C6 RESOURCES, LLC

AN AFFILIATE OF SHELL OIL COMPANY

- NORTHERN CALIFORNIA CO2 REDUCTION PROJECT – CLASS V UIC INJECTION WELL APPLICATION

TABLE OF CONTENTS

LIST OF FIGURES

Attachment B – Maps of Well/Area and Area of Review

Attachment D – Maps and Cross Sections of USDWs

Attachment F – Maps and Cross Sections of Geological Structure

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

Attachment P – Monitoring Program

Attachment Q – Plugging and Abandonment Plan

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF APPENDICES

I. US EPA UNDERGROUND INJECTION CONTROL PERMIT APPLICATION – EPA FORM 7520-6 (REV. 8-01)

Insert EPA Form 7520-6 Area Permit for both the Injection Well & Observation Well

OMB No. 2040-0042   Approval Expires 4/30/07

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: C6 Resources, LLC, an affliate of Shell Oil Company			Owner Name: Same		
Street Address: 200 Dairy Ashford, Wood Creek		Phone Number: (281) 544-2853	Street Address:		Phone Number:
City: Houston	State: TX	ZIP CODE: 77079	City:	State:	ZIP CODE:

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
☐ Yes ☐ No	☐ Private ☐ Federal ☐ Other	☐ Owner ☐ Operator	

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

☐ A. Operating	Date Started (mo day year)	☐ B. Modification/Conversion	☒ C. Proposed

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

☐ A. Individual ☐ B. Area	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
	0	2	Northern California CO2 Reduction Project

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)
V	Other	"Class V: for small-scale injection of CO2 for a geologic carbon sequestration pilot test	2

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

Latitude Deg	Latitude Min	Latitude Sec	Longitude Deg	Longitude Min	Longitude Sec	Township and Range Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
38	07	00.5	-121	50	26.4	11	3N	1E	NE	1,700	N	2,125	W

XII. Indian Lands (Mark 'x')

☐ Yes
☐ 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.)*
Edward Hymes, President C6 Resources, LLC	(832) 544-4972
C. Signature: [signature]	D. Date Signed:

EPA Form 7520-6 (Rev. 8-01)

Well Class and Type Codes

Class I		Wells used to inject waste below the deepest underground source of drinking water.
Type	**"I"**	Nonhazardous industrial disposal well
	"M"	Nonhazardous municipal disposal well
	"W"	Hazardous waste disposal well injecting below USDWs
	"X"	Other Class I wells (not included in Type "I," "M," or "W")
Class II		Oil and gas production and storage related injection wells.
Type	**"D"**	Produced fluid disposal well
	"R"	Enhanced recovery well
	"H"	Hydrocarbon storage well (excluding natural gas)
	"X"	Other Class II wells (not included in Type "D," "R," or "H")
Class III		Special process injection wells.
Type	**"G"**	Solution mining well
	"S"	Sulfur mining well by Frasch process
	"U"	Uranium mining well (excluding solution mining of conventional mines)
	"X"	Other Class III wells (not included in Type "G," "S," or "U")

Other Classes Wells not included in classes above.
Class V wells which may be permitted under §144.12.
Wells not currently classified as Class I, II, III, or V.

Attachments to Permit Application

Class	**Attachments**
I new well	A, B, C, D, F, H – S, U
existing	A, B, C, D, F, H – U
II new well	A, B, C, E, G, H, M, Q, R; optional – I, J, K, O, P, U
existing	A, E, G, H, M, Q, R, – U; optional – J, K, O, P, Q
III new well	A, B, C, D, F, H, I, J, K, M – S, U
existing	A, B, C, D, F, H, J, K, M – U
Other Classes	To be specified by the permitting authority

INSTRUCTIONS - Underground Injection Control (UIC) Permit Application

Paperwork Reduction Act: The public reporting and record keeping burden for this collection of information is estimated to average 394 hours for a Class I hazardous well application, 252 hours for a Class I non-hazardous well application, 32 hours for a Class II well application, and 119 hours for a Class III well application. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, DC 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

This form must be completed by all owners or operators of Class I, II, and III injection wells and others who may be directed to apply for permit by the Director.

I. **EPA I.D. NUMBER** - Fill in your EPA Identification Number. If you do not have a number, leave blank.

II. **OWNER NAME AND ADDRESS** - Name of well, well field or company and address.

III. **OPERATOR NAME AND ADDRESS** - Name and address of operator of well or well field.

IV. **COMMERCIAL FACILITY** - Mark the appropriate box to indicate the type of facility.

V. **OWNERSHIP** - Mark the appropriate box to indicate the type of ownership.

VI. **LEGAL CONTACT** - Mark the appropriate box.

VII. **SIC CODES** - List at least one and no more than four Standard Industrial Classification (SIC) Codes that best describe the nature of the business in order of priority.

VIII. **WELL STATUS** - Mark Box A if the well(s) were operating as injection wells on the effective date of the UIC Program for the State. Mark Box B if wells(s) existed on the effective date of the UIC Program for the State but were not utilized for injection. Box C should be marked if the application is for an underground injection project not constructed or not completed by the effective date of the UIC Program for the State.

IX. **TYPE OF PERMIT** - Mark "Individual" or "Area" to indicate the type of permit desired. Note that area permits are at the discretion of the Director and that wells covered by an area permit must be at one site, under the control of one person and do not inject hazardous waste. If an area permit is requested the number of wells to be included in the permit must be specified and the wells described and identified by location. If the area has a commonly used name, such as the "Jay Field," submit the name in the space provided. In the case of a project or field which crosses State lines, it may be possible to consider an area permit if EPA has jurisdiction in both States. Each such case will be considered individually, if the owner/operator elects to seek an area permit.

X. **CLASS AND TYPE OF WELL** - Enter in these two positions the Class and type of injection well for which a permit is requested. Use the most pertinent code selected from the list on the reverse side of the application. When selecting type X please explain in the space provided.

XI. **LOCATION OF WELL** - Enter the latitude and longitude of the existing or proposed well expressed in degrees, minutes, and seconds or the location by township, and range, and section, as required by 40 CFR Part 146. If an area permit is being requested, give the latitude and longitude of the approximate center of the area.

XII. **INDIAN LANDS** - Place an "X" in the box if any part of the facility is located on Indian lands.

XIII. **ATTACHMENTS** - Note that information requirements vary depending on the injection well class and status. Attachments for Class I, II, III are described on pages 4 and 5 of this document and listed by Class on page 2. Place EPA ID number in the upper right hand corner of each page of the Attachments.

XIV. **CERTIFICATION** - All permit applications (except Class II) must be signed by a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, and by a principal executive or ranking elected official for a public agency. For Class II, the person described above should sign, or a representative duly authorized in writing.

INSTRUCTIONS - Attachments

Attachments to be submitted with permit application for Class I, II, III and other wells.

A. **AREA OF REVIEW METHODS** - 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 well bore unless the use of an equation is approved in advance by the Director.

B. **MAPS OF WELL/AREA AND AREA OF REVIEW** - 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:

Class I

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;

Class II

In addition to requirements for Class I, include pertinent information known to the applicant. This requirement does not apply to existing Class II wells;

Class III

In addition to requirements for Class I, include public water systems and pertinent information known to the applicant.

C. **CORRECTIVE ACTION PLAN AND WELL DATA** - 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:

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.

Class II

In addition to requirement for Class I, in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the area of review which penetrate formations affected by the increase in pressure. This requirement does not apply to existing Class II wells.

Class III

In addition to requirements for Class I, the corrective action proposed under 40 CFR 144.55 for all Class III wells.

D. **MAPS AND CROSS SECTION OF USDWs** - 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 source of drinking water which may be affected by the proposed injection. (Does not apply to Class II wells.)

E. **NAME AND DEPTH OF USDWs (CLASS II)** - For Class II wells, submit geologic name, and depth to bottom of all underground sources of drinking water which may be affected by the injection.

F. **MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA** - 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 sections illustrating the regional geologic setting. (Does not apply to Class II wells.)

G. **GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES (Class II)** - For Class II wells, submit appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and fracture pressure.

H. **OPERATING DATA** - 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; (5) for Class II wells, source and analysis of the physical and chemical characteristics of the injection fluid; (6) for Class III wells, a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

I. **FORMATION TESTING PROGRAM** - 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.

For Class II wells the testing program must be designed to obtain data on fluid pressure, estimated fracture pressure, physical and chemical characteristics of the injection zone. (Does not apply to existing Class II wells or projects.)

For Class III wells the testing must be designed to obtain data on fluid pressure, fracture pressure, and physical and chemical characteristics of the formation fluids if the formation is naturally water bearing. Only fracture pressure is required if the program formation is not water bearing. (Does not apply to existing Class III wells or projects.)

J. **STIMULATION PROGRAM** - Outline any proposed stimulation program.

K. **INJECTION PROCEDURES** - Describe the proposed injection procedures including pump, surge, tank, etc.

L. **CONSTRUCTION PROCEDURES** - Discuss the construction procedures (according to §146.12 for Class I, §146.22 for Class II, and §146.32 for Class III) 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.)

M. **CONSTRUCTION DETAILS** - Submit schematic or other appropriate drawings of the surface and subsurface construction details of the well.

N. **CHANGES IN INJECTED FLUID** - Discuss expected changes in pressure, native fluid displacement, and direction of movement of injection fluid. (Class III wells only.)

O. **PLANS FOR WELL FAILURES** - Outline contingency plans (proposed plans, if any, for Class II) to cope with all shut-ins or wells failures, so as to prevent migration of fluids into any USDW.

P. **MONITORING PROGRAM** - 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.

Q. **PLUGGING AND ABANDONMENT PLAN** - 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.

R. **NECESSARY RESOURCES** - 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.

S. **AQUIFER EXEMPTIONS** - 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.

T. **EXISTING EPA PERMITS** - List program and permit number of any existing EPA permits, for example, NPDES, PSD, RCRA, etc.

U. **DESCRIPTION OF BUSINESS** - Give a brief description of the nature of the business.

ATTACHMENT A AREA OF REVIEW METHODS

Because the volume of CO_2 to be injected is small and the duration of the injection period is limited (less than 2 months), the pressure cone created by the injection activity will be limited in both time and space. It is the incremental pressure increase (i.e., the pressure increase over background static pressure) that is the pressure of concern, since that is the pressure that is a result of the injection activity. The pressure increase will be highest at the point of injection (Injection Well) and will drop off rapidly away from the well. Note that downhole pressure and temperature monitoring will occur in both the Injection Well and the Observation Well. Therefore, the injection induced pressure increase will be closely monitored, both during the injection period and during the decay of pressure with time after injection ceases.

A.1 DETERMINATION OF THE CONE OF INFLUENCE

The methodology used to calculate the allowable pressure buildup for the "cone of influence" is generally consistent with previous methods (Price, 1971; Johnston and Greene, 1979; Barker, 1981; Collins, 1986; Davis, 1986; Johnston and Knape, 1986; Warner and Syed, 1986; Clark et al., 1987; Warner, 1988). The basic underlying assumption in the approach is that, in the absence of nearby, naturally occurring, vertically transmissive conduits (faults and fractures) between the injection interval and underground sources of drinking water, the only potential pathway between the injection interval and underground sources of drinking water is an artificial penetration. To pose a potential threat to underground sources of drinking water, the pressure increase in the injection interval would have to be greater than the pressure necessary to displace the material residing within the borehole - the “Critical Pressure Rise.” Therefore, the "cone of influence" is the area within which injection interval pressures exceed this calculated critical pressure rise.

A static mud column exerts pressure. For a well to provide a pathway for fluid movement, the pressures acting on the static mud column (pressure due to injection plus original formation pressure) must be greater than the static mud column pressure. In a static column of drilling mud, the gel strength of the mud must also be considered.

In this case, for upward fluid movement to begin, original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on a simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g$$

where:

P_f = original formation pressure (pounds per square inch [psi])

P_i = formation pressure increase due to injection (psi)

P_s = static fluid column pressure (psi)

P_g = gel strength pressure (psi)

Therefore, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$$P_i > P_s + P_g - P_f$$

Static mud column pressure is calculated using the equation:

$$P_s = 0.052 \times h \times M$$

where:

P_s = pressure of static mud column (psi)

h = depth to the injection reservoir from the 50 foot fallback (feet)

M = fluid mud weight (pounds per gallon)

and 0.052 is the conversion factor so that P_s is in psi.

Data from the Rio Vista field indicate that formation pressures in the intervals to be penetrated beneath the Montezuma Hills are generally normally pressured, with pressure gradients between 0.43 psi per foot of depth and 0.46 psi per foot of depth (Johnson, 1990). However, strata below the Anderson sandstone may exhibit higher pressure gradients (see Attachment G).

In an artificial penetration filled with a column of drilling mud, the gel strength of the mud must also be considered, as it provides additional resistance to flow. In this case, for upward fluid movement to begin, original formation pressure (Pf) plus the pressure due to injection (Pi) must be greater than the static fluid column pressure plus the gel strength of the mud:

$$P_g = \frac{0.00333 \text{ x } G \text{ x } h}{d}$$

where:

P_g = pressure due to gel strength (psi)

G = gel strength (pounds/100 feet^2)

h = depth to the injection reservoir from the 50 ft fallback (feet)

d = borehole diameter (inches)

where 0.00333 is the conversion factor, such that P_g is in psi.

Drilling mud weights for the wells drilled in the sections surrounding the Permit Area show that a 9.3 pounds per gallon mud is a conservative wellbore fluid, as all wells through the Anderson sandstone used at least 9.3 pounds per gallon or greater mud weight. The calculated "critical pressure rise" above the native formation pressure is 388 psi (334 psi due to mud column pressure and 54 psi due to gel strength), using conservative assumptions. As shown in Figure N-14 (Attachment N), the 388 psi incremental pressure contour is contained well within a one-quarter-mile radius of the Injection Well. Therefore, the one-quarter-mile radius Area of Review is appropriate for this pilot project.

References

Barker, S. E., 1981, Determining the area of review for industrial effluent disposal wells: M. S. Thesis, The University of Texas at Austin, Austin, Texas, p. 146.

Clark, J. E., Howard, M. R., and Sparks, D. K., 1987, Factors that can cause abandoned wells to leak as verified by case histories from Class II injection, Texas Railroad Commission files: International Symposium on Subsurface Injection of Oilfield Brines, Underground Injection Practices Council, New Orleans, LA., p. 166-223.

Collins, R. E. and Kortum, D., 1989, Drilling mud as a hydraulic seal in abandoned wellbores: Underground Injection Practices Council, 1989 Winter Meeting, San Antonio, Texas.

Davis, K. E., 1986, Factors effecting the area of review for hazardous waste disposal wells: Proceedings of the International Symposium on Subsurface Injection of Liquid Wastes, New Orleans, National Water Well Association, Dublin, Ohio, p. 148-194.

Johnson, D.S., 1990, Rio Vista Gas Field – U.S.A. Sacramento Basin, California, in Foster, N.H., and Beaumont, C.A., Eds., Atlas of Oil and Gas Fields, Structural Traps III, AAPG Treatise of Petroleum Geology, Atlas of Oil and Gas Fields, Tulsa Oklahoma, p. 243-263.

Johnston, O. C. and Greene, C. J., 1979, Investigation of artificial penetrations in the vicinity of subsurface disposal wells: Texas Department of Water Resources.

Johnston, O. C. and Knape, B., 1986, Pressure effects of the static mud column in abandoned wells: Texas Water Commission LP86-06, 106 p.

Pierce, M. S., 1989, Long-term properties of clay, water-based drilling fluids: Proceedings of the International Symposium on Class I & II Injection Well Technology, Dallas, Texas, Underground Injection Practices Council Research Foundation, p. 115 132.

Price, W. H., 1971, The determination of maximum injection pressure for effluent disposal wells, Houston, Texas, Area: M. S. Thesis, The University of Texas at Austin, Austin, Texas, p. 84.

Warner, D. L. and Syed, T., 1986, Confining layer study: Supplemental Report, Prepared for U.S. EPA Region V, Chicago, Illinois.

Warner, D. L., 1988, Abandoned oil and gas industry wells and their environmental implications: Prepared for the American Petroleum Institute.

ATTACHMENT B MAPS OF WELL/AREA AND AREA OF REVIEW

B.1 AREA OF REVIEW MAP

The topographic map shown in Figure B-1 includes the following features, which can be found in the public record:

- The numbers, or names, and locations of all producing wells, injection wells, abandoned wells, and dryholes;
- Surface water bodies and springs. The map identifies wells, springs, other surface water bodies, and drinking water wells located near the Permit Area (minimum one-quarter-mile radius);
- The locations of mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and surface faults (known or suspected).

The water wells shown in Figure B-1 are listed in Table B-1.

An Area of Review with a fixed radius of one-quarter of a mile surrounding the Permit Area is used for this project. This radius is significantly larger than the modeled CO_2 plume perimeter, which is measured in hundreds of feet from the point of injection (see Attachment N). Figure B-3 shows the proposed Permit Area, within which the Injection Well and the Observation Well will both be located. The one-quarter-mile Area of Review perimeter surrounding the Permit Area is also shown. As shown in Figure B-1, only one groundwater well is located within this one-quarter-mile Area of Review radius. There are no active or plugged and abandoned gas wells within this Area of Review.

An aerial photograph of the Montezuma Hills area, where the CO_2 pilot test will take place (Figure B-2), is also provided. The aerial photograph identifies the perimeter of the Permit Area (red polygon) and illustrates the rural nature of the site and surroundings. The Permit Area and surrounding land is used for agricultural activities and supports an extensive wind farm. Locations of the various county roads and access roads to the windmills are apparent on the photo.

Table B-1
Water Well Information

Map Number	Well ID	Installation Date	Total Depth (feet bgs)[a]	Screened Depth (feet bgs)[a]	Depth to Water (feet bgs)[a]	Well Type	Owner
1	03N01E11	Jul-1989	200	160-200	--	New Domestic Well	US Windpower
2	03N01E12A1	Aug-1975	120	40-80 100-120	--	New Domestic Well	Calvin Anderson
3	03N01E14	Jun-1981	74	56.5-74[b]	55-60	New stock (windmill) well	Freese Bros.
4	03N01E02	Oct-1981	149	142.5-149[b]	5	Reconstructed Irrigation well	Freese Bros.
5	03N01E02	Sep-1988	200	30-40 50-60 160-200	--	New Domestic Well	Alan Freeze
6	03N01E03K	Aug-1991	220	25-30 70-80 100-110 190-200	--	New Domestic Well	Ian Anderson
7	03N01E03	Apr-1994	64[b]	--	--	--	Mark Peugh
8	03N01E03	Apr-1994	120	70-80 100-120	--	New Domestic Well	Mark Peugh

(a) feet bgs = feet below ground surface
(b) Estimated depths based on other well log information

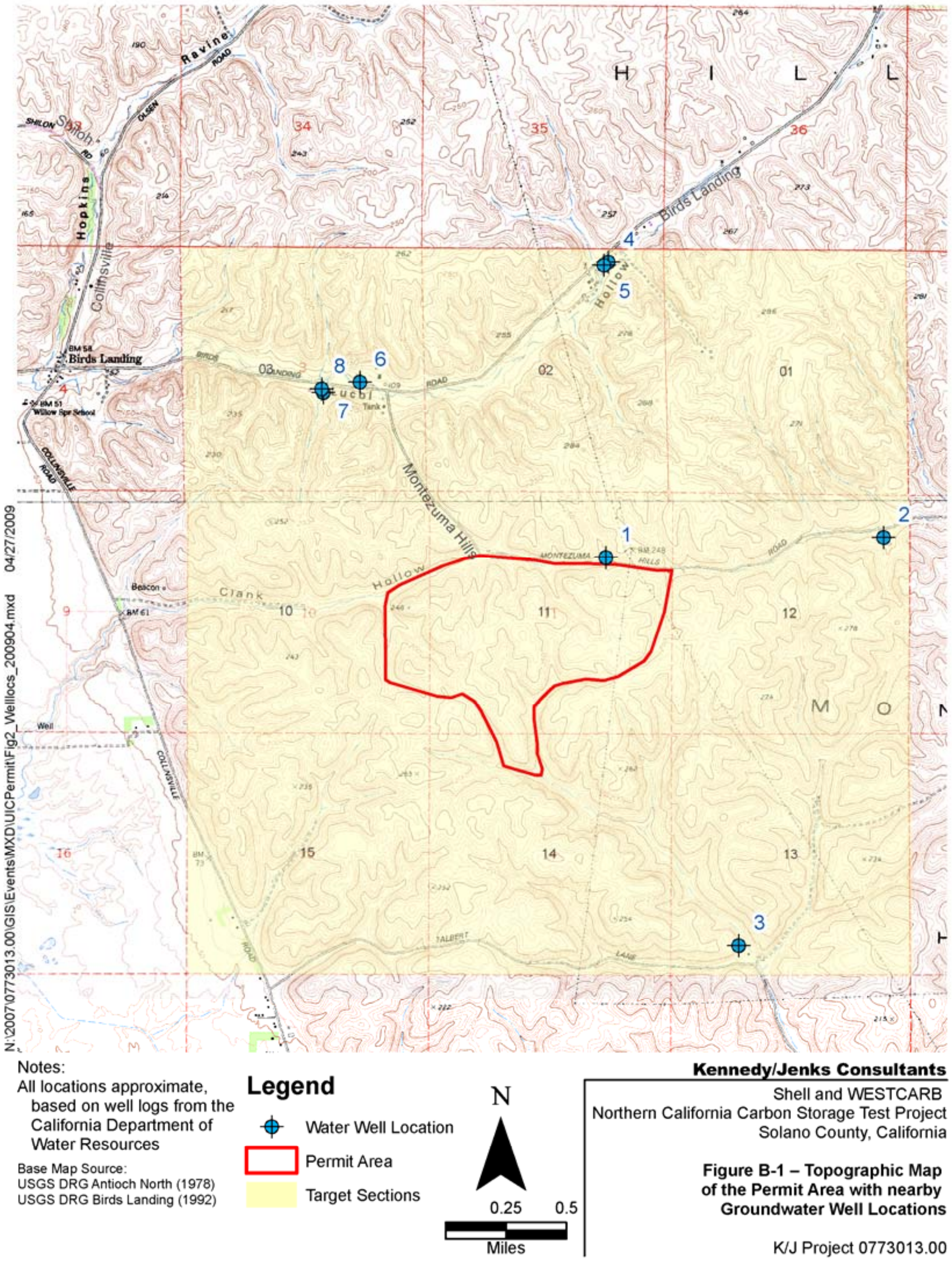


Figure B-1 Topographic Map of the Permit Area with Nearby Groundwater Well Locations

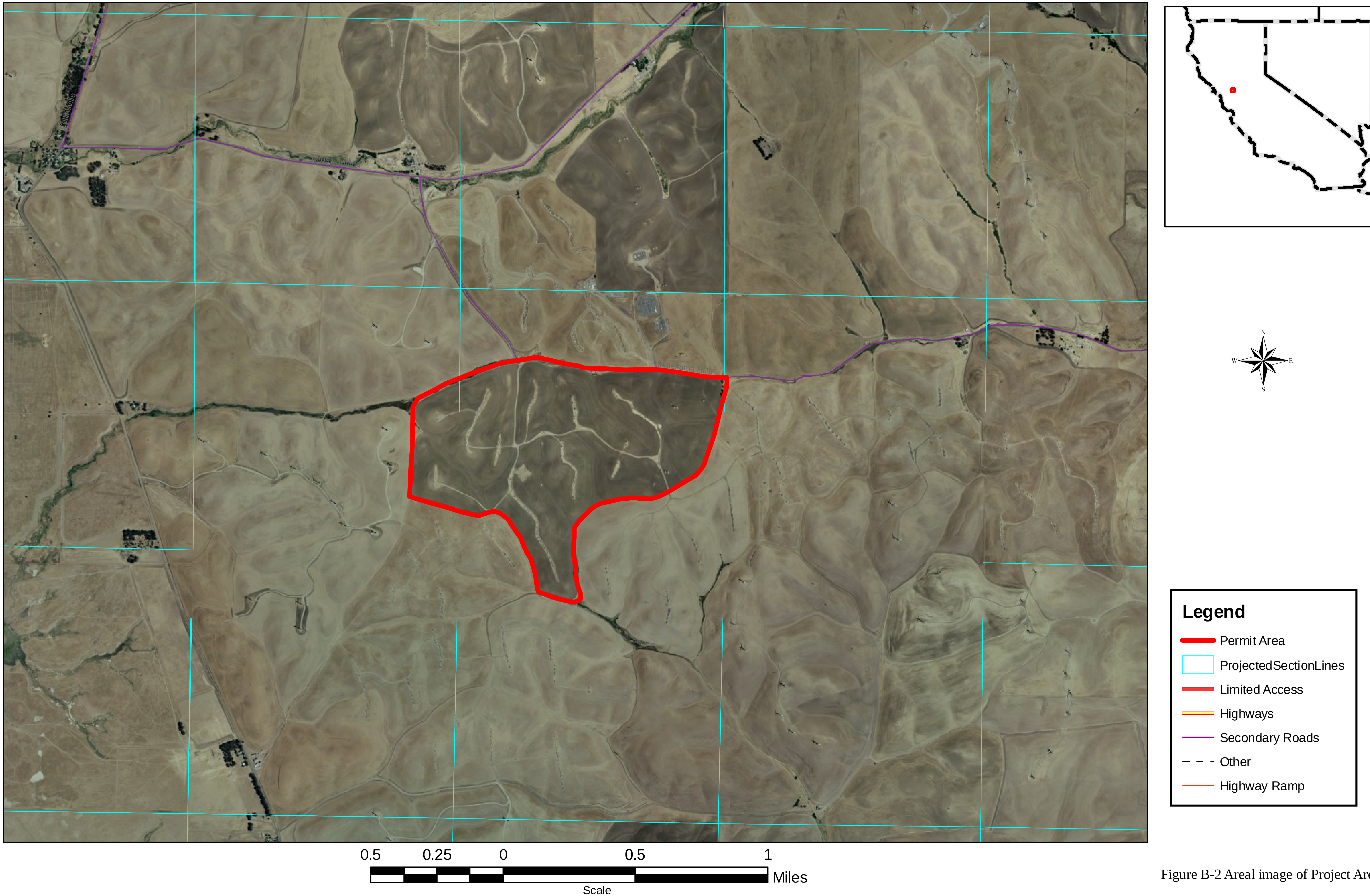


Figure B-2 Areal image of Project Area

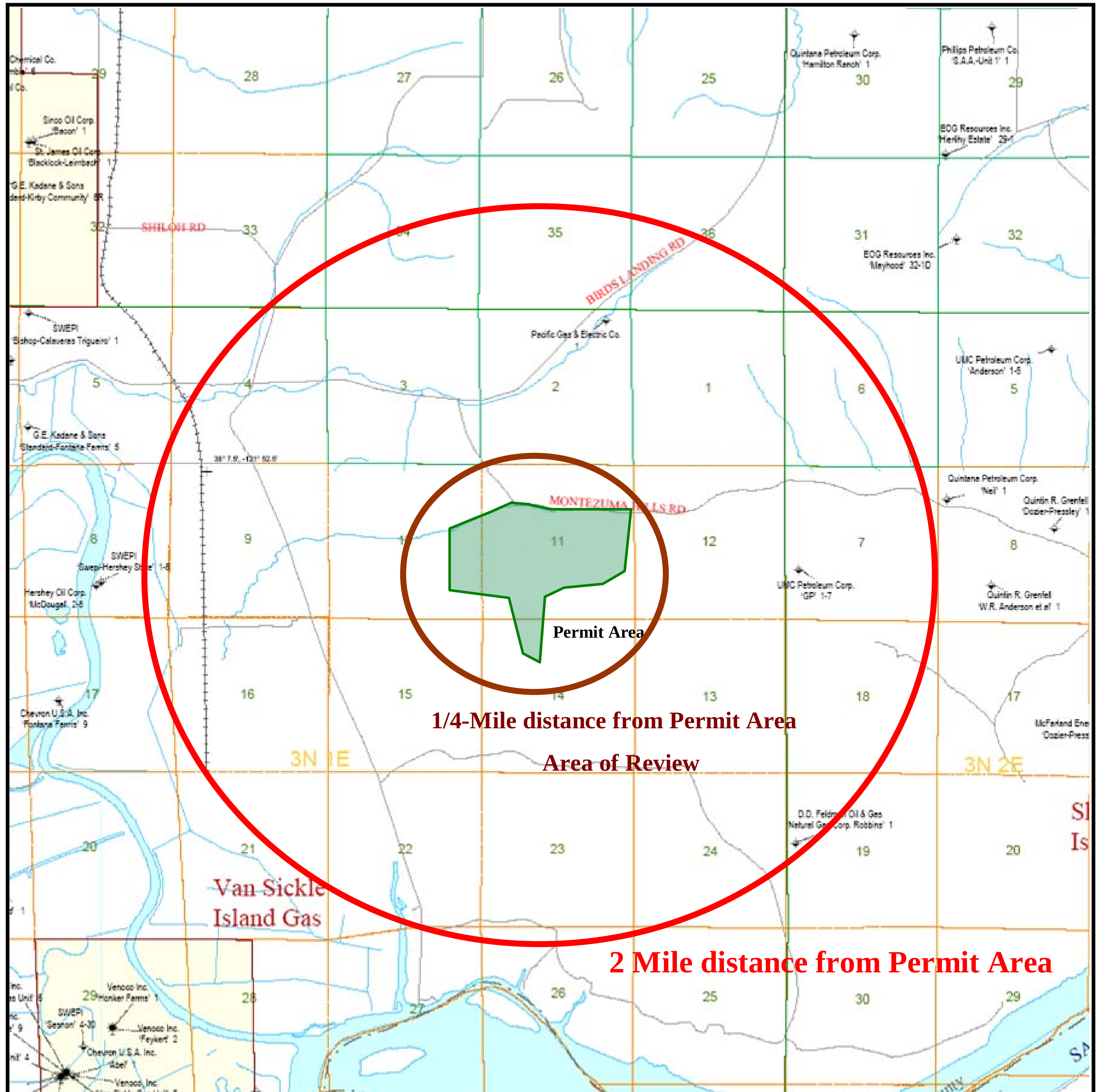


Figure B-3 Portion of State of California, Division of Oil, Gas, and Geothermal Resources Map 612 showing Project Area and nearby wells (DOGGR, 2008).

ATTACHMENT C CORRECTIVE ACTION PLAN AND WELL DATA

C.1 CORRECTIVE ACTION PLAN

No artificial penetrations are located within the one-quarter-mile Area of Review (Figure B-3, Attachment B). In fact, no wells that penetrate the Confining Zone or the Injection Zone are located within a one-mile radius of the Permit Area. This provides a significant buffer area and margin of safety.

The three wells closest to the Permit Area are located more than one mile from its perimeter (see Table C-1 and Figure B-3). This is well beyond the predicted lateral extent of the injected CO_2, which is measured only in several hundreds of feet (see Attachment N). State forms data for these three closest wells are included in Appendix C-1. The wells are described below:

- Pacific Gas & Electric Birds Landing No. 1 was not drilled sufficiently deep (total depth of only 5,002 feet) to penetrate any of the proposed injection interval sands (Domengine, Hamilton, Anderson, Upper Martinez, and Martinez123) or any of the confining zone shales (Nortonville, Capay, Meganos, Anderson, and Martinez). Therefore, this well cannot be a conduit for movement of injected CO_2 or native formation brine from the CO_2 Pilot Injection Interval.

- MCOR Oil & Gas Corp. (UMC Petroleum Corp.) Grandpa Peter No. 1-7 well was drilled in 1980. This well is sufficiently deep to penetrate the Domengine, Hamilton, Anderson, and Upper Martinez injection interval sands and all of the confining zone shales (Nortonville, Ione-Capay, Meganos, Anderson, and Martinez). Surface casing (9-5/8-inch) was set to 1,050 feet and cemented to the surface to protect freshwater sources. After logging operations were completed at total depth (11,000 feet), the well was plugged with cement plugs spotted at 1,322 to 1,792 feet (open hole), 1,001 to 1,099 feet (in and out of surface casing), and 5 to 30 feet (at surface), and abandoned. Since no “kicks” were observed during drilling of the well, the employed mud density of 72 pounds per cubic foot to 74 pounds per cubic foot (9.35 to 9.60 pounds per gallon equivalent mud weight) was sufficient to overbalance the background static pressures in the potential injection interval sands. Based on the mud density overbalance and the resistance and protection from the cement plugs, this well will not be a conduit for movement of CO_2 or formation brine from the CO_2 Pilot Injection Interval.

- DD Feldman Oil & Gas Corp. Natural Gas Corp. Robbins No. 1 well was drilled in

1951. This well is sufficiently deep to penetrate the Domengine Injection Interval sand and the Nortonville Confining Zone shale. Total depth of the well (7,010 feet) is within the uppermost Ione-Capay shale. Surface casing (10-3/4-inch) was set at 514 feet and cemented to surface to protect freshwater sources. After logging operations were completed at total depth (7,010 feet), the well was plugged with cement plugs spotted at 1,123 to 1,205 feet (open hole), 457 to 557 feet (in and out of surface casing), and 0 to 15 feet (at surface), and abandoned. Since no "kicks" were observed during drilling of the well, the employed mud density of 80 pounds per cubic foot (10.4 pounds per gallon equivalent mud weight) was sufficient to overbalance the background static pressures in the Domengine Injection Interval sand. Based on the mud density overbalance and the resistance and protection from the cement plugs, this well will not be a conduit for movement of CO_2 or formation brine from the CO_2 Pilot Injection Interval, should the Domengine sand be used. Since the well was not drilled sufficiently deep to penetrate any of the other proposed injection interval sands (Hamilton, Anderson, Upper Martinez, and Martinez123), this well cannot be a conduit for movement of CO_2 or formation brine from the pilot zone should one of the deeper sands be used.

Given the sparse well density in the syncline between Van Sickle Island Gas and Kirby Hills Gas fields to the west and Sherman Island Gas and Rio Vista Gas fields to the east, there is no risk that CO_2 will migrate out of the potential CO_2 Pilot Injection Interval sands during the short-duration test. Injection rates and interval pressures will be closely monitored before, during, and following injection of CO_2. Therefore, no corrective action is currently recommended for any wells. This is based on the following:

- The extent of the injected CO_2 Plume is measured on the order of hundreds of feet from the point of injection. This is very small in comparison to the distance to the nearest abandoned well (greater than one mile).

- The incremental pressure field that results from the injection of CO_2 is limited in area extent to within a radial distance of approximately two miles from the point of injection. The incremental pressure increase drops off exponentially as a function of distance away from the point of injection, and is less than a 1 percent increase over the original background pressure within a half mile radius of the Injection Well. This is insufficient to displace the drilling mud left in the nearby wells.

In the event it is determined that corrective action is required it will be implemented in accordance with 40 CFR §§ 144.55 and 146.7.

APPENDIX C-1
STATE FORMS DATA FOR NEARBY ARTIFICIAL PENETRATIONS

APPENDIX C-1
STATE FORMS DATA FOR NEARBY ARTIFICIAL PENETRATIONS
DD FELDMAN NATURAL GAS CORP. ROBBINS NO. 1

FORM 159 (9-49)

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS

REPORT OF WELL ABANDONMENT

Coalinga , California, September 14 , 19 51

Mr. Anthony E. L. Morris, Acting Agent
D. D. Feldman Oil and Gas
921 Westwood Blvd., Room 233
Los Angeles 24, California

095 00423

Dear Sir:

Your report of abandonment of Well No. "Natural Gas Corp. Robbins" 1, Sec. 19, T. 3 N., R. 2 E., M. D. B. & M., ----- oil field, Solano County, dated July 26, 1951, has been examined in conjunction with records filed in this office.

A review of the reports and records shows that the requirements of this Division, which are based on all information filed with it, have been fulfilled.

	Map				Form
9-19-51 GH					✓

GWH:ef
cc: Company
Mr. Marshall Brown,
Natural Gas Corp. of Calif.

R. D. BUSH
State Oil and Gas Supervisor

By G. G. Peirce
Deputy Supervisor

40778 8-51 6500 SPO

DIVISION OF OIL AND GAS
CHECK LIST - RECORDS RECEIVED AND WELL STATUS

Company ______ Well No. ______

API No. ______ Sec. ______, T. ______, R. ______, ______ B.&M.

County ______ Field ______

RECORDS RECEIVED **DATE**

Well Summary (Form OG100) ______
History (Form OG103) ______
Core Record (Form OG101) ______
Directional Survey ______
Sidewall Samples ______
Other ______
Date final records received ______
Electric logs: ______

STATUS

Producing - Oil. ____
Idle - Oil ____
Abandoned - Oil ____
Drilling - Idle ____
Abandoned - Dry Hole ____
Producing - Gas ____
Idle - Gas ____
Abandoned - Gas ____
Gas-Open to Oil Zone ____
Water Flood Source ____

STATUS

Water Disposal ____
Water Flood ____
Steam Flood ____
Fire Flood ____
Air Injection ____
Gas Injection ____
CO_2 Injection ____
LPG Injection ____
Observation ____

DATE ______
RECOMPLETED ______
REMARKS ______

ENGINEER'S CHECK LIST

1. Summary, History, & Core record (dupl.) ______
2. Electric Log ______
3. Operator's Name ______
4. Signature ______
5. Well Designation ______
6. Location ______
7. Elevation ______
8. Notices ______
9. "T" Reports ______
10. Casing Record ______
11. Plugs ______
12. Surface Inspection ______
13. Production ______
14. E Well on Prod. Dir. Sur. ______

CLERICAL CHECK LIST

1. Location change ____ (F-OGD165) ______
2. Elevation change ____ (F-OGD165) ______
3. Form OGD121 ______
4. Form OG159 (Final Letter) ______
5. Form OGD150b (Release of Bond) ______
6. Duplicate logs to archives ______
7. Notice of Records due (F-OGD170) ______

Blue Sheet N/A

RECORDS NOT APPROVED
Reason: ______

RECORDS APPROVED ______

RELEASE BOND ______
Date Eligible ______
(Use date last needed records were received.)

MAP AND MAP BOOK ______

OGD2 (10-76-OSR1-1M)

LONG BEACH OFFICE - USE REVERSE SIDE

OG 100 7-48

SUBMIT LOG IN DUPLICATE

FILL THIS IN WITH TYPEWRITER. WRITE ON ONE SIDE OF PAPER

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

WELL SUMMARY REPORT

Operator: D. D. Feldman Oil & Gas Field: Wildcat Solano County

Well No.: Natural Gas Corp.-Robbins #1 Sec. 19, T. 3N, R. 2E, MD B. & M.

Elevation above sea level 51.6 feet.

Location: 2290'S & 5430'E from NW cor. Section 24-3N-1E

All depth measurements taken from top of K. B., which is 10 feet above ground.

In compliance with the provisions of Chapter 93, Statutes of 1939, the information given herewith is a complete and correct record of the present condition of the well and all work done thereon, so far as can be determined from all available records.

Date: 7-26-51

Signed: A. E. L. Morris

A. E. L. Morris (Engineer or Geologist)

(Superintendent)

Title: Agent (President, Secretary or Agent)

Commenced drilling 6-30 ~~Completed~~ drilling Abd. 7-21-51 Drilling tools ~~Cable~~ Rotary

Total depth 7010 Plugged depth 1123-1205

Junk

GEOLOGICAL MARKERS	DEPTH
Top Markley	2820
Top Domengine	6540

Commenced producing Never (date) Flowing/gas lift/pumping (cross out unnecessary words)

	Clean Oil bbl. per day	Gravity Clean Oil	Per Cent Water including emulsion	Gas Mcf. per day	Tubing Pressure	Casing Pressure
Initial production	Abandoned					
Production after 30 days						

Casing Record (Present Hole)

Size of Casing (A. P. I.)	Depth of Shoe	Top of Casing	Weight of Casing	New or Second Hand	Seamless or Lapweld	Grade of Casing	Size of Hole Drilled	Number of Sacks of Cement	Depth of Cementing if through perforations
10 3/4	514	0	28# & 32#	New	Slip Jt.	H-40	15"	Inside 396 Outside 144	

095 00428

Perforations

Size of Casing	From	To	Size of Perforations	Number of Rows	Distance Between Centers	Method of Perforations
	ft.	ft.				
	ft.	ft.				
	ft.	ft.				
	ft.	ft.				
	ft.	ft.				

Electrical Log Depths 514-7010 Neutron Log 6450-7010 (Attach Copy of Log)

FORM 103

SUBMIT IN DUPLICATE

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

History of Oil or Gas Well

OPERATOR D. D. Feldman Oil & Gas FIELD Wildcat

Well No. Natural Gas Corp.-Robbins #1 Sec. 19, T. 31, R. 25, MD B. & M.

Signed A E L Morris

A. E. L. Morris

Date July 26, 1951 Title Agent (President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form in reporting the history of all important operations at the well, together with the dates thereof, prior to the first production. Include in your report such information as size of hole drilled to cementing or landing depth of casings, number of sacks of cement used in the plugging, number of sacks or number of feet of cement drilled out of casing, depth at which cement plugs started, and depth at which hard cement encountered. If the well was dynamited, give date, size, position and number of shots. If plugs or bridges were put in to test for water, state kind of material used, position and results of pumping or bailing.

Date	
1951	
6-30	Spud in 3:00 P.M. with 15" Dunlap bit & drilled to 514'.
7-1	Cemented 10 3/4", 28# & 32#, H-40 equiv., slip joint, new National casing at 514' with 356 sacks of Permanente Type "C" cement. Mixing time 18 minutes, displacing time 7 minutes, in place 7:00 A.M. Cemented outside casing with 144 sacks Permanente Type "C" cement, filled to surface.
7-2	Installed blowout preventer & tested with 1000 psi. Drilled out shoe & drilled ahead to 6225 with 9 7/8" bits.
7-12	Ran Schlumberger Electric Log & Dipmeter.
7-13	Drilled ahead with 9 7/8" bits to 6909'.
7-17	Broke drive shaft of #1 rig motor.
7-18	Stuck drill pipe while down for repairs. Spotted 25 barrels of crude - freed pipe. Drilled ahead to 7010'. Ran Schlumberger Electric Log to total depth. Ran Lane Wells Neutron Log 6450-7010'.
7-20	With open end 4 1/2" drill pipe hung 1205', displaced 80 sacks Permanente Type "C" cement, calcium chloride treated, in place 11:15 P.M. Waited four hours found top cement 1123'.
7-21	With drill pipe hung 547 displaced 80 sacks of Permanente Type "C" cement, calcium chloride treated, in place 3:50 A.M. Found top plug 457'. Rig released 6:00 A.M., July 21, 1951.

on July 21, 1951 plugged surface pipe from surface to 15' with 10 sacks of cement! - See Letter dated Sept. 10, 1951 [illegible]

Bit Information:

15" Dunlap	1
9 7/8" Reed Jet	3
9 7/8" Smith K2P	6
9 7/8" Globe 2 Com.	8
9 7/8" Hughes 2 Com.	1
	19

FORM 101
(CALIFORNIA STATE PRINTING OFFICE)

SUBMIT IN DUPLICATE

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

LOG AND CORE RECORD OF OIL OR GAS WELL

Operator D. D. Feldman Oil & Gas Field Wildcat

Well No. Natural Gas Corp.-Robbins #1 Sec. 19, T. 3N, R. 2W, MDB & M.

FORMATIONS PENETRATED BY WELL

DEPTH TO		Thickness	Drilled or Cored	Recovery	DESCRIPTION
Top of Formation	Bottom of Formation				
0	2800		Drilled		Non-Marine clay & gravel.
2800	6250		Drilled		Interbedded brown to gray clay, & siltstone with fine to medium grained gray sands & sandstones.
6250	6580		Drilled		Dark brown, brittle, platy shale with fish scales & common glauconite.
6580	6900		Drilled		Fine to medium grained gray sands with few interbedded dark brown siltstone.
6900	7010		Drilled		Dark brown to gray siltstone with minor amounts fine gray sand.
					Total depth
					No cores taken

FORM 111 (1-49)

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

REPORT ON PROPOSED OPERATIONS

No. P 6-953

Coalinga, Calif. July 25, 1951

Mr. Anthony E. L. Morris
921 Westwood Blvd., Rm. 225,
Los Angeles 24, Calif.

Acting Agent for D. B. FELDMAN OIL AND GAS

DEAR SIR:

Your proposal to abandon Well No. "Natural Gas Corp. Robbins" 1,

Section 19, T. 3 N., R. 2 E., M.D. B. & M., ----- Field, Solano County,

dated July 23, 1951, received July 24, 1951, has been examined in conjunction with records filed in this office.

Present conditions as shown by the records and the proposal are as follows:

RECORDS IN ADDITION TO OR AT VARIANCE WITH THOSE SHOWN IN THE NOTICE BELOW:
On July 19, 1951, Mr. A. E. L. Morris reported that the well was drilled to a total depth of 7010 feet.

THE NOTICE STATES:
"The present condition of the well is as follows:

1. Complete casing record.
   10-3/4, H-40 equiv., slip joint, new National casing cemented at 514' with 256 sacks inside and 144 sacks outside.
2. Last produced. Never
   No shows of oil or gas were encountered."

PROPOSAL:
"The proposed work is as follows:

1) Plug fresh - brackish water contact with 100 feet of cement at approximately 1200'.
2) Plug 50' in and 50' out of shoe of surface pipe.
3) Plug surface of 10-3/4 with 10' of cement."

DECISION:
THE PROPOSAL IS APPROVED.

Bond No. 14003-12-2801-51
GHC:ef
cc: Company
Mr. Marshall Brown,
Natural Gas Corporation of California

R. D. BUSH
State Oil and Gas Supervisor

By G. H. Pierce Deputy

43266 4-51 25M SPO

FORM 108. 30296 1-43 5M
CALIFORNIA STATE PRINTING OFFICE

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

Notice of Intention to Abandon Well

This notice must be given at least five days before work is to begin

Los Angeles Calif. July 23 1951

DIVISION OF OIL AND GAS

Coalinga, Calif.

In compliance with Sec. 3228, 3229, 3230, 3231 and 3232, Ch. 93, Stat. 1939, notice is hereby given that it is our intention to abandon well No. Natural Gas Corporation - Robbins #1

Sec. 19, T. 3N, R. 2E, MD B. & M. - Field,

Solano County, commencing work on the 20th day of July 1951.

The present condition of the well is as follows:

1. Complete casing record.

   10-3/4, H-40 equiv., slip joint, new National casing cemented at 514' with 356 sacks inside and 144 sacks outside.

2. Last produced. Never

Date	Net oil	Gravity	Cut
Never			

The proposed work is as follows:

No shows of oil or gas were encountered.

1) Plug fresh - brackish water contact with 100 feet of cement at approximately 1200'.

2) Plug 50' in and 50' out of shoe of surface pipe.

3) Plug surface of 10-3/4 with 10' of cement.

D. D. FELDMAN D/B/A.
D. D. FELDMAN OIL AND GAS
(Name of Operator)

By [signature]

ADDRESS NOTICE TO DIVISION OF OIL AND GAS IN DISTRICT WHERE WELL IS LOCATED

FORM 111 (1-49)

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

REPORT ON PROPOSED OPERATIONS

No. P 6-942

Coalinga, Calif. June 4, 1951

Mr. Anthony E. L. Morris
921 Westwood Blvd., Rm. 235, Los Angeles 24, Calif.
XXXX for D. D. FELDMAN OIL AND GAS

Dear Sir:

Your proposal to drill Well No. "Natural Gas Corp. Robbins" 1, Section 19, T. 3 N., R. 2 E., M. D. B. & M., ----- Field, Solano County, dated May 31, 1951, received June 4, 1951, has been examined in conjunction with records filed in this office.

Present conditions as shown by the records and the proposal are as follows:

THE NOTICE STATES:

"Legal description of lease See attached plat
Location of Well: 2290 ft. South and 5430 ft. East from NW Corner, Section 24, T.3-N, R.1-E, M.D.B.&M.
Elevation of ground above sea level 51.6 feet.
All depth measurements taken from top of Kelly Bushing which is 9.5 feet above ground."

PROPOSAL:

"PROPOSED CASING PROGRAM

Size of Casing Inches A.P.I.	Weight	Grade and Type	Top	Bottom	Cementing Depths
10-3/4	28#	H-40 equiv.	0	500	500 ft. to surface
5-1/2	17#	J-55	0	7000	Shoe

Intended zone or zones of completion:

Name	Perforated Interval
Domengine	3100 - 3200
Hamilton	4300 - 4400
Anderson	4800 - 4900
Cretaceous	6500 - 7000

It is understood that if changes in this plan become necessary we are to notify you before running casing."

DECISION:

THE PROPOSAL IS APPROVED PROVIDED THAT:

1. Water suitable for irrigation shall be protected from contamination.
2. Mud fluid of sufficient weight and proper consistency to prevent blow-outs shall be used in drilling, and the column of mud fluid shall be maintained to the surface at all times, particularly while pulling the drill pipe.
3. Adequate blow-out prevention equipment shall be provided and kept ready for operation at all times, including the time of running the casing.
4. The 10-3/4" casing shall be cemented with sufficient cement to fill back of this casing from the shoe to the ground surface.
5. This Division shall be consulted prior to landing or cementing any casing below the 10-3/4" surface pipe.

Moran/Pence 7-17-51
TD 7010
no shows
To Abandon

pk 12 at - 130
across 10¾ shoe
10' at surface

Bond No. 14003-12-2801-51
CHC:ef
cc: Company

R. D. BUSH
State Oil and Gas Supervisor

By G. G. [signature] Deputy

29489 8-50 10M SPO

FORM 105

STATE OF CALIFORNIA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

Notice of Intention to Drill New Well

This notice and surety bond must be filed before drilling begins

5

095-00428

Los Angeles, Calif. May 31 1951

DIVISION OF OIL AND GAS

In compliance with Section 3203, Chapter 93, Statutes of 1939, notice is hereby given that it is our intention to commence the work of drilling well No. Natural Gas Corp. - Robbins No. 1, Sec. 19, T. 3N, R. 2E, M D B. & M., Field, Solano County.

Legal description of lease See attached plat (Attach map or plat to scale)

Location of Well: 2290 ft. South and 5430 ft. East from NW Corner, Section 24, T.3-N, R.2-E, M.D.B.&M. (Give exact footage from section corners or other legal subdivision or streets)

Elevation of ground above sea level 51.6 feet.

All depth measurements taken from top of Kelly Bushing (Derrick Floor, Rotary Table or Kelly Bushing) which is 9.5 feet above ground.

PROPOSED CASING PROGRAM

SIZE OF CASING INCHES A.P.I.	WEIGHT	GRADE AND TYPE	TOP	BOTTOM	CEMENTING DEPTHS
10-3/4	28#	H-40 equiv.	o	500	500 ft. to surface
5-1/2	17#	J-55	o	7000	Shoe

Intended zone or zones of completion:

NAME	PERFORATED INTERVAL
Domengine	3100 - 3200
Hamilton	4300 - 4400
Anderson	4800 - 4900
Cretaceous	6500 - 7000

1951

095 00428

It is understood that if changes in this plan become necessary we are to notify you before running casing.

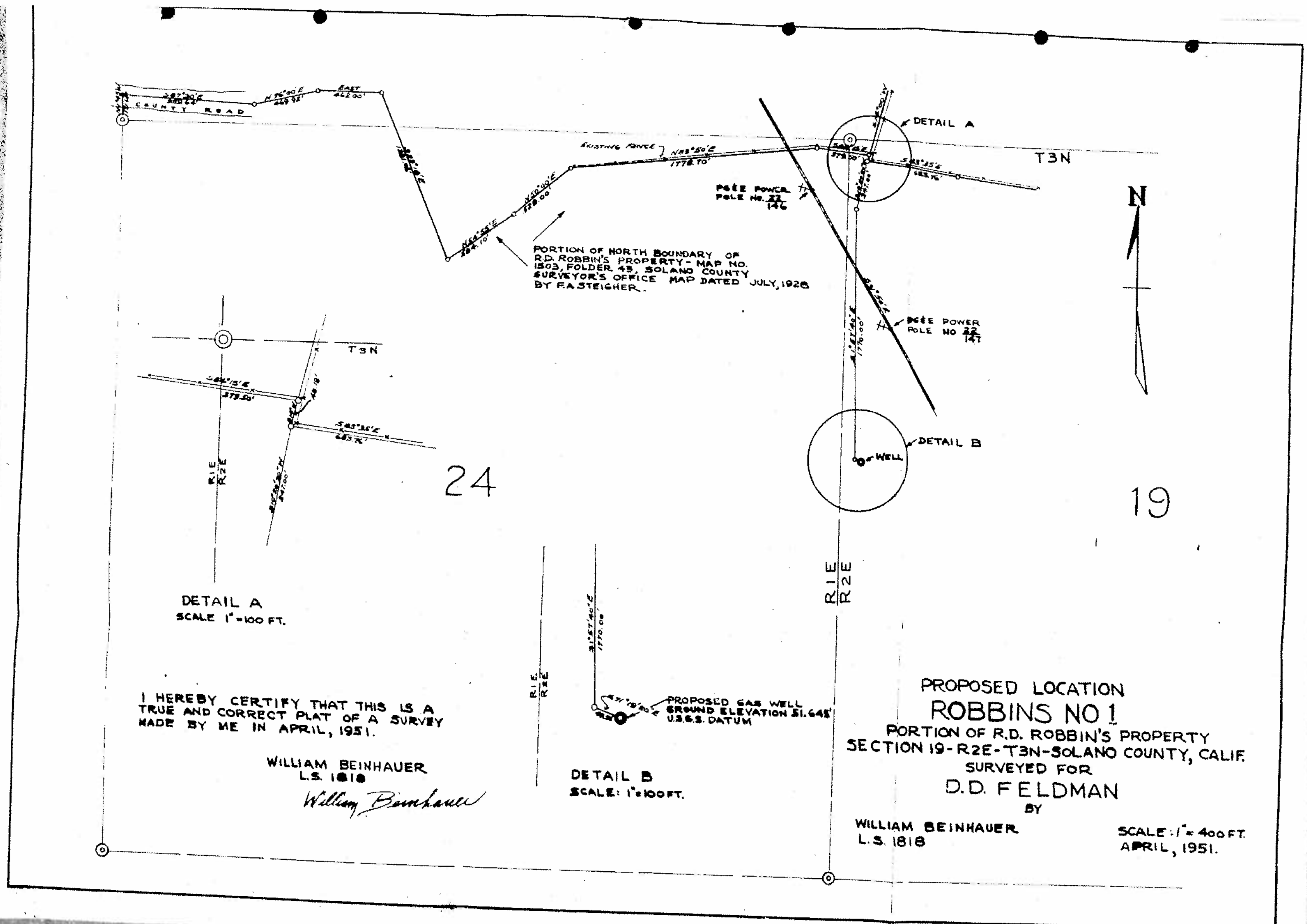
D. D. FELDMAN d/b/a
D. D. FELDMAN OIL AND GAS (Name of Operator)

Address 921 Westwood Boulevard
Los Angeles 24, California

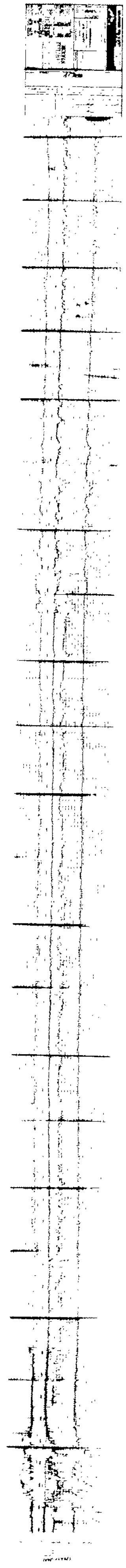
Telephone Number ARizona 3-7220

By [signature]
Manager, West Coast Division

SEND ONE COPY OF NOTICE TO DIVISION OFFICE IN DISTRICT WHERE WELL IS LOCATED



COUNTY ROAD
EAST
462.00'
EXISTING FENCE
N 88°50' E
1778.70'
PORTION OF NORTH BOUNDARY OF R.D. ROBBIN'S PROPERTY - MAP NO. 1503, FOLDER 43, SOLANO COUNTY SURVEYOR'S OFFICE MAP DATED JULY, 1928 BY F.A. STEIGHER.
P.G.&E. POWER POLE No. 22/146
P.G.&E. POWER POLE No. 22/147
DETAIL A
DETAIL B
WELL
T3N
N
24
19
R1E R2E
DETAIL A
SCALE 1" = 100 FT.
DETAIL B
SCALE: 1" = 100 FT.
PROPOSED GAS WELL
GROUND ELEVATION 51.64'
U.S.G.S. DATUM
I HEREBY CERTIFY THAT THIS IS A TRUE AND CORRECT PLAT OF A SURVEY MADE BY ME IN APRIL, 1951.
WILLIAM BEINHAUER
L.S. 1818
William Beinhauer
PROPOSED LOCATION
ROBBINS NO 1
PORTION OF R.D. ROBBIN'S PROPERTY
SECTION 19-R2E-T3N-SOLANO COUNTY, CALIF.
SURVEYED FOR
D.D. FELDMAN
BY
WILLIAM BEINHAUER
L.S. 1818
SCALE: 1" = 400 FT.
APRIL, 1951.



APPENDIX C-1
STATE FORMS DATA FOR NEARBY ARTIFICIAL PENETRATIONS
MCOR OIL & GAS CORP. (UMC PETR. CORP.)
GRANDPA PETER NO 1-7

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

REPORT OF PROPERTY AND WELL TRANSFER

Field or county: COUNTY

District: 6

Former owner: MCOR OIL AND GAS CORP.

Date: 2/26/90

Name and location of well(s):

(see attached list)

Description of the land upon which the well(s) is (are) located:

Date of transfer, sale, assignment, conveyance, or exchange: 5/1/90

New owner: UMC PETROLEUM CORP.

Address: 1201 Louisana, Suite 1400
Houston, TX 77002

Type of organization: CORP.

Telephone No.:

Reported by: Althea L. Schultz - MCOR

Confirmed by: Althea L. Schultz - UMC

New operator new status (status abbreviation): PA

Request designation of agent:

Old operator new status (status abbreviation): AB

Remarks:

Deputy Supervisor: Robert A. Reid

Signature: Robert A. Reid RCH

OPERATOR STATUS ABBREVIATIONS
PA – Producing Active
NPA – No Potential, Active
PI – Potential Inactive
NPI – No Potential, Inactive
Ab – Abandoned or No More Wells

FORM AND RECORD CHECK LIST

Form or record	Initials	Date	Form or record	Initials	Date
Form OGD121			Map and book		
Form OGD148			Notice to be cancelled		
New well cards			Bond status		
Well records			EDP files		
Electric logs					
Production reports					

OGD156 (2/85/DWRR/2M)

SOLANO COUNTY

"C.W.O.D." 3-31	6/2N/1E	095-00378
'Anderson" 1-5	5/3N/2E	095-20430
'GP" 1-7	7/3N/2E	095-20436
Dozier & Pressley" 1-9	9/3N/2E	095-20697
'Hastings Ranch" 1-15	15/5N/2E	095-20473
"Gunn" 1-9	9/4N/1E	095-20490
Hastings Ranch" 1-23	23/5N/2E	095-20387
'Sanchez" 1-25	25/5N/2E	095-20412
'Petersen Rnach" 1-32	32/5N/2E	095-20392
"McCulloch Rush Trust" 1	1/4N/1W	095-00328
"Rush Trust" 2	12/4N/2W	095-00331
"McCulloch-Macson GWA" 1	8/5N/1W	095-00342
"Robinson" 1-4	4/4N/2E	095-20718
"McCulloch-Macson-Uhl" 1	32/6N/1W	095-00506

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

REPORT OF WELL ABANDONMENT

Woodland, California

April 27, 1981

J. E. Walton, Agent
MOOR OIL & GAS CORP.
5405 Stockdale Highway, Suite 203
Bakersfield, CA 93309

Your report of abandonment of well "GP" 1-7 (Name and number),

A.P.I. No. 095-20436, Section 7, T. 3N, R. 2E, M.D. B. & M.,

Rio Vista Gas field, Solano County,

dated 10-2-80 received 10-14-80, has been examined in conjunction with records filed in this office, and we have determined that all of the requirements of this Division have been fulfilled.

Environmental inspection made and approved 4-23-81

Blanket Bond
RH:rmc
cc:Co.,L.A.

M. G. MEFFERD
State Oil and Gas Supervisor

By [signature]
Deputy Supervisor
JOHN C. SULLIVAN

OG159 (11-76-GSR1-8M)

DIVISION OF OIL AND GAS

CHECK LIST - RECORDS RECEIVED AND WELL STATUS

Company McCulloch Oil & Gas Co. Well No. "DP" 1-7

API No. 095-20436 Sec. 7, T. 3N, R. 2E, M.D. B.&M.

County Solano Field --

RECORDS RECEIVED	DATE
Well Summary (Form OG100)	10-14-80
History (Form OG103)	✓
Core Record (Form OG101)	
Directional Survey	
Sidewall Samples	
Other	
Date final records received	
Electric logs:	
2 DI-Focused 5"	10-14-80
2 DI- ✓ 2"	✓
2 Comp. Density	✓
2 Mud	✓
2 Four Arm Dip. 2"	✓
2 Four Arm Dip. 5"	✓

STATUS		STATUS	
Producing - Oil		Water Disposal	
Idle - Oil		Water Flood	
Abandoned - Oil		Steam Flood	
Drilling - Idle		Fire Flood	
Abandoned - Dry Hole		Air Injection	
Producing - Gas		Gas Injection	
Idle - Gas		CO_2 Injection	
Abandoned - Gas		LPG Injection	
Gas-Open to Oil Zone		Observation	
Water Flood Source			

DATE

RECOMPLETED

REMARKS

ENGINEER'S CHECK LIST

1. Summary, History, & Core record (dupl.) ✓
2. Electric Log ✓
3. Operator's Name ✓
4. Signature ✓
5. Well Designation ✓
6. Location ✓
7. Elevation ✓
8. Notices ✓
9. "T" Reports
10. Casing Record
11. Plugs
12. Surface Inspection
13. Production
14. E Well on Prod. Dir. Sur.

2 Density Neutron 10-14-80

CLERICAL CHECK LIST

1. Location change (F-OGD165)
2. Elevation change (F-OGD165)
3. Form OGD121 ✓
4. Form OG159 (Final Letter) - Yes
5. Form OGD150b (Release of Bond) B/B.
6. Duplicate logs to archives
7. Notice of Records due (F-OGD170)

Needs S.T.

RECORDS NOT APPROVED

Reason: Need: surface inspection

All else O.K.

[initials] 11-13-80

RECORDS APPROVED

RELEASE BOND

Date Eligible

(Use date last needed records were received.)

MAP AND MAP BOOK

OGD2 (3-77-GSR1-4M)

LONG BEACH OFFICE - USE REVERSE SIDE

DIVISION OF OIL AND GAS
RECEIVED
OCT 14 1980
WOODLAND, CALIFORNIA

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

API No. 095-20436

WELL SUMMARY REPORT

Operator: McCulloch Oil and Gas Corporation	Well: ~~MCOR #1-7 "Grandpa Peter"~~ "GP" 1-7				
Field: Exploratory"	County: Solano	Sec. 7	T. 3N	R. 2E	B.&M. M.D.
Location (Give surface location from property or section corner, street center line and/or California coordinates): 400'East and 1850'North of the Southwest corner of Section 7-T3N-R2E-M.D.B.&M.		Elevation of ground above sea level: 182.5'			

Commenced drilling (date): 12:00 Midnight 8-8-80	Total depth (1st hole): 11,000' (2nd): (3rd):	Depth measurements taken from top of: ☐ Derrick Floor ☐ Rotary Table ☒ Kelly Bushing Which is 22.0 feet above ground
Completed drilling (date): 4:00 a.m. 9-8-80	Present effective depth: Well Plugged and Abandoned	GEOLOGICAL MARKERS / DEPTH: Top of McCormack Sand — 10,670'
Commenced producing (date): ☐ Flowing ☐ Pumping ☐ Gas lift	Junk:	
Name of producing zone(s): N/A		Formation and age at total depth: Martinez - Paleocene

	Clean Oil (bbl per day)	Gravity Clean Oil	Percent Water including emulsion	Gas (Mcf per day)	Tubing Pressure	Casing Pressure
Initial Production						
Production After 30 days						

CASING RECORD (Present Hole)

Size of Casing (API)	Top of Casing	Depth of Shoe	Weight of Casing	Grade and Type of Casing	New or Second Hand	Size of Hole Drilled	Number of Sacks or Cubic Feet of Cement	Depth of Cementing (if through perforations)
9-5/8"	Surface	1050'	36#	K-55 ST&C	N	12-1/4"	220 sacks	

PERFORATED CASING (Size, top, bottom, perforated intervals, size and spacing of perforation and method.)

Was the well directionally drilled? If yes, show coordinates at total depth
☐ Yes ☒ No

Electrical log depths
1st Run: 9882' to 1050'; 2d Run: 10,938' to 9850'.

Other surveys
CNDL, Dipmeter

In compliance with Sec. 3215, Division 3 of the Public Resources Code, the information given herewith is a complete and correct record of the present condition of the well and all work done thereon, so far as can be determined from all available records.

Name: J. E. Walton	Title: Agent	
Address: 5405 Stockdale Hwy., Suite 110	City: Bakersfield, CA	Zip Code: 93309
Telephone Number: (805) 832-9100	Signature: J. E. Walton	Date: 10-2-80

OG100 (12-76-GSRJ-12M) SUBMIT IN DUPLICATE

SUBMIT IN DUPLICATE
RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

History of Oil or Gas Well

Operator McCulloch Oil and Gas Corporation Field or County Solano
Well MIOR #1-7 "Grandpa Peter" Sec. 7, T 3N, R 2E M.D.B. & M.
A.P.I. No. 095-20436 Name J. E. Walton (Person submitting report) Title Agent (President, Secretary or Agent)
Date September 2, 1980

Signature E. Walton

5405 Stockdale Hwy., Suite 110 Bakersfield, CA 93309 (Address) (805) 832-9100 (Telephone Number)

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests and initial production data.

Date	
1980	
8-8	Commenced operations at 12:00 Midnight on 8-8-80. Picked up Dyna-Drill. Drilled rathole and mousehole. Unloaded casing. Worked on conductor pipe. Spudded in at 2:00 p.m. on 8-8-80. Depth: 1060'. Survey: 499' - 0°15'. Drilled 12-1/4" hole to 1060'. Surveyed at 499'. Circulated.
8-9	Depth: 1060'. Wiped hole to collars. Circulated. POH. Rigged up and ran 26 joints (1052') of 9-5/8", 36#, K-55 ST&C casing with the cement guide shoe at 1050', insert float valve at 1014', and 3 centralizers at 1040', 958' and 917'. Rigged up Halliburton and cemented 20' of water ahead of 120 sacks of Class "G" cement mixed with 1:1 Poz Mix with 4% gel followed by 100 sacks of Class "G" cement mixed with 3% $CaCl_2$. Total slurry - 460 cu.ft. Bumped plug with 1000 psi. 20 cu.ft. returns. Float held. CIP at 1:45 p.m. WOC. Laid casing. Welded on head.
8-10	Depth: 1792'. Mud Wt.: 68. Vis.: 54. Survey: 1541' - 0°30'. Nippled up BOPE. Set in table in rig floor. Tested blind rams. Repaired leak. Made up BHA and RIH. Drilled out float. Waited on DOG. Tested BOPE. Witnessed and approved by the DOG. Drilled out shoe joint and shoe. Drilled 8-3/4" hole from 1060' to 1541'. Surveyed at 1541'. Drilled 8-3/4" hole from 1541' to 1792'. Background gas - 1-2 units. Maximum gas - 5 units.
8-11	Depth: 3441'. Mud Wt.: 72.5. Vis.: 43. Surveys: 2066' - 0°30'; 2570' - 0°45'; 2983' - 0°30'. Drilled 8-3/4" hole from 1792' to 2066'. Surveyed at 2066'. Drilled 8-3/4" hole from 2066' to 2570'. Surveyed at 2570'. Drilled 8-3/4" hole from 2570' to 2983'. Circulated. Surveyed at 2983'. Tripped for Bit #3 at 2983'. Drilled 8-3/4" hole from 2983' to 3183'. Worked on flowline and pitcher nipple. Drilled 8-3/4" hole from 3183' to 3441'. Lost approximately 60 barrels of mud at 3300'. Lost returns for about 5 minutes. Background gas - 12-15 units. Trip gas - 37 units at 2983'. Connection gas - av. of 10-14 units; 40 units at 3425'.

MCOR #1-7 "Grandpa Peter"
Section 7-T3N-R2E-M.D.B.&M.
Solano County, California
History (Cont'd.)
Page 2

<u>1980</u>

8-12 Depth: 4066'. Mud Wt.: 72.5. Vis.: 45. Surveys: 3453' - 1°; 3956' - $0^\circ 45'$. Drilled 8-3/4" hole from 3441' to 3453'. Circulated and surveyed at 3453'. Drilled 8-3/4" hole from 3453' to 3956'. Worked on electrical. Surveyed at 3956'. Pulled to shoe. Worked on electrical. RIH. Drilled 8-3/4" hole from 3956' to 4066'. Background gas - 10-15 units. Trip gas - 220 units at 3944'. Connection gas - 5-7 units.

8-13 Depth: 4991'. Mud Wt.: 74. Vis.: 42. Surveys: 4438' - $1^\circ 45$; 4938' - $1^\circ 30'$. Drilled 8-3/4" hole from 4066' to 4438'. Dry job. Tripped for Bit #4 at 4438'. Surveyed at 4438'. Cut drilling line. Drilled 8-3/4" hole from 4438' to 4938'. Surveyed at 4938'. Drilled 8-3/4" hole from 4938' to 4991'. Background gas - 15 units. Trip gas - 38 units at 4438'. Connection gas - 3-9 units.

8-14 Depth: 5600'. Mud Wt.: 74. Vis.: 43. Survey: 5315' - $1^\circ 45'$. Installed new wash pipe and packed in swivel. Drilled 8-3/4" hole from 4991' to 5315'. Dry job. Surveyed at 5315'. Tripped for Bit #5 at 5315'. Drilled 8-3/4" hole from 5315' to 5600'. Background gas - 10-12 units. Trip gas - 6 units at 5315'.

8-15 Depth: 6262'. Mud Wt.: 74. Vis.: 43. Survey: 6198' - $1^\circ 15'$. Drilled 8-3/4" hole from 5600' to 6110'. Packed swivel. Drilled 8-3/4" hole from 6110' to 6198'. Dry job. Surveyed at 6198'. Tripped for Bit #6 at 6198'. Slipped line. Drilled 8-3/4" hole from 6198' to 6262'. Background gas - 5-6 units. Trip gas - 8 units at 6198'.

8-16 Depth: 6762'. Mud Wt.: 74. Vis.: 40. Survey: 6762' - $1^\circ 30'$. Drilled 8-3/4" hole from 6262' to 6762'. Dry job. Surveyed at 6762'. Background gas - 5 units.

8-17 Depth: 7189'. Mud Wt.: 74. Vis.: 42. Tripped for Bit #7 at 6762'. Drilled 8-3/4" hole from 6762' to 7189'. Background gas - 3-4 units. Trip gas - 13 units. Maximum in coal beds - 78 units.

1980

8-18 Depth: 7493'. Mud Wt.: 75. Vis.: 41. Survey: 7254' - 3°45'. Drilled 8-3/4" hole from 7189' to 7254'. Surveyed at 7254'. Tripped for Bit #8 at 7254'. Reamed from 7192' to 7254'. Drilled 8-3/4" hole from 7254' to 7493'. Background gas - 3 units.

8-19 Depth: 7783'. Mud Wt.: 72.5. Vis.: 37. Survey: 7647' - 4°0'. Drilled 8-3/4" hole from 7493' to 7623'. Survey at 7623' no good. Drilled 8-3/4" hole from 7623' to 7647'. Surveyed at 7647'. Wiper trip. Drilled 8-3/4" hole from 7647' to 7783'. Background gas - 3 units. Cuttings gas - 1 unit.

8-20 Depth: 8025'. Mud Wt.: 73. Vis.: 39. Drilled 8-3/4" hole from 7783' to 7865'. Tripped for Bit #9 at 7865'. Reamed from 7815' to 7865'. Drilled 8-3/4" hole from 7865' to 8025'. Background gas - 6 units. Trip gas - 36 units.

8-21 Depth: 8530'. Mud Wt.: 74. Vis.: 40. Survey: 8379' - 2°0'. Circulated for loggers. Drilled 8-3/4" hole from 8025' to 8379'. Surveyed at 8379'. Drilled 8-3/4" hole from 8379' to 8418'. Tripped for Bit #10 at 8418'. Drilled 8-3/4" hole from 8418' to 8530'. Background gas - 3-28 units. Trip gas - 29 units at 8418'.

8-22 Depth: 8775'. Mud Wt.: 74. Vis.: 38. Survey: 8645' - 1°45'. Drilled 8-3/4" hole from 8530' to 8645'. Surveyed at 8645'. Tripped for Bit #11 at 8645'. Reamed from 8345' to 8445'. Drilled 8-3/4" hole from 8645' to 8775'. Background gas - 3-6 units. Trip gas - 16 units at 8645'. No shows.

8-23 Depth: 9061'. Mud Wt.: 73. Vis.: 38. Drilled 8-3/4" hole from 8775' to 9061'. Circulated and wiped hole. Background gas - 1-15 units.

8-24 Depth: 9369'. Mud Wt.: 74. Vis.: 42. Wiped hole. Drilled 8-3/4" hole from 9061' to 9354'. Survey at 9354' was no good. Tripped for Bit #12 at 9354'. Drilled 8-3/4" hole from 9354' to 9369'. Background gas - 3-39 units. Trip gas - 18 units at 9354'.

1980

8-25 Depth: 9632'. Mud Wt.: 72. Vis.: 43. Drilled 8-3/4" hole from 9369' to 9589'. Survey at 9589' was no good. Tripped for Bit #13 at 9589'. Drilled 8-3/4" hole from 9589' to 9632'. Background gas - 4-16 units. Trip gas - 25 units at 9589'.

8-26 Depth: 9903'. Mud Wt.: 72. Vis.: 41. Drilled 8-3/4" hole from 9632' to 9903'. Background gas - 1-14 units. No shows.

8-27 Depth: 9948'. Mud Wt.: 72. Vis.: 40. Survey: 9948' - 2°0'. Drilled 8-3/4" hole from 9903' to 9948'. Surveyed at 9948'. Wiped hole. Reamed from 9904' to 9948'. Circulated for logs. POH. Waited on loggers. Ran DIL Sonic from 9882' to 1050'. Background gas - 1-5 units.

8-28 Depth: 9948'. Mud Wt.: 74. Vis.: 44. Ran CNDL from 9880' to 6000'; Dipmeter to 9016'. Could not run Dipmeter to T.D. RIH with drill pipe and RR Bit #12. Washed. Reamed from 9016' to 9948'. Circulated hole clean. POH.

8-29 Depth: 10,015'. Mud Wt.: 72. Vis.: 40. POH for logs. Ran Dipmeter from 9875' to 6000'. Dipmeter Tool not functioning. Survey voided. Waited on orders. RIH with Bit #14. Reamed from 9883' to 9948'. Drilled 8-3/4" hole from 9948' to 10,005'. Worked on electrical problems. Drilled 8-3/4" hole from 10,005' to 10,015'. Background gas - 4-11 units. Trip gas - 36 units.

8-30 Depth: 10,235'. Mud Wt.: 72. Vis.: 38. Drilled 8-3/4" hole from 10,015' to 10,235'. Background gas - 3-12 units.

8-31 Depth: 10,379'. Mud Wt.: 73. Vis.: 40. Drilled 8-3/4" hole from 10,235' to 10,298'. Survey at 10,298' was no good. Tripped for Bit #15 at 10,298'. Strapped out - found 1.60 difference - no correction. Reamed from 10,245' to 10,298'. Drilled 8-3/4" hole from 10,298' to 10,379'. Background gas - 5-6 units. Trip gas - 13 units at 10,298'.

9-1 Depth: 10,574'. Mud Wt.: 73. Vis.: 42. Drilled 8-3/4" hole from 10,379' to 10,574'. Circulated for trip. Background gas - 5-68 units. Break from 10,446' to 10,449'.

1980

9-2 Depth: 10,684'. Mud Wt.: 72. Vis.: 40. Survey: 10,574' - 4°45'. Surveyed at 10,574'. Tripped for Bit #16 at 10,574'. Reamed from 10,485' to 10,574'. Drilled 8-3/4" hole from 10,574' to 10,684'. Background gas - 5-30 units. 30 units was at 10,588' where there was 70% sand.

9-3 Depth: 10,850'. Mud Wt.: 73. Vis.: 39. Survey: 10,850' - 4°. Drilled 8-3/4" hole from 10,684' to 20,850'. Surveyed at 10,850'. POH. Background gas - 4 units.

9-4 Depth: 11,000'T.D. Mud Wt.: 73. Vis.: 40. Tripped for Bit #17 at 10,850'. Slipped drilling line. Drilled 8-3/4" hole from 10,850' to 11,000'. Circulated. Wiper trip - 20 stands. Circulated for logs. POH. Background gas - 3 units. Trip gas - 54 units at 10,850'. Show: 10,970' - 87 units (90% lignite).

9-5 Depth: 11,000'T.D. Mud Wt.: 73. Vis.: 42. Waited on loggers. Rigged up and ran DIL Sonic from 10,938' to 9850'; CNDL/GR from 10,930' to 9850'. Rigged down loggers. RIH. Circulated to clean hole. POH. Rigged up and ran Dipmeter. Trip gas on clean out run was 10 units.

9-6 Depth: 11,000'T.D. Finished running Dipmeter from 9875' to 6000'. Could not reach T.D. with Dipmeter. Rigged down Dresser Atlas and waited on orders. RIH. Circulated. Dry job. Laid down drill pipe and collars.

9-7 Depth: 11,000'T.D. Loaded out lay-down machine. Rigged up Halliburton. Cemented Plug No.1: Hung open-ended at 1792'. Cemented with 218 sacks of Class "G" cement mixed with 3% $CaCl_2$. CIP at 7:30 a.m. WOC. Tagged Plug No.1 at 1322'. Witnessed and approved by the DOG. Pulled to 1099' and cemented with 57 sacks of Class "G" cement. CIP at 12:15 p.m. WOC. Tagged Plug No.2 at 1001'. Laid down drill pipe. Set surface plug. Stripped cellar, cleaned pits, cut off head and welded on plate.

9-8 Rig released at 4:00 a.m. on 9-8-80. Well plugged and abandoned.

MOOR #1-7 "Grandpa Peter"

BIT RECORD

Bit #	Size	Mfg.	Type	Ser. No.	In	Out	Ftg.	Hours
1	12-1/4"	Reed	12J	146591	40'	1060'	1020'	15
2	8-3/4"	Smith	DTJ	BD8988	1060'	2983'	1923'	22-1/2
3	8-3/4"	Hughes	OSC3J	ZS068	2983'	4438'	1455'	24
4	8-3/4"	Reed	Y12J	901773	4438'	5315'	877'	24-1/2
5	8-3/4"	Smith	DTJ	AT3575	5315'	6198'	883'	21-1/2
6	8-3/4"	Security	S3J	81361	6198'	6762'	564'	21-1/2
7	8-3/4"	Hughes	OSC3J	CZ787	6762'	7254'	492'	26-3/4
8	8-34/"	Reed	FP12J	295781	7254'	7865'	611'	44-1/2
9	8-3/4"	Hughes	OSC3J	AN489	7865'	8418'	553'	19-3/4
10	8-3/4"	Reed	Y11J	643142	8418'	8645'	227'	14
11	8-3/4"	Smith	FDT	BD8910	8645'	9354'	709'	46
12	8-3/4"	Hughes	OSC3AJ	AN483	9354'	9589'	235'	16
13	8-3/4"	Smith	FDT	BD8904	9589'	9948'	359'	36
14	8-3/4"	Reed	FP13J	439663	9948'	10,298'	350'	38-1/2
15	8-3/4"	Smith	FDT	BC9446	10,298'	10,574'	276'	32
16	8-3/4"	Smith	FDT	BC9091	10,574'	10,850'	276'	36
17	8-3/4"	Hughes	J2	C6092	10,850'	11,000'	150'	12

McCulloch Oil and Gas Corporation

DIVISION OF OIL AND GAS
RECEIVED
OCT 14 1980
WOODLAND, CALIFORNIA

October 9, 1980

Division of Oil and Gas
117 W. Main Street, Suite #11
Woodland, California 95695

ATTENTION: Mr. John C. Sullivan

SUBJECT: Confidentiality of MCOR #1-7 "Grandpa Peter"

Gentlemen:

McCulloch Oil and Gas Corporation hereby requests that the well histories, all logs, mud logs, and all other well data concerning McCulloch's #1-7 "Grandpa Peter" well, Section 7, T3N, R2E, M.D.B.&M. be closed for inspection by all parties other than those who obtain written authorization from McCulloch Oil and Gas Corporation.

It is understood that this information will be classified as Confidential by your office for a period of two years or until such information is released to public inspection by McCulloch. Your assistance in this matter will be appreciated.

Very truly yours,

McCULLOCH OIL AND GAS CORPORATION

J. E. Walton

J. E. Walton
District Manager

JEW:dkl

cc: F. H. Roth/McCulloch

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

REPORT OF PROPERTY AND WELL TRANSFER

Field or county	Former owner
See attached list	McCulloch Oil & Gas Corp.

Name and location of well(s)

See attached list

Description of the land upon which the well(s) is (are) located

--

Date of transfer sale, assignment, conveyance, or exchange	New owner	Type of organization
June 5,1980	MCOR Oil & Gas Corporation	Corp.
	Address: 5405 Stockdale Highway, Suite 110 Bakersfield, CA 93309	Reported by: W.R.Mainland for MCOR Oil & Gas Corp.
	Telephone No.	Confirmed by: J.E.Walton for McCulloch Oil & Gas Corp.

New operator new status (status abbreviation): PA

Old operator new status (status abbreviation): AB

Remarks: Change in operating name only.

Date	District	Deputy Supervisor	Signature
Dec. 3, 1980	6	John C. Sullivan	John Sullivan

OPERATOR STATUS ABBREVIATIONS	Form or record	Initials	Date	Form or record	Initials	Date
PA - Producing Active	Form OG134A or OG134B			Map and book		
NPA - No Potential, Active	Form OGD121			Notice to be cancelled		
PI - Potential Inactive	Form OGD148			Bond status		
NPI - No Potential, Inactive	New well cards			EDP files		
Ab - Abandoned or No More Wells	Well records					
	Electric logs					
	Production reports					

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

No. T 680-300

Report on Operations

J. E. Walton, Agent
McCULLOCH OIL AND GAS CORPORATION
5405 Stockdale Highway
Suite 203
Bakersfield, CA 93309

Woodland Calif.
September 18, 1980

Your operations at well "GP" 1-7, API No. 095-20436, Sec. 7, T3N, R.2E, M.D. B.& M. Rio Vista Gas Field, in Solano County, were witnessed on 9-7-80. R. Adams, representative of the supervisor, was present from 1130 to 1225. There were also present H. Hamilton, & J. Cooper.

Present condition of well: 9 5/8" cem. 1050'. TD 11,000'. Plugged with cement 1792'-1322' and 1099'-999'±.

The operations were performed for the purpose of abandonment.

DECISION

The plugging operations as witnessed and reported are approved.

KPH:kw
cc: Co., L.A.

CONFIDENTIAL STATUS

M. G. MEFFERD
State Oil and Gas Supervisor

By John C. Sullivan
Deputy Supervisor
John C. Sullivan

OG109 (10-78-GSRI-15M)

(300)

DIVISION OF OIL AND GAS
Cementing/Plugging Memo

Operator M.C.O.R. O & G Corp. Well No. "G.P. Peters" 1-7
API No. 095-20436 Sec. 7, T. 3N, R. 2E, ____ B&M
Field Rio Vista, County Solano. On 9/7/80
Mr. R L Adams, representative of the supervisor was present from 1130 to 1225.
There were also present [illegible], J Cooper

Casing record of well: 9 5/8" cem. 1050, TD 11,000'. Plugged w/ cem. 1792'-1322', & 1099'-999±'.

The operations were performed for the purpose of Abandonment

☑ The plugging/cementing operations as witnessed and reported are approved.

☐ The location and hardness of the cement plug @ ____________' is approved.

Hole size: —" fr. —' to —', 8 3/4" to 11,000' & ______" to ______'

Casing				Cemented			Top of Fill		Squeezed Away	Final Press.	Perfs.
Size	Wt.	Top	Bottom	Date	MO-Depth	Volume	Annulus	Casing			

Casing/tubing recovered: ______" shot/cut at ______', ______', ______' pulled fr. ______';

______" shot/cut at ______', ______', ______' pulled fr. ______'.

Junk (in hole): ____________

Hole fluid (bailed to) at ______'. Witnessed by ____________

Mudding	Date	Bbls.	Displaced	Poured	Fill	Engr.

Cement Plugs		Placing	Placing Witnessed		Top Witnessed			
Date	Sx./cf	MO & Depth	Time	Engr.	Depth	Wt/Sample	Date & Time	Engr.
9-7-80	218 sx	OE D.P. 1792'	—	—	1322'	Wt	9-7-80 1140	R Adams
9-7-80	57 sx	O.E. D.P. 1099'	1215	R Adams	999±'	—	—	

OGD10 (2-77-GSR1-6M)

ERNEST
DISHMAN

707-374-6361

Pressure test

A-H
"SERPA" 4

MONTGOMERY
"RIG 9"

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

No. P 680-440

REPORT ON PROPOSED OPERATIONS

-- (field code)
-- (area code)
-- (pool code)

J. E. Walton, Agent
McCULLOCH OIL AND GAS CORPORATION
5405 Stockdale Highway
Suite 203
Bakersfield, CA 93309

Woodland, California
September 18, 1980

Your proposal to abandon well "GP" 1-7, A.P.I. No. 095-20436, Section 7, T. 3N, R. 2E, M.D. B. & M., --- field, --- area, --- pool, Solano County, dated 9-8-80, received 9-10-80 has been examined in conjunction with records filed in this office.

THE PROPOSAL, COVERING WORK ALREADY COMPLETED IN ACCORDANCE WITH PRIOR AGREEMENT, IS APPROVED.

THIS DIVISION SHALL BE NOTIFIED:
1. To inspect and approve the clean-up of the wellsite before approval of abandonment will be issued.

NOTE: RECORDS FOR WORK DONE UNDER THIS APPROVAL ARE DUE WITHIN 60 DAYS AFTER COMPLETION OF THE WORK AND/OR SUSPENSION OF OPERATIONS.

Blanket Bond
KPH:kw
cc: Co., L.A.

CONFIDENTIAL STATUS

A copy of this report must be posted at the well site prior to commencing operations.

M. G. MEFFERD, State Oil and Gas Supervisor

By John C. Sullivan
Deputy Supervisor
John C. Sullivan

OG111 (1-79-GSRI-5M)

STATE OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

DIVISION OF OIL AND GAS
RECEIVED
SEP 10 1980
WOODLAND, CALIFORNIA

Notice of Intention to Abandon Well

This notice must be given at least five days before work is to begin.

FOR DIVISION USE ONLY			
CARDS	BOND	FORMS	
		OGD114	OGD121
✓	B/B	✓	✓

DIVISION OF OIL AND GAS

In compliance with Section 3229, Division 3, Public Resources Code, notice is hereby given that it is our intention to abandon Well No. ~~MCOR #1-7 "Grandpa Peter"~~ "GP" 1-7, API No. 095-20436, Sec. 7, T. 3N, R. 2E, M.D. B. & M., ______ Field, Solano County, commencing work on September 7, 19 80

The present condition of the well is:

1. Total depth: 11,000'
2. Complete casing record, including plugs and perforations:

   9-5/8", 36#, K-55 ST&C 0 - 1050'

3. Last produced N/A (Date) (Oil, B/D) (Gas, Mcf/D) (Water, B/D)

   or

4. Last injected N/A (Date) (Water, B/D) (Gas, Mcf/D) (Surface pressure)

Additional data for dry hole (show depths)

5. Oil or gas shows

   None

6. Stratigraphic markers:
7. Formation and age at total depth:
8. Base of fresh water sands: 1450' (DOG est 1400)

The proposed work is as follows:

1. Run in hole with open-ended drill pipe to 1800' and set a fresh water plug from 1800' to 1300' with 218 sacks of Class "G" cement premixed with 3% $CaCl_2$.
2. Run in hole with open-ended drill pipe to 1100' and set a shoe plug from 1100' to 1000' with 57 sacks of Class "G" cement premixed with 3% $CaCl_2$.
3. Install a 25' surface plug in 9-5/8" casing from 30' to 5'.
4. Cut off 5' below ground level and weld 1/2" steel plate on top of casing stub.
5. Location and hardness of downhole and surface cement plugs plus cleanup of location to be witnessed by Division of Oil and Gas.

It is understood that if changes in this plan become necessary we are to notify you immediately.

Address 5405 Stockdale Hwy., Suite 110 (Street)
Bakersfield, (City) California (State) 93309 (Zip)
Telephone Number (805) (Area Code) 832-9100 (Number)

McCulloch Oil and Gas Corporation (Name of Operator)
By J. E. Walton (Signature) J. E. Walton 9-8-80 (Date)
Type of Organization Corporation (Corporation, Partnership, Individual, etc.)

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

No. P 680-439

REPORT ON PROPOSED OPERATIONS

-- (field code)
-- (area code)
-- (pool code)

J. E. Walton, Agent
McCULLOCH OIL AND GAS CORPORATION
5405 Stockdale Highway
Suite 203
Bakersfield, CA 93309

Woodland, California
September 18, 1980

Your supplementary proposal to drill well "GP" 1-7, A.P.I. No. 095-20436, Section 7, T. 3N, R. 2E, M.D. B. & M., --- field, --- area, --- pool, Solano County, dated 8-29-80, received 9-2-80 has been examined in conjunction with records filed in this office.

THE PROPOSAL IS APPROVED.

THIS DIVISION SHALL BE NOTIFIED:

a. Before deviating from the proposed casing program and/or placing any plugs in the hole. Additional requirements shall be outlined at that time.

NOTE: 1. RECORDS FOR WORK DONE UNDER THIS APPROVAL ARE DUE WITHIN 60 DAYS AFTER COMPLETION OF THE WORK AND/OR SUSPENSION OF OPERATIONS.
2. In all other respects the well shall be drilled in accordance with the provisions set forth in our report No. P680-346, dated 8-4-80.

Blanket Bond
KPH:kw
cc: Co., L.A.

CONFIDENTIAL STATUS

A copy of this report must be posted at the well site prior to commencing operations.

M. G. MEFFERD, State Oil and Gas Supervisor

By John C. Sullivan
Deputy Supervisor
John C. Sullivan

OG111 (1-79-GSRI-6M)

FORM 107

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

Supplementary

~~Notice of Intention to Deepen, Redrill, Plug~~ or Alter ~~Casing in~~ Well

This notice must be given before work begins; one copy only

Woodland Calif. August 29 1980

DIVISION OF OIL AND GAS

In compliance with Section 3203, Chapter 93, Statutes of 1939, notice is hereby given that it is our intention to commence the work of deepening, redrilling, plugging or altering casting at Well No. ~~MCOR~~ "BP" #1-7 ~~"Grandpa Peter"~~
(Cross out unnecessary words)

, Sec. 7, T. 3N, R. 2E, M. D. B. & M.

Field, Solano County.

(095-20436)

The present condition of the well is as follows:

DIVISION OF OIL AND GAS
RECEIVED
SEP 2 1980
WOODLAND, CALIFORNIA

1. Total depth. 9948' (drilling)

2. Complete casing record, including plugs:

9-5/8", 36#, K-55 ST&C 0 - 1050'

3. Last produced. N/A (Date) (Oil, B/D) (Water, B/D) (Gas Mcf/D)

The proposed work is as follows:

1. Deepen 8-3/4" hole from 10,000' to 11,000'.

5405 Stockdale Hwy., Suite 110
(Address)

(805) 832-9100
(Telephone No.)

McCulloch Oil and Gas Corporation
(Name of Operator)

By J.E. Walton
J. E. Walton

ADDRESS ONE COPY OF NOTICE TO DIVISION OF OIL AND GAS IN DISTRICT WHERE WELL IS LOCATED

39938-708 1-68 15M OSP

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

No. T 680-250

DIVISION OF OIL AND GAS

Report on Operations

J. E. Walton, Agent
McCULLOCH OIL AND GAS CORPORATION
5405 Stockdale Highway
Suite 203
Bakersfield, CA 93309

Woodland Calif.
August 14, 1980

Your operations at well "GP" 1-7, API No. 095-20436, Sec. 7, T. 3N, R. 2E M.D. B.& M. --- Field, in Solano County, were witnessed on 8-10-80. R. Hauser, representative of the supervisor, was present from 1600 to 1635. There were also present H. Hamilton, Company Foreman.

Present condition of well: 9 5/8" cem. 1050'. TD 1050' (standing cemented).

The operations were performed for the purpose of testing the blowout prevention equipment and installation.

DECISION:

The blowout prevention equipment and installation are approved.

KPH:kw
cc: Co., L.A.

CONFIDENTIAL STATUS

M. G. MEFFERD
State Oil and Gas Supervisor

By [signature]
Deputy Supervisor
John C. Sullivan

OG109 (10-78-GSRI-15M)

3-29-80
Phoned Walton /KPH
ok to deepen well to 11,000'.
File Supp. to Drill,
surf. csg. to 1050'.

[illegible signature]

DIVISION OF OIL AND GAS
BLOWOUT PREVENTION EQUIPMENT MEMO

T 250

Operator McCULLOCH Well "G.P." 1-7 Field —— County SOLANO

VISITS:	Date	Engineer	Time	Operator's Rep.	Title
1st	5/10/80	B.L.H	1600 to 1635	H HAMILTON	C.F.
2nd			to		

Casing record of well: 9 5/8" cem. 1050. T.D. 1050. (STANDING CEMENTED)

OPERATION: Testing (inspecting) the blowout prevention equipment and installation.
DECISION: The blowout prevention equipment and installation are approved.

Proposed Well Opns: ______ MPSP: ______ psi

REQUIRED BOPE CLASS: III B2M

Hole size: 12 1/4 " fr. SUR ' to 1050 ', ______ " to ______ ' & ______ " to ______ '

CASING RECORD (BOPE ANCHOR STRING ONLY)					Cement Details	Top of Cement	
Size	Weight(s)	Grade (s)	Shoe at	CP at		Casing	Annulus
9 5/8	36#	K-55	1050		120 sx "G" 11% gel F/d by 100 sx G" 3% CaCl2 bbn/1000psi		SUR

BOP STACK							a	b	a/b	TEST DATA			
API Symb.	Ram Sz.	Mfr.	Model or Type	Size In.	Press. Rtg.	Date Last Overhaul	Gal. to Close	Rec.Time Min.	Calc.GPM Output	psi Drop to Close	Secs.to Close	Test Date	Test Press
		S	P RAMS		3M							5/10	950
		S	B RAMS		3M					Company		5/10	1500
		H	BAG		3M							5/10	800

ACTUATING SYSTEM

Accum.Unit(s) Wkg.Press. 1500 psi
Total Rated Pump Output —— gpm
Distance From Well Bore 50'T ft.

	Mfr.	Accum. Cap.	Precharge
1	HYDRIL	80 gal.	750 psi
2		gal.	psi

CONTROL STATIONS	Elec.	Hyd.
✓ Manif. at accum.unit		✓
Remote at Drlr's stn.	✓	
Other:		

EMERG. BACKUP SYST.			Press.	Wkg.Fl.
✓ N2 Cyl	No: 3	Tpe:	1 2000	gal
Other:			2 2100	gal
			3 2100	gal
			4	gal
			5	gal
			6	gal

AUXILIARY EQUIPMENT	No.	Sz. (in)	Rated Press.	Connections Weld	Flan.	Thrd.
✓ Fill-Up Line						
✓ Kill Line						
✓ Control Valve(s)						
✓ Check Valve(s)						
✓ Auxil. Pump Connec.						
✓ Choke Line						
✓ Control Valve(s)						
✓ Pressure Gauge						
✓ Adjustable Choke(s)						
✓ Bleed Line						
✓ Upper Kelly Cock						
✓ Lower Kelly Cock						
✓ Standpipe Valve						
✓ Standpipe Pressure Ga.						
✓ Pipe Safety Valve						
✓ Internal Preventer						

HOLE FLUID MONITORING EQUIPMENT	Alarm Aud.	Alarm Vis.	Class
✓ Calibrated Mud Pit			A
✓ Pit Level Indicator	✓	✓	B
✓ Pump Stroke Counter		✓	B
✓ Pit Level Recorder		✓	C
✓ Flow Sensor		✓	C
✓ Mud Totalizer		✓	C
Calibrated Trip Tank			
Other:			

TOTCO

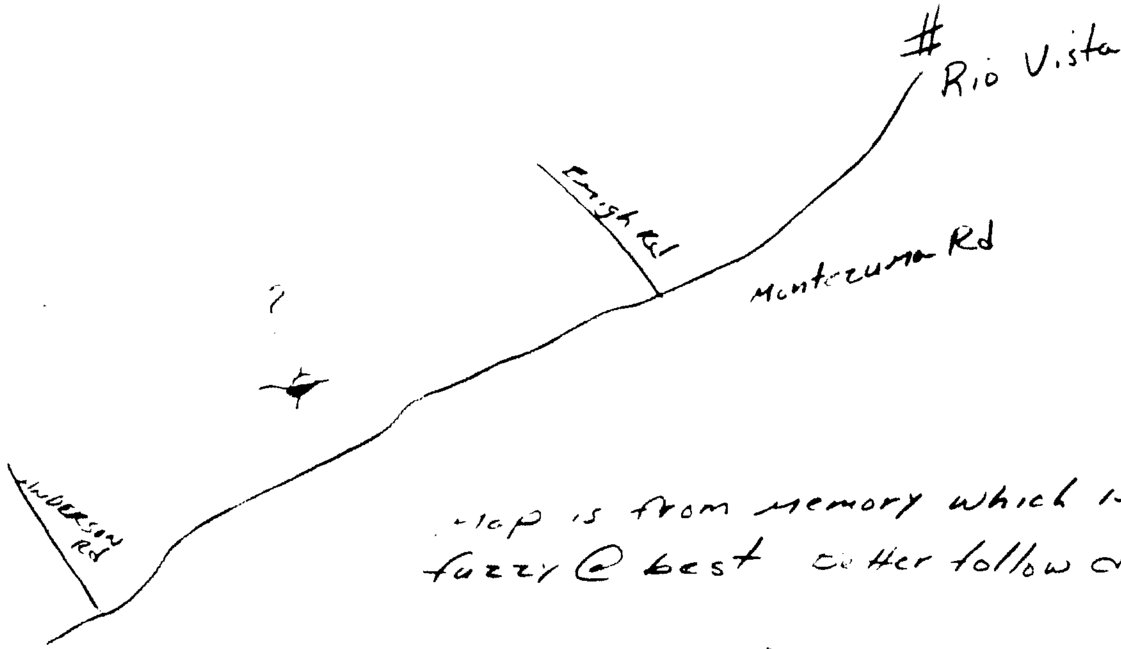
REMARKS:

Hole Fluid Type	Weight	Storage-Pits

OGD 9(5-79-DWRR-3M)

MONTEZUMA HILLS Rd S

Follow Montezuma Hills Rd.
approx. 8.3 mi. Smo out of Rio Vista
Turn Rt @ STOP .5 mi approx
go left through gate over
hill to loc.



Map is from memory which is fuzzy @ best better follow dir.

M.C.O.R "G.P." 1-7
7-3N-2E
Abd 1-7-80
Solano Co.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

No. P 680-346

REPORT ON PROPOSED OPERATIONS

--- (field code)
--- (area code)
--- (pool code)

WELL CLASSIFICATION:
EXPLORATORY-NEW FIELD

J. E. Walton, Agent
McCULLOCH OIL AND GAS CORPORATION
5405 Stockdale Highway
Suite 203
Bakersfield, CA 93309

Woodland, California
August 4, 1980

Your proposal to drill well "GP" 1-7, A.P.I. No. 095-20436, Section 7, T. 3N, R. 2E, M.D. B. & M., --- field, --- area, --- pool, Solano County, dated 7-24-80, received 7-28-80 has been examined in conjunction with records filed in this office.

THE PROPOSAL IS APPROVED PROVIDED THAT:

1. The 9 5/8" casing is cemented with sufficient cement to fill behind this casing from the shoe to the ground surface.
2. The 5 1/2" casing is cemented with sufficient cement to fill behind this casing from the shoe to at least 500 feet above the uppermost oil or gas zone.
3. Drilling fluid of a quality and in sufficient quantity to control all subsurface conditions in order to prevent blowouts is used.
4. Blowout prevention equipment conforming to Class III B 2M requirements is installed on the 9 5/8" casing and maintained in operating condition at all times. See Manual M07 and attached sheet.
5. Blowout prevention equipment conforming to Class "III" 5M requirements is installed on the 5 1/2" casing and maintained in operating condition at all times. See Manual M07 and attached sheet.
6. Fresh water protection for this well shall be as shown on attached exhibit A.
7. The division is furnished copies of any draw down or back pressure tests performed. In addition the division will monitor the production for a period of six months and if anomalous water production is indicated, remedial action will be ordered.
8. THIS DIVISION IS NOTIFIED:
   a. Before deviating from the proposed casing program and/or placing any plugs in the hole. Additional requirements shall be outlined at that time.
   b. To witness a test of the installed blowout prevention equipment prior to drilling out the shoe of the 9 5/8" casing. The blind/blank rams shall be tested by the operator prior to calling the Division inspector. Test information of the blind/blank ram test shall be entered on the tour sheet along with the signature of the person in charge.

NOTE:
1. RECORDS FOR WORK DONE UNDER THIS APPROVAL ARE DUE WITHIN 60 DAYS AFTER COMPLETION OF THE WORK AND/OR SUSPENSION OF OPERATIONS.
2. Information on file in this office indicates that the base of the useable fresh water deposits should be encountered at a depth of approximately 1400'.
3. This well has been granted confidential status for two years from the date of its completion or abandonment.

Blanket Bond
KPH:kw
cc: Co., L.

A copy of this report must be posted at the well site prior to commencing operations.

CONFIDENTIAL STATUS

M. G. MEFFERD, State Oil and Gas Supervisor

By John C. Sullivan
Deputy Supervisor
John C. Sullivan

OG111 (1-79-GSRI-5M)

EXHIBIT A

NO. P. 680-346

Date August 4, 1980

McCULLOCH OIL AND GAS CORP.

Well No. "GP" 1-7 | Sec. 7 | T. 3N | R. 2E

Field --- | County Solano

FRESH WATER PROTECTION REQUIREMENTS FOR THE ABOVE WELL ARE AS FOLLOWS:

Fresh waters are to be protected by cement behind the 5 1/2" casing. Sufficient cement shall be used to fill to at least 100 feet above the base of the fresh water deposits, which is estimated to be at 1400'. To insure the above, one of the following operations shall be performed:

a. The 5 1/2" casing shall be cemented through the shoe with 125 percent of the volume of cement calculated to fill the casing/hole annulus from the shoe to 100 feet above the base of the fresh water deposits.

b. The 5 1/2" casing shall be cemented through ports, set between 50 feet and 100 feet below the base of the fresh water deposits, with sufficient cement to fill 500 feet of the casing/hole annulus.

c. A cement bond, temperature survey, or other survey shall be run to determine that the cement in the annulus is 100 feet above the base of the fresh water deposits.

If either item "a" or "b" is not performed, or if a survey in item "c" indicates an unsatisfactory cement lift, the well casing shall be recemented to comply with the above requirements.

1400

'Request Confidential Status"

Explor N.F.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

Notice of Intention to Drill New Well

DIVISION OF OIL AND GAS
RECEIVED
JUL 28 1980
CALIFORNIA

C.E.Q.A. INFORMATION			
EXEMPT [X] CLASS 3	NEG. DEC. [ ] S.C.H. NO.	E.I.R. [ ] S.C.H. NO.	DOCUMENT NOT REQUIRED BY LOCAL JURISDICTION [ ]

See Reverse Side

FOR DIVISION USE ONLY					
MAP	MAP BOOK	CARDS	BOND		
612	9-31-80	✓✓	B1B	✓	✓

In compliance with Section 3203, Division 3, Public Resources Code, notice is hereby given that it is our intention to commence drilling well MCOR # 1-7 "~~Grandpa Peter~~" GP, API No. 095-20436 (Assigned by Division)

Sec. 7, T. 3N, R. 2E, MD B. & M., _____ Field, Solano County.

Legal description of mineral-right lease, consisting of 1253.70 acres, is as follows: (Attach map or plat to scale)

See attached plat

Do mineral and surface leases coincide? Yes X No ___ If answer is no, attach legal description of both surface and mineral leases, and map or plat to scale.

Location of well 1850 feet N (Direction) along section/~~property~~ line and 400 feet E (Direction) (Cross out one)

at right angles to said line from the SW corner of section/~~property~~ 7 or (Cross out one)

T3N, R2E, MDB&M

Is this a critical well according to the definition on the reverse side of this form? Yes [ ] No [X]

If well is to be directionally drilled, show proposed coordinates (from surface location) at total depth:
_____ feet _____ (Direction) and _____ feet _____ (Direction)

Elevation of ground above sea level 182.5 feet. 205 Kb

All depth measurements taken from top of Kelly Bushing (Derrick Floor, Rotary Table, or Kelly Bushing) that is 23 feet above ground.

PROPOSED CASING PROGRAM

SIZE OF CASING INCHES API	WEIGHT	GRADE AND TYPE	TOP	BOTTOM	CEMENTING DEPTHS	CALCULATED FILL BEHIND CASING
9 5/8"	36#	K-55 LT&C	Surface	1050'	Surface	
5 ½"	17# ~~20#~~	N-80 LT&C	Surface	10,000'	According to Division of Oil and Gas Regulations	

(A complete drilling program is preferred and may be submitted in lieu of the above program.)

Intended zone(s) of completion McCormack Sand (Name, depth, and expected pressure) Estimated total depth 10,000'

It is understood that if changes in this plan become necessary we are to notify you immediately.

Name of Operator	Type of Organization (Corporation, Partnership, Individual, etc.)	
McCulloch Oil And Gas Corp. ~~MCOR Oil and Gas Corporation~~	Corporation	
Address: 5405 Stockdale Hwy., Suite 110	City: Bakersfield	Zip Code: 93309
Telephone Number: (805)832-9100 / Name of Person Filing Notice: J.E. WALTON	Signature: JEWalton	Date: 7-24-80

This notice and indemnity or cash bond shall be filed, and approval given, before drilling begins. If operations have not commenced within one year of receipt of the notice, this notice will be considered cancelled.

OG105 (10-78-GSRI-10M)

* H.11/5-11024 7-29-80

7-29-80 Hill/5-11024 **

Ken:

No bond on file for MCOR ---

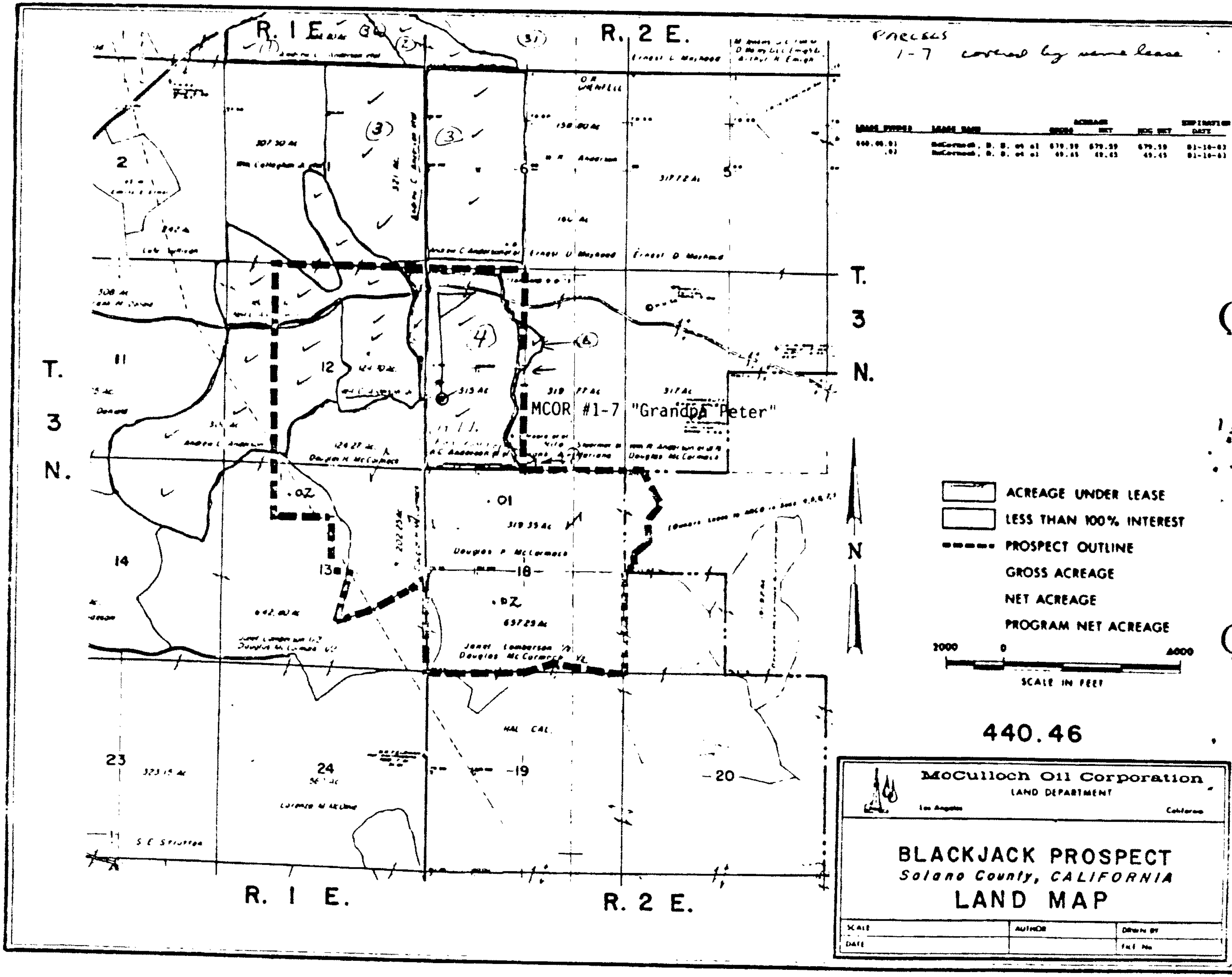
Can you contact Jack Walton re change in operator name to McCulloch? 7-28-80

Looking into the problem. checked w/ Bill Hill. KH

Called McC——

7-29-80

Jack Walton on Van
Bill Hill on Other line
talked to other person
named(?)
Told him needed date
on Blanket Bond Rider
change & told him would
not approve "Grandpa Peter"
told him we would change
to "G. P." if we didn't
hear to contrary JCS



PARCELS 1-7 covered by same lease
R. 1 E.
R. 2 E.
T. 3 N.
MCOR #1-7 "Grandpa Peter"
N
ACREAGE UNDER LEASE
LESS THAN 100% INTEREST
PROSPECT OUTLINE
GROSS ACREAGE
NET ACREAGE
PROGRAM NET ACREAGE
2000 0 4000
SCALE IN FEET
440.46
McCulloch Oil Corporation
LAND DEPARTMENT
BLACKJACK PROSPECT
Solano County, CALIFORNIA
LAND MAP

APPENDIX C-1
STATE FORMS DATA FOR NEARBY ARTIFICIAL PENETRATIONS
PACIFIC GAS & ELECTRIC BIRDS LANDING NO. 1

Coalinga, California

July 14, 1932

PACIFIC GAS & ELECTRIC CO.

Well No. 1,
Sec. 2, T. 3 N., R. 1 E.
M. D. B. & M., Solano County

MEMORANDUM OF ABANDONMENT

This well was abandoned in the condition shown on the log dated May 1, 1922 and history dated June 28, 1922. Notice of intention to abandon, dated May 1, 1922 was filed on June 1, 1922, the proposal reading as follows: "Bridge at 1800' and leave a fresh water well. 8 1/4" casing salvaged, 10" and 13 1/2" casing left in the hole." This notice was not answered and has a penciled notation thereon initialed by former Deputy Supervisor R. M. Barnes reading as follows: "Held pending receipt of log and history which was received July 17, 1922. Proposed work already done. Do not answer."

The well was evidently in a satisfactory condition and there is no reason to believe that it will do any damage. The well record has therefore been closed.

The well was included in the list of abandoned wells published in "Summary of Operations - California Oil Fields", Volume 11, No. 1, July, 1925.

H V Dodd
Deputy Supervisor

HVD:LL

Reference to file of data

Maps	Model	Cross Section	Cards	Forms	
				114	121
W. C. F. Q. K.					✓

VISION OF OIL AND GAS
CHECK LIST - RECORDS RECEIVED AND WELL STATUS

Company ______ Well No. ______

API No. ______ Sec. ______, T. ______, R. ______, ______ B.&M.

County ______ Field ______

RECORDS RECEIVED — **DATE**

Well Summary (Form OG100) ______
History (Form OG103) ______
Core Record (Form OG101) ______
Directional Survey ______
Sidewall Samples ______
Other ______
Date final records received ______
Electric logs: ______

STATUS

Producing - Oil ____
Idle - Oil ____
Abandoned - Oil ____
Drilling - Idle ____
Abandoned - Dry Hole ____
Producing - Gas ____
Idle - Gas ____
Abandoned - Gas ____
Gas-Open to Oil Zone ____
Water Flood Source ____

STATUS

Water Disposal ____
Water Flood ____
Steam Flood ____
Fire Flood ____
Air Injection ____
Gas Injection ____
CO_2 Injection ____
LPG Injection ____
Observation ____

DATE ______
RECOMPLETED ______
REMARKS ______

ENGINEER'S CHECK LIST

1. Summary, History, & Core record (dupl.) ______
2. Electric Log ______
3. Operator's Name ______
4. Signature ______
5. Well Designation ______
6. Location ______
7. Elevation ______
8. Notices ______
9. "T" Reports ______
10. Casing Record ______
11. Plugs ______
12. Surface Inspection ______
13. Production ______
14. E Well on Prod. Dir. Sur. ______

CLERICAL CHECK LIST

1. Location change ____ (F-OGD165) ______
2. Elevation change ____ (F-OGD165) ______
3. Form OGD121 ______
4. Form OG159 (Final Letter) ______
5. Form OGD150b (Release of Bond) ______
6. Duplicate logs to archives ______
7. Notice of Records due (F-OGD170) ______

Plue check N/A

RECORDS NOT APPROVED
Reason: ______

RECORDS APPROVED ______

RELEASE BOND ______
Date Eligible ______
(Use date last needed records were received.)
MAP AND MAP BOOK ______

LONG BEACH OFFICE - USE REVERSE SIDE

Form 100 [illegible]

Fill this blank in with typewriter. Write on one side of paper only

CALIFORNIA STATE MINING BUREAU

FERRY BUILDING, SAN FRANCISCO

LOG OF OIL OR GAS WELL

Field **Montezuma Hills.** Company **Pacific Gas & Electric Co.**

Township **[illegible]** Range **[illegible]** Section **[illegible]** Elevation **[illegible]** Number of Well **1**

In compliance with the provisions of Chapter 718, Statutes of 1915, the information given herewith is a complete and correct record of the present condition of the well and all work done thereon, so far as can be determined from all available records.

Signed [signature]

Date **May 1, 192[illegible]**

Title **Field Superintendent.** (President, Secretary or Agent)

The summary on this page is for the ORIGINAL condition of the well

Oil Sands

1st sand from **none encountered.** 4th sand from .... to ....
2d sand from .... to .... 5th sand from .... to ....
3d sand from .... to .... 6th sand from .... to ....

Important Water Sands

1st sand from **45'** to **48'** 3d sand from **Salt water -may be from**
2d sand from **810 ?** to .... 4th sand from **4337,21'; 4512',2'or 4551'whichis 4'thick.**

Casing Record

Size of Casing	Where Landed	Where Cut	Weight Per Foot	Threads Per Inch	Kind of Shoe	Make of Casing	Yes	No	Cemented Number of Sacks
13 1/8"		not cut			13 1/2"				
	2049'[illegible]"	[illegible]	50#	10	common	Nat. Tube.	yes		370.
10"	2932'6"	2000'	40#	10	10" common	Rep. Special.	yes		200
8 1/4"	4324'5"	2955'6"	32 & 36#		8 1/4"	" " "	"		197.

Cementing or Other Shut-off Record

Casing Size	Sacks	Time Set	Method	Test and Result (Give water level and bailing results)
		none used.		

Plugs and Adapters

Heaving Plug—Material **10" bridged at 1800'** Length .... Where set ....

Adapters —Material .... Size ....

Tools

Rotary Tools were used from **0'** ft. to **6002'** ft. .... ft.

Cable Tools were used from .... ft. to .... ft. .... ft.

Perforations

State clearly whether a machine was used or casing was drilled in shop

From	To	Size of Holes	Number of Rows	Holes Per Foot	Machine—Shop
ft.	ft.				
ft.	ft.	none used.			
ft.	ft.				
ft.	ft.				
ft.	ft.				

Thirty days after completion well produced .... barrels of oil per day.

The gravity of oil was .... degrees Baumé. Water in oil amounted to .... per cent.

Names of Drillers	Names of Tool Dressers
[illegible]	Joe [illegible]
John [illegible]	Al [illegible]
W.F. [illegible]	Walter [illegible]

Date drilling started **July 10, 192[illegible]** Date well was completed **May 1, 192[illegible]**

Formations Penetrated by Well

Depth to Top of Formation	Depth to Bottom of Formation	Thickness	Name of Formation
0	240	240	River deposits _Sand; sandy clays, and fine grvels
240	860	[illegible]	San Pablo- Vivianite Sandstone -interbeded with blue and yellow shales. 641 to 697 Black tuff.
860	3290	2430	Markley-sandy blue shales. 2770 to 2935 Carbonaceous material.
3290	5002	1712	Tejon-Brown fossiliferous shale., with varying amounts of sand.

101 36728 3-6-18—15M

CALIFORNIA STATE MINING BUREAU

LOG OF OIL OR GAS WELL—Continued

Field. SOLANO COUNTY Company PACIFIC GAS AND ELECTRIC COMPANY

Township 3 North Range 1 East Section 2 Number of well 1

FORMATIONS PENETRATED BY WELL

Depth to Top of Formation	Depth to Bottom of Formation	Thickness	Name of Formation
1	21		Black Adobe Soil
21	61		Brown Sandy Clay
61	68		Micacious Sand Stone
68	98		Sandy Shale
98	183		Bluish Gray Shale
183	210		Gravel and Sand
210	240		Gravel and sand with sandstone lenses.
240	290		Soft Brown Clay
290	293		Hard Gray Sandstone
293	343		Blue sandy clay with sandstone lenses.
343	411		Gray Sandstone with small clay lenses
411	547		Bluish and yellow sandy clay with sandstone lenses
547	572		Fine Conglomerate cemented with fine sand stone and sand pebbles.
572	640		Blue sandy clay containing rounded quartz pebbles.
640	741		Grayish blue sandy shale containing quartzite pebbles
741	860		Blue sandy shale with sandstone lenses.
860	1010		Blue and yellow sandy shale containing sandstone lenses and conglomerates.
1010	1159		Blue and yellow and brown sandy shale containing sandstone lenses and quartz pebbles.
1159	1206		Blue, gray and sandy shales with lenses of fine gravel and sandstone.
1206	1457		Blue, green & chocolate shales; small lenses of sand and gravel.
1457	1473		Hard fine grained sandstone and some gravel.
1473	1532		Hard sandy greenish blue shale.
1532	1772		Greenish blue shale; small lenses of sand and gravel.
1772	1961		Hard greenish blue sandy shale lenses of chocolate shale.
1961	2240		Soft blue sandstone with blue shale lenses.
2240	2935		Blue sandy shale with lenses of fine sand and containing carbonaceous material similar to lignite.
2935	3018		Dark gray sandstone; small lenses of clay.
3018	3200		Fine white sand; small lenses of blue shale.
3200	3213		Very hard shaell; fine white quartz.
3213	3219		Dark brown sandy shale.
3219	3221		Very hard shell.
3221	3231		Brown sandy shale.
3231	3264		Soft gray sandy clay very sticky.
3264	3290		Hard sandstone with lenses of brown shale.
3290	3292		Hard shell.
3292	3320		Brown sandy shale and sticky blue clay lenses.
3320	3434		Brown and blue sandy shale; blue clay lenses.
3434	3573		Dark brown fossiliferous shale with numerous sand lenses.
3573	3575		Hard shell.

Form 101. 30728 3 6-18 15M

CALIFORNIA STATE MINING BUREAU

LOG OF OIL OR GAS WELL—Continued

SHEET 2

Field. SOLANO COUNTY Company PACIFIC GAS AND ELECTRIC CO.

Township 3 North Range 1 East Section 2 Number of well 1

FORMATIONS PENETRATED BY WELL

Depth to Top of Formation	Depth to Bottom of Formation	Thickness	Name of Formation
3575	3952		Dark Brown fossiliferous shale with numerous sand lenses
3952	4353		Dark Brown fossiliferous shale containing shapp angular sand and pebbles.
4353	4384		Same but softer with some fine clay.
4384	4385		Hard fine grained gray sandstone.
4385	4519		Gray sandy shale
4519	4527		Gray angular sandy shale.
4527	4545		Soft Brown sandy shale.
4545	4551		Gray angular sand some shales.
4551	4881		Dark brown and gray sandy shale with lenses of angular shad
4881	4886		Gray quartz sand
4886	4994		Brown sandy shale with quartz sand lenses.
4994	5002		Fine Gray sand.

Form 103. 6415 10-20 10M

CALIFORNIA STATE MINING BUREAU

HISTORY OF OIL OR GAS WELL

FIELD: SOLANO COUNTY COMPANY: PACIFIC GAS AND ELECTRIC COMPANY

Township: 5 North Range: 1 East Section: 2 Number of well: 1

Signed: (President, Secretary or Agent)

Date: June 28, 1922 Title: Agent

It is of the greatest importance to have a complete history of the well. Please state in detail the dates of redrilling, together with the reasons for the work and its results. If there were any changes made in the casing, state fully, and if any casing was "sidetracked" or left in the well, give its size and location. If the well has been dynamited, give date, size, position, and number of shots. If plugs or bridges were put in to test for water, state kind of material used, position, and results of pumping or bailing.

Drilled to depth of 500 ft. with 25" bit to land 20" 8 guage double stove pipe casing; formation swelled to such extent had to ream hole with 28" bit in order to land the casing. Resumed drilling with 19¼" bit. 20" casing collapsed at 223 ft. probably weakened on account of having been cut by bit. Used 12" and 18" swedges but were unable to force it into shape. At the point where it collapsed the 12" swedge passed outside of the casing. Pulled 223 ft. of casing without difficulty and inserted impression block and determined shape of casing. Made cone shaped fishing tool and removed all of the casing and resumed drilling with 19¼" bit in open hole to depth of 1945'5" where we landed and cemented 13½" casing (370 sacks of cement) successfully. Resumed drilling with 13½" bit to depth of 2932'6" where we landed 10" 40# casing and cemented successfully with 200 sacks of cement. Drilled to depth of 4324'5" with 9-7/8" bit and landed 2146' of 36# and 2178'5" of 32# 8¼" casing and cemented off successfully using 197 sacks of cement. Drilled to depth of 5002' with 7-7/8" bit. We removed 2922' of 8¼" casing. Cut the 10" casing at 2000', 1850' and 1500' and could get vibration but could not pull the casing. We assume that the 13½" casing had become elongated and pressed against the 10". We bridged the hole at 1800'.

CALI[illegible]ORNIA STATE MINING BU[illegible]REAU

DEPARTMENT OF PETROLEUM AND GAS

Report on Test of Water Shut-off

(BAILING)

No. T 5-1004

Coalinga, Cal. [illegible]pril 15, 19[illegible]2

F. C. Stormer,

Suisun, Cal.

[illegible] P[illegible]I[illegible]IC [illegible] & [illegible]L[illegible]CTRIC Company

Well No. 1 Section 2 T. 3N R. 1E M. D. B. & M.,

XXXXXX in Solano County, was tested for

[illegible]pril ? 19 22 "No representative

[illegible] was present as prescribed in Section 19, Chapter 718, Statutes 1915, as amended, and there were also present

B. Ibbotson, Federal Drilling Co., Ralph D. Copley, Geologist

[illegible] tor and normal fluid level ?

[illegible] water shut-off: 2237'10" ft. of 8¼ in. 32 lb.; 2086'7" ft. of 8¼" in. 36 lb. casing was cemented / XXXXX in brown fossiliferous shale. (Formation)

4324' 5" 197 sacks --- cement by Perkins method; Rotary tools (Size and kind)

[illegible] On drilling ahead for test, cement found at 4303'5".

13½" ctd 1949'5", [illegible]S.O. 10" ctd 2935'; 8¼" ctd 4324'5".

4362' 9" [illegible] " [illegible] " [illegible] " for this test.

4362' [illegible] ?

Not given [illegible] " ft. water bailed to 2500 ft.

Not given After 17 hours top of oil found at ft., top of water found at 2500 ft.

Result of bailing test:

"This test was not witnessed by a member of this department, because of distance and time required, but was witnessed and the above data reported by Mr. [illegible] O. Jack, Field Supt. for the Pacific Gas and Electric Company.

[illegible] 17 hours for the test, no oil and no water entered the well.

[illegible] shut-off is approved.

CC- [illegible] - 2
[illegible] Jack

R. E. COLLOM,
State Oil and Gas Supervisor

By [illegible] Deputy

Form 109b. 11104 5-21 5M

RMB/LH

Form 108. 36199—2-5-18—10M

CALIFORNIA STATE MINING BUREAU

Department of Petroleum and Gas

STATE MINING BUREAU
RECEIVED
JUL 17 1922
COALINGA, CALIFORNIA

Notice of Intention to Abandon Well

This notice must be given at least five days before work is to begin

Bird's Landing Cal. May1 1922.

Mr. R. M. Barnes.
Deputy State Oil and Gas Supervisor
Coalingo Cal.

Dear Sir:

In compliance with Section 16, Chapter 718, Statutes of 1915, notice is hereby given that it is our intention to abandon well number 1 Section 2 T. [illegible] R. [illegible], Mt. Diablo B. & M., Oil Field Solano. County, commencing work on the 1st day of May 1922.

The present condition of the well is as follows:

Open to [illegible]'-7 7/8" hole -drilling thru 8" casing.

The proposed work is as follows:

Bridge at 1800' and leave a fresh water well. 8 1/4 " casing salvaged ,10" and 13 1/2 " casing left in the hole.

Held pending receipt of log and history which was received July 17 1922. Proposed work already done.

not answer

Reference to file of data

Maps	Model	Cross Section	Cards	Forms 114	Forms 121
				✓	✓

Respectfully yours,

PACIFIC GAS & ELECTRIC CO.
(Name of Company or Operator)

By [signature]

Address notice to Deputy State Oil and Gas Supervisor in charge of district where well is located

CALIFORNIA STATE MINING BUREAU

DEPARTMENT OF PETROLEUM AND GAS

Report on Test of Water Shut-off
(BAILING)

No. T 5-944

Coalinga, Cal. Nov. 25, 1921

Mr John. A. Britton,

San Francisco, Cal.

Agent for BACIFIC GAS & ELECTRIC Company

DEAR SIR:

Your well No. 1 Section 2 T. 3N R. 1E, M. D. B. & M.

[redacted]d, in Solano County, was tested for shut-off of water on Nov. 14, 1921 (Time and date) Mr. R. M. Barnes designated by the supervisor, was present as prescribed in Section 19, Chapter 718, Statutes 1915, as amended, and there were also present

H. H. McClintock, Supt.

E. D. Copley, Geologist

Location of water tested top and normal fluid level 20'

Depth and manner of water shut-off: 1949'5" ft. of 13½ in. 50 lb. casing was cemented / [redacted] in blue shale (Formation)

at 1949'5" ft with 270 sacks Santa Cruz cement by Perkins method; 19½" Rotary (Size and kind) tools were used in landing water string. reported 11/14/21

Casing record of well 13½"-1949'5".

Reported total depth of hole 1958' ft. Hole bridged from - ft. to - ft. Hole cleaned out to 1958 ft. for this test.

At time of test depth of hole measured 1954 ft. and bailer brought up sample of blue clay.

At 10:30 a. m. Nov. 13, 1921 (Time and date) oil bailed to - ft., water bailed to 500 ft.

At 10:00 a. m. Nov. 14, 1921 (Time and date) top of oil found at no oil ft., top of water found at 425 ft.

Result of bailing test:

Mr. McClintock and Mr. Copley reported the following:

1. Drilled 24" rotary hole reamed to 29" to a depth of 500' and landed 20" S. P. casing at 494'.
2. Drilled ahead to 1942' with 19½" bit.
3. Hole stood for 4 days and S. P. casing was found collapsed at 223'.
4. Entire 494' of S. P. casing was removed.
5. After cementing 13½" casing, same was centered and sufficient surface material (clay) placed back of it to probably fill space between casing and wall of hole from 500' to surface

The Inspector witness the following:

1. Cementing depth of 1942'9", which was reported on our form 106, dated Nov. 7, 1921, was actual amount of casing in hole, top of same being 6'8" below derrick floor;

R. E. COLLOM,
State Oil and Gas Supervisor

(Continued)

By R. M. Barnes Deputy

Form 109b 11164 5-21 5M

MEMORANDUM OF TEST OF WATER SHUT-OFF
(Bailing)

Pirdie's Landing Cal ~~March~~ 7...192...
April 11

Mr. R. M. Barnes
Deputy State Oil and Gas Supervisor

........Coalinga............Calif.

Dear Sir:

In compliance with your....written.....................communication
(telegraphic, telephonic, written)
of..March 28.............192.8...., stating that a member of the Department of Petroleum and Gas would not be present, and authorizing me to witness test of shut-off of water at well No......1.................of Pacific Gas & Electric Co. Company, Sec...[illegible]., T.[illegible]., R.[illegible]., M.D.B. & M., I have witnessed the test of water shut-off and submit the following data relative thereto:

Location and kind of water tested..

Depth and manner of water shut-off: (..[illegible]...ft. of..8 1/4....in...[illegible]...lb.) (..[illegible]...ft. of..8 1/4....in...[illegible]....lb.) casing was (cemented) (landed)

Brown fossiliferous

in. Shale....at [illegible] ft. with 197....sacks Portland cement by Perkins method;
(formation)
...Rotary.............tools were used in landing water string. Casing record of
(size and kind)
well................................Total depth of hole..[illegible] ft. Hole bridged from ....ft. to ....ft. with.................. Hole cleaned out
(bridge material)
to [illegible]...ft. for this test. At time of test depth of hole measured.[illegible]... ft., from which depth bailer brought up. .... At............................
(formation) (time and date)
oil bailed to ....ft., water bailed to [illegible].....ft., and hole allowed to stand undisturbed until...17 Hours............., when top of oil was found at
(time and date)
...........ft., top of .Fresh at [illegible]........water was found at ....ft.
(fresh, salt, sulphur, etc.)
On drilling ahead for this test, cement was encountered inside of the casing at .[illegible]..ft. Others present were..B. Abbotson, Federal Drilling Co. ......
Ralph Copley Geologist P.G.&E. Co.

Respectfully yours,

[signature]

Field Sup't Pacific Gas & Electric Co.
(position and company)

MEMORANDUM OF TEST OF WATER SHUT-OFF

(Bailing) Fird's Landing [illegible] March 7

.................Cal. April 1 192_

STATE MINING BUREAU

RECEIVED APR 11 1922

COALINGA, CALIFORNIA

Mr. P. V. Parsee.

Deputy State Oil and Gas Supervisor

Coalinga Calif.

Dear Sir:

In compliance with your written (telegraphic, telephonic, written) communication of March 30 192......, stating that a member of the Department of Petroleum and Gas would not be present, and authorizing me to witness test of shut-off of water at well No. 1 of Pacific Gas & Electric Co Company, Sec. 2, T. 8? R. 1? M. D. B. & M., I have witnessed the test of water shut-off and submit the following data relative thereto:

Location and kind of water tested..

Depth and manner of water shut-off:
(2086'7" ft. of 8 1/4 in. 2? lb.)
(2287'10" ft. of 8 1/4 in. 8? lb.) casing was (cemented / landed)
(.............ft. of..........in..........lb.)

in Brown fossiliferous Shale (formation) at 4824'8" ft. with 107 sacks Portland cement by Perkins method;

..........................(size and kind) tools were used in landing water string. Casing record of well.................................Total depth of hole 4852'9" ft. Hole bridged from ....ft. to ....ft. with ....(bridge material) Hole cleaned out to 4852'9" ft. for this test. At time of test depth of hole measured 4852'9" ft., from which depth bailer brought up.............(formation) At...........................(time and date) oil bailed to ....ft., water bailed to ....ft., and hole allowed to stand undisturbed until 17 Hours (time and date), when top of oil was found at ....ft., top of ....(fresh, salt, sulphur, etc.) water was found at ....ft.

On drilling ahead for this test, cement was encountered inside of the casing at 4853'8" ft. Others present were B. Abbotson, Federal Drilling Co. R. D. Copley – Geologist P. G. & E. Co.

Respectfully yours,

[signature]

Field Supt Pacific Gas & Electric Co.

(position and company)

Form 106. 4508 6-20 5M

STATE MINING BUREAU
RECEIVED
COALINGA, CALIFORNIA

CALIFORNIA STATE MINING BUREAU

Department of Petroleum and Gas

Notice of Test of Water Shut-off

This notice must be given at least five days before the test, and a longer time is desirable

San Francisco Cal. March 28, 1922

Mr. R. M. Barnes.

Deputy State Oil and Gas Supervisor

Coalinga. Cal.

DEAR SIR:

In compliance with Section 19, Chapter 718, Statutes of 1915, notice is hereby given that it is our intention to test the shut-off of water in well number 1 Section 2 T. 3 N R. 1 E, M. D. B. & M., ---------- Oil Field, Solano County, on the 4th day of April 1922.

8½ inch 32 - 36 lb. casing was cemented in Chocolate Shale (Formation) at 4330' (Depth)

on Tues. March 21 1922. (Date)

197 sacks of cement were used.

The Perkins method was used in placing the cement.

Fluid level will be bailed to a depth of 1800 feet and left undisturbed for at least 12 hours before your inspection.

The well is 4352' 9" feet deep. There is not plug or bridge from - feet to - feet

Reference to file of data

Maps	Model	Cross Section	Cards	Forms	
				114	121
				✓	✓

095 00422

Respectfully yours,

PACIFIC GAS AND ELECTRIC COMPANY.
(Name of Company or Operator)

By [signature]
Its Vice-President and General Manager.

Address notice to Deputy State Oil and Gas Supervisor in charge of district where well is located

CALIFORNIA STATE MINING BUREAU

DEPARTMENT OF PETROLEUM AND GAS

Report on Test of Water Shut-off

No. T. 5-944

Page 2

Company PACIFIC GAS & ELECTRIC

Well No. 1 Sec. 2 T. 8N R. 1E M. D. B. & M.

(Continued from page 1)

therefore correct depth of 13⅜" shoe below derrick floor is 1949'5".

2. While standing 23½ hours for the test, 5' of water entered the well, equivalent to 0.9 bbl. per 24 hours. This may be attributed to "drainback" from the casing.

The shut-off is approved.

cc- H. E. McClintock
E. B. Henley

EMB/LH

R. E. COLLOM
[redacted]
State Oil and Gas Supervisor

By A. M. L. Barnes, Deputy

Form 109x ... 1941

Form 106. 4508 6-20 5M

CALIFORNIA STATE MINING BUREAU

Department of Petroleum and Gas

Notice of Test of Water Shut-off

1921

This notice must be given at least five days before the test, and a longer time is desirable

SAN FRANCISCO, Cal. November 7, 1921

Mr. R. M. Barnes

Deputy State Oil and Gas Supervisor

Coalinga, Cal.

DEAR SIR:

In compliance with Section 19, Chapter 718, Statutes of 1915, notice is hereby given that it is our intention to test the shut-off of water in well number 1 Section 2 T. 3N R. 1E M.D. B & M., -------- Oil Field, SOLANO County, on the 12th day of November 1921

13¼ inch 50 lb. casing was cemented in Blue Shale (Formation) at 1942'9" (Depth)

on Wed. October 26 1921 (Date)

400 sacks of cement were used.

The Perkins method was used in placing the cement.

Fluid level will be bailed to a depth of 500 feet and left undisturbed for at least 12 hours before your inspection.

The well is 1953'4½" feet deep. There ~~is not~~ is a plug or bridge from 1942'27/8 feet to 1953'4½ feet

Respectfully yours,

Pacific Gas and Electric Company,
(Name of Company or Operator)

By John A. Britton
Its Vice-President & General Manager.

Address notice to Deputy State Oil and Gas Supervisor in charge of district where well is located

CALIFORNIA STATE MINING BUREAU

DEPARTMENT OF PETROLEUM AND GAS

Report on Proposed Operations

No. P 5-1447

Coalinga, Cal. June 1, 1921

Mr. John A. Britton,

San Francisco, Cal.

XXXXX PACIFIC GAS & ELECTRIC Company

Dear Sir:

Your proposal commence drilling Well No. 1 Section 2 T 3N R 1E M. D. B. & M.,

XXXXXXXXXX Solano County, dated May 17, 1921

has been examined in conjunction with records filed in this office.

Present conditions as shown by the records and the proposal are as follows:

THE NOTICE STATES:

"The well is 375 feet S. and 925 feet W. from N.E. Cor. of Section 2.

The elevation of the derrick floor above sea level is not given feet. 1085

We estimate that productive oil or gas formation should be encountered at a depth of about 3500 feet, more or less."

PROPOSAL:

"We propose to use the following strings of casing either cementing or landing them as here indicated:

Size of Casing	Weight	New or Second Hand	Depth	Landed or Cemented
10"	40#	New	3000'	Cemented

XXXXXXXXXXX

"It is understood that if changes in this plan become necessary we are to notify you if possible before cementing or landing the casing."

RECOMMENDATION:

The proposal to drill this well is approved, providing that steps will be taken to thoroly test all oil or gas bearing formations and to protect all formations, found worthy of protection, from the infiltration of water or dissipation of gas.

This office is not in possession of accurate information as to the depth at which oil or gas bearing formation may be encountered or as to the depth at which water should be shut off above same.

Please notify this office, on our form 106 (copies enclosed), when a string of casing has been set for the purpose of shutting off water, in order that the test for effectiveness of shut-off may be witnessed.

R. E. COLLOM

[redacted]

State Oil and Gas Supervisor

By R M Barnes Deputy

RMB/LO

Form 111

Form 105. 47750 8-19 10M

095-00422

CALIFORNIA STATE MINING BUREAU

Department of Petroleum and Gas

Notice of Intention to Drill New Well

This notice must be given before drilling begins

STATE MINING BUREAU RECEIVED MAY 25 1921

San Francisco, Cal. May 17 1921

Mr. R. M. Barnes,

Deputy State Oil and Gas Supervisor

Coalinga, Cal.

DEAR SIR:

In compliance with Section 17, Chapter 718, Statutes of 1915, notice is hereby given that it is our intention to commence the work of drilling well number 1 Section 2 T. 3 N R. 1 E, M.D. B. & M., ________ Oil Field, Solano County.

The well is 375 feet N. or S., and 925 feet E. or W. from NE Cor. of Section 2
(Give location in distance from section corners or other corners of legal subdivision)

The elevation of the derrick floor above sea level is 1685 feet. secured at well

We propose to use the following strings of casing either cementing or landing them as here indicated:

Size of Casing, Inches	Weight, Lbs. Per Foot	New or Second Hand	Depth	Landed or Cemented
10"	40	New	3000	Cemented

It is understood that if changes in this plan become necessary we are to notify you if possible before cementing or landing the casing.

We estimate that productive oil or gas formation should be encountered at a depth of about 3500 feet, more or less.

Respectfully yours,

Pacific Gas and Electric Company
(Name of Company or Operator)

By John A. Britton
Its Vice-President and General Manager.

Reference to file of data

Maps	Model	Cross Section	Cards	Forms 114	Forms 121
				✓	✓

Address notice to Deputy State Oil and Gas Supervisor in charge of district where well is located

Coalinga, Calif.
March 30, 1922

Mr. E. W. Henley, Manager,
Land and Tax Department,
Pacific Gas & Electric Co.,
445 Sutter Street,
San Francisco, Calif.

Dear Sir:

I have your notice, dated March 29th, of intention to test effectiveness of water shut off by 8¼" casing cemented at 4330' in your well No. 1, Sec. 2, T. 3 N., R. 1 E. on April 4th.

This office cannot have a representative present at the time of test and a representative of the company is hereby authorized to witness the test and forward data regarding same to this office upon the enclosed memorandum form.

Thanking you for your attention to this matter, I am

Yours truly,

RE/LB

Deputy Supervisor.

P. S. Allowing a safety factor of 2, 8¼" casing can safely be bailed to a depth of 3000' below the level of the fluid which stands back of it. Unless there is danger of formations heaving or of a gas blow-out, the casing should be bailed to 3000' for the test.

2017

PACIFIC GAS AND ELECTRIC COMPANY
445 SUTTER STREET
SAN FRANCISCO, CALIFORNIA.

OFFICE OF
LAND AND TAX DEPARTMENT

STATE MINING BUREAU
RECEIVED
DEC
COALINGA, CALIFORNIA

December 22, 1921.

Mr. R. M. Barnes,
Coalinga, California.

Dear Sir:

We have landed and cemented our ten (10") inch casing at 2935 ft., in our Well No.1 in Section 2, Township 3 North, Range 1 East, Solano County, Calif. We expect to commence drilling on Tuesday, December 27th and should be ready to test out on Wednesday, the 28th.

Our reason for cementing at this point was not because we encountered any water but because we do not care to carry our ten (10") inch casing to a greater depth.

Kindly advise us of your desires in the matter.

Yours very truly,
E. B. Henley,
Manager Land and Tax Department,
By W. G. Jack

WGJ:EO'C.

FORM 108. 88470 11-48 14,280 SPO

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

Notice of Intention to Abandon Well

This notice must be given at least five days before work is to begin; one copy only

memo

~~Coalinga~~ Calif. Jan 5 1950

DIVISION OF OIL AND GAS

Coalinga Calif.

In compliance with Secs. 3228, 3229, 3230, 3231 and 3232, Ch. 93, Stat. 1939, notice is hereby given that it is our intention to abandon well No. Pacific Gas & Electric Co Well No 1

Sec. 2, T. 3N, R. 1E, MD B.&M. ——— Field, Solano County, commencing work on the ——— day of ——— 1950

The present condition of the well is as follows:

1. Complete casing record.

13½" cem 1949'; 10" cem 2935', cut at 2000', 1800', & 1500'
8¼" cem 4324', cut & pulled from 2922'.
T.D. 5002'. No showings of oil or gas.
Hole bridged at 1800' and abandoned in 1922 by P.G.&E. Co.

2. Last produced. ——— (Date) ——— (Net oil) ——— (Gravity) ——— (Gas)

The proposed work is as follows:

1. Clean out hole to 1500' and try to pull 10" casing.
2. If successful, cap stub of 10" with 20' of cement and locate top of cement after it sets.
3. Fill remainder of hole with rotary mud or surface earth and place 10' of cement at surface.

memo

L. L. Allen
P. O. Box 70
Pittsburg, California

L. L. A.
P.O. Box
Pittsburg

(Name of Operator)

By ———

ADDRESS NOTICE TO DIVISION OF OIL AND GAS IN DISTRICT WHERE WELL IS LOCATED

Well Records

Pacific Gas & Electric Co
#1-2-3N/1E MDB&M

History of Operations

Rotary tools - Fish-tail bits

24" hole reamed to 22" to depth of 500'

Set 20" S.P. casing at 494'

Drilled with 19½" bit to 1942'.

Hole stood 4 days and found S.P. casing collapsed at 223' Aug 27th, probably due to "swelling" of Suisun clays.

Fished out entire 494' of S.P. casing with special slip socket. Found casing was partially collapsed for number of joints above and below 220'.

After cementing 13⅜" centered casing and backfilled around it with surface material - clay - probably filling hole from 500' to surface

There are three geologists on job - one for each tour and Prof. Willis of Stanford is consulting geologist.

Ditch samples have been taken every 2'.

Core samples have been taken as follows:-

[illegible] - 1700 every 100'

[illegible] 20'

Cores taken with Shell G [illegible] barrel

Formations down to 1960' consists of shales and clays - with no sands below

[illegible] - River 287'

[illegible] Bad [illegible]'

Monterey 1345'

1960'

Expect 200' of diatomaceous shale at bottom of Monterey group and figure that 13/3 is cemented about 100' above diatomaceous. Expect some oil or gas at contact.

Main body of [illegible] gas expected some 2000' deeper in Meganos group.

P. G. & E. Boring For Natural Gas

The Pacific Gas & Electric Co. has a derrick up 114 feet just north of Wilcox Ranch at Montezuma station on the San Francisco-Sacramento Railroad. The drill is of the rotary type, said to be the very latest and best well boring machinery in existence. Drilling started last week and the well is down about 200 feet. A sump has been built on the west and lower side of the derrick and several acres around the well have been fenced off to allow the workmen to continue their work without interruption from the many sightseers that arrive on the trains to watch the progress of the work. The company has secured leases on nearly all the land in the vicinity of the Montezuma hills on a royalty basis. The company is boring for gas, but it is believed by many people that oil will be obtained in commercial quantities.

Modified Meter Rates

Well Is Abandoned

Pacific Gas & Electric Company's Search for Oil at Birds Landing Fails

RIO VISTA, May 15.—The Pacific Gas & Electric oil well, near Bird's Landing, has been shut down and the drilling apparatus is now being removed. This is according to Superintendent Jacks of the company.

The well has reached the depth of 5002 feet, according to Jacks, and no indications of oil were struck. The company has considered the drilling of another test well near Denverton, said the superintendent, but as yet no definite decision has been reached on the matter.

ALLEN'S
PRESS CLIPPING BUREAU
Clipping from
SAN FRANCISCO,
CHRONICLE
May 20, 1921

PACIFIC GAS & ELECTRIC TO DRILL FOR GAS IN MONTEZUMA HILLS

"Cal. Oil Production Not at Peak"—Agency; Union's 1921 Sales Show Increa[illegible]

By E. E. ALBERTSON
[illegible] The Chronicle

The [illegible] Gas and Electric Company [illegible] in [illegible] gas [illegible] in the Montezuma hills, Solano county, Vice-President and General Manager John A. Britton said yesterday that the company had secured leases on 11,000 acres of land and that actual drilling would start about June 1.

E. E. ALBERTSON

Evidences of natural gas are plentiful in Solano county in Fairfield and Suisun. It is now used for lighting and heating in a small way, but the present production amounts to little more than seepage.

Acting on the advice of its engineers and consulting geologists, the company has acquired leases in the Montezuma hills, where it is hoped to tap the main reservoir of natural gas.

The site of the first well is about eight or ten miles distant from where the Honolulu Consolidated is now drilling for oil.

It is expected that it will be necessary to sink at least 3000 feet, which will require sixty to ninety days. The derrick and boiler are up, and most of the drilling tools are now on the ground.

The discovery of a large reservoir of natural gas in Solano county would be an immense asset for industrial San Francisco. Natural gas has a high heat content, sometimes running as high as 1000 British thermal units per cubic foot, as against an average of about 570 units for artificial gas.

UNION OIL SALES LARGE

Union Oil Company of California's sales for the first four months of 1921 were at the rate of more than $70,000,000 a year. The figures show an increase of about $2,250,000 over the corresponding period of 1920.

The company's California production was given a fresh impetus last week by the bringing in of three new wells on the Chapman lease in Orange county with a total initial daily production of 5800 barrels. The wells are known as Chapman Nos. 2, 5 and 6.

This new production is of about 22 degrees in gravity and very rich in gasoline. In fact, the percentage of gasoline content is the highest of any new oil the Union has struck recently.

The Union also continues to prosecute development work vigorously in Wyoming. It was one of the first companies to enter the new territory on the Montana-Wyoming line just west of the South Dakota boundary. Reports from that State say the Union is moving five rigs for tests on this new prospect.

PEAK NOT REACHED IN OIL

"It is evident that the production of crude oil in California has not yet reached its highest peak," says the Independent Oil Producers' Agency in a statement accompanying its April production statistics now in the mails, "since each succeeding month records another increase in production.

"The future is exceedingly bright to consumers of oil, with the possibility of additional production.

"It must be remembered, however, that each increase in production does not necessarily affect the gasoline production of the State, since all crudes of oil vary as to the refining [illegible] content. If [illegible] is brought to the surface it will tend to increase the ground storage inasmuch as the demand which will prevail during July, August and September will be for refining crude to meet the needs of gasoline consumers.

"There is no doubt that the situation in the midcontinent fields affects the local situation in so far as price is concerned.

"Consumers of petroleum have been concerned to some extent as to the future of the industry. The petroleum industry has always met the demands made upon it. With a general readjustment of economic conditions taking place there should be no concern as to the future."

The agency places the increase in oil in storage in California during April at 1,013,281 barrels, or about 180,000 barrels less than the Standard's figures.

TREASURY NOTE ALLOTMENT

Subscriptions amounting to $16,500,000 were received in the Twelfth Federal Reserve district to the last issue of Treasury certificates of indebtedness, known as Series A 1922, and running from May 16, 1921, to February 16, 1922, at 5½ per cent interest, according to a telegram received yesterday from the Treasury Department by Governor John U. Calkins of the Federal Reserve Bank of San Francisco. The Treasury allotted, however, only $14,840,000 of the certificates to the Twelfth district.

Subscriptions throughout the United States totalled $522,100,000, more than twice the amount of $250,000,000 or thereabouts offered. Ten of the Federal Reserve districts oversubscribed their quotas. The total amount allotted was $248,170,000.

AMERICAN POWER OFFERING

[illegible] & Co., [illegible] Savings Bank and W. [illegible] & Co. are offering $4,500,000 American Power and Light Company twenty-year 6 per cent secured gold bonds, due May 1, 1941, at 95½ per cent and interest to yield 6.15 per cent. These bonds are secured by $7,000,000 general mortgage 6 per cent bonds of subsidiary companies, due May 1, 1941. Actual net income for the year ended March 31, 1921, was 2.17 times annual interest charges on total funded debt, including this issue.

604 RIGS DRILLING

Of the 174 rigs erected during April, says the Independent Producers' Agency, about thirty were in the vicinity of Devil's Den, where shallow production is being sought. The number of wells engaged in drilling, 604, registers an increase of seventy-one strings. The forty-eight wells completed with an initial daily output of approximately 15,000 barrels, brought the active producing wells to 8766. Ten wells were abandoned during the month.

SECURITY BANK AND TRUST NOW

The Security Savings Bank, which not long ago celebrated its golden anniversary, will henceforth be known as the Security Bank and Trust Company. The bank has just received a charter from the State Banking Department authorizing it to transact business under this name.

HUTCHINSON DIVIDEND CUT

Directors of the Hutchinson Sugar Plantation Company at their meeting here yesterday reduced the monthly dividend rate from 20 cents a share to 10 cents. The June dividend is payable June 6 to stock of record on May 26.

FINANCIAL PERSONALS

Henry C. Abrahams, field economist for the Richard D. Wyckoff Analytical Service, was a visitor in the financial district yesterday.

DIVIDENDS DECLARED

Texas Company—A regular quarterly dividend of 3 per cent, payable June 30 to stock of record on June 17.

Procter & Gamble—Regular quarterly dividend on the 8 per cent preferred stock, payable June 15 to stock of record on May 25.

American Locomotive Company—Regular quarterly dividend of 1½ per cent on the common and 1¾ per cent on the preferred stocks, both payable June 30 to stock of record on June 13.

Middle States Oil and Industrial Alcohol also declared the regular dividends. Hocking Valley R. R. deferred its dividend.

UNION OIL RUMOR DENIED

An official of the Union Oil Company of Delaware denied that negotiations looking to a merger of that company with another oil-producing corporation were pending, as reported in Wall street, says the New York Tribune. The report said the executive committees of both corporations had approved the merger and that the committees were working out plans of consolidation.

FINANCIAL NOTES

Price of Pennsylvania crude oil was cut from $3.50 to $3.25 a barrel in Pittsburgh yesterday.

New York Stock Exchange will close May 28 and 30.

Grass Valley has voted a $140,000 high school bond issue.

National Bank of Belgium reduced its discount rate from 5½ per cent to 5 per cent.

[illegible] of contracts and orders caused the business depression, says Comptroller of Currency Crissinger.

Steel trade reports see practically no change in industry over the past week and predict little, if any, improvement during the summer months.

President Starbuck of the New York Air Brake Company says that it has been decided to reduce the dividend rate from a 10 to a 5 per cent per annum basis.

Cities Service Company earnings in the twelve months ended April 30, after charges and preferred dividends, were $14,848,816. Gross totaled $23,[illegible].

George G. Palmer, president of the U. S. Food Products Corporation, told the stockholders at the annual meeting yesterday that earnings have improved since the first of the year and that future prospects were bright. He said that the Liberty Yeast Company, a subsidiary which last year lost about $200,000, was now operating at a profit. The company has 40,000 barrels of whisky in foreign countries, which is being withdrawn under permit from the Government to be sold here for medicinal use.

H. F. Sinclair resigned as president of the Sinclair Consolidated Oil Company yesterday and was elected chairman of the board. His brother, E. W. Sinclair, was chosen president.

Artificial Penetration Map ID #	Operator	Lease and W	e g Surface Casing Depth (feet)	Protection Casing Size (inch)	Protection Casing Depth (feet)	Protection Casing Cutoff (feet)	Hole Size (inch)
1	DD Feldman O&G	Nat Gas Corp R	514	--	--	--	9 7/8
2	MCOR (UMC Petr Corp.)	1-7 Grandpa	1,050	--	--	--	8 3/4
3	Pacific Gas & Electric	Birds Land	1,949	10 8 1/4	2,933 4,325	0 2,922	9 7/8 7 7/8

ATTACHMENT D MAPS AND CROSS SECTIONS OF USDWS

The project area lies within the Montezuma Hills in southern Solano County (Figure B-1, in Attachment B). The Montezuma Hills form a 10-mile-wide area of low rolling hills. The hills are bordered by steep bluffs except to the north, where they merge with the alluvial plain (Olmstead and Davis, 1961). The hills are bordered to the south by the Sacramento and San Joaquin Rivers.

The Montezuma Hills lie along the southwestern border of the Sacramento Valley and along the eastern margin of the California Coast Range (Figure D-1). The proposed project area is underlain by the Quaternary Montezuma formation (Olmstead and Davis, 1961; Division of Mines Geology, 1981), which outcrops in the Montezuma Hills (Figure D-1). The area is underlain by the Quaternary-, Tertiary-, and Mesozoic-aged strata that have undergone regional folding and faulting typical of the California Coast Range (Olmstead and Davis, 1961).

D.1 REGIONAL WATER SUPPLY

The Montezuma Hills are a sparsely populated area in rural southern Solano County. Most of the water supply for the municipal and agricultural users in Solano County is provided by the Solano County Water Agency, through the Solano Project. The extent of the Solano County Water Agency service area is shown on Figure D-2. The Solano Project provides surface water from Lake Berryessa through a system of canals and diversions to the following cities and facilities:

- City of Fairfield
- City of Suisun City
- City of Vacaville
- City of Vallejo
- Solano Irrigation District
- Maine Prairie Water District
- University of California at Davis

- California State Prison – Solano

The City of Vacaville, about 25 miles northwest of the Permit Area, gets approximately two-thirds of its municipal water supply from the Sonoma County Water Agency and the rest from groundwater located under the city.

The Cities of Rio Vista and Dixon obtain their water supply exclusively from groundwater (Figure D-2). The City of Rio Vista is the closest municipal water supply system and is located approximately eight miles northeast of the Permit Area (Figure D-2). Rio Vista relies solely on groundwater for its water supply. The City of Rio Vista currently uses six wells ranging from 500 to 1,000 feet in depth, producing approximately 1,800 acre feet per year of groundwater to meet the city's water needs (SCWA, 2005b). The city's Well #9 was constructed along the northeast margin of the Montezuma Hills, with screened intervals between 230 and 780 feet below ground surface (SCWA, 2005a). The City of Dixon is located about 25 miles north of the Permit Area.

Most agricultural growers in Solano County use surface water supplied by the Solano Irrigation District (SID), but SID also has its own groundwater wells to supplement its surface water supply from the Solano Project. These wells are located outside of the Montezuma Hills. Maine Prairie Water District and Reclamation District No. 2068 provide surface water to their growers and do not currently use groundwater underlying their districts. Growers outside of irrigation districts that provide surface water rely entirely on groundwater unless they have an individual right to a surface water supply.

Many rural residential landowners have individual shallow groundwater wells that serve their domestic needs. Some small rural residential water systems also distribute groundwater to their customers in Solano County, but no rural systems are known to be located in the Montezuma Hills area.

D.2 GROUNDWATER BASINS

The project area lies within the Central Valley Hydrogeologic Province. The largest groundwater basin in Solano County is the Solano Subbasin (a subbasin of the Sacramento Valley Groundwater Basin), which underlies northeastern Solano County. This groundwater basin extends from the foothills above Vacaville southward to the Sacramento River. The western subbasin border is defined by the hydrologic divide roughly delineated by the English Hills and the Montezuma Hills. Figure D-3 shows a cross-sectional view of the formations within the basin.

The primary water-bearing formations comprising the Solano Subbasin are of late Tertiary to Quaternary age. Fresh water-bearing units include younger alluvium, older alluvium, and the Tehama formation (Thomasson et al., 1960). These units pinch out and are absent near the Coast Range on the west and thicken to a section of nearly 3,000 feet near the basins eastern margin. The Tehama formation is the major-water bearing unit in the Solano Groundwater Subbasin. More saline water-bearing sedimentary units underlie the Tehama formation; therefore, the base of the Tehama formation is generally considered to be the saline water boundary (Thomasson et al., 1960).

There are two primary production levels to the groundwater basin. The shallower aquifer provides agricultural water and local domestic supplies. The shallower aquifer is underlain by the Tehama formation aquifer. This aquifer is quite deep (over 1,000 feet) under Vacaville, but surfaces in the English Hills area north and west of Vacaville. Vacaville's wells draw from the Tehama formation for their groundwater supply.

The Suisun-Fairfield Basin is the second largest groundwater basin in Solano County. The Suisun-Fairfield Groundwater Basin lies to the west and northwest of the Montezuma Hills and underlies the Cities of Fairfield and Suisun City. The unit is composed of unconsolidated and partially consolidated sediments; up to 1,500 feet thick near Suisun Bay and the Sacramento Delta (Dawson et al., 2008). This basin is not significantly used for groundwater supply due to low yields and poor water quality (SCWA 2005b).

Groundwater in the Solano Subbasin flows generally eastward away from the Montezuma Hills and towards the Sacramento River. In the Suisun-Fairfield Basin, groundwater flows generally southward towards the wetlands surrounding Suisun Bay (Thomasson et al., 1960). Groundwater fluxes between aquifers have not been defined in the literature, and exchanges of groundwater from the aquifer with the Sacramento River, Delta, and Suisun Bay have not been published.

The Permit Area generally lies along the hydrologic divide that forms the boundary between the Solano Subbasin and the Suisun-Fairfield Valley Basin. The Montezuma Hills are underlain by Quaternary-aged alluvial deposits of the Montezuma and Tehama formations. However, the older alluvial sediments that underlie the Montezuma Hills are not as productive as the adjacent groundwater subbasins that are composed on younger alluvial sediments. The Montezuma Hills are not considered part of Solano County’s primary groundwater resources.

D.3 ESTIMATION OF THE BASE OF USDW

Geologic units below the Tehama are composed of marine sediments that typically contain brackish to saline waters (Thomasson et al., 1960). Therefore, the California Department of Water Resources generally considers the saline water-bearing sedimentary units that underlie the Tehama formation to be the base of the fresh-water-bearing sediments and are not considered as part of the groundwater aquifer by the California Department of Water Resources (DWR, 2006).

The base of the fresh water-bearing unit was defined at 2,700 feet below sea level in the Putah area adjacent to the Montezuma Hills (Olmstead and Davis, 1961), based on geophysical log evaluations from natural gas wells in the area. Based on the natural gas well geophysical logs, the inferred base of the Tehama formation appears to occur at an elevation of about 2,300 feet below sea level. As shown on Figure D-3, the base of the fresh water is essentially at the base or just below the base of the Tehama formation, at 2,000 to 3,000 feet below sea level (Olmstead and Davis, 1961). These well-to-well correlations show that the base of the freshwater-bearing sediments appear to be consistent across the area.

Figure D-3 provides a regional cross section of the Sacramento Valley showing the relative depth of the base of the fresh water-bearing unit. The upper contact of this unit generally coincides with the fresh/saline water boundary at depths as shallow as a few hundred feet near the Coast Range on the west to nearly 3,000 feet near the axis of the basin (Berkstresser et al., 1973).

Figure D-4 provides a cross section (Krug et al., 1992) showing the stratigraphic relationship between the base of the fresh water-bearing unit and deeper formations that contain natural gas fields. The undifferentiated Neogene section shown on Figure D-4 includes both the Montezuma and Tehama formations and represents the groundwater aquifer. Underlying the Tehama formation are geologic units of volcanic and marine sedimentary origin containing brackish to saline water that typically has low permeabilities relative to the Tehama formation. These units include sedimentary rocks of volcanic origin (Pliocene to Oligocene age) and marine sedimentary rocks (Oligocene to Cretaceous age). Further information about the geologic units is presented in Attachment E.

The deeper units below the base of the fresh water-bearing unit in the vicinity of the Montezuma Hills have low permeabilities and contain higher salinity groundwater and/or natural gas (Olmstead and Davis, 1961). For example, the Markley formation (Figure D-4), composed of brown sandstone and light gray shale, has groundwater with sodium chloride concentrations of approximately 5,000 parts per million (Krug et al., 1992 and EDAW, 2006).

The base of the lowermost underground source of drinking water (USDW), as defined in 40 CFR §144.3 (water with less than 10,000 milligrams per liter (mg/l) total dissolved solids (TDS)), in the area surrounding the Permit Area was evaluated by calculating apparent formation water salinities (based on estimated formation water temperature and measured formation log porosity and resistivity) as a function of depth for local oil and gas wells. Fundamentally, electrical conduction in sedimentary rocks almost always results from the transport of ions in the pore-filled formation water (Schlumberger, 1988). High-porosity sediments with open, well-connected pores show low resistivities, and low-porosity sediments, with sinuous and constricted pore systems, show high resistivities. It has been established that the resistivity of a clean, water-bearing formation is proportional to the resistivity of the saline formation water (Schlumberger, 1988). Over the years, several slightly differing equations have been proposed that solve the relationship between formation resistivity factor and porosity, such as the Archie Equation (consolidated formations), the Humble Equation (unconsolidated formations), and the Shell Equation (low-porosity carbonates), among others.

The base of underground sources of drinking water have not been precisely defined in the project area, so formation water testing in each of the major potential injection interval sandstones is critical. A full logging suite has been designed specifically to define water quality in the subsurface and characterize the extent of underground sources of drinking water. Open-hole sampling, to recover high-quality formation fluid samples from each of the proposed injection interval sandstones, is included in the program and will help “calibrate” open-hole log calculations to define water quality in the other sands. A detailed laboratory analytical program is also designed for the recovered formation fluid samples, to fully characterize physical and chemical makeup of formation waters.

Formation fluid properties from the hydrocarbon productive intervals in the Rio Vista field are included in Johnson (1990), providing regional water quality information. These data are shown in Figure D-5. The figure shows the salinity ranges for the productive sands, where available. Note that the salinities for formations below the Domengine generally exceed 10,000 parts per million NaCl, and upper-end salinities in the Domengine approach 10,000 parts per million NaCl. As the correlative injection interval sandstones occur at much shallower depths in the Rio Vista field than are anticipated beneath the Permit Area, formation waters at the project location are expected to be more saline.

To provide more site-specific water quality data estimates near the Permit Area, log-based salinity calculations were performed on well logs surrounding the syncline. Figure D-6 shows an example using the open-hole well logs for the Enron Mayhood 32-1D well, approximately three miles northeast of the Permit Area. Sodium chloride (NaCl) content (in parts per million) for the encountered formations as a function of depth was estimated using the Archie Equation, the Humble Equation, and the Modified Archie Equation. Note that the Archie Equation predicts lower sodium chloride content than either the Humble or Modified Archie equations. The well logs show sodium chloride content increasing with depth through the base of the Markley formation. Note the abrupt, apparent freshening of formation waters within the Domengine sandstone. The apparent fresher formation water in the Domengine is consistent with reported water quality from the Rio Vista field (Johnson, 1990). Apparent sodium chloride content in the Hamilton sandstone straddles the lowermost underground source of drinking water limit, while apparent sodium chloride content in the Anderson sandstone exceeds 10,000 parts per million NaCl. A similar pattern of water quality as a function of depth, seen in the Enron Mayhood 32-1D well, is also observed in the other wells surrounding the syncline. The salinity ranges in each sand from the area wells is shown with the open boxes on Figure D-6. These data may place the lowermost underground source of drinking water as deep as the mid-Hamilton sandstone beneath the Permit Area.

References

Archie, G. E., 1942, The electrical resistivity log as an aid in determining some reservoir characteristics, Petroleum Transactions of the AIME, v. 146, p. 54-62.

Berkstresser, C.F., Jr., 1973, Base of fresh ground-water -- approximately 3,000 micromhos - - in the Sacramento Valley and Sacramento-San Joaquin Delta, California: U.S. Geological Survey Water-Resources Investigations 40-73, 1 map.

Dawson, B.J., Bennett V, G.L., and Belitz, K., 2008, Ground-Water Quality Data in the Southern Sacramento Valley, California, 2005—Results from the California GAMA Program: U.S. Geological Survey Data Series 285, 93 p. Available at http://pubs.usgs.gov/ds285

Department of Water Resources (DWR), 2006, California's Groundwater. Bulletin 118, Sacramento Valley Groundwater Basin, Solano Subbasin. Last update 2/27/04. State of California, the Resources Agency, Department of Water Resources.

EDAW, 2006, Solano County General Plan Update, August 28, 2006, http://solanocountygeneralplan.net/documents. htm#2008DEIR

Johnson, D.S., 1990, Rio Vista Gas Field – U.S.A. Sacramento Basin, California, in Foster, N.H., and Beaumont, C.A., Eds., Atlas of Oil and Gas Fields, Structural Traps III, AAPG Treatise of Petroleum Geology, Atlas of Oil and Gas Fields, Tulsa Oklahoma, p. 243-263.

Krug, E.H., Cherven, V.B., Hatten, C.W., and Roth, J.C., 1992, Subsurface structure in the Montezuma Hills, Southwestern Sacramento Basin: in Cherven, V.B. and Edmondson, W.F., Eds., Structural Geology of the Sacramento Basin, The Pacific Section AAPG, Bakersfield, California, p. 41-60.

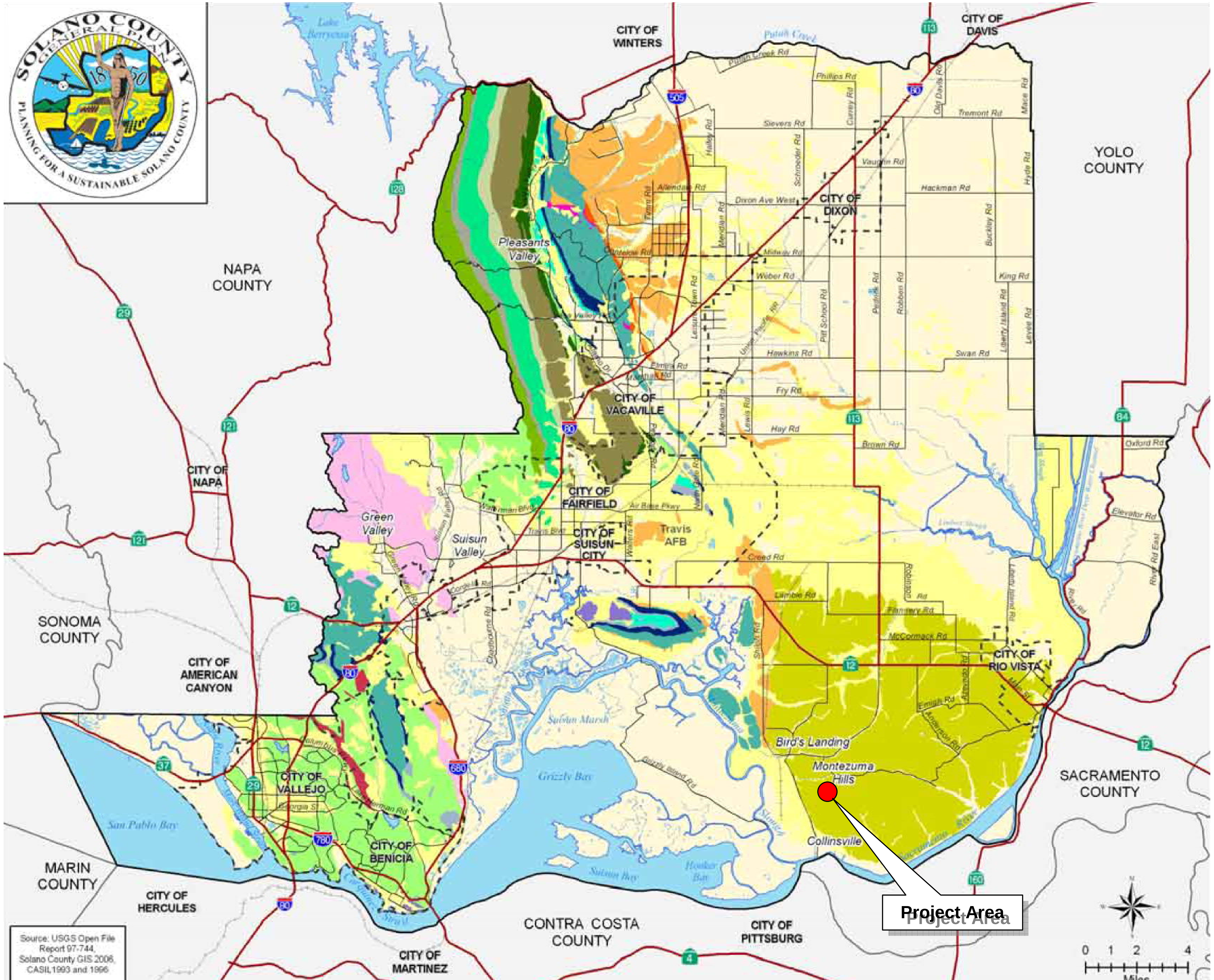
Olmsted, F.H., and Davis, G.H., 1961, Geologic features and ground-water storage capacity of the Sacramento Valley, California: U.S. Geological Survey Water-Supply Paper 1497, 241 p.

Schlumberger, 1988, Archie's Law: Electrical conduction in clean, water-bearing rock: The Technical Review, v. 36, n. 3, Schlumberger Educational Services, Houston, Texas, p. 4-13.

Solano County Water Agency (SCWA), 2005a, Integrated Regional Water Management and Strategic Plan, February, http://www.scwa2.com/UWMP_IRWMP.aspx.

Solano County Water Agency (SCWA), 2005b, Urban Water Management Plan, Approved by SCWA Board of Directors October 13, 2005.

Thomasson, H.G., Jr., Olmsted F.H., and LeRoux E.F., 1960, Geology, water resources and usable ground-water storage capacity of part of Solano County, California: U.S. Geological Survey Water-Supply Paper 1464, 693 p.



Source: Solano County General Plan EIR (EDAW, 2006), Exhibit 4.7-1, Geologic Subunits

Legend

Quaternary
- Holocene Alluvium
- Pleistocene Alluvium
- Montezuma Formation

Upper Tertiary
- Tehama Formation
- Neroly Sandstone
- Putnam Peak Basalt
- Sonoma Volcanics

Lower Tertiary
- Capay Formation
- Markley Formation
- Nortonville Shale
- Domingene Sandstone
- Vacaville Shale
- Martinez Formation

Mesozoic
- Forbes Formation
- Guinda Formation
- Funks Formation
- Sites Formation
- Yolo Formation
- Venado Formation
- Undivided
- Franciscan Complex

Great Valley Sequence

Basemap Layers
- Roadways
- Highways
- Railroads
- Streams and Creeks
- Major Water Features
- Municipal Service Areas
- Adjacent Counties

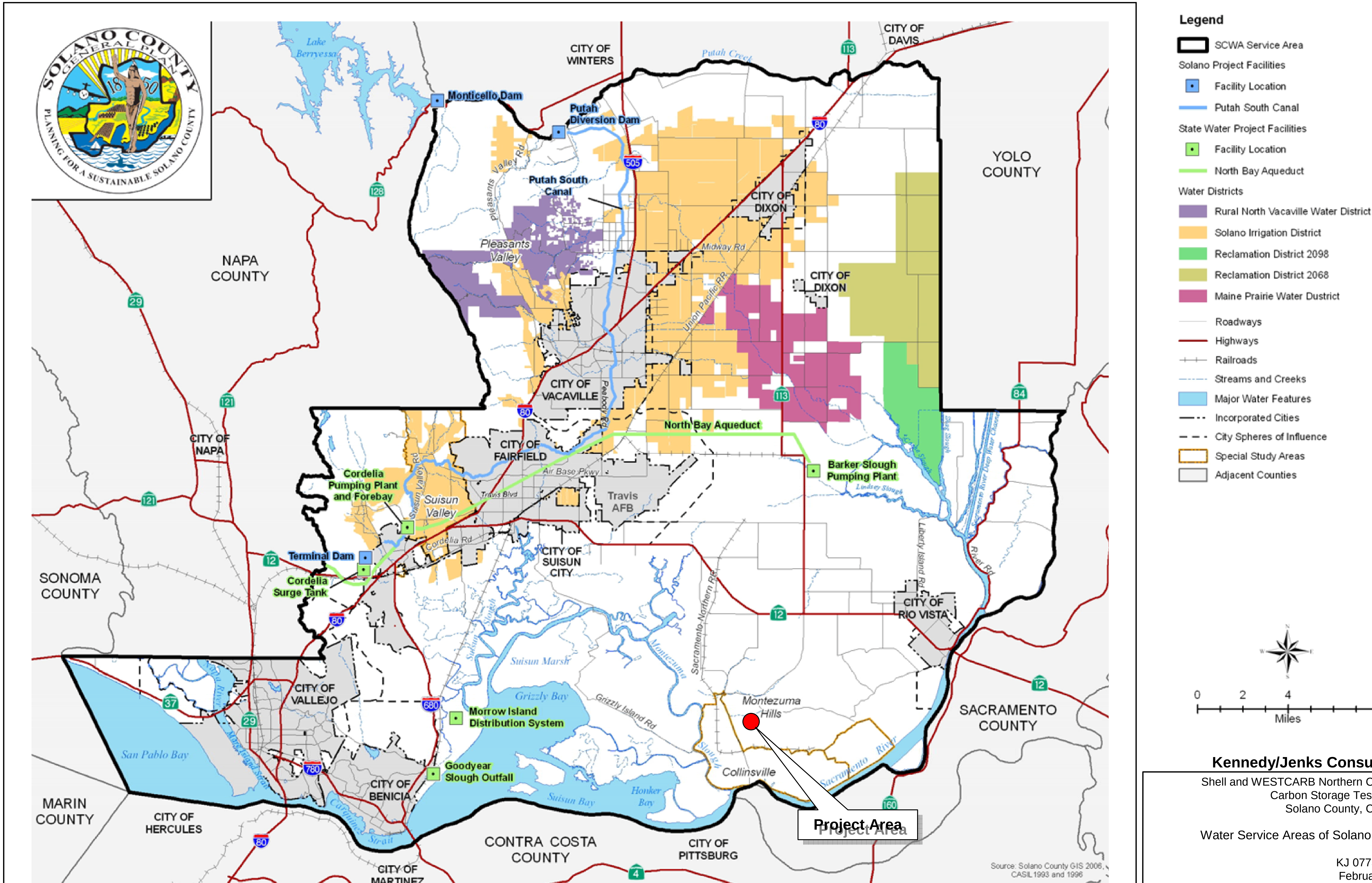
Kennedy/Jenks Consultants

Shell and WESTCARB Northern California
Carbon Storage Test Project
Solano County, California

Geologic Map of Solano County

KJ 0773013.00
February 2009

Figure D-1



Source: Solano County General Plan (EDAW, 2006), Figure 10-1, Water Service Areas and Facilities

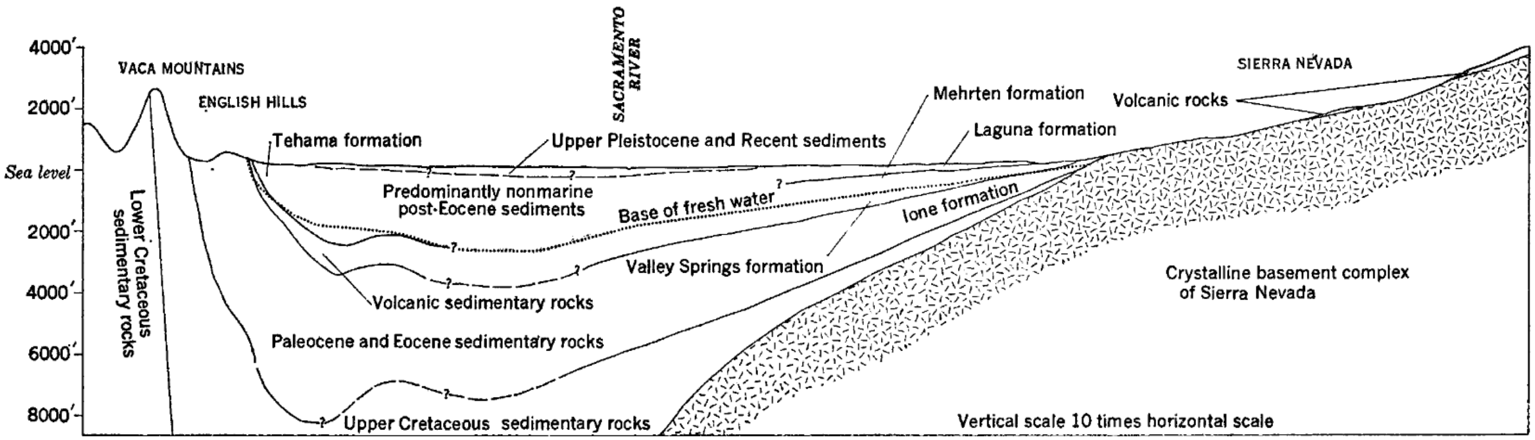
Kennedy/Jenks Consultants

Shell and WESTCARB Northern California
Carbon Storage Test Project
Solano County, California

Water Service Areas of Solano County

KJ 0773013.00
February 2009

Figure D-2



Kennedy/Jenks Consultants

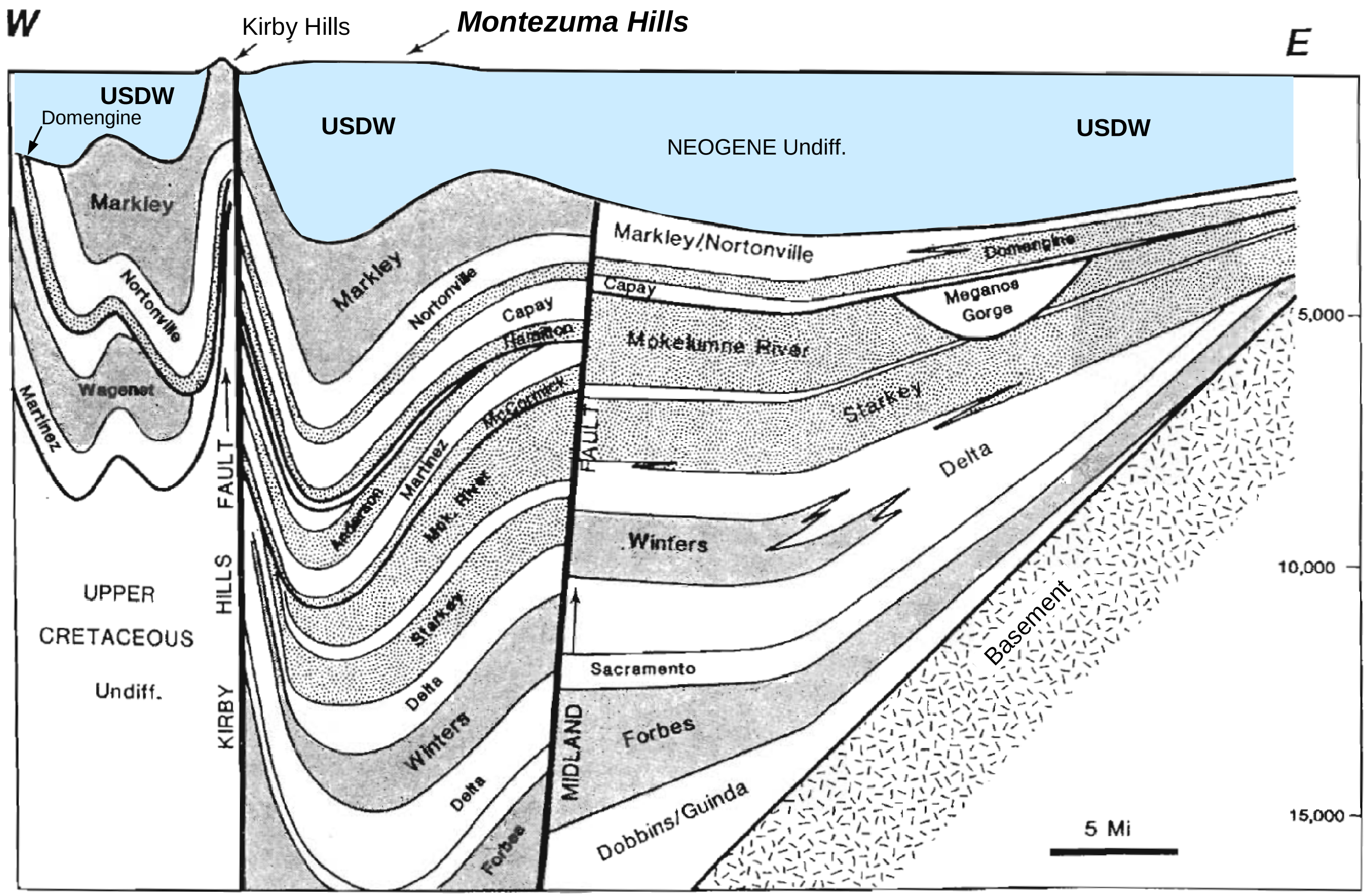
Shell and WESTCARB Northern Caifornia
Carbon Storage Test Project
Solano County, California

Central Valley Hydrogeological Cross Section

KJ 0773013.00
February 2009

Figure D-3

Source: Olmstead and Davis (1961)



Underground Source of Drinking Water (USDW)

Source: Adapted from Krug, *et al* (1992)

Kennedy/Jenks Consultants

Shell and WESTCARB Northern Caifornia
Carbon Storage Test Project
Solano County, California

Montezuma Hills Cross Section Showing Underground Source of Drinking Water (USDW)

KJ 0773013.00, February 2009

Figure D-4

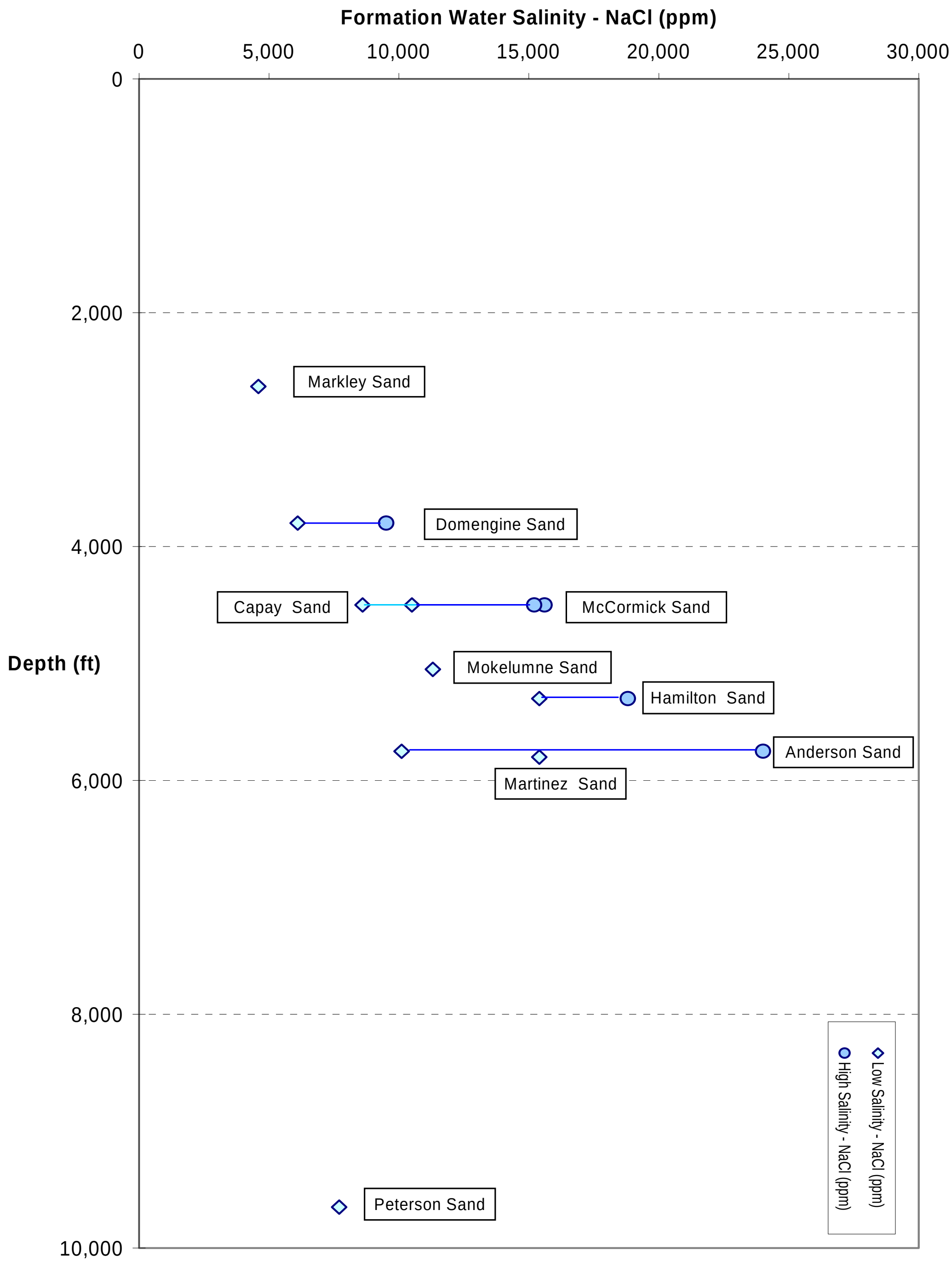


Figure D-5 Produced Water Salinity (NaCl (ppm)) in Rio Vista Field (data from Johnson, 1990)

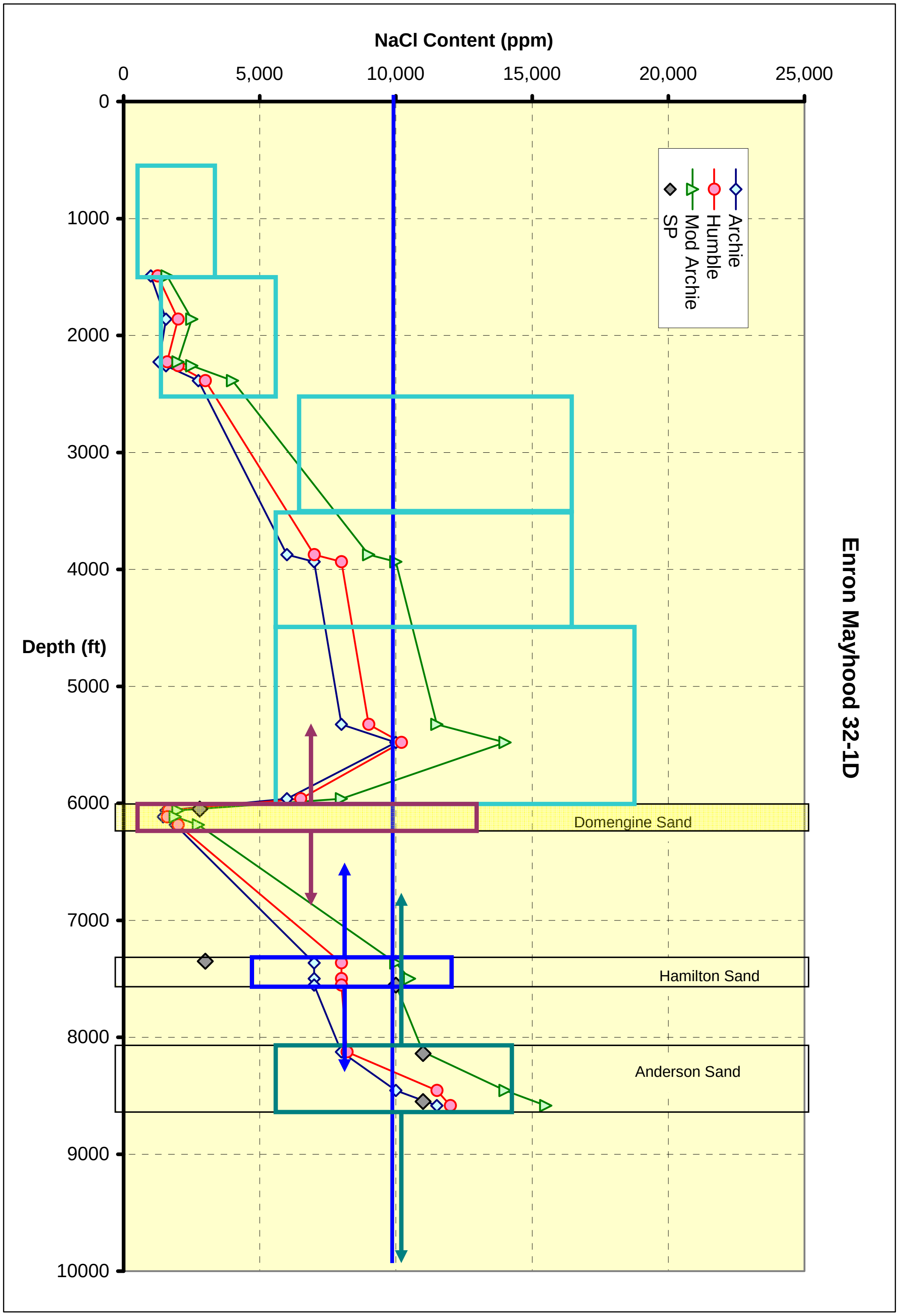


Figure D-6 Log Calculated Apparent Water Quality with Depth (Note boxes show high-low salinity range and arrows show depth ranges in local data)

ATTACHMENT E NAME AND DEPTH OF USDWS

E.1 GEOLOGIC UNITS SUMMARY

The primary water-bearing units in Solano County include the following:

- Younger Alluvium
- Montezuma formation (earlier mapped as older alluvium)
- Tehama formation
- Volcanic Sedimentary Rocks
- Eocene and Paleocene Rocks
- Upper Cretaceous formations

The Younger Alluvium consists of loose grayish-brown silt and fine-grained sand; some silty clay, medium- to coarse-grained sand, and gravel (Olmstead and Davis, 1961). These deposits have moderate permeability, but are largely above the water table in Solano County. This unit occurs as a water-bearing unit primarily east of Dixon.

E.2 GROUNDWATER AQUIFER DESCRIPTIONS

The "Older" Alluvium consists of Pleistocene-aged deposits that include the Montezuma formation (Olmstead and Davis, 1961). These consist of stream-laid silt, silty clay, gravel, and sand. The Montezuma formation is similar in character to the Tehama formation, and often mapped as such (Olmstead and Davis, 1961). Thickness throughout most of Solano County ranges from 60 to 130 feet. Permeability of the units is extremely variable and ranges from about 3,000-4,500 gallons per day per square foot (gpd/ft^2) for gravel-and-sand aquifers to less than 1 gpd/ft^2 for some of the interbedded silts and clay layers. Water is typically of the calcium magnesium bicarbonate type and is of excellent quality for irrigation but is often too hard to be desirable for domestic use.

The Tehama formation is the major water-bearing unit in the Solano Groundwater Subbasin. The unit ranges between 1,500 and 2,500 feet in thickness (Olmstead and Davis, 1961) and is composed of silt, clay, silty sands, and conglomerate, with varying permeability (Graymer, Jones and Brabb, 2002). The water quality is similar to that found in the older alluvium; however, waters in wells more than 1,000 feet deep contain significant concentrations of sodium, which is somewhat high for continued irrigation use (DWR, 2006; SCWA, 2005).

E.3 DEEPER FORMATION DESCRIPTIONS

Strata beneath the Tehama formation include the volcanic sedimentary rocks of Oligocene to Pliocene age. These units include sandstone, siltstones, and shales that include a high percentage of sediments derived from volcanic rocks. These units include the Mehrten formation, Neroly formation, Kirker tuff, and Sonoma volcanics in the lower part of the Wolfskill formation (Olmstead and Davis, 1961), consisting of fluvial, lacustrine, and shallow-water marine sedimentary rocks, including white, gray, blue, pink, and purple siltstone, sandstone, shale, and conglomerate. This unit's thickness ranges from 0 feet to over 400 feet in Solano County. The permeability of most of these units is very low. Electric logs of gas and gas-test wells indicate that the water contained in these volcanic sedimentary rocks is too saline for irrigation or domestic use. The volcanic sedimentary rocks are below the Tehama formation and are considered to be below the base of the fresh water-bearing unit.

Eocene-Paleocene marine sedimentary formations underlie the volcanic sedimentary rocks (DWR, 2006). These formations consist of sandstone siltstone, shale, and some conglomerate, all of marine and lagoonal origin (Olmstead and Davis, 1961). The individual geologic units within the Eocene-Paleocene marine sedimentary formations include the Markley sandstone member and Nortonville shale member of the Kreyenbagen formation, Domengine formation, Capay shale, Hamilton formation, Anderson formation, Meganos formation, and possibly the Martinez formation (Paleocene). These units are of low permeability and contain higher salinity groundwater and/or natural gas. Additional information on these formations is provided in Attachment G. Below is a brief description of the general geologic characteristics for these units.

- The Markley formation is composed of sandstone and shale.
- The Nortonville Shale is approximately 430 feet thick and acts as a confining layer for the nearby Rio Vista Gas Field.
- The Domengine sandstone contains interbedded sandstones and shales and is the main natural gas reservoir for the Rio Vista Field.

- The marine Ione-Capay Shale is approximately 900 feet thick and acts as a confining layer.
- The Hamilton Sandstone is a light gray, fine grained sandstone in the Rio Vista Field.
- The Meganos Shale is 900 feet thick and acts as another confining zone.
- The Anderson formation is composed of sandstone, siltstone, and shale. The sandstone forms a reservoir; whereas, the siltstone and shale act as a confining zone.
- The Martinez formation consists of sandstone and siltstones that form both reservoirs and confining layers.

The anticipated depth range for Eocene-Paleocene marine sedimentary formations is approximately 8,000 to 14,430 feet. The Eocene-Paleocene marine sedimentary formations are separated from the Tehama formation by multiple confining layers and permeable buffer units.

Upper Cretaceous-aged strata underlie the Eocene-Paleocene marine sedimentary formations. The individual geologic units within the Upper Cretaceous include the Venado, Yolo, Sites, Funks, Guinda, and Forbes formations. These units have very low permeabilities and contain either high salinity groundwater or natural gas (Olmstead and Davis, 1961). These units are below the potential target injection interval for the CO_2 Pilot.

References

Olmstead, F.H., and Davis, G.H., 1961, Geologic features and ground-water storage capacity of the Sacramento Valley, California: U.S. Geological Survey Water-Supply Paper 1497, 241 p.

Department of Water Resources (DWR). 2006, California's Groundwater. Bulletin 118. Sacramento Valley Groundwater Basin, Solano Subbasin. Last update 2/27/04. State of California, the Resources Agency, Department of Water Resources.

Graymer, R.W., D.L. Jones, and E.E. Brabb, 2002, Geologic Map and Map Database of Northeastern San Francisco Bay Region, California - Most of Solano County and Parts of Napa, Marin, Contra Costa, San Joaquin, Sacramento, Yolo, and Sonoma Counties, U.S. Geological Survey Miscellaneous Field Studies Map MF-2403.

Solano County Water Agency (SCWA), 2005, Urban Water Management Plan, Approved by SCWA Board of Directors October 13, 2005.

ATTACHMENT F MAPS AND CROSS SECTIONS OF GEOLOGICAL STRUCTURE OF AREA

F.1 REGIONAL GEOLOGY

The California Geological Survey defines eleven geomorphic provinces in California based on a common geologic record, landscape, or landform (Figure F-1; CGS, 2002). Each province represents a unique area of the state with distinct geology, structure (i.e., faulting), topographic relief, and climate. The pilot site at Montezuma Hills is located in the Great Valley Geomorphic Province, a structural trough or basin filled with up to 40,000 feet of Jurassic- to Holocene-aged marine and nonmarine clastic sediments. The Great Valley province is situated between the Sierra Nevada volcano-plutonic arc province to the east and the Franciscan subduction complex province to the west. Tectonically, the Sierra Nevada, Great Valley, and Franciscan provinces represent a late Mesozoic- to Cenozoic-aged Andean-type arc-trench system produced from the convergence and subduction of the Pacific plate under North America.

Marine and deltaic sediments were deposited along the western convergent margin of the Cordilleran Mountains, which underwent rapid uplift and erosion during the Late Jurassic- to Late Cretaceous-aged Cordilleran Orogeny. Thick marine sediments continued to accumulate along the Farallon-North American Plate boundary during the early Cenozoic era before the California Coastal Range began its rapid uplift during the middle Cenozoic. Cenozoic evolution of the Coastal Range, characterized by intense faulting and alternating periods of uplift and subsidence, created the western boundary of the Central Valley structural trough. Corresponding uplift and subsidence of the Central Valley resulted in the deposition of alternating layers of undifferentiated nonmarine and marine sediments, respectively, across the basin (Dott and Batten, 1976).

F.1.1 Stratigraphy

The Sacramento Basin (Figure F-2) of the Pacific Coast Region (USGS, 1995) is a gas-producing province with 73 gas fields located throughout the province and two small oil fields (Brentwood and West Brentwood) in the southern part of the basin. Figure F-3 presents a cross-section of the basin, and Figure F-4 presents a stratigraphic column for the area of interest. A geologic map for the San Francisco Bay region is presented as Figure F-5.

The Domengine formation, which is a late Eocene-aged sandstone, provides most of the gas production in the southern Sacramento Basin; however, other reservoir rocks include sandstones in the Winters formation, Starkey sands, Mokelumne River formation, Martinez formation, Capay formation, Nortonville shale, Markley formation, Lathrop sands, Tracy sands, Blewett sands, Azevedo sands, and Garzas sands (Figure F-3). Most of these sandstones are of marine origin, ranging in thickness from 4 to 550 feet and having porosities and permeabilities ranging from 10 to 34 percent and 5 to 2,406 millidarcies (mD). Organics in the Winters shale or Sacramento shale are suspected of being the source of hydrocarbons for the Winters-Domengine natural gas system (Magoon and Valin, 1995).

Alternating sandstone and shale units characterize the stratigraphic section of the Sacramento Valley. The Nortonville shale marks the last (stratigraphically shallowest) major marine shale. The Capay shale, which lies below the Domengine and above the Hamilton formation, occupies a unique position marking the last major marine transgression into the valley. This shale is an excellent marker; it is widespread and is conspicuous on electric logs. The base of the shale provides the only consistent marker on which a general map of the valley can be constructed. Post-Capay movement of the valley, southward tilting, sub-basins, the trough, and the axis of the basin are readily discernable on the structure of the base of the Capay shale.

Below the Capay shale lie the older Meganos, Anderson sand/shale, and Upper Martinez to Cretaceous Martinez123, Starkey, Winters, and deeper formations. Several major unconformities and gorges also exist (i.e., Markley, Meganos, and Martinez gorges) resulting in truncation of the older zones and onlap of the younger strata located above the unconformity. Differential structural movements contributed to areas of local deposition of varied character, which makes correlation difficult in some parts of the basin. Abrupt facies changes in the Sacramento Valley are indicative of rapid environmental changes during Late Cretaceous time.

The Midland fault system had a large effect on deposition in the southern Sacramento Basin. Movement along the Midland fault resulted in thickening of strata on the downthrown (westerly) side, especially in the post-Hamilton sand section (Johnson, 1992). Removal or nondeposition of the Hamilton sand, Meganos shale, Anderson sand, Martinez shale, and the upper portions of the McCormick sand occurred east of the Midland fault, with the Capay shale laying directly on top of lower portions of the McCormick sand (see Figure F-4). The primary cause of erosion of the late Paleocene- and early Eocene-aged strata is believed to be related to eustatic sea level changes (Krug et al., 1992). A greater amount of movement along the Midland fault occurred during deposition of the Capay shale, which is more than twice as thick on the downthrown side of the fault, with the Capay shale generally thickening in the westerly direction across the fault system (Johnson, 1992). Offset of the Capay across the Midland fault is approximately 450 feet

(Johnson, 1992). Thickening of the strata to the west of the Midland fault is the norm; however, both the Anderson sand and the Meganos shale thin across the crest of the Rio Bravo field, located northeast of the project area.

After Capay time, the “sanding up” of the Sacramento Valley continued, interrupted only by the restricted Eocene Nortonville-Markley marine transgression. The Domengine sandstone, originating primarily from the east but partly from the south and southwest, was deposited over almost the entire restricted basin, thinning and pinching out (absent) only in the vicinity of Winters, California. Like the Meganos, the Domengine sandstone becomes more continental in character and contains more numerous plant remains eastward in the basin. On their extreme eastern side and southward, they commingle and become one body with the Nortonville sandstone. The Nortonville-Markley becomes increasingly difficult to identify on electric logs, as correlations are made basinward. The Markley sandstone is of almost continental character eastward, but thickens markedly and becomes increasingly marine in character westward into the Rio Vista basin beneath the Montezuma Hills. Its marked increase in thickness towards the deepest part of this basin is a measure of the magnitude of the differential movements of that time.

Figure F-6 shows the location of two cross sections superimposed on the Domengine formation Top Structure map. Figures F-7 and F-8 present structural/stratigraphic cross sections across the Montezuma Hills area. Figure F-7 presents an east-west section across the syncline. The Permit Area is located between the two westerly wells (i.e., between the McDougal 2-8 and the Grandpa Peter 1-7 wells). Figure F-8 presents a north-south structural/stratigraphic cross section that runs along the eastern margin of the Montezuma Hills area. The Permit Area would project into the Grandpa Peter 1-7 well location. These sections show the continuity of the sandstone formations through the pilot area and, more importantly, the continuity and thickness of the confining marine shales that will contain the CO_2.

F.1.2 Structure

The Montezuma Hills are underlain by an asymmetric structural syncline that plunges in a southerly direction. This syncline has been termed the “Rio Vista Basin” in the literature and includes the thickest, most complete Paleogene stratigraphy in the Sacramento Basin (Krug et al., 1992). The Kirby Hills fault, to the west, and the Sherman Island fault (part of the Midland fault system), to the east, define the margins of the synclinal structure. Most of the faults in the Sherman Island fault system dip to the east, and mapped offsets range from 100 feet to over 400 feet on Paleocene strata (Krug et al., 1992). Offsets on the Kirby Hills fault system, which defines the western margin of the Rio Vista basin, are up to 1,000 feet (Krug et al., 1992). Neogene faults with strike slip and/or reverse slip components have been superimposed over the Paleogene normal faulting along the Kirby Hills fault system, with several of the Neogene-aged faults mapped at surface (MacKevett, 1992). East of the Kirby Hills fault system, strata dip steeply into the Rio Vista basin.

The Midland fault, located six miles east of the Montezuma Hills, is the closest major fault zone and is a dominant structural feature in the southern Sacramento Basin. The Midland fault does not exhibit a surface trace; rather, it is thought to be a blind, high-angle west-dipping normal growth fault with a north-northwest trend or strike (Bennett, 1987). Offsets on the Midland fault range from hundreds of feet at the northern end to several thousand feet at its southern end (Pepper and Johnson, 1992). Historically, the Midland fault trace was identified and mapped using subsurface correlation between stratigraphic units and seismic reflection data derived from wells and geophysical surveys collected during gas exploration. Krug et al. (1992) surmised that the Midland fault accommodated extension and subsidence that occurred in the late-Cretaceous to early-Tertiary Sacramento Valley forearc basin. Thickening of the strata on the downthrown side of the fault, as well as structural dip reversal, occurs towards the fault. This dip reversal (roll over) into the fault produces the domal structures that form natural gas traps along the Midland fault system (Rio Vista, Lindsey Slough, Bunker, and Dutch Slough). Normal displacement along the fault ended by the Eocene epoch (Arleth, 1968; Krug et al., 1992); however, minor normal displacement may have occurred in late Miocene time (Weber-Band, 1998). Weber-Band (1998) inferred, from seismic reflection data, that post-Miocene reactivation of the Midland fault occurred to accommodate reverse slip caused by horizontal shortening of the crust. Estimates for the long-term average slip rate for the Midland fault range between 0.004–0.02 in/year (0.1–0.5 mm/yr).

Figures F-9 through F-12 present structure contour maps for the horizons of interest for the CO_2 Pilot. In descending stratigraphic order, they are: 1) The Domengine formation Top Structure Map (Figure F-9); the Hamilton formation Top Structure Map (Figure F-10); the Anderson formation Top Structure Map (Figure F-11); and, Martinez123 formation Top Structure Map (Figure F-12). The perimeter of the Permit Area is highlighted in red within Township/Range 3 North/1 East. The maps are presented at a scale of “1 to 36,000”, with 50-foot contour lines.

The maps were extracted from the regional model, built in PETREL[1]. Note that no faults are identified in the synclinal area in the immediate vicinity of the pilot test; however, the east and west margins of the mapped area are bounded by the Kirby Hills fault, 3.2 miles to the west, and the Sherman Island fault, 6 miles to the east. The maps show that the Permit Area located to the east of the axis of the syncline at each horizon, with up dip being directed to the east-northeast.

F.1.3 Seismicity

F.1.3.1 Natural Seismicity

The seismicity of the San Francisco Bay area is concentrated along transverse faults associated with movement of the Pacific Oceanic plate in a northward direction relative to the North American continental crustal plate. Faults are planes of weakness in the earth's crust where one side has moved relative to the other. Slow movement deep in the earth causes stresses to build up within its brittle outer crust. Friction prevents slip along this weak zone until the crustal stress exceeds its frictional strength. An earthquake occurs when the stress that has accumulated over perhaps hundreds to thousands of years is relieved in a few seconds by failure and slip on a fault. Major earthquakes (magnitude 6 and above) in California occur primarily in the strong, brittle basement rock at depths on the order of 6 miles or more (Foxall and Friedmann, 2008).

Figure F-13 shows the occurrence of seismic events over the previous 30 years in the vicinity of the proposed Permit Area. The figure also shows the system of arrays continuously monitoring for seismic events (NC Stations = Northern California Seismicity Project stations and BK Stations = University of California, Berkeley stations). The recorded seismic events are concentrated along the transverse faults located near the coast. Away from the coast, to the east, the number of seismic events diminishes (Figure F-13). Most of the recorded events are deep. Figure F-14 shows a "zoom in" of the red-boxed area. Ninety percent of the seismic events located within this zoomed in area, as shown in Figure F-14, are deeper than 8 miles (13 kilometers), well below the formations of interest for the pilot test.

---

[1] Petrel is a Schlumberger owned Windows PC software application intended to aggregate oil reservoir data from multiple sources. It allows the user to interpret seismic data, perform well correlation, build reservoir models suitable for simulation, submit and visualize simulation results, calculate volumes, produce maps and design development strategies to maximize reservoir exploitation. It addresses the need for a single application able to support the "seismic-to-simulation" workflow, reducing the need for a multitude of highly specialized tools. By bringing the whole workflow into a single application risk and uncertainty can be assessed throughout the life of the reservoir.

Modern wells are designed to withstand seismic deformations. They are constructed from flexible steel casing designed to deform, but not rupture, from distortions much larger than those caused by the passage of seismic waves from earthquakes. Several existing oil and gas fields throughout Southern California and the San Joaquin basin are located near and have experienced major earthquakes, with relatively few problems. For example, only 14 of 1,725 active wells within the oilfields close to the 1983 magnitude 6.8 Coalinga earthquake suffered collapsed or parted well casings (Foxall and Friedmann, 2008).

F.1.3.2 Induced Seismicity

Human activity, such as building dams, mining, nuclear weapons testing, oil and gas extraction, and fluid injection, have been known to induce seismic events because they can change the stress within the crust, resulting in slip along pre-existing faults. Earthquakes induced by fluid injection are caused by increasing the fluid pressure at depth. This lowers the frictional resistance on pre-existing faults and may cause them to slip under the existing stress loading, which would normally be too low to cause failure. Like naturally-occurring earthquakes, the vast majority of induced earthquakes are much too small (less than magnitude 3) to be felt or to cause damage and can be detected only by sensitive instruments.

Since seismic activity in the area occurs very deep in the earth, it is not likely that shallow pressure changes resulting from the pilot test will affect this deeper naturally occurring seismicity. The absence of faults seen on the geophysical seismic reflection data lines located in the vicinity of the Permit Area infers that there are no, or only small scale (sub-seismic resolution) faults that will see higher than normal pressures as a result of the pilot injection. The wells will have a complete program of tests to determine the fracture pressure and the fracture closure pressure of the injection interval. During CO_2 injection, the pressure will remain below a safe operating pressure by a specified margin in the permit, which will keep area pressures low and prevent hydraulic fracturing from occurring in the formation.

Deep injection wells are common in the Sacramento and San Joaquin Valleys. California's Division of Oil, Gas, and Geothermal Resources regulates hundreds of Class II injection wells in the northern California area. These Class II injection wells are very similar in design and function to the proposed pilot wells. According to California's Division of Oil, Gas, and Geothermal Resources, seismic activity has never impacted Class II injection activities in the surrounding area (EPA, 2006a). Also, high pressure slurry fracture injection has been conducted for over eleven years at the THUMS platform located near the City of Long Beach, California, with no earthquake activity attributed to it (EPA, 2006b).

F.1.3.3 Seismicity Monitoring

During the project, pressure and temperature will be closely monitored, both at the surface and down hole. Data collected from these instruments will confirm the impact of injection within the target formation. Additionally, an additional seismic array element to the existing Northern California networks will be installed near the pilot area (see Attachment P, Section P.1.5 for more details). Recordings from this additional element will be used with available records from the existing broad area networks to resolve any seismic events occurring near the pressure field induced by pilot CO_2 injection test.

References

Arleth, K.H., 1968, Maine Prairie gas field, Solano County, California, in Beebe, B.W., and Curtis, B.F., eds. Natural Gases of North America: American Association of Petroleum Geologists Memoir 9, v. 1, p. 79-84.

Bennett, J.H., 1987. Vacaville-Winters Earthquakes 1892: Solano and Yolo Counties. California Geology, April 1987, Vol. 40, No. 4.

California Dept. of Conservation, 1982, California Oil & Gas Fields: Volume 1 (Northern California), p. 337, California Dept. of Conservation, Division of Oil, Gas & Geothermal Resources.

California Dept. of Conservation, Division of Oil and Gas (DOG), 1983, California Oil & Gas Fields, v. 3, Northern California: California Dept. of Conservation, Division of Oil and Gas, publication TR10.

California Geological Survey (CGS), 2002, California Geomorphic Provinces, Note 36, California Dept. of Conservation, California Geological Survey, p. 4.

Dott, R.H. and R.L. Batten, 1976, *Evolution of the Earth*, 2nd Ed., p. 504. McGraw-Hill, Inc., New York, NY.

EPA, 2006a, EPA Response to comments on the Draft Class I Underground Injection Control Permit for Hilmar Cheese Company: USEPA Region 9, San Francisco, CA. http://www.epa.gov/region/water/groundwater/uic-pdfs/hilmar-response-to-comments-final.pdf

EPA, 2006b, EPA Response to comments on the Draft Class V Experimental Underground Injection Control Permit for the City of Los Angeles: USEPA Region 9, San Francisco, CA.http://www.epa.gov/region/water/groundwater/uic-pdfs/la-class-v-response-comments.pdf

Foxall, W., and Friedmann, S.J., 2008, Frequently Asked Questions About Carbon Sequestration and Earthquakes: Lawrence Livermore National Laboratory Document No. LLNL-BR-408445. 3 p.

Johnson, D.S., 1990, Rio Vista Gas Field – U.S.A. Sacramento Basin, California, in Foster, N.H., and Beaumont, C.A., Eds., Atlas of Oil and Gas Fields, Structural Traps III, AAPG Treatise of Petroleum Geology, Atlas of Oil and Gas Fields, Tulsa Oklahoma, p.243-263.

Johnson, D.S., 1992, Tectonic effects on the Upper Cretaceous and Paleogene stratigraphy along the Midland Fault System, Southern Sacramento Basin, California: in Cherven, V.B. and Edmondson, W.F., Eds., Structural Geology of the Sacramento Basin, The Pacific Section AAPG, Bakersfield, California, p. 15-25.

Krug, E.H., Cherven, V.B., Hatten, C.W., and Roth, J.C., 1992, Subsurface structure in the Montezuma Hills, Southwestern Sacramento Basin: in Cherven, V.B. and Edmondson, W.F., Eds., Structural Geology of the Sacramento Basin, The Pacific Section AAPG, Bakersfield, California, p. 41-60.

Magoon, L.B. and Valin, Z.C., 1995, Sacramento Basin Province (009), in the 1995 National Assessment of United States Oil and Gas Resources, U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995.

MacKevett, N.H., 1992, The Kirby Hill Fault Zone: in Cherven, V.B. and Edmondson, W.F., Eds., Structural Geology of the Sacramento Basin, The Pacific Section AAPG, Bakersfield, California, p. 41-60.

Pepper, M.W., and Johnson, D.S., 1992, The Midland Fault System, Southern Sacramento Basin, California: in Cherven, V.B. and Edmondson, W.F., Eds., Structural Geology of the Sacramento Basin, The Pacific Section AAPG, Bakersfield, California, p. 27-40.

USGS, U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995, 1995 National Assessment of United States Oil and Gas Resources: U.S. Geological Survey Circular 1118, U.S. Government Printing Office, Washington, D.C., 20 p.

USGS, 2006, Assessment of Undiscovered Natural Gas Resources of the Sacramento Basin Province of California: U.S. Geological Survey Fact Sheet 2007-3014.

Weber-Band, J., 1998, Neotectonics of the Sacramento-San Joaquin Delta area, east-central Coast Ranges, California: Ph.D. dissertation, University of California, Berkeley, 216 p.

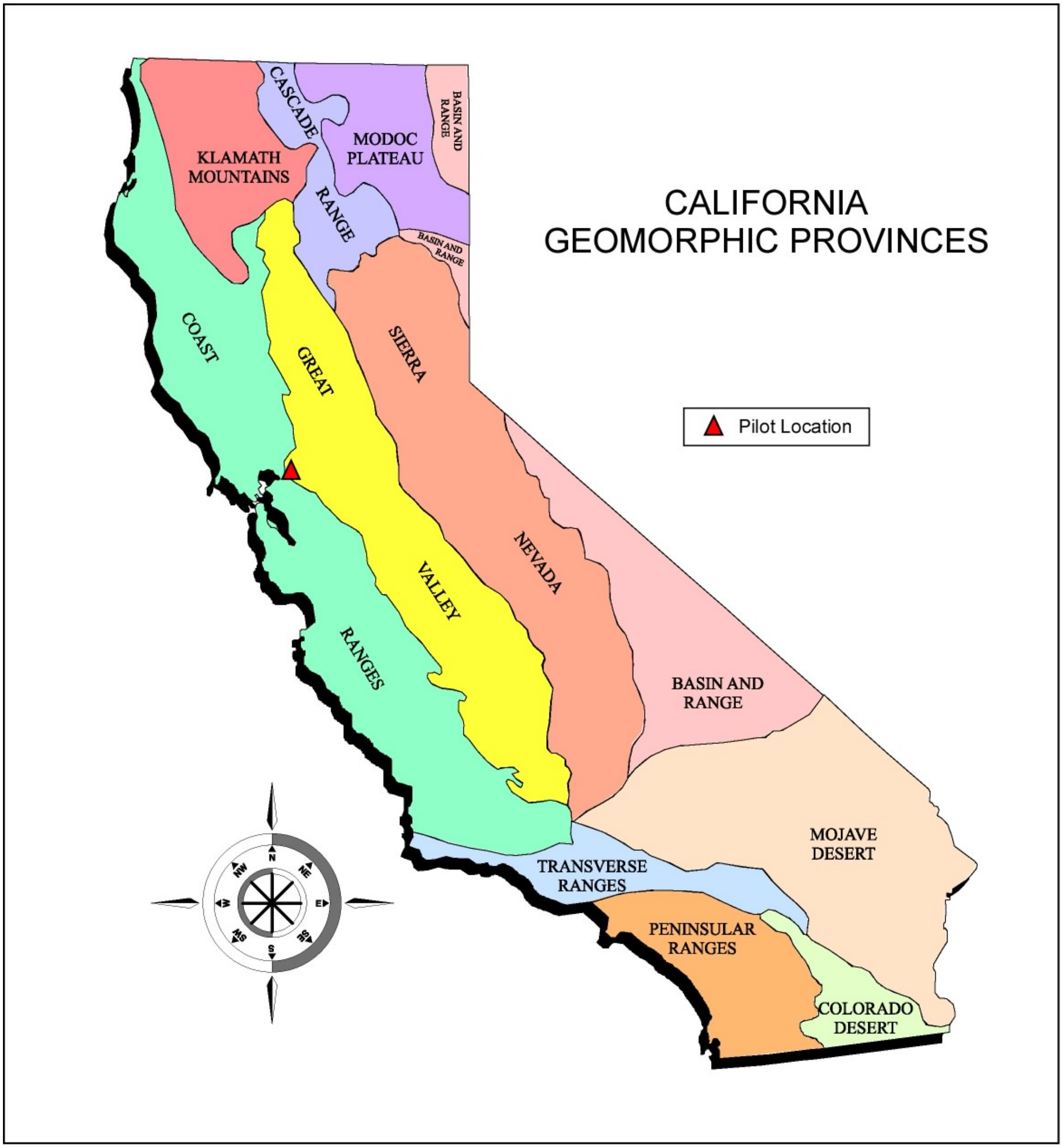


Figure F-1 California Geomorphic Provinces (modified from CGS, 2002)

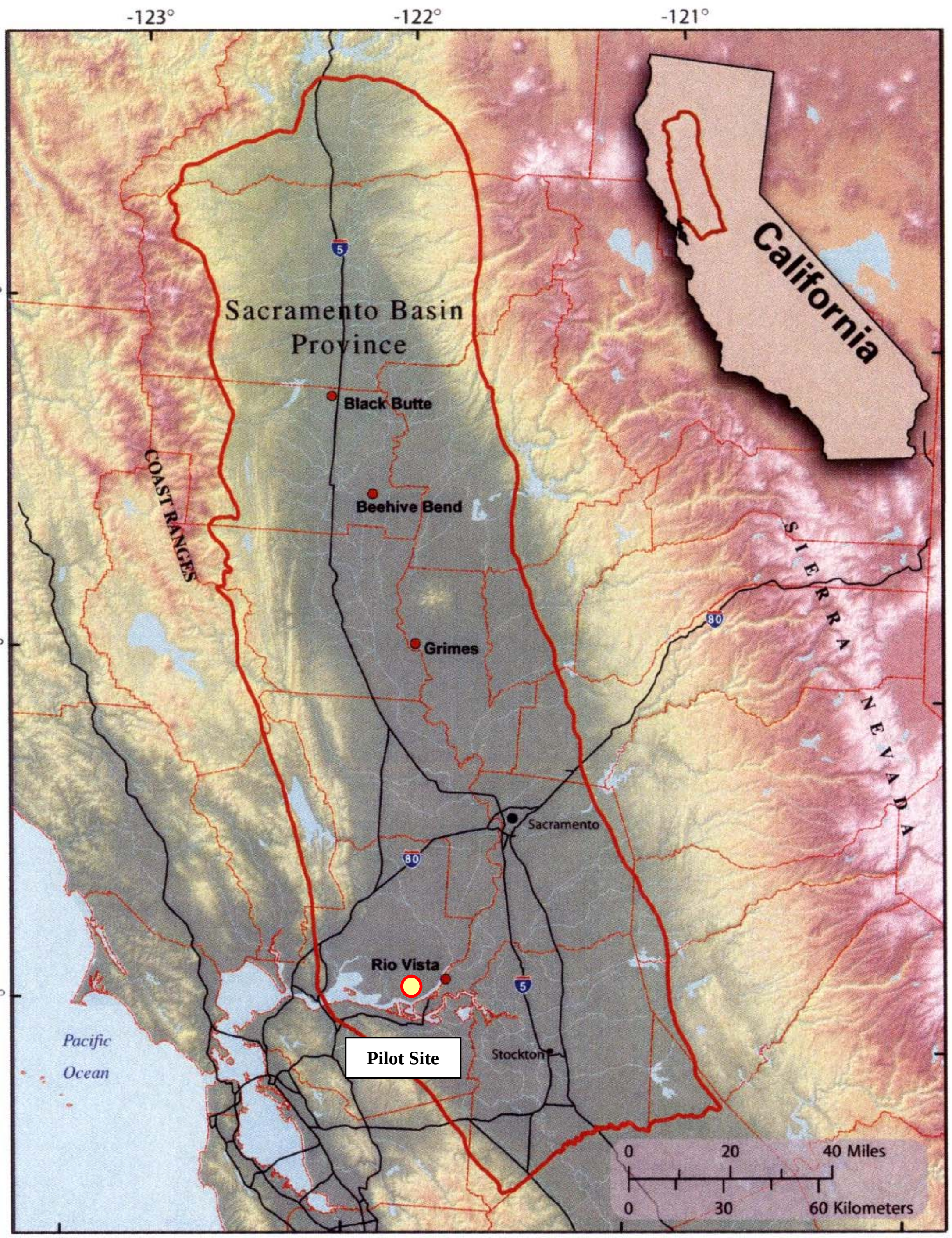


Figure F-2 Outline of Sacramento Basin Province and Pilot Site Location (modified from USGS 2006)

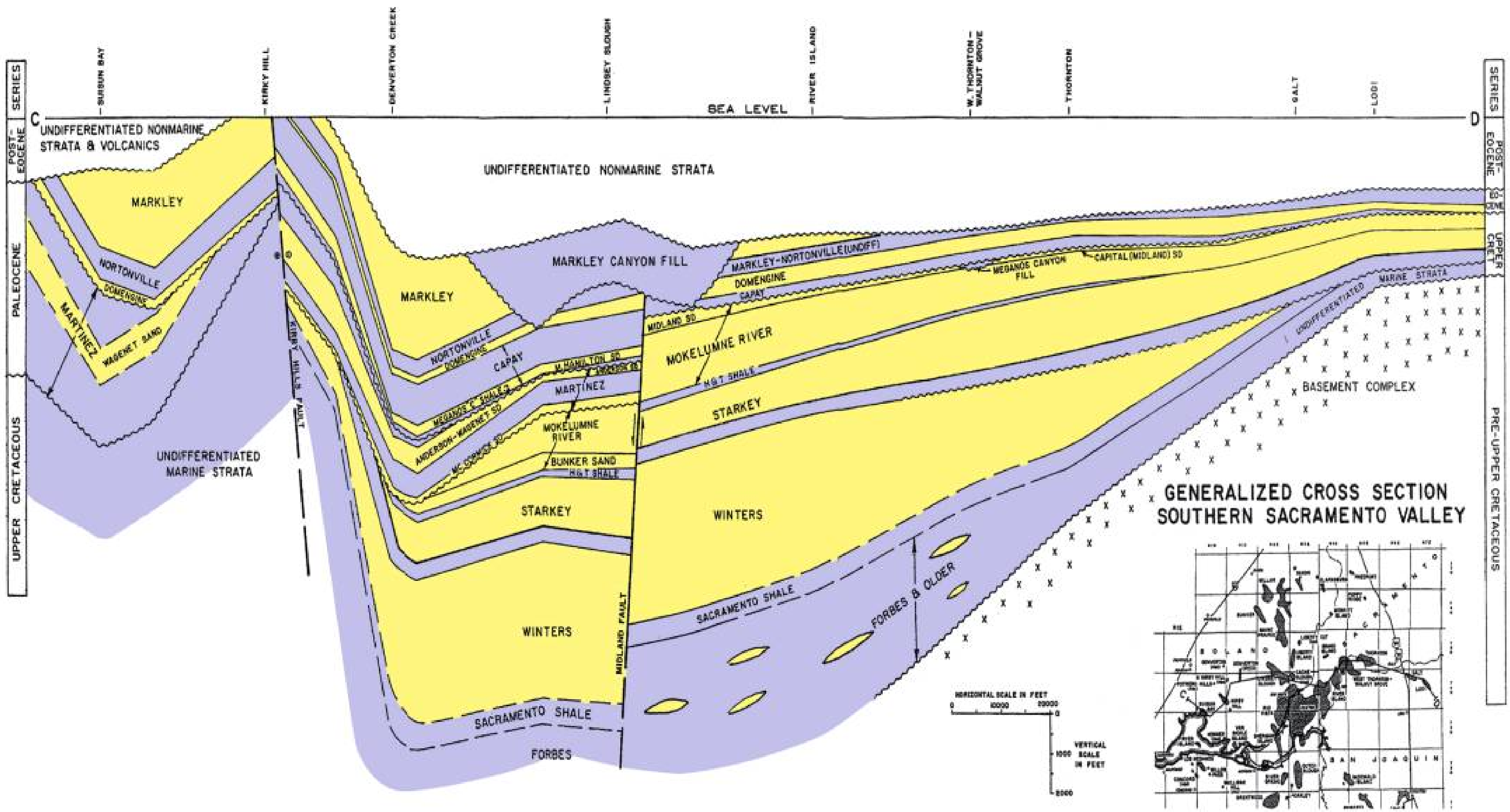
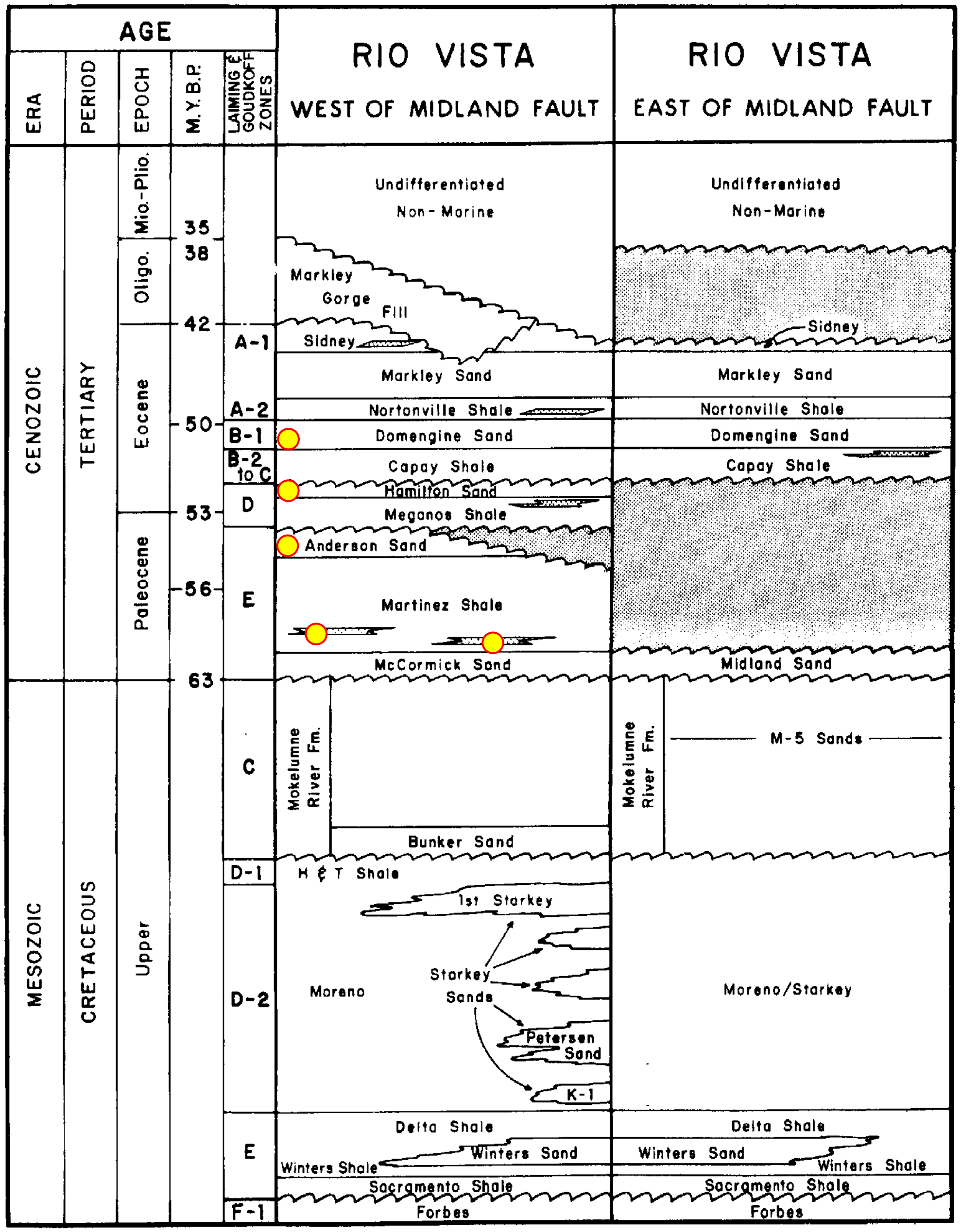


Figure F-3 Generalized Cross Section Through the Southern Sacramento Valley (modified from DOGGR, 1983)



Potential Injection Zone Sands

Figure F-4 Stratigraphic Column for the Rio Vista Field (Johnson, 1990)

U.S. DEPARTMENT OF THE INTERIOR
U.S. GEOLOGICAL SURVEY

MISCELLANEOUS FIELD STUDIES MAP MF- 2403
Version 1.0
Pamphlet accompanies map

Geologic Map and Map Database of Northeastern San Francisco Bay Region, California

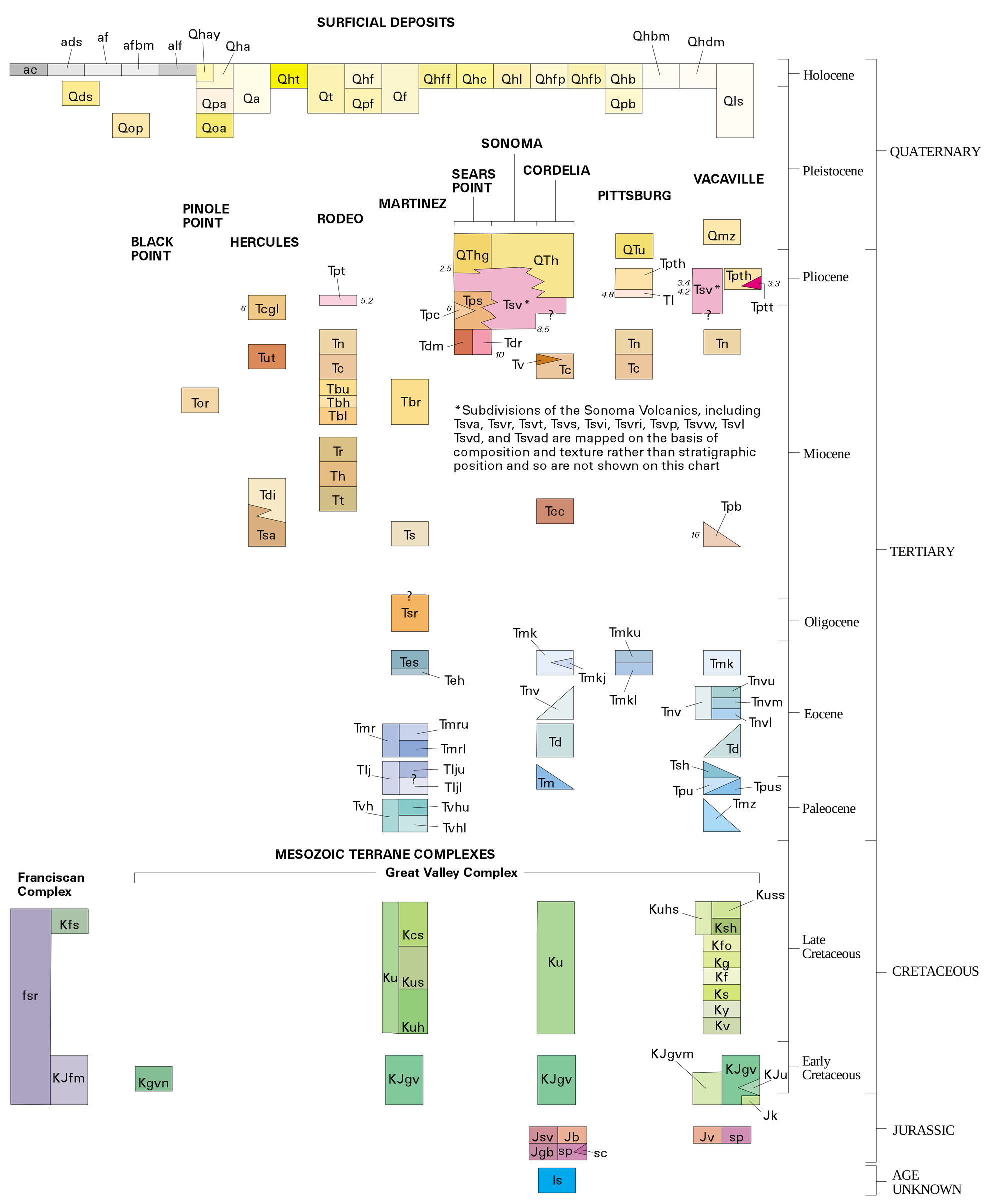
Most of Solano County and Parts of Napa, Marin, Contra Costa, San Joaquin, Sacramento, Yolo, and Sonoma Counties

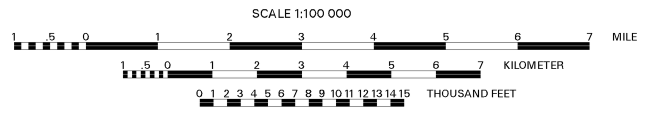
By

R.W. Graymer, D.L. Jones, and E.E. Brabb

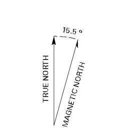
2002

CORRELATION OF MAP UNITS
[numbers, radiometric ages (Ma); see Description of Map Units in pamphlet for specific age data]

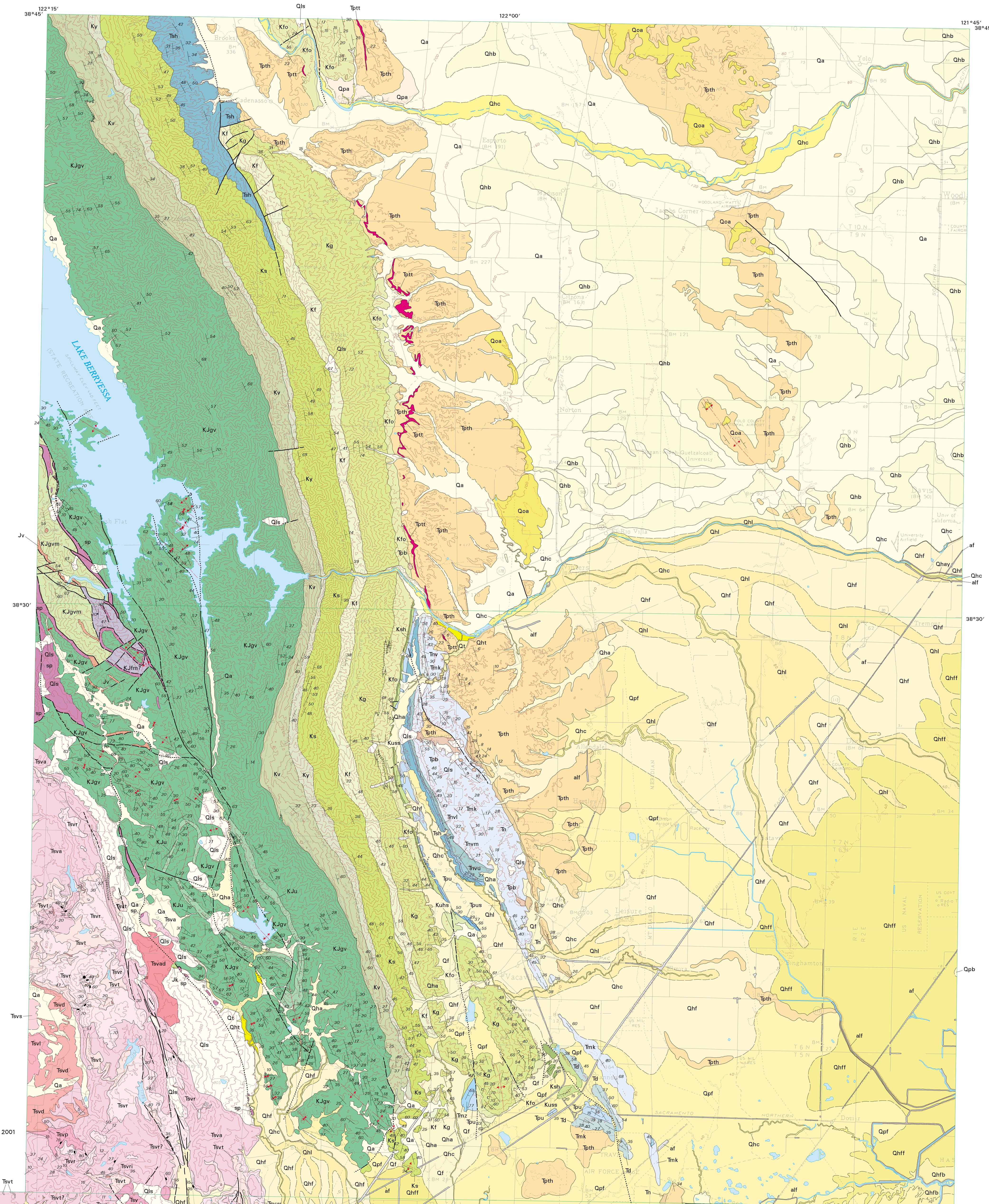




MAP LOCATION



APPROXIMATE MEAN DECLINATION AT CENTER OF MAP, 2002



Base from Aitken, 1997, A digital version of the 1970 U.S. Geological Survey San Francisco Bay Region 1:125,000 scale topographic map

Stateplane projection, Zone 3

Digital Cartography by R.W. Graymer, 2001

Edited by Jan Zigler

Manuscript approved for publication, August 8, 2002

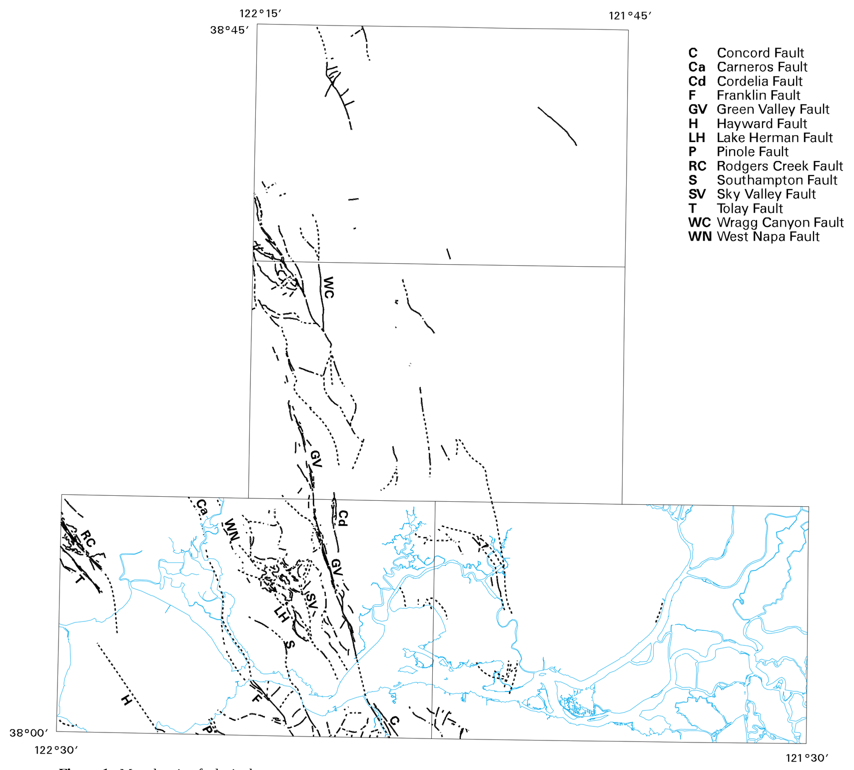
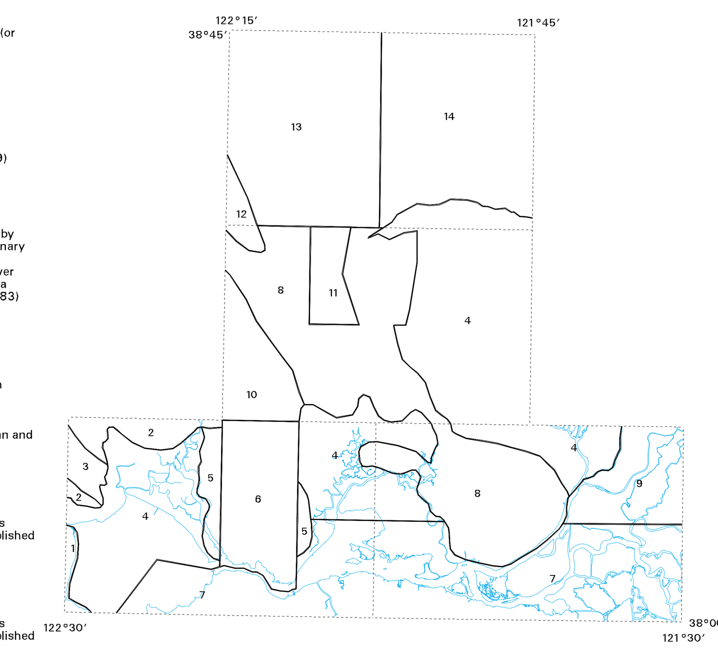


Figure 1. Map showing faults in the map area

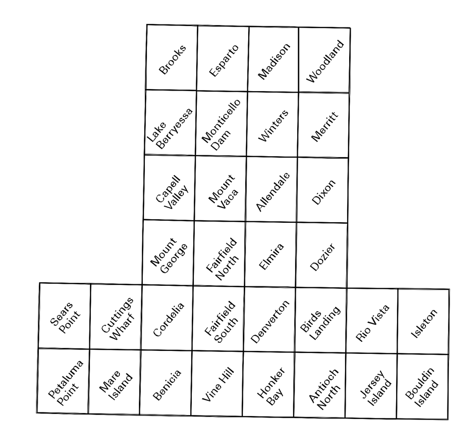
SOURCES OF DATA

[See the accompanying pamphlet (or digital file solmf.txt or solmf.pdf) for references cited]

1. Modified from Blake and others (2000)
2. Modified from Fox and others (1985b)
3. Modified from Youngman (1989)
4. Modified from Knudsen and others (2000), some buried faults from Unruh and Hector (1999)
5. Mostly based on new mapping by authors, 1998-2000, some Quaternary geology from Knudsen and others (2000), some additions from Weaver (1949), active faults from California Division of Mines and Geology (1983)
6. Modified from Graymer and others (1999)
7. Modified from Graymer and others (1994) and Helley and Graymer (1997), buried faults from Unruh and Hector (1999)
8. Modified from Weaver (1949), unpublished mapping by Sonneman and Switzer, 1961-62, and Sims and others (1973), buried faults from Unruh and Hector (1999)
9. Modified from Atwater (1982)
10. Modified from Sims and others (1973) which was based on unpublished mapping by Fox, 1971
11. Modified from Emerson and Roberts (1962), Sims and others (1973)
12. Modified from Sims and others (1973) which was based on unpublished mapping by Moiseyev, 1967, and Taliaferro, undated
13. Modified from Boyd (1956) and Sims and others (1973)
14. Modified from Helley and Barker (1979)



INDEX MAP OF SOURCES OF DATA



INDEX MAP OF 7.5-MINUTE QUADRANGLES

INDEX MAP OF ASSEMBLAGES

LIST OF MAP UNITS

SURFICIAL DEPOSITS

- ac — Artificial channel deposits (Holocene, historic)
- ads — Dredge spoils (Holocene, historic)
- af — Artificial fill (Holocene, historic)
- afbm — Artificial fill over bay mud (Holocene, historic)
- alf — Artificial levee fill (Holocene, historic)
- Qhay — Younger alluvium (late Holocene)
- Qha — Alluvium (Holocene)
- Qht — Terrace deposits (Holocene)
- Qhf — Alluvial fan deposits (Holocene)
- Qhff — Fine-grained alluvial fan deposits (Holocene)
- Qhc — Stream channel deposits (Holocene)
- Qhl — Natural levee deposits (Holocene)
- Qhfp — Floodplain deposits (Holocene)
- Qhfb — Floodbasin deposits (Holocene)
- Qhb — Basin deposits (Holocene)
- Qhbm — Bay mud deposits (Holocene)
- Qhdm — Delta mud deposits (Holocene)
- Qa — Alluvium (Holocene and late Pleistocene)
- Qt — Terrace deposits (Holocene and late Pleistocene)
- Qf — Alluvial fan deposits (Holocene and late Pleistocene)
- Qls — Landslide deposits (Holocene and Pleistocene)
- Qds — Dune sands (early Holocene and latest Pleistocene)
- Qpa — Alluvium (late Pleistocene)
- Qpf — Alluvial fan deposits (late Pleistocene)
- Qpb — Basin deposits (late Pleistocene)
- Qop — Pediment deposits (late and early Pleistocene)
- Qoa — Alluvium (late and early Pleistocene)

BLACK POINT ASSEMBLAGE
Great Valley Complex

- Kgvn — Novato Conglomerate (Early Cretaceous)

PINOLE POINT ASSEMBLAGE

- Tor — Orinda Formation (late Miocene)

HERCULES ASSEMBLAGE

- Tcgl — Conglomerate (late Miocene)
- Tut — Tuffaceous sandstone (late Miocene)
- Tdi — Diatomite (middle to early Miocene)
- Tsa — Sandstone (middle to early Miocene)

RODEO ASSEMBLAGE

- Tpt — Pinole Tuff (Pliocene)
- Tn — Neroly Sandstone (late Miocene)
- Tc — Cierbo Sandstone (late Miocene)
- Briones Sandstone (late and middle Miocene)
  - Tbu — Upper member
  - Tbh — Hercules Shale Member
  - Tbl — Lower member
- Tr — Rodeo Shale (middle Miocene)
- Th — Hambre Sandstone (middle Miocene)
- Tt — Tice Shale (middle Miocene)

MARTINEZ ASSEMBLAGE

- Tbr — Briones Sandstone (late and middle Miocene)
- Ts — Sobrante Sandstone (early Miocene)
- Tsr — San Ramon Sandstone (early Miocene and (or) Oligocene)
- Tes — Escobar Sandstone of Weaver (1953) (Eocene)
  - Teh — Basal shale member
- Tmr — Muir Sandstone of Weaver (1953) (Eocene)
  - Tmru — Upper member
  - Tmrl — Lower member
- Tlj — Las Juntas Shale of Weaver (1953) (Eocene and Paleocene)
  - Tlju — Upper member
  - Tljl — Lower member
- Tvh — Vine Hill Sandstone of Weaver (1953) (Paleocene)
  - Tvhu — Upper member
  - Tvhl — Lower member

Great Valley Complex

- Ku — Undivided sandstone, siltstone, and shale (Late Cretaceous)
  - Kcs — Massive sandstone
  - Kus — Sandstone, siltstone, and shale
  - Kuh — Massive sandstone
- KJgv — Massive sandstone and shale (Early Cretaceous and Late Jurassic)

SEARS POINT ASSEMBLAGE

- QThg — Huichica and Glen Ellen Formations, undivided (early Pleistocene and Pliocene)
- Tsv — Sonoma Volcanics (Pliocene and late Miocene)
  - Tsva — Andesite to basalt flows
  - Tsvr — Rhyolite flows
  - Tsvt — Ash-flow tuff
  - Tsvs — Volcanic sand and gravel
- Petaluma Formation (early Pliocene and late Miocene)
  - Tps — Mudrock, sandstone, and conglomerate
  - Tpc — Claystone
- Donall Ranch volcanics of Youngman (1989) (late Miocene)
  - Tdm — Mafic member
  - Tdr — Rhyolite member

SONOMA ASSEMBLAGE

- QTh — Huichica Formation (early Pleistocene and Pliocene)
- Sonoma Volcanics (Pliocene and late Miocene)
  - Tsvt — Ash-flow tuff

CORDELIA ASSEMBLAGE

- QTh — Huichica Formation (early Pleistocene and Pliocene)
- Tsv — Sonoma Volcanics (Pliocene and late Miocene)
  - Tsva — Andesite to basalt flows
  - Tsvi — Andesite to dacite plugs and dikes
  - Tsvr — Rhyolite flows
  - Tsvri — Rhyolite plugs and dikes
  - Tsvp — Rhyolite and perlitic flows and plugs
  - Tsvt — Ash-flow tuff
  - Tsvw — Welded ash-flow tuff
  - Tsvl — Lithic tuff
  - Tsvs — Volcanic sandstone, siltstone, and conglomerate
  - Tsvd — Diatomite
- Tc — Cierbo Sandstone (late Miocene)
  - Tv — Intercalated basalt
- Tcc — Claremont Shale (Miocene)
- Tmk — Markley Sandstone (Eocene)
  - Tmkj — Jameson Shale Member
- Tnv — Nortonville Shale Member of Kreyenhagen Formation (Eocene)
- Td — Domengine Sandstone (Eocene)
- Tm — Meganos Formation (Eocene and (or) Paleocene)

Great Valley Complex

- Ku — Sandstone and shale (Late Cretaceous)
- KJgv — Sandstone and shale (Early Cretaceous and Late Jurassic)
- Jsv — Keratophyre (Jurassic)
- Jb — Massive and pillow basalt (Jurassic)
- Jgb — Gabbro (Jurassic)
- sp — Serpentinite (Jurassic)
- sc — Silica-carbonate rock
- ls — Limestone (age unknown)

PITTSBURG ASSEMBLAGE

- QTu — Sandstone, siltstone, and gravel (early Pleistocene and late Pliocene)
- Tpth — Tehama Formation (Pliocene)
- Tl — Lawlor Tuff (Pliocene)
- Tn — Neroly Sandstone (late Miocene)
- Tc — Cierbo Sandstone (late Miocene)
- Markley Sandstone (Eocene)
  - Tmku — Upper member
  - Tmkl — Lower member

VACAVILLE ASSEMBLAGE

- Qmz — Montezuma Formation (early Pleistocene)
- Tpth — Tehama Formation (Pliocene)
  - Tptt — Putah Tuff member
- Tsv — Sonoma Volcanics (Pliocene and late Miocene)
  - Tsva — Andesite to basalt flows
  - Tsvad — Andesite to dacite flows
  - Tsvr — Rhyolite flows
  - Tsvt — Ash-flow tuff
  - Tsvs — Volcanic sandstone, siltstone, and conglomerate
- Tn — Neroly Sandstone (late Miocene)
- Tpb — Putnam Peak Basalt (Miocene)
- Tmk — Markley Sandstone (Eocene)
- Tnv — Nortonville Shale Member of Kreyenhagen Formation (Eocene)
  - Tnvu — Upper member
  - Tnvm — Middle member
  - Tnvl — Lower member
- Td — Domengine Sandstone (Eocene)
- Tsh — Shale (Eocene)
- Tpu — Shale and sandstone (Paleocene)
  - Tpus — Basal sandstone member
- Tmz — Martinez Formation (Paleocene)

Great Valley Complex

- Kuhs — Sandstone and shale (Late Cretaceous)
  - Kuss — Sandstone
  - Ksh — Siliceous shale
- Kfo — Forbes Formation (Late Cretaceous)
- Kg — Guinda Formation (Late Cretaceous)
- Kf — Funks Formation (Late Cretaceous)
- Ks — Sites Formation (Late Cretaceous)
- Ky — Yolo Formation (Late Cretaceous)
- Kv — Venado Formation (Late Cretaceous)
- KJgv — Sandstone and shale (Early Cretaceous and Late Jurassic)
  - KJu — Sandstone member
  - KJgvm — Mélange
  - Jk — Knoxville Formation (Late Jurassic)
- Jv — Basalt and keratophyre (Jurassic)
- sp — Serpentinite (Jurassic)

Franciscan Complex

- Kfs — Sandstone (Late Cretaceous)
- KJfm — Metagraywacke (Early Cretaceous and Late Jurassic)
- fsr — Mélange

Contact—Depositional or intrusive contact, dashed where approximately located, dotted where concealed, hachured where gradational

Fault—Dashed where approximately located, short dashed where inferred, dotted where concealed, queried where location is uncertain

Reverse or thrust fault—Dashed where approximately located, dotted where concealed. Sawteeth on upper plate

Anticline—Shows fold axis, dashed where approximately located, dotted where concealed

Syncline

Strike and dip of bedding

Strike and dip of bedding, top indicator observed

Strike and dip of bedding, approximate

Overturned bedding

Overturned bedding, top indicator observed

Vertical bedding

General strike and dip direction of bedding

Strike and dip of foliation

Strike and dip of joints

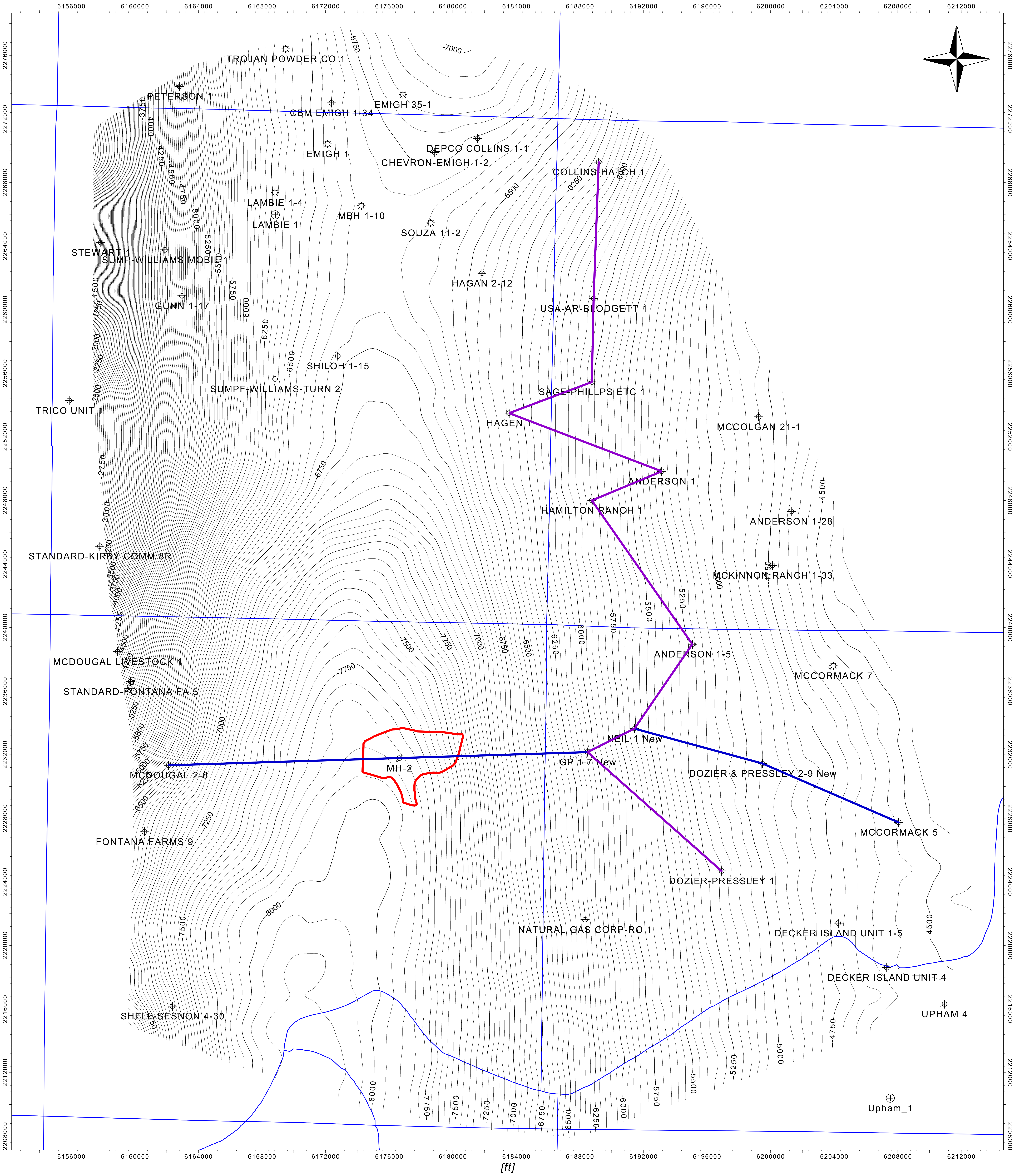
Horizontal joint

Digital data and cartography prepared using Arc/Info 8.1 running under Solaris 2.6 on a UNIX workstation.

This map was printed on an electronic plotter directly from digital files. Dimensional calibration may vary between electronic plotters and between X and Y directions on the same plotter, and paper may change size due to atmospheric conditions; therefore, scale and proportions may not be true on plots of this map.

For sale by U.S. Geological Survey, Map Distribution, Box 25286, Federal Center, Denver, CO 80225, 1-888-ASK-USGS

This publication also includes a digital geologic map (GIS) database. The data files, as well as digital versions of the map sheet and pamphlet, are available on the World Wide Web at: http://geopubs.wr.usgs.gov/map-mf/mf2403

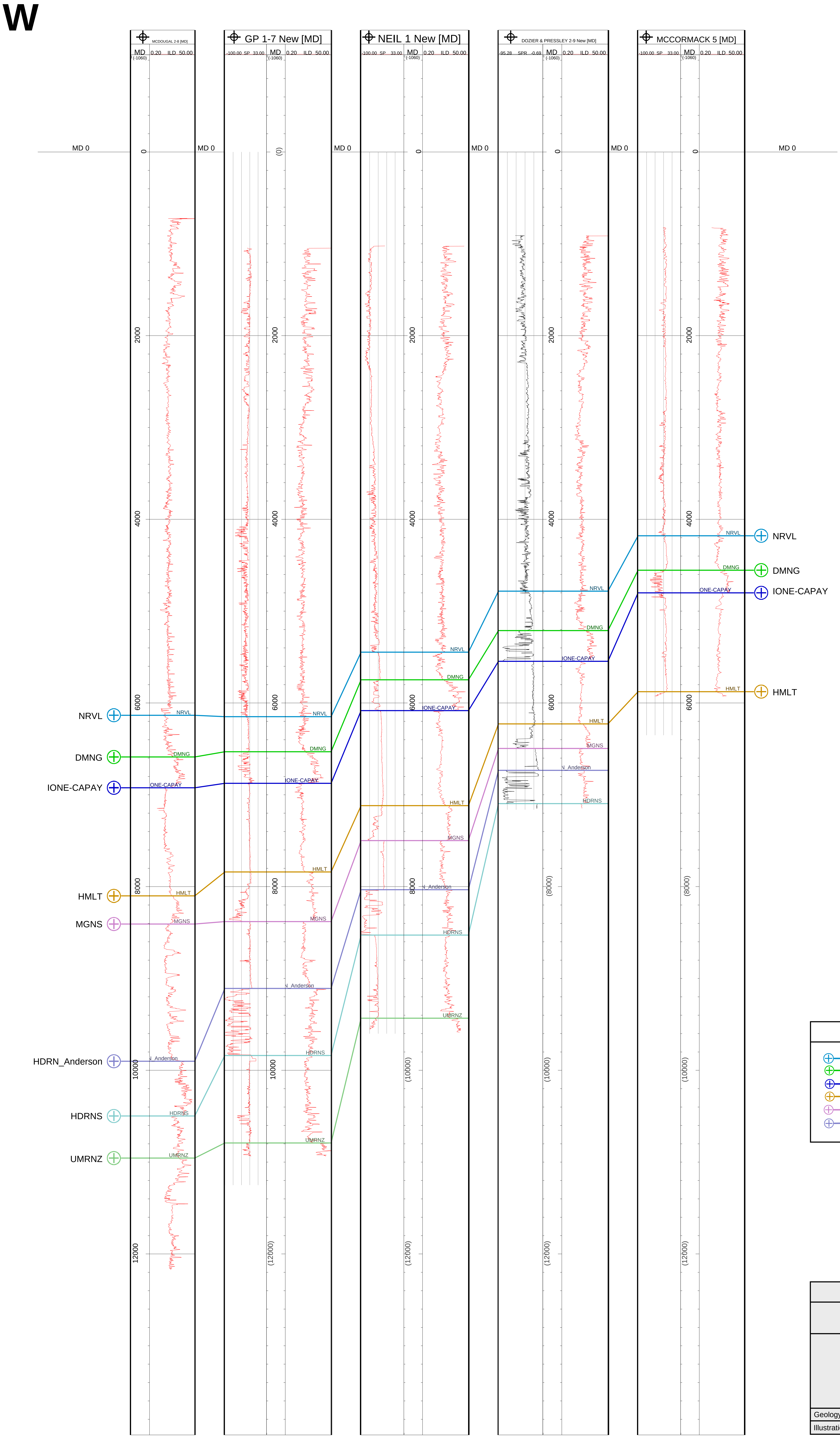


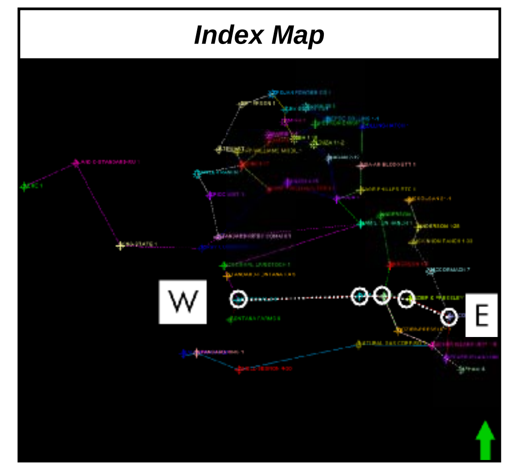
Symbol legend
- township_range.prn
- Coco Properties
- Plugged and abandoned
- Gas
- Undefined
- Temporarily abandoned
- Planned gas injector

0 2500 5000 7500 10000 12500ft

1:50000

Domengine Formation Top Structure Map	
Country: USA	Scale (ft): 1:50000
Area: Sacramento Basin	Contour inc (ft): 50
Horizon Name: Domengine	





Legend

NRVL = Nortonville Shale	HDRNS = Anderson Shale
DMNG = Domengine Sandstone	UMRNZ = Upper Martinez Sandstone
IONE-CAPAY = Ione-Capay Shale	UMRNZS = Upper Martinez Shale
HMLT = Hamilton Sandstone	MRNZ123 = Martinez 123 Complex Sandstone
MGNS = Meganos Shale	Base MRNZ123 = Base of Martinez 123 Complex Sandstone
HDRN_Anderson = Anderson Sandstone	

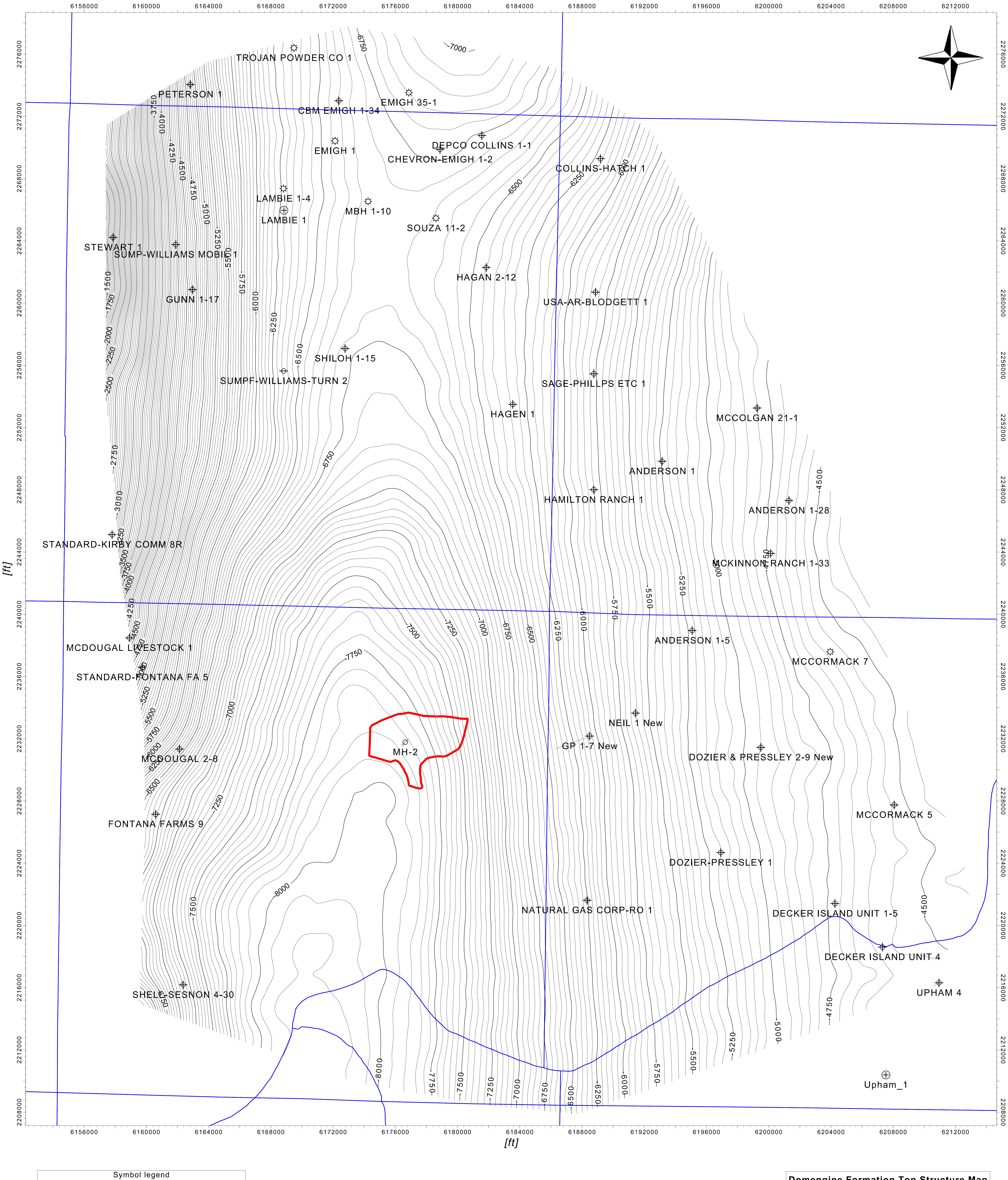
Project Confidential	
C6 Resources, LLC	*Project Information*
Figure F-7 East - West Cross Section through Project Area	*C6 Resources, LLC* *Class V Underground Injection Control Permit Application and Technical Report*
Geology: Innocent Ofoma (PG)/ Karan "Kris" Dick (PG) | Date: July 2009	
Illustration Layout by: E. Shane Salinas (TA)	

Legend

NRVL = Nortonville Shale	HDRNS = Anderson Shale
DMNG = Domengine Sandstone	UMRNZ = Upper Martinez Sandstone
IONE-CAPAY = Ione-Capay Shale	UMRNZS = Upper Martinez Shale
HMLT = Hamilton Sandstone	MRNZ123 = Martinez 123 Complex Sandstone
MGNS = Meganos Shale	Base MRNZ123 = Base of Martinez 123 Complex Sandstone
HDRN_Anderson = Anderson Sandstone	

Project Confidential

C6 Resources, LLC	***Project Information***
Figure F-8 North - South Cross Section through Project Area	*C6 Resources, LLC* *Class V Underground Injection Control Permit Application and Technical Report*
Geology: Innocent Ofoma (PG)/ Karan "Kris" Dick (PG) — Date: July 2009	
Illustration Layout by: E. Shane Salinas (TA)	



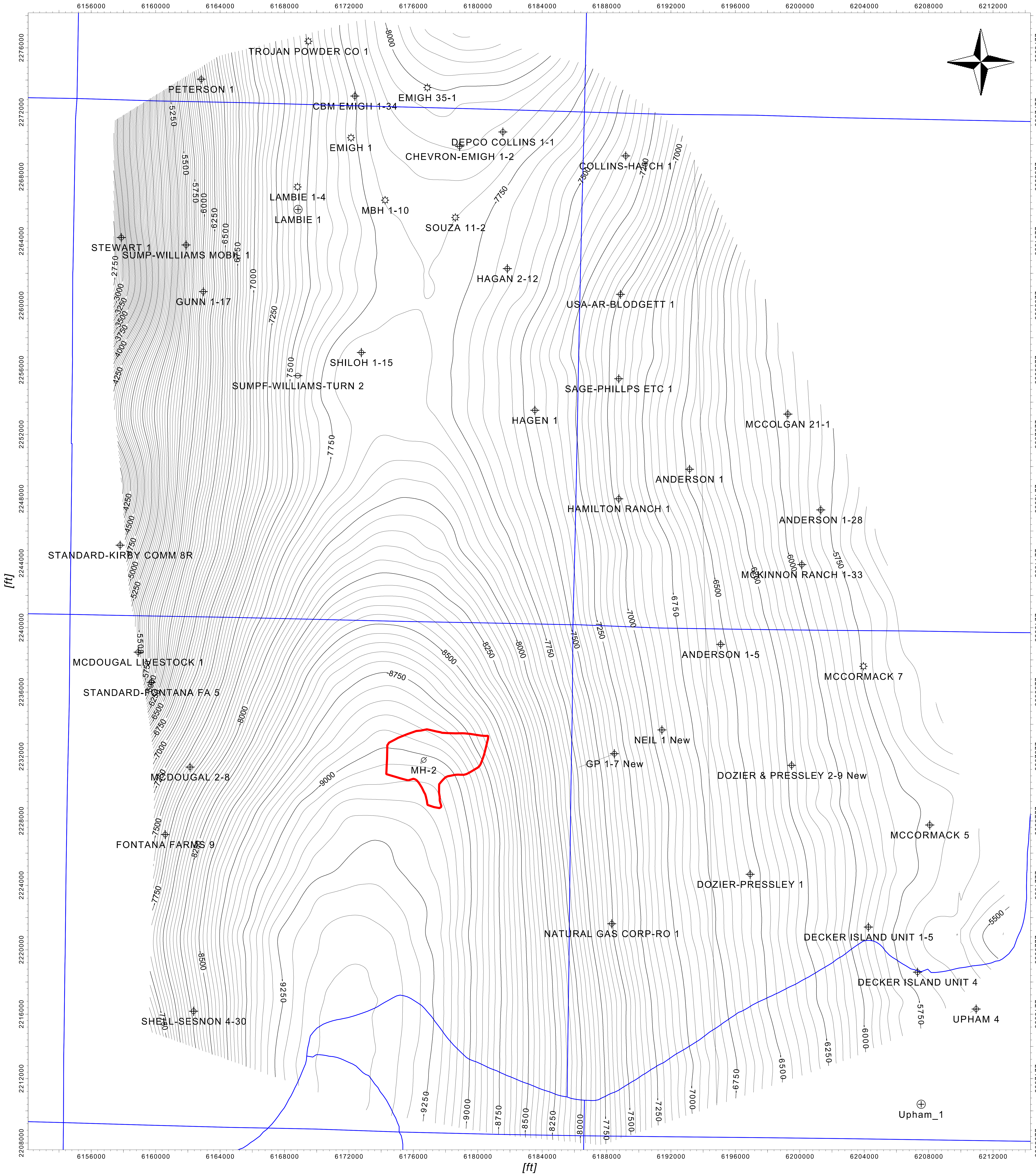
Symbol legend
- township_range.prn
- Coco Properties
- Plugged and abandoned
- Gas
- Undefined
- Temporarily abandoned
- Planned gas injector

0 2500 5000 7500 10000 12500ft

1:50000

Domengine Formation Top Structure Map

Country	Scale (ft)
USA	1:50000
Area	Contour inc (ft)
Sacramento Basin	50
Horizon Name: Domengine	

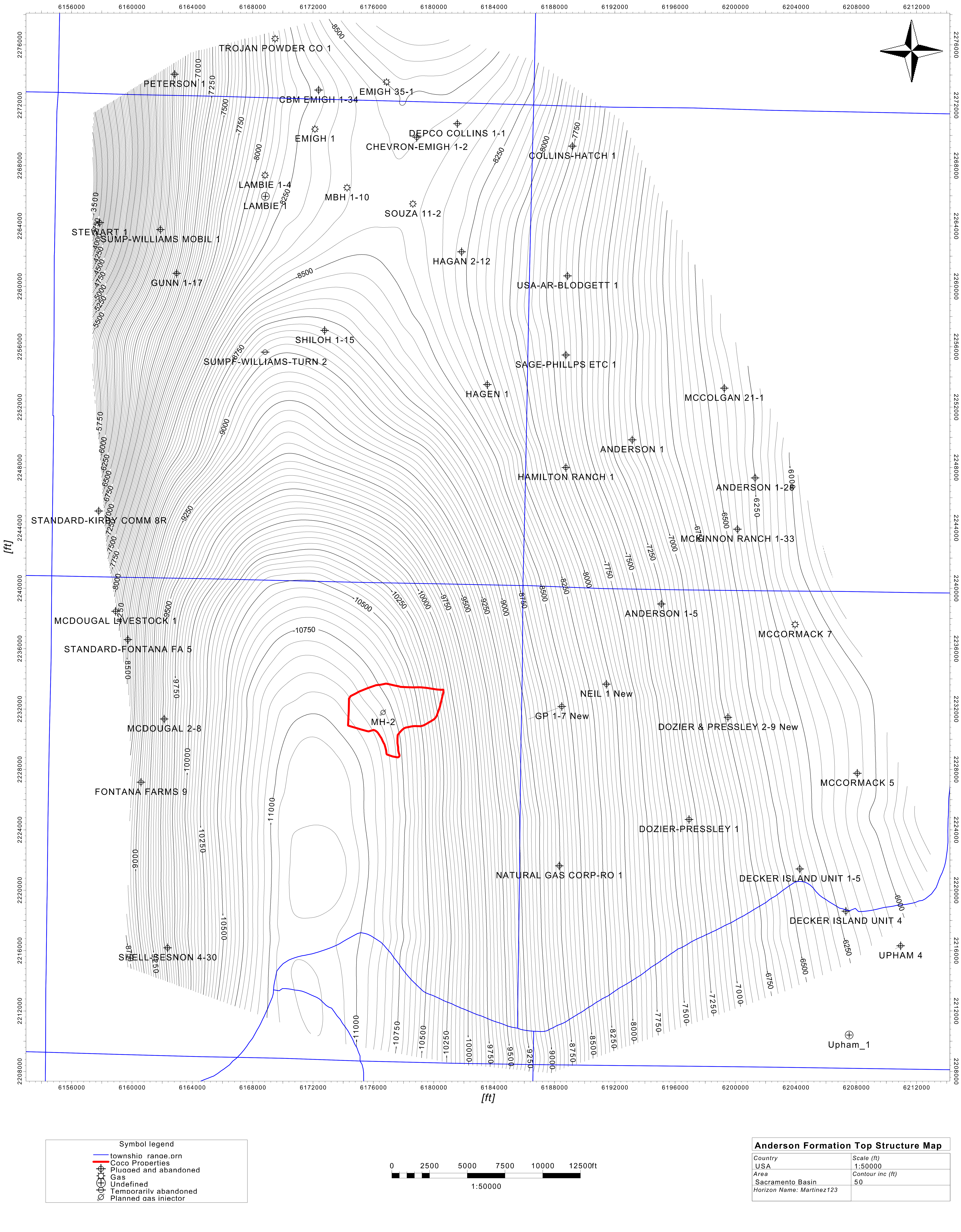


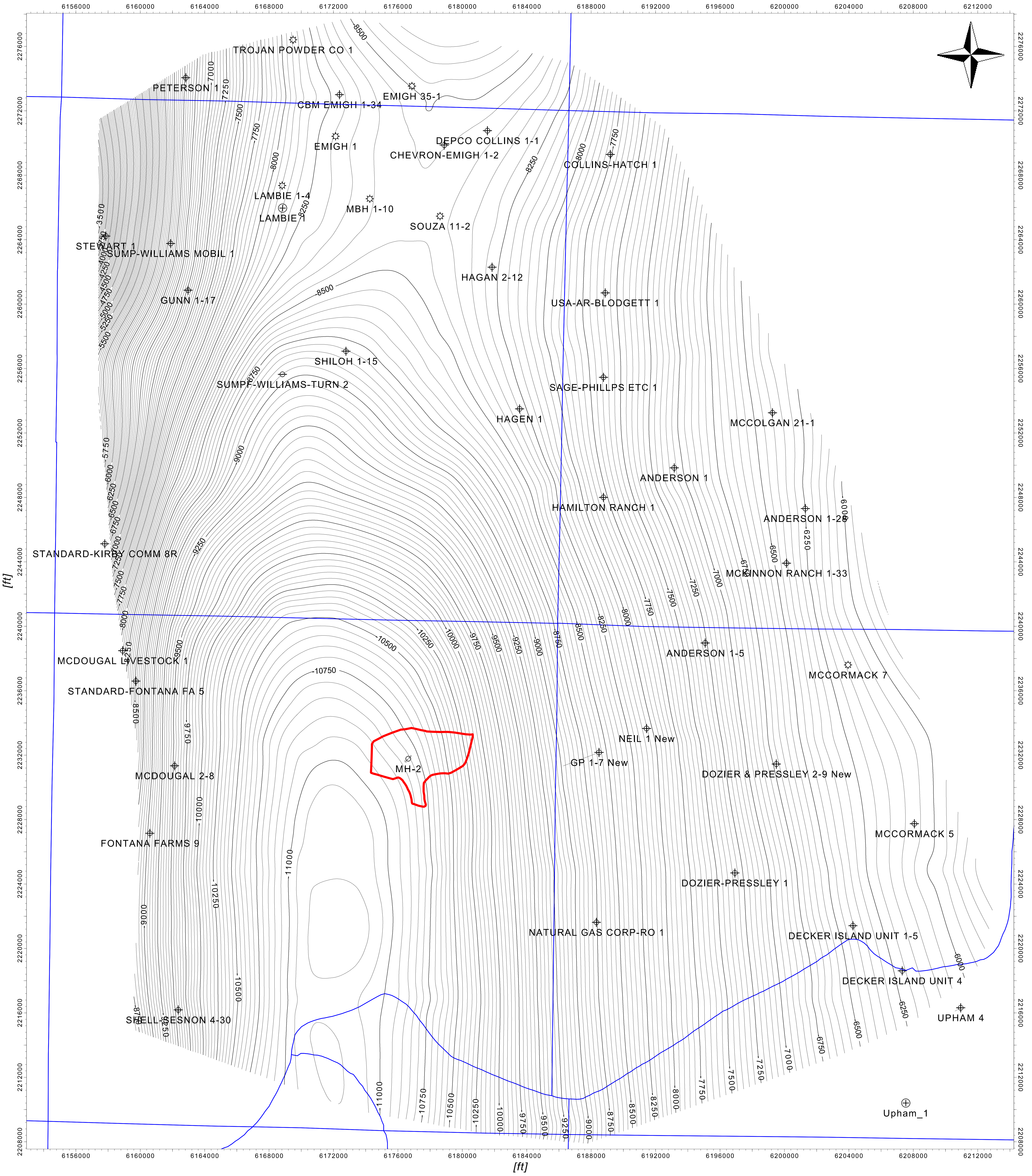
Symbol legend
- township_range.prn
- Coco Properties
- Plugged and abandoned
- Gas
- Undefined
- Temporarily abandoned
- Planned gas injector

0 2500 5000 7500 10000 12500ft

1:50000

Hamilton Formation Top Structure Map	
Country: USA	Scale (ft): 1:50000
Area: Sacramento Basin	Contour inc (ft): 50
Horizon Name: Hamilton	


TROJAN POWDER CO 1
PETERSON 1
CBM EMIGH 1-34
EMIGH 35-1
EMIGH 1
DEPCO COLLINS 1-1
CHEVRON-EMIGH 1-2
COLLINS-HATCH 1
LAMBIE 1-4
LAMBIE 1
MBH 1-10
SOUZA 11-2
STEWART 1
SUMP-WILLIAMS MOBIL 1
HAGAN 2-12
GUNN 1-17
USA-AR-BLODGETT 1
SHILOH 1-15
SUMPF-WILLIAMS-TURN 2
SAGE-PHILLPS ETC 1
HAGEN 1
MCCOLGAN 21-1
ANDERSON 1
HAMILTON RANCH 1
ANDERSON 1-28
STANDARD-KIRBY COMM 8R
MCKINNON RANCH 1-33
ANDERSON 1-5
MCDOUGAL LIVESTOCK 1
MCCORMACK 7
STANDARD-FONTANA FA 5
NEIL 1 New
MH-2
GP 1-7 New
DOZIER & PRESSLEY 2-9 New
MCDOUGAL 2-8
MCCORMACK 5
FONTANA FARMS 9
DOZIER-PRESSLEY 1
NATURAL GAS CORP-RO 1
DECKER ISLAND UNIT 1-5
DECKER ISLAND UNIT 4
SHELL-GESNON 4-30
UPHAM 4
Upham_1
[ft]
[ft]
Symbol legend
township_range.prn
Coco Properties
Plugged and abandoned
Gas
Undefined
Temporarily abandoned
Planned gas injector
0 2500 5000 7500 10000 12500ft
1:50000
Anderson Formation Top Structure Map
Country
USA
Scale (ft)
1:50000
Area
Sacramento Basin
Contour inc (ft)
50
Horizon Name: Martinez123



Symbol legend
- township_range.pro
- Coco Properties
- Plugged and abandoned
- Gas
- Undefined
- Temporarily abandoned
- Planned gas injector

0 2500 5000 7500 10000 12500ft

1:50000

Martinez123 Formation Top Structure Map	
Country: USA	Scale (ft): 1:50000
Area: Sacramento Basin	Contour inc (ft): 50
Horizon Name: Martinez123	

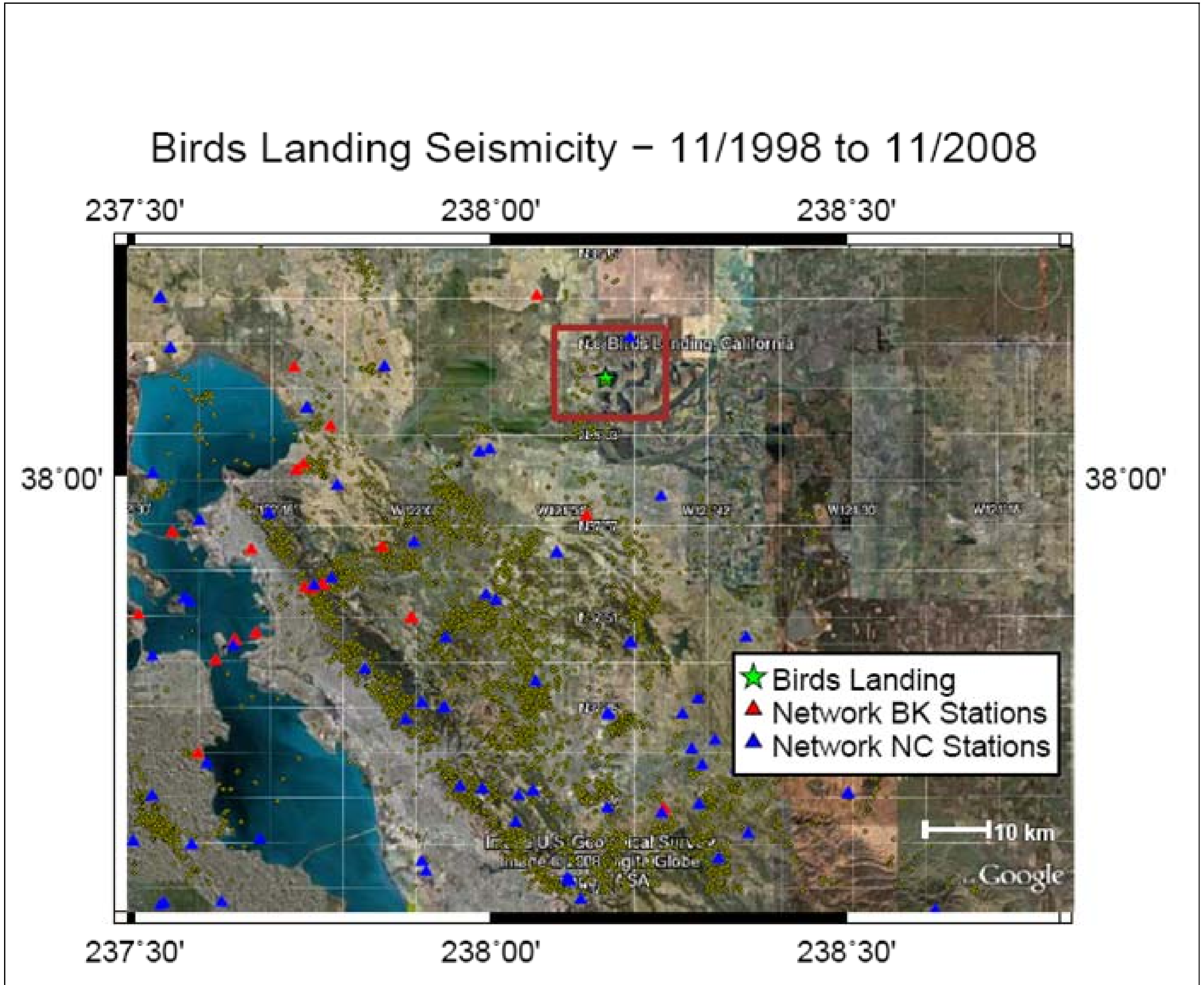


Figure F-13 Map of the San Francisco Bay area showing seismic events (yellow dots) and the monitoring network stations (red and blue triangles). Seismic events are concentrated along major fault systems.

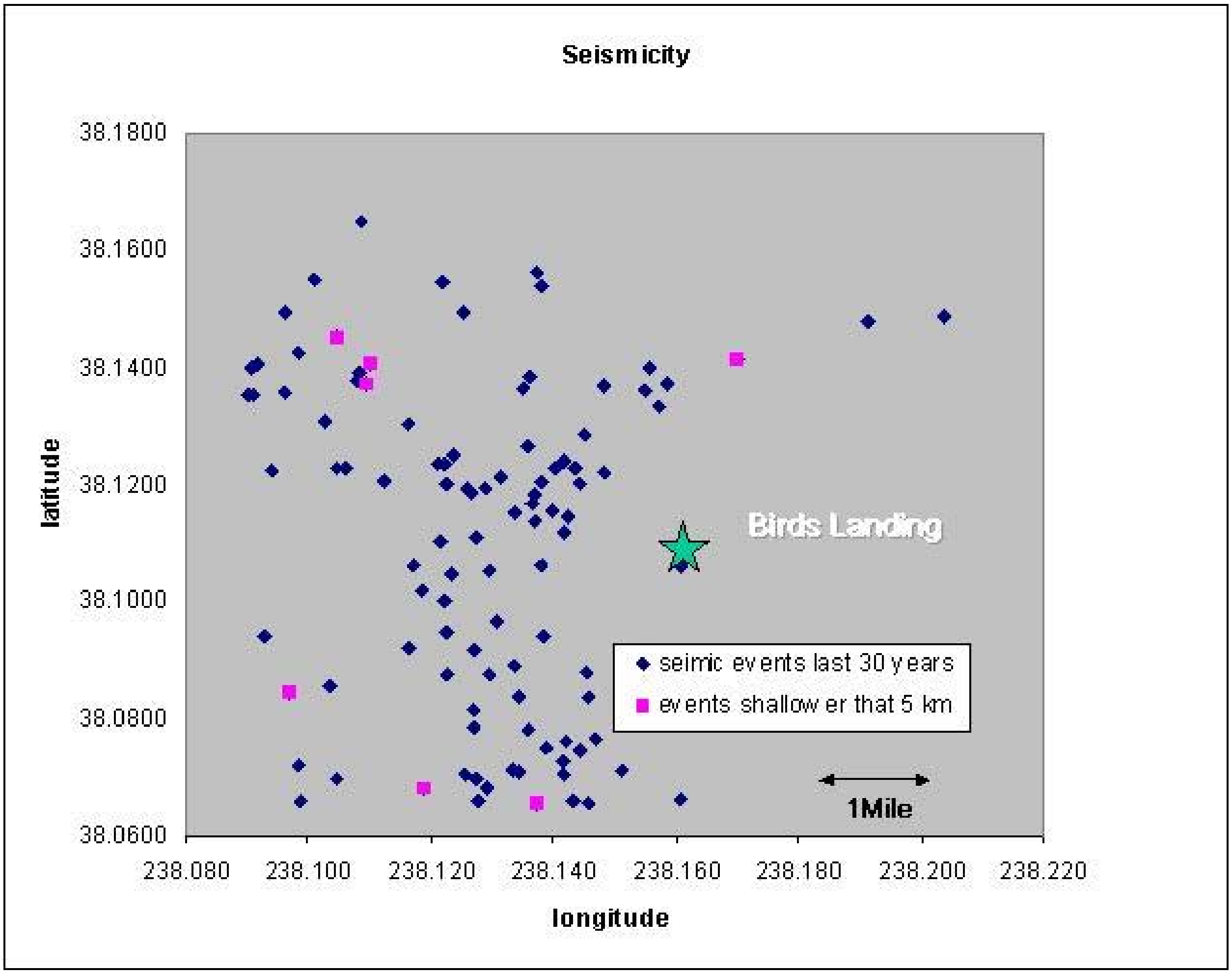


Figure F-14 A detail map near Birds Landing showing seismic events within a 30 year time period ending 11/08. Most of these events were deeper than 3 miles (5 kilometers). The seven events located shallower that 3 miles were only magnitude 2.

ATTACHMENT G GEOLOGIC DATA ON INJECTION AND CONFINING ZONES

G.1 INJECTION AND CONFINING ZONES

The objectives of the Injection Well are to appraise and establish the presence of sealing confining zone shales and permeable injection interval sandstones beneath the Montezuma Hills synclinal structure (Rio Vista basin). There are five potential "pairs" of strata that are expected to form confining interval/injection interval combinations beneath the test site. They are (in stratigraphic order, shallowest to deepest):

- **Nortonville Shale/Domengine Sandstone**
- **Ione-Capay Shale/Hamilton Sandstone**
- **Meganos Shale/Anderson Sandstone**
- **Anderson Shale/ Upper Martinez Sandstone**
- **Martinez Shale/Martinez123 Sandstone**

A type log of the anticipated strata present beneath the test site is presented as Figure G-1. This figure shows the relationship between the potential confining zone/injection interval pairs. Note that the potential major injection interval sandstones are separated by thick shales of marine origin. These shales will provide laterally extensive seals for the pilot.

G.1.1 Nortonville Shale/Domengine Sandstone

The top of the Nortonville shale is anticipated at a depth of 7,415 feet true vertical depth subset (TVDss) or 7,645 feet below rig Kelly bushing (RKB) in the Injection Well, and the shale is expected to be approximately 340 feet thick. Being of a marine origin, the Nortonville shale was deposited over a broad area and is observed in the wells surrounding the syncline. Its thickness and lateral extent will make the Nortonville shale an excellent confining zone for the underlying Domengine sandstone.

The Domengine sandstone is the primary productive interval in the nearby Rio Vista field (termed the “Emigh” in the field). The Domengine consists of a series of interbedded marine sand and marine shales. In general, the lower units in the Domengine are cleaner, with better sorting and rounder grains (Johnson, 1990). The upper Domengine sands contain glauconite, and tend to be dirtier, finer grained, and less mature (Johnson, 1990). Average depth of the sand in Rio Vista is 3,800 to 4,300 feet, and average porosity of the sand is 34 percent (Johnson, 1990). Anticipated depth of the top of the Domengine sand in the Injection Well is 7,765 feet TVDss. In the offset MCOR Grandpa Peter #1-7 well, there is approximately 200 feet of gross sand and 70 feet of net sand (50% spontaneous potential deflection) in the Domengine interval.

G.1.2 Ione-Capay Shale/Hamilton Sandstone

The Ione-Capay shale underlies the Domengine sand and is anticipated to be at a depth of 8,120 feet TVDss in the Injection Well. The Capay shale lies unconformably on top of the Hamilton sand and is of marine origin. Data from the Rio Vista field indicates that the lower Capay was deposited in outer neritic environments, while the upper Capay appears to be of inner-neritic to brackish environments (Johnson, 1990). Based on this progression to shallower marine environments, it appears that the Capay was deposited during a shoaling of the basin. The Capay is described as a soft to firm, gummy, light to medium gray shale that is moderately cohesive (Johnson, 1990). The Capay shale is expected to be approximately 900 feet thick in the Injection Well and an excellent confining zone based on its broad regional extent.

The top of the Eocene-aged Hamilton sand is anticipated to be at a depth of approximately 9,000 feet TVDss in the Injection Well. The Hamilton sand is described as a light gray, very-fine to fine grained, micaceous, friable sand in the Rio Vista field (Johnson, 1990). The Hamilton sandstone contains shallow marine burrows and fossils in outcrop areas near Brentwood (south of the Sacramento River) (Krug et al., 1992). Eastward coarsening of the Hamilton and eastward onlap of the overlying Capay shale indicate that the sequence represents a transgressive deposit, with the transgression proceeding from west to east during a major rise in sea level. Average porosity of the Hamilton sand is 27 percent in the Rio Vista field (Johnson, 1990). In the offset MCOR Grandpa Peter #1-7 well, there is approximately 245 feet of gross sand and 105 feet of net sand (50% spontaneous potential deflection) in the Hamilton sand interval.

G.1.3 Meganos Shale/Anderson Sandstone

The Meganos shale underlies the Hamilton sand and is anticipated to be at a depth of 9,715 feet

TVDss in the Injection Well. The Paleocene-Eocene-aged Meganos shale lies unconformably on top of the Anderson sand and is of marine origin. Data from the Rio Vista field indicates that the Meganos shale is a soft, clayey, light to medium gray to black shale (Johnson, 1990). The Meganos shale is expected to be more than 950 feet thick in the Injection Well and an excellent confining zone based on its broad lateral extent.

The top of the Paleocene-aged Anderson sand is anticipated to be at a depth of approximately 10,650 feet TVDss in the Injection Well. The Anderson sand is described as a light gray, fine to medium grained, micaceous quartz sand in the Rio Vista field (Johnson, 1990). The Anderson sandstone exhibits a blocky to fining upward log character, contains lignite beds, and may largely be of non-marine origin (Krug et al., 1992). Average porosity of the Anderson sand in the Rio Vista field is 31 percent (Johnson, 1990). In the offset MCOR Grandpa Peter #1-7 well, there is approximately 600 feet of gross sand and 420 feet of net sand (50% spontaneous potential deflection) in the Anderson. The Anderson sandstone thickens rapidly from east to west, away from the Midland fault system.

G.1.4 Anderson Shale/ Upper Martinez Sandstone

The Anderson shale underlies the Anderson sand and is anticipated to be at a depth of 11,350 feet TVDss in the Injection Well. The Paleocene-aged Anderson shale is of marine origin. Data from the Rio Vista field indicate that the Anderson shale is described as a firm to hard, medium to dark brown siltstone with light to medium gray claystone (Johnson, 1990). The Anderson shale is expected to be approximately 900 feet thick and an excellent confining zone in the Injection Well.

The top of the Paleocene-aged Upper Martinez sand is anticipated to be at a depth of approximately 12,245 feet TVDss in the Injection Well. In the offset MCOR Grandpa Peter #1-7 well, there is approximately 50 feet of gross sand and 35 feet of net sand (50% spontaneous potential deflection) in the Upper Martinez.

G.1.5 Martinez Shale/Martinez123 Sandstone

The Martinez shale underlies the Upper Martinez sand and is anticipated to be at a depth of 12,410 feet TVDss in the Injection Well. The Paleocene-aged Martinez shale lies conformably on top of the Martinez123 sand complex and is of marine origin. Data from the Rio Vista field describes the shale as a firm to hard, medium to dark brown siltstone with light to medium gray claystone (Johnson, 1990). The Martinez shale is expected to be approximately 120 feet thick and an excellent confining zone in the Injection Well based on its broad lateral extent.

The top of the Paleocene-aged Martinez123 sand complex is anticipated to be at a depth of approximately 12,530 feet TVDss in the Injection Well. The formation is interpreted to have been deposited in a submarine fan system, and is up to 1,000 feet thick west of the Sherman Island fault system (Krug et al., 1992). The offset MCOR Grandpa Peter #1-7 well penetrated to just above the top of the Martinez123 sand complex.

G.2 SUBSURFACE PROPERTIES

An objective of the Injection Well is to appraise and evaluate the geology beneath the Montezuma Hills area and determine the suitability of the site for the pilot CO_2 injection test. Although determinations of many of the subsurface properties of the strata require installation of the well, some subsurface properties can be estimated from available offset well data and state records.

G.2.1 Temperature Profile

Temperatures of fluids produced from formations were not found during file searches of area wells. Bottomhole temperatures from the open-hole well log headers in the Montezuma Hills area are used to establish the temperature gradient profile. These data indicate normally increasing temperature with depth. The computed temperature gradient is approximately:

$$T\left({}^{o}F\right) = 80^{o}F + 0.0135 * Depth$$

G.2.2 Pore Pressure and Fracture Pressure

Pore pressure prediction and geomechanics are utilized to generate pore pressure and fracture pressure gradients, which are key parameters used in drilling program design, especially for mud weight and casing. The tectonic settings in the Montezuma Hills area are assumed (will be verified through data acquisition and pilot testing program) to range from thrust fault regime to strike slip regime; that is, overburden pressure is either the smallest or the intermediate of the three principal stresses.

Pore pressures are predicted from sonic logs in the crest region of the Montezuma Hills, calibrated by pore pressure data from drill stem test measurements in the offset wells. Overburden pressure is predicted by integration of open-hole density log data.

Fracture pressure is predicted using overburden and pore pressure. If the region is, in fact, a thrust-fault setting, fracture pressure is approximately equal to the overburden pressure, this gives the high case. If the region is, rather, an extensional normal-fault setting, fracture pressure is approximately a function of overburden pressure, pore pressure, and the Poisson's ratio of the rock, which gives the low case.

From both offset well pressure data and sonic-based prediction, it appears that overpressure (relative to the normal hydrostatic gradient) starts at about 9,500 feet in the crestal regions surrounding the syncline (below the Anderson sand). At the Injection Well location, which is located in the center of the syncline, using a depth-related pressure model, the start of overpressure corresponds to the Hamilton sand (9,000 feet TVDss). However, the most likely case comes from using a stratigraphy-related pressure model, where the start of overpressure corresponds to the depth of Anderson shale (11,350 feet TVDss) at the Injection Well.

Pore pressure, overburden stress, and fracture pressure prediction for the formations beneath the pilot site are presented in Table G-1 and are shown diagrammatically in Figure G-2.

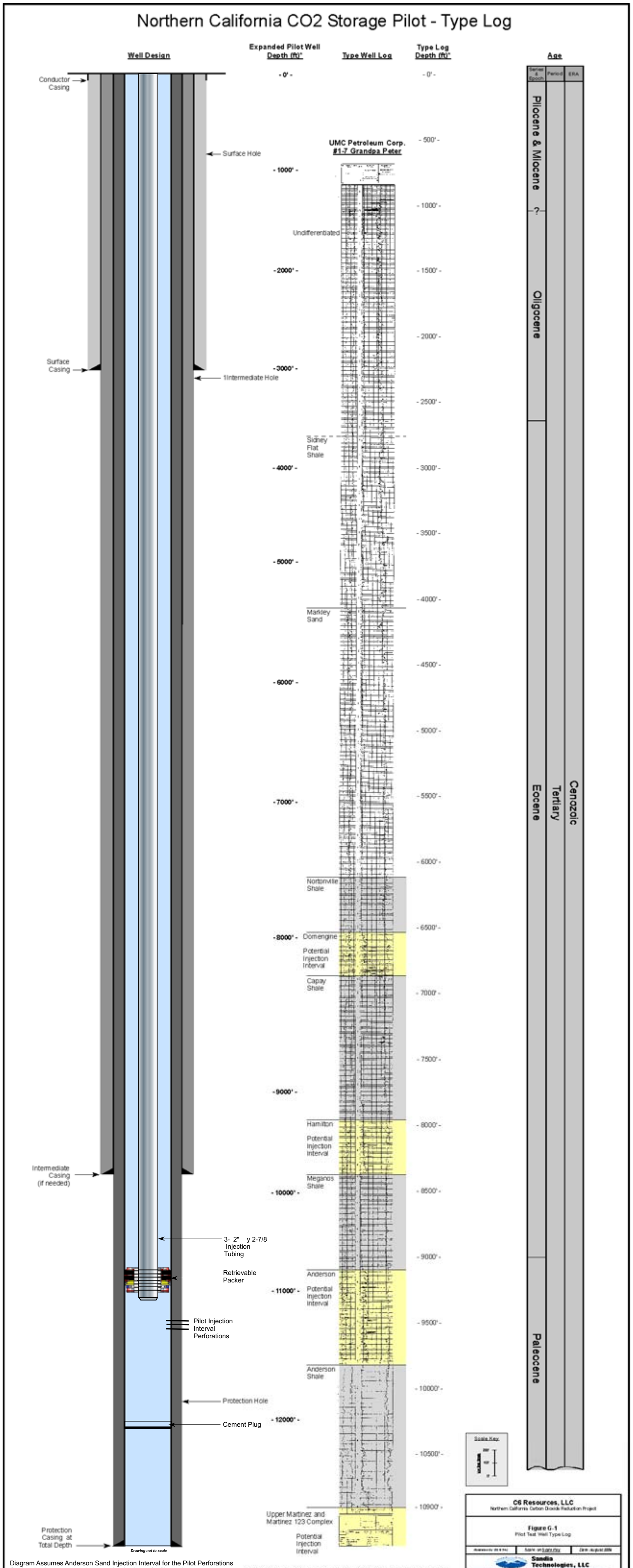
Table G-1 Pore Pressure, Overburden Stress, and Fracture Pressure Prediction

Targets	TVD (ft ss)	Pore pressure (ppg)	Overburden Stress (ppg)	Fracture Pressure Mean (ppg)
Nortonville	7,415	8.5	13.97	17.54
Domengine	7,765	8.5	13.88	17.61
Capay	8,120	8.5	13.79	17.68
Hamilton	9,000	8.5	13.60	17.85
Meganos	9,715	8.5	13.47	17.97
Anderson	10,650	8.5	13.35	18.14
Anderson shale	11,350	8.5	13.28	18.25
Upper Martinez	12,245	12.0	15.07	18.39
Martinez shale	12,410	11.98	15.06	18.41
Martinez123	12,530	11.95	15.05	18.43

ppg = pounds per gallon

References

Johnson, D.S., 1990, Rio Vista Gas Field – U.S.A. Sacramento Basin, California, in Foster, N.H., and Beaumont, C.A., Eds., Atlas of Oil and Gas Fields, Structural Traps III, AAPG Treatise of Petroleum Geology, Atlas of Oil and Gas Fields, Tulsa Oklahoma, p. 243-263.



Northern California CO2 Storage Pilot - Type Log
Well Design
Expanded Pilot Well Depth (ft)*
Type Well Log
Type Log Depth (ft)*
Age
Series & Epoch
Period
ERA
Conductor Casing
Surface Hole
Surface Casing
1Intermediate Hole
Intermediate Casing (if needed)
3- 2" y 2-7/8 Injection Tubing
Retrievable Packer
Pilot Injection Interval Perforations
Protection Hole
Cement Plug
Protection Casing at Total Depth
Drawing not to scale
- 0' -
- 1000' -
- 2000' -
- 3000' -
- 4000' -
- 5000' -
- 6000' -
- 7000' -
- 8000' -
- 9000' -
- 10000' -
- 11000' -
- 12000' -
UMC Petroleum Corp.
#1-7 Grandpa Peter
Undifferentiated
Sidney Flat Shale
Markley Sand
Nortonville Shale
Domengine
Potential Injection Interval
Capay Shale
Hamilton
Potential Injection Interval
Meganos Shale
Anderson
Potential Injection Interval
Anderson Shale
Upper Martinez and Martinez 123 Complex
Potential Injection Interval
- 0' -
- 500' -
- 1000' -
- 1500' -
- 2000' -
- 2500' -
- 3000' -
- 3500' -
- 4000' -
- 4500' -
- 5000' -
- 5500' -
- 6000' -
- 6500' -
- 7000' -
- 7500' -
- 8000' -
- 8500' -
- 9000' -
- 9500' -
- 10000' -
- 10500' -
- 10900' -
Pliocene & Miocene
?
Oligocene
Eocene
Paleocene
Tertiary
Cenozoic
Scale Key
C6 Resources, LLC
Northern California Carbon Dioxide Reduction Project
Figure G-1
Pilot Test Well Type Log
Sandia Technologies, LLC
Diagram Assumes Anderson Sand Injection Interval for the Pilot Perforations
Casing depths are approximate and only shown for illustration
*NOTE: DEPTHS SCALED TO EXPECTED VALUES AT PILOT SITE

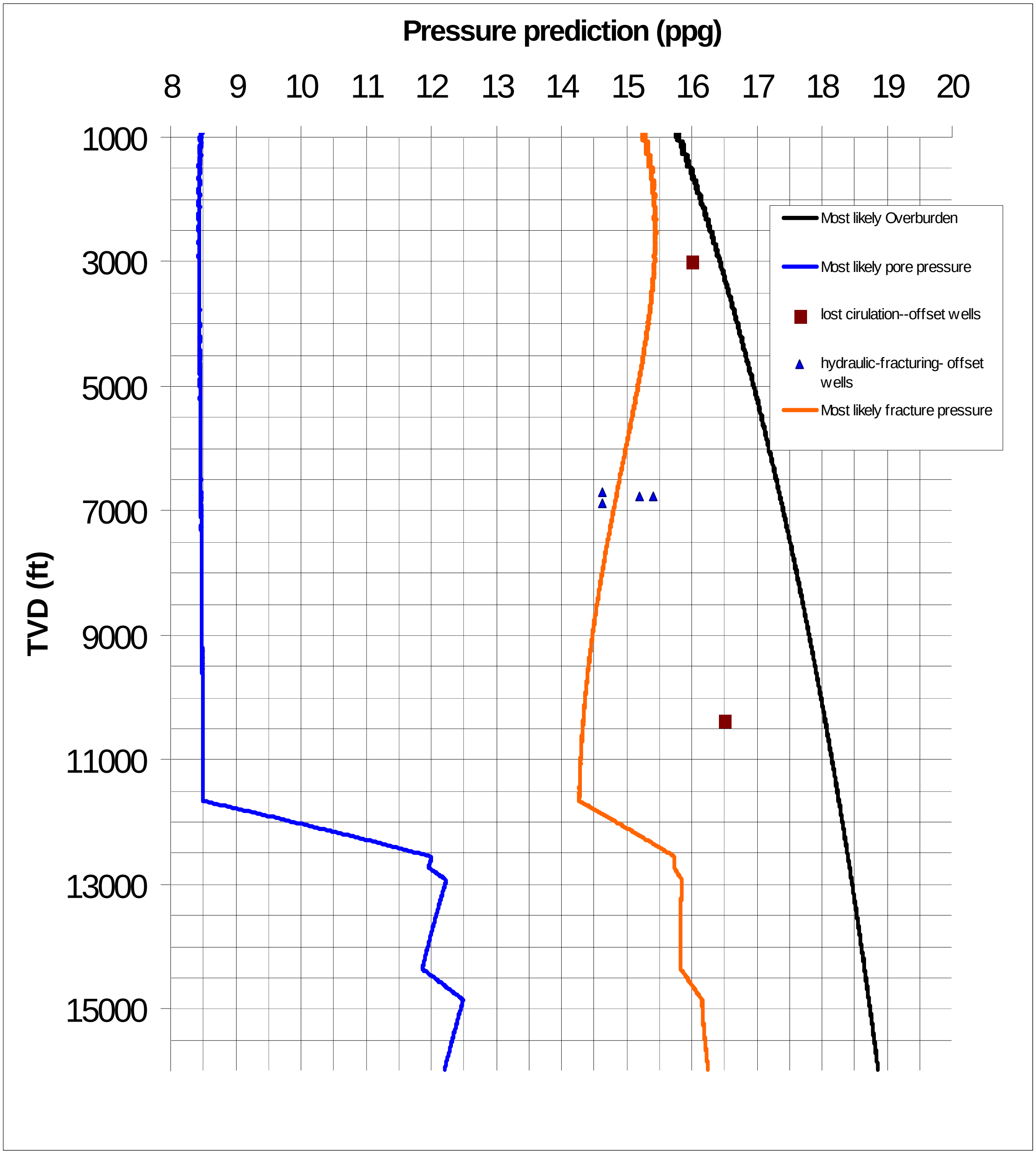


Figure G-2 Pore and Fracture Pressure Predictions

ATTACHMENT H OPERATING DATA

Proposed operating data for the Injection Well is detailed in this attachment, including: average and maximum daily rate and volume of the fluids to be injected; average and maximum injection pressure; and nature of annulus fluid. Chemical and physical characteristics, including density and corrosiveness, of injection fluids are detailed in Section P.1.1 of Attachment P.

H.1 WELL OPERATING DATA

The project is designed for 2,000 to 6,000 tonnes (≈2,200 to 6,600 US short tons) of CO_2 to be injected into the injection interval over a one- to two-month period. An average daily flow to the Injection Well of several hundred tons of CO_2 per day is expected; however, the actual rate will depend on formation characteristics and CO_2 deliverability to the well location. Since the exact well-to-well distance and storage volume (porosity-thickness) of the injection interval to be used during the pilot is not yet established, the cumulative injection volume may be as much as 10,000 tonnes. The actual volume required is that which is needed in order to ensure that the CO_2 plume extends beyond the Observation Well.

Injection rate, duration, and cumulative tonnage injected described in this plan are subject to revision, once well data and baseline data become available. These results will allow the development of more accurate models to predict actual formation performance.

Table H-1 Fluid Injection Rate and Pressure Summary

Fluid	Average Daily Rate (MMSCF CO_2 /day)	Maximum Daily Rate (MMSCF CO_2/day)	Total Volume (tons)	Average Pressure (psi)	Maximum Pressure (psi)
CO_2	10	62	10,000	2,500	4,000
	Average Daily Rate (barrels/min)	**Maximum Daily Rate (barrels/min)**	**Total Volume (barrels)**	**Average Pressure (psi)**	**Maximum Pressure (psi)**
Test Water*	42	20	3,000	1,000	4,000

* Formation testing prior to CO_2 injection using native water. Note that maximum rates during the minifrac and step-rate injection test is used

Surface injection pressure is expected to range from 700 to 4,500 psi when injecting CO_2 at an injection rate (liquid side of the pump) of 1 to 2 barrels per minute.

The annular completion fluid for the wells will be an inhibited KCl brine or native brine solution with a density appropriate to establish well control. Corrosion inhibitor, biocide, and oxygen scavenger additives will be mixed with the annular completion fluid prior to pumping into the well.

ATTACHMENT I FORMATION TESTING PROGRAM

The proposed formation testing program will consist of open-hole evaluation, cased-hole testing, and pilot study baseline and injection monitoring activities designed to characterize subsurface injection intervals and containment/confining intervals. The primary formation evaluation objectives are to capture data to accurately evaluate, appraise, and optimize the following towards meeting the well objectives:

- Salinity ranges for the potential injection intervals
- Adequate permeability for injection
- Fracture pressure of the injection intervals for containment
- Accurate casing depths and coring zones

Program results will provide a better understanding of reservoir development/architecture in the pilot area. The testing program will define formation lithologies and petrophysical characteristics (porosity, permeability, grain density, etc.), gather data formation fluid chemical and physical characteristics, and determine the progression of formations pressures (and formation stress characteristics) and temperatures with depth. The formation testing program will form the basis for the pilot baseline testing and testing conducted during injection of CO_2.

I.1 OPEN-HOLE TESTING PROGRAM

The open-hole testing program will focus on the collection of lithologic samples and well logs that will be used to characterize the penetrated lithologies.

I.1.1 Mud Logging

Drilling fluids typically consist of drilling muds and various additives used to cool the drill bit and flush the sediments and rock fragments cut by the drill bit (drill cuttings) from the hole. Mud logging refers to the process of collecting and examining the drill cuttings and fluids (i.e., collecting grab samples).

A mud logger will be used to collect samples of the drill cuttings and fluid samples during the drilling operation to log the hole and identify the lithology and petrology of the rock strata. The logger estimates the sample depth by calculating and tracking the “lag” time, which is the time it takes for the cuttings to travel from the bit to the land surface. The greater the depth of the well, the greater the calculated “lag” time. The cuttings will be labeled, washed, dried, and examined with a binocular microscope to identify the predominant rock type. Rock types are often correlated with drilling rates to provide further information on the depth and subsurface distribution of the rock strata. The chloride content of the drilling fluids and mud pit volumes will be monitored to determine if saline water is flowing into the borehole from high-permeability formations.

The mud logger will be rigged up during setting of the surface casing string and will log the open-hole from drill out of the surface casing to total well depth. The logger will provide a rock lithology description, using 30-foot samples (or better based on drill rate), catalogue wet and dry samples, monitor the circulating mud for entrained gases (total gas, C_1, C_2, C_3, and C_4), record drill rate, and monitor other well indicators for evidence of increasing well pressures. The logger will also be tasked with providing proactive correlation and surveillance of tops with offset wells.

I.1.2 Coring Program

Whole-core open-hole coring will be conducted to obtain samples for off-site petrophysical, geochemical, geomechanical, and hydrologic laboratory measurement and analysis. Conventional cores of the overlying containment/confining (seal) shale (Meganos Shale) and the target injection interval (Anderson Sand) are proposed in order to determine seal integrity, geomechanical properties, porosity, permeability, and other special rock properties. Core points will be picked based initially on geophysical profile, and then refined at the wellsite based on correlations to offset wells. Where conventional cores are not taken or do not adequately sample main reservoir sands, a sufficient number of rotary sidewall samples will be taken to further define the potential reservoir’s permeability (see Section I.1.4 – Open-hole Logging Program). Exact depths of the sidewall samples will be determined from evaluation of the wireline logs.

The following whole core depths are proposed for the Injection Well. Core depths will be picked based on correlation from the Injection Well mud and open hole logs to nearby wells.

Approximate Core Depth	Formation/Lithology
9,715 feet (TVDss)	Meganos Shale
10,650 feet (TVDss)	Anderson sand

Recovered cores will be analyzed, at a minimum, for the following:

- Core Gamma Ray (whole core only)
- Lithologic Description
- Routine Analysis (Air Permeability and porosity)
- Bulk Density

Additional (special) core analyses may be performed on select core samples. These include:

- Whole Core CT Scan
- X-ray Diffraction
- Scanning Electron Microscope
- Thin-section Petrography
- Mercury Injection Capillary Pressure
- Cap Rock Permeability
- Rock Mechanical Properties (tri-axial stress/strain)
- Rock Accoustical Properties
- Nuclear Magnetic Resonance (T2)

Specific tests will be selected by the Project Team based on the evaluation of the whole cores and the open-hole geophysical well logs obtained at that time.

Core screening in the field may also include use of a mini-permeameter for preliminary permeability measurements of cored sands. This will be used as a “field decision tool” because of the possibility that decreasing reservoir permeability with depth would make the well, or deeper portions of the well, unsuitable for use.

I.1.3 Leak-off Testing

After cementing each casing string, a leak-off test will be run to verify that the casing, cement, and formation immediately below the casing seat can withstand the anticipated wellbore pressures required to drill to the next casing string depth. The test will be conducted following drill out of the float equipment and a short section of new formation. The calculated fracture pressure from the test will be used as the maximum pressure that may be imposed on that formation to the next casing point. The observed shape of the leak-off test is primarily controlled by the local stresses, which will also provide geomechanical information about the local stress field.

I.1.4 Open-hole Well Logging Program

The open-hole logging program is designed to provide correlation with offset wells and define the subsurface lithology, overburden characteristics, hole dimensions and stress directions (breakouts), acoustic properties for seismic, geomechanical properties, and the presence/absence of hydrocarbons. The following geophysical well logs will be run in the open-hole section of the appraisal well:

Surface Casing Hole

- Natural gamma ray
- Spontaneous Potential
- Resistivity
- Borehole caliper

Protection Casing Hole

- Dual Induction/Spontaneous Potential
- Natural gamma ray
- Porosity (density, neutron, and sonic (compressional and shear))
- Borehole caliper
- Fluid sampler
- Formation imaging tool

- Nuclear magnetic resonance tool
- Mechanical/rotary sidewall coring tool

The logging tools to be run, that are beyond the general regulatory requirements, are detailed as follows:

Nuclear Magnetic Resonance Tool

During open-hole logging of the intermediate (if run) and protection casing holes, a nuclear magnetic resonance tool may be run for better definition of permeability and porosity through the potential injection interval sands. Running of this tool is contingent on the adequacy of the borehole and the results of the characterization of the formation fluids.

Mechanical/Rotary Sidewall Cores

Horizontal rotary sidewall coring may be taken in the injection sands and/or the confining zone shales during the open-hole logging of the intermediate and protection hole. These cores will be used to supplement the conventional core data. The Project Team, based on the evaluation and percent recovery of the conventional cores, will determine if sidewall coring is necessary and select actual core depths, based on the open-hole logs.

Formation Fluid Sampling

During open-hole logging of the intermediate (if run) and protection casing open holes, fluid samples will be recovered from each of the major sand intervals (Domengine, Hamilton, Anderson, Upper Martinez, and Martinez123). The samples will be used to determine formation fluid characteristics. Exact sampling depths will be determined from the open-hole logs. Samples will be attempted from intervals with porosity/permeability development and smooth in-gauge or near in-gauge borehole. A sampler with pump-through capacity is preferred so that fluid parameters (resistivity, temperature) can be monitored as the near-wellbore area is purged of mud filtrate. In this way, fluid is excluded from the sample chamber until an uncontaminated sample can be recovered. The drilling mud may be “tagged” with Optitrack 600 (MI Swaco). The optical analyzer module is sensitive to Optitrack 600 and will be used to further discriminate mud filtrate from background formation fluid.

- Well-site fluid handling and testing requirements:
  - Procedures for handling recovered samples will conform to C6 Resources, LLC handling requirements.
  - Each fluid sample will be tested initially for pH, chlorides concentration, density, and resistivity at temperature.
  - Additional tests may be conducted pending Advanced Water Chemistry unit availability.
  - Before being transported off-site for further testing, fluids will be restored into sample bottles and clearly labeled with:
    - exact well name and number,
    - sampling depth (or rig location),
    - reservoir/sand/zone name,
    - expected fluid type,
    - a description of what the sample is,
    - sample bottle position,
    - sampling inventory reference number,
    - person who oversaw the sampling,
    - date and time of sampling, and
    - any applicable transfer history.

- Offsite fluid analysis requirements:
  - Gas to liquid ratio (GLR)
  - Mineral composition (ICP) cations and anions
  - pH
  - Density
  - Resistivity
  - Organic acids
  - Offsite analysis results to be submitted upon completion of testing:
    - MDT report
    - Sample transfer report
    - Advanced Water Chemistry report
    - QC'd Advanced Water Chemistry report
    - Full completed inventory list

I.2 CASED-HOLE TESTING PROGRAM

The cased-hole testing program will focus on demonstrating the integrity of the well, determining the borehole track in the subsurface, and further characterizing the injection interval sands.

I.2.1 Cased-hole Logging

The cased-hole logging program is designed to demonstrate integrity of the cement and tubulars, derive the geometry of the wellbore path, and characterize the subsurface temperature gradient.

The following geophysical well logs will be run in the completed cased-hole section of the appraisal well:

Cased Hole (0 – 11,000 feet)

- Cement evaluation and casing inspection tool
- Gyroscopic survey
- Differential temperature survey

Additional diagnostic cased-hole logs may be run at the discretion of the Project Team.

I.2.2 Pressure-Transient Testing

Pressure transient testing may be used to define reservoir properties and evaluate the completion condition of the wells. Step-rate tests and mini-frac tests can be used to define the breakdown pressure, formation closure pressure and formation fracture pressures of the formations of interest using low volume/high rate injection techniques. Constant rate injection/falloff or production/buildup tests and cross-well interference tests can be used to measure formation transmissibility, storativity, and completion condition of the well(s). A more detailed testing procedure will be developed and conducted in the chosen pilot testing interval following installation of the Injection Well. The various types of transient tests being considered are outlined in the following subsections.

I.2.2.1 Mini-frac Injection Test

A mini-frac injection test, using native or commercial brine, may be performed on the injection interval sand. A mini-frac analysis provides a method of estimating the formation fracture pressure as well as the fracture closure pressure of the potential storage formation. This type of analysis quantifies the fracturing process as estimated from the measured pressure decline. The main purpose of the mini-frac test, also known as a fracture diagnostic test, is to measure the formation fracture pressure which will help in designing the step-rate injection test (SRT - mentioned in the next section) that also measures the formation fracture pressure. This is necessary to eliminate/reduce errors that may occur during the estimation of formation fracture pressure using step rate test results, as the SRT analysis is a graphical technique.

The mini-frac test will also measure the fracture closure pressure, which is essential for understanding the in-situ minimum stress state of the rock. The formation fracture pressure is the upper limit of the fracture closure pressure so the determination of fracture closure pressure will help in detecting and estimating the fluid loss rates and fracture dimensions in the event of unintentional creation of fractures during actual CO_2 injection. It is also an important input to induced seismicity studies that require knowledge about the in-situ stress state of the formation.

For the purposes of this project, the mini-frac testing will be initiated with the injection of a small volume of fluid through an isolated section of perforated casing, creating a small fracture. Once the fracture has occurred, the injection rate will be stabilized. Following stabilization of the injection rate, injection will continue for fifteen to thirty minutes. After stable injection has been observed for the estimated time frame, the injection pumps will cease injection. If time and volumes allow, the injection pumps will be stepped down in equal time increments. This will allow for estimation of perforation and near-wellbore friction losses. The relationship between the decreasing rate and pressure results in a determination of near-wellbore pressure losses.

I.2.2.2 Step-rate Injection Test

A step rate injection test, using formation or commercial brine, may be performed on the injection interval sand. A Mini-frac pressure injectivity test (described in the previous section) may be performed ahead of the step rate test to assess receptivity of the potential injection interval. From these data, a detailed step rate test plan will be designed and performed, so that test injection pressures span the range from the measured initial shut-in to the parting pressure of the injection interval.

If the mini-frac test is performed, the step rate test will then be initiated following pressure recovery from the pre-injection test. Injection will be initiated and stepped up in equal rate increments using equal time intervals (approximately 30 minutes per step). The 30-minute increments should be sufficient to allow for proper rate stabilization of the injection pump(s) and allow sufficient time to overcome wellbore storage effects between each rate change (especially at the low rates).

The step rate test will be designed for either 5 steps (20 percent rate increase increments to 100 percent maximum rate) or 8 steps (15 percent rate increase increments to 100 percent maximum rate) to gather a sufficient number of points for valid test analysis. The step rate test results will be used to limit the maximum bottomhole injection pressure and surface injection pressure so that the reservoir and seal formations are not fractured.

I.2.2.2 Constant Rate Injection/Falloff Test

To determine and to monitor formation characteristics, a Fall Off Pressure Test using formation or commercial brine may be performed prior to CO_2 injection in order to investigate formation properties (e.g., permeability etc), presence/absence of near well bore boundaries, and wellbore conditions (skin, completion efficiency, and wellbore storage). The injection brine will be filtered to remove suspended solids (e.g., sand, silt, drilling mud) and temporarily stored in an above ground frac-tank. Fluorescein will be added to the water to trace the fluid before injecting the tagged water back into the injection well at a constant rate. Downhole pressure and temperature will be monitored in both the injection and observation wells during the injectivity test. The pressure transient response observed during injection and the pressure fall-off period will be analyzed to determine well and formation characteristics.

ATTACHMENT J FORMATION STIMULATION PROGRAM

Following perforation completion of each well, the well may be back surged to allow cleaning of the perforation tunnels. Back surging the well will remove particulates and invaded drilling fluids from the near-wellbore area. If the well is back surged, flow will be routed at surface to frac tanks via flow iron piping. Fluid returns may be monitored via a tap in the flow line for conductivity, pH, temperature, and chlorides. The well may be flowed until monitored parameters stabilize, indicating that native formation brine is being pulled from formation.

However, if back surging of the well does not result in acceptable injection characteristics, a stimulation program consisting of a small volume acid treatment may be performed. The purpose of the acid treatment will be solely to remove formation skin damage due to invasion of solids during the course of drilling and/or to open flow channels in the perforation tunnels. The acid treatment will consist of the following acids, with actual volumes, compositions, and additives to be determined at the time of treatment and formation characteristics determined from core and wireline log evaluation:

- 5 to 20% Hydrochloric Acid (HCl).
- Additional acids (HCl/HF) may be selected after performing mineralogical and acid solubility evaluation of the injection reservoir(s).
- Chemicals may be added to the acid to limit clay swelling, reduce emulsions, and inhibit reaction to the carbon steel well completion equipment. The type and quantity of these chemicals will be determined based on formation characteristics determined from core and wireline log evaluation.

The spent acid fluids may be displaced from the wellbore and near-wellbore area using a brine flush, or by back flowing the fluids back to surface, after the acid stimulation treatment is complete. Additional stimulation treatments and/or backwashing events may be necessary if injection performance of the well remains unacceptable.

ATTACHMENT K INJECTION PROCEDURES

This attachment provides a description of the proposed surface installations for the pilot test. The facilities, with the exception of the surface wellhead and annulus systems, are designed to be temporary in nature. A flow diagram for the proposed surface facilities is provided as Figure K-1. Monitoring instrumentation is more fully discussed in Attachment P.

K.1 SURFACE FACILITIES

The Injection Well surface facilities will provide carbon dioxide (CO_2) from storage to the Injection Well wellhead. The Injection Well Surface Facilities will consist of:

- CO_2 storage tanks
- Injection pump (truck or skid)
- Inline temperature monitor
- Inline pressure monitor
- Inline flow meter
- Inline heater
- Annulus pressurization and monitoring system
- Surge protection system

K.1.1 Carbon Dioxide Storage Tanks

Liquid carbon dioxide will be hauled to the location by commercial haulers and transferred to carbon dioxide storage tanks. The temporary storage tank facility will be designed for onsite storage of approximately 120 to 240 tons, or more, of liquid carbon dioxide in two or more storage vessels (60-ton portable storage tanks). Horizontal 60-ton vessels, with a maximum working pressure of 350 pounds per square inch gauge (psig), will be used. The vessels will be fitted with safety valves and a pressure vent system. This volume will provide approximately 24 hours, or more, of storage under average flow conditions anticipated for the pilot test. If required, soil under the storage vessels may be stabilized to support the load, or the vessels may be braced to distribute the load over a larger area.

K.1.2 Injection Pumps

One or more injection pumps will be used during the CO_2 injection program. The pump(s) will be temporary and will be either truck mounted or skid mounted. It is anticipated that the pump(s) will be on location only during the active injection phase of the pilot test, plus setup and demobilization time. The injection pump(s) will have a working liquid capacity of 42 gallons per minute (gpm) or better, and a maximum operating pressure of 4,500 psig or better. Actual wellhead injection pressure (and bottomhole injection pressure) will be maintained so as not to initiate fractures in either the injection interval or the overlying and underlying containment intervals. The injection pump(s) will be designed for pumping cool liquid CO_2 under the conditions for the injection tests scheduled during the project. The CO_2 provider or a third-party pumping vendor will supply the injection pumps.

Additionally, one or more injection pumps will be used during the well and pressure transient testing program that may be performed using commercial or formation brine water. The pump(s) will be temporary and will be either truck mounted or skid mounted. It is anticipated that the pump(s) will be on location only during the active hydrologic test injection phase of the pilot test (one to two days), plus set up and demobilization time. The injection pump(s) will have a working liquid capacity of 840 gallons per minute or better, and a maximum operating pressure of 5,000 psig, or better. Note that the hydrologic testing program may be designed to operate above fracture pressure in the injection interval; therefore, larger or more pumps may be required in order to operate above fracture pressure during the short-term hydrologic testing.

K.1.3 Inline Temperature/Pressure/Flow Monitors

Temperature, pressure, and flow will be monitored and recorded continuously immediately upstream of the Injection Well wellhead. Additional temperature, flow, and/or pressure probes may be located upstream or downstream of the injection pump(s) and immediately downstream of the carbon dioxide heater to facilitate pump operation efficiency. The inline temperature and pressure probes will be used to control the surface injection pressure and the temperature of the carbon dioxide injected during the project.

K.1.4 Inline Heater

An inline heater may be installed between the injection pump(s) and the Injection Well. If used, the heater will be adjusted to regulate the discharge temperature of the carbon dioxide. This heater may be an integrated component to the truck or skid mounted injection pumps or may be independent of the injection pump system. The carbon dioxide heater will be used to regulate the temperature of the carbon dioxide to approximately 40 to 70 °F and sized accordingly (minimum 500 MBtu/hr, or better). Electricity will be used as the preferred energy source for the heater. Alternative energy sources will be reviewed for the heater.

K.1.5 Annulus Pressurization and Monitoring System

The Injection Well and Observation Well annulus pressurization and monitoring system will maintain a positive pressure versus the tubing pressure at all times. Pressurization of the annulus will be through use of either high-pressure nitrogen bottles (nitrogen blanket on a pressurized annulus fluid reserve tank) or through a high-pressure, small volume pump connected to a low pressure annulus fluid reserve tank. Annulus pressure will be monitored and recorded continuously. Separate systems may be installed for each well.

K.1.6 Well Cellar Box

The Injection Well wellhead and Observation Well wellhead will be located within individual cellar boxes installed at location grade. Rat and mouse holes (approximately 15-feet in depth) will be installed, one inside of the cellar and the second approximately two feet outside of cellar, at each well location. The rat and mouse holes will be backfilled at the completion of drilling operations.

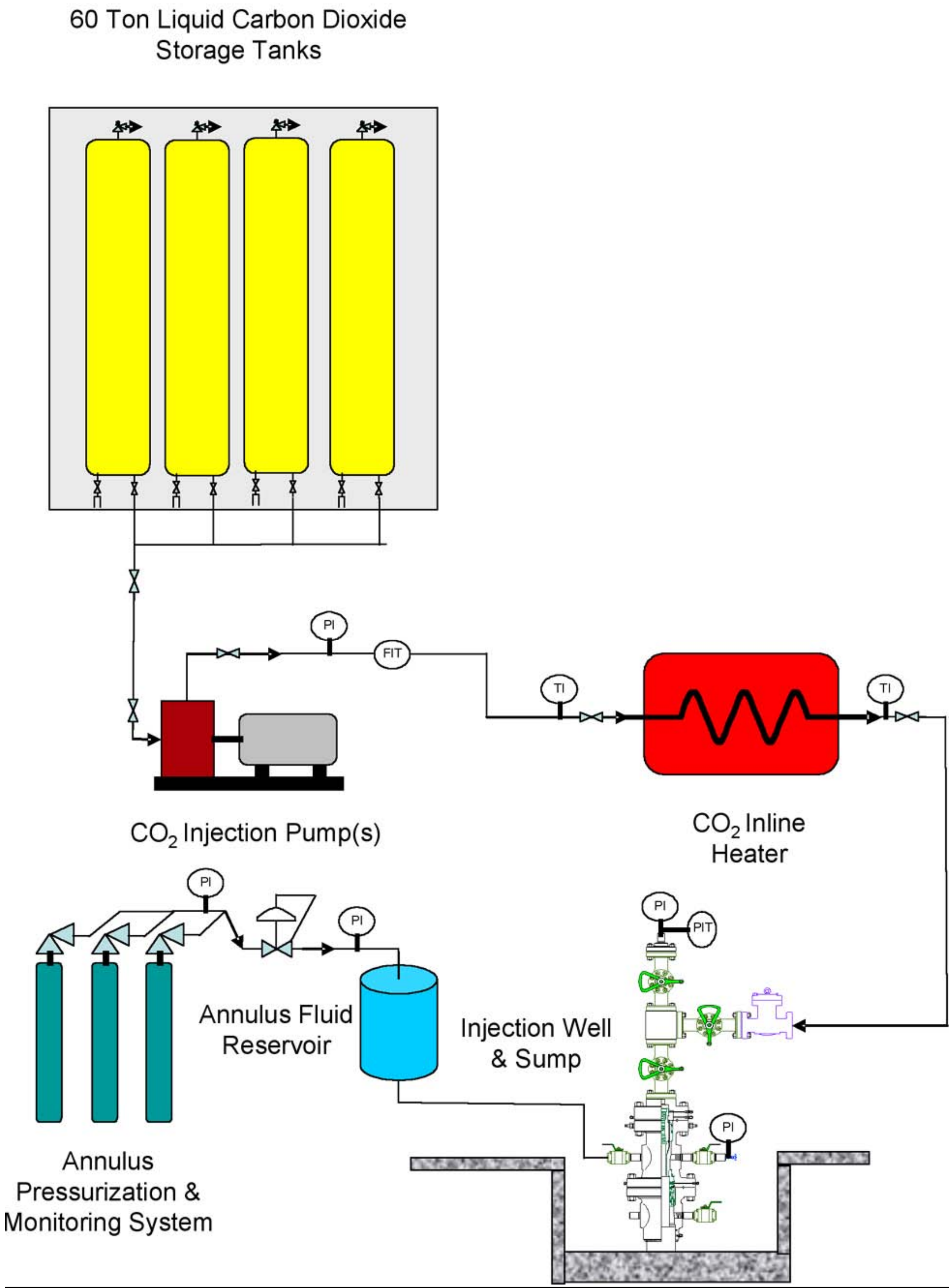


Figure K-1 Proposed Temporary CO_2 Surface Facilities.

ATTACHMENT L CONSTRUCTION PROCEDURES

L.1 WELL CONSTRUCTION PLANS

The Project Team is requesting a Class V permit to drill one injection well and one observation well. General standards for the construction of the proposed Injection Well and the proposed Observation Well are identified in this section. Schematics of proposed well options are contained in Attachment M. Enclosed information is presented in a range format, which includes several well options. Once an optimal well design option is selected and finalized, C6 Resources, LLC will notify EPA with detailed information. C6 Resources, LLC will update EPA on a periodic basis according to the progress of detailed engineering design work to occur in the next several months.

As currently anticipated, the Injection and Observation wells will be a deep stratigraphic pilot test with a proposed total depth ranging from +/- 11,000 to 14,500 feet below the rig floor (RF). Note that subsequent depths in this section are referenced to the rig floor. Both wells are expected to penetrate the stratigraphic section down through the Anderson sandstone or Martinez123 sandstone. Drilling sequence of the two wells is currently being determined. Following evaluation of data from the first well in sequence (Injection or Observation well), the drilling program for the second well may be adjusted and optimized.

Both wells will be drilled to the designated CO_2 pilot test interval. One of the two wells may or may not penetrate the full stratigraphic section seen in the other well. For example, if a shallower injection target such as Anderson sandstone is determined to be suitable for injection, during drilling of the first well in sequence, there still could be a potential to appraise deeper to Martinez 123 sandstone in the first and/or second well in drilling sequence. However, if shallower sandstone targets are not suitable for injectivity testing, C6 Resources, LLC could decide to drill to appraise deeper targets up to the depth of Martinez 123 sandstone.

As C6 Resources, LLC proceeds with detailed engineering design, there is a potential that the roles of the Injection and Observation wells could be reversed or changed for a number of reasons, for example if any drilling order complications arise.

EPA and California Department of Oil, Gas, and Geothermal Resources (DOGGR) will receive the following prior to spud of the pilot wells:

- Complete Well Book with final programs for casing, cement, drilling fluid, well trajectories, well schematics, drilling procedures, waste disposal operations, temporary abandonment, and risk mitigation plans.

L.1.1 Well Construction Information

The following subsections describe the procedures that will be followed to drill, sample, complete, and test each well in order to achieve project construction goals.

L.1.1.1 Total Well Depth

Proposed total drilling depth range is from approximately 11,000 to 14,500 feet below the rig floor. At this total depth, the well will be either below Anderson sandstone or Martinez123 sandstone. This will provide sufficient over-hole below the anticipated base of the Anderson sandstone or Martinez123 sandstone for logging and testing purposes. Note that formation characteristics will be monitored in both wells, and a determination will be made in real time as to whether the wells will be drilled to total depth. This determination will be based on actual encountered formation characteristics.

It is likely that one of the two wells will only be drilled to just below the designated CO_2 pilot injection test interval, should a shallower interval be more suitable for testing.

L.1.1.2 Well Casing Specifications

Currently there are two dominant well design options (Slender wellbore and Large wellbore) for Injection and Observation wells. However, there are other designs still in consideration that are not completely discounted and are currently being reviewed.

Well casing design is based on the most conservative design premise for kick burst pressures and collapse evacuation depths. Conservative C6 Resources, LLC design factors provide the casing integrity required for all drilling operations loads. C6 Resources, LLC Global Standards for casing design factors are shown in Table L -1.

In addition to evaluation of load cases, worst case scenario simulations, such as a tubing leak on surface, were performed with maximum injection pressure of 3,000 psi to ensure that the injection casing burst rating is adequate taking into account the aforementioned C6 Resources, LLC design factors.

Table L-1 C6 Resources, LLC Design Factors

	Pipe	Connection
Triaxial Burst/Yield	1.25	1.15
Collapse	1.0	1.0
Tensile Load (Running)	1.3	1.3

Table L-2 shows the casing specifications range for all considered options. These ranges apply to Injection and/or Observation well for both well design options. The casing strings have been designed to last for the whole well life cycle from the pilot test to development stage, if pursued.

A more definitive hole size and casing program will be provided as an update during detailed engineering design. Currently, C6 Resources, LLC is currently investigating potential surface casing shoe depths in the range from 3,000 feet to +/-4,500 feet, taking into account openhole exposure time, lithology, and casing shoe kick tolerance requirements. Furthermore, C6 Resources, LLC will re-evaluate the selection of competent shale for intermediate casing shoe after analysis of offset drilling cuttings, core samples, and logs by the geologist.

Other contingency design options currently being reviewed include the following:

- Cementing of the injection casing string into the previously set intermediate casing string to provide for at least a 500 foot overlap of continuous cement. This will replace the base option of cementing the injection casing string to surface thereby eliminating the risk of severe lost circulation and hole collapse.

- Liner tieback option for injection casing string, especially if there is a need to drill deeper into the Martinez123.

- Use of expandable tubular technology in the deeper zones ranging from Anderson sandstone to Martinez 123 sandstone in case C6 Resources, LLC would not be able to drill the well to total depth with the specified bit and hole sizes due to hole problems.

Table L-2 Proposed Well Scenarios – Casing Specifications

TUBULAR	Hole Depth (ft)**	Hole Size (in)	Size (in)	Weight (lb./ft)	Grade	Thread
CONDUCTOR*	50 – 100	--	16 - 20	94 - 106.5	K-55 – L-80	ST&C – BT&C
SURFACE CASING	2,500 – 4,500	12 1/4 - 17 1/2	9 5/8 - 13-3/8	43.5 - 72	K-55 – L-80	ST&C – BT&C
INTERMEDIATE CASING***	9,000 – 12,000	8 1/2 - 12 1/4	7 - 9 5/8	26 - 53.5	K-55 – L-80	ST&C – BT&C
PROTECTION CASING	11,000 – 14,500	6 1/8 - 8 1/2	4 1/2 -7	13.5 - 32	K-55 – L-80	ST&C – BT&C

Numbers indicate all inclusive range of all possible options currently being considered. As detailed design progresses, C6 Resources, LLC will provide a more specific value within the provided range.

* Conductor will be either jetted or hammered to setting depth and then cemented in place

** All casing strings are run and cemented to surface. The numbers indicate a final section depth range.

*** Intermediate casing is a contingency and not part of base case casing designs

L.1.1.3 Well Drilling Program

The following subsections contain the proposed step-by-step program for drilling and completing the well. A step-by-step drilling program will be provided in the subsequent updates to the EPA as the detailed engineering design work progresses. The Injection Well will be used to appraise the full stratigraphic section, and to inject the CO_2 fluid during the experiment and post-injection monitoring of the sands of interest. The Observation Well will be used to monitor the sands of interest during and after CO_2 injection.

C6 Resources, LLC will perform safety audit during rig-up of the drilling rig and drilling camp to ensure equipment setup complies with project requirements and environmental standards.

Proposed evaluation program, such as logging and coring, is located in Section I.1.4. Detailed description of casing and accessories is located in Section L.1.1.2 – Well Casing Specifications. For details on the proposed cement slurry, please refer to Section L.1.3 – Well Construction Cementing Program.

Please note that there may be a time gap between drilling of Injection and Observation wells to allow for evaluation of data from the well drilled first in sequence and identification of pilot test interval that can range anywhere from Anderson sandstone to Martinez 123 sandstone. After the pilot test interval has been identified on the first well, the second well will be drilled up to similar depth of just below the pilot test interval.

The following notifications will be performed by C6 Resources, LLC:

- Before commencing drilling operations, C6 Resources, LLC will file with the DOGGR supervisor or the district deputy a written notice of intention to commence drilling. Drilling will not commence until approval is given by supervisor or district deputy. DOGGR will be verbally notified at least 24 hours prior to the spud of the well.

- DOGGR will be notified to witness when C6 Resources, LLC performs all blowout preventer equipment testing and casing pressure testing as per DOGGR regulations. Original copy of the test record will be sent to the office with a copy at the wellsite with other important records.
- C6 Resources, LLC will notify DOGGR and USEPA of all upcoming cementing jobs
- Before commencing abandonment operations, C6 Resources, LLC will file with the DOGGR

supervisor or the district deputy a written notice of intention to abandon the well. Abandonment will not proceed until approval is given by supervisor or district deputy.

Bottomhole assembly planned for drilling each hole section in Injection and Observation wells:

- Each hole section could have a number of different arrangements for bottomhole assembly required to reach hole section total depth and achieve well objectives in an efficient and safe manner. It will include a number of combinations from the following items: a drill bit, evaluation tools, directional tools, vertical hold tools, drill collars, and associated subs.

- Further detail on a variety of bottomhole assemblies will be provided as an update during or upon completion of detailed engineering design work.

GENERAL NOTES

All depths referenced are approximate and are based on the expected log depth.

Actual depths may vary based on lithology of local formations.

COMPLETION PROCEDURE

CASING AND CEMENT EVALUATION

1. Perform safety audit during rig-up to ensure that equipment setup complies with project requirements.
2. Install well control equipment and test.
3. Pick up workstring and perform wellbore cleanout and displacement.
4. Pull the workstring from the well.
5. Rig up wireline equipment and lubricator to the top of the annular blow out preventer (BOP). Perform a pressure test on the lubricator. Run cement evaluation/casing inspection/caliper logs, differential temperature survey, and gyroscopic survey as

detailed in Section I.1.4. Run cement bond log initially under zero pressure. A repeat run at elevated pressure may be necessary to remove effects from potential micro-annulus. Run cement evaluation/casing inspection logs to surface or approximately 500 feet above the top of calculated annular cement. Rig down wireline equipment.

6. Perform a pressure test on the casing to 1,500 pounds per square inch gauge (psig) for at least 30 minutes. Record the pressure test on a strip, circular, or digital recording device. Note, DOGGR & USEPA may witness casing pressure test. The original copy of the pressure test record MUST be sent in to the office and made part of the well report. Keep a copy of the pressure test record at the well site with other important records.

WELL COMPLETION – CO_2 PILOT

7. Run any pre-experiment testing that requires the well(s) to be clear of completion equipment (such as vertical seismic profiling (VSP) and cross well seismic).
8. Rig up wireline unit and set up perforating charges. Run in hole and correlate perforation gun(s) on depth. Perforate the CO_2 Pilot interval as determined from the open-hole logs.
9. Backsurge or stimulate the completion as necessary (see Attachment J).
10. Set a retrievable plug to just below the CO_2 Pilot Formation perforations to minimize wellbore storage effects in both wells. Spot sand on top of plug.
11. Pick up completion packer(s) and tubing. Attach any downhole monitoring equipment and control lines. Run the completion assembly into the well. Once on bottom, circulate the well with clean brine.
12. Space out tubing string, and set the packer approximately 10 to 20 feet above the uppermost perforation in the CO_2 Pilot Formation injection interval.
13. Land the tubing into the wellhead.
14. Install wellhead equipment and feed control lines through the wellhead.
15. Allow well to equilibrate and perform annulus pressure test. Note: DOGGR & USEPA may witness annulus pressure test. The original copy of the pressure test

record <u>MUST</u> be sent in to the office and made part of the well report. Keep a copy of the pressure test record at the well site with other important records.

16. Rig down the rig and move out associated equipment.

GENERAL NOTES

All depths referenced are approximate and are based on the expected log depth.

Actual depths may vary based on lithology of local formations.

L.1.1.4 Contingency Plans

In the event that unforeseen events occur, detailed plans to remedy the specific problem will be developed, with input from all parties involved. These plans will then be implemented to solve the specific problem. The following are general contingency plans to address specific problems.

<u>Lost Circulation</u>

Zones of severe lost circulation have not been identified by review of local offset data. Some fluid losses are anticipated during the drilling of the surface, intermediate, and protection hole, as part of normal operations. Permeable fresh water and saline water sands will be penetrated during well installation operations. These will be treated as necessary by the addition of lost circulation material during the drilling of the hole. Low mud weights and solids concentration in the drilling fluid will help minimize losses. Any other lost circulation events would be mitigated with appropriate lost circulation material.

<u>Overpressured Zones</u>

Review of nearby well and field data indicates that pore pressures increase with depth above a freshwater gradient. Offset well data indicates that the normal hydrostatic pressure regime extends down to at least 10,000 feet. Encountered overpressure zones will be drilled with appropriate mud weights to sufficiently overbalance the formation and to deliver well objectives.

During the drilling of the wells, the following measures will be used to monitor, control, and contain formation pressure:

- Mud logger to monitor drill rate and mud volume data

- Hydrostatic pressure exerted by drilling fluid
- Blowout prevention equipment

Swelling Formations

Review of offset well data indicates that there is significant reaming (hole opening or re-drilling) operations on a majority of wells due to swelling clay and shale formations that were drilled with drilling fluid properties not intended for that environment. These swelling formations are present in all intervals from surface to depths of 14,500 feet. Excessive reaming slowed down the drilling operations on offset wells creating non productive time for re-drilling the hole that had been already drilled and, in some instances, creating stuck pipe events with drill pipe, logging tools, and casing not being able to reach planned casing shoe depth.

In that respect, C6 Resources, LLC will design for appropriate and fit for purpose drilling fluid with quality control and quality assurance that could involve the use of water based drilling fluid or oil based drilling fluid (invert mud) with a range of additives to mitigate the risk of swelling formations and minimize the non-productive drilling time of reaming and stuck pipe events.

Stuck Pipe/Tools/Casing

The possibility of stuck pipe exists due to the presence of permeable sand layers in the well path. Drilling jars will be used, if needed, in the drilling of the protection hole to assist in freeing stuck pipe. Fluid loss control of the drilling fluid will be maintained to reduce the probability of differential sticking of the work string. In the event that the work string becomes stuck in the hole, procedures will be utilized to free the pipe.

In the event that C6 Resources, LLC cannot run the casing to the planned casing shoe depth after every possible attempt has been made to clean hole, circulate and work the casing to land the casing at planned depth, the casing will be set at the hold-up depth with well design changes and a possibility for a sidetrack. Alternately, the use of technologies, such as expandable tubulars, to help reach total depth may also be employed.

EPA and DOGGR notification and consent will be obtained before sidetrack operations are implemented.

During detailed well engineering design, C6 Resources, LLC will optimize the openhole exposure time in each hole section through drilling performance evaluation and minimize the non-productive time of reaming and stuck pipe events.

Verticality Control

Review of offset data did not reveal any significant issues with maintaining verticality in vertical wells. There is evidence of a minimal natural inclination drift.

During detailed engineering design, C6 Resources, LLC will optimize bottomhole assembly and drill bit design with potential use of directional tools or verticality tools to achieve desired well path and desired separation between two wells.

Formation Influx

Review of offset data did not reveal any significant formation influx events. Adequate trip margin (minimum of 200 psi) on drilling fluid density to stay overbalanced with formation pressure, and C6 Resources, LLC well control standards will be utilized.

Coring Equipment Issues

There is a minimal potential for coring issues to occur that could result in inability to core and/or poor core recovery. C6 Resources, LLC will mitigate this risk through optimal coring bit and drilling fluid selection, use of coring jars, implementing good circulation control, and hole cleaning practices.

L.1.1.5 Drilling Fluids Program

Detailed design of the drilling fluid program for both wells will undergo quality assurance and quality control as per C6 Resources, LLC Global well drilling practices and standards. In light of the offset well analysis that revealed swelling formations, stuck pipe events, and reaming with extended openhole exposure times, C6 Resources, LLC drilling fluid program could include a range of mud types from water based to oil based (invert) to mitigate the aforementioned risks by providing adequate borehole stability and well control.

The following will be taken into account during drilling fluid program design for each hole section in both wells:

- C6 Resources, LLC will design the drilling fluid to provide sufficient trip margin in the magnitude of 200 – 500 psi in all hole sections to ensure that there is an overbalanced drilling operation.

- Lost circulation material (LCM) may be used to treat for fluid losses in shallow sands and/or deeper formations. The fluid system may be pre-treated with LCM before encountering any known or suspected loss zones.
- High-viscosity sweeps may be used to assist in hole cleaning.
- Mud weight will be increased as required for hole stability within the limits of the formation fracture gradient.
- Mud weight, viscosity, and fluid loss values will be finalized during detailed design.
- Drilling fluid program will accommodate appropriate additives to mitigate swelling formations, among other issues.
- Certain drilling fluid properties could be adjusted in the field to meet drilling objectives.

Preliminary mud weight ranges are as follows: 8.5- 9.5 pounds per gallon from 0 – 4,500 ft, 9.0 – 12.5 pounds per gallon from 4,500 – 11,000 ft, and 9.5 – 14 pounds per gallon from 11,000 – 14,500 ft.

During detailed engineering design or after its completion, C6 Resources, LLC will send updates on the drilling fluid program reflecting all the necessary details.

WASTE FLUID AND SOLIDS MANAGEMENT PLANNING

Prior to mobilizing equipment to the well location, the area beneath the drill rig footprint and surrounding area will be cleared and graded. The area will be constructed in a manner to divert any collected liquids to the well cellar or to a sump. The liquids collected in the cellar or sump will be periodically removed and recycled within the active fluid system or disposed of in an approved facility according to their classification.

Drilling mud that is circulated out of the hole will flow through solids control equipment consisting, at a minimum, of a shale shaker, centrifuge to remove drill cuttings and other solids from the circulating mud system. All drill cuttings and removed solids will be contained and characterized for proper disposal according to applicable state regulations. Mud and cuttings will be hauled to a landfill authorized to accept them by trucks powered by diesel engines. Most of the drilling waste (drilling mud, cement, and cuttings) is classified as non-hazardous. Non-hazardous drilling waste can be solidified and transported to one of several C6 Resources, LLC-approved landfill sites in the 40 mile radius. If any waste is classified as hazardous, it will be transported to nearest chemical waste management facility.

Wastewater that would be separated from drilling fluid and drilling cuttings would have a high brine concentration. Any brine that is produced could be potentially taken to an existing approved injection well in Rio Vista, a distance of 10 miles, or other approved facility and will be injected.

L.1.2 Proposed Cementing Program of Injection and Observation Wells

Detailed design of the cementing program for both wells will undergo quality assurance and quality control as per C6 Resources, LLC Global well drilling practices and standards including densities and composition of pre-flush, and lead and tail slurries, as well as excess volume, thickening times, pumping rates and pressures. Surface, intermediate, and protection casing strings in each well (depending on final well design) will be cemented from corresponding casing shoe to surface (or to the overlap 500 feet into the previously cemented casing string) with Class G cement (or better). Final cement volumes with appropriate excess volumes will be determined from the open-hole caliper log.

Please note that the following may or may not be performed on any or all of the casing strings in one or both wells to ensure there is a good cement bond without any leak paths:

- Use of stage tools for cement job
- Use of foam cement
- Use of swellable elastomers in cement
- Continuous cement to surface with overlaps of +/-500 feet.

CEMENTING ACCESSORIES

Cementing and casing accessories for all casing strings in both wells would include float shoe, float collar, and centralizers. Centralizers will be utilized to guarantee a minimum standoff of 70% or greater for the given wellbore trajectory. A combination of rigid and semi-rigid centralizers will be used to accomplish the required standoff.

During detailed engineering design or after its completion, C6 Resources, LLC will send updates on the drilling fluid program reflecting all the necessary details.

ATTACHMENT M CONSTRUCTION DETAILS

Well diagrams with construction details are shown in Figures M-1 (Injection Well) and M-2 (Observation Well).

ATTACHMENT N CHANGES IN INJECTION FLUID

N.1 SUMMARY

A reservoir dynamic model was constructed using the 3-dimensional compositional simulator GEM[2]. It is used primarily to evaluate the pilot well injectivity in the CO_2 Pilot Injection Interval, with an uncertain permeability, ranging from 2 millidarcies (mD) to 100 mD. The model was also run to predict the extent of plume movement and pressure buildup underground during the injection and post-injection time periods.

Based on the simulation results, the pilot is planned to inject 2,000 to 6,000 metric tons of carbon dioxide (CO_2) into an approximately 50-foot-thick, blocky sub-sand layer in either the Anderson or the Domengine formations. It is intended to inject the target volume within approximately one to two months, with the full achievable injection capacity under matrix injection conditions. Modeling shows that the CO_2 plume fringe will move less than 200 feet from the injection well location during the injection for the above mentioned injection volume, unless the injection interval is highly heterogeneous. An observation well will be drilled, likely on the up dip side of the geological structure, with a target distance of up to 100 to 200 feet away from the injection well.

If very low permeability (less than 8 mD) is encountered in the injection interval, the low well injectivity could pose an issue of lengthy pilot injection duration (e.g. longer than two months to inject 6,000 metric tons). In this situation, C6 Resources, LLC will make a decision to proceed with the pilot injection test or evaluate the feasibility of injecting for a longer time.

N.2 DYNAMIC MODEL

GEM is an efficient, multidimensional, equation-of-state (EOS) compositional simulator that can simulate the mechanisms of CO_2 sequestration process in subsurface saline formations, including multiphase flow, solubility trapping, residual gas trapping, and mineral trapping.

In this pilot simulation, CO_2 chemical reactions with subsurface minerals are ignored, as these reactions are considered as impacting only the long term. Dissolution of salt is treated by means

[2] GEM (**G**eneralized **E**quation-of-State **M**odel Reservoir Simulator) is a full equation-of-state compositional reservoir simulator with advanced features for modeling recovery processes where the fluid composition affects recovery. GEM also models asphaltenes, coal bed methane and the geochemistry of the sequestration of various gases including acid gases and CO_2. GEM provides reservoir simulation capabilities that include the effects of asphaltene precipitation and plugging.

of local equilibrium solubility. No precipitation of salt is modeled, and formation porosity and permeability are kept constant over the simulation time. Dry zone effect due to the irreducible water vaporization into CO_2 phase is modeled. Even though the characteristic of CO_2 relative permeability curve in the dry zone is still debatable in the scientific world at present, the type of CO_2-Water relative permeability model illustrated in Figure N-1a is considered the most probable and, therefore, is used in this simulations study. Based on this type of relative permeability model, the irreducible water saturation in the dry zone can drop to zero, and the CO_2 relative permeability end point at water saturation of zero can reach 1.

Figure N-1b shows another type of relative permeability model, in which the end point of the CO_2 curve at water saturation of zero (dry zone) is the same as that at the original irreducible water saturation, normally much less than 1. This is considered the most conservative type (not very likely) of CO_2-Water relative permeability model, in terms of characterizing the CO_2 relative permeability end point value in the dry zone. Therefore, it was applied in the simulation only when attempting to scope the worst case of well injectivity (see the section N.3).

The geological model of the pilot area was extracted from the structural regional model, built in PETREL and imported into the GEM dynamic model. Geological structure, formation stack, dip, and lateral extension in the pilot area are therefore captured. The static model imported does not include formation rock properties like permeability, porosity, and net-to-gross. More detailed geological heterogeneity is not incorporated at this stage of simulation, due to the scarcity of near-by well control.

The areal dimension of the pilot model is approximately 7 kilometers by 7 kilometers. A volumetric multiplier was applied to the boundary grids to model artificial constant boundary condition, which eliminates the boundary effect on the simulated pressure distribution. A 56-foot sub-sand layer within the Anderson formation was selected to be the notional pilot injection interval for this simulation. The injection interval was at the lower end of the Anderson formation, located just above the underlying Anderson shale. Both areal and vertical local grid refinement were then performed for grids in the vicinity of the well and in the target injection interval, in order to increase the prediction accuracy. The refined grid is 14 feet by 14 feet by 5 feet. See Figure N-2 for the area depth map and partial cross section of the pilot model.

The notional pilot injection interval is at a depth of about 11,250 feet true vertical depth sub sea (TVDss), with an estimated pore pressure of 5,000 pounds per square inch (psi). Formation temperature is estimated to be approximately 228 ^{o}F. Overlying and underlying layers are shale.

Constant properties, namely net-to-gross, porosity, permeability, vertical permeability to horizontal permeability (KvKh) ratio, relative permeability model, and rock compressibility were applied to all grids in the injection interval. The base case values are summarized in Table N-1.

A brine salinity of 12,000 parts per million sodium salt (NaCl) is assumed to generate the pressure-volume-temperature properties of brine under varying pressures (4,000 – 6,000 pounds per square inch (psi)) and constant temperature (228 ^{o}F). See Figure N-3 for the pressure-volume-temperature properties of brine and pure CO_2.

Table N-1 Base Case Rock Properties

Properties	Values
Net-to-Gross Thickness	1
Porosity, fraction	0.2
Permeability, millidarcies	10 (discrete cases for 100md, 20md, 8md, 5md, 2md)
KvKh Ratio	0.1
CO_2 -Water Relative Permeability Model	Base Case Model (for each permeability cases)
Rock Compressibility, 1/psi	2.8E-6

N.3 INJECTION PREDICTION

The well injectivity is largely unknown for the time being, due to uncertainties on injection interval properties (porosity, permeability, relative permeability, rock compressibility, fracture pressure, etc.) and well completion quality (well skin). This injection prediction work is therefore focused on identifying the possible injection rate potentials in a few subsurface scenarios, which bound expected conditions. The pilot is planned to inject under matrix condition, minimizing the possibility of creating cracks or fractures in both the injection interval sand layer and in the overlying/underlying shale confining layers. To achieve this goal, the bottomhole injection pressure during the injection operation will be maintained below the fracture pressure of the injection interval sand layer, within a safe margin. The safe margin was determined by taking a five percent discount (reduction) from the estimated formation breakdown pressure (6,679 psi) plus considering maintaining the operational pressure 10 percent below the fracture pressure. Therefore, a bottomhole injection pressure constraint of 5,711 psi was applied in the pilot simulation model. Skin of 5 is assumed as the base case for completion quality.

The simulation model essentially predicts the maximum injection rate profile over time. Figure N-4 presents a typical maximum injection rate profile from the simulation. Injection rate ramps up at the beginning and then stabilizes. The rate ramping phenomenon is due to the CO_2–Water relative permeability phenomenon. Initially, the CO_2 saturation and relative permeability value is zero, assuming that no CO_2 saturation is present in the formation. As CO_2 is injected, CO_2 saturation increases in pore spaces, especially near the well. When the CO_2 relative permeability reaches the end point of its curve, the injection rate stabilizes. The length of the ramping period and the absolute injection rate on the profile not only depend on the relative permeability and absolute rock permeability, but also relate to other subsurface parameters such as rock compressibility, porosity, and skin. Basically, rock permeability, relative permeability, rock compressibility, porosity, and skin are key influencing parameters for well injectivity.

The uncertainty of well injection rate potentials was therefore evaluated by constructing and running the low-low case (the worst case), low case (conservative case), base case (likely case), and high case (optimistic case) models, in which the inputs for the injectivity influential parameters vary. Table N-2 gives the comparison of these inputs in the low-low case, low case, base case, and high case models. Note, the uncertainty ranges of these inputs, namely the relative permeability, rock compressibility, and skin value were currently defined based on analogue data and experience. They are subject to scrutiny once hard data or measurement from the appraisal well core analysis and well tests becomes available.

The base case injection rate potentials for each rock permeability case are then summarized in Table N-3. The low-low case, low case, and high case injection rate results are summarized in Table N-4, Table N-5 and Table N-6, respectively.

Table N-2 Injection Prediction Models

Model	**Relative Permeability Model**	**Rock Compressibility**	**Well Skin**	**Porosity (fraction)**
Low-Low Case	Low (Figure N-1b type)	1E-6 /psi	15	0.15
Low Case	Low (Figure N-1a type)	1E-6 /psi	15	0.15
Base Case	Mid (Figure N-1a type)	2.8E-6 /psi	5	0.20
High Case	High (Figure N-1a type)	5E-6 /psi	0	0.25

Table N-3 Base Case Injection Rates

Permeability Case	Base Case, MMscf/day		Base Case, Tons/day	
	Initial Minimum Rate	Maximum Rate	Initial Minimum Rate	Maximum Rate
100 mD	13	46	688	2,435
20 mD	2	9	106	476
10 mD	0.9	4	48	212
8 mD	0.65	3	34	164
5 mD	0.35	1.6	19	85
2 mD	0.06	0.3	3	16

Table N-4 Low-Low Case Injection Rates

Permeability Case	Low Case, MMscf/day		Low Case, Tons/day	
	Initial Min Rate	Max Rate	Initial Min Rate	Max Rate
100 mD	5	23.5	265	1,244
20 mD	0.8	3.3	42	175
10 mD	0.33	1.3	17	69
8 mD	0.25	0.9	13	48
5 mD	0.12	0.4	6	21
2 mD	0.02	0.04	1	2

Table N-5 Low Case Injection Rates

Permeability Case	Low Case, MMscf/day		Low Case, Tons/day	
	Initial Min Rate	Max Rate	Initial Min Rate	Max Rate
100 mD	5	33	265	1,747
20 mD	0.8	6.0	42	318
10 mD	0.33	2.7	17	143
8 mD	0.25	2.0	13	106
5 mD	0.12	1.0	6	53
2 mD	0.02	0.2	1	11

Table N-6 High Case Injection Rates

Permeability Case	High Case, MMscf/day		High Case, Tons/day	
	Initial Min Rate	Max Rate	Initial Min Rate	Max Rate
100 mD	34	60	1,800	3,176
20 mD	6.0	11	318	582
10 mD	2.5	5.0	132	265
8 mD	1.9	4.0	101	212
5 mD	1.0	2.0	53	106
2 mD	0.16	0.4	8	21

Moreover, fracture pressure is another important factor impacting well injectivity, as it affects the operational pressure window. Depending on the difference between the measured formation fracture pressure and the estimated fracture pressure (currently mean value of 6,679 psi in Anderson sand for the depth of 10,730 feet TVDss), the injection rate results will be reviewed again before the pilot test execution.

Above all, this simulation study scoped the injection rate potentials, based on the current knowledge on the uncertainties of subsurface parameters. It is advised to use the above injection rate results only as guidance in the pilot operation. The actual pilot injection rate will be determined by the fracture pressure and other subsurface parameters determined by the injection test and other tests on the appraisal well.

N.4 ESTIMATION OF PILOT INJECTION DURATION

The simulation work to predict the injection rate potential also yields an estimate of the pilot injection duration (Figure N-5). Table N-7 summarizes the predicted pilot injection durations from the low-low case, low case, base case, and high case injection models.

The low case, base case, and high case results are used as the main basis for model predictions. For an injection volume of 6,000 tons, two months of injection would be required if permeability in the CO_2 Pilot injection interval is equal to 8 mD and less that two months for higher permeabilities. If permeability is 5mD in the injection interval, injecting 6,000 tons could take up to four months. In the 2 mD case (not included in Table N-7), injecting 3,000 tons would even take 5, 7, and 12 months given the high case, base case, and low case injectivity, respectively.

Long pilot injection duration (longer than 2 months) greatly challenges the operation management and leads to high cost. As such, if the permeability of the potential CO_2 Pilot injection interval is low (e.g. less than 8 mD), a decrease in well injectivity and subsequent increase in pilot injection duration will call for more rigorous review to select other formation(s), if available, before the decision for proceeding with the pilot injection test can be finally made.

Table N-7 Predicted Pilot Duration

Volume, tons	**Estimated Pilot Duration (Low-Low Case Injectivity), days**				
	100md	**20md**	**10md**	**8md**	**5md**
3,000	3	20	49	69	148
6,000	5	36	92	135	283
10,000	7	58	-	-	-
Volume, tons	**Estimated Pilot Duration (Low Case Injectivity), days**				
	100md	**20md**	**10md**	**8md**	**5md**
3,000	3	14	30	40	78
6,000	5	23	51	67	124
10,000	7	35	78	102	190
Volume, tons	**Estimated Pilot Duration (Base Case Injectivity), days**				
	100md	**20md**	**10md**	**8md**	**5md**
3,000	2	8	18	25	45
6,000	3	15	32	42	77
10,000	5	26	55	66	125
Volume, tons	**Estimated Pilot Duration (High Case Injectivity), days**				
	100md	**20md**	**10md**	**8md**	**5md**
3,000	1	5	11	15	28
6,000	2	11	23	29	51
10,000	4	17	36	47	85

Should the low-low case ever be used as the decision basis, not only a review of pilot decision in the low permeability cases (< 8mD) is needed, but also the injection volume would be limited up to 3,000 tons for the cases with permeability ranging from 8mD to 15mD, so as to complete the pilot injection within 2 months.

N.5 PLUME MOVEMENT

Movement of the CO_2 plume can be separated into two stages. The first stage is during the injection period, when the displacement force dominates CO_2 movement and distribution in the injection interval. The CO_2 plume at this stage is piston-like on a cross section map. The second stage is after shut-in of the injection well, when gravity and capillary (hysteresis phenomenon: from CO_2 drainage to water imbibition) forces dominate the movement and distribution of CO_2. However, during both stages, the movement of the plume is also somewhat retarded by the CO_2 going into solution in the brine.

N.5.1 Injection Volume Effect

In either stage, CO_2 plume size is closely linked to the injection volume. The larger the injected CO_2 volume, the bigger the plume will be. This is simply understandable from a material balance point of view. Figure N-6 presents such a relationship during the injection period. Figure N-7 and Figure N-8 display this for the post injection period. For an injection volume of 2,000 – 6,000 tons, the plume radius is 80 to 175 feet during the injection period (excluding the 2 mD case, as the pilot test is unlikely to be performed in a 2 mD injection interval) and can increase to 400 feet, or more (in the 100 mD, 6,000 ton case), post-injection. However, the CO_2 plume size is not very significant as it is in the range of a few hundred feet away from the point of injection, given the likely permeability case (less than or equal to 20md) in the injection interval and the limited injection volume (less than 6,000 tons) planned.

N.5.2 Permeability Effect

Figure N-6, Figure N-7, and Figure N-8 also reveal the effect of permeability on the plume size. During the injection stage, for a given injected volume, lower permeability in the injection interval leads to a bigger plume (see Figure N-6). The main reason for this is that the residual or trapped water saturation, i.e., the water retained by the capillary forces in the pores of the rock after CO_2 filling the pores is larger in case of low permeability rocks than high permeability rocks. This means that there will be less pore space available for gas to fill up the pores in low permeability rocks than high permeability rocks. Therefore, during injection, CO_2 will move ahead to fill up more pore spaces in low permeability rocks than in high permeability rocks for the same amount of CO_2 injection. This allows injected CO_2 to override the water more under other forces, like gravity, resulting in further movement of CO_2 at the top of the injection interval. Nevertheless, the permeability effect on plume size during the injection stage is observed to be as small as tens of feet (Figure N-6). In contrast, permeability impacts the plume movement much more during the post-injection stage (Figure N-7 and Figure N-8). For the 6,000-ton injected volume, the CO_2 plume in a 100 mD formation moves 160 feet further by the end of one-year post injection; while the plume in a 20 mD formation moves only an additional 45 feet further (Figure N-8). The CO_2 plume area maps and cross section maps are displayed in Figure N-9 and Figure N-10 for the 20 mD-6,000 ton case and the 100 mD-6,000 ton case, respectively. These two figures not only show the plume migration distances after injection, but also clearly indicate the direction of movement towards the up dip side of the structure.

For the obvious permeability effect on the plume movement after injection, vertical permeability is believed to be a great contributor. Higher vertical permeability promotes the effectiveness of the gravity force and allows faster CO_2 movement to the top of the injection interval, which leads to greater plume movement distances just under the top seal. Vertical movement of CO_2 is larger in the case of high permeability rocks because the vertical permeability is also high. By altering KvKh ratios in the model, the results provide confirmation of this effect (see Figure N-11). The results also demonstrate that vertical permeability has negligible impact on the plume size for the injection period, mainly because the viscous (lateral) displacement force is solely the dominant force during that stage.

N.5.3 Porosity Effect

Porosity, one of the indicators for the injection interval storage capacity, also affects the CO_2 plume size. Taking the injection stage as the example, Figure N-12 illustrates the porosity effect on CO_2 plume radius in a 10mD injection interval. Obviously, a poorer porosity (0.15) leads to a bigger plume radius for a given injection volume. Moreover, this effect grows larger when injection volume increases. For the injection volume of 2,000 to 6,000 tons, the porosity effect on the plume radius is in the tens of feet.

With the current uncertainty about the injection interval porosity (range from 0.15 – 0.25), the porosity effect on the CO_2 plume size implies that a wider range of plume size should be expected, on top of the variations induced by the permeability uncertainty (seen in Figure N-6). Figure N-13, therefore, demonstrates this wider range of the plume radius during the injection stage, considering the combination effects from both permeability and porosity uncertainties. In this figure, for the injection volume range of 2,000 – 6,000 tons, the plume radius can vary from 75 feet to 200 feet during the injection stage.

N.6 SUBSURFACE PRESSURE

The CO_2 injection process inevitably induces pressure increase underground. The pressure wave travels much further than the CO_2 plume. The magnitude of pressure increase depends on the injection interval properties (thickness, permeability, relative permeability, porosity, and rock compressibility), well completion (skin), and operational envelopes (injection pressure, injection rate, and overall injection volume). The peak pressure underground occurs at the end of the injection period and then drops back to the original formation pressure over time. In terms of area distribution, the subsurface pressure increase has the highest value at the injection well location and gets lower at further distances. For the 20 mD-6,000 ton case, the boundary of pressure increase goes no more than two miles away from the point of injection (Figure N-14). More importantly, the pressure in the injection interval recovers back to its original formation pressure just 90 days after cessation of injection (Figure N-14).

N.7 OBSERVATION WELL DISTANCE

The simulation results discussed in section N.5 already show that the CO_2 plume radius during the injection stage can range from 75 feet to 200 feet for the injection volume of 2,000 – 6,000 tons. In order to see the CO_2 breakthrough during the injection of such volume, the observation well is better placed within this 75 to 200 foot distance range. The shorter distance is preferred, because it means less risk of missing detection and probably less required injection volume and injection duration. In all, the shorter distance implies more chance of monitoring success and less operating cost.

N.8 CONCLUSIONS

For various scenarios, the pilot simulation results provide insights for well injectivity, pilot injection duration, and CO_2 plume size over different injection volumes. Guided by the simulation results, the pilot is planned to inject 2,000 to 6,000 metric tons of CO_2 within a two month period under matrix injection conditions. The Observation Well will be placed up to 100 to 200 feet away from the Injection Well on the up dip side of the structure. If low permeability (less than 8 mD) is found in the target injection interval by the appraisal well (Injection Well), the well injectivity will be thoroughly reviewed again before a final decision is made on proceeding with the pilot test. Very low injectivity significantly increases the pilot injection duration, and hence, challenges and increases cost for managing injection.

Some key learning points from this simulation are highlighted as below:

- Permeability, CO_2 – water relative permeability, porosity, rock compressibility, fracture pressure, and well completion skin are all influential factors for the well injectivity.

- CO_2 plume size is closely associated with the overall injection volume. The greater the injection volume, the bigger the CO_2 plume becomes.

- The viscous force dominates the CO_2 plume movement during the injection stage, while gravity force and capillary force (including hysteresis) reshape the CO_2 plume during the post-injection period, leading to further plume movement, both vertically and laterally.

- CO_2 trapping mechanisms, like CO_2 solution in brine and CO_2 capillary trapping, retards the CO_2 plume size post injection. During injection, only CO_2 solution in brine helps reduce the plume size.

- Permeability effect on CO_2 plume size during the injection stage is observed to be much smaller than during the post-injection stage. The relative dominance of the displacement force over other forces, like gravity and capillary forces, in these two stages should be the underlying reason.

- Porosity, indicating the injection interval storage capacity, also affects CO_2 plume size. A lower porosity leads to a bigger plume for a given injection volume, and the effect increases as the injection volume increases.

- Injection interval pressure increase induced by the CO_2 pilot injection process should not be a concern, considering the limited area affected (no more than 2 miles away from the Injection Well in the case of injecting 6,000 tons into a 20 mD interval) and its fast return to original formation pressure within three months following cessation of injection.

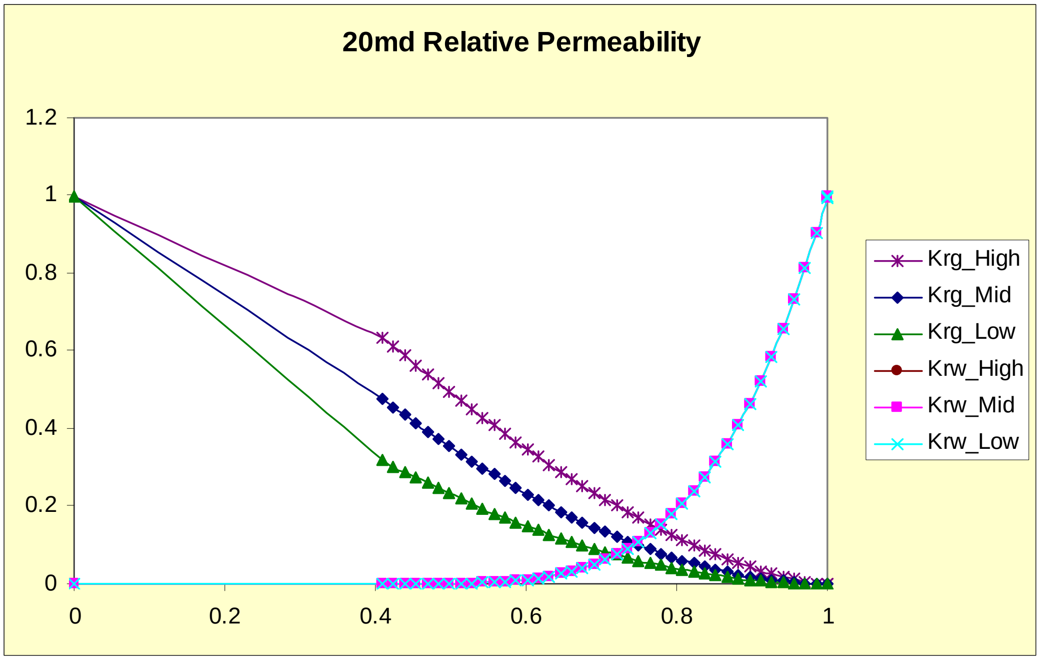


Figure N-1a CO_2 -Water Relative Permeability Model (20 mD rock)

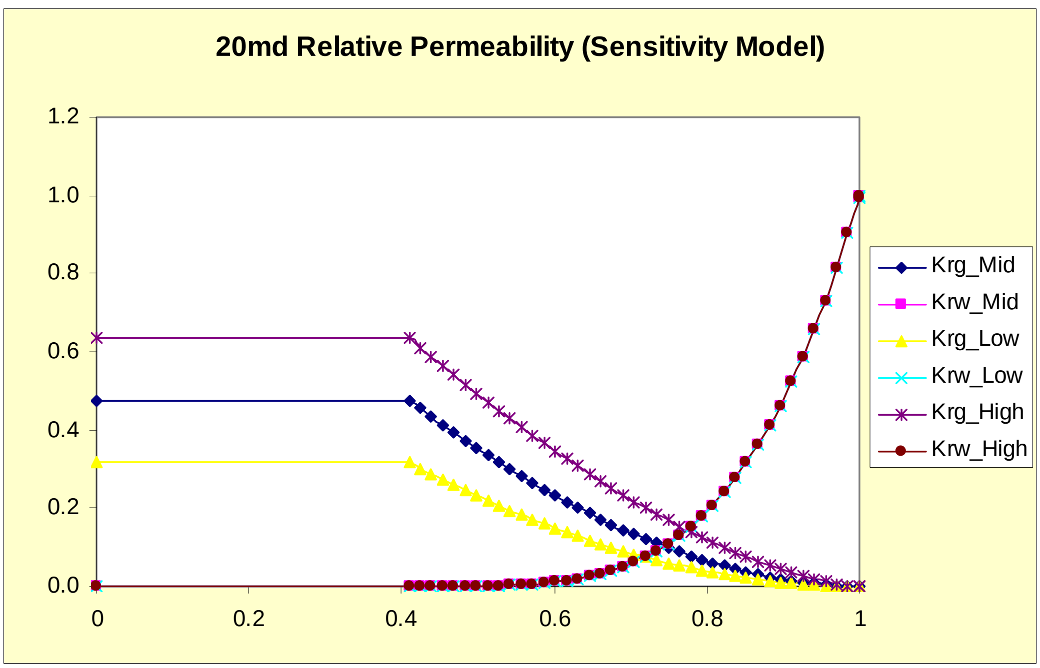
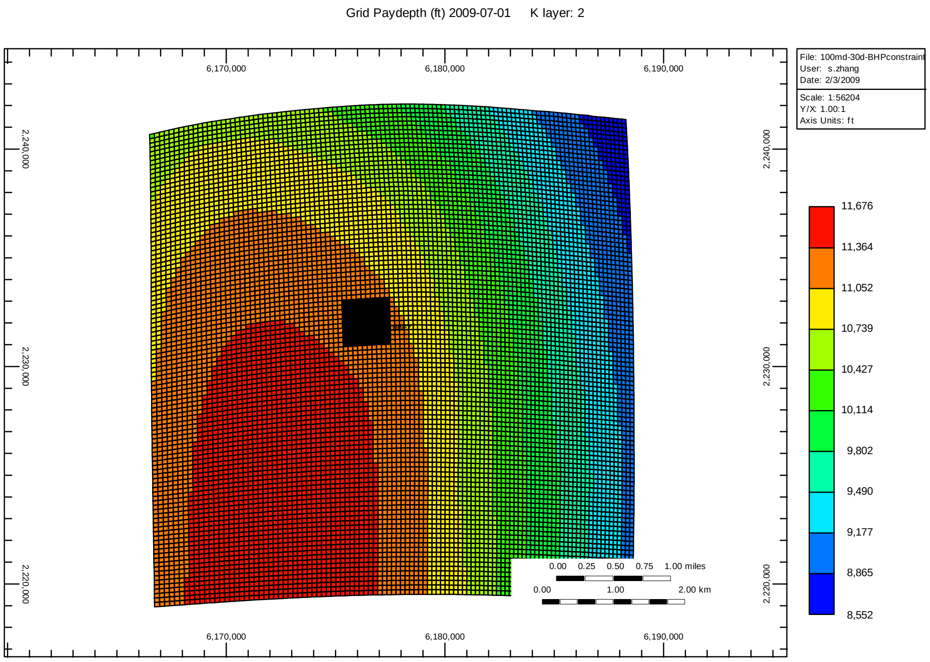
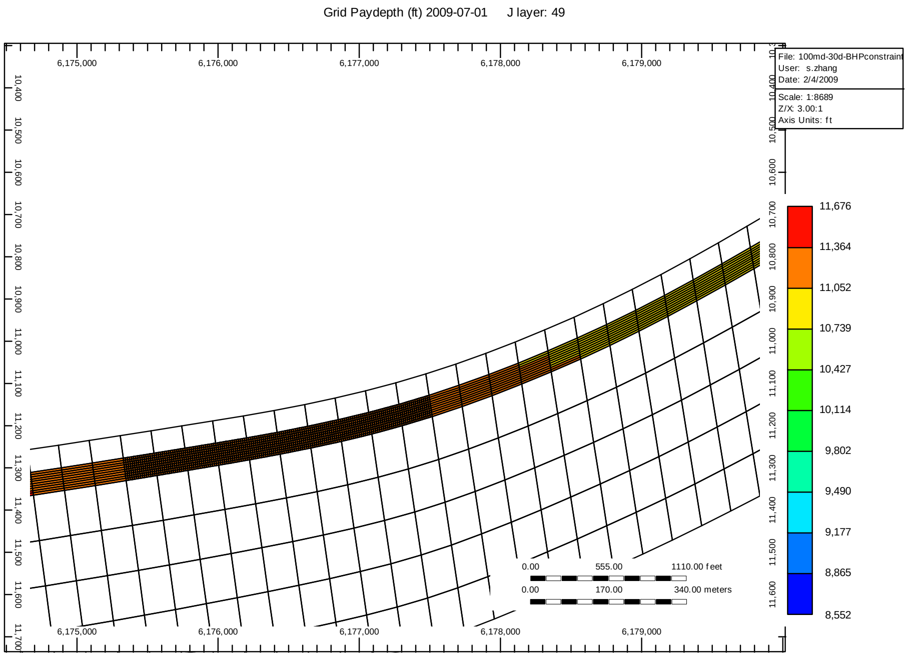


Figure N-1b Relative Permeability Sensitivity Model (20 mD rock)



Area Depth Map of the Pilot Model



Cross Section Map of the Pilot Model

Figure N-2

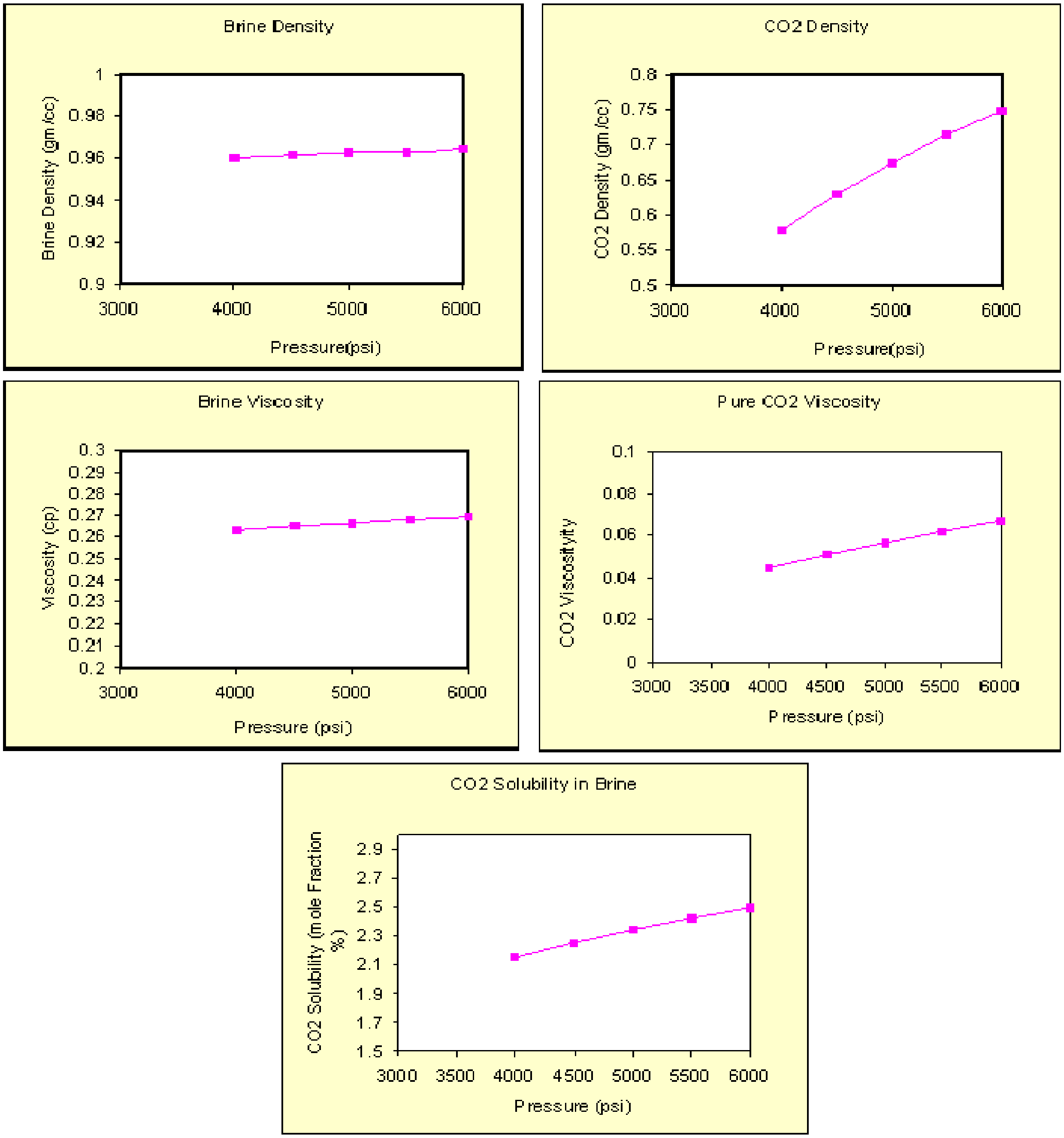


Figure N-3 PVT Properties of Brine and CO_2

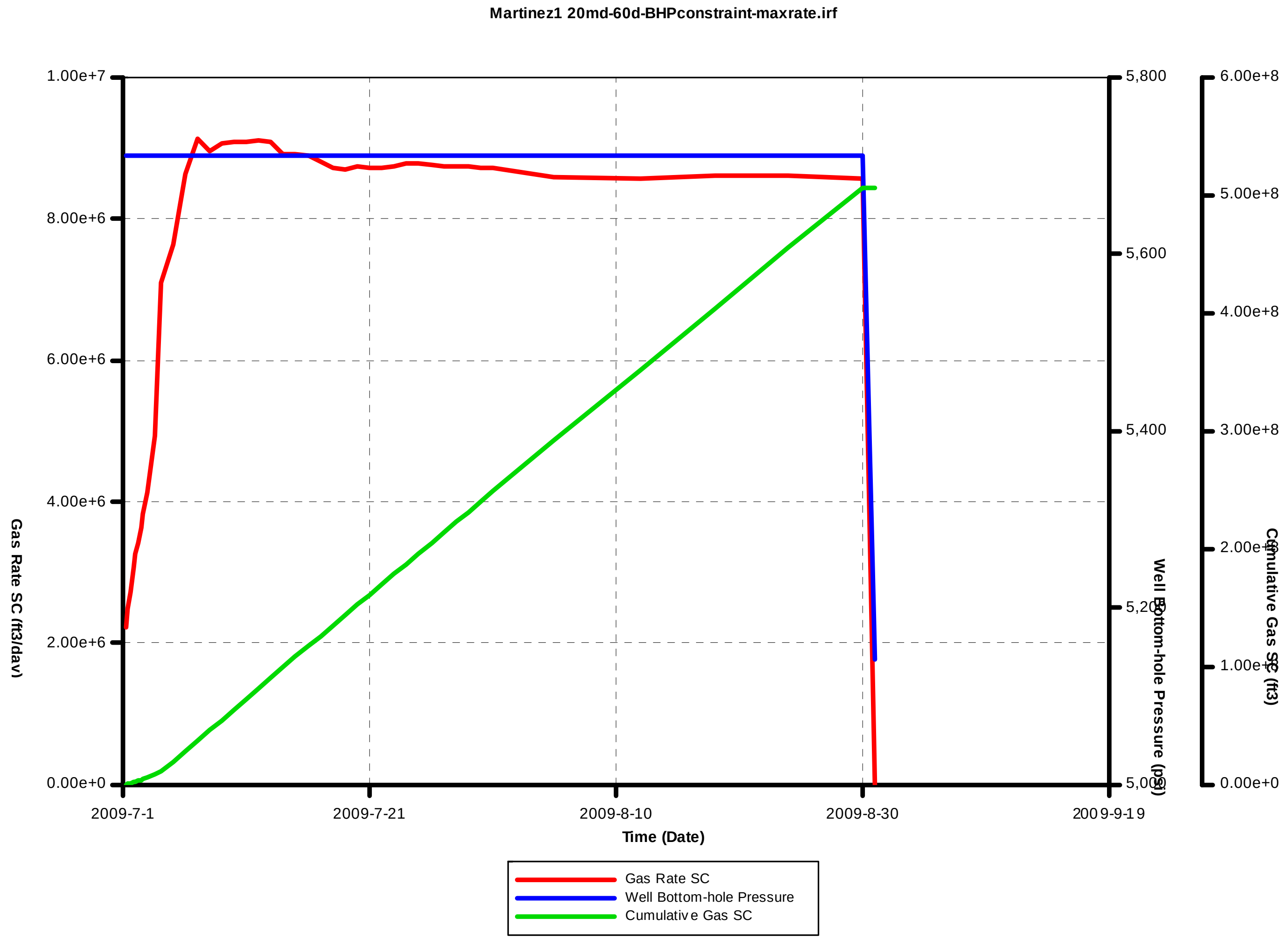


Figure N-4 Base Case Injection Profile into the 20 mD Sand

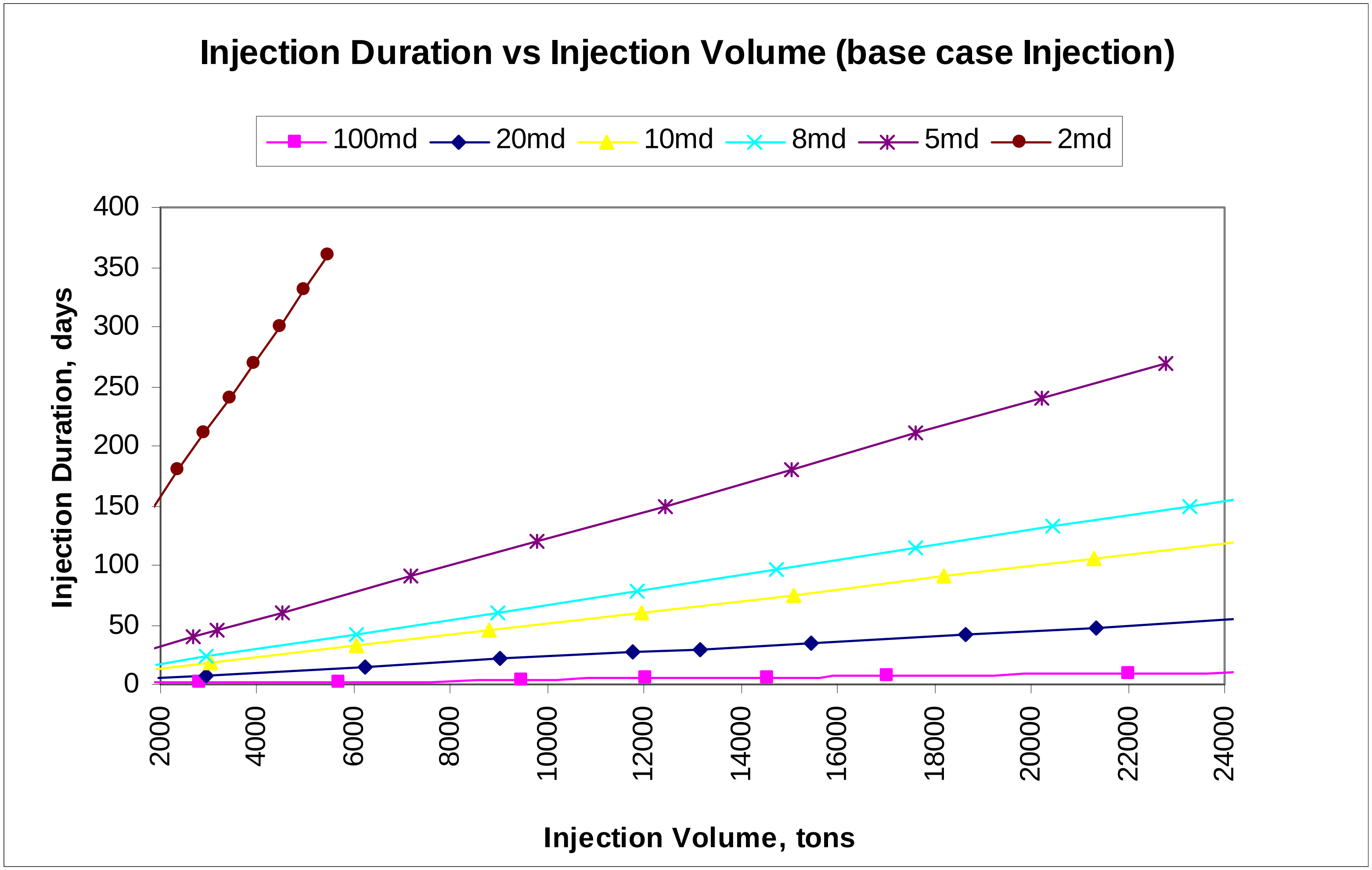


Figure N-5 Predicted Pilot Injection Duration (Base Case Injectivity)

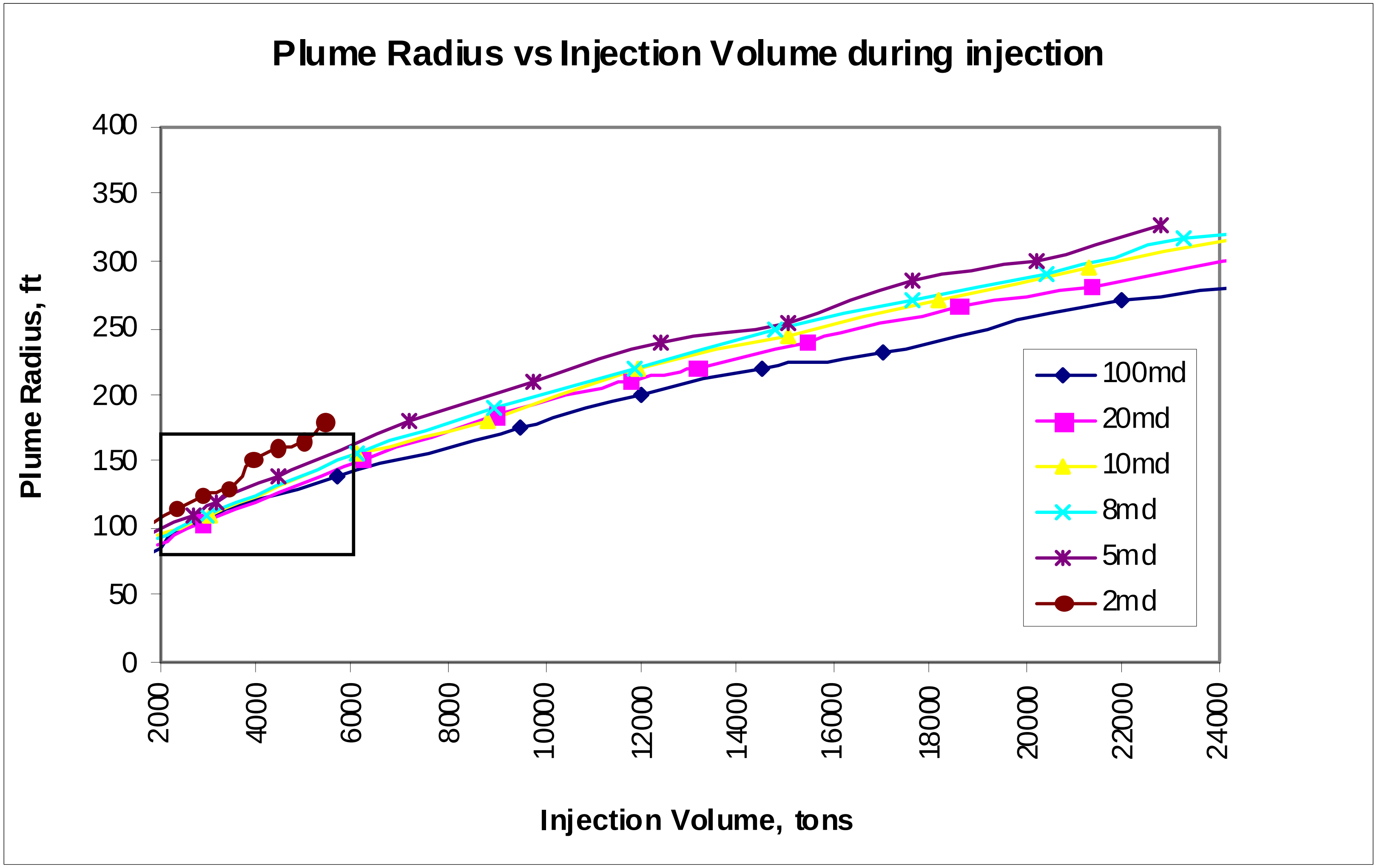


Figure N-6 CO_2 Plume Size during Injection

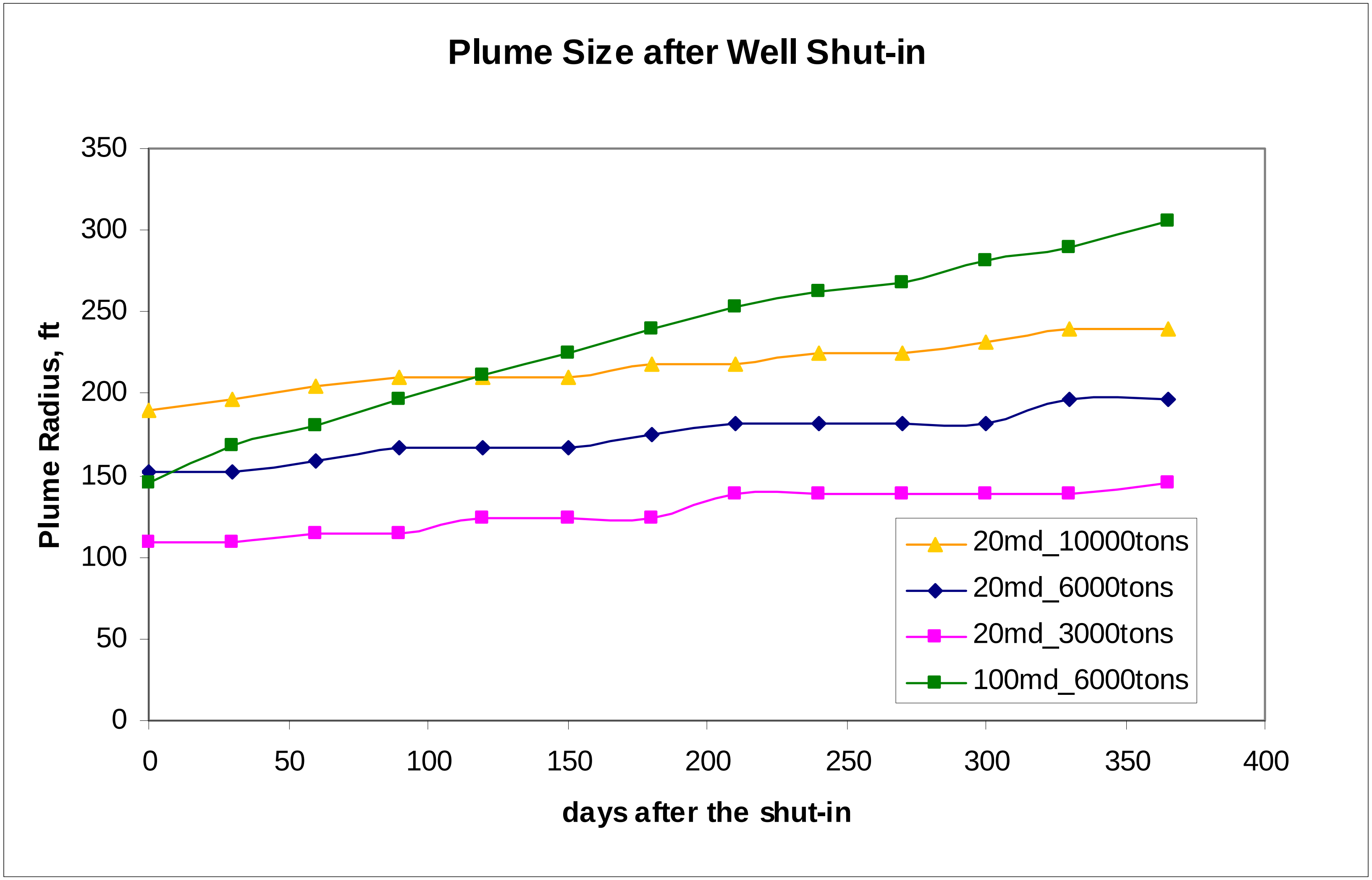


Figure N-7 CO_2 Plume Size Following Cessation of Injection

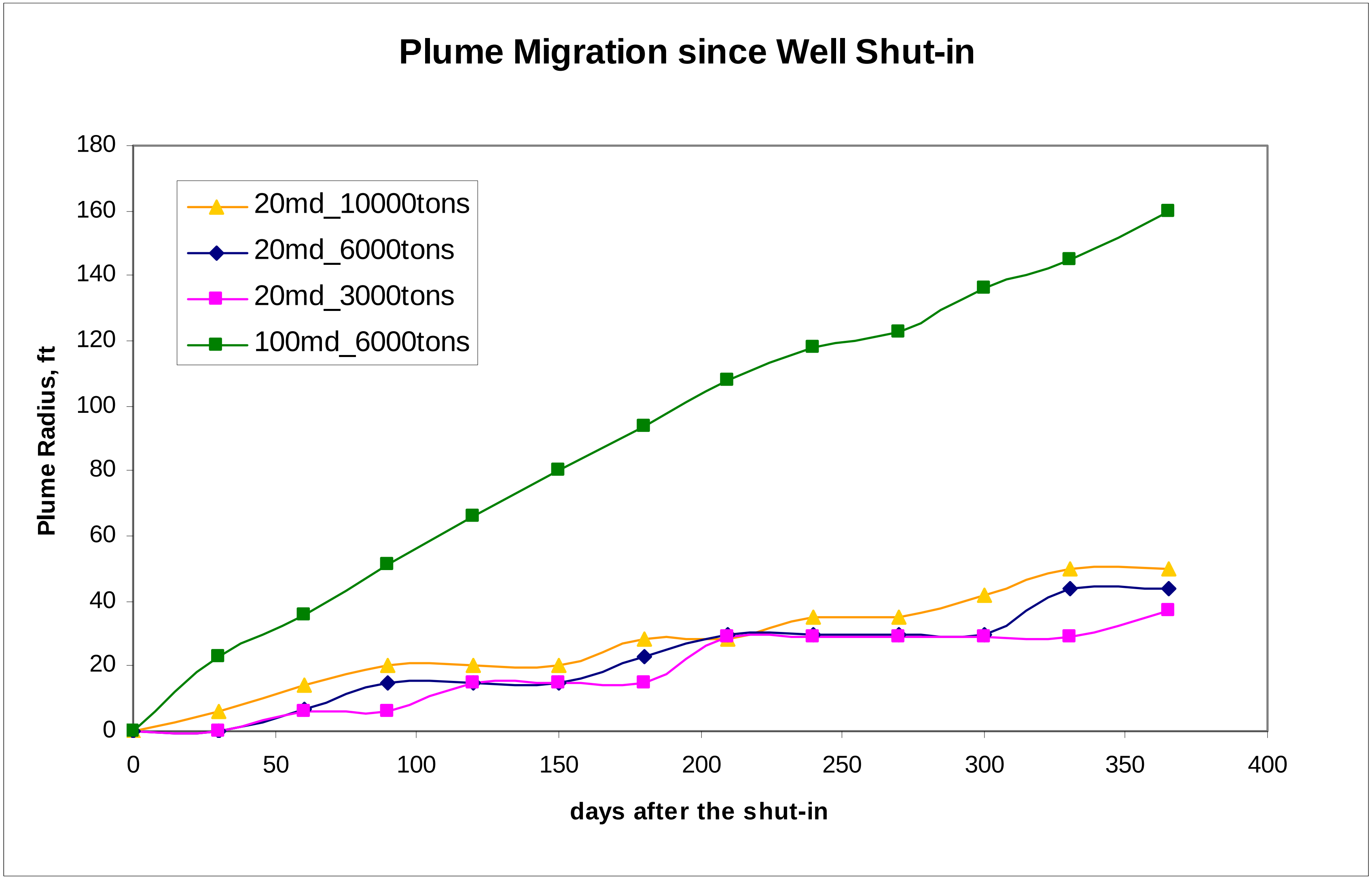


Figure N-8 CO_2 Plume Incremental Movement Following Cessation of Injection

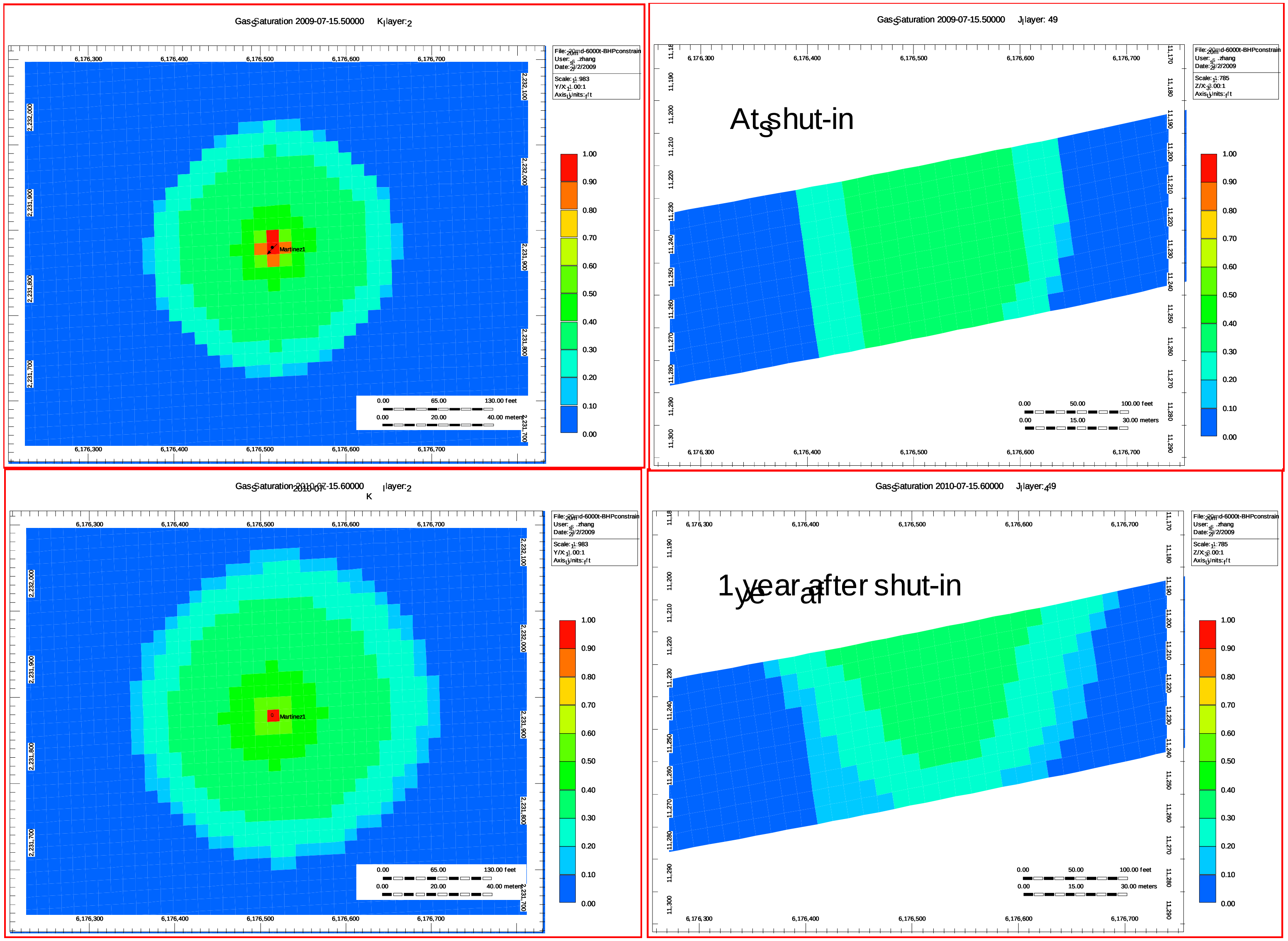


Figure N-9 CO_2 Plume Maps in the 20md-6,000ton Case

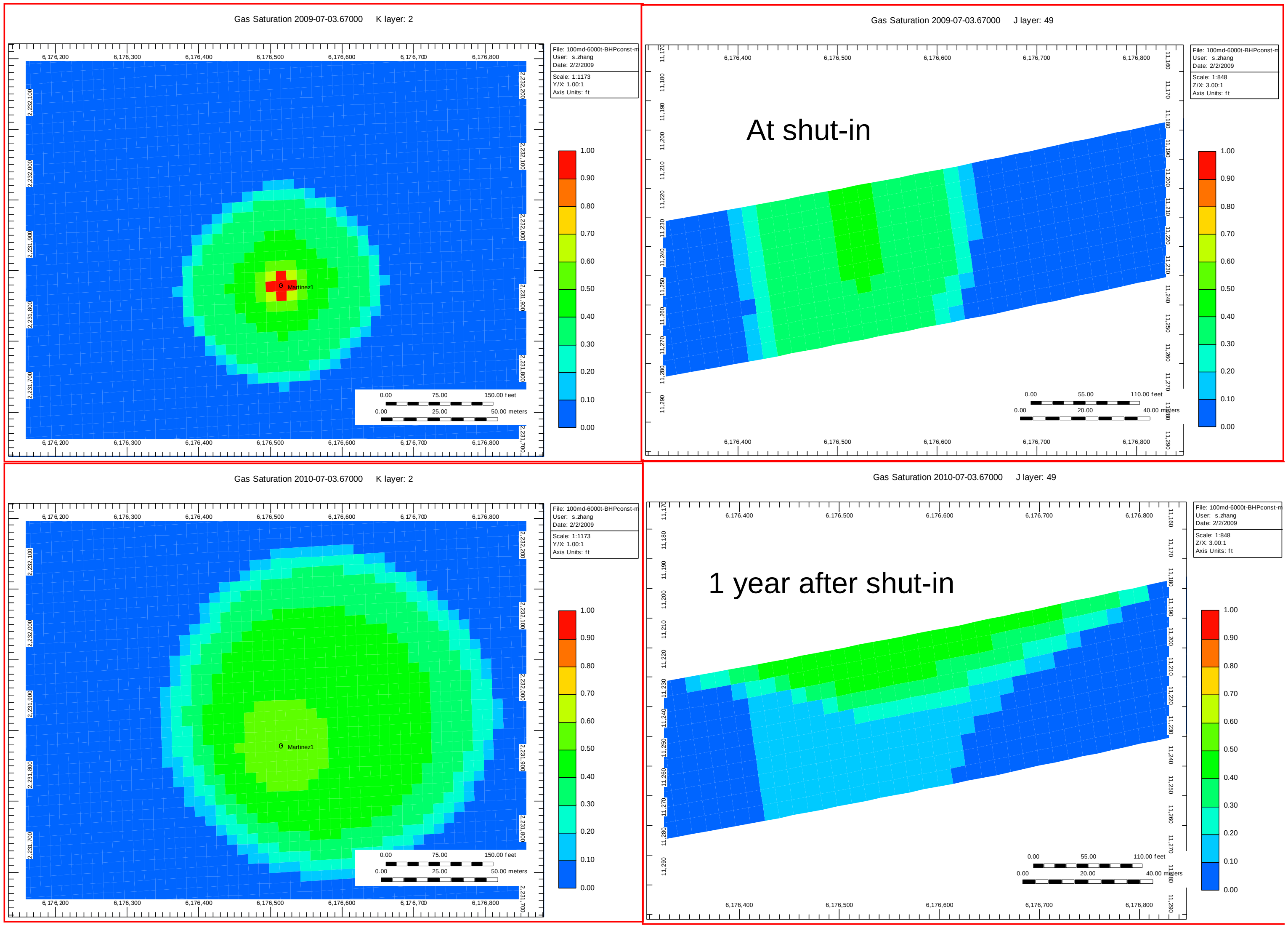


Figure N-10 CO_2 Plume Maps in the 100md-6,000ton Case

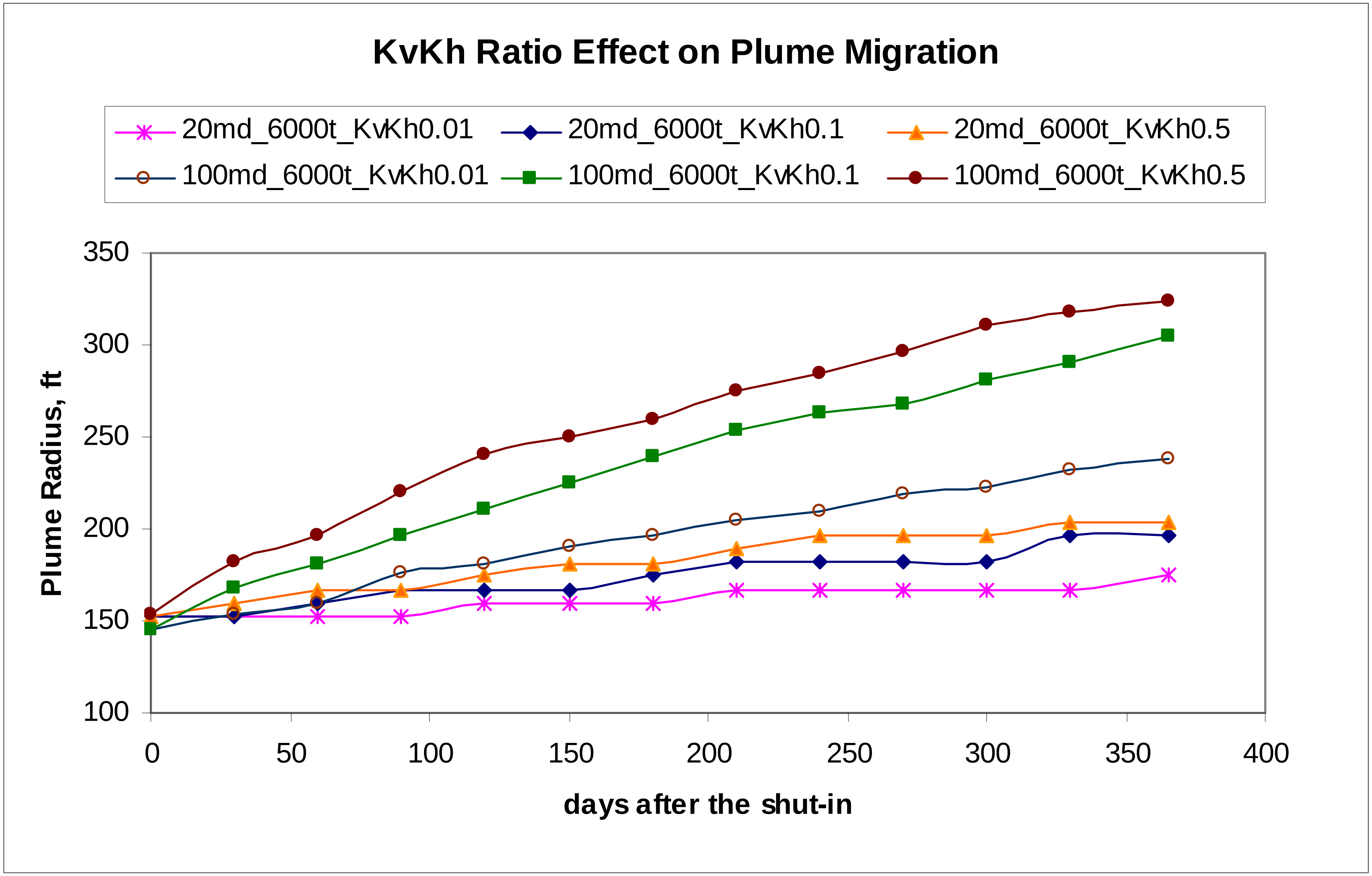


Figure N-11 Vertical Permeability Effect on CO_2 Plume Size

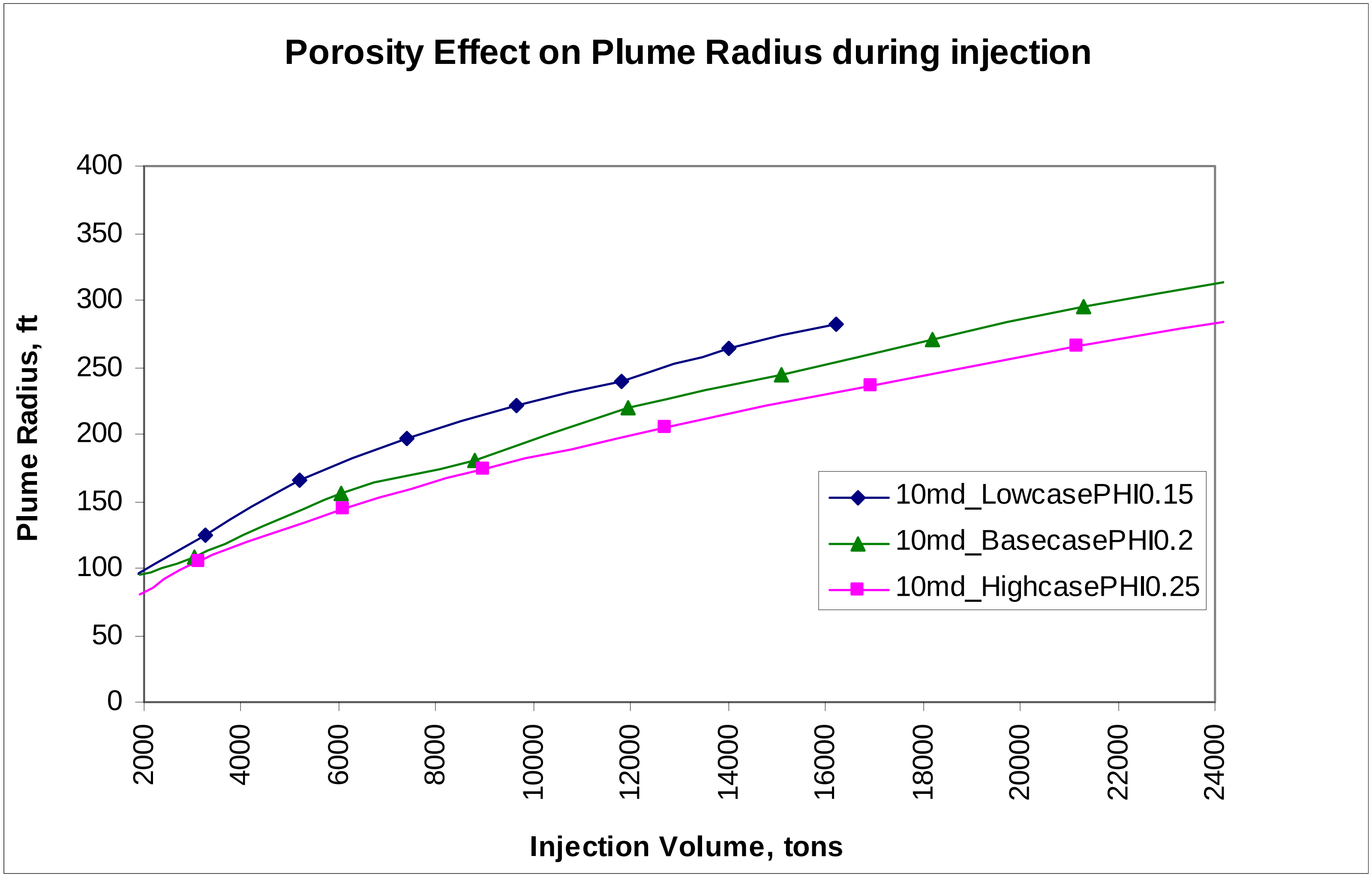


Figure N-12 Porosity Effect on CO_2 Plume Size during Injection

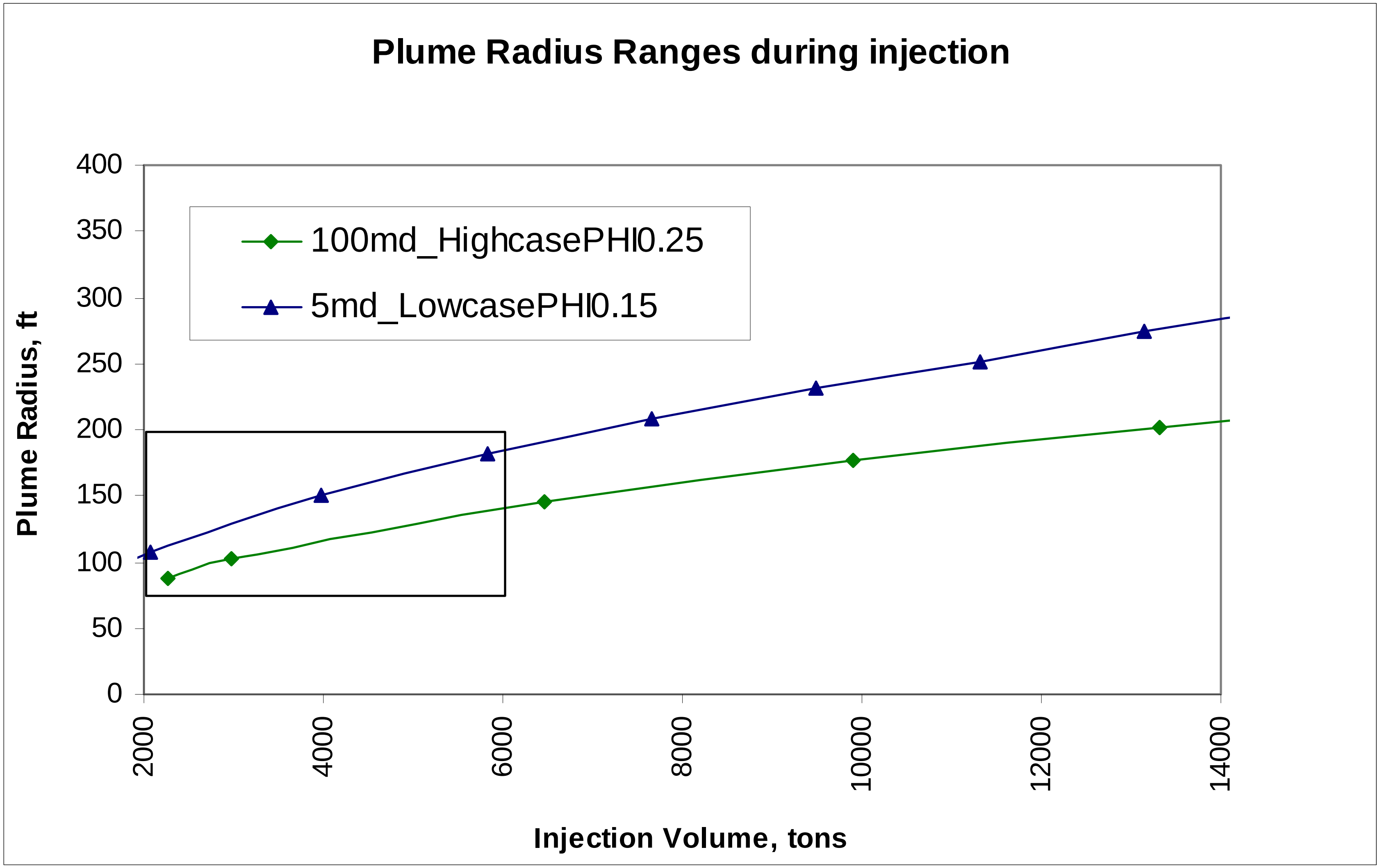


Figure N-13 CO_2 Plume Radius Ranges during Injection

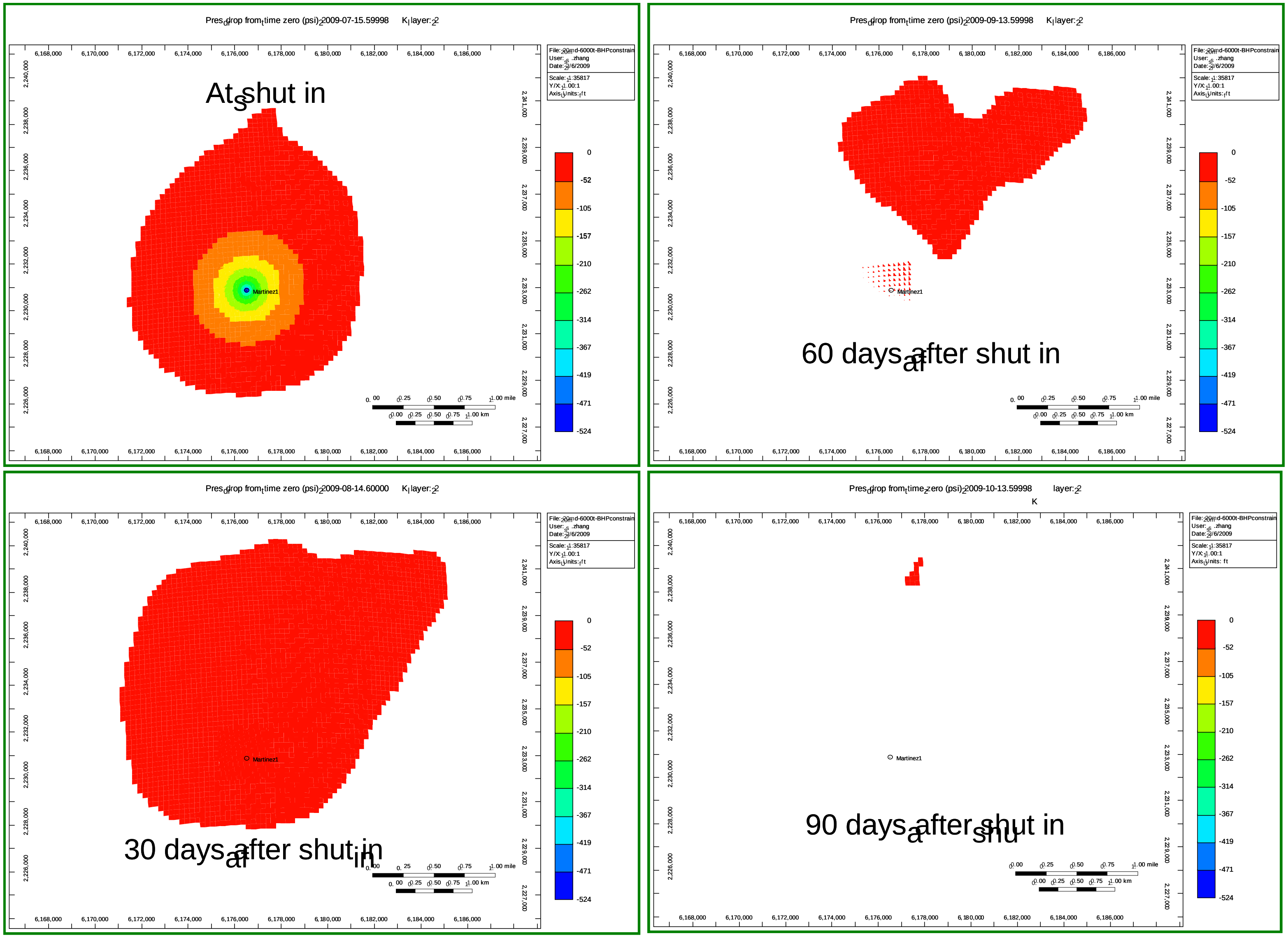


Figure N-14 Pressure Maps in the 20md-6,000ton Case

ATTACHMENT O PLANS FOR WELL FAILURES

O.1 WELL FAILURE CONTINGENCY PLANS

The actual volume of CO_2 injected is at the discretion of the Project Team and is dependent on the actual specific volume needed to extend the plume beyond the Observation Well. The only onsite "generated" fluids will potentially be formation brines recovered during back surge of the wells and sampling events. The intent is to re-inject the formation brines during well and/or reservoir testing that result from back surge activities. If these brines cannot be injected for some reason (such as contamination with mud filtrate), they will be sent offsite for proper disposal. Sufficient storage for CO_2 (and any other fluids (such as commercial or formation brine for testing) to be injected) will be maintained onsite so that short-term unintended disruption in injection will not occur. If the onsite CO_2 cannot be injected for some reason (i.e., such as due to well failure), further delivery of CO_2 to the site will be stopped.

O.1.1 Well Failure Analysis Procedure

Pressure gauges will be installed at the wellhead on the injection tubing and on the annulus between the injection tubing and the protection casing on both the Injection Well and the Observation Well. These gauges will be maintained in good working order at all times. Recording devices will be installed to record at a minimum: a) injection tubing pressure; b) injection flow rate; c) injection fluid temperature; d) injection volume; and e) tubing - protection casing annulus pressure. All gauges, pressure/temperature sensing devices, and recording devices will be tested and calibrated at installation. Test and calibration records will be maintained for the duration of the pilot test. All instruments will be housed in weatherproof enclosures, where appropriate.

Site personnel will monitor and record the above parameters while CO_2 injection activities are ongoing and during the post-injection monitoring phase. If an anomaly in a monitored parameter is detected, or if a monitored parameter value is exceeded, the Project Team will immediately investigate and identify the cause of the problem. If, upon investigation, the subject well appears to lack mechanical integrity, the Project Team will:

a) Immediately cease injection of CO_2, unless injection is authorized by the Executive Director;

b) Take all steps necessary to determine the presence or absence of a leak; and

c) Notify the Executive Director within 24 hours of the incident or shutdown.

If a loss of mechanical integrity is discovered during the investigation (or during mechanical integrity testing), the Project Team will:

a) Immediately cease injection of CO_2; Take reasonable steps necessary to determine if there has been a release of CO_2 or any other fluids into any unauthorized zone;

b) Notify the Executive Director within 24 hours after the loss of mechanical integrity is discovered;

c) Notify the Executive Director when injection can be expected to resume; and

d) Restore and demonstrate mechanical integrity to the satisfaction of the Executive Director prior to resuming injection of CO_2.

If there is evidence that there has been a release to an unauthorized zone, the Project Team will:

a) Notify the Executive Director within 24 hours of obtaining such evidence;

b) Take the necessary steps to identify and characterize the extent of any release;

c) Propose a remediation plan for the Executive Director's review and approval;

d) Comply with any remediation plan specified by the Executive Director;

e) Implement any remediation plan specified by the Executive Director; and

f) Notify the local health authority, place a notice in a newspaper of general circulation, and send notification by mail to adjacent landowners where such a release is into an underground source of drinking water (USDW) or freshwater aquifer currently serving as a water supply.

ATTACHMENT P MONITORING PROGRAM

P.1 WELL MONITORING PROGRAM

Proposed monitoring requirements for the wells shall, at a minimum, include:

- The recovery and analysis of the injected fluids from the target injection formation at the Injection Well with sufficient frequency to yield representative history;
- Installation and use of continuous recording devices to monitor Injection Well pressure/temperature at the wellhead and the injection formation, injection flow rate and volume, and the pressure at the wellhead on the annulus between the tubing and the protection casing;
- The analysis of the fluids (native and injected) from the target injection formation at the Observation Well with sufficient frequency to yield a representative history;
- Installation and use of continuous recording devices to monitor Observation Well pressure/temperature at the target injection formation, pressure/temperature at the wellhead, and the pressure at the wellhead on the annulus between the tubing and the long string of casing;
- A demonstration of mechanical integrity following initial well completion, following any unseating of the tubing from the packer or wellhead, and at least once every five years during the life of each well.
- Monitoring the temperature profile on outside of production, intermediate, and surface casing of each well; and
- All monitored data will be collected in a central data acquisition device and fed back to C6 Resources, LLC.

Proposed quarterly reporting requirements are:

- The physical, chemical, and other relevant characteristics of all injection fluids;
- The physical, chemical, and other relevant characteristics of target injection formation fluids at both the injection well and the observation well;
- Monthly average, maximum, and minimum values for injection pressure and temperature, flow rate and volume, and annular pressure at each well, as well as the pressure/ temperature at the target injection formation;
- The results of other monitoring prescribed as above;
- Results of any tests of mechanical integrity; and
- Results of any other test on the Injection Well or the Observation Well as required by the Director.

P.1.1 Analysis of Injected Fluids

All of the fluids anticipated for injection are nonhazardous. None of the fluids are subject to Federal Land Ban Disposal Restrictions under 40 CFR §148 Subpart B.

Carbon Dioxide

Carbon dioxide (CO_2) is anticipated to be in a supercritical state when injected into the test interval [ambient conditions well above 31.1 ^{o}C (87.9 ^{o}F) and 72.8 atmospheres (atm) pressure (1,070.6 pounds per square inch (psi))] and will remain supercritical once it has equilibrated to formation conditions. A supercritical fluid possesses the characteristics of both a fluid and a gas in that, although it is compressible like a gas, it has liquid-like densities (Figure P-1 and P-2). At a supercritical state, CO_2 has a density of 29.2 pounds per cubic foot, for a specific gravity of 0.47 (assuming a pure water density of 62.29 pounds per cubic foot).

A commercial grade source of CO_2 (or better) will be used for the pilot test injection. A typical analysis of "commercial" quality CO_2 is shown in Table P-1 (note that source and grade of CO_2 has not been finalized at this time).

Although dry supercritical CO_2 is inert, it is much more reactive in the presence of water or NaCl brines, forming carbonic acid when the injected CO_2 goes into solution. In general, geochemical modeling for the injection of CO_2 into brines indicates that the pH in the formation brine should not drop below a value of about pH 5.3, due to the buffering provided by naturally occurring reactive minerals in subsurface formations.

Representative samples of the CO_2 used for the pilot test will be taken at the source or from the on-site storage tanks and analyzed for chemical characteristics (purity). Results of the analyses will be recorded and reported.

Native Brines

It is anticipated that small volumes of formation brine may be produced during the pilot test. Activities that may produce brine include: (1) potential back surging of the wells during initial development of the completion; (2) fluids generated during potential reservoir testing of the wells for aquifer characterization; and (3) fluids generated during potential artificial lift activities required for fluid sampling (purging of the wells) or through the U-tube sampler. Representative samples of the recovered formation brines will be analyzed and recorded for both chemical and physical properties for site characterization. Produced native brine fluids from well development may be reinjected during pressure transient tests of the target injection formation. Formation brines contaminated with mud filtrate and other produced brines that aren't reinjected will be sent off location for proper disposal.

Table P-1 Typical Commercial Grade Carbon Dioxide Specifications

Component	Standard
Purity	95% v/v min.
Moisture	30 pounds of water per mmcf
Oxygen	10 ppm by weight, max.
Nitrogen	4 mole %
Hydrocarbons	5 mole %
Total sulfur content	35 ppm by weight, max.
Hydrogen Sulfide	20 ppm by weight, max.

* From Kinder Morgan
** ppm = parts per million

Tracers

Tracers may be added to the formation brine and CO_2 to study fluid flow processes, characterize fluid saturations, and detect any leakage out of the injection reservoir up the wellbore or through the cap rock. A variety of tracers may be used including perfluorocarbon tracers (PFT), noble gases, fluorescein, and sulfur hexafluoride (SF_6). Note that the drilling mud may be "tagged" with Optitrack 600 (MI Swaco) in the intermediate and protection casing holes (see Section I.1.3 of Attachment I). The optical analyzer module on the modular formation fluid sampler to be used in the open-hole logging program is sensitive to Optitrack 600, which will be used to discriminate between mud filtrate and uncontaminated formation fluid.

Perfluorocarbons are used in human medical treatments, and noble gases are chemically inactive. Approximately 60 kilograms (kg)[132 pounds] of perfluorocarbon tracers may be used during the pilot test, with maximum expected concentrations in the injectate of 30 micrograms per milliliter (µg/mL) [equivalent to 30 parts per million], and those at the observation well may be lower than 1 nannogram per milliliter (ng/mL), or approximately 1 part per billion.

Approximately 4.22 kg (9.33 pounds) of noble gases will also be used as tracers. Concentrations of the noble gases in the injectate will likely range from 0.04 to 164 parts per million, depending on the gas type used. Concentrations of the noble gasses at the observation well will vary from 100 percent of the gas phase initially injected (i.e., 0.04 to 164 parts per million) to zero several days after the tracer tagged injected CO_2 passes the observation well. Fluorescein and/or Eosin fluorescent dyes approved for use in groundwater and surface water tracing has been widely used in environmentally sensitive areas. Approximately 10 kg may be added to the hydrologic test brine used for pressure transient testing, producing concentrations in the parts per million range.

Potential project tracers are listed in Table P-2.

P.1.2 Well Monitoring Equipment

Pressure gauges will be installed at the wellhead on the injection tubing and the on the annulus between the injection tubing and the protection casing on both the Injection Well and the Observation Well. These gauges will be maintained in good working order at all times. Recording devices will be installed to continuously record at a minimum: a) injection tubing pressure and temperature; b) injection flow rate; c) injection volume; and d) tubing by protection casing annulus pressure. Downhole pressure/temperature gauges will also be placed in each well at the target injection formation. A data acquisition system will be used to collect, sequence, and archive data from each of the wells. The system will allow onsite monitoring and may be configured to allow offsite, real-time access of the data feed to remote location users. All gauges, pressure/temperature sensing devices, and recording devices will be tested and calibrated at installation and thereafter, following manufacturers recommendations and schedule. Test and calibration records will be maintained for the duration of the pilot test. All instruments will be housed in weatherproof enclosures, where appropriate. The data acquisition will be such that the site personnel can monitor all of the recorded parameters while reservoir testing (brine) and/or CO_2 injection activities are ongoing and during the post-injection monitoring phase.

Wellhead Devices

Digital pressure and temperature probes will be installed on the wellheads to allow continuous recording of key data. Wellhead pressure transducer specifications will be approximately 0 to 5,000 psi, rated at 0.25% of full scale accuracy, or better, for tubing/flow line and casing annulus pressure. Temperature probe specifications will be approximately -50 ^{o}C to 200 ^{o}C, at 1.2 ^{o}C accuracy, or better, for tubing/flow line temperature. A flow meter (or controller) will be placed in the CO_2 injection line to monitor the CO_2 injection rate and cumulative volume injected.

Table P-2 Potential Tracers

Tracer	Concen-tration (injectate)	Concen-tration (produced fluids)	Maximum Expected Total Weight	Comments
FLUTEC-TG PMCH (perfluoromethylcyclohexane)	30 ug/mL (30 ppm)	1 ng/mL (1 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human-or eco-toxicity
FLUTEC-TG PTMCH (perfluoro-1,3,5-trimethylcyclohexane)	30 ug/mL (30 ppm)	1 ng/mL (1 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human-or eco-toxicity
FLUTEC-TG o-PDMCH (perfluoro-1,2-dimethylcyclohexane)	30 ug/mL (30 ppm)	1 ng/mL (1 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human-or eco-toxicity
FLUTEC-TG m-PDMCH (perfluoro-1,3-dimethylcyclohexane)	7 ug/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human-or eco-toxicity
FLUTEC-TG p-PDMCH (perfluoro-1,4-dimethylcyclohexane)	7 ug/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human-or eco-toxicity
FLUTEC-TG PMCP (perfluoromethylcyclopentane)	30 ug/mL (30 ppm)	1 ng/mL (1 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human-or eco-toxicity
FLUTEC-TG PDMCB (perfluorodimethylcyclobutane)	7 ug/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human-or eco-toxicity
FLUTEC-TG PECH (perfluoroethylcyclohexane)	7 ug/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human-or eco-toxicity
^{20}Ne (Neon 20)	30.3 ppm	Variable	0.63 kg	No known human-or eco-toxicity
^{36}Ar (Argon 36)	164 ppm	Variable	3.42 kg	No known human-or eco-toxicity
^{84}Kr (Krypton 84)	7.64 ppm	Variable	0.16 kg	No known human-or eco-toxicity
^{132}Xe (Xenon 132)	0.4 ppm	Variable	0.01 kg	No known human-or eco-toxicity
Fluorescein and/or Eosin	1 ppm	5 ppb	10kg	No known human- or eco-toxicity

*ppm = parts per million, ppb = parts per billion

Downhole Devices

Downhole pressure and temperature sensors will be installed at the target injection formation in both the Injection Well and the Observation Well when the tubing is installed. The pressure and temperature sensors will be located beneath the packer as close to the injection interval as possible. Backup gauges may be placed above the packer. The downhole sensors will be surface read-out gauges so that real-time changes in reservoir response can be observed and recorded. Specification range for pressure will be 0 to 20,000 psi, and temperature probe specifications will be approximately -20 ^oC to 175 ^oC, at $\pm$0.5 ^oC accuracy, which has sufficient range to cover the expected conditions during the testing. The downhole sensors will be temperature-compensated and will transmit both a pressure and temperature signal up the cable and to a control box, which powers the sensor. Each sensor will be placed on a carrier pup-joint or mandrel, with box and pins set to match the tubing string. The wireline cable will be strapped/clamped to the outside of the tubing. A pass-through port through each packer will be required to allow the downhole gauge wireline to "pass-through" from the surface to the sensor. Additionally, each wellhead will require a port for the wireline to pass through at surface.

P.1.3 Mechanical Integrity Testing

Mechanical integrity tests will be performed during completion of the Injection Well and Observation Well, as detailed in Attachment L. The following tests will be performed:

- Pressure testing of the surface casing, prior to drill-out; pressure testing of the intermediate casing (if run), prior to drill-out; and pressure testing of the protection casing, prior to completion.
- Radioactive tracer survey of the completed Injection Well following perforation of the test interval.
- Annulus pressure test of the completed Injection Well and Observation Well, with tubing and packer in place.

Casing Pressure Tests - A demonstration of the integrity of the surface casing, the intermediate casing (if run), and the protection casing will be conducted. The surface casing test will be made prior to drill out of the shoe with the pipe rams closed on the drill pipe. The surface casing pressure test will be conducted for a minimum of thirty minutes at a pressure equal to or greater than 1,000 psi, using a recording gauge to document the test. The test will be deemed successful if there is less than a five percent change in pressure over the thirty minute period.

The intermediate casing test (if run) will be made following completion of the cement evaluation log run. The intermediate casing test will be made prior to drill out of the shoe with the pipe rams closed on the drill pipe. The intermediate casing pressure test will be conducted for a minimum of thirty minutes at a pressure equal to or greater than 1,500 psi, using a recording gauge to document the test. The test will be deemed successful if there is less than a five percent change in pressure over the thirty minute period.

The protection casing test will be made following completion of the cement evaluation log run. The protection casing pressure test will be conducted for a minimum of thirty minutes at a pressure equal to or greater than 1,500 psi, using a recording gauge to document the test. The test will be deemed successful if there is less than a five percent change in pressure over the thirty minute period.

Radioactive Tracer Survey - A demonstration that the injectate is confined to the target injection formation will be conducted upon completion of well development in the Injection Well. This demonstration will consist of a radioactive tracer survey performed while injecting into the well. The survey will include both a slug chase profile from inside the injection tubing string down to the perforations, to demonstrate the integrity of the well casing, and a stationary time drive survey, to demonstrate the integrity of the cement. During the time-drive survey, the lower detector on the tool will be set 10 feet above the top of the uppermost perforation. Each radioactive tracer test component will have at least one repeat survey to confirm results.

Annulus Pressure Test - A demonstration of the absence of significant leaks in the casing, tubing, and/or packer will be conducted by performing a pressure test on the annular space between the tubing and protection casing following completion of each well. This test will be conducted for a minimum of thirty minutes at a pressure equal to or greater than the maximum allowable injection pressure specified in the permit. The test will be deemed successful if there is less than a five percent change in pressure over the thirty minute period. The annulus pressure test will be performed each time a mechanical change is made to a well or when specified by the Executive Director.

A pressure differential of at least 350 psi between the tubing and annular pressures will be maintained throughout the annular pressure test. These tests will be run in accordance with procedures in Attachment L. Other tests may be run as specified by the Executive Director.

P.1.4 Monitoring of Nearby Natural and Induced Seismicity

Ongoing measurements of seismic activity are standard in this part of California. An additional array element will be installed in an approximately 100-foot deep well drilled near the pilot area. Recordings from this additional element will be used with available records from broad area network monitoring to resolve any seismic events occurring near the pressure field induced by pilot test CO_2 injection. Since natural seismicity is typically centered very deep in the subsurface, the additional array element(s) will allow determination of the depth of the event center to separate natural seismicity from any injection induced seismicity.

P.1.5 Reporting

Quarterly, the Project Team will submit accurate reports to the Environmental Protection Agency (EPA) containing, at minimum, the following information:

1. Monthly average, maximum, and minimum values for the continuously monitored parameters specified for the Injection Well and Observation Well, unless more detailed records are requested by EPA;
2. Injected fluid analyses (and any introduced tracers) to be included in the next quarterly report following completion;
3. Results of any additional mechanical integrity tests, pressure falloff tests, static bottomhole pressures, or other tests required by USEPA;
4. Report of any well workovers completed; and
5. A narrative description of all non-compliance events that occurred during the reporting period.

A quarterly report will be submitted for the reporting periods by the respective due dates as listed below:

January, February, March	April 28
April, May, June	July 28
July, August, September	October 28
October, November, December	January 28

P.1.6 Records Keeping

For a period of five years, the Project Team will retain all monitoring data, including required observations, calibration and maintenance records, recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete this permit application. Reports summarizing well construction, workover/completion changes, mechanical integrity testing, and plugging and abandonment will also be retained. Information reflecting the nature, composition, and volume of all injected fluids will also be kept for the retention period. At the conclusion of the retention period, all records shall thereafter be retained at a location designated by the Executive Director for that purpose.

Mechanical integrity tests will be performed during completion of the Injection Well and Observation Well, as detailed in Attachment L.

P.2 BASELINE AND CO_2 PILOT TEST MONITORING

Baseline monitoring activities will be performed to evaluate the composition, physical properties, pressure, and temperature of native fluids found in the saline formation and near-surface groundwater. Baseline measurements will be compared to data collected during CO_2 injection and post-injection to look for changes in geochemistry, hydrochemistry, and fluid pressures, indicating potential leakage from the target injection formation into overlying formations.

P.2.1 Reservoir Fluid Sampling

A u-tube sampler (Figure P-3; Freifeld et al., 2005; Freifeld and Trautz, 2006) will be installed in the Observation Well during the well completion and prior to the CO_2 injection test. A u-tube sampler may also be installed in the Injection Well. The inlet to the u-tube will be located in the perforated test interval allowing collection of baseline fluid samples from the interval prior to CO_2 injection. Baseline water samples will be collected and analyzed for the indicator parameters listed in Table P-3 as part of the baseline characterization for the test. The indicator parameter and rationale for selecting the parameter are provided in the table.

Table P-3 Baseline analyses to be performed on water samples collected from the injection interval

Parameter	Rationale for Selection
Select organics	Organics dissolve in CO_2 and may be mobilized when CO_2 is injected into the reservoir
Perfluorocarbon tracers (PFT)	PFTs may be used as tracers during CO_2 injection

Dissolved gases (e.g., O_2 , CO_2 , methane)	General geochemical reservoir characterization
Noble gases	Background level for use as tracer during CO_2 flood
Alkalinity, pH, electrical conductance	Changes in parameters indicate arrival of CO_2 front

Table P-4 Baseline analyses to be performed on gas samples collected from the injection interval.

Parameter	**Rationale for Selection**
Inorganic gases (e.g., O_2 , CO_2)	General geochemical composition of reservoir gases
Organic gases (e.g., methane)	Geochemical composition and characterization of the natural gas
Noble gases	Background level for use as tracer during CO_2 flood, identify mantle-derived volatiles

P.2.2 Vertical Seismic Profiling

The Vertical Seismic Profile (VSP) method is a seismic exploration tool, which has been used in oil and gas exploration for over 25 years. Recent work has shown that the VSP method can detect and spatially map the location of CO_2 plumes injected for sequestration (Daley, 2007b). The VSP method uses seismic sensors in the subsurface (in a well) along with sources on the surface that generate vibrations that travel through the earth. By using subsurface sensors, the seismic wave field can be recorded in the earth, thereby reducing surface noise and recording waves propagating both downward from the source and upward from deeper geologic formations. In the more common surface seismic survey, only the upward-traveling reflected waves are recorded. Recording the wave field in the subsurface provides a powerful tool for monitoring CO_2 plumes because the velocity of the wave field is reduced when the wave field passes through porous formations where saline brine has been replaced by CO_2, which is less dense than the brine.

A VSP survey may be performed twice, before and after CO_2 injection. The post injection survey will be compared to the pre-injection baseline survey to detect CO_2-induced changes. A simple pre-VSP test of seismic response at the well site may be conducted to ensure that the VSP method will be successful. This may include use of a single seismic sensor deployed by wireline to record the seismic response from a surface source.

Multiple seismic sensors will be deployed in the well during each VSP survey. Depending on the service contractor selected, there may be up to 80 three-component sensors temporarily installed in the well, or there may be a shorter string with several sensors that is moved to successive locations in the well. This will be accomplished by either standard wireline deployment (like well logging) or by special tubing-conveyed deployment. For tubing deployment, a workover rig will be required. The sensors will span the interval from below the selected reservoir to several hundred feet above it and will be temporarily clamped in place to maximize coupling to the well casing and surrounding rock formation. The deployment decision will be made based primarily on the trade-off between cost and data quality.

The surface sources will be either vibroseis trucks or explosive shot holes. Permitting and access will control final source site selection; however, the initial plan is to have source locations on an approximate radial “star” pattern. Each source location provides a cross section of data along the azimuth connecting the surface source and the sensors in the well. By acquiring data from multiple azimuths and multiple offset distances, a 3-Dimensional image can be obtained.

The VSP data will be processed to enhance the reflections from subsurface interfaces, including those related to the CO_2 injections. Time-lapse differences between the baseline survey and the post-injection surveys will be used to identify the spatial extent of the injected CO_2.

P.2.3 Cross-well Seismic Profiling

Active source borehole seismic monitoring may be performed between the Injection Well and the Observation Well before, during, and after CO_2 injection. As differentiated from the pre- and post-CO_2 injection VSP surveys, which provide a 3-dimensional image of the size and shape of the entire CO_2 plume, the crosswell surveys provide a higher resolution 2-dimensional image for the plane between the two wells. This image has higher resolution because the source (like the receivers) is downhole, close to and within the reservoir, rather than at the surface where the signal is subject to statics effects.

Two types of cross-borehole seismic surveys may be performed:

- Pre- and post-CO_2 injection (time-lapse) crosswell tomography surveys. Multiple hydrophones will be deployed in the Observation Well, and a piezoelectric or orbital vibrator source will be moved to multiple locations in the Injection Well.

- Continuous active-source seismic monitoring (CASSM) survey during CO_2 injection. The hydrophone array in the Observation Well used for the tomography surveys will be operated for the CASSM survey, with the vibrator source at a single fixed location in the Injection Well.

The CASSM survey (Daley et al., 2007a; Daley et al., 2008) may be used to monitor the growth of the plume between the wells, and the time-lapse crosswell data sets will provide full tomographic imaging of the plume after injection stops. The CASSM survey will be 'book-ended' by the crosswell tomography surveys. The opportunity to obtain a pair of bookend crosswell data sets with full tomographic coverage will advance the interpretation of the CASSM survey to later arriving energy (reflections/scattering) that can be better identified in the crosswell data sets because of their much greater ray coverage. Together, these surveys will allow for imaging of the CO_2 plume and monitoring of its growth during injection. Acquiring both types of data is important because individual reflections identified in the crosswell surveys could be used to monitor temporal changes in saturation in specific volumes using the CASSM data. With only a CASSM survey, these later arriving reflections cannot be adequately mapped in space to allow interpretation. The data will also be correlated with fluid sampling data obtained during and after CO_2 injection as the plume expands from the injection well to the monitoring well.

P.2.4 Time-lapse Thermal Perturbation Study of CO_2 Phase Saturation

A new method for detection of CO_2 leakage outside the wellbore is under consideration for use on the project. Because of the strong contrast in thermal conductivity between supercritical CO_2 and water, the thermal conductivity of the formation is highly dependent on CO_2 saturation. A Distributed Thermal Perturbation Sensor (DTPS), consisting of a fiber-optic distributed temperature sensor and a linear heating cable, may be deployed in the well. By measuring thermal conductivity with the DTPS prior to CO_2 injection and periodically after injection, it is expected that supercritical CO_2 saturation can be determined near the wellbore (within 3 feet), buoyant migration of CO_2 can be assessed, and leakage into the confining formation can be monitored. The method has recently been successfully demonstrated in Germany with the heating cable and sensors located outside the well.

P.2.5 Reservoir Saturation Monitoring

Schlumberger's Residual Saturation Tool combines the traditional methods of evaluating formation saturation, thermal decay time logging, and carbon/oxygen (C/O) logging into one tool. The dual-burst thermal decay time tools look at the thermal neutron adsorption, described by the capture cross section of the formation, to infer water saturation. A high absorption rate indicates high salinity water, and a low rate implies fresh water or hydrocarbons. The induced gamma ray spectrometer tool is used for C/O logging, which measures gamma rays emitted from inelastic neutron scattering to determine carbon and oxygen in the formation. A high C/O ratio indicates the presence of hydrocarbons, and a low ratio indicates water or gas zones (Adolph et al., 1994).

P.3 CO_2 PILOT TEST INJECTION

Injection of CO_2 will begin following baseline characterization. Liquid CO_2 will be trucked to the site using transporters and transferred into above-ground storage tanks. The liquid CO_2 will be pumped from the tanks through a heater, where the liquid CO_2 will vaporize to a gas before injecting it down the tubing inside the injection well. The heater will be designed to warm the CO_2 at the wellhead to a relatively constant up hole temperature ranging from 40 to 70 ^{o}F. The CO_2 gas will warm and compress as it goes down the well. Under hydrostatic pressures and temperatures expected at depth, the gas will become a supercritical fluid below a depth of 2,625 feet, significantly above any of the proposed injection intervals.

The injection plan calls for up to 6,000 tonnes of CO_2 that may be injected into the injection interval over a one- to two-month period. Injection rates, rate duration, and cumulative tonnage injected described in this plan are subject to revision once site characterization and baseline data become available. Baseline characterization results will allow the development of more accurate site-specific models to design and predict actual test performance.

Downhole pressure and temperature sensors will be installed in the Injection Well and the Observation Well when the tubing is installed. The downhole sensors will be tied into the data acquisition system, so that reservoir response can be sequenced and archived with the surface data. Therefore, pressure and temperature will be continuously monitored and recorded during any injection activities. Monitoring includes both the active injection phase and the subsequent falloff phase following secession of injection activity. Both the active injection and post-injection phase data can be analyzed and interpreted to determine formation properties, including permeability; compressibility; existence of reservoir boundary effects; fluid properties; and well completion efficiency. The post-injection monitoring phase may last several months to allow the injected CO_2 plume to stabilize and the injection interval to recover back to its natural condition.

References

Daley, T.M., Ajo-Franklin, J.B., Doughty, C., 2008, Integration of crosswell CASSM (Continuous active source seismic monitoring) and flow modeling for imaging of a CO_2 plume in a brine aquifer: extended abstract accepted to SEG annual meeting.

Daley, T.M., Solbau, R.D., Ajo-Franklin, J.B., Benson, S.M., 2007a, Continuous active-source monitoring of CO_2 injection in a brine aquifer: Geophysics, v 72, n 5, pp A57–A61, DOI:10.1190/1.2754716.

Daley, T.M., Myer, L.R., Peterson, J.E., Majer, E.L., Hoversten, G.M., 2007b, Time-lapse crosswell seismic and VSP monitoring of injected CO_2 in a brine aquifer: Environmental Geology, DOI:10.1007/s00254-007-0943-z.

Freifeld, B.M., Trautz, R.C., Kharaka, Y.K., Phelps, T.J., Myer, L.R., Hovorka, S.D., and Collins, D.J., 2005, The U-Tube: A novel system for acquiring borehole fluid samples from a deep geologic CO_2 sequestration experiment: *J. Geophys. Res. Solid Earth*, v 110, B10203, doi:10.1029/2005JB003735.

Freifeld, B.M., and Trautz, R.C., 2006, Real-time Quadrupole Mass Spectrometer analysis of deep borehole fluid samples acquired using the U-Tube sampling methodology: *Geofluids*, doi: 10.1111/j.1468-8123.2006.00138.x.

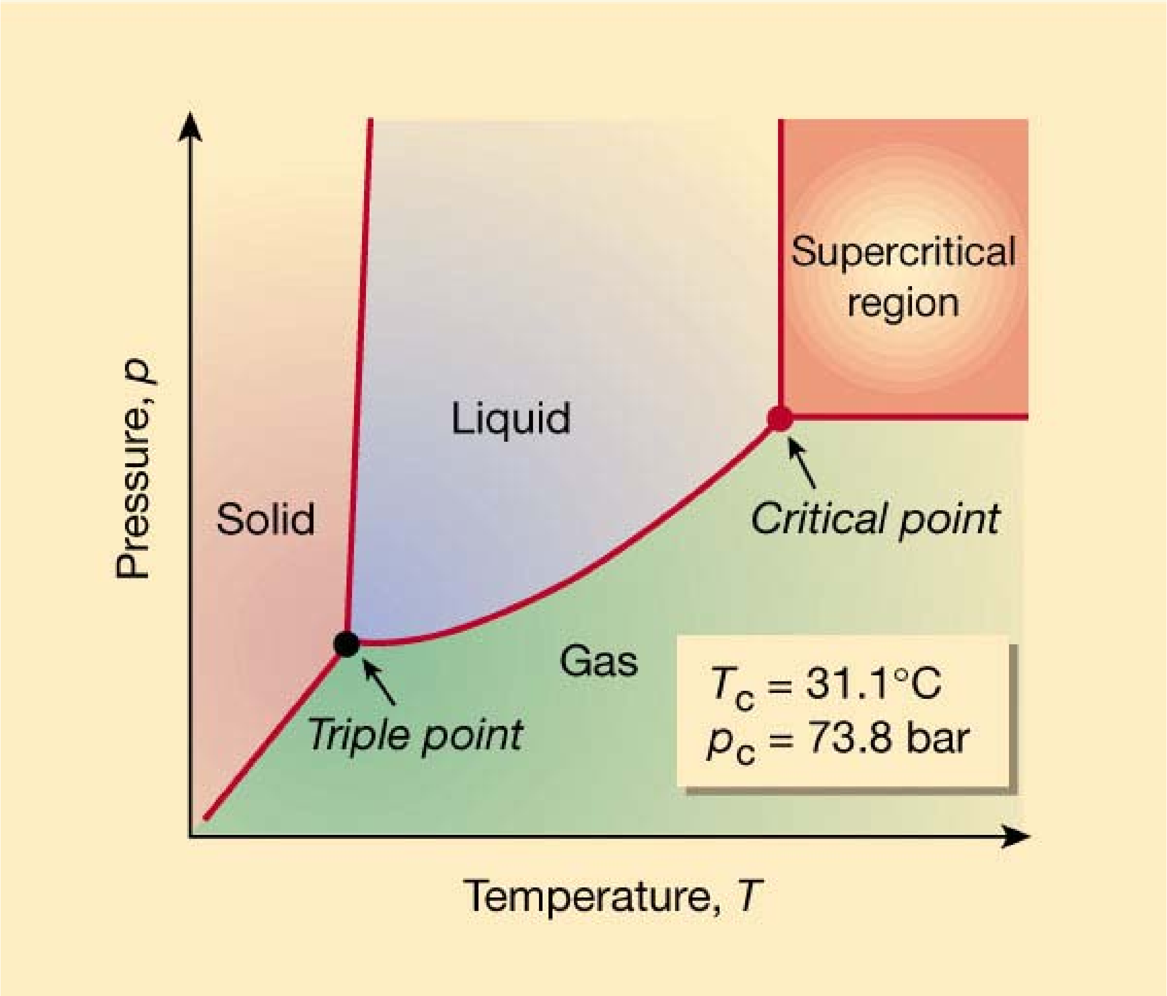


Figure P-1 Carbon Dioxide Phase Diagram

(http://www.nature.com/nature/journal/v405/n6783/images/405129aa.2.jpg).

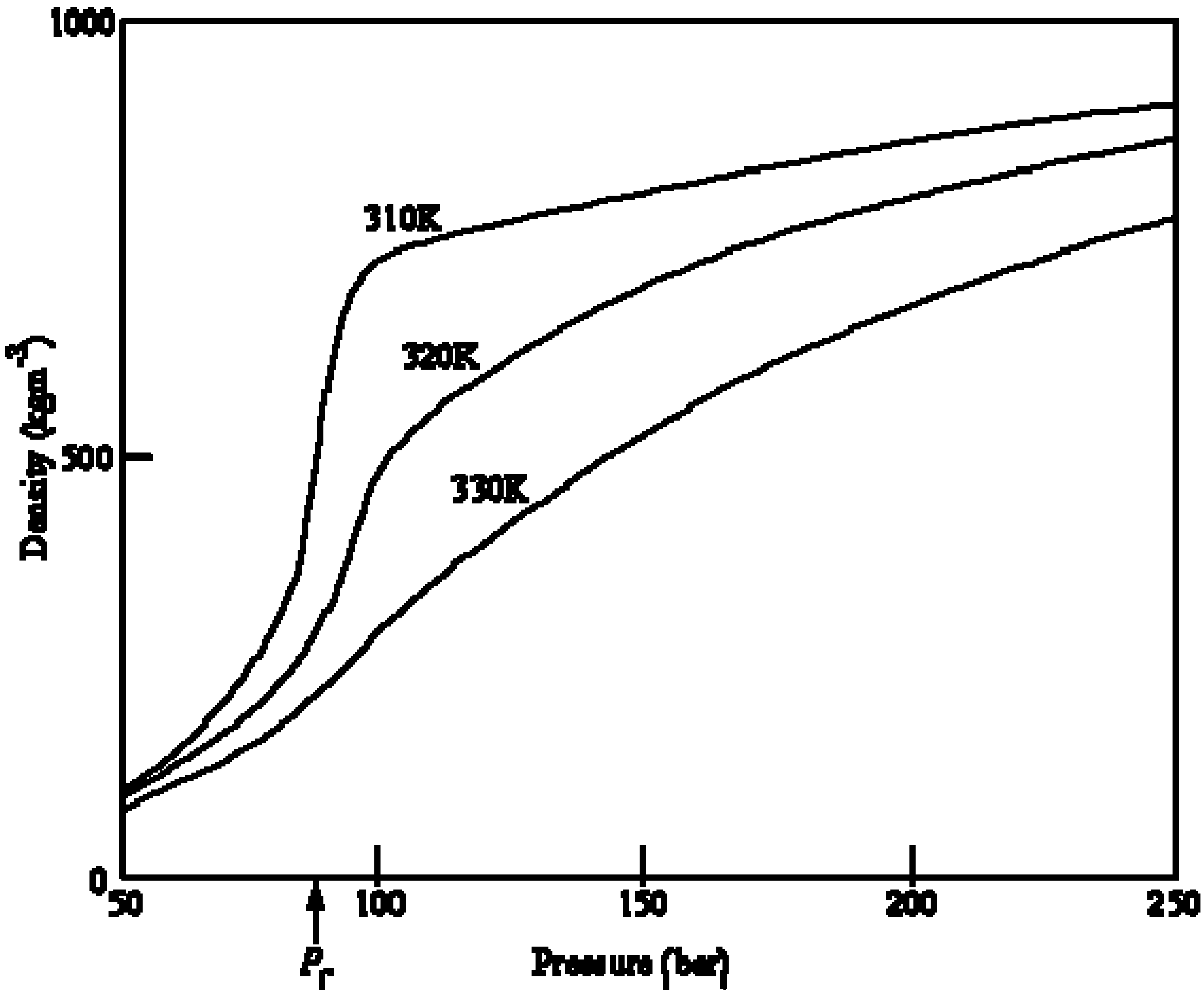


Figure P-2 Variation of Carbon Dioxide Density with Pressure and Temperature (**www.chem.leeds.ac.uk/People/CMR/props.html**).

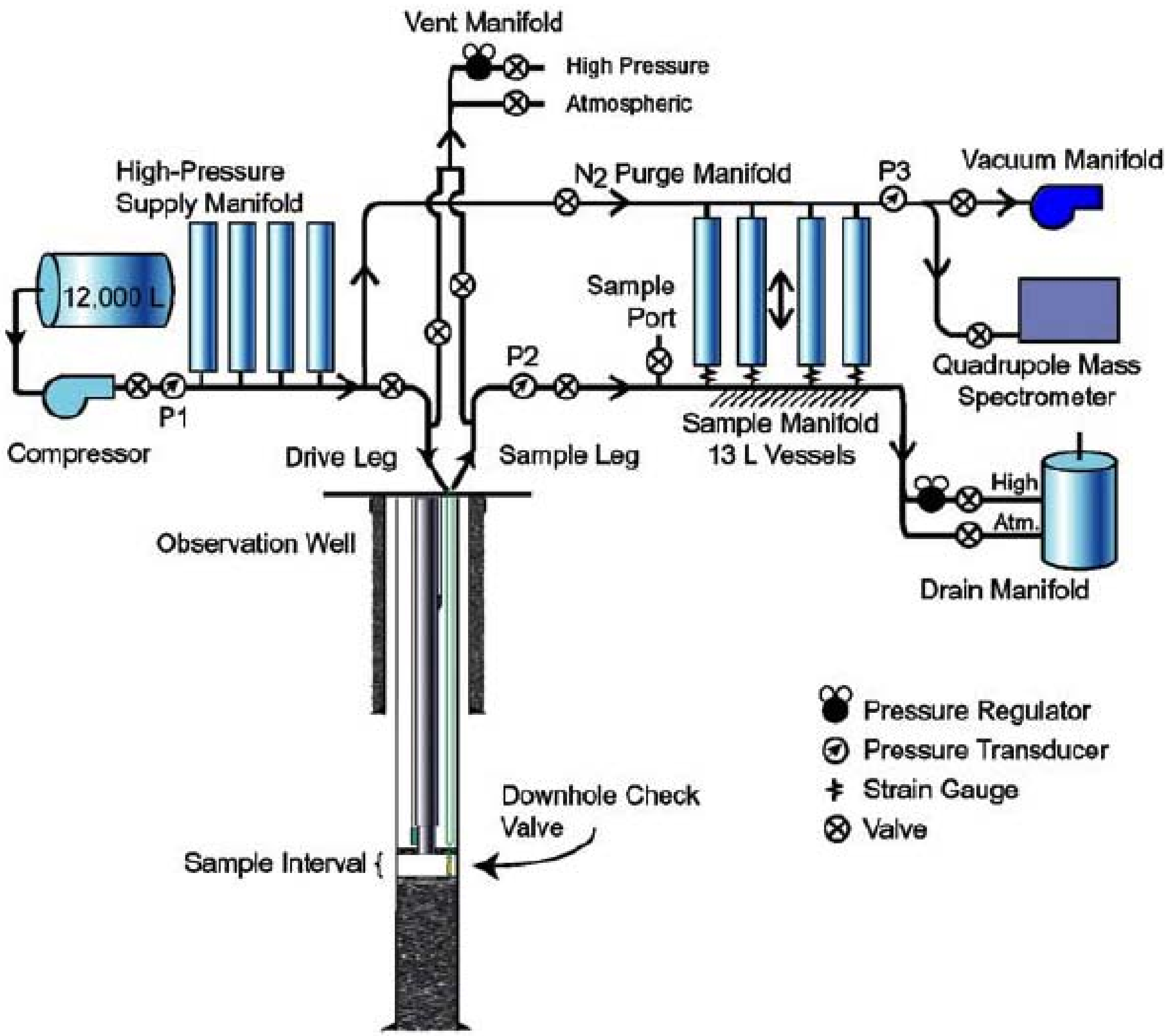


Figure P-3 U-tube Sampler Configuration Used to Collect Fluid Samples.

APPENDIX P-1
MATERIAL SAFETY DATA SHEETS FOR PROJECT TRACERS

APPENDIX P-1
MATERIAL SAFETY DATA SHEETS FOR PROJECT TRACERS
FLUORESCEIN

ScienceLab.com
Chemicals & Laboratory Equipment

Health	2
Fire	1
Reactivity	0
Personal Protection	E

Material Safety Data Sheet
Fluorescein MSDS

Section 1: Chemical Product and Company Identification

Product Name: Fluorescein

Catalog Codes: SLF1135, SLF1645

CAS#: 2321-07-5

RTECS: LM5075000

TSCA: TSCA 8(b) inventory: Fluorescein

CI#: Not available.

Synonym: CI Solvent Yellow 94; Spiro[isobenzofuran-1(3H),9'-[9H]xanthen]-3-one, 3'6'-dihydroxy-; 2-(6-Hydroxy-3-oxo-(3H)-xanthen-9-yl)benzoic acid; D & C Yellow #7; Fluorescein, alcohol soluble.

Chemical Name: Fluorescein

Chemical Formula: $C_{20}H_{12}O_5$

Contact Information:

Sciencelab.com, Inc.
14025 Smith Rd.
Houston, Texas 77396

US Sales: **1-800-901-7247**
International Sales: **1-281-441-4400**

Order Online: ScienceLab.com

CHEMTREC (24HR Emergency Telephone), call:
1-800-424-9300

International CHEMTREC, call: 1-703-527-3887

For non-emergency assistance, call: 1-281-441-4400

Section 2: Composition and Information on Ingredients

Composition:

Name	CAS #	% by Weight
Fluorescein	2321-07-5	100

Toxicological Data on Ingredients: Fluorescein LD50: Not available. LC50: Not available.

Section 3: Hazards Identification

Potential Acute Health Effects: Hazardous in case of skin contact (irritant), of eye contact (irritant), of ingestion, of inhalation.

Potential Chronic Health Effects:
CARCINOGENIC EFFECTS: Not available.
MUTAGENIC EFFECTS: Mutagenic for bacteria and/or yeast.
TERATOGENIC EFFECTS: Not available.
DEVELOPMENTAL TOXICITY: Not available.
Repeated or prolonged exposure is not known to aggravate medical condition.

Section 4: First Aid Measures

Eye Contact:
Check for and remove any contact lenses. In case of contact, immediately flush eyes with plenty of water for at least 15 minutes. Get medical attention.

Skin Contact:
In case of contact, immediately flush skin with plenty of water. Cover the irritated skin with an emollient. Remove contaminated clothing and shoes. Wash clothing before reuse. Thoroughly clean shoes before reuse. Get medical attention.

Serious Skin Contact:
Wash with a disinfectant soap and cover the contaminated skin with an anti-bacterial cream. Seek medical attention.

Inhalation:
If inhaled, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Get medical attention.

Serious Inhalation: Not available.

Ingestion:
Do NOT induce vomiting unless directed to do so by medical personnel. Never give anything by mouth to an unconscious person. If large quantities of this material are swallowed, call a physician immediately. Loosen tight clothing such as a collar, tie, belt or waistband.

Serious Ingestion: Not available.

Section 5: Fire and Explosion Data

Flammability of the Product: May be combustible at high temperature.

Auto-Ignition Temperature: Not available.

Flash Points: CLOSED CUP: Higher than 93.3°C (200°F).

Flammable Limits: Not available.

Products of Combustion: These products are carbon oxides (CO, CO_2).

Fire Hazards in Presence of Various Substances:
Slightly flammable to flammable in presence of open flames and sparks, of heat.
Non-flammable in presence of shocks.

Explosion Hazards in Presence of Various Substances:
Risks of explosion of the product in presence of mechanical impact: Not available.
Risks of explosion of the product in presence of static discharge: Not available.

Fire Fighting Media and Instructions:
SMALL FIRE: Use DRY chemical powder.
LARGE FIRE: Use water spray, fog or foam. Do not use water jet.

Special Remarks on Fire Hazards: Not available.

Special Remarks on Explosion Hazards: Not available.

Section 6: Accidental Release Measures

Small Spill:
Use appropriate tools to put the spilled solid in a convenient waste disposal container. Finish cleaning by spreading water on the contaminated surface and dispose of according to local and regional authority

requirements.

Large Spill:
Use a shovel to put the material into a convenient waste disposal container. Finish cleaning by spreading water on the contaminated surface and allow to evacuate through the sanitary system.

Section 7: Handling and Storage

Precautions:
Keep locked up.. Keep away from heat. Keep away from sources of ignition. Empty containers pose a fire risk, evaporate the residue under a fume hood. Ground all equipment containing material. Do not breathe dust. Wear suitable protective clothing. In case of insufficient ventilation, wear suitable respiratory equipment. If you feel unwell, seek medical attention and show the label when possible. Avoid contact with skin and eyes. Keep away from incompatibles such as oxidizing agents.

Storage: Keep container tightly closed. Keep container in a cool, well-ventilated area. Do not store above 24°C (75.2°F).

Section 8: Exposure Controls/Personal Protection

Engineering Controls:
Use process enclosures, local exhaust ventilation, or other engineering controls to keep airborne levels below recommended exposure limits. If user operations generate dust, fume or mist, use ventilation to keep exposure to airborne contaminants below the exposure limit.

Personal Protection:
Splash goggles. Lab coat. Dust respirator. Be sure to use an approved/certified respirator or equivalent. Gloves.

Personal Protection in Case of a Large Spill:
Splash goggles. Full suit. Dust respirator. Boots. Gloves. A self contained breathing apparatus should be used to avoid inhalation of the product. Suggested protective clothing might not be sufficient; consult a specialist BEFORE handling this product.

Exposure Limits: Not available.

Section 9: Physical and Chemical Properties

Physical state and appearance: Solid. (Solidcrystalline powder.)

Odor: Not available.

Taste: Not available.

Molecular Weight: 332.31 g/mole

Color: Yellow (Yellowish-Red) to Red.

pH (1% soln/water): Not applicable.

Boiling Point: Not available.

Melting Point: 315°C (599°F)

Critical Temperature: Not available.

Specific Gravity: Not available.

Vapor Pressure: Not applicable.

Vapor Density: Not available.

Volatility: Not available.

Odor Threshold: Not available.

Water/Oil Dist. Coeff.: Not available.

Ionicity (in Water): Not available.

Dispersion Properties: See solubility in water, methanol, acetone.

Solubility:
Easily soluble in acetone.
Soluble in methanol, hot alcohol, glacial acetic acid, alkali hydroxides, and carbonates.
Insoluble in cold water, diethyl ether, petroleum ether, benzene.

Section 10: Stability and Reactivity Data

Stability: The product is stable.

Instability Temperature: Not available.

Conditions of Instability: Excess heat, excess dust generation, incompatible materials

Incompatibility with various substances: Reactive with oxidizing agents.

Corrosivity: Non-corrosive in presence of glass.

Special Remarks on Reactivity: Not available.

Special Remarks on Corrosivity: Not available.

Polymerization: Will not occur.

Section 11: Toxicological Information

Routes of Entry: Inhalation. Ingestion.

Toxicity to Animals:
LD50: Not available.
LC50: Not available.

Chronic Effects on Humans: MUTAGENIC EFFECTS: Mutagenic for bacteria and/or yeast.

Other Toxic Effects on Humans: Hazardous in case of skin contact (irritant), of ingestion, of inhalation.

Special Remarks on Toxicity to Animals: Not available.

Special Remarks on Chronic Effects on Humans: Not available.

Special Remarks on other Toxic Effects on Humans:
Acute Potential Health Effects:
Skin: May cause skin irritation.
Eyes: Causes eye irritation.
Ingestion: May cause irritation of the gastrointestinal (digestive) tract.
Inhalation: may cause respiratory tract irritation.
The toxicological properties of this substance have not been fully investigated.

Section 12: Ecological Information

Ecotoxicity: Not available.

BOD5 and COD: Not available.

Products of Biodegradation:
Possibly hazardous short term degradation products are not likely. However, long term degradation products may arise.

Toxicity of the Products of Biodegradation: The product itself and its products of degradation are not toxic.

Special Remarks on the Products of Biodegradation: Not available.

Section 13: Disposal Considerations

Waste Disposal:
Waste must be disposed of in accordance with federal, state and local environmental control regulations.

Section 14: Transport Information

DOT Classification: Not a DOT controlled material (United States).

Identification: Not applicable.

Special Provisions for Transport: Not applicable.

Section 15: Other Regulatory Information

Federal and State Regulations:
TSCA 8(b) inventory: Fluorescein
SARA 313 toxic chemical notification and release reporting: Fluorescein

Other Regulations: EINECS: This product is on the European Inventory of Existing Commercial Chemical Substances.

Other Classifications:

WHMIS (Canada): Not controlled under WHMIS (Canada).

DSCL (EEC):
R36/38- Irritating to eyes and skin.
S24/25- Avoid contact with skin and eyes.
S37- Wear suitable gloves.
S45- In case of accident or if you feel unwell, seek medical advice immediately (show the label where possible).

HMIS (U.S.A.):

Health Hazard: 2

Fire Hazard: 1

Reactivity: 0

Personal Protection: E

National Fire Protection Association (U.S.A.):

Health: 2

Flammability: 1

Reactivity: 0

Specific hazard:

Protective Equipment:
Gloves.
Lab coat.
Dust respirator. Be sure to use an approved/certified respirator or equivalent.
Splash goggles.

Section 16: Other Information

References: Not available.

Other Special Considerations: Not available.

Created: 10/10/2005 08:18 PM

Last Updated: 10/10/2005 08:18 PM

APPENDIX P-1
MATERIAL SAFETY DATA SHEETS FOR PROJECT TRACERS
KRYPTON

Linde Gas Linde

Linde Gas LLC (216) 642-6600
P.O. Box 94737
Cleveland, Ohio 44101
www.us.lindegas.com

MATERIAL
SAFETY
DATA SHEET

No. 39

PRODUCT NAME Krypton	CAS # 7439-90-9
TRADE NAME AND SYNONYMS Krypton, compressed	DOT I.D. No.: UN 1056
CHEMICAL NAME AND SYNONYMS Krypton	DOT Hazard Class: Division 2.2
	Formula Kr
ISSUE DATES AND REVISIONS Revised January 1995	Chemical Family: Inert Gas

HEALTH HAZARD DATA

TIME WEIGHTED AVERAGE EXPOSURE LIMIT

None listed (ACGIH 1994-1995). Should be considered a simple asphyxiant. Oxygen levels should be maintained at greater than 18 molar percent (Continued on Page 4)

SYMPTOMS OF EXPOSURE

Effects of exposure to high concentrations so as to displace the oxygen in the air necessary for life are headache, dizziness, labored breathing and eventual unconsciousness.

TOXICOLOGICAL PROPERTIES

Krypton is nontoxic but the liberation of a large amount in a confined area could displace the amount of oxygen in air necessary to support life.

Krypton is not listed in the IARC, NTP or by OSHA as a carcinogen or potential carcinogen.

Persons in ill health where such illness would be aggravated by exposure to krypton should not be allowed to work with or handle this product.

RECOMMENDED FIRST AID TREATMENT

PROMPT MEDICAL ATTENTION IS MANDATORY IN ALL CASES OF OVEREXPOSURE TO KRYPTON. RESCUE I PERSONNEL SHOULD BE EQUIPPED WITH SELF-CONTAINED BREATHING APPARATUS.

Inhalation: Conscious persons should be assisted to an uncontaminated area and inhale fresh air. Quick removal from the contaminated area is most important. Unconscious persons should be moved to an uncontaminated area, given assisted respiration and supplemental oxygen. Further treatment should be symptomatic and supportive.

HAZARDOUS MIXTURES OF OTHER LIQUIDS, SOLIDS, OR GASES

None

PHYSICAL DATA

BOILING POINT -244°F (-153.3°C)	LIQUID DENSITY AT BOILING POINT 150.6 lb/ft^3 (2412 kg/m^3)
VAPOR PRESSURE @ 70°F (21.1°C) Above the critical temp. of -82.8°F (- 63.8°C)	GAS DENSITY AT 70°F. 1 atm .2172 lb/ft^3 (3.479 kg/m^3)
SOLUBILITY IN WATER Negligible	FREEZING POINT -250.9°F (-157.2°C)
EVAPORATION RATE N/A (Gas)	SPECIFIC GRAVITY (AIR=1) @ 70°F (21.1°C) = 2.9
APPEARANCE AND ODOR Colorless, odorless gas	

FIRE AND EXPLOSION HAZARD DATA

FLASH POINT (Method used) N/A	AUTO IGNITION TEMPERATURE N/A	FLAMMABLE LIMITS % BY VOLUME (See Page 4) LEL N/A UEL N/A
EXTINGUISHING MEDIA Nonflammable, inert gas		ELECTRICAL CLASSIFICATION Nonhazardous

SPECIAL FIRE FIGHTING PROCEDURES

If cylinders are involved in a fire, safely relocate or keep cool with water spray.

UNUSUAL FIRE AND EXPLOSION HAZARDS

None

REACTIVITY DATA

STABILITY		CONDITIONS TO AVOID
Unstable		None
Stable	X	

INCOMPATIBILITY (Materials to avoid) None

HAZARDOUS DECOMPOSITION PRODUCTS None

HAZARDOUS POLYMERIZATION		CONDITIONS TO AVOID
May Occur		None
Will Not Occur	X	

SPILL OR LEAK PROCEDURES

STEPS TO BE TAKEN IN CASE MATERIAL IS RELEASED OR SPILLED

Evacuate all personnel from affected area. Use appropriate protective equipment. If leak is in container or container vlave, contact your closest supplier location o' call the emergency telephone number listed herein.

WASTE DISPOSAL METHOD

Do not attempt to dispose of waste or unused quantities. Return in the shipping container properly labeled, with any valve outlet plugs or caps secured and valve protection cap in place to your supplier. For emergency disposal assistance, contact your closest supplier location or call the emergency telephone number listed herein.

SPECIAL PROTECTION INFORMATION

RESPIRATORY PROTECTION (Specify type)	Positive pressure air line with mask or self-contained breathing apparatus should be available for emergency use.	
VENTILATION: See Local Exhaust	LOCAL EXHAUST: See Last Page	SPECIAL: N/A
	MECHANICAL (Gen.): N/A	OTHER: N/A
PROTECTIVE GLOVES: Any material		
EYE PROTECTION: Safety goggles or glasses		
OTHER PROTECTIVE EQUIPMENT: Safety shoes		

SPECIAL PRECAUTIONS*

SPECIAL LABELING INFORMATION

DOT Shipping Name: Krypton, compressed — DOT Hazard Class: Division 2.2

DOT Shipping Label: Nonflammable Gas — I.D. No.: UN 1956

SPECIAL HANDLING RECOMMENDATIONS

Use only in well-ventilated areaS. Valve protection caps must remain in place unless container is secured With valve outlet piped to use point. Do not drag, slide or roll cylinders. Use a suitable hand truck for cylinder movement. Use a pressure reducing regulator when connecting cylinder to lower preSsure (<3,000 psig) piping or systems. Do not heat cylinder by any meanS to increase the discharge rate of product from the cylinder. Use a check valve or trap in the discharge line to prevent hazardous back flow into the cylinder.

For additional handling recommendations, consult Compressed Gas Association's Pamphlet P-1, P-9, P-14, and Safety Bulletin SB-2.

SPECIAL STORAGE RECOMMENDATIONS

Protect cylinders from physical damage. Store in cool, dry, well-ventilated area away from heavily trafficked areas and emergency exits. Do not allow the temperature where cylinders are stored to exceed 125F (52C). Cylinders should be stored upright and firmly secured to prevent falling or being knocked over. Full and empty cylinders should be segregated. Use a "first in - first out'. inventory system to prevent full cylinders being stored for excessive periods of time.

For additional storage recommendations, consult Compressed Gas Association's Pamphlets P-1, P-9, P-14, and Safety Bulletin SB-2.

SPECIAL PACKAGING RECOMMENDATIONS

Krypton is noncorrosive and may be used with any common structural material.

OTHER RECOMMENDATIONS OR PRECAUTIONS

Compressed gas cylinders should not be refilled except by qualified producers of compressed gases. Shipment of a compressed gas cylinder which has not been filled by the owner or with his (written) consent is a violation of Federal Law (49CFR). (Continued on Page 4)

*Various Government Agencies (i.e. Department of Transportation, Occupational Safety and Health Administration, Food and Drug Administration and others) may have specific regulations concerning the transportation, handling, storage or use of this product which will not be reflected in this data sheet. The customer should review these regulations to ensure that he is in full compliance.

HEALTH HAZARD DATA

TIME WEIGHTED AVERAGE EXPOSURE LIMIT: (Continued)

at normal atmospheric pressure (pO_2>135 torr). OSHA 1993 PEL (8 Hr. TWA) None listed.

SPECIAL PROTECTION INFORMATION

LOCAL EXHAUST:

To prevent accumulation of high concentrations so as to reduce the oxygen level in the air to less than 18 molar percent.

SPECIAL PRECAUTIONS

OTHER RECOMMENDATIONS OR PRECAUTIONS: (Continued)

Always secure cylinders in an upright position before transporting them. NEVER transport cylinders in trunks of vehicles, enclosed vans, truck cabs or in passenger compartments. Transport cylinders secured in open flatbed or in open pick-up type vehicles.

Reporting under SARA, Title III, Section 313 not required.

NFPA 704 NO. for krypton = 1 O O None

APPENDIX P-1
MATERIAL SAFETY DATA SHEETS FOR PROJECT TRACERS
OPTITRAK*600

MATERIAL SAFETY DATA SHEET

MSDS NO. 12335 **Trade Name:** OPTITRAK* 600 **Revision Date:** 07/18/2007

1. CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

Trade Name:	OPTITRAK* 600
Chemical Family:	Dye
Product Use:	Oil well drilling fluid additive.
Emergency Telephone (24 hr.):	281-561-1600
Supplied by:	M-I L.L.C. P.O. Box 42842 Houston, TX 77242 www.miswaco.com
Telephone Number:	281-561-1512
Prepared by:	Product Safety Group
Revision Number:	1

HMIS Rating

Health: 2 **Flammability:** 1 **Physical Hazard:** 0 **PPE:** E

HMIS Key: 4=Severe, 3=Serious, 2=Moderate, 1=Slight, 0=Minimal Hazard. *Chronic effects - See Section 11. See Section 8 for Personal Protective Equipment recommendations.

2. HAZARDS IDENTIFICATION

Emergency Overview: Warning! May cause an allergic reaction. May cause mechanical irritation of eyes, skin and respiratory tract. Long term inhalation of particulates may cause lung damage.

Canadian Classification:

UN PIN No: Not regulated. **WHMIS Class:** D2B

Physical State: Powder, dust. **Odor:** None **Color:** Blue

Potential Health Effects:

Acute Effects

Eye Contact:	May cause mechanical irritation
Skin Contact:	May cause mechanical irritation. May cause an allergic skin reaction.
Inhalation:	May cause mechanical irritation.
Ingestion:	May cause gastric distress, nausea and vomiting if ingested. May cause an allergic reaction.

Carcinogenicity & Chronic Effects:	See Section 11 - Toxicological Information.
Routes of Exposure:	Eyes. Dermal (skin) contact. Inhalation.
Target Organs/Medical Conditions Aggravated by Overexposure:	Eyes. Skin. Respiratory System.

3. COMPOSITION/INFORMATION ON INGREDIENTS

Ingredient	CAS No.	Wt. %	Comments:
Blue dye		100	No comments.

4. FIRST AID MEASURES

Eye Contact: Promptly wash eyes with lots of water while lifting eye lids. Continue to rinse for at least 15 minutes. Get medical attention if any discomfort continues.

Skin Contact: Wash skin thoroughly with soap and water. Remove contaminated clothing and launder before reuse. Get medical attention if any discomfort continues.

Inhalation: Move person to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Get medical attention.

Ingestion: Dilute with 2 - 3 glasses of water or milk, if conscious. Never give anything by mouth to an unconscious person. If signs of irritation or toxicity occur seek medical attention.

General notes: Persons seeking medical attention should carry a copy of this MSDS with them.

5. FIRE FIGHTING MEASURES

Flammable Properties

Flash Point: F (C): NA
Flammable Limits in Air - Lower (%): ND
Flammable Limits in Air - Upper (%): ND
Autoignition Temperature: F (C): ND
Flammability Class: NA
Other Flammable Properties: Particulate may accumulate static electricity. Dusts at sufficient concentrations can form explosive mixtures with air.
Extinguishing Media: Carbon dioxide. Foam. Water mist.

Protection Of Fire-Fighters:

Special Fire-Fighting Procedures: Do not enter fire area without proper personal protective equipment, including NIOSH/MSHA approved self-contained breathing apparatus. Evacuate area and fight fire from a safe distance. Water spray may be used to keep fire-exposed containers cool. Keep water run off out of sewers and waterways.

Hazardous Combustion Products: Oxides of: Sulfur. Carbon. Nitrogen.

6. ACCIDENTAL RELEASE MEASURES

Personal Precautions: Use personal protective equipment identified in Section 8.

Spill Procedures: Evacuate surrounding area, if necessary. Wet product may create a slipping hazard. Contain spilled material. Avoid the generation of dust. Sweep, vacuum, or shovel and place into closable container for disposal.

Environmental Precautions: Do not allow to enter sewer or surface and subsurface waters. Waste must be disposed of in accordance with federal, state and local laws.

7. HANDLING AND STORAGE

Handling: Put on appropriate personal protective equipment. Avoid contact with skin and eyes. Avoid generating or breathing dust. Product is slippery if wet. Use only with adequate ventilation. Wash thoroughly after handling.

Storage: Store in dry, well-ventilated area. Keep container closed. Store away from incompatibles. Follow safe warehousing practices regarding palletizing, banding, shrink-wrapping and/or stacking.

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

Exposure Limits (TLV & PEL - 8H TWA):

Ingredient	CAS No.	Wt. %	ACGIH TLV	OSHA PEL	Other	Notes
Blue dye		100	NA	NA	NA	(1)

Notes
(1) Control as an ACGIH particulate not otherwise specified (PNOS): 10 mg/m^3 (Inhalable); 3 mg/m^3 (Respirable) and an OSHA particulate not otherwise regulated (PNOR): 15 mg/m^3 (Total); 5 mg/m^3 (Respirable).

Engineering Controls: Use appropriate engineering controls such as, exhaust ventilation and process enclosure, to ensure air contamination and keep workers exposure below the applicable limits.

Personal Protection Equipment

All chemical Personal Protective Equipment (PPE) should be selected based on an assessment of both the chemical hazards present and the risk of exposure to those hazards. The PPE recommendations below are based on our assessment of the chemical hazards associated with this product. The risk of exposure and need for respiratory protection will vary from workplace to workplace and should be assessed by the user.

Eye/Face Protection: Dust resistant safety goggles.

Skin Protection: Not normally necessary. If needed to minimize irritation: Wear appropriate clothing to prevent repeated or prolonged skin contact. Wear chemical resistant gloves such as: Nitrile. Neoprene.

Respiratory Protection: All respiratory protection equipment should be used within a comprehensive respiratory protection program that meets the requirements of 29 CFR 1910.134 (U.S. OSHA Respiratory Protection Standard) or local equivalent.

If exposed to airborne particles of this product use at least a NIOSH-approved N95 half-mask disposable or re-useable particulate respirator. In work environments containing oil mist/aerosol use at least a NIOSH-approved P95 half-mask disposable or re-useable particulate respirator.

General Hygiene Considerations: Work clothes should be washed separately at the end of each work day. Disposable clothing should be discarded, if contaminated with product.

9. PHYSICAL AND CHEMICAL PROPERTIES

Color:	Blue
Odor:	None
Physical State:	Powder, dust.
pH:	6.5 - 7.5 (1 g/l water)
Specific Gravity (H2O = 1):	0.8 - 1.0 at 68F (20C)
Solubility (Water):	Soluble
Melting/Freezing Point:	ND
Boiling Point:	ND
Vapor Pressure:	ND
Vapor Density (Air=1):	ND
Evaporation Rate:	ND
Odor Threshold(s):	ND

10. STABILITY AND REACTIVITY

Chemical Stability:	Stable
Conditions to Avoid:	ND

10. STABILITY AND REACTIVITY

Materials to Avoid: Oxidizers.
Hazardous Decomposition Products: For thermal decomposition products, see Section 5.
Hazardous Polymerization: Will not occur

11. TOXICOLOGICAL INFORMATION

Component Toxicological Data: Any adverse component toxicological effects are listed below. If no effects are listed, no such data were found.

Ingredient	CAS No.	Acute Data
Blue dye		Oral LD50: >5000 mg/kg (rat)

Ingredient	Component Toxicological Summary
Blue dye	This blue dye 1 has caused mutagenicity using the Salmonella/microsome preincubation and micronucleus assays. Other mutagenicity tests were negative. This compound has caused allergic reactions when ingested, injected and in skin prick tests. (HSDB)

Product Toxicological Information:
Long term inhalation of particulate can cause irritation, inflammation and/or permanent injury to the lungs. Illnesses such as pneumoconiosis ("dusty lung"), pulmonary fibrosis, chronic bronchitis, emphysema and bronchial asthma may develop.

12. ECOLOGICAL INFORMATION

Ingredient	CAS No.	Data
Blue dye		IC0 >300 (sludge organisms); LC50 96H: 1000 mg/l (trout)

Product Ecotoxicity Data: Contact M-I Environmental Affairs Department for available product ecotoxicity data.

Biodegration: ND
Bioaccumulation: ND
Octanol/Water Partition Coefficient: ND

13. DISPOSAL CONSIDERATIONS

Waste Classification: ND

Waste Management: Under U.S. Environmental Protection Agency (EPA) Resource Conservation and Recovery Act (RCRA), it is the responsibility of the user to determine at the time of disposal, whether the product meets RCRA criteria for the hazardous waste. This is because product uses, transformations, mixtures, processes, etc., may render the resulting materials hazardous. Empty containers retain residues. All labeled precautions must be observed.

Disposal Method: Recover and reclaim or recycle, if practical. Should this product become a waste, dispose of in a permitted industrial landfill. Ensure that the containers are empty by the RCRA criteria prior to disposal in a permitted industrial landfill.

14. TRANSPORT INFORMATION

U.S. DOT Shipping Description: Not regulated under TDG, IMDG, ICAO/IATA.

Canada TDG Shipping Description: Not regulated.
UN PIN No: Not regulated.

IMDG Shipping Description: Not regulated.

ICAO/IATA Shipping Description: Not regulated.

15. REGULATORY INFORMATION

U.S. Federal and State Regulations

SARA 311/312 Hazard Catagories: Immediate (acute) health hazard.

SARA 302/304, 313; CERCLA RQ, California Proposition 65: Note: If no components are listed below, this product is not subject to the referenced SARA and CERCLA regulations and is not known to contain a Proposition 65 listed chemical at a level that is expected to pose a significant risk under anticipated use conditions.

International Chemical Inventories

Australia AICS - Components are listed or exempt from listing.
Canada DSL - Components are listed or exempt from listing.
China Inventory - Components are listed or exempt from listing.
European Union EINECS/ELINCS - Components are listed or exempt from listing.
Japan METI ENCS - Components are listed or exempt from listing.
Korea TCCL ECL - Components are listed or exempt from listing.
U.S. TSCA - Components are listed or exempt from listing.
U.S. TSCA - No components are subject to TSCA 12(b) export notification requirements.

Canadian Classification:

Controlled Products Regulations Statement: This product has been classified in accordance with the hazard criteria of the CPR and the MSDS contains all the information required by the CPR.

WHMIS Class: D2B

16. OTHER INFORMATION

The following sections have been revised: 1, 2, 3, 8, 16

NA - Not Applicable, ND - Not Determined.

*A mark of M-I L.L.C.

Disclaimer:
MSDS furnished independent of product sale. While every effort has been made to accurately describe this product, some of the data are obtained from sources beyond our direct supervision. We can not make any assertions as to its reliability or completeness; therefore, user may rely on it only at user's risk. We have made no effort to censor or conceal deleterious aspects of this product. Since we cannot anticipate or control the conditions under which this information and product may be used, we make no guarantee that the precautions we have suggested will be adequate for all individuals and/or situations. It is the obligation of each user of this product to comply with the requirements of all applicable laws regarding use and disposal of this product. Additional information will be furnished upon request to assist the user; however, no warranty, either expressed or implied, nor liability of any nature with respect to this product or to the data herein is made or incurred hereunder.

APPENDIX P-1
MATERIAL SAFETY DATA SHEETS FOR PROJECT TRACERS
RHODAMINE 6G

MSDS Number: **R5500** * * * * * *Effective Date:* ***06/20/07*** * * * * * *Supercedes:* ***05/07/07***

MSDS Material Safety Data Sheet

24 Hour Emergency Telephone: 908-859-2151
CHEMTREC: 1-800-424-9300

National Response in Canada
CANUTEC: 613-996-6666

Outside U.S. And Canada
Chemtrec: 703-527-3887

NOTE: CHEMTREC, CANUTEC and National Response Center emergency numbers to be used only in the event of chemical emergencies involving a spill, leak, fire, exposure or accident involving chemicals.

From: Mallinckrodt Baker, Inc.
222 Red School Lane
Phillipsburg, NJ 08865

All non-emergency questions should be directed to Customer Service (1-800-582-2537) for assistance.

Rhodamine 6G

1. Product Identification

Synonyms: C.I. Basic Red 1; C.I. 45160; Basic Rhodamine Yellow
CAS No.: 989-38-8
Molecular Weight: 479.02
Chemical Formula: C28H30N2O3.HCl
Product Codes: U874

2. Composition/Information on Ingredients

Ingredient	CAS No	Percent	Hazardous
Rhodamine 6G	989-38-8	90 - 100%	Yes

3. Hazards Identification

Emergency Overview

WARNING! HARMFUL IF SWALLOWED. CAUSES IRRITATION.

SAF-T-DATA(tm) Ratings (Provided here for your convenience)

Health Rating: 1 - Slight
Flammability Rating: 0 - None
Reactivity Rating: 1 - Slight
Contact Rating: 1 - Slight
Lab Protective Equip: GOGGLES; LAB COAT; PROPER GLOVES
Storage Color Code: Green (General Storage)

Potential Health Effects

Inhalation:
May be harmful.
Ingestion:
None identified.
Skin Contact:
None identified.
Eye Contact:
None identified.
Chronic Exposure:
No information found.
Aggravation of Pre-existing Conditions:
No information found.

4. First Aid Measures

Inhalation:
If inhaled, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Prompt action is essential.
Ingestion:
Induce vomiting immediately as directed by medical personnel. Never give anything by mouth to an unconscious person. Get medical attention.
Skin Contact:
In case of contact, flush skin with water.
Eye Contact:
In case of eye contact, immediately flush with plenty of water for at least 15 minutes.

5. Fire Fighting Measures

Fire:
Not expected to be a fire hazard.
Explosion:
None identified.
Fire Extinguishing Media:
Use extinguishing media appropriate for surrounding fire.
Special Information:
In the event of a fire, wear full protective clothing and NIOSH-approved self-contained breathing apparatus with full facepiece operated in the pressure demand or other positive pressure mode.

6. Accidental Release Measures

Wear self-contained breathing apparatus and full protective clothing. With clean shovel, carefully place material into clean, dry container and cover; remove from area. Flush spill area with water.

7. Handling and Storage

Keep container tightly closed. Suitable for any general chemical storage area. Containers of this material may be hazardous when empty since they retain product residues (dust, solids); observe all warnings and precautions listed for the product.

8. Exposure Controls/Personal Protection

Airborne Exposure Limits:
None established.
Ventilation System:
A system of local and/or general exhaust is recommended to keep employee exposures as low as possible. Local exhaust ventilation is generally preferred because it can control the emissions of the contaminant at its source, preventing dispersion of it into the general work area. Please refer to the ACGIH document, *Industrial Ventilation, A Manual of Recommended Practices*, most recent edition, for details.
Personal Respirators (NIOSH Approved):
For conditions of use where exposure to the substance is apparent and engineering controls are not feasble, consult an industrial hygienist. For emergencies, or instances where the exposure levels are not known, use a full-facepiece positive-pressure, air-supplied respirator. WARNING: Air purifying respirators do not protect workers in oxygen-deficient atmospheres.
Skin Protection:
Wear impervious protective clothing, including boots, gloves, lab coat, apron or coveralls, as appropriate, to prevent skin contact.
Eye Protection:
Use chemical safety goggles and/or full face shield where dusting or splashing of solutions is possible. Maintain eye wash fountain and quick-drench facilities in work area.

9. Physical and Chemical Properties

Appearance:
Brown to black crystalline solid.
Odor:
No information found.
Solubility:
Slight (0.1-1%)
Specific Gravity:
No information found.
pH:
No information found.
% Volatiles by volume @ 21C (70F):
0
Boiling Point:
No information found.
Melting Point:
No information found.
Vapor Density (Air=1):
Not applicable.
Vapor Pressure (mm Hg):
Not applicable.
Evaporation Rate (BuAc=1):
No information found.

10. Stability and Reactivity

Stability:
Stable under ordinary conditions of use and storage.
Hazardous Decomposition Products:
Oxides of nitrogen, ammonia, hydrogen chloride.
Hazardous Polymerization:
Will not occur.
Incompatibilities:
Strong oxidizing agents.

Conditions to Avoid:
No information found.

11. Toxicological Information

\--------\Cancer Lists\--

Ingredient	NTP Carcinogen Known	NTP Carcinogen Anticipated	IARC Category
Rhodamine 6G (989-38-8)	No	No	3

12. Ecological Information

Environmental Fate:
No information found.
Environmental Toxicity:
No information found.

13. Disposal Considerations

Whatever cannot be saved for recovery or recycling should be managed in an appropriate and approved waste disposal facility. Processing, use or contamination of this product may change the waste management options. State and local disposal regulations may differ from federal disposal regulations. Dispose of container and unused contents in accordance with federal, state and local requirements.

14. Transport Information

Not regulated.

15. Regulatory Information

\--------\Chemical Inventory Status - Part 1\---------------------------------

Ingredient	TSCA	EC	Japan	Australia
Rhodamine 6G (989-38-8)	Yes	Yes	Yes	Yes

\--------\Chemical Inventory Status - Part 2\---------------------------------

Ingredient	Korea	Canada DSL	Canada NDSL	Phil.
Rhodamine 6G (989-38-8)	Yes	Yes	No	Yes

\--------\Federal, State & International Regulations - Part 1\----------------

Ingredient	SARA 302 RQ	SARA 302 TPQ	SARA 313 List	SARA 313 Chemical Catg.
Rhodamine 6G (989-38-8)	No	No	Yes	No

\--------\Federal, State & International Regulations - Part 2\----------------

Ingredient	CERCLA	RCRA 261.33	TSCA 8(d)
Rhodamine 6G (989-38-8)	No	No	No

Chemical Weapons Convention: No TSCA 12(b): No CDTA: No

```
SARA 311/312:  Acute: Yes     Chronic: Yes  Fire: No  Pressure: No
Reactivity: No          (Pure / Solid)
```

Australian Hazchem Code: None allocated.
Poison Schedule: None allocated.
WHMIS:
This MSDS has been prepared according to the hazard criteria of the Controlled Products Regulations (CPR) and the MSDS contains all of the information required by the CPR.

16. Other Information

NFPA Ratings: Health: **1** Flammability: **0** Reactivity: **0**
Label Hazard Warning:
WARNING! HARMFUL IF SWALLOWED. CAUSES IRRITATION.
Label Precautions:
Avoid contact with eyes, skin, clothing.
Keep in tightly closed container. Wash thoroughly after handling.
Label First Aid:
If swallowed, induce vomiting immediately as directed by medical personnel. Never give anything by mouth to an unconscious person. In case of contact, immediately flush eyes or skin with plenty of water for at least 15 minutes. Remove contaminated clothing and shoes. Wash clothing before reuse.
Product Use:
Laboratory Reagent.
Revision Information:
MSDS Section(s) changed since last revision of document include: 3, 15.
Disclaimer:

Prepared by: Environmental Health & Safety
Phone Number: (314) 654-1600 (U.S.A.)

APPENDIX P-1
MATERIAL SAFETY DATA SHEETS FOR PROJECT TRACERS
SULFUR HEXAFLUORIDE

Airgas

NFPA RATING

FLAMMABILITY: 0
HEALTH: 1
INSTABILITY: 0
OTHER

MATERIAL SAFETY DATA SHEET

Prepared to U.S. OSHA, CMA, ANSI and Canadian WHMIS Standards

PART I *What is the material and what do I need to know in an emergency?*

1. PRODUCT IDENTIFICATION

CHEMICAL NAME; CLASS:	**SULFUR HEXAFLUORIDE - SF_6**
	Document Number: 001048
PRODUCT USE:	For General Analytical Chemical Uses
SUPPLIER/MANUFACTURER'S NAME:	AIRGAS INC.
ADDRESS:	259 N. Radnor-Chester Road Suite 100 Radnor, PA 19087-5283
BUSINESS PHONE:	1-610-687-5253
EMERGENCY PHONE:	1-800-949-7937 International: 423-479-0293
DATE OF PREPARATION:	May 20, 1996
DATE OF REVISION:	March 26, 2004

2. COMPOSITION and INFORMATION ON INGREDIENTS

CHEMICAL NAME	CAS #	mole %	EXPOSURE LIMITS IN AIR					
			ACGIH-TLV		OSHA-PEL		NIOSH	OTHER
			TWA ppm	STEL ppm	TWA ppm	STEL ppm	IDLH ppm	ppm
Sulfur Hexafluoride	2551-62-4	> 99.8%	1000	NE	1000	NE	NE	NIOSH REL: TWA = 1000 DFG MAK: TWA = 1000 PEAK = 8•MAK 15 min. average value, 1-hr interval
Maximum Impurities		< 0.2%	None of the trace impurities in this mixture contribute significantly to the hazards associated with the product. All hazard information pertinent to this product has been provided in this Material Safety Data Sheet, per the requirements of the OSHA Hazard Communication Standard (29 CFR 1910.1200) and State equivalent standards.					

NE = Not Established. See Section 16 for Definitions of Terms Used.

NOTE (1): ALL WHMIS required information is included in appropriate sections based on the ANSI Z400.1-1998 format. This gas mixture has been classified in accordance with the hazard criteria of the CPR and the MSDS contains all the information required by the CPR.

3. HAZARD IDENTIFICATION

EMERGENCY OVERVIEW: Sulfur Hexafluoride is a colorless, odorless, non-toxic, non-flammable gas which is shipped as a liquefied gas. The liquefied gas will rapidly boil at standard temperatures and pressures. The main health hazard associated with releases of this gas is asphyxiation, by displacement of oxygen. Sulfur Hexafluoride can decompose at very high temperatures or when subjected to an electric discharge forming highly toxic decomposition products, including sulfur tetrafluoride and hydrogen fluoride. Contact with the liquefied gas can cause frostbite to any contaminated tissue. Sulfur Hexafluoride is not flammable or reactive under typical emergency response situations.

3. HAZARD IDENTIFICATION (Continued)

SYMPTOMS OF OVEREXPOSURE BY ROUTE OF EXPOSURE: The most significant route of overexposure for this gas is by inhalation. The following paragraphs describe symptoms of exposure by route of exposure.

INHALATION: High concentrations of this gas can cause an oxygen-deficient environment. Individuals breathing such an atmosphere may experience symptoms which include headaches, ringing in ears, dizziness, drowsiness, unconsciousness, nausea, vomiting, and depression of all the senses. The skin of a victim of overexposure may have a blue color. Under some circumstances of overexposure, death may occur. The effects associated with various levels of oxygen are as follows:

CONCENTRATION	**SYMPTOMS OF EXPOSURE**
12-16% Oxygen:	Breathing and pulse rate increased, muscular coordination slightly disturbed.
10-14% Oxygen:	Emotional upset, abnormal fatigue, disturbed respiration.
6-10% Oxygen:	Nausea and vomiting, collapse or loss of consciousness.
Below 6%:	Convulsive movements, possible respiratory collapse, and death.

HAZARDOUS MATERIAL IDENTIFICATION SYSTEM			
HEALTH HAZARD (BLUE)	1		
FLAMMABILITY HAZARD (RED)	0		
PHYSICAL HAZARD (YELLOW)	0		
PROTECTIVE EQUIPMENT			
EYES	RESPIRATORY	HANDS	BODY
	See Section 8		See Section 8
For Routine Industrial Use and Handling Applications			

See Section 16 for Definition of Ratings

OTHER POTENTIAL HEALTH EFFECTS: If Sulfur Hexafluoride is subjected to electrical discharge, highly toxic decomposition products are formed which may include sulfur tetrafluoride and other sulfur fluorides, sulfuryl fluoride, thionyl fluorides, sulfur oxides, hydrogen sulfide and/or hydrogen fluoride. Exposure to these decomposition products may result in pulmonary edema, a potentially fatal accumulation of fluid in the lungs. Symptoms of pulmonary edema include shortness of breath, pain in the chest and difficulty breathing. Symptoms may not develop for up to 24 hours after exposure. Contact with liquid or rapidly expanding gases (which are released under high pressure) may cause frostbite. Symptoms of frostbite include change in skin color to white or grayish-yellow. The pain after contact with liquid can quickly subside.

HEALTH EFFECTS OR RISKS FROM EXPOSURE: An Explanation in **Lay Terms**. Overexposure to Sulfur Hexafluoride may cause the following health effects:

ACUTE: The most significant hazard associated with this gas is inhalation of oxygen-deficient atmospheres. Symptoms of oxygen deficiency include respiratory difficulty, ringing in ears, headache, dizziness, indigestion, nausea, and possible death. Contact with liquid or rapidly expanding gases (which are released under high pressure) may cause frostbite.

CHRONIC: There are currently no known adverse health effects associated with chronic exposure to this gas.

TARGET ORGANS: ACUTE: Respiratory system. CHRONIC: None known.

PART II *What should I do if a hazardous situation occurs?*

4. FIRST-AID MEASURES

RESCUERS SHOULD NOT ATTEMPT TO RETRIEVE VICTIMS OF EXPOSURE TO SULFUR HEXAFLUORIDE WITHOUT ADEQUATE PERSONAL PROTECTIVE EQUIPMENT. At a minimum, Self-Contained Breathing Apparatus Personal Protective equipment should be worn.

Remove victim(s) to a safe location. Trained personnel should administer supplemental oxygen and/or cardio-pulmonary resuscitation, if necessary. Only trained personnel should administer supplemental oxygen. Victim(s) must be taken for medical attention. Rescuers should be taken for medical attention, if necessary. Take copy of label and MSDS to physician or other health professional with victim(s).

In case of frostbite, place the frostbitten part in warm water. DO NOT USE HOT WATER. If warm water is not available, or is impractical to use, wrap the affected parts gently in blankets. Alternatively, if the fingers or hands are frostbitten, place the affected area of the body in the armpit. Encourage victim to gently exercise the affected part while being warmed. Seek immediate medical attention.

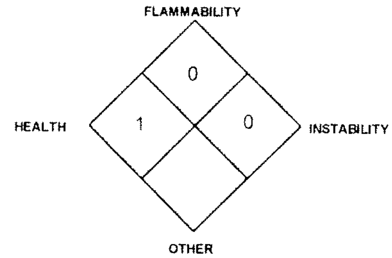
MEDICAL CONDITIONS AGGRAVATED BY EXPOSURE: Pre-existing respiratory conditions may be aggravated by overexposure to Sulfur Hexafluoride.

RECOMMENDATIONS TO PHYSICIANS: Treat symptoms and reduce overexposure.

5. FIRE-FIGHTING MEASURES

FLASH POINT: Not applicable.
AUTOIGNITION TEMPERATURE: Not applicable.
FLAMMABLE LIMITS (in air by volume, %):
Lower (LEL): Not applicable.
Upper (UEL): Not applicable.
FIRE EXTINGUISHING MATERIALS: Non-flammable, inert gas. Use extinguishing media appropriate for surrounding fire.
UNUSUAL FIRE AND EXPLOSION HAZARDS: Although Sulfur Hexafluoride is a non-flammable gas, it can present minor health hazards to firefighters. Sulfur Hexafluoride does not burn; however, containers, when involved in fire, may rupture or burst in the heat of the fire. Products of thermal decomposition of Sulfur Hexafluoride includes toxic gases (e.g., sulfuryl and thionyl fluorides).
Explosion Sensitivity to Mechanical Impact: Not sensitive.
Explosion Sensitivity to Static Discharge: Not sensitive.

NFPA RATING



See Section 16 for Definition of Ratings

SPECIAL FIRE-FIGHTING PROCEDURES: Structural firefighters must wear Self-Contained Breathing Apparatus and full protective equipment. In the event of fire, cool containers of Sulfur Hexafluoride with water to prevent failure. Use a water spray or fog to reduce or direct vapors. If cylinders are exposed to heat, the cylinder may rupture or burst and release the contents. It may be prudent to remove potentially heat-exposed cylinders from the area surrounding a fire, if it is safe for fire-fighters to do so.

6. ACCIDENTAL RELEASE MEASURES

SPILL AND LEAK RESPONSE: Uncontrolled releases should be responded to by trained personnel using pre-planned procedures. Proper protective equipment should be used. In case of a release, clear the affected area, protect people, and respond with trained personnel. Minimum Personal Protective Equipment should be **Level B: protective clothing, mechanically-resistant gloves and Self-Contained Breathing Apparatus**. Locate and seal the source of the leaking gas. Allow the gas to dissipate. Monitor the surrounding area for Sulfur Hexafluoride and oxygen levels. Sulfur Hexafluoride must be below the levels indicated in Section 2 (Composition and Information on Ingredients). The atmosphere must have at least 19.5 percent oxygen before personnel can be allowed in the area without Self-Contained Breathing Apparatus. Attempt to close the main source valve prior to entering the area. If this does not stop the release (or if it is not possible to reach the valve), allow the gas to release in-place or remove it to a safe area and allow the gas to be released there.

PART III *How can I prevent hazardous situations from occurring?*

7. HANDLING and STORAGE

WORK PRACTICES AND HYGIENE PRACTICES: As with all chemicals, avoid getting Sulfur Hexafluoride IN YOU. Do not eat or drink while handling chemicals. Be aware of any signs of dizziness or fatigue; exposures to fatal concentrations of Sulfur Hexafluoride could occur without any significant warning symptoms.
STORAGE AND HANDLING PRACTICES: Sulfur Hexafluoride should be stored in dry, well-ventilated areas separate from incompatibles, such as strong oxidizing agents, and away from sources of heat. Compressed gases can present significant safety hazards. Store containers away from heavily trafficked areas and emergency exits. Post "No Smoking or Open Flames" signs in storage or use areas. Since Sulfur Hexafluoride is non-corrosive, any of the common structural metals may be used under ordinary conditions.
SPECIAL PRECAUTIONS FOR HANDLING GAS CYLINDERS: Protect cylinders against physical damage. Store in cool, dry, well-ventilated fireproof area, away from flammable materials and corrosive atmospheres. Store away from heat and ignition sources and out of direct sunlight. Do not store near elevators, corridors or loading docks. Do not allow area where cylinders are stored to exceed 52°C (125°F). Use only storage containers and equipment (pipes, valves, fittings to relieve pressure, etc.) designed for the storage of Liquid Sulfur Hexafluoride. Do not store containers where they can come into contact with moisture. Cylinders should be stored upright and be firmly secured to prevent falling or being knocked over. Cylinders can be stored in the open, but in such cases, should be protected against extremes of weather and from the dampness of the ground to prevent rusting. Never tamper with pressure relief devices. The following rules are applicable to situations in which cylinders are being used:
Before Use: Move cylinders with a suitable hand-truck. Do not drag, slide or roll cylinders. Do not drop cylinders or permit them to strike each other. Secure cylinders firmly. Leave the valve protection cap, if provided, in-place until cylinder is ready for use.
During Use: Use designated CGA fittings and other support equipment. Do not use adapters. Do not heat cylinder by any means to increase the discharge rate of the product from the cylinder. Use check valve or trap in discharge line to prevent hazardous backflow into the cylinder. Do not use oils or grease on gas-handling fittings or equipment.
After Use: Close main cylinder valve. Replace valve protection cap, if provided. Mark empty cylinders "EMPTY".

7. HANDLING and STORAGE (Continued)

NOTE: Use only DOT or ASME code containers. Close valve after each use and when empty. Cylinders must not be recharged except by or with the consent of owner. For additional information refer to the Compressed Gas Association Pamphlet P-1, *Safe Handling of Compressed Gases in Containers*. Additionally, refer to CGA Bulletin SB-2 *"Oxygen Deficient Atmospheres"*.

PROTECTIVE PRACTICES DURING MAINTENANCE OF CONTAMINATED EQUIPMENT: Follow practices indicated in Section 6 (Accidental Release Measures). Make certain application equipment is locked and tagged-out safely. Purge gas handling equipment with inert gas (e.g., Nitrogen) before attempting repairs.

8. EXPOSURE CONTROLS - PERSONAL PROTECTION

VENTILATION AND ENGINEERING CONTROLS: Use with adequate ventilation. Local exhaust ventilation is preferred, because it prevents Sulfur Hexafluoride dispersion into the work place by eliminating it at its source. If appropriate, install automatic monitoring equipment to detect the level of Sulfur Hexafluoride and oxygen.

RESPIRATORY PROTECTION: Maintain Sulfur Hexafluoride levels below those indicated in Section 2 (Composition and Information on Ingredients) and oxygen levels above 19.5% in the workplace. If respiratory protection is needed, use only protection authorized in the U.S. Federal OSHA Standard (29 CFR 1910.134), applicable U.S. State regulations, or the Canadian CSA Standard Z94.4-93 and applicable standards of Canadian Provinces. Oxygen levels below 19.5% are considered IDLH by OSHA. In such atmospheres, use of a full-facepiece pressure/demand SCBA or a full facepiece, supplied air respirator with auxiliary self-contained air supply is required under OSHA's Respiratory Protection Standard (1910.134-1998).

EYE PROTECTION: Splash goggles, face-shields or safety glasses. If necessary, refer to U.S. OSHA 29 CFR 1910.133, or Canadian Standards.

HAND PROTECTION: Wear mechanically-resistant gloves when handling cylinders of Sulfur Hexafluoride. If necessary, refer to U.S. OSHA 29 CFR 1910.138 or appropriate Standards of Canada.

BODY PROTECTION: Use body protection appropriate for task. Transfer of large quantities under pressure may require protective equipment appropriate to protect employees from splashes of liquefied product, as well provide sufficient insulation from cold. If a hazard of injury to the feet exists due to falling objects, rolling objects, where objects may pierce the soles of the feet or where employee's feet may be exposed to electrical hazards, use foot protection, as described in U.S. OSHA 29 CFR.

9. PHYSICAL and CHEMICAL PROPERTIES

VAPOR DENSITY: 6.162 kg/m^3 (0.38 lb/ft^3)

SPECIFIC GRAVITY (air = 1): 5.114

SOLUBILITY IN WATER, v/v @ 20 °C: 0.001%

VAPOR PRESSURE (psig): 320

EXPANSION RATIO: Not applicable.

EVAPORATION RATE (nBuAc = 1): Not applicable.

MELTING POINT: -50.8°C (-59.4°F)

BOILING POINT: (Sublimation Point) -63.7°C (-82.7°F)

pH: Not applicable.

ODOR THRESHOLD: Not applicable. Odorless.

COEFFICIENT WATER/OIL DISTRIBUTION: Not applicable. SPECIFIC VOLUME (ft^3/lb): 2.5

APPEARANCE AND COLOR: Sulfur Hexafluoride is a colorless, odorless gas.

HOW TO DETECT THIS SUBSTANCE (warning properties): There are no unusual warning properties associated with a release of Sulfur Hexafluoride. In terms of leak detection, fittings and joints can be painted with a soap solution to detect leaks, which will be indicated by a bubble formation.

10. STABILITY and REACTIVITY

STABILITY: Normally stable, inert gas.

DECOMPOSITION PRODUCTS: Sulfur fluorides and hydrogen fluoride. Sulfur Hexafluoride may be partially decomposed if subjected to static discharge. Sulfur Hexafluoride is not corrosive to most metals under normal conditions. Some of the breakdown products are corrosive and will be enhanced by the presence of moisture or at high temperatures. Sulfur Hexafluoride also decomposes slightly in the presence of certain metals at temperatures in excess of 204°C (400°F), this effect being most pronounced with silicon and carbon steels. Sulfur Hexafluoride is non-reactive with most chemicals. Sulfur Hexafluoride, however, can react violently with disilane. Sulfur Hexafluoride is only stable at elevated temperatures [e.g., 204°C (> 400°F)] when contained in aluminum, stainless steel, copper, brass, or silver. Other metals can cause slow decomposition to sulfur-fluoride compounds. If this decomposition occurs in the presence of oxygen, thionyl fluoride compounds can be generated.

HAZARDOUS POLYMERIZATION: Will not occur.

CONDITIONS TO AVOID: Contact with incompatible materials. Cylinders exposed to high temperatures or direct flame can rupture or burst.

PART IV *Is there there any other useful information about this material?*

11. TOXICOLOGICAL INFORMATION

TOXICITY DATA: The following data are for Sulfur Hexafluoride:

LD_{50} (Intravenous-Rabbit) 5790 mg/kg

LCLo (Inhalation-Mammal-Species Unspecified) 300 gm/m3: Peripheral Nerve and Sensation: flaccid paralysis with appropriate anesthesia; Behavioral: muscle weakness, rigidity (including catalepsy)

Male rats were exposed for periods of 16-24 hours to 20% oxygen and 80% Sulfur Hexafluoride at 1 atmosphere ambient pressure showed no changes.

SUSPECTED CANCER AGENT: Sulfur Hexafluoride is not found on the following lists: FEDERAL OSHA Z LIST, NTP, CAL/OSHA, IARC; therefore it is not considered to be, nor suspected to be a cancer-causing agent by these agencies.

IRRITANCY OF PRODUCT: Contact with rapidly expanding gases can cause frostbite and damage to exposed skin and eyes.

SENSITIZATION OF PRODUCT: Sulfur Hexafluoride is not known to be a human skin or respiratory sensitizer.

REPRODUCTIVE TOXICITY INFORMATION: Listed below is information concerning the effects of Sulfur Hexafluoride on the human reproductive system.

Mutagenicity: Sulfur Hexafluoride is not reported to cause mutagenic effects in humans.

Embryotoxicity: Sulfur Hexafluoride is not reported to cause embryotoxic effects in humans.

Teratogenicity: Sulfur Hexafluoride is not reported to cause teratogenic effects in humans.

Reproductive Toxicity: Sulfur Hexafluoride is not reported to cause adverse reproductive effects in humans.

A mutagen is a chemical which causes permanent changes to genetic material (DNA) such that the changes will propagate through generation lines. An embryotoxin is a chemical which causes damage to a developing embryo (i.e. within the first eight weeks of pregnancy in humans), but the damage does not propagate across generational lines. A teratogen is a chemical which causes damage to a developing fetus, but the damage does not propagate across generational lines. A reproductive toxin is any substance which interferes in any way with the reproductive process.

BIOLOGICAL EXPOSURE INDICES (BEIs): Currently, Biological Exposure Indices (BEIs) are not applicable for Sulfur Hexafluoride.

12. ECOLOGICAL INFORMATION

ENVIRONMENTAL STABILITY: The gas will be dissipated rapidly in well-ventilated areas.

EFFECT OF MATERIAL ON PLANTS or ANIMALS: Any adverse effect on animals would be related to oxygen deficient environments. No adverse effect is anticipated to occur to plant-life, except for frost produced in the presence of rapidly expanding gases.

EFFECT OF CHEMICAL ON AQUATIC LIFE: No data are currently available on the effects of Sulfur Hexafluoride on aquatic life.

13. DISPOSAL CONSIDERATIONS

PREPARING WASTES FOR DISPOSAL: Product removed from the cylinder must be disposed of in accordance with appropriate U.S. Federal, State, and local regulations or with regulations of Canada and its Provinces. Return cylinders with residual product to Airgas, Inc. Do not dispose of locally.

14. TRANSPORTATION INFORMATION

THIS GAS IS HAZARDOUS AS DEFINED BY 49 CFR 172.101 BY THE U.S. DEPARTMENT OF TRANSPORTATION.

PROPER SHIPPING NAME:	Sulfur hexafluoride
HAZARD CLASS NUMBER and DESCRIPTION:	2.2 (Non-Flammable Gas)
UN IDENTIFICATION NUMBER:	UN 1080
PACKING GROUP:	Not Applicable
DOT LABEL(S) REQUIRED:	Class 2.2 (Non-Flammable Gas)

NORTH AMERICAN EMERGENCY RESPONSE GUIDEBOOK NUMBER (1996): 126

MARINE POLLUTANT: Sulfur Hexafluoride is not classified by the DOT as a Marine Pollutant (as defined by 49 CFR 172.101, Appendix B).

14. TRANSPORTATION INFORMATION (Continued)

TRANSPORT CANADA TRANSPORTATION OF DANGEROUS GOODS REGULATIONS: This gas is considered as Dangerous Goods, per regulations of Transport Canada. The use of the above U.S. DOT information from the U.S. 49 CFR regulations is allowed for shipments that originate in the U.S. For shipments via ground vehicle or rail that originate in Canada, the following information is applicable.

PROPER SHIPPING NAME:	Sulfur hexafluoride
HAZARD CLASS NUMBER and DESCRIPTION:	Class 2.2 (Non-Flammable Gas)
UN IDENTIFICATION NUMBER:	UN 1080
PACKING GROUP:	Not Applicable
HAZARD LABEL(S) REQUIRED:	Class 2.2 (Non-Flammable Gas)
SPECIAL PROVISIONS:	None
EXPLOSIVE LIMIT & LIMITED QUANTITY INDEX:	42
ERAP INDEX:	0.12
PASSENGER CARRYING SHIP INDEX:	None
PASSENGER CARRYING ROAD OR RAIL VEHICLE INDEX:	75

MARINE POLLUTANT: Air is not a Marine Pollutant.

15. REGULATORY INFORMATION

ADDITIONAL U.S. REGULATIONS:

U.S. SARA REPORTING REQUIREMENTS: Sulfur Hexafluoride is not subject to the reporting requirements of Sections 302, 304 and 313 of Title III of the Superfund Amendments and Reauthorization Act.

U.S. SARA THRESHOLD PLANNING QUANTITY: There are no specific Threshold Planning Quantities for this gas. The default Federal MSDS submission and inventory requirement filing threshold of 10,000 lb (4,540 kg) may apply, per 40 CFR 370.20.

U.S. CERCLA REPORTABLE QUANTITIES (RQ): Not applicable.

U.S. TSCA INVENTORY STATUS: Sulfur Hexafluoride is listed on the TSCA Inventory.

OTHER U.S. FEDERAL REGULATIONS: Not applicable.

CALIFORNIA SAFE DRINKING WATER AND TOXIC ENFORCEMENT ACT (PROPOSITION 65): Sulfur Hexafluoride is not on the California Proposition 65 lists.

CGA LABELING (For Compressed Gas):

CAUTION: LIQUID AND GAS UNDER PRESSURE.
CAN CAUSE RAPID SUFFOCATION.
MAY CAUSE FROSTBITE.
Store and use with adequate ventilation.
Do not get liquid in eyes, on skin or clothing.
Cylinder temperature should not exceed 52°C (125°F).
Close valve after each use and when empty.
Use in accordance with the Material Safety Data Sheet.

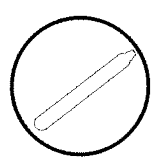
FIRST-AID: **IF INHALED**, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Call a physician.
IN CASE OF FROSTBITE, obtain immediate medial attention.
DO NOT REMOVE THIS PRODUCT LABEL.

ADDITIONAL CANADIAN REGULATIONS:

CANADIAN DSL/NDSL INVENTORY STATUS: Sulfur Hexafluoride is on the DSL Inventory.

CANADIAN ENVIRONMENTAL PROTECTION ACT (CEPA) PRIORITIES SUBSTANCES LISTS: Sulfur Hexafluoride is not on the CEPA Priorities Substances Lists.

CANADIAN WHMIS CLASSIFICATION AND SYMBOLS: **Class A:** Compressed Gases



16. OTHER INFORMATION

PREPARED BY:
CHEMICAL SAFETY ASSOCIATES, Inc.
PO Box 3519, La Mesa, CA 91944-3519
619/670-0609

DEFINITIONS OF TERMS

A large number of abbreviations and acronyms appear on a MSDS. Some of these which are commonly used include the following:

CAS #: This is the Chemical Abstract Service Number that uniquely identifies each constituent. **EXPOSURE LIMITS IN AIR:**

CEILING LEVEL: The concentration that shall not be exceeded during any part of the working exposure.

LOQ: Limit of Quantitation.

MAK: Federal Republic of Germany Maximum Concentration Values in the workplace.

NE: Not Established. When no exposure guidelines are established, an entry of NE is made for reference.

NIC: Notice of Intended Change.

NIOSH CEILING: The exposure that shall not be exceeded during any part of the workday. If instantaneous monitoring is not feasible, the ceiling shall be assumed as a 15-minute TWA exposure (unless otherwise specified) that shall not be exceeded at any time during a workday.

NIOSH RELs: NIOSH's Recommended Exposure Limits.

PEL-Permissible Exposure Limit: OSHA's Permissible Exposure Limits. This exposure value means exactly the same as a TLV, except that it is enforceable by OSHA. The OSHA Permissible Exposure Limits are based in the 1989 PELs and the June, 1993 Air Contaminants Rule (Federal Register: 58: 35338-35351 and 58: 40191). Both the current PELs and the vacated PELs are indicated. The phrase, "Vacated 1989 PEL," is placed next to the PEL that was vacated by Court Order.

SKIN: Used when a there is a danger of cutaneous absorption.

STEL-Short Term Exposure Limit: Short Term Exposure Limit, usually a 15-minute time-weighted average (TWA) exposure that should not be exceeded at any time during a workday, even if the 8-hr TWA is within the TLV-TWA, PEL-TWA or REL-TWA.

TLV-Threshold Limit Value: An airborne concentration of a substance that represents conditions under which it is generally believed that nearly all workers may be repeatedly exposed without adverse effect. The duration must be considered, including the 8-hour.

TWA-Time Weighted Average: Time Weighted Average exposure concentration for a conventional 8-hr (TLV, PEL) or up to a 10-hr (REL) workday and a 40-hr workweek.

IDLH-Immediately Dangerous to Life and Health: This level represents a concentration from which one can escape within 30-minutes without suffering escape-preventing or permanent injury.

HAZARDOUS MATERIALS IDENTIFICATION SYSTEM HAZARD RATINGS: This rating system was developed by the National Paint and Coating Association and has been adopted by industry to identify the degree of chemical hazards.

HEALTH HAZARD:

0 (Minimal Hazard: No significant health risk, irritation of skin or eyes not anticipated. *Skin Irritation*: Essentially non-irritating. PII or Draize = "0". *Eye Irritation*: Essentially non-irritating, or minimal effects which clear in < 24 hours [e.g. mechanical irritation]. Draize = "0". *Oral Toxicity LD_{50} Rat*: < 5000 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: < 2000 mg/kg. *Inhalation Toxicity 4-hrs LC_{50} Rat*: < 20 mg/L.); **1** (Slight Hazard: Minor reversible Injury may occur; slightly or mildly irritating. *Skin Irritation*: Slightly or mildly irritating. *Eye Irritation*: Slightly or mildly irritating. *Oral Toxicity LD_{50} Rat*: > 500-5000 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: > 1000-2000 mg/kg. *Inhalation Toxicity LC_{50}* 4-hrs *Rat*: > 2-20 mg/L); **2** (Moderate Hazard: Temporary or transitory injury may occur. *Skin Irritation*: Moderately irritating; primary irritant; sensitizer. PII or Draize > 0, < 5. *Eye Irritation*: Moderately to severely irritating and/or corrosive; reversible corneal opacity; corneal involvement or irritation clearing in 8-21 days. Draize > 0, ≤ 25. *Oral Toxicity LD_{50} Rat*: > 50-500 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: > 200-1000 mg/kg. *Inhalation Toxicity LC_{50} 4-hrs Rat*: > 0.5-2 mg/L.); **2** (Moderate Hazard: Temporary or transitory injury may occur. *Skin Irritation*: Moderately irritating; primary irritant; sensitizer. PII or Draize > 0, < 5. ; *Eye Irritation*: Moderately to severely irritating and/or corrosive; reversible corneal opacity; corneal involvement or irritation clearing in 8-21 days. Draize > 0, ≤ 25. *Oral Toxicity LD_{50} Rat*: > 50-500 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: > 200-1000 mg/kg. *Inhalation Toxicity LC_{50} 4-hrs Rat*: > 0.5-2 mg/L. **3** (Serious Hazard): Major injury likely unless prompt action is taken and medical treatment is given; high level of toxicity; corrosive. *Skin Irritation*: Severely irritating and/or corrosive; may destroy dermal tissue, cause skin burns, dermal necrosis.

HAZARDOUS MATERIALS IDENTIFICATION SYSTEM HAZARD RATINGS (continued):

HEALTH HAZARD (continued):

3 (continued): PII or Draize > 5-8 with destruction of tissue. *Eye Irritation*: Corrosive, irreversible destruction of ocular tissue; corneal involvement or irritation persisting for more than 21 days. Draize > 80 with effects irreversible in 21 days. *Oral Toxicity LD_{50} Rat*: > 1-50 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: > 20-200 mg/kg. *Inhalation Toxicity LC_{50} 4-hrs Rat*: > 0.05-0.5 mg/L.); **4** (Severe Hazard: Life-threatening; major or permanent damage may result from single or repeated exposure. *Skin Irritation*: Not appropriate. Do not rate as a "4", based on skin irritation alone. *Eye Irritation*: Not appropriate. Do not rate as a "4", based on eye irritation alone. *Oral Toxicity LD_{50} Rat*: ≤ 1 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: ≤ 20 mg/kg. *Inhalation Toxicity LC_{50} 4-hrs Rat*: ≤ 0.05 mg/L).

FLAMMABILITY HAZARD:

0 (Minimal Hazard-Materials that will not burn in air when exposure to a temperature of 815.5°C [1500°F] for a period of 5 minutes.); **1** (Slight Hazard-Materials that must be pre-heated before ignition can occur. Material require considerable pre-heating, under all ambient temperature conditions before ignition and combustion can occur, Including: Materials that will burn in air when exposed to a temperature of 815.5°C (1500°F) for a period of 5 minutes or less; Liquids, solids and semisolids having a flash point at or above 93.3°C [200°F] (e.g. OSHA Class IIIB, or; Most ordinary combustible materials [e.g. wood, paper, etc.]; **2** (Moderate Hazard-Materials that must be moderately heated or exposed to relatively high ambient temperatures before ignition can occur. Materials in this degree would not, under normal conditions, form hazardous atmospheres in air, but under high ambient temperatures or moderate heating may release vapor in sufficient quantities to produce hazardous atmospheres in air, Including: Liquids having a flash-point at or above 37.8°C [100°F] Solid materials in the form of course dusts that may burn rapidly but that generally do not form explosive atmospheres; Solid materials in a fibrous or shredded form that may burn rapidly and create flash fire hazards (e.g. cotton, sisal, hemp; Solids and semisolids that readily give off flammable vapors.); **3** (Serious Hazard- Liquids and solids that can be ignited under almost all ambient temperature conditions. Materials in this degree produce hazardous atmospheres with air under almost all ambient temperatures, or, unaffected by ambient temperature, are readily ignited under almost all conditions, including: Liquids having a flash point below 22.8°C [73°F] and having a boiling point at or above 38°C [100°F] and below 37.8°C [100°F] [e.g. OSHA Class IB and IC]; Materials that on account of their physical form or environmental conditions can form explosive mixtures with air and are readily dispersed in air [e.g., dusts of combustible solids, mists or droplets of flammable liquids]; Materials that burn extremely rapidly, usually by reason of self-contained oxygen [e.g. dry nitrocellulose and many organic peroxides]); **4** (Severe Hazard-Materials that will rapidly or completely vaporize at atmospheric pressure and normal ambient temperature or that are readily dispersed in air, and which will burn readily, including: Flammable gases; Flammable cryogenic materials; Any liquid or gaseous material that is liquid while under pressure and has a flash point below 22.8°C [73°F] and a boiling point below 37.8°C [100°F] [e.g. OSHA Class IA; Material that ignite spontaneously when exposed to air at a temperature of 54.4°C [130°F] or below [e.g. pyrophoric]).

PHYSICAL HAZARD:

0 (*Water Reactivity*: Materials that do not react with water. *Organic Peroxides*: Materials that are normally stable, even under fire conditions and will not react with water. *Explosives*: Substances that are Non-Explosive. Unstable *Compressed Gases*: No Rating. *Pyrophorics*: No Rating. *Oxidizers*: No "0" rating allowed. *Unstable Reactives*: Substances that will not polymerize, decompose, condense or self-react.); **1** (*Water Reactivity*: Materials that change or decompose upon exposure to moisture. *Organic Peroxides*: Materials that are normally stable, but can become unstable at high temperatures and pressures. These materials may react with water, but will not release energy. *Explosives*: Division 1.5 & 1.6 substances that are very insensitive explosives or that do not have a mass explosion hazard. *Compressed Gases*: Pressure below OSHA definition.

DEFINITIONS OF TERMS (Continued)

HAZARDOUS MATERIALS IDENTIFICATION SYSTEM HAZARD RATINGS (continued):

PHYSICAL HAZARD (continued):

Pyrophorics: No Rating. *Oxidizers*: Packaging Group III; Solids: any material that in either concentration tested, exhibits a mean burning time less than or equal to the mean burning time of a 3:7 potassium bromate/cellulose mixture and the criteria for Packing Group I and II are not met. Liquids: any material that exhibits a mean pressure rise time less than or equal to the pressure rise time of a 1:1 nitric acid (65%)/cellulose mixture and the criteria for Packing Group I and II are not met. *Unstable Reactives*: Substances that may decompose, condense or self-react, but only under conditions of high temperature and/or pressure and have little or no potential to cause significant heat generation or explosive hazard. Substances that readily undergo hazardous polymerization in the absence of inhibitors.); **2** (*Water Reactivity*: Materials that may react violently with water. *Organic Peroxides*: Materials that, in themselves, are normally unstable and will readily undergo violent chemical change, but will not detonate. These materials may also react violently with water. *Explosives*: Division 1.4 – Explosive substances where the explosive effect are largely confined to the package and no projection of fragments of appreciable size or range are expected. An external fire must not cause virtually instantaneous explosion of almost the entire contents of the package. *Compressed Gases*: Pressurized and meet OSHA definition but < 514.7 psi absolute at 21.1°C (70°F) [500 psig]. *Pyrophorics*: No Rating. *Oxidizers*: Packing Group II Solids: any material that, either in concentration tested, exhibits a mean burning time of less than or equal to the mean burning time of a 2:3 potassium bromate/cellulose mixture and the criteria for Packing Group I are not met. Liquids: any material that exhibits a mean pressure rise time less than or equal to the pressure rise of a 1:1 aqueous sodium chlorate solution (40%)/cellulose mixture and the criteria for Packing Group I are not met. *Unstable Reactives*: Substances that may polymerize, decompose, condense, or self-react at ambient temperature and/or pressure, but have a low potential for significant heat generation or explosion. Substances that readily form peroxides upon exposure to air or oxygen at room temperature); **3** (*Water Reactivity*: Materials that may form explosive reactions with water. *Organic Peroxides*: Materials that are capable of detonation or explosive reaction, but require a strong initiating source, or must be heated under confinement before initiation; or materials that react explosively with water. *Explosives*: Division 1.2 – Explosive substances that have a fire hazard and either a minor blast hazard or a minor projection hazard or both, but do not have a mass explosion hazard. *Compressed Gases*: Pressure $\geq$ 514.7 psi absolute at 21.1°C (70°F) [500 psig]. *Pyrophorics*: No Rating. *Oxidizers*: Packing Group I Solids: any material that, in either concentration tested, exhibits a mean burning time less than the mean burning time of a 3.:2 potassium bromate/cellulose mixture. Liquids: Any material that spontaneously ignites when mixed with cellulose in a 1:1 ratio, or which exhibits a mean pressure rise time less than the pressure rise time of a 1:1 perchloric acid (50%)/cellulose mixture. *Unstable Reactives*: Substances that may polymerize, decompose, condense or self-react at ambient temperature and/or pressure and have a moderate potential to cause significant heat generation or explosion.); **4** (*Water Reactivity*: Materials that react explosively with water without requiring heat or confinement. *Organic Peroxides*: Materials that are readily capable of detonation or explosive decomposition at normal temperature and pressures. *Explosives*: Division 1.1 & 1.2-explosive substances that have a mass explosion hazard or have a projection hazard. A mass explosion is one that affects almost the entire load instantaneously. *Compressed Gases*: No Rating. *Pyrophorics*: Add to the definition of Flammability "4". *Oxidizers*: No "4" rating. *Unstable Reactives*: Substances that may polymerize, decompose, condense or self-react at ambient temperature and/or pressure and have a high potential to cause significant heat generation or explosion.). **2** (materials that on intense or continued exposure under fire conditions could cause temporary incapacitation or possible residual injury);

NATIONAL FIRE PROTECTION ASSOCIATION HAZARD RATINGS (continued):

HEALTH HAZARD (continued): **3** (materials that can on short exposure could cause serious temporary or residual injury); **4** (materials that under very short exposure could cause death or major residual injury).
FLAMMABILITY HAZARD: **0** Materials that will not burn under typical fire conditions, including intrinsically noncombustible materials such as concrete, stone, and sand. **1** Materials that must be preheated before ignition can occur. Materials in this degree require considerable preheating, under all ambient temperature conditions, before ignition and combustion can occur. **2** Materials that must be moderately heated or exposed to relatively high ambient temperatures before ignition can occur. Materials in this degree would not under normal conditions form hazardous atmospheres with air, but under high ambient temperatures or under moderate heating could release vapor in sufficient quantities to produce hazardous atmospheres with air. **3** Liquids and solids that can be ignited under almost all ambient temperature conditions. Materials in this degree produce hazardous atmospheres with air under almost all ambient temperatures or, though unaffected by ambient temperatures, are readily ignited under almost all conditions. **4** Materials that will rapidly or completely vaporize at atmospheric pressure and normal ambient temperature or that are readily dispersed in air and will burn readily.
INSTABILITY HAZARD: **0** Materials that in themselves are normally stable, even under fire conditions. **1** Materials that in themselves are normally stable, but that can become unstable at elevated temperatures and pressures. **2** Materials that readily undergo violent chemical change at elevated temperatures and pressures. **3** Materials that in themselves are capable of detonation or explosive decomposition or explosive reaction, but that require a strong initiating source or that must be heated under confinement before initiation. **4** Materials that in themselves are readily capable of detonation or explosive decomposition or explosive reaction at normal temperatures and pressures.

FLAMMABILITY LIMITS IN AIR: Much of the information related to fire and explosion is derived from the **N**ational **F**ire **P**rotection **A**ssociation (**NFPA**). Flash Point - Minimum temperature at which a liquid gives off sufficient vapors to form an ignitable mixture with air. Autoignition Temperature: The minimum temperature required to initiate combustion in air with no other source of ignition. LEL - the lowest percent of vapor in air, by volume, that will explode or ignite in the presence of an ignition source. UEL - the highest percent of vapor in air, by volume, that will explode or ignite in the presence of an ignition source.

TOXICOLOGICAL INFORMATION:

Human and Animal Toxicology: Possible health hazards as derived from human data, animal studies, or from the results of studies with similar compounds are presented. Definitions of some terms used in this section are: **LD_{50}** - Lethal Dose (solids & liquids) which kills 50% of the exposed animals; **LC_{50}** - Lethal Concentration (gases) which kills 50% of the exposed animals; **ppm** concentration expressed in parts of material per million parts of air or water; **mg/m^3** concentration expressed in weight of substance per volume of air; **mg/kg** quantity of material, by weight, administered to a test subject, based on their body weight in kg. Other measures of toxicity include **TDLo**, the lowest dose to cause a symptom and **TCLo** the lowest concentration to cause a symptom; **TDo**, **LDLo**, and **LDo**, or **TC**, **TCo**, **LCLo**, and **LCo**, the lowest dose (or concentration) to cause lethal or toxic effects. **Cancer Information:** The sources are: **IARC** - the International Agency for Research on Cancer; **NTP** - the National Toxicology Program, **RTECS** - the Registry of Toxic Effects of Chemical Substances, **OSHA** and **CAL/OSHA**. IARC and NTP rate chemicals on a scale of decreasing potential to cause human cancer with rankings from 1 to 4. Subrankings (2A, 2B, etc.) are also used. **Other Information: BEI** - ACGIH Biological Exposure Indices, represent the levels of determinants which are most likely to be observed in specimens collected from a healthy worker who has been exposed to chemicals to the same extent as a worker with inhalation exposure to the TLV.

DEFINITIONS OF TERMS (Continued)

ECOLOGICAL INFORMATION:

EC is the effect concentration in water. **BCF** = Bioconcentration Factor, which is used to determine if a substance will concentrate in lifeforms which consume contaminated plant or animal matter. **TL_m** = median threshold limit; Coefficient of Oil/Water Distribution is represented by **log K_{ow}** or **log K_{oc}** and is used to assess a substance's behavior in the environment.

REGULATORY INFORMATION:

U.S. and CANADA:

This section explains the impact of various laws and regulations on the material. **ACGIH:** American Conference of Governmental Industrial Hygienists, a professional association which establishes exposure limits. **EPA** is the U.S. Environmental Protection Agency. **NIOSH** is the National Institute of Occupational Safety and Health, which is the research arm of the U.S. **O**ccupational **S**afety and **H**ealth **A**dministration (**OSHA**). **WHMIS** is the Canadian Workplace Hazardous Materials Information System. **DOT** and **TC** are the U.S. Department of Transportation and the Transport Canada, respectively. Superfund Amendments and Reauthorization Act **(SARA)**; the Canadian Domestic/Non-Domestic Substances List **(DSL/NDSL)**; the U.S. Toxic Substance Control Act **(TSCA)**; Marine Pollutant status according to the **DOT**; the Comprehensive Environmental Response, Compensation, and Liability Act **(CERCLA or Superfund)**; and various state regulations. This section also includes information on the precautionary warnings which appear on the material's package label. **OSHA** - U.S. Occupational Safety and Health Administration.

APPENDIX P-1
MATERIAL SAFETY DATA SHEETS FOR PROJECT TRACERS
XENON

AIR PRODUCTS

Material Safety Data Sheet

Version 2.2
Revision Date 07/20/2004

MSDS Number 300000000137
Print Date 07/24/2005

1. PRODUCT AND COMPANY IDENTIFICATION

Product name	:	Xenon
Chemical formula	:	Xe
Synonyms	:	Xenon
Product Use Description	:	General Industrial
Company	:	Air Products and Chemicals,Inc 7201 Hamilton Blvd. Allentown, PA 18195-1501
Telephone	:	800-345-3148
Emergency telephone number	:	800-523-9374 USA 01-610-481-7711 International

2. COMPOSITION/INFORMATION ON INGREDIENTS

Components	CAS Number	Concentration (Volume)
Xenon	7440-63-3	100 %

Concentration is nominal. For the exact product composition, please refer to Air Products technical specifications.

3. HAZARDS IDENTIFICATION

Emergency Overview

Can cause rapid suffocation.
Compressed liquefied gas.
Avoid breathing gas.
Direct contact with liquid can cause frostbite.
Self contained breathing apparatus (SCBA) may be required.

Potential Health Effects

Inhalation	:	In high concentrations may cause asphyxiation. Symptoms may include loss of mobility/consciousness.Victim may not be aware of asphyxiation. Asphyxiation may bring about unconsciousness without warning and so rapidly that victim may be unable to protect themselves.
Eye contact	:	Contact with liquid may cause cold burns/frost bite.
Skin contact	:	Contact with liquid may cause cold burns/frost bite.
Ingestion	:	Ingestion is not considered a potential route of exposure.

Chronic Health Hazard : Not applicable.

Exposure Guidelines

Primary Routes of Entry : Inhalation

Target Organs : None.

Symptoms : Exposure to oxygen deficient atmosphere may cause the following symptoms: Dizziness. Salivation. Nausea. Vomiting. Loss of mobility/consciousness.

Aggravated Medical Condition

None known.

4. FIRST AID MEASURES

General advice : Remove victim to uncontaminated area wearing self contained breathing apparatus. Keep victim warm and rested. Call a doctor. Apply artificial respiration if breathing stopped.

Eye contact : In the case of contact with eyes, rinse immediately with plenty of water and seek medical advice. Keep eye wide open while rinsing. Seek medical advice.

Skin contact : Wash frost-bitten areas with plenty of water. Do not remove clothing. Cover wound with sterile dressing.

Ingestion : Ingestion is not considered a potential route of exposure.

Inhalation : Move to fresh air. If breathing has stopped or is labored, give assisted respirations. Supplemental oxygen may be indicated. If the heart has stopped, trained personnel should begin cardiopulmonary resuscitation immediately. In case of shortness of breath, give oxygen.

5. FIRE-FIGHTING MEASURES

Suitable extinguishing media : All known extinguishing media can be used.

Specific hazards : Upon exposure to intense heat or flame, cylinder will vent rapidly and or rupture violently. Product is nonflammable and does not support combustion. Move away from container and cool with water from a protected position. If possible, stop flow of product. Keep adjacent cylinders cool by spraying with large amounts of water until the fire burns itself out. Most cylinders are designed to vent contents when exposed to elevated temperatures.

Special protective equipment for fire-fighters : Wear self contained breathing apparatus for fire fighting if necessary.

6. ACCIDENTAL RELEASE MEASURES

Personal precautions : Gas/vapor heavier than air. May accumulate in confined spaces, particularly at

	or below ground level. Evacuate personnel to safe areas. Wear self-contained breathing apparatus when entering area unless atmosphere is proved to be safe. Ventilate the area. Monitor oxygen level.
Environmental precautions	: Should not be released into the environment. Do not discharge into any place where its accumulation could be dangerous. Prevent further leakage or spillage. Prevent from entering sewers, basements and workpits, or any place where its accumulation can be dangerous.
Methods for cleaning up	: Ventilate the area.
Additional advice	: If possible, stop flow of product. Increase ventilation to the release area and monitor oxygen level. If leak is from cylinder or cylinder valve, call the Air Products emergency telephone number. If the leak is in the user's system, close the cylinder valve, safely vent the pressure, and purge with an inert gas before attempting repairs.

7. HANDLING AND STORAGE

Handling

Only experienced and properly instructed persons should handle compressed gases. Protect cylinders from physical damage; do not drag, roll, slide or drop. Do not allow storage area temperature to exceed 50°C (122°F). Before using the product, determine its identity by reading the label. Know and understand the properties and hazards of the product before use. When doubt exists as to the correct handling procedure for a particular gas, contact the supplier. Do not remove or deface labels provided by the supplier for the identification of the cylinder contents. When moving cylinders, even for short distances, use a cart (trolley, hand truck, etc.) designed to transport cylinders. Leave valve protection caps in place until the container has been secured against either a wall or bench or placed in a container stand and is ready for use. Use an adjustable strap wrench to remove over-tight or rusted caps. Before connecting the container, check the complete gas system for suitability, particularly for pressure rating and materials. Before connecting the container for use, ensure that back feed from the system into the container is prevented. Ensure the complete gas system is compatible for pressure rating and materials of construction. Ensure the complete gas system has been checked for leaks before use. Employ suitable pressure regulating devices on all containers when the gas is being emitted to systems with lower pressure rating than that of the container. Never insert an object (e.g. wrench, screwdriver, pry bar, etc.) into valve cap openings. Doing so may damage valve, causing a leak to occur. Open valve slowly. If user experiences any difficulty operating cylinder valve discontinue use and contact supplier. Close container valve after each use and when empty, even if still connected to equipment. Never attempt to repair or modify container valves or safety relief devices. Damaged valves should be reported immediately to the supplier. Close valve after each use and when empty. Replace outlet caps or plugs and container caps as soon as container is disconnected from equipment. Do not subject containers to abnormal mechanical shocks which may cause damage to their valve or safety devices. Never attempt to lift a cylinder by its valve protection cap or guard. Always use backflow protective device in piping. When returning cylinder install valve outlet cap or plug leak tight. Never use direct flame or electrical heating devices to raise the pressure of a container. Containers should not be subjected to temperatures above 50°C (122°F). Prolonged periods of cold temperature below -30°C (-20°F) should be avoided. Never attempt to increase liquid withdrawal rate by pressurizing the container without first checking with the supplier. Never permit liquefied gas to become trapped in parts of the system as this may result in hydraulic rupture.

Storage

Full containers should be stored so that oldest stock is used first. Containers should be stored in the vertical position and properly secured to prevent toppling. The container valves should be tightly closed and where appropriate valve outlets should be capped or plugged. Container valve guards or caps should be in place.

Observe all regulations and local requirements regarding storage of containers. Stored containers should be periodically checked for general condition and leakage. Protect containers stored in the open against rusting and extremes of weather. Containers should not be stored in conditions likely to encourage corrosion. Containers should be stored in a purpose build compound which should be well ventilated, preferably in the open air. Keep containers tightly closed in a cool, well-ventilated place. Store containers in location free from fire risk and away from sources of heat and ignition. Full and empty cylinders should be segregated. Do not allow storage temperature to exceed 50°C (122°F). Return empty containers in a timely manner.

Technical measures/Precautions

Containers should be segregated in the storage area according to the various categories (e.g. flammable, toxic, etc.) and in accordance with local regulations. Keep away from combustible material.

8. EXPOSURE CONTROLS / PERSONAL PROTECTION

Engineering measures

Provide natural or mechanical ventilation to prevent oxygen deficient atmospheres below 19.5% oxygen.

Personal protective equipment

Respiratory protection	:	Self contained breathing apparatus (SCBA) or positive pressure airline with mask are to be used in oxygen-deficient atmosphere. Air purifying respirators will not provide protection. Users of breathing apparatus must be trained.
Hand protection	:	Sturdy work gloves are recommended for handling cylinders. The breakthrough time of the selected glove(s) must be greater than the intended use period.
Eye protection	:	Safety glasses recommended when handling cylinders.
Skin and body protection	:	Safety shoes are recommended when handling cylinders.
Special instructions for protection and hygiene	:	Ensure adequate ventilation, especially in confined areas.

9. PHYSICAL AND CHEMICAL PROPERTIES

Form	:	Compressed gas.
Color	:	Colorless gas
Odor	:	No odor warning properties.
Molecular Weight	:	131 g/mol
Relative vapor density	:	4.5 (air = 1)
Relative density	:	1.5 (water = 1)
Density	:	0.343 lb/ft3 (0.0055 g/cm3) at 70 °F (21 °C) Note: (as vapor)

Specific Volume	: 2.93 ft3/lb (0.1829 m3/kg) at 70 °F (21 °C)
Boiling point/range	: -162 °F (-108 °C)
Critical temperature	: 62 °F (16.6 °C)
Melting point/range	: -170 °F (-112 °C)
Water solubility	: 0.644 g/l

10. STABILITY AND REACTIVITY

Stability	: Stable under normal conditions.

11. TOXICOLOGICAL INFORMATION

Acute Health Hazard

Ingestion	: No data is available on the product itself.
Inhalation	: No data is available on the product itself.
Skin.	: No data is available on the product itself.

12. ECOLOGICAL INFORMATION

Ecotoxicity effects

Aquatic toxicity	: No data is available on the product itself.
Toxicity to other organisms	: No data available.

Persistence and degradability

Mobility	: No data available.
Bioaccumulation	: No data is available on the product itself.

Further information

This product has no known eco-toxicological effects.

13. DISPOSAL CONSIDERATIONS

Waste from residues / unused products	: Return unused product in orginal cylinder to supplier. Contact supplier if guidance is required.
Contaminated packaging	: Return cylinder to supplier.

14. TRANSPORT INFORMATION

CFR

Proper shipping name : Xenon
Class : 2.2
UN/ID No. : UN2036

IATA

Proper shipping name : Xenon
Class : 2.2
UN/ID No. : UN2036

IMDG

Proper shipping name : XENON
Class : 2.2
UN/ID No. : UN2036

CTC

Proper shipping name : XENON
Class : 2.2
UN/ID No. : UN2036

Further Information
Avoid transport on vehicles where the load space is not separated from the driver's compartment. Ensure vehicle driver is aware of the potential hazards of the load and knows what to do in the event of an accident or an emergency.

15. REGULATORY INFORMATION

OSHA Hazard Communication Standard (29 CFR 1910.1200) Hazard Class(es)
Compressed Gas.

Country	Regulatory list	Notification
USA	TSCA	Included on Inventory.
EU	EINECS	Included on Inventory.
Canada	DSL	Included on Inventory.
Australia	AICS	Included on Inventory.
South Korea	ECL	Included on Inventory.
China	SEPA	Included on Inventory.
Philippines	PICCS	Included on Inventory.
Japan	ENCS	Included on Inventory.

EPA SARA Title III Section 312 (40 CFR 370) Hazard Classification:
Sudden Release of Pressure Hazard.

US. California Safe Drinking Water & Toxic Enforcement Act (Proposition 65)
This product does not contain any chemicals known to State of California to cause cancer, birth defects or any other harm.

16. OTHER INFORMATION

NFPA Rating

Health	:	0
Fire	:	0
Instability	:	0
Special	:	SA

HMIS Rating

Health	:	0
Flammability	:	0
Physical hazard	:	3

REVISION NOTES : 14. TRANSPORT INFORMATION

Prepared by : Air Products and Chemicals, Inc. Global EH&S Product Safety Department

For additional information, please visit our Product Stewardship web site at
http//www.airproducts.com/productstewardship/

ATTACHMENT Q PLUGGING AND ABANDONMENT PLAN

Q.1 WELL PLUGGING AND ABANDONMENT PLANS

General well closure procedures and any post-closure care plans are detailed in the following subsections. These procedures follow the requirements outlined under California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) Onshore Well Regulations for proper well abandonment (State of California, California Code of Regulations, Title 14 – Natural Resources, Division 2 – Department of Conservation, March 2007) and the procedures will be consistent with the requirements of 40 CFR § 146.10. A temporary abandonment program will be included as part of the well book prior to commencement of operations, while an exact final plugging and abandonment program will be developed prior to actual well abandonment. The detailed plan, to be submitted on EPA Form 7520-14, will be based on final "as-built" well construction and the specific zone(s) perforated and used for the pilot test in each well. The well-specific plan will include: 1) information on type, number, and placement of the proposed plugs; 2) type, grade, and quality of the cement(s) to be used; and, 3) the method that will be used to place the plugs. The plan will be submitted a minimum of 60 days in advance of well plugging for review and approval. In general, the program will be designed such that cement plugs are spotted to protect oil and gas resources, to prevent degradation of usable water sources, and to protect the surface.

Downhole pressure and temperature sensors will be installed in the Injection Well and the Observation Well when the tubing is installed, allowing for the monitoring of pressure and temperature during both the active injection phase and the subsequent falloff phase following secession of injection activity. The post-injection monitoring phase may last several months to allow the injected CO_2 plume to stabilize and the injection interval to recover back to its natural condition. Since the decay in pressure in the Injection interval will be carefully monitored, no post-closure monitoring is planned.

Q.1.1 Temporary Well Abandonment Procedures

After the completion of the pilot test, the wells will be actively monitored for a minimum period of 6 months, to allow the injected CO_2 plume to stabilize and the injection interval to recover back to its natural condition and then they will be temporarily abandoned. The temporary abandonment procedures shall follow the requirements outlined under California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) Onshore Well

Regulations for proper well abandonment (State of California, California Code of Regulations, Title 14 – Natural Resources, Division 2 – Department of Conservation, March 2007):

A. Notice of intent to plug will be made at least 60 days prior to planned closure. The following detailed information will be provided (EPA Form 7520-14) at that time:

1. Type and number of plugs.
2. Placement of each plug, including the elevation of both the top and bottom of the plug.
3. Type, grade, and quantity of the plugging material and additives to be used.
4. Method used to place plugs in hole.
5. Procedure used to temporarily abandon the well.

B. Temporary Abandonment operations for the pilot well(s) will, at a minimum, be conducted as follows (see Figure Q-1):

1. Move workover rig onto location.
2. Kill well with appropriate fluid to overbalance the formation Remove wellhead and nipple up blow out preventers.
3. Pull injection tubing, injection packer(s), and downhole instrumentation from the well.
4. Run in the well open-ended and circulate the well with kill fluid for the temporary.
5. Set a cement retainer above the perforated zone and squeeze off perforations with cement. Release from cement retainer and reverse circulate any excess cement from the well. Pressure test against the cement retainer and casing to confirm closure/seal of the perforations.
6. Run in well open-ended and place a cement plug from the top of the retainer to ensure that all flow paths are closed off. The cement plug will extend at least 200 feet above the top of the retainer.
7. Allow cement to set and tag top of plug to verify depth. Following tagging of plug top, pressure up on the plug to 1,000 psi for at least 30 minutes in order to verify integrity of the protection casing and the cement plug. Record and

8. Run in hole and set a retrievable bridge plug 10 feet above the top of the cement plug.
9. Displace hole completely with appropriate fluid sufficient to over balance the formation by at least 150 psi.
10. Pull out of hole and leave a minimum 1,000 feet (exact footage will depend on pressures observed during the pilot test) of kill string in the hole.
11. Close all wellhead valves and install pressure gauges for monitoring of both the "A" and "B" annulus.

A temporary abandonment report will be filed with the EPA and DOGGR within 30 days after completion of operations.

Q.1.2 Final Abandonment and Plugging Procedures

At the end of field life, the Injection and the Observation Wells will be completely abandoned and decommissioned. The general procedures for well closure are described below and may be modified prior to performing field operations according to the direction of the EPA and/or DOGGR:

A. Notice of intent to plug will be made at least 60 days prior to planned closure. The following detailed information will be provided (EPA Form 7520-14) at that time:

1. Type and number of plugs.
2. Placement of each plug, including the elevation of both the top and bottom of the plug.
3. Type, grade, and quantity of the plugging material and additives to be used.
4. Method used to place plugs in hole.
5. Procedure used to plug and abandon the well.
6. Any information on newly constructed or discovered wells, or additional well data, within the Area of Review.

B. Plugging operations for the pilot well(s) will, at a minimum, be conducted as follows (Figure Q-1):

1. Move workover rig onto location.
2. Kill well with appropriate fluid to overbalance the formation. Remove wellhead and nipple up blow out preventers.
3. Pull injection tubing, injection packer(s), and downhole instrumentation from the well.
4. Run in the well open-ended and displace the well with plugging mud for the permanent abandonment. Per State of California, California Code of Regulations, Title 14, Division 2, Chapter 4, Article 3, 1732 (b) [March 2007], the plugging mud must be of sufficient density and consistency to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling that interval and prevent movement of fluids into the wellbore.
5. Set a cement retainer above the perforated zone and squeeze off perforations with cement. Release from cement retainer and reverse circulate any excess cement from the well. Pressure test against the cement retainer and casing to confirm closure/seal of the perforations.
6. Run in well open-ended and place a cement plug from the top of the retainer to ensure that all flow paths are closed off. The cement plug will extend at least 200 feet above the top of the retainer.
7. Allow cement to set and tag top of plug to verify depth. Following tagging of plug top, pressure up on the plug to 1,000 psi for at least 30 minutes in order to verify integrity of the protection casing and the cement plug. Record and chart the pressure test. Note EPA and DOGGR may witness the casing/cement pressure test.
8. Spot a high-viscosity pill below the freshwater-saltwater interface (at surface casing shoe). Place a 200 foot cement plug across the freshwater-saltwater interface (surface casing shoe). Wait on cement to set and tag top of cement to confirm depth.
9. Final cement plug at surface should be at least 200 feet in length, measured below the intended casing cut-off point (or as close as practical). All

uncemented casing annuli should also be plugged with cement or removed to a depth below the intended surface plug.

10. Cut off casing five to ten feet below ground surface (or depth as designated by the surface owner with approval of the Director) and fill any and all open annular spaces with cement.
11. Weld steel plate on top of the cut casing around the circumfrence of the casing. Plate is to be at least as thick as the outer well casing and inscribed with the well identification (last five digits of the assigned API well number).

An abandonment and plugging report will be filed with the EPA and DOGGR within 30 days after completion of operations.

Q.1.3 General Well Abandonment and Plugging – Unsuitable Well

In the event that the data from the Injection Well drilling indicates that the site is unsuitable for the pilot test, the well will be abandoned following the completion of the open-hole evaluation program, prior to moving the drilling rig off of location.

A. Abandonment and plugging operations for the well will, at a minimum, be conducted as follows:

1. Pull evaluation equipment from the well.
2. Run in the hole open ended and place a cement plug from at least 50 feet below the intermediate casing shoe to at least 50 feet above the intermediate casing shoe.
3. Allow cement to set and tag top of plug to verify depth. Wait on cement to set and tag top of cement to confirm depth. Following tagging of plug top, pressure up on the plug to 1,000 psi for at least 30 minutes in order to verify integrity of the cement plug. Record and chart the pressure test. Note EPA and DOGGR may witness the casing/cement pressure test.
4. Spot a high-viscosity pill below the freshwater-saltwater interface (surface casing shoe). Place a minimum 100 foot cement plug across the freshwater-saltwater interface in the intermediate casing. Wait on cement to set and tag

top of cement to confirm depth. Wait on cement to set and tag top of cement to confirm depth.

5. Final cement plug at surface should be at least 25 feet in length, measured below the intended casing cut-off point. All uncemented casing annuli should also be plugged with cement or removed to a depth below the intended surface plug.
6. Cut off casing five to ten feet below ground surface (or depth as designated by the surface owner with approval of the Director) and fill any and all open annular spaces with cement.
7. Weld steel plate on top of the cut casing around the circumfrence of the casing. Plate is to be at least as thick as the outer well casing and inscribed with the well identification (last five digits of the assigned API well number).

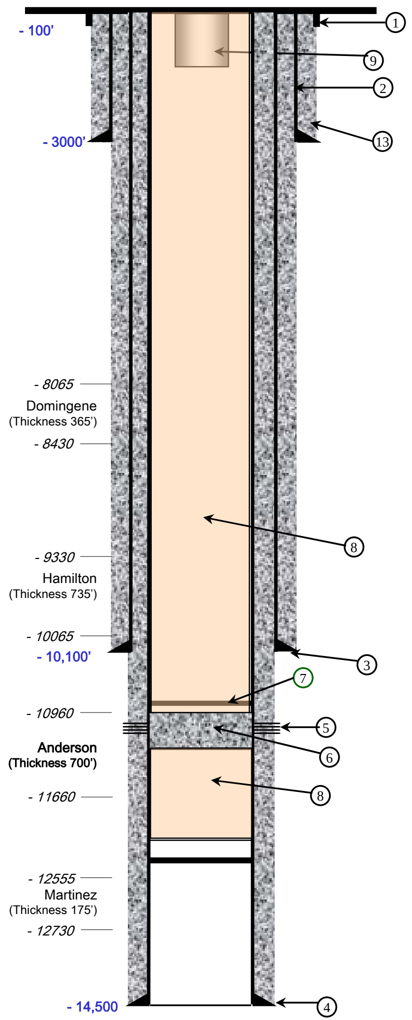
A plugging report will be filed with the EPA and DOGGR within 30 days after completion of operations

SHELL – CO_2 Pilot Injection Well Plugging and Abandonment Plans

INJECTION WELL

INJECTION WELL

TEMPORARY ABANDONMENT



NOTE: Abandonment procedures for the Monitor Well are similar

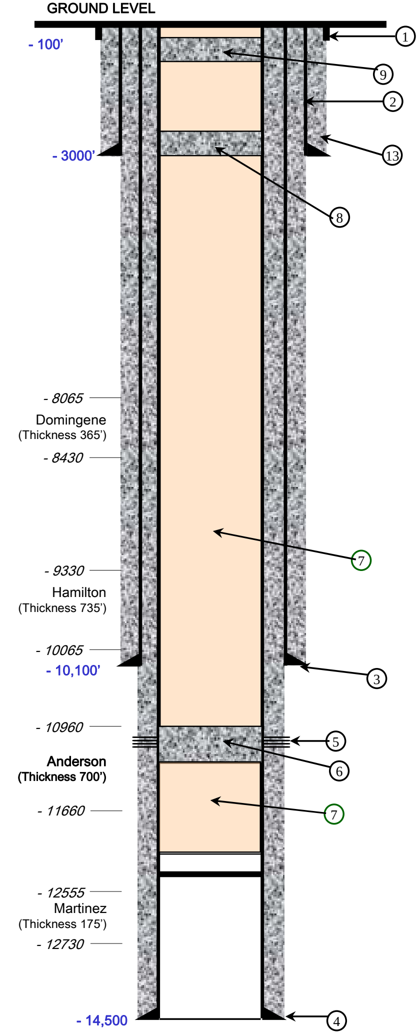
All depths reference RKB
RKB = 25' above GL (est.)
GL= 79.7'

SCHEMATIC DESCRIPTION

1) Conductor casing 20", set to 100'
2) Surface casing 13-3/8", set to 3,000'
3) Intermediate casing 9-5/8", set to 10,100' (below the Hamilton)
4) Production casing 7", set to TD
5) Perforations (55')
6) Cement plug across perforations (~300' long with top of cement minimum of 200' above the top perforation)
7) Retrievable bridge plug
8) Kill fluid (>formation pressure)
9) Minimum 1000' kill string

INJECTION WELL

PERMANENT ABANDONMENT



NOTE: Abandonment procedures for the Monitor Well are similar

All depths reference RKB
RKB = 25' above GL (est.)
GL= 79.7'

SCHEMATIC DESCRIPTION

1) Conductor casing 20", set to 100'
2) Surface casing 13-3/8", set to 3,000'
3) Intermediate casing 9-5/8", set to 10,100' (below the Hamilton)
4) Production casing 7", set to TD
5) Perforations (55')
6) Cement plug across perforations (~300' long with top of cement minimum of 200' above the top perforation)
7) Kill fluid (>formation pressure) with properties meeting any applicable Ca DOGGR requirements
8) Minimum 200' long cement plug across freshwater-saltwater interface
9) Minimum 200' long surface plug just below casing cut-off point

Drawing not to scale

Project Description: SHELL CCS Project – CO_2 Pilot Injection Well with abandonment details	Figure Q-1 Well Schematic for the Injection Well		Illustration by: KDF	Date: 3/23/10

ATTACHMENT R NECESSARY RESOURCES

C6 Resources, LLC estimates a plugging cost of $417,000 per well (rounded to nearest $1,000), as shown in Table R-1.

Table R-1 Well Plugging Cost Estimate

	DESCRIPTION OF OPERATIONS	UNIT	UNIT/DAYS	COST PER UNIT	TOTAL COST
1	Workover Rig Mobilization	1	1	50000	$50,000
2	Rig Day Rate	1	10	12000	$120,000
3	Rig Rental Tools	1	10	2000	$20,000
4	BOP rental	1	10	600	$6,000
5	Cement Retainer	2	1	3000	$6,000
6	Cement Retainer Service hand	1	5	800	$4,000
7	Drilling/Completion Fluid	1000	1	30	$30,000
8	Drilling/Completion Fluid Services	1	8	800	$6,400
9	Cement and Additives	2	1	5000	$10,000
10	Cement Services	3	3	800	$7,200
11	Welding/Casing Cutting	1	1	5000	$5,000
12	Logistics	1	1	15000	$15,000
13	Location clean up/ waste disposal	1	1	15000	$15,000
14	Consultant Fees - Planning	1	5	1200	$6,000
15	Consultant Fees - Site Supervision	1	10	1200	$12,000
16	Workover Rig De-Mobilization	1	1	50000	$50,000
	WELL ABANDONMENT OPERATIONS COST				**$362,600**
	Contingency 15%				**$54,390**
	TOTAL WELL ABANDONMENT OPERATIONS COST PER WELL				**$416,990**
	TOTAL WELL ABANDONMENT OPERATIONS COST FOR 2 WELLS				**$833,980**

The cost estimate follows the plugging procedure proposed in Attachment Q, which is consistent with California Department of Conservation, Division of Oil, Gas, and Geothermal Resources rules for onshore well abandonment.

As owner of the wells, C6 Resources, LLC will post a bond for well closure prior to initiation of field activities through:

Marsh USA Inc.

1000 Main St., Suite #3000

Houston, TX 77002

.