 CFR 262: Standards for Generation of Hazardous Waste. PEC manages hazardous waste under California EPA ID CAL000336991.

Shipment of Hazardous Materials subject to U.S. Department of Transportation Regulation (49 CFR 172.101)

PEC ships materials meeting the definition of a U.S. Department of Transportation (DOT) hazardous material pursuant to 40 CFR 49.173 to off-site facilities under Hazardous Materials Certificate of Registration 061615 003001XZ issued by DOT. The majority of DOT hazardous materials shipped from the PEC are universal and hazardous wastes. Much of the California hazardous waste shipped from the PEC does not meet the definition of a DOT hazardous material (i.e., used oil and absorbents contaminated with oil).

Greenhouse Gas Reporting (40 CFR 98)

The PEC reports annual greenhouse gas emissions to the USEPA using the Agency's online Cal-eGGRT greenhouse gas reporting tool. Equipment at the PEC subject to reporting under the federal greenhouse gas reporting rules include the four natural gas fired combustion turbines and switch gear containing sulfur hexafluoride.

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ATTACHMENT U

Description of Business

Table of Contents

ATTACHMENT U – DESCRIPTION OF BUSINESS

PERMIT APPLICATION REQUIREMENTS

As stated in the U.S. Environmental Protection Agency Form 7520-6, Attachment U requires the applicant to “Give a brief description of the nature of the business.”

FACILITY DESCRIPTION

The Panoche Energy Center (PEC) facility is a nominal 400 megawatt (MW)-cycle peaking power plant utilizing four General Electric LMS-100 fast start natural-gas fired turbine engines and associated supporting equipment and systems. Each of the LMS-100 engines is capable of generating approximately 100 MW. Auxiliary equipment includes mechanical draft cooling tower, circulating water pumps, water treatment equipment, natural gas compressors, generator step-up and auxiliary transformers, and water storage tanks (Figure 3).

California’s Need for Peak-Demand Power

In December 2004, the California Public Utilities Commission authorized Pacific Gas & Electric (PG&E) to “plan for and procure the resources necessary to provide reliable service to their customer loads for the planning period 2005 through 2014.” PG&E analysts evaluated models of the electric distribution grid and determined that 1,200 MW of new peaking generation were required in 2008 and another 1,000 MW of new peaking and dispatchable generation would be required in 2010 (Peltier, 2010).

Demand on the electric power grid is not constant and has both seasonal and diurnal variation. The design and purpose of peaking power plants such as the PEC is to provide rapid support of the electric-power grid in response to changing load conditions. Dispatched in combination with base load plants, peaking power plants help ensure the dependable and consistent delivery of electric power to the State’s citizens.

As the result of their analysis of peak power demand within their service area, PG&E undertook acquisition of new peaking and dispatchable generation with issuance of a competitive bid request for offers (RFO) issued on 18 March 2005. In response to the RFO, the facility’s developers submitted a successful bid resulting in execution of a Power Purchase Agreement (PPA) for 400 MWs of dispatchable gas-fired generation in April 2006 (Peltier, 2010).

Panoche Energy Center, a Purpose-Built Peaking Power

The PEC facility, which is owned and operated by Panoche Energy Center, LLC (the Applicant), is a purpose-built peaking facility designed to support the electric power grid during periods of high demand and in the event of loss of other generating resource (i.e., scheduled and unscheduled maintenance of other power plants).

The fast start requirements of the PPA resulted in selection of the 100-MW GE LMS-100 combustion turbine (CT) due to its ability to ramp from cold start to full load in approximately 10 minutes. In addition, each of the four CTs can supply 100-MW blocks of electric power generation when dispatched by the utility to the critical Path 15 corridor. The GE LMS-100 is a purpose built aero-derivative engine designed to meet the need for efficient mid-range (80 MW to 160 MW) peaking capacity. Key to the efficiency of the LMS100 is the inclusion of an inter-cooler. The inter-cooler increases the turbine's efficiency by precooling compressed inlet air prior to the engine's high-pressure compressor (Peltier, 2010).

The intercooler is a heat exchanger utilizing circulating water from the facility's cooling tower to remove heat from the compressed inlet air. At the cooling tower, heat is removed from the returning circulating water through evaporative cooling. Evaporation causes the salinity of the circulating water to increase. To maintain water quality, a portion of the circulating water is continually removed (blowdown) during operation. This cooling tower blowdown constitutes one of the major wastewater sources at the facility. The facility's four injection wells are key to the disposal of this and other non-hazardous wastewater sources and to the plant's support of California's energy needs.

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